August 28th, 2017

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

RE: Essex Powerlines Corporation 2018 Cost of Service Application
Board File Number: EB-2017-0039

Dear Ms. Walli,

Please find attached to this letter a digital copy of the Essex Powerlines Corporation ("EPLC") Cost of Service Application for Electricity Distribution Rates and Charges (the "Application") commencing May 1st, 2018.

EPLC has also included the excel models that EPLC is required to file in live format:

- Cost of Service Checklist;
- Chapter 2 Appendices;
- PILs Model;
- Revenue Requirement Workform;
- Cost Allocation Model;
- RTSR Model;
- Deferral & Variance Account Continuity Schedule;
- Lost Revenue Adjustment Mechanism Variance Account Workform;

Two (2) hard copies of the Application have also been filed with the Board.

We ask that all correspondence and orders pertaining to this proceeding be delivered to the following individuals:

Ms. Lindsay Thiessen
Manager of Regulatory Accounting
Essex Powerlines Corporation
2730 Highway #3
Oldcastle, ON, N0R 1L0
Telephone: 519-737-9811 x158
Email: lthiessen@essexpowerlines.ca

Mr. Scott Stoll
Aird & Berlis LLP.
181 Bay Street, Suite 1800, Box 754
Toronto, ON, M5J 2T9
Telephone: 416-865-4703
Email: sstoll@airdberlis.com

If you have any questions or concerns whatsoever, please do not hesitate to contact me anytime.

Yours truly,

[Original Signed By]

Joe Barile
General Manager
Essex Powerlines Corporation

Cc: Mr. Khalil Viraney, Ontario Energy Board
Mr. Kristopher Taylor, Essex Power Corporation
Mr. Raymond Tracey, Essex Power Corporation
Ms. Lindsay Thiessen, EPLC

Exhibit 1: Administration

Table of Contents

List of Attachments

1-A. Certification of Evidence

1-B. 2017 Cost of Service Filing Checklist

1-C. EPLC Service Territory Maps

1-D Green Energy Act Plan

1-E. EPLC Scorecards

1-F. Customer Engagement Activities Summary

1-G. Customer Engagement Studies (Convergys & Innovative)

1-H. Audited Financial Statements (2010-2016)

1-I. Reconciliation of Audited Financial Statements to RRR Trial Balances

1-J. EPC Annual Reports (2015-2016)

1-K. Corporate Governance Documentation

1-L. Unanimous Shareholder Agreement – Article III

1-M. MIFRS Transition Summary Impact

1.1 Application

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

AND IN THE MATTER OF an Application by Essex 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 1st, 2018.

("this Application")

Applicant's Name: Essex Powerlines Corporation

(the "Applicant" or "EPLC").

1.1.1 Certification of Evidence

For the EPLC Certification of Evidence, please refer to Attachment 1-A.

1.1.2 Filing Requirement Checklist

EPLC has completed the OEB's 2018 Cost of Service Filing Checklist. Please refer to Attachment 1-B.

1.2 A History of Essex Powerlines

1.2.1 Overview

Restructuring of the utility industry presented many challenges and opportunities when the *Investing in Ontario Act, 2008* (Bill 35) was passed. Existing public utility commissions had to evolve and become standard Ontario business corporations, owned by local municipalities that they served. The new corporations answered to the Ontario Energy Board ("OEB") and were responsible for regulatory, rate setting and licensing matters in the electricity market.

At that time, the four municipalities of Amherstburg, LaSalle, Leamington and Tecumseh made a strategic decision to pool the resources of their utilities together to avoid various costs of deregulation and to maximize efficiencies of scale.

On June 1, 2000, the Town of Amherstburg, LaSalle, Tecumseh and the Municipality of Leamington amalgamated their small utilities to form what is currently known as the Essex Power Group of Companies. The distribution assets, such as the wires were transferred to Essex Powerlines Corporation ("EPLC"). Essex Power Services Corporation ("EPSC") received the employees such as lineman and the billing clerks and Essex Power Corporation ("EPC") received the finance, analyst and management positions required to oversee the subsidiaries and provide administrative financial support.

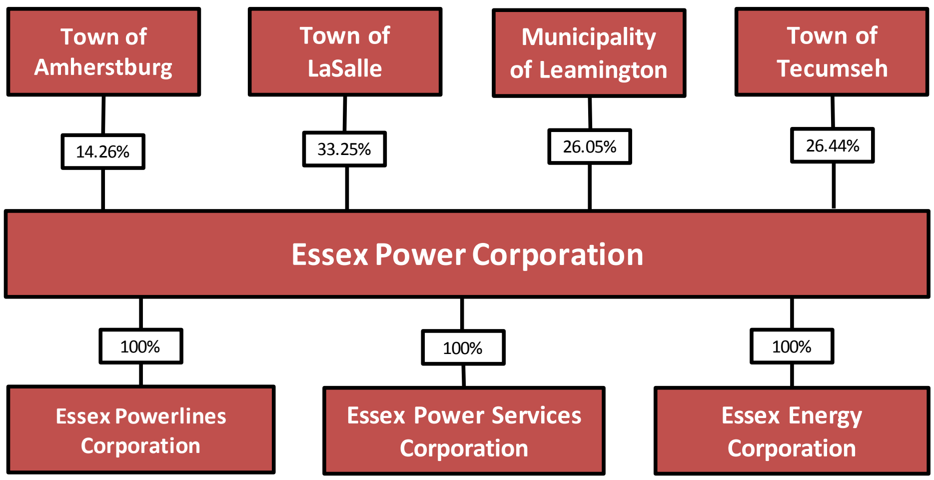
All administration from the four utilities was consolidated. Operations such as billing, collecting, finance, payroll and accounts payable were centralized in November 2000, administrative staff was located at the Essex County Civic Centre in Essex Ontario. Outside staff were moved to the Oldcastle service station in the spring of 2003. All staff were consolidated into the Oldcastle service station in 2012.

Today, Essex Powerlines Corporation strives to provide value to its now approximately 30,000 customers by minimizing outages and providing best in class customer service with increases to electricity distribution rates in-line with the rate of inflation. This Application will outline the various ways that EPLC is achieving these goals.

1.2.2 Corporate Entities

Figure 1 below illustrates EPLC's corporate structure and its relationship with its four respective shareholders.

Figure 1 – Essex Power Corporate Structure



Essex Power Corporation is owned by four municipally owned shareholders; the Town of Amherstburg (14.26%), the Town of LaSalle (33.25%), the Municipality of Leamington (26.06%) and the Town of Tecumseh (26.44%). While equity percentages differ for each shareholder, they each hold equal voting rights. Essex Power Corporation serves as the holding company for its subsidiary group of companies.

Essex Powerlines Corporation is a wholly owned subsidiary of Essex Power Corporation. EPLC is a licensed LDC (Distribution License ED-2002-0499) which distributes electricity to approximately 30,000 customers across its four shareholder communities.

Essex Power Services Corporation is a wholly owned unregulated subsidiary of Essex Power Corporation and aims to provide best in class municipal and LDC services such as streetlight maintenance, subdivision work and is also an IESO registered Meter Service Provider (MSP1034).

Essex Energy Corporation is a wholly owned unregulated subsidiary of Essex Power Corporation. Essex Energy Corporation ("EEC") is a dynamic energy technology company providing various services and technology related solutions to electrical utilities, generators, transmitters and consumers across North America.

1.3 Applicant Overview

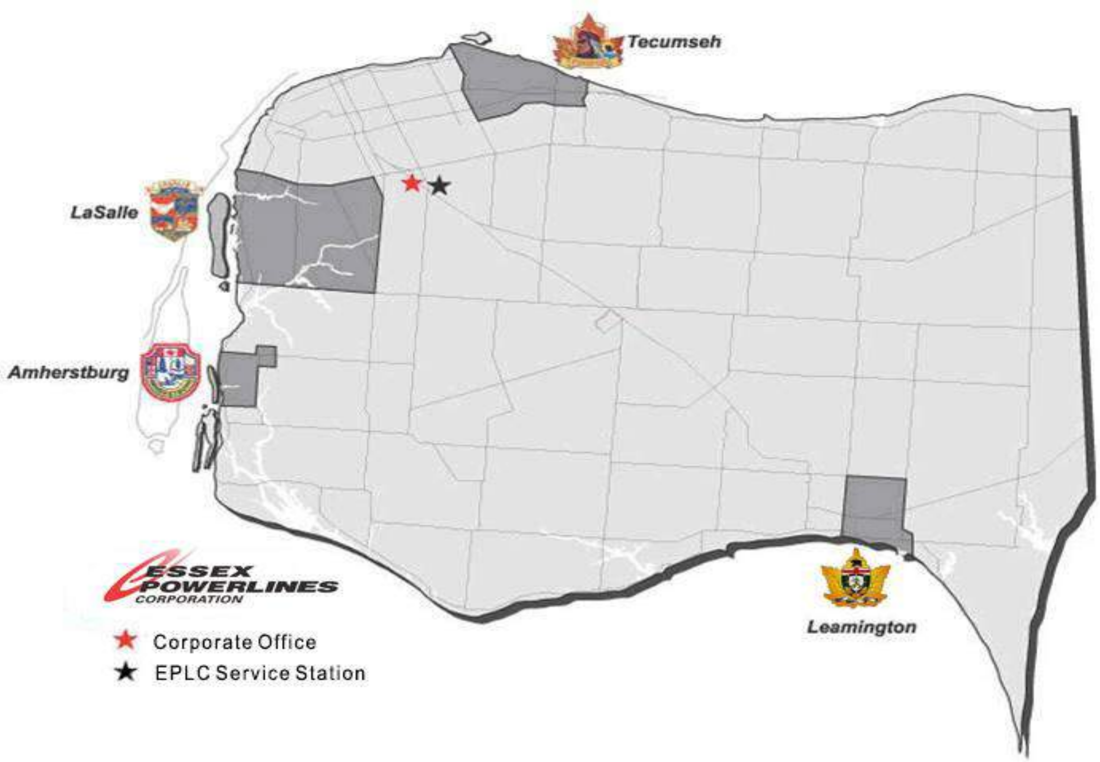
1.3.1 Overview of Service Area

EPLC services the four non-contiguous areas of its shareholder municipalities. EPLC services only portions of Amherstburg, Leamington and Tecumseh while it services the entire Town of LaSalle. EPLC's service territory is formally defined in Schedule 1 its OEB approved Distribution License (ED-2002-0499) as:

1. The Town of LaSalle as of June 1, 1991;
2. The Town of Amherstburg as of December 31, 1997;
3. The Town of Tecumseh and the Village of St. Clair Beach as of December 31, 1998;
4. The Town of Leamington as of December 31, 1998;

Figure 2 below is a map of EPLC's service territory as well as the locations of our EPC corporate office (200-2199 Blackacre Drive, Oldcastle, Ontario) and EPLC's service station (2730 Highway #3, Oldcastle, Ontario).

Figure 2 – EPLC Service Territory



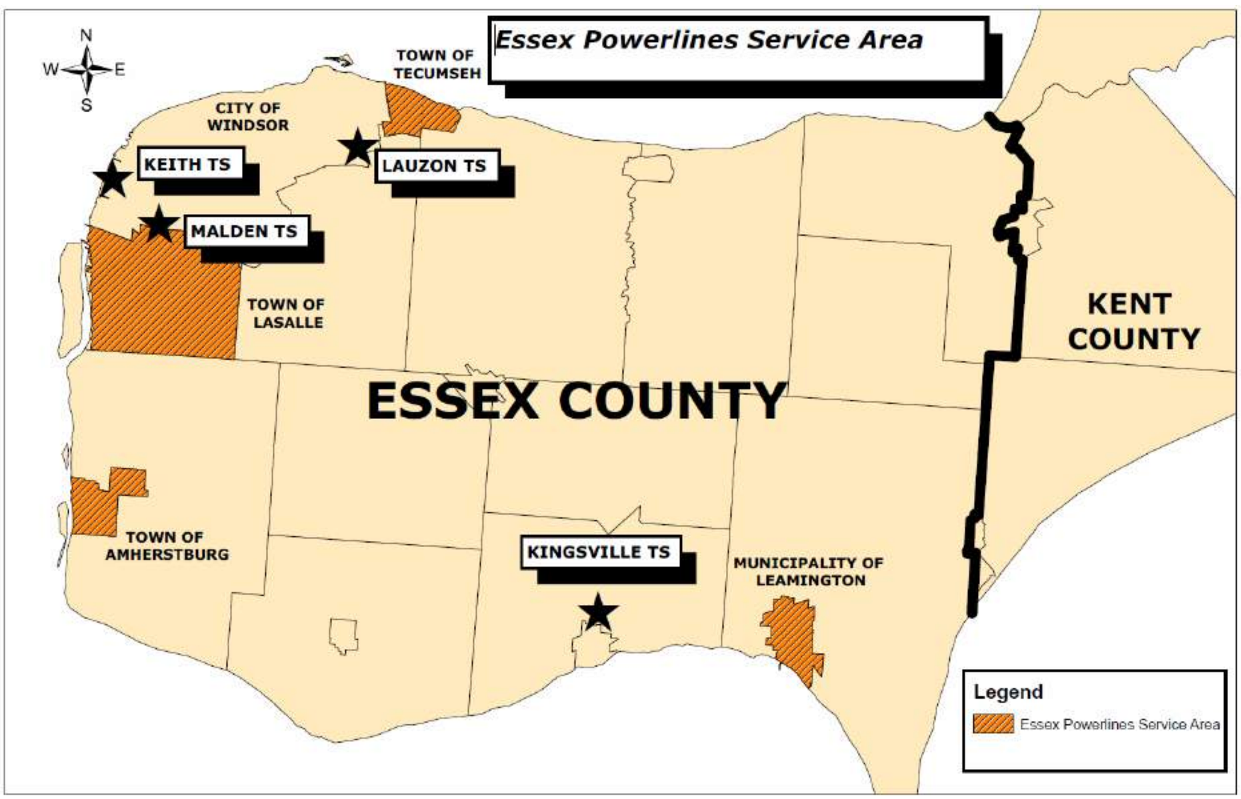
1.3.2 Identification of Embedded or Host Utilities

EPLC is wholly embedded in Hydro One Networks Inc's ("HONI") distribution system. EPLC is fed from four separate HONI transformer stations at 27.6 kV:

i) Keith TS (Services portions of LaSalle & Amherstburg);
ii) Kingsville TS (Services Leamington);
iii) Lauzon TS (Services Tecumseh);
iv) Malden TS (Services portions of LaSalle & Amherstburg);

Figure 3 below shows the geographic location of each transformer station.

Figure 3 – Transformer Station Locations



HONI borders all four of EPLC's service territories however Enwin Utilities Ltd also borders both Tecumseh to the west and LaSalle to the north.

HONI is also embedded in EPLC's service territories in the Town of Amherstburg.

1.3.3 Transmission Assets

EPLC does not have any transmission or high voltage assets (>50kV) deemed previously by the Board as distribution assets and does not have any such assets for which EPLC is seeking Board approval to be deemed as distribution assets in this Application.

1.4 Management Discussion & Analysis

1.4.1 The Renewed Regulatory Framework for Electricity ("RRFE")

The OEB released the *"Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach"* on October 18th, 2012. Through the RRFE, the OEB determined that the four (4) following outcomes are appropriate for Ontario distributors:

i) **Customer Focus:** services are provided in a manner that responds to identified customer preferences;

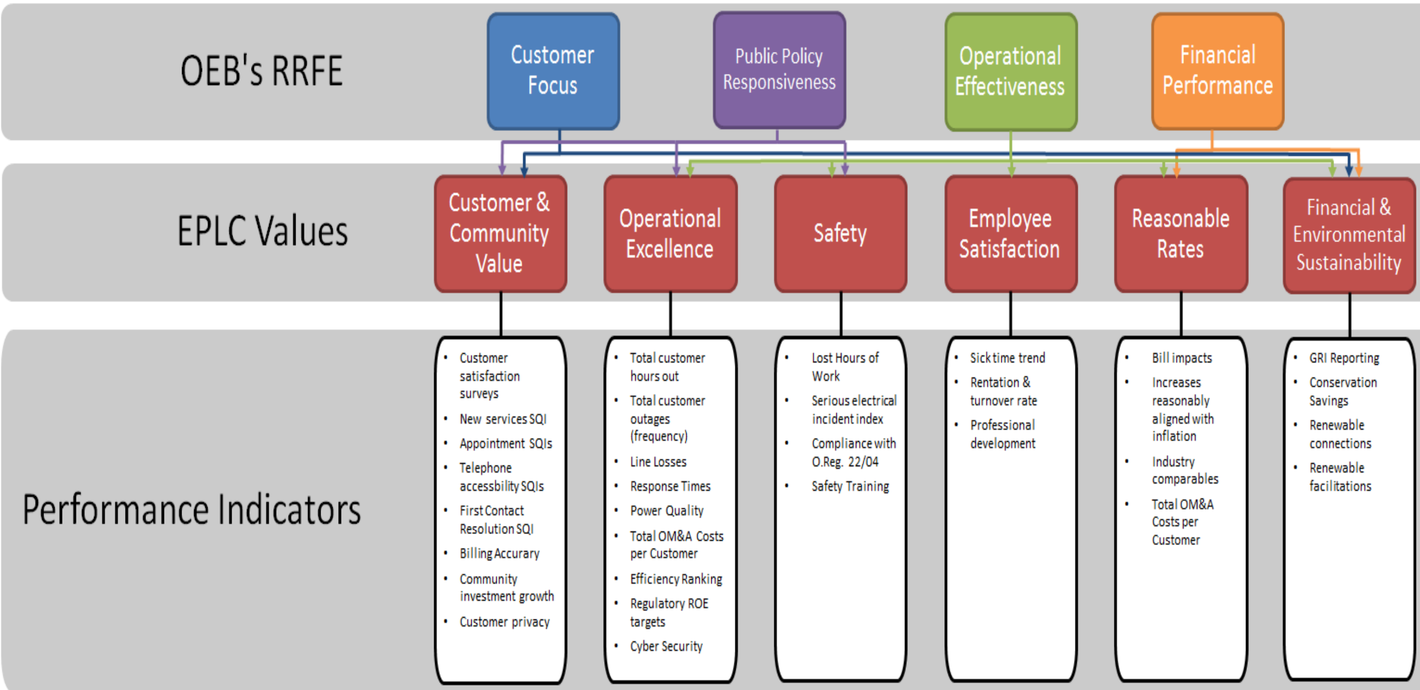
ii) **Public Policy Responsiveness:** utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board);

iii) **Operational Effectiveness:** continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;

iv) **Financial Performance:** financial viability is maintained; and savings from operational effectiveness are sustainable;

EPLC has striven to best align its corporate values with the OEB's four RRFE outcomes. Figure 4 below outlines how these outcomes align with EPLC values and the performance indicators that are used to monitor, track and enhance EPLC performance. EPLC's Values and its associated Performance indicators will be further described throughout this Application.

Figure 4 – EPLC's RRFE Value Alignment



1.4.2 Business Plan & Objectives

EPLC's business plan and objectives are currently centered around four (4) primary themes:

- Tying EPLC's key values with the RRFE;
- Deploying "Best-In-Class" solutions and technologies on common platforms with various channel partners;
- Standardizing to a common primary voltage class & assets;
- Developing and implementing a "Self-Healing Grid";

EPLC's mandate is to implement the items above, which will have material benefits for customers, all while maintaining reasonable distribution rates.

EPC's Mission & Vision Statement

EPC's mission and vision statements are presented below and are consistent across each of its affiliated companies:

Mission Statement:

Essex Power Corporation is a dynamic energy company that provides safe, reliable and economical energy supply and services to our customers. Our commitment to innovation, performance management and leading by example has built the foundation at Essex Power and our affiliates to establish a diverse set of energy products and services that are valued by our customers. At Essex Power, *"Your Power Is Our Priority"*.

Vision Statement:

Essex Power Corporation's vision is to be an Energy Provider that utilizes "best in class" people, processes, and technology to lead the market place in sustainable energy solutions. Our customers will receive the greatest value by integrating an economic and environmental balance to the products and services we will deliver to them. As an Energy Provider we will be a community leader in ensuring that environmental stewardship is a vital component of our services to increase customer awareness of proper energy utilization and management.

EPLC's Core Values & the RRFE

Customer & Community Value

Description of Value & Ties to RRFE: EPLC's core value of driving Customer & Community Value is defined as follows:

"EPLC is dedicated to meeting and exceeding customer & community needs by providing services that are cost effective and put the needs of its customers first."

This value can be tied to the OEB's RRFE outcomes of Customer Focus and Public Policy Responsiveness.

Examples of EPLC's commitment to this value can be demonstrated as follows:

- Customer Satisfaction Surveys;
- Conservation & Demand Management program participation;
- Investing back in each of four shareholder communities through various charitable organizations;
- Maintaining just and reasonable rates in line with inflation;

Key Performance Metrics & Historical Performance: The following outline the key performance indicators that are employed by EPLC for Customer & Community Value as well as historical performance to date since the measure has been tracked:

- **CUSTOMER SATISFACTION SURVEYS (SCORECARD MEASURE):**

Customer Satisfaction Surveys

2010	2011	2012	2013	2014	2015	2016
N/A	N/A	N/A	N/A	81.00%	81.00%	81.00%

Description of Metric: EPLC began tracking Customer Satisfaction in 2014 and has contracted third parties to complete telephone surveys related to their overall satisfaction with EPLC services. Further details on these surveys can be found in section 1.5 below.

Targets & Goals: While there is no industry standard for this metric, EPLC strives for continuous improvement in customer satisfaction over a period of time. EPLC's results to date can be found below.

- **NEW SERVICES SERVICE QUALITY INDICATOR (SCORECARD MEASURE):**

New Services Connected

2010	2011	2012	2013	2014	2015	2016
98.60%	98.30%	93.20%	92.70%	93.00%	92.30%	90.50%

Description of Metric: The Distribution System Code ("DSC") requires that all electricity distributors complete a connection for new service under 750 Volts within five business days at least 90% of the time.

Targets & Goals: EPLC's target is to maintain connections above the 90% target. EPLC has consistently performed above industry standard for the seven year period as shown below.

- **APPOINTMENT SERVICE QUALITY INDICATORS (SCORECARD MEASURE):**

Appointments Scheduled

2010	2011	2012	2013	2014	2015	2016
97.73%	96.95%	96.83%	96.49%	95.55%	98.52%	98.78%

Description of Metric: The DSC requires that all electricity distributors shall schedule an appointment to take place within 5 business days of the day on which all applicable service conditions are satisfied or on such later date as may be agreed upon by the customer at least 90% of the time.

Targets & Goals: EPLC's target is to maintain appointments schedule above the 90% target. EPLC has consistently performed above industry standard for the seven year period as shown above.

Appointments Met

2010	2011	2012	2013	2014	2015	2016
94.90%	95.50%	95.70%	94.30%	94.70%	94.80%	90.80%

Description of Metric: The DSC requires that where requested, all electricity distributors must offer to schedule a meeting within a window of time that is no greater than four hours and the distributor must arrive for the appointment within the scheduled timeframe at least 90% of the time.

Targets & Goals: EPLC's target is to maintain appointments met above the 90% target. EPLC has consistently performed above industry standard for the seven year period as shown above.

Appointments Rescheduled

2010	2011	2012	2013	2014	2015	2016
100%	100%	100%	100%	100%	100%	100%

Description of Metric: The DSC requires that all electricity distributors that miss an appointment as described in the two prior metrics, must attempt to contact the customer affected and reschedule the missed appointment within one business day 100% of the time.

Targets & Goals: EPLC's target is to maintain rescheduled at the 100% target. EPLC has consistently performed at the industry standard for the seven year period as shown above.

- **Telephone Accessibility Service Quality Indicators (Scorecard Measure):**

Telephone Accessibility

2010	2011	2012	2013	2014	2015	2016
70.60%	67.00%	68.50%	66.40%	78.00%	79.20%	73.60%

Description of Metric: The DSC requires that all electricity distributors must answer qualified customer care calls within 30 seconds at least 65% of the time.

Targets & Goals: EPLC's target is to maintain responding to customer care calls above the 65% threshold established by the Board. EPLC has consistently performed above industry standard for the seven year period as shown above.

Telephone Call Abandon Rate

2010	2011	2012	2013	2014	2015	2016
4.92%	5.79%	7.05%	1.65%	1.25%	1.42%	0.80%

Description of Metric: The DSC requires that no more than 10% of all qualified calls to an electricity distributor's customer care number are abandoned before they answered.

Targets & Goals: EPLC's target is to maintain responding to customer care calls as quickly as possible and with an Abandon Rate below 10%. EPLC has consistently performance above industry standard for the seven year period as shown above.

- **FIRST CONTACT RESOLUTION (SCORECARD MEASURE):**

First Contact Resolution

2010	2011	2012	2013	2014	2015	2016
N/A	N/A	N/A	N/A	99.60%	99.28%	98.25%

Description of Metric: EPLC began tracking First Contact Resolution in 2014. This metric measures the percentage of time that a customer's inquiry is resolved during its first contact with EPLC.

Targets & Goals: EPLC's goal is to improve its First Contact Resolution rates, year over year. To date, EPLC has performed well in this metric but will continue to implement process improvements and continue to continually monitor as the metric is relatively new.

- BILLING ACCURACY (SCORECARD MEASURE):

Billing Accuracy

2010	2011	2012	2013	2014	2015	2016
N/A	N/A	N/A	N/A	99.84%	98.05%	99.90%

Description of Metric: The DSC requires that an LDC must issue an accurate bill at least 98% of the time on a yearly basis. The metric is calculated by dividing the total number of inaccurate bills into the total number of bills issued.

Targets & Goals: EPLC's target is to meet the DSC target of 98% Billing Accuracy. Since implemented in 2014, EPLC has been compliant with this metric.

- CYBER SECURITY INCIDENTS (INTERNALLY DRIVEN MEASURE):

Cyber Security Incidents

2010	2011	2012	2013	2014	2015	2016
N/A	N/A	N/A	N/A	N/A	N/A	N/A

Description of Metric: With the recent introduction of the Proposed Cyber Security Framework ("CSF"), EPLC will be monitoring the total number of privacy related items that affect its customers moving forward.

Targets & Goals: EPLC's target is to maintain zero Cyber Security incidents per year. This is a new metric and EPLC does not have any relevant historical data to measure.

Operational Excellence

Description of Value & Ties to RRFE: EPLC's core value of delivering Operational Excellence is defined as follows:

"EPLC strives for Operational Excellence through all services that it provides by advocating continuous improvement and implementing Best-In-Class and cost effective solutions that deliver customer value."

This value can be tied to the OEB's RRFE outcomes of Operational Effectiveness and Public Policy Responsiveness.

Examples of EPLC's commitment to this value can be demonstrated as follows:

- Development of EPLC's Distribution System Plan ("DSP") as attached in Exhibit 2, Attachment 2-C;
- Implementing Best-In-Class Solutions & Shared Services (further described below);
- Facilitating the Self-Healing Grid (further described below);
- Progressing towards a Single Distribution Voltage (further described below);
- Successful and cost effective implementation of public policy initiatives such as Smart Meters, Time of Use Billing, Renewable Generation Connections and Facilitation, Conservation & Demand Management programs, etc;
- Maintaining just and reasonable rates in line with inflation;

Key Performance Metrics & Historical Performance: The following outline the key performance indicators that are employed by EPLC for its Operational Excellence Value as well as historical performance to date since the measure has been tracked:

- TOTAL AVERAGE CUSTOMER HOURS OUT (SCORECARD MEASURE):

Total Average Customers Hours Out

2010	2011	2012	2013	2014	2015	2016
6.738	5.289	4.53	5.37	3.82	2.23	2.54

Description of Metric: This metric tracks the average number of customer hours of interruption the average EPLC customer experiences in a given year. It is calculated by dividing the total number of customer hours of interruption by EPLC's number of total customers.

Targets & Goals: EPLC's target is to realize year over year reductions to customer outages and be within a 5 year historical average. EPLC has been able to reduce the number of customer hours of interruption over the course of the previous 3 years.

Total Average Customers Hours Out – No LoS

2010	2011	2012	2013	2014	2015	2016
4.481	1.773	0.89	2.24	1.16	1.34	0.63

Description of Metric: This metric tracks the average number of customer hours of interruption minus the number of customer hours relating to Loss of Supply ("LoS") from upstream HONI, which is outside of EPLC control. It is calculated by dividing the total number of customer hours of interruption (net of LoS events) by EPLC's number of total customers.

Targets & Goals: EPLC's target is to realize year over year reductions to customer outages and be within a 5 year historical average. EPLC has been able to reduce the number of customer hours of interruption over the course of the previous 3 years.

- TOTAL CUSTOMER OUTAGES - FREQUENCY (SCORECARD MEASURE):

Total Customer Outages – Frequency

2010	2011	2012	2013	2014	2015	2016
3.318	2.823	3.83	3.58	2.46	1.84	3.20

Description of Metric: This metric tracks the average number of customer interruptions (frequency) the average EPLC customer experiences in a given year. It is calculated by dividing the total number of customer interruptions by EPLC's number of total customers.

Targets & Goals: EPLC's target is to realize year over year reductions to outage frequency and be within a 5 year historical average. EPLC has been able to reduce the number of customer interruptions over the course of the previous 3 years.

Total Customer Outages – Frequency – No LoS

2010	2011	2012	2013	2014	2015	2016
1.631	0.912	0.61	1.12	0.66	0.83	0.50

Description of Metric: This metric tracks the average number of customer interruptions (frequency) minus the number of customer interruptions relating to Loss of Supply ("LoS") from upstream HONI, which is outside of EPLC control. It is calculated by dividing the total number of customer of interruptions (net of LoS events) by EPLC's number of total customers.

Targets & Goals: EPLC's target is to realize year over year reductions to outage frequency and be within a 5 year historical average. EPLC has been able to reduce the number of customer interruptions over the course of the previous 3 years.

- LINE LOSSES (INTERNALLY DRIVEN MEASURE):

Line Losses

2010	2011	2012	2013	2014	2015	2016
6.02%	6.02%	6.02%	6.02%	6.02%	6.02%	6.02%

Description of Metric: Line losses represent the electricity lost as a result of heat and transformation, in the transmission and distribution systems. Efficiency and savings in losses result in on-bill customer related savings and is a priority for EPLC.

Targets & Goals: EPLC's target is to slowly reduce electricity losses. While EPLC's Board Approved secondary losses have remained flat since 2010, as part of this Application, EPLC is reducing its losses by 2.47% resulting in significant customer related savings. For further information, please see Exhibit 2.

- OUTAGE RESPONSE TIMES (INTERNALLY DRIVEN MEASURE):

Outage Response Time (Hours)

2010	2011	2012	2013	2014	2015	2016
N/A	N/A	N/A	N/A	N/A	N/A	N/A

Description of Metric: This metric tracks the average response time where EPLC representatives arrive at the scene of an outage from the time it is initially contacted. EPLC has begun detailed tracking of this metric beginning in 2017.

Targets & Goals: EPLC's target is to realize year over year reductions to outage response time and at least remain within a 5 year historical average. EPLC aims to be able to demonstrate a downward trend in this metric between 2017 and 2020.

- **TOTAL OM&A COSTS PER CUSTOMER (INTERNALLY DRIVEN MEASURE):**

OM&A Costs per Customer

2010	2011	2012	2013	2014	2015	2016
$194.46	$197.44	$214.46	$212.94	$235.64	$235.45	N/A

Description of Metric: OM&A costs are one of the best ways that LDCs in Ontario can use to manage the electricity distribution rates that are charged to customers. EPLC tracks the OM&A Costs per Customer that are recorded in the Board's Yearbook of Electricity Distributors.

Targets & Goals: EPLC's target is to maintain reasonable year over year increases and be below (positively) the Ontario industry average. EPLC has performed consistently and well below (positively) the industry average.

- **EFFICIENCY RANKING (INTERNALLY DRIVEN MEASURE):**

Efficiency Ranking

2010	2011	2012	2013	2014	2015	2016
2 of 3	2 of 3	2 of 5	2 of 5	2 of 5	2 of 5	2 of 5

Description of Metric: The Board, through the Pacific Economics Group, regularly issues an efficiency ranking of electricity distributors in Ontario based on a statistical total cost benchmarking study. Under the previous methodology (2010/2011), EPLC ranked in category 2 of 3 (mid-range) whereas EPLC currently ranks in the second of five tiers (with tier 1 being the most efficient) based on a methodology change implemented by the Board in 2013.

Targets & Goals: EPLC's target is to maintain its current Efficiency Ranking (tier 2) and continue to realize actual costs below the Board's expected costs generated by the econometric model. EPLC is proud of its current Tier 2 status and plans to maintain its position as one of Ontario's most efficient distributors.

- **CYBER SECURITY INCIDENTS (INTERNALLY DRIVEN MEASURE):**

Cyber Security Incidents

2010	2011	2012	2013	2014	2015	2016
N/A	N/A	N/A	N/A	N/A	N/A	N/A

Description of Metric: With the recent introduction of the Proposed CSF, EPLC will be monitoring the total number of privacy related items that affect its customers moving forward.

Targets & Goals: EPLC's target is to maintain zero Cyber Security incidents per year. This is a new metric and EPLC does not have any relevant historical data to measure.

Safety

Description of Value & Ties to RRFE: EPLC's core value of advocating the importance of Safety across its entire operation can be defined as follows:

"EPLC is committed to a Safety First mentality across its entire operation."

This value can be tied to the OEB's RRFE outcomes of Operational Effectiveness and Public Policy Responsiveness.

Examples of EPLC's commitment to this value can be demonstrated as follows:

- Joint Health & Safety Committee ("JHSC");
- First Aid, CPR and defibrillator training;
- Specialized Safety Training;
- School Electrical Safety Awareness;
- Implementation of new technologies to make day to day operations safer and more efficient;

Key Performance Metrics & Historical Performance: The following outline the key performance indicators that are employed by EPLC for its Safety Value as well as historical performance to date since the measure has been tracked:

- Lost Hours of Work (Internally Driven Measure):

Lost Time (Hours)

2010	2011	2012	2013	2014	2015	2016
N/A	N/A	8.00	56.00	0.00	8.00	72.00

Description of Metric: Lost Time (Hours) occurs when an employee is injured while completing work for the employer and is then unable to complete their respective regular duties. EPLC measures Lost Time (Hours) through the Workplace Safety and Insurance Board statement of claim.

Targets & Goals: EPLC's goal is zero Lost Time (Hours) every year.

- SERIOUS ELECTRICAL INCIDENT INDEX (INTERNALLY DRIVEN MEASURE):

Serious Electrical Incidents Index – EPLC Employee

2010	2011	2012	2013	2014	2015	2016
0	0	0	0	0	0	0

Serious Electrical Incidents Index – 3rd Party

2010	2011	2012	2013	2014	2015	2016
7	3	2	4	7	3	2

Description of Metric: In collaboration with the Electrical Safety Authority ("ESA"), EPLC monitors the number of non-occupational Serious Electrical Incidents occurring on EPLC's distribution system.

Targets & Goals: EPLC's goal is zero Serious Electrical Incidents for both its staff and 3rd parties.

- COMPLIANCE WITH O.REG. 22/04 (SCORECARD MEASURE):

Compliance with O.Reg. 22/04

2010	2011	2012	2013	2014	2015	2016
C	C	NI	NC	C	NI	NC

Description of Metric: In collaboration with ESA, EPLC monitors its compliance with Ontario Regulation 22/04 ("O.Reg. 22/04"). O.Reg. 22/04 establishes specific safety standards for LDCs and specifically requires LDC's to receive approval of equipment, plans, specifications and inspection of construction prior to implementation. An independent consultant selected by ESA reviews EPLC compliance annually and results are presented in one of three outcomes (which are presented in the table above):

- *Non-Compliance ("NC"):* A substantial failure to comply with O.Reg. 22/04 or continuing failure to comply with a previously identified NI item;
- *Needs Improvement ("NI"):* A failure to comply with O.Reg. 22/04 or or non-pervasive failure to comply with adequate, established procedures for complying with O.Reg. 22/04;
-
- *Compliance ("C"):* Substantially meets the requirements of O.Reg. 22/04;

Targets & Goals: EPLC's goal is to be compliant every year with O.Reg. 22/04.

Employee Satisfaction

Description of Value & Ties to RRFE: EPLC's core value of driving Employee Satisfaction is defined as follows:

"EPLC is committed to encouraging and developing engaged and empowered employees."

This value can be tied to the OEB's RRFE outcomes of Operational Effectiveness.

Examples of EPLC's commitment to this value can be demonstrated as follows:

- Wellness Committee;
- Employee Assistance Program;
- Corporate Charity Events;
- Employee Recognition;
- Corporate Team Building Events;

Key Performance Metrics & Historical Performance: The following outline the key performance indicators that are employed by EPLC for Employee Satisfaction Value as well as historical performance to date since the measure has been tracked. EPLC is also evaluating options for additional metrics in the near future:

- SICK TIME TREND (INTERNALLY DRIVEN MEASURE):

Sick Time (Days Lost)

2010	2011	2012	2013	2014	2015	2016
N/A	↑	↑	↑	↓	↓	↑

Description of Metric: EPLC monitors the year over year average sick days and sick events per EPLC employee. EPLC assesses increases or decreases year over year to track overall sick time trends.

Targets & Goals: EPLC's sick time goal is to decrease sick time on a year over year basis and provide a safe and friendly workplace for all employees.

- RETENTION & TURNOVER RATES (INTERNALLY DRIVEN MEASURE):

Retention & Turnover

2010	2011	2012	2013	2014	2015	2016
2	3	4	2	3	5	4

Description of Metric: EPLC monitors the year over year turnover of both management and non-management staff to ensure continuity, reliability, safety of its workplace while also gauging overall happiness of EPLC employees.

Targets & Goals: EPLC's target is to maintain consistent staffing levels and ensure EPLC employees have a safe and friendly workplace. The majority of EPLC's historical turnover presented above is directly related to retirements.

- PROFESSIONAL DEVELOPMENT (INTERNALLY DRIVEN MEASURE):

2010	2011	2012	2013	2014	2015	2016
N/A	N/A	N/A	N/A	N/A	N/A	N/A

Description of Metric: Professional Development is a new metric that EPLC has begun tracking in 2017 and aims to provide EPLC employees with an opportunity to increase their overall learning opportunities whether by attending formal classes, conferences, industry trade shows, etc.

Targets & Goals: EPLC has not yet established a target for this metric however EPLC aims to be able to demonstrate an upward trend and employee adoption between 2017 and 2020.

Reasonable Rates

Description of Value & Ties to RRFE: EPLC's core value of maintaining Reasonable Rates is defined as follows:

"EPLC will implement Best-In-Class technologies and solutions to provide our employees with the necessary information to make prudent decisions, control costs and minimize interruptions while providing reasonable rates for our electricity customers."

This value can be tied to the OEB's RRFE outcomes of Operational Effectiveness and Financial Performance.

Examples of EPLC's commitment to this value can be demonstrated as follows:

- Maintaining just and reasonable rates, generally in line with inflation;
- Prudent Investments in Smart Grid (see Exhibit 2, Attachment 2-C);
- Controllable Costs per Customer in line with leaders in Ontario;

Key Performance Metrics & Historical Performance: The following outline the key performance indicators that are employed by EPLC in order to maintain its Reasonable Rates Value as well as historical performance to date since the measure has been tracked:

- DISTRIBUTION RATE IMPACTS (INTERNALLY DRIVEN MEASURE):

Distribution Rate Impacts

2010	2011	2012	2013	2014	2015	2016
N/A	0.18%	0.88%	0.05%	1.55%	0.00%	1.95%

Description of Metric: EPLC monitors the year over year Distribution Charge (volumetric and fixed) changes to its customers to insure impacts are manageable for customers and not generally unreasonable.

Targets & Goals: EPLC's target is to maintain just and reasonable rates for its customers that, where possible, are aligned with the rate of inflation.

- INCREASES REASONABLY ALIGNED WITH INFLATION (INTERNALLY DRIVEN MEASURE):

Distribution Rate Impacts Aligned with Inflation

2010	2011	2012	2013	2014	2015	2016
N/A	-2.910%	-1.332%	-0.942%	-0.810%	-1.190%	0.140%

Description of Metric: EPLC monitors the year over year Distribution Charge (volumetric and fixed) changes to its customers to insure impacts are manageable for customers and not generally unreasonable. EPLC then subtracts the year over year change to Ontario's Consumer Price Index for all items (intended to reflect estimated inflation rate). If the resulting value is positive, EPLC's rates have outpaced the rate of inflation. If the resulting value is negative, EPLC's rates have not kept up with the rate of inflation.

Targets & Goals: EPLC's target is to maintain just and reasonable rates for its customers that, where possible, are aligned with the rate of inflation.

- INDUSTRY COMPARABILITY – OM&A RANK (INTERNALLY DRIVEN MEASURE):

Industry Comparability – OM&A Rank

2010	2011	2012	2013	2014	2015	2016
18th	12th	10th	8th	13th	16th	N/A

Description of Metric: OM&A costs are one of the best ways that LDCs in Ontario can use to manage the electricity distribution rates that are charged to customers. EPLC tracks the OM&A Costs per Customer that are recorded in the Board's Yearbook of Electricity Distributors and sorts them from lowest to highest. EPLC then records its appropriate ranking.

Targets & Goals: EPLC's target is to maintain its current position which is currently below (positively) the Ontario industry average. EPLC has performed consistently and well below (positively) the industry average.

- **TOTAL OM&A COSTS PER CUSTOMER (INTERNALLY DRIVEN MEASURE):**

OM&A Costs per Customer

2010	2011	2012	2013	2014	2015	2016
$194.46	$197.44	$214.46	$212.94	$235.64	$235.45	N/A

Description of Metric: OM&A costs are one of the best ways that LDCs in Ontario can use to manage the electricity distribution rates that are charged to customers. EPLC tracks the OM&A Costs per Customer that are recorded in the Board's Yearbook of Electricity Distributors.

Targets & Goals: EPLC's target is to maintain reasonable year over year increases and be below (positively) the Ontario industry average. EPLC has performed consistently and well below (positively) the industry average.

Financial & Environmental Sustainability

Description of Value & Ties to RRFE: EPLC's core value of championing Financial & Environmental Sustainability is defined as follows:

"EPLC strives to achieve balanced economic, social and environmental returns that ensure the future viability of our company for the benefit and well-being of our shareholders and the communities we serve."

This value can be tied to the OEB's RRFE outcomes of Operational Effectiveness, Customer Focus and Financial Performance.

Examples of EPLC's commitment to this value can be demonstrated as follows:

- Yearly Global Reporting Initiative ("GRI") Reporting;
- Conservation & Demand Management program participation;
- Renewable Energy Facilitations;
- Maintaining just and reasonable rates in line with inflation;

Key Performance Metrics & Historical Performance: The following outline the key performance indicators that are employed by EPLC in order to monitor and grow its Financial & Environmental Sustainability Value as well as historical performance to date since the measure has been tracked:

- **GRI REPORTING PROGRESS (INTERNALLY DRIVEN MEASURE):**

GRI Reporting Progress

2010	2011	2012	2013	2014	2015	2016
N/A	N/A	C	C	C	B	B

Description of Metric: The Global Reporting Initiative ("GRI") is an independent organization that has established international sustainability Standards for business based on their respective economic, environmental and social impacts. EPLC has filed sustainability reports through GRI since 2012. For additional information, please see EPLC's sustainability reports included as Attachment 1-J.

Targets & Goals: EPLC's target is realize year over year improvements in our filing obligations and reaching enhanced and more stringent standards. EPLC was successful in reaching a "B" status in 2015 and is assessing new GRI requirements and standards in to 2017.

- **CONSERVATION & DEMAND MANAGEMENT SAVINGS & RESULTS (DISTRIBUTION LICENSE DRIVEN MEASURE):**

Conservation & Demand Management Savings & Results

2010	2011	2012	2013	2014	2015	2016
N/A	9.77%	30.23%	61.40%	108.00%	12.05%	N/A

Description of Metric: In 2010, the Board amended EPLC's Distribution License to require EPLC to achieve specific Conservation & Demand Management savings targets. EPLC has diligently tracked its progress to target throughout the previous 2011-2014 and current 2015-2020 Conservation & Demand Management frameworks.

Targets & Goals: EPLC's target is to meet its mandated conservation & demand management goals established in cooperation with the IESO. EPLC successfully met and exceeded its consumption target during the 2011-2014 framework and is on its way to meeting its 2015-2020 goals.

- **Renewable Connections (Internally Driven Measure):**

Renewable Connections

2010	2011	2012	2013	2014	2015	2016
9	27	40	31	13	12	22

Description of Metric: The DSC requires LDC's to connect renewable generation that meet specific requirements to its distribution system that reasonably. In the spirit of the Green Energy Act and provincial policy, EPLC established this measure to track renewable connections to its distribution system and ensure that all was being done to facilitate connections for renewable generators.

Targets & Goals: EPLC's target is to facilitate the connection of as much renewable generation as the system will safely allow. To date, EPLC has yet to refuse the connection of a renewable generator that has reasonably requested access to EPLC's distribution system.

- **Regulated ROE Targets (Scorecard Measure):**

Regulated ROE

2010	2011	2012	2013	2014	2015	2016
N/A	N/A	N/A	N/A	N/A	11.58%	7.25%

Description of Metric: The Board requires that Distributors remain within a 3% maximum deadband of its deemed ROE or that Distributor would likely be required to file a Cost of Service Application with the Board as soon as possible. EPLC has been monitoring its actual ROE formally since 2015.

Targets & Goals: EPLC's target is to maintain its Regulated ROE within the 3% maximum deadband of EPLC's deemed ROE of 9.85% prescribed by the Board. EPLC has been within this deadband since tracking of this statistic formally began in 2015.

Best-In-Class Solutions & Shared Services

EPLC has worked closely with a variety of service providers to maximize the scope and quality of services rendered to customers. One such example of a Best-In-Class technology deployment was in 2012. EPLC has partnered with its sister company Essex Energy Corporation ("EEC") and were successfully awarded Smart Grid Fund ("SGF") funding to demonstrate the capabilities and functionality of a new software product called SmartMAP.

The SmartMAP product provides many cost effective advantages for small and medium sized distributors that utilizes smart meter data as its primary source of information. SmartMAP aims to enhance the Operations, Engineering and Customer Service departments in the effective management of renewable generation integration, outage identification & restoration, and an overall faster, more efficient and cost effective decision making tool.

The implementation of SmartMAP has enabled:

- Integration of existing smart meters with the Outage Management System to transmit "last gasp" data in real time, allowing the analysis component to pinpoint exact outage locations, predict causes, and suggest switching changes to restore power faster;
- Transformer loading profile (kWh vs. time of day, kVA vs. time of day) aiding in identification of under or overloaded assets;
- Reporting of line losses from wholesale meters, transformers and residential meters;
- Identification and locating of low voltage conditions which could be signs of failing equipment or wrong transformer tap settings;
- Reconciling of loads connected to each transformer to assist in identifying non-technical losses;
- Web application available to operations personnel so reporting and problem solving is made quicker and easier;
- Ability to send critical alarms and messages about the network to a cellular phone through the use of email or SMS;
- Visual monitoring of real time operational data from field devices (fault/line monitors, automated reclosers or switches, and any other field device capable of providing real time feedback) on a graphic display;
- A common platform for data and analysis that can be utilized by different LDCs across any geography;

EPLC, along with its partner Collus Powerstream, was recently awarded the Innovation Excellence Award by the Electricity Distributors Association for the joint "Digital Grid 2.0" project which featured the SmartMAP product.

Essex Powerlines – An Efficient Single Voltage Utility

For more than a decade now, EPLC has made it a priority to complete the necessary conversion work to simplify its distribution system, reduce inventory, shrink maintenance costs and reduce its distribution losses for the benefit of EPLC's customers. While EPLC generally only controls approximately 20% of the total electricity bill (ie distribution charges), reducing losses has been a key focus at EPLC since distribution losses affect a broader portion of the electricity bill.

EPLC has eliminated eight (8) substations (with the last one coming out of service in 2015) and converted significant lengths of line to become as close to a single voltage utility as technically possible. EPLC still has a small number of step down transformers in remote areas however, EPLC plans to convert them when most technically and financially feasible.

As a result of this work, EPLC has been able to significantly reduce distribution losses throughout its distribution system resulting in significant savings for our customers. More information about the conversion work can be found in EPLC's DSP as attached in Exhibit 2, Attachment 2-C. The rate impacts resulting from the conversion work are further outlined in Exhibit 8 of this Application however the impacts to EPLC's secondary loss factor are summarized in Figure 5 below.

Figure 5 – EPLC Conversion Results

Line Loss Category	2017 (Actual)	2018 (Proposed)	Variance
Secondary Metered Customer	1.0602	1.0355	-0.0247
Primary Metered Customer	1.0496	1.0251	-0.0245

Figure 6 below shows the resulting bill impacts from EPLC's loss factor reduction which are significant and affect many non-distribution portions of the bill.

Figure 6 – EPLC Loss Factor Bill Impacts

Rate Class	kWh	kW	2017 BAP Rates	2018 Proposed Rates	$ Increase (Decrease)	% Increase (Decrease)
Residential	750	-	$ 126.61	$ 126.10	$ (0.51)	-0.40%
General Service Less Than 50 kW	2,000	-	$ 322.06	$ 319.92	$ (2.14)	-0.66%
General Service 50 to 4,999 kW	40,000	100	$ 6,600.60	$ 6,209.96	$ (390.64)	-5.92%
Unmetered Scattered Load	700	-	$ 139.72	$ 130.22	$ (9.50)	-6.80%
Sentinel Lighting	36	0.1	$ 10.34	$ 9.94	$ (0.39)	-3.81%
Street Lighting	36	0.1	$ 10.09	$ 9.99	$ (0.11)	-1.07%
Embedded Distributor	200,000	500	$ 50,648.72	$ 50,306.09	$ (342.63)	-0.68%

The Self-Healing Grid

In 2014, EPLC completed its first iteration of its Green Energy Act Plan (“GEA Plan”) and subsequently a Smart Grid Development Plan. Along with SmartMAP, EPLC outlined its plan to shift to a smarter grid that was capable of reducing the impact of Loss of Supply incidents to our customers. By installing upgrades in three key areas, EPLC is evolving its grid into a “Self-Healing Grid”. These three categories include:

i) **Line Monitors:** The installation of line monitors provides EPLC with a significant improvement to the information that it currently collects relating to the day-to-day operation of its system. This improved information allows EPLC to make better operational, engineering and planning decisions. Integrating this data into the SmartMAP toolset has also provided EPLC near real-time data at a fraction of the cost of SCADA implementation.

ii) **Reclosers:** Historically, EPLC’s service territory consisted solely of manual load break switches which required manual operation and provided no fault protection. Fault protection was provided by a station breaker or an upstream recloser outside of EPLC service territory. With the implementation of smart recloser, EPLC is facilitating the capabilities of remote operation, real-time outage detection as well as the ability to isolate itself from an upstream distributor/transmitter. Further, incremental data about EPLC’s distribution system is gathered and fed into the SmartMAP toolset.

iii) **Wholesale Meters:** EPLC has upgraded its wholesale metering installation to ION TCP/IP installations in order to enhance meter data transfer, add outage detection and facilitate real-time data acquisition. These upgrades to EPLC’s wholesale meter data have been implemented directly into the SmartMAP toolset.

As Loss of Supply incidents continue to cause over 75% of EPLC's total customer hours of outage, EPLC continues to make prudent investments to minimize customer outage impacts and enhance overall customer value.

1.5 Customer Engagement

The RRFE strongly encourages distributor interaction and engagement of their customers in an effort to better align the strategic goals of the distributor with the customer needs. In its day to day business, EPLC currently engages its customers in a variety of ways including, but not limited to:

- Website/Social Media Updates;
- Bill Inserts & Flyers;
- Conservation and Demand Management Initiatives;
- Telephone Interactions (Inbound/Outbound);
- eCare Online Billing Portal;

In order to support this Application and in the spirit of the RRFE, EPLC conducted incremental customer engagement outlined in this Section 1.5 as well as in Attachments 1-F and 1-G. EPLC customers from all classes were considered and were overall satisfied with EPLC's level of service.

1.5.1 Selection of Customer Satisfaction & Engagement Consultants

EPLC determined it was important to engage overall customer satisfaction as well as solicit feedback on our Distribution System Plan ("DSP") in two separate engagements. Two separate contactors were engaged in order to provide redundancy and message clarity and to ensure that customer feedback can be properly integrated into the final draft of the DSP. EPLC initially contracted Innovative Research Group ("Innovative") in late 2014 and later engaged Convergys Analytics ("Convergys") in August 2016 in order to assess overall customer satisfaction. EPLC also contracted Innovative in April 2017 in order to solicit customer feedback on our draft DSP so that we could later incorporate this feedback directly into the Plan.

1.5.2 Customer Satisfaction Surveys

In late 2014 and in August 2016, EPLC engaged Innovative and Convergys respectively, to assess overall customer satisfaction with existing EPLC services. The 2014 study was mainly commissioned for OEB scorecard compliance whereas the Convergys study was specifically commissioned for the purpose of this Application.

Innovative Survey Overview & Results – 2014

Overview:

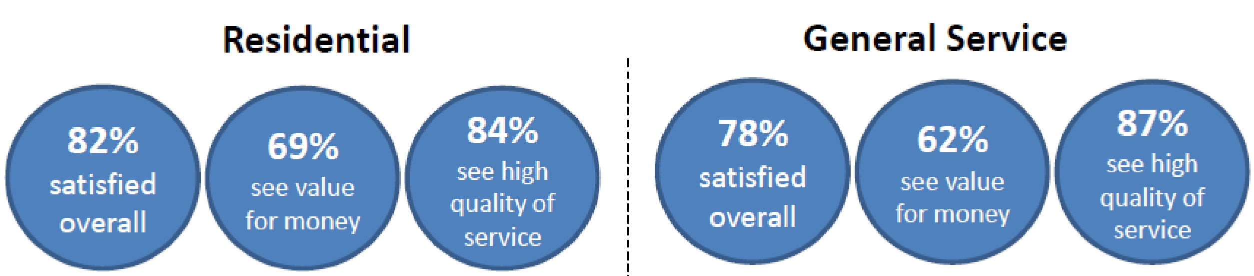
EPLC provided Innovative with all of its residential and general service less than 50kW customer contacts. For the purpose of this study, Innovative randomly sampled 210 residential customers and 98 general service less than 50kW ("GS<50") customers in mid-October 2014. The random sampling spanned all four of EPLC distinct service territories.

Results:

The following, as well as Figure 7 below, summarizes the key results from this round of customer engagement (from page 5 and 6 of the report):

- 82% of residential customers and 78% of GS<50 respondents are at least somewhat satisfied with EPLC services and 38% are very satisfied;
- Approximately 90% of EPLC customers are satisfied with reliability and power quality;
- 50% of residential and 65% GS<50 respondents are concerned with the rising price of electricity;
- 85% of residential and 73% of GS<50 customers are confident that their bills are accurate;
- 37% of residential and 54% of GS<50 respondents have indicated that they had previously contacted EPLC and 80% of residential and 77% of GS<50 respondents thought EPLC was helpful, knowledgeable (76%, 77%), courteous (86%, 85%) and were happy with the quality of information provided (76%, 73%).
- Approximately 60% of customers were happy with how EPLC communicated with them;

Figure 7 – Innovative Survey Overall Findings



Convergys Survey Overview, Results & Recommendations– 2016

Overview:

EPLC provided Convergys with all of its residential, GS<50 and general service greater than 50kW ("GS>50") customer contacts. For the purpose of this study, Convergys randomly sampled 400 residential customers and 100 business customers (both GS<50 and GS>50) in mid-October 2016. The random sampling spanned all four of EPLC distinct service territories.

Results:

The following summarizes the key results from the round of customer engagement (from page 5 of the report):

- Overall satisfaction is high at 81% however there are opportunities to improve in key areas described below;
- Business customers are more satisfied than residential customers by 8%;
- Business customers identified Reliability and Power Quality as their highest satisfaction drivers;
- Residential customers identified Customer Service as their highest satisfaction driver;
- Customers almost exclusively used the telephone to contact EPLC;

Figure 8 – Convergys Survey Overall Findings

Recommendations:

The following outline the recommendations and takeaways from the Convergys survey (from page 21 of the report):

- ***Prioritize Key Drivers of Satisfaction:*** Minimize impact of dissatisfaction by investing in service reliability and customer service;

- ***Promote Self-Service Solutions:*** Enhance and invest in self-service solutions as almost all customers are currently contacting EPLC via telephone. Self-service options will help alleviate stress on EPLC call center;
- ***Be Proactive & Reactive When Communicating Billing:*** Customers from all classes are growing concerned with rate increases and enhanced bill explanations and customer communications will help alleviate customer concern and confusion.

1.5.3 Summary of Community Open House Meetings

EPLC hosted a series of four separate Open House Meetings; one in each of our shareholder communities. The intent of these Open House Meetings was to solicit feedback on our draft DSP as well as gather as much general feedback as possible from EPLC customers, regardless of rate class. EPLC created a Customer Consultation Workbook (Appendix 1-F) that was presented to visiting customers. EPLC also posted the Customer Consultation Workbook on its website and asked for customers to submit feedback online in order to accommodate those who could not make the various Open House Meetings.

The following can be used to summarize the feedback received during the Open House Meetings and through its website:

- Electricity bills, in general, are becoming increasingly more difficult to afford, especially for senior citizens on a fixed income;
- System reliability and minimizing outages was important;
- Customers appreciated the opportunity to speak with to their electricity provider that had a local presence;
- Customers, in general, were satisfied with the services being provided by EPLC;

EPLC advertised the four Open House Meetings in the four largest local papers as well as through social media. An example of the ad that EPLC used can be found below as Figure 9.

Figure 9 – Open House Meeting Advertisement

1.5.4 Innovative DSP Survey

Innovative Research Group Survey Overview, Results & Recommendations– 2017

Overview:

EPLC provided Innovative Research Group ("Innovative") with all of its residential, GS<50 and GS>50 customer contacts. For the purpose of this study, Innovative randomly sampled 500 residential customers and 60 GS<50 customers in June of 2017. The random sampling spanned all four of EPLC distinct service territories.

It should be noted that EPLC also gave Innovative its GS>50 customer information however was not able to receive a sample size that significant enough to report on.

Results:

The following summarizes the key results from this round of customer engagement (from page 2 of the report) for Residential customers:

- Residential customers are primarily concerned with the overall cost of electricity but may be willing to pay more where they were to received enhanced reliability;
- EPLC Residential customers are highly satisfied with the service they are receiving from EPLC (85%);
- 57% of residential customers prioritized lower rates ahead of reliability (21%);
- 78% of EPLC residential customers indicated that there were no important priorities that EPLC needed to consider moving forward;
- 49% of residential customers opted for EPLC to spend what was required in order to maintain consistent unplanned outages however 71% of customers were not averse to spending on improved reliability even if that meant bill increases;
- Overall, 82% of residential customers gave social permission for EPLC to raise rates aligned with this Application;

The following summarizes the key results from this round of customer engagement (from page 3 of the report) for GS<50 customers:

- GS<50 customers are primarily concerned with the overall cost of electricity however most respondents would prefer that EPLC spend what is needed to reduce unexpected outages;

- GS<50 customers felt that EPCL should invest what it takes to replace and maintain aging infrastructure to maintain reliability even at the cost of raising rates;
- Overall, GS<50 customers gave social permission for EPLC to raise rates aligned with this Application;

1.5.5 Summary of Customer Needs & Feedback

EPLC has identified a strong, consistent theme throughout its various customer engagement activities. The following outlines, in order, customer engagement feedback and resulting customer needs:

- **Focus on reasonable distribution rates, generally in-line with the rate of inflation;**
    - Customers have accepted the proposed rate plan.
    - Concern heard from all rate classes however more so with Residential customers.
- **Focus on improving and maintaining service reliability;**
    - Customers supported the proposed investment plan.
    - Concern heard from all rate classes however more so with commercial customers.

1.5.6 Addressing Customer Needs & Preferences

EPLC has actively engaged its customer base and has consistently heard strong messages from customers from all classes that EPLC should focus on reasonable distribution rates in-line with the rate of inflation and improving and maintaining existing service reliability. EWPLC firmly believes that both primary customer needs are addressed in this Application.

EPLC is proposing to reduce total bills for all customer classes as summarized below in Figure 10 as well as in Section 1.6.9 of this Exhibit.

Figure 10 – Proposed EPLC Total Bill Impacts

Rate Class	kWh	kW	2017 BAP Rates	2018 Proposed Rates	$ Increase (Decrease)	% Increase (Decrease)
Residential	750	-	$ 126.61	$ 126.10	$ (0.51)	-0.40%
General Service Less Than 50 kW	2,000	-	$ 322.06	$ 319.92	$ (2.14)	-0.66%
General Service 50 to 4,999 kW	40,000	100	$ 6,600.60	$ 6,209.96	$ (390.64)	-5.92%
Unmetered Scattered Load	700	-	$ 139.72	$ 130.22	$ (9.50)	-6.80%
Sentinel Lighting	36	0.1	$ 10.34	$ 9.94	$ (0.39)	-3.81%
Street Lighting	36	0.1	$ 10.09	$ 9.99	$ (0.11)	-1.07%
Embedded Distributor	200,000	500	$ 50,648.72	$ 50,306.09	$ (342.63)	-0.68%

As part of this Application, EPLC has included its first Distribution System Plan ("DSP") that outlines EPLC's historical and forward looking capital plans. While EPLC previously had detailed capital plans prior to the creation of the DSP, the exercise of creating the DSP has further cemented EPLC's strategy of grid modernization and the path towards the Self-Healing Grid described in Section 1.4.2 above. The Self-Healing Grid initiative is EPLC's primary goal towards the reduction of unplanned interruptions. Currently, more than 75% of EPLC's total customer hours of interruption are related to upstream events beyond the control of EPLC. The Self-Healing Grid initiative aims to limit the impact of these unplanned events through the use of automation and smart grid devices.

With EPLC's suite of Best-In-Class solutions, EPLC will also continue to upgrade its customer service toolsets to provide better real-time information about its distribution system, faster response times on customer inquiries, clearer and simpler bill presentment and outage communication.

1.5.7 Other Consultations

EPLC engages with various key stakeholders at a local and provincial level. The following summarizes EPLC's other key stakeholder consultations:

- ***Municipal Shareholder Consultations:*** EPLC regularly communicates with its four shareholder Municipalities on an as needed basis. EPLC conducts a yearly council presentation at each of its shareholder Municipalities to update the Municipality and community at large about major EPLC initiatives and current/upcoming events. EPLC also conducts an Annual General Meeting for which all major local stakeholders are invited where EPLC's year over year results and Annual Report are presented;

- ***CDM Customer Participation Consultations:*** EPLC has been proud to deliver a full complement of conservation initiatives since 2006 administered in partnership with the former Ontario Power Authority ("OPA") and now Independent Electricity System Operator ("IESO"). EPLC has consistently taken a customer-first approach to conservation and through this longstanding offering; EPLC has had daily interactions with customers of all sizes and across its entire system.

- ***Transmitter Consultations (HONI):*** EPLC regularly meets and consults with HONI transmission staff to discuss various planning and operational items. These meetings have been initiated by both parties and can vary in format, topic and length. EPLC is also part of the Windsor-Essex (Group 1) planning areas for the four communities that it currently services. EPLC was involved in the creation of a regional plan for the area.

- ***Neighboring, Host and Embedded LDC Consultations:*** EPLC regularly meetings and consults with HONI distribution, neighboring LDCs as well as other industry experts to discuss various planning, regulatory, financial, operational and billing related items. EPLC is also part of the Windsor-Essex (Group 1) planning areas for the four communities that it currently services. EPLC was involved in the creation of a regional plan for the area.

1.6 Executive Summary

1.6.1 Revenue Requirement

In this Application, EPLC is requesting approval of a proposed Service Revenue Requirement of $13,175,916 which represents an increase of $1,184,986 or approximately 1.2% per year since EPLC's previous COS Application in 2010. Figure 11 below further describes EPLC's proposed increase to Service Revenue Requirement and Rate Base.

Figure 11 – Service Revenue Requirement

	2010 Board Approved	2018 Test Year	Variance	% Change	Yearly % Change
	A	B	C = B - A		
Revenue Requirement:					
OM&A	$ 6,254,188	$ 7,710,275	$ 1,456,087	23.3%	2.9%
Depreciation	$ 2,247,501	$ 1,848,004	$ (399,497)	-17.8%	-2.2%
Property Tax	$ 32,001	$ 42,538	$ 10,537	32.9%	4.1%
Income Tax	$ 545,581	$ 227,249	$ (318,332)	-58.3%	-7.3%
Return on Rate Base	$ 2,898,637	$ 3,334,829	$ 436,192	15.0%	1.9%
Total	**$ 11,977,909**	**$ 13,162,895**	**$ 1,184,986**	**9.9%**	**1.2%**
Rate Base	**$ 41,119,713**	**$ 59,927,210**	**$ 18,807,497**	**45.7%**	**5.7%**

The primary drivers for each of the Revenue Requirement categories described above are further detailed below:

- **Operating, Maintenance & Administration ("OM&A")**: EPLC's OM&A has increased by approximately $1.46M. Detailed analysis of EPLC's OM&A expenses is included with Exhibit 4 of this Application. Approximately $340k of the OM&A increase relates to the adoption of International Financial Reporting Standards ("IFRS") starting in 2013.

- **Depreciation**: The decrease in Depreciation is a result of EPLC migrating to IFRS starting in 2013. The new accounting standard generally increased the useful lives of EPLC assets thereby reducing overall Depreciation expense. Please refer to Exhibit 4 of this Application for additional information on EPLC's Depreciation expense.

- **Payments-in-Lieu of Taxes ("PILs")**: The decrease in the PILs component of Revenue Requirement of approximately $318k is consistent with decrease in accounting depreciation and increase in OM&A due to the adoption of IFRS mentioned above.

- **Return on Rate Base:** The increase relating to the Return on Rate Base is driven mainly by EPLC's increase in Rate Base of approximately $18.8M from 2010 to 2018. Further details can be found in Exhibit 2 of this Application. This increase has been partially offset by a proposed decrease to EPLC's Weighted Average Cost of Capital ("WACC") from 7.05% in 2010 to 5.56% in 2018 as well as a corresponding decrease in the percentage factor used to calculate Working Capital from 15.0% in 2010 to 7.5% in 2018.

1.6.2 Budgeting & Accounting Assumptions

The budgeting process is a key process required in order to assess EPLC's historical results and guide future initiatives. EPLC's management team develops operating and capital budgets which are reviewed and tested by senior management and eventually reviewed and approved by the EPLC Board of Directors. This process ensures that EPLC's key strategic initiatives and goals are being met while also being responsible and accountable to EPLC's electricity ratepayers.

As part of this Application, EPLC has compiled information using the MIFRS method of presentation for 2015 and forward. Impacts flowing from changes to depreciation and overhead capitalization changes normally required under MIFRS were recognized in 2013 upon conversion to Revised CGAAP. EPLC's 2017 Bridge Year forecast is based on both budgeted and actual balances. EPLC has included detailed explanations throughout this application as it relates to Revenue (Exhibit 3), OM&A (Exhibit 4) and Capital (Exhibit 2).

1.6.3 Load Forecast Summary

EPLC's Load Forecast is weather normalized and considers historical purchased load, conservation & demand management, weather conditions and local economic conditions. EPLC's Load Forecast is further explained in Exhibit 3 of this Application.

EPLC is forecasting 529,961,552 kWh before adjustments for Conservation & Demand Management ("CDM") in the Test Year (2018) which represents a 3.29% decrease from 2016 Actual consumption and a 0.39% increase from 2016 Normalized consumption.

EPLC's forecast for the Test Year (2018) after adjustment for CDM is 518,917,436 kWh.

1.6.4 Rate Base & Capital Plan

As part of this Application, EPLC has included its first Distribution System Plan ("DSP") that outlines EPLC's historical and forward looking capital plans. EPLC's DSP is included as Attachment 2-C of Exhibit 2 of this Application.

While EPLC previously had detailed capital plans prior to the creation of the DSP, the exercise of creating the DSP has further cemented EPLC's strategy of grid modernization, implementing the Single Voltage Utility initiative (summarized in Section 1.4 above) and the path forward towards the Self-Healing Grid (also summarized in Section 1.4 above). EPLC's DSP also seeks to properly balance investment in new infrastructure with operating and maintenance costs to minimize total cost over the life of the asset.

As outlined in Figures 12 and 13 below, as well as throughout the DSP, EPLC's levels of capital investment, for each Board prescribed category (System Access, System Renewal, System Service, General Plant), are relatively consistent, on a year over year basis and increase marginally into the 2018-2022 forecast periods.

Figure 12 – Historical Capital Spend by Category

Category	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Budget	Budget
	$ '000								
System Access	$ 1,928	$ 1,502	$ 1,717	$ 1,766	$ 2,532	$ 2,341	$ 1,759	$ 1,712	$ 1,746
System Renewal	$ 1,675	$ 1,833	$ 2,698	$ 3,113	$ 3,012	$ 2,695	$ 2,125	$ 2,655	$ 2,693
System Service	$ 693	$ 940	$ 885	$ 185	$ 177	$ 2,196	$ 1,005	$ 787	$ 707
General Plant	$ 960	$ 251	$ 1,272	$ 450	$ 487	$ 547	$ 384	$ 1,504	$ 1,037
Total Expenditure	**$ 5,255**	**$ 4,526**	**$ 6,572**	**$ 5,513**	**$ 6,208**	**$ 7,779**	**$ 5,274**	**$ 6,658**	**$ 6,183**

Figure 13 – Forecasted Capital Spend by Category

Category		Forecast Periods				
	2017	2018	2019	2020	2021	2022
	$ '000					
System Access	$ 1,712	$ 1,746	$ 1,781	$ 1,816	$ 1,853	$ 1,835
System Renewal	$ 2,655	$ 2,693	$ 1,362	$ 2,304	$ 2,248	$ 2,195
System Service	$ 787	$ 707	$ 2,186	$ 1,126	$ 1,243	$ 1,342
General Plant	$ 1,504	$ 1,037	$ 856	$ 976	$ 927	$ 968
Total Expenditure	**$ 6,658**	**$ 6,183**	**$ 6,185**	**$ 6,222**	**$ 6,270**	**$ 6,339**

A further comparison of EPLC's 2010 Actual capital expenditures compared to the proposed 2018 Test Year is included as Figure 14 below.

Figure 14 – 2010 Actual vs. 2018 Test Year Capital Spend

Category	2010	2018	Variance
	A	B	C = B - A
	$ '000		
System Access	$ 1,928	$ 1,746	$ (182)
System Renewal	$ 1,675	$ 2,693	$ 1,018
System Service	$ 693	$ 707	$ 15
General Plant	$ 960	$ 1,037	$ 77
Total Expenditure	**$ 5,255**	**$ 6,183**	**$ 928**

Figure 15 below outlines EPLC's historical Rate Base from 2010 Board Approved to the proposed 2018 Test Year.

Figure 15 – Historical Rate Base Summary

Description	2010 BAP	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Accounting Standard	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Gross Fixed Assets	$ 50,352,171	$ 49,083,254	$ 51,669,129	$ 57,371,669	$ 60,692,887	$ 65,778,218	$ 72,109,472	$ 76,452,554	$ 81,886,262	$ 86,844,505
Accumulated Depreciation	$ (16,335,848)	$ (16,290,184)	$ (18,356,056)	$ (20,735,930)	$ (22,530,327)	$ (23,960,238)	$ (26,444,103)	$ (27,550,955)	$ (29,220,080)	$ (31,068,084)
Net Book Value	$ 34,016,323	$ 32,793,070	$ 33,313,273	$ 36,635,739	$ 38,162,560	$ 41,817,980	$ 45,665,369	$ 48,901,599	$ 52,666,182	$ 55,776,421
Average Net Book Value	**$ 33,009,250**	**$ 32,138,850**	**$ 33,053,071**	**$ 34,974,405**	**$ 37,399,149**	**$ 39,990,270**	**$ 43,741,674**	**$ 47,283,484**	**$ 50,783,891**	**$ 54,221,302**
Total Working Capital	$ 54,069,758	$ 54,778,916	$ 56,734,399	$ 58,590,963	$ 57,589,775	$ 64,252,177	$ 69,042,180	$ 78,624,142	$ 74,975,367	$ 76,078,771
Allowance Factor	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	7.50%
Working Capital Allowance	**$ 8,110,464**	**$ 8,216,837**	**$ 8,510,160**	**$ 8,788,644**	**$ 8,638,466**	**$ 9,637,827**	**$ 10,356,327**	**$ 11,793,621**	**$ 11,246,305**	**$ 5,705,908**

Figure 11 above demonstrates a Rate Base increase of $18.8M (45%) from 2010 BAP $41,119,714 to 2018 Test Year $59,927,210. The majority of the Rate Base increase is related to asset renewal and expansion such as voltage conversion, cable replacement and pole replacement along with key EPLC initiatives such as the Single Voltage Utility initiative. Increases to Rate Base are mitigated to a proposed significant reduction to EPLC's working capital. EPLC is proposing the deemed Allowance Factor of 7.5% as part of this Application.

1.6.5 Operations, Maintenance & Administrative Expense

EPLC is proposing the recovery of $7,710,275 in OM&A expenses for the 2018 Test Year. These increases represent a $1,509,909 or 24.4% increase over the 2010 Board Approved amount of $6,200,366.

The proposed OM&A expenditures for the 2018 Test Year were determined through a detailed budgeting and business planning process. As described above in Section 1.4, EPLC has implemented core value alignment with the Board's Renewed Regulatory Framework for Electricity Distributor ("RRFE") outcomes. EPLC six (6) core values are:

i) Customer & Community Value ("C&C");
ii) Operational Excellence ("OE");
iii) Safety ("Saf");
iv) Employee Satisfaction ("ES");
v) Reasonable Rates ("RR");
vi) Financial & Environmental Sustainability ("F&ES");

Figure 16 below outlines the incremental changes to OM&A by major contributor and its respective alignment with EPLC's core values as part of this Application. Figure 7 is intended to capture the major drivers of OM&A increases between the 2010 BAP to the projected 2018 Test Year. Further details are available in Exhibit 4 of this Application.

Figure 16 – EPLC Test Year OM&A & Core Value

Line Item	Amount	EPLC Core Value
2010 BAP OM&A	**$ 6,200,366**	
Inflationary Increases on Labour & Non-Labour Items	$ 815,725	All
Impact of IFRS Changes on OM&A	$ 340,213	All
Regulatory Re-alignment	$ 217,000	OE, C&C, F&ES
Control Room Support	$ 186,000	OE, Saf, C&C
Cybersecurity Maintenance	$ 286,463	OE, C&C
Other Immaterial Adjustments	$ (335,492)	All
2018 Test Year OM&A	**$ 7,710,275**	

When normalized for the impact of IFRS-compliant capitalization, OM&A has increased by $1,169,696 which equates to an 18.9% increase over an eight (8) year period. This translates to a 2.4% year over year average annual increase to OM&A. EPLC proposes that this increase is reasonable, consistent with EPLC's Core Values and in-line with the rate of inflation.

1.6.6 Cost of Capital

EPLC followed the Report of the Board on the *Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084, December 11th, 2009*), the OEB's *Review of Existing Methodology of the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084, January 14th, 2016)* and the OEB's letter titled *Cost of Capital Parameter Updates for 2017 Cost of Service and Custom Incentive Rate-setting Applications (October 27th, 2016)*.

EPLC acknowledges and understands that these rates are subject to change at such time that the 2018 Cost of Capital parameters are issued by the OEB.

For the purpose of this Application, EPLC has completed its application with a deemed capital structure of 56% Long Term Debt, 4% Short Term Debt and 40% Equity in accordance with the OEB issued documentation listed above. No significant changes to this structure are expected in the foreseeable future.

1.6.7 Cost Allocation & Rate Design

EPLC followed the Board's Cost Allocation Report (March 31st, 2011), the Board's letter relating to the treatment of Streetlighting connection (June 12th, 2015) and the 2018 Cost Allocation Model (Version 3.5).

Figure 17 below outlines the resulting Revenue to Cost ("RTC") ratios as well as the EPLC proposed RTC ratios. Further information can be found in Exhibit 7 of this Application.

Figure 17 – Proposed Revenue to Cost Ratios

Rate Class	Previously Approved Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
Residential	100.23%	96.54%	97.37%	85% to 115%
General Service < 50 kW	49.56%	118.57%	118.57%	80% to 120%
General Service > 50 kW	159.99%	95.92%	95.92%	80% to 120%
Intermediate Use	336.93%	0.00%	0.00%	80% to 120%
Street Lights	32.36%	112.65%	112.65%	80% to 120%
Unmetered Scattered Load	132.66%	129.76%	120.00%	80% to 120%
Sentinel Lights	38.09%	126.10%	120.00%	80% to 120%
Embedded Distributor	N/A	194.34%	120.00%	80% to 120%

For the purpose of this Application, EPLC is proposing to eliminate the Intermediate Use rate class, expand the General Service >50 kW class from 50-2,999 kW to 50-4,999 kW and adding an Embedded Distributor rate class.

The transition to fixed Residential rates is described in Exhibit 8 of this Application.

Figure 18 below compares EPLC's current Board approved distribution rates with EPLC's proposed rates as part of this Application.

Figure 18 – Current vs. Proposed Distribution Rates

Rate Class	Monthly Service Charge			Distribution Volumetric Charge		
	2017 Approved	2018 Proposed	% Difference	2017 Approved	2018 Proposed	% Difference
Residential	$ 20.31	$ 23.96	17.97%	$ 0.0078	$ 0.0040	-48.72%
General Service < 50 kW	$ 35.13	$ 35.94	2.31%	$ 0.0120	$ 0.0123	2.50%
General Service > 50 kW	$ 232.69	$ 238.04	2.30%	$ 2.2101	$ 2.2573	2.14%
Intermediate Use	$ 1,528.73	$ -	N/A	$ 1.4176	$ -	N/A
Street Lights	$ 3.30	$ 3.38	2.42%	$ 8.9407	$ 9.1461	2.30%
Unmetered Scattered Load	$ 9.53	$ 8.98	-5.77%	$ 0.0297	$ 0.0280	-5.72%
Sentinel Lights	$ 3.41	$ 3.31	-2.93%	$ 9.7922	$ 9.5148	-2.83%
Embedded Distributor	$ -	$ 550.00	N/A	$ -	$ 1.2155	N/A

Also not included in Distribution rates but of significant benefit to EPLC customers is a significant reduction in distribution losses summarized in Figure 19 below as a result of EPLC's Single Voltage Utility initiative highlighted throughout this Application.

Figure 19 – Current vs. Proposed Loss Factors

Description	2017 Approved	2018 Proposed
Total Loss Factor - Secondary Metered Customer <5,000 kW	1.0602	1.0355
Total Loss Factor - Primary Metered Customer <5,000 kW	1.0496	1.0251

1.6.8 Deferral & Variance Accounts

EPLC is requesting the approval of disposition of Group 1, Group 2 and Other Deferral & Variance Accounts ("DVA") in the amount of $1,882,606 which will be refunded to customers. Details are summarized in Exhibit 9 of this Application.

EPLC is proposing a one year disposition period for all DVAs and is not requesting the creation of any new accounts.

1.6.9 Bill Impacts

Throughout the customer engagement process detailed in section 1.5 above, EPLC has repeatedly heard that electricity rates in Ontario are too high. EPLC has worked diligently to keep its rates just and reasonable for its customers. Figures 20 & 21 below outline the proposed bill impacts to EPLC's customers.

Figure 20 – Proposed Distribution Rate Impacts

Rate Class	kWh	kW	2017 BAP Rates	2018 Proposed Rates	$ Increase (Decrease)	% Increase (Decrease)
Residential	750	-	$ 26.85	$ 27.75	$ 0.90	3.35%
General Service Less Than 50 kW	2,000	-	$ 59.72	$ 61.33	$ 1.61	2.70%
General Service 50 to 4,999 kW	40,000	100	$ 451.78	$ 463.77	$ 11.99	2.65%
Unmetered Scattered Load	700	-	$ 30.18	$ 28.58	$ (1.60)	-5.30%
Sentinel Lighting	36	0.1	$ 4.38	$ 4.26	$ (0.12)	-2.80%
Street Lighting	36	0.1	$ 4.19	$ 4.29	$ 0.11	2.53%
Embedded Distributor	200,000	500	$ 1,337.74	$ 1,157.75	$ (179.99)	-13.45%

Figure 21 – Proposed Total Bill Impacts

Rate Class	kWh	kW	2017 BAP Rates	2018 Proposed Rates	$ Increase (Decrease)	% Increase (Decrease)
Residential	750	-	$ 126.61	$ 126.10	$ (0.51)	-0.40%
General Service Less Than 50 kW	2,000	-	$ 322.06	$ 319.92	$ (2.14)	-0.66%
General Service 50 to 4,999 kW	40,000	100	$ 6,600.60	$ 6,209.96	$ (390.64)	-5.92%
Unmetered Scattered Load	700	-	$ 139.72	$ 130.22	$ (9.50)	-6.80%
Sentinel Lighting	36	0.1	$ 10.34	$ 9.94	$ (0.39)	-3.81%
Street Lighting	36	0.1	$ 10.09	$ 9.99	$ (0.11)	-1.07%
Embedded Distributor	200,000	500	$ 50,648.72	$ 50,306.09	$ (342.63)	-0.68%

EPLC firmly believes that both the proposed Distribution Rate Impacts as well as the proposed Total Bill Impacts are reasonable and follow in line, generally, with overall inflationary increases. EPLC does not believe that any rate mitigation would be required for the purpose of this Application as no specific class exceeds 10% of EPLC's proposed Total Bill Impacts.

1.7 Financial Information

1.7.1 Audited Financial Statements

Audited financial statements from 2010 through 2016 are attached as Attachment 1-H.

1.7.2 Reconciliation Between Audited Financial Statements & Regulatory Accounting

A reconciliation between EPLC's audited financial statements & regulatory accounting is attached as Attachment 1-I.

1.7.3 Annual Report

Annual reports from 2015 and 2016 for EPC are attached as Attachment 1-J.

1.7.4 Prospectus or Information Circulars

EPLC does not have or plan to have any prospectus, information circulars or similar documentation.

1.7.5 Changes in Tax Status

EPLC has not experienced a change in tax status since its last Cost of Service application and is currently a corporation incorporated under the Ontario Business Corporations Act.

1.7.6 Statement of Accounting Standard Used

The Accounting Standards Board required qualifying rate regulated entities to adopt IFRS by January 1st, 2015.

EPLC has implemented the regulatory accounting changes required for compliance beginning in 2013.

1.7.7 Non-Utility Business Accounting

EPLC is involved is in Non-Utility Businesses which include:

- Water Billing;

- Streetlight Maintenance;
- Renewable Generation
- Conservation & Demand Management

EPLC confirms that accounting for these activities is segregated from EPLC's rate regulated activities in accordance with the:

- OEB's Guidelines: Regulation and Accounting Treatments for Distributor-Owned Generation Facilities (G-2009-0300, September 15th, 2009);
- Accounting Procedures Handbook for Electricity Distributors (January 1st, 2012);
- Affiliate Relationships Code for Electricity Distributors and Transmitters (March 15, 2010);

1.8 Materiality Threshold

As per Section 2.0.8, Chapter 2 of the OEB's Filing Requirements, issued on July 14th, 2016, EPLC's Revenue Requirement is greater than $10 million and less than $200 million, therefore materiality is calculated at 0.5% of its proposed Revenue Requirement. Figure 22 below outlines this methodology. For the purposes of this Application, EPLC used $65,000 as its materiality threshold.

Figure 22 – Materiality Threshold Calculation

Description	2018 Test Year
Revenue Requirement	$ 13,162,895
Materiality Threshold	0.5%
Materiality Calculated	$ 65,814
Materiality Used	$ 65,000

1.9 Administrative

1.9.1 Table of Contents

The Table of Contents is included on page 2 of this Exhibit.

1.9.2 Contact Information

The Applicant's Address for Service:

Essex Powerlines Corporation
2730 Highway #3,
Oldcastle, Ontario
N0R 1L0

Email: regulatory@essexpowerlines.ca

Contacts:

Mr. Raymond Tracey
President & CEO
Essex Power Corporation
Telephone: (519) 946-2000 x211
Email: rtracey@essexpower.ca

Mr. Kristopher Taylor
Director of Corporate Strategy
Essex Power Corporation
Telephone: (519) 946-2000 x219
Email: ktaylor@essexpower.ca

Mr. Giuseppe Barile
General Manager
Essex Powerlines Corporation
Telephone: (519) 737-9811 x217
Email: jbarile@essexpowerlines.ca

Primary Application Contact

Ms. Lindsay Thiessen
Manager of Regulatory Accounting

Essex Powerlines Corporation
Telephone: (519) 737-9811 x158
Email: lthiessen@essexpowerlines.ca

1.9.3 Legal Representation

Aird & Berlis LLP
Brookfield Place
181 Bay Street, Suite 1800
Box 754
Toronto, Ontario
M5J 2T9

Scott Stoll
Partner
Telephone: (416) 865-4703
Fax: (416) 863-1515
Email: sstoll@airdberlis.com

1.9.4 Internet Address & Social Media

All Application materials will be posted on the EPLC website and will also be communicated via our social media profiles outlined below:

Website: www.essexpowerlines.ca

Twitter: www.twitter.com/essexpowerlines

The Application will also be available on the Board's website at www.ontarioenergyboard.ca as EB-2017-0039.

1.9.5 Affected Customers & Publication

All residents, commercial, industrial and institutional customers that receive electricity from EPLC will be affected by this Application.

EPLC proposes to post the Notice of Application in the primary publication in the region which is the Windsor Star. The Windsor Star is the largest newspaper publisher in the area and has circulation that encompasses our entire service territory.

EPLC also proposes to promote the Notice of Application on its website and via its social media accounts.

1.9.6 Bill Impacts for Publication

Figures 23, 24 and 25 below outline EPLC's proposed Bill Impacts for publication.

Figure 23 – Proposed Distribution Rate Impacts

Rate Class	kWh	kW	2017 BAP Rates	2018 Proposed Rates	$ Increase (Decrease)	% Increase (Decrease)
Residential	750	-	$ 26.85	$ 27.75	$ 0.90	3.35%
General Service Less Than 50 kW	2,000	-	$ 59.72	$ 61.33	$ 1.61	2.70%
General Service 50 to 4,999 kW	40,000	100	$ 451.78	$ 463.77	$ 11.99	2.65%
Unmetered Scattered Load	700	-	$ 30.18	$ 28.58	$ (1.60)	-5.30%
Sentinel Lighting	36	0.1	$ 4.38	$ 4.26	$ (0.12)	-2.80%
Street Lighting	36	0.1	$ 4.19	$ 4.29	$ 0.11	2.53%
Embedded Distributor	200,000	500	$ 1,337.74	$ 1,157.75	$ (179.99)	-13.45%

Figure 24 – Proposed Total Bill Impacts

Rate Class	kWh	kW	2017 BAP Rates	2018 Proposed Rates	$ Increase (Decrease)	% Increase (Decrease)
Residential	750	-	$ 126.61	$ 126.10	$ (0.51)	-0.40%
General Service Less Than 50 kW	2,000	-	$ 322.06	$ 319.92	$ (2.14)	-0.66%
General Service 50 to 4,999 kW	40,000	100	$ 6,600.60	$ 6,209.96	$ (390.64)	-5.92%
Unmetered Scattered Load	700	-	$ 139.72	$ 130.22	$ (9.50)	-6.80%
Sentinel Lighting	36	0.1	$ 10.34	$ 9.94	$ (0.39)	-3.81%
Street Lighting	36	0.1	$ 10.09	$ 9.99	$ (0.11)	-1.07%
Embedded Distributor	200,000	500	$ 50,648.72	$ 50,306.09	$ (342.63)	-0.68%

Figure 25 – Bill Impacts

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total						Total	
		A		B		C		A + B + C	
		$	%	$	%	$	%	$	%
Residential - RPP	kWh	$ 0.90	3.4%	$ 0.08	0.3%	$ (0.38)	-1.1%	$ (0.51)	-0.4%
GS<50 - RPP	kWh	$ 1.61	2.7%	$ (0.73)	-1.1%	$ (1.70)	-2.1%	$ (2.14)	-0.7%
GS 50-4,999 - Non-RPP	kW	$ 11.99	2.7%	$(278.96)	-35.3%	$ (341.84)	-2.1%	$ (390.64)	-5.9%
Embedded Distributor - Non-RPP	kW	$(179.99)	-13.5%	$(283.95)	-17.8%	$ (283.95)	-17.8%	$ (342.63)	-0.7%
USL - RPP	kWh	$ (1.60)	-5.3%	$ (8.00)	-22.0%	$ (8.34)	-20.0%	$ (9.50)	-6.8%
Sentinel Lights - Non-RPP	kW	$ (0.12)	-2.8%	$ (0.33)	-7.0%	$ (0.35)	-7.0%	$ (0.39)	-3.8%
Street Lights - Non-RPP	kW	$ 0.11	2.5%	$ (0.08)	-1.7%	$ (0.09)	-2.0%	$ (0.11)	-1.1%
Residential 10th Percentile - RPP	kWh	$ 2.78	12.1%	$ 0.81	3.4%	$ 1.02	3.7%	$ 0.72	1.2%

1.9.7 Form of Hearing

As outlined in 1.9.6 above, EPLC maintains that bill impacts are at or below inflation for all impacted customers. As a result, EPLC requests that this Application be disposed of by way of written hearing in order to expedite approvals and limit cost.

1.9.8 Effective Date

EPLC requests that the Board make a Decision and Order effective May 1st, 2018 in accordance with the Board's Filing Requirements.

Where the Board is unable to render this decision in time for the Applicant to make rates effective May 1st, 2018, EPLC requests that the Board declare its rates interim effective May 1st, 2018 until a Decision and Order for 2018 rates is declared.

1.9.9 Approvals Requested

In this Application, EPLC is requesting the following, consistent with Board Appendix 2-A:

i) Approval to charge distribution rates effective May 1st, 2018 to recover Service Revenue Requirement of $13,162,895 which includes a Revenue Deficiency of $280,095 as detailed in Exhibit 6 of this Application. The schedule of proposed rates is set out in Exhibit 8 of this Application;

ii) Approval of the DSP as presented in Exhibit 2 of this Application;

iii) Approval of revised Low Voltage rates as presented in Exhibit 8 of this Application;

iv) Approval of revised Retail Transmission Rates (Network & Connection) as presented in Exhibit 8 of this Application;

v) Approval of revised Wholesale Market and Rural Rate Protection charges as presented in Exhibit 8 of this Application;

vi) Approval to continue the Specific Service Charges and Transformer Allowance approved in EPLC's 2017 Distribution Rates (EB-2016-0069);

vii) Approval of revised Loss Factors as presented in Exhibit 8 of this Application;

viii) Approval of the rate riders for a one year disposition of Group 1, Group 2 and Other Deferral and Variance Accounts as presented in Exhibit 9 of this Application;

ix) Approval of the rate rider for a one year disposition of the Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") for lost revenue as presented in Exhibits 4 and 9 of this Application;

x) Approval of the rate rider for a three year disposition of Stranded Meter assets ("SMRR") in relation to the smart metering initiative, as presented in Exhibit 9 of this Application;

xi) Approval to charge HONI, an Embedded Distributor, as per rates proposed in Exhibit 7 of this Application;

xii) Approval to eliminate the General Service 3,000 to 4,999 kW service classification;

xiii) Approval to increase the qualification threshold of the General Service 50 to 2,999 kW service classification to 50 to 4,999 kW;

EPLC may request additional Approvals where required and as permitted by the OEB.

1.9.10 Deviations from Filing Requirements

EPLC has not knowingly deviated from the Filing Requirements for Electricity Distribution Rate Applications.

1.9.11 Methodology Changes

EPLC has not knowingly applied any significant methodology changes to the information presented in this Application.

1.9.12 Board Directives

EPLC has no outstanding utility-specific directives from the Board since submitting its last Cost of Service application (EB-2009-0143) for May 1st, 2010 distribution rates.

1.9.13 Conditions of Service

EPLC's Conditions of Service are posted online on its website:

www.essexpowerlines.ca/conditions-of-service

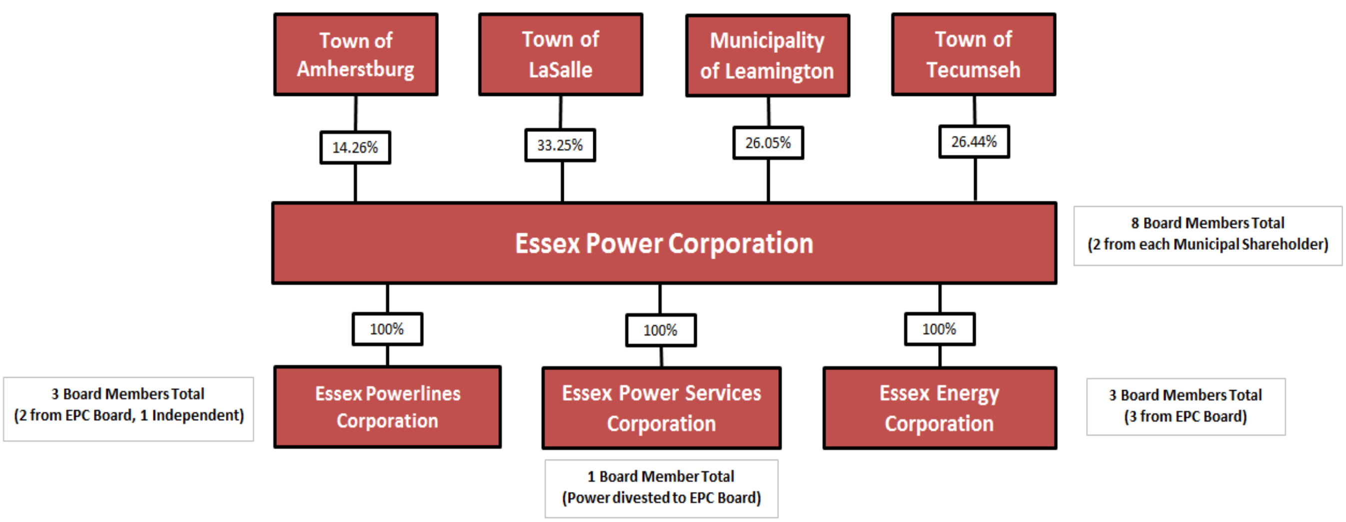
All proposed changes in this Application are not currently represented in the existing version of the Conditions of Service. EPLC's Conditions of Service will be updated upon the approval of this Application.

1.10 Corporate Governance

1.10.1 Corporate & Utility Organizational Structure

EPC is wholly (100%) owned by four (4) municipal shareholders. Figure 26 below illustrates EPLC's corporate structure and its relationship with its four respective shareholders as mandated by the Essex Power Unanimous Shareholder Agreement ("USA"). The Board Governance section of EPLC's USA is included as Attachment 1-L of this Exhibit.

Figure 26 – Essex Power Corporate Structure



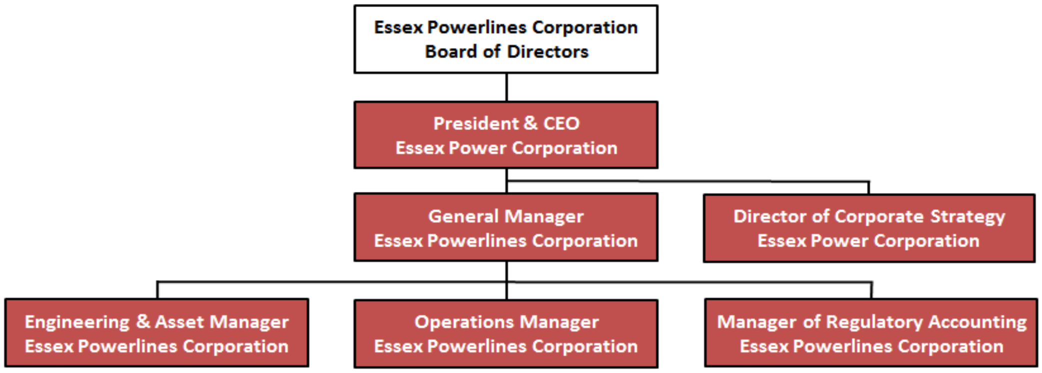
Although each Shareholder has a different equity stake, they all possess equal (25%) voting rights and have equal representation on the EPC/EPLC Boards. EPLC is not currently planning any changes to its corporate structure.

1.10.2 Board of Directors & Independence

The EPC Board of Directors consists of eight (8) total directors of which two (2) members represent each shareholder municipality. Each shareholder municipality must be represented by at least one elected official and one independent member from within its respective the community.

The EPLC Board of Directors consists of three (3) total Directors where two (2) are appointed from the EPC Board and one (1) is independent. The EPLC management team that reports to the Board of Directors is outlined as Figure 27 below.

Figure 27 – EPC/EPLC Management Team



1.10.3 Board Mandate

Board Members are to operate and direct the Essex Power Group of companies in accordance with the Essex Power USA as shown in Attachment 1-L.

1.10.4 Board Meetings

EPC and EPLC Board Meetings are held quarterly on the fourth Wednesday of the month at 4:00 PM. Board Meeting materials are posted on a secure website the Friday preceding the meeting.

1.10.5 Orientation

EPLC believes that it is imperative that Directors have the proper skills and education in order to effectively participate and perform their respective duties. EPLC provides new directors with on-site training, facilities tour and an orientation package that includes details relating to:

- Corporate Structure;
- Current Board Governance;
- Overview of the Essex Power Group of Companies;
- Relevant Governance Review Reports;
- An Overview of Regulatory Requirements in Ontario;
- Current Business Plan;
- Current Annual Report;
- Director's Liabilities;
- Meeting Schedules;

Attachment 1-K herein outlines some of the documentation that Directors receive as part of their orientation.

1.10.6 Code of Conduct

Board Members are to conduct themselves in accordance with the Essex Power USA as shown in Attachment 1-L.

1.10.7 Nomination of Directors

Nomination of Directors is performed by each Shareholder municipality in accordance with the Essex Power USA as shown in Attachment 1-L.

1.10.8 Board Committees

The EPC Board of Directors established two Committees of the Board that relate to governance of EPC and all of its subsidiaries, including EPLC. All meetings are separate and distinct from any Board Meetings described in 1.10.4 above.

- ***Audit Committee:*** The Audit Committee meets quarterly and/or at the call of the Chair. The Committee is comprised of three (3) EPC Board Members, directed by the EPC Board and approved by the EPC Chair on a two year term. Members are required to be financially literate.
- ***Human Resource ("HR") & Governance Committee:*** The HR & Governance Committee meets bi-annually and/or at the call of the Chair. The Committee is comprised of three (3) EPC Board Members, directed by the EPC Board and approved by the EPC Chair on a two year term.

1.11 Letters of Comment

As of the date of this Application, EPLC has not received any Letters of Comment. EPLC intends to respond to any Letters of Comment that arise as a result of this proceeding in accordance with the Filing Requirements.

Attachment 1-A

Certificate of Evidence

ESSEX POWERLINES CORPORATION

August 28th, 2017

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

RE: Certificate of Evidence

As General Manager of Essex Powerlines Corporation, I certify that the evidence filed in this Application is accurate, consistent and complete to the best of my knowledge and belief.

If you have any questions or concerns, please do not hesitate to contact me anytime.

Yours truly,

Joe Barile
General Manager
Essex Powerlines Corporation

Attachment 1-B

2018 Cost of Service Filing Checklist

2018 Cost of Service Checklist

Essex Powerlines Corporation

EB-2017-0039

Date: August 28th, 2017

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
GENERAL REQUIREMENTS			
Ch 1, Pg. 2	Certification by a senior officer that the evidence filed is accurate, consistent and complete	Yes	
Ch 1, Pg. 3	Confidential Information - Practice Direction has been followed	N/A	No confidential info has been filed.
7	Chapter 2 appendices in live Microsoft Excel format; PDF and Excel copy of current tariff sheet	Yes	
8	If applicable, late applications filed after the commencement of the rate year for which the application is intended to set rates is converted to the following rate year.	N/A	
8 & 9	Aligning rate year with fiscal year - request for proposed alignment	N/A	
10	Text searchable and bookmarked PDF documents	Yes	
10	Links within Excel models not broken and models names so that they can be identified (e.g. RRWF instead of Attachment A)	Yes	
10	Materiality threshold; additional details beyond the threshold if necessary	Yes	Section 1.8
11	Proposal for disposition of any balances in existing DVAs for renewable generation and smart grid development, if applicable	Yes	Exhibit 9
11	State accounting standard(s) used in historical, bridge and test years. Provide a summary of changes to its accounting policies made since the applicant's last cost of service filing. Identify all material changes or confirm no material changes in the adoption of IFRS. Appendix 2-Y	Yes	Attachment 1-M
RESS Guideline	Two hardcopies of application sent to OEB the same day as electronic filing (p10 of RESS Guideline)	Yes	
EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS			
Table of Contents			
12 & 13	Table of Contents listing major sections and subsections of the application. Electronic version of application appropriately bookmarked to provide direct access to each section	Yes	
Executive Summary			
13	Summary identifying key elements of the proposals and the Business Plan underpinning application, as guided by the Rate Handbook including plain language information about its goals	Yes	Section 1.6
Administration			
13	Primary contact information (name, address, phone, fax, email)	Yes	Section 1.9.2
13	Identification of legal (or other) representation	Yes	Section 1.9.3
13	Applicant's internet address for viewing of application and any social media accounts used by the applicant to communicate with customers	Yes	Section 1.9.4
13	Statement identifying customers materially affected by the application including any change to any rate or charge and specific statement of what individual customer or customer groups would be affected by the proposed change	Yes	Section 1.9.5
13	Statement identifying where notice should be published and why	Yes	Section 1.9.5
13	Bill impacts - distribution only impacts for 750 kWh residential and 2000 kWh GS<50 (sub-total A of Tariff Schedule and Bill Impact Spreadsheet Model) to be used for notice; proposed bill impacts based on alternative consumption profiles and customer groups as appropriate given consumption patterns of a distributors customers	Yes	Section 1.9.6
14	Form of hearing requested and why	Yes	Section 1.9.7
14	Requested effective date	Yes	Section 1.9.8
14	Statement identifying all deviations from Filing Requirements; identify concerns with models or changes to models	Yes	Section 1.9.10
14	Statement identifying and describing any changes to methodologies used vs previous applications	Yes	Section 1.9.11
14	Identification of OEB directions from any previous OEB Decisions and/or Orders. The applicant must clearly indicate how these are being addressed in the current application (e.g., filing of a study as directed in a previous decision)	Yes	Section 1.9.12
14	Reference to Conditions of Service - LDC does not need to file Conditions of Service, but must provide reference to website and confirm version is current; identify if there are changes to Conditions of Service (a) since last CoS application or (b) as a result of the current application. Confirmation that there are no rates and charges linked in the Conditions of Service that are not in the distributor's Tariff of Rates and Charges must be provided	Yes	Section 1.9.13
14	Description of the corporate and utility organizational structure, showing the main units and executive and senior management positions within the utility. Include a corporate entities relationship chart, showing the extent to which the parent company is represented on the utility company's Board of Directors and a description of the reporting relationships between utility and parent company management. Also include any planned changes in corporate or operational structure, including any changes in legal organization and control	Yes	Section 1.10.1
14	List of approvals requested (and relevant section of legislation), including accounting orders - a PDF copy of Appendix 2-A should be provided in this section	Yes	Section 1.9.9

2018 Cost of Service Checklist

Essex Powerlines Corporation

EB-2017-0039

Filing Requirement Page # Reference

Date: August 28th, 2017

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
Distribution System Overview			
14	Description of Service Area (including map, communities served)	**Yes**	Section 1.3.1
15	Description of whether the distributor is a host distributor and/or embedded distributor. Identification of embedded and/or host distributors; if partially embedded provide %load from host distributor. If the distributor is a host, the applicant should identify whether there is a separate Embedded Distributor customer class or if any embedded distributors are included in other customer classes such as GS > 50 kW	**Yes**	Section 1.3.2
15	Statement as to whether or not the distributor has had any transmission or high voltage assets deemed by the OEB as distribution assets and whether or not there are any such assets the distributor is seeking approval for in this application	**Yes**	Section 1.3.3
Application Summary			
At a minimum, the items below must be provided. Applicants must also identify all proposed changes that will have a material impact on customers.			
15	Revenue Requirement - service RR, increase/decrease ($ and %) from change from previously approved and main drivers	**Yes**	Section 1.6.1
15	Budgeting and Accounting Assumptions - economic overview and identification of accounting standard used for test year and brief explanation of impacts arising from any change in standards	**Yes**	Section 1.6.2
16	Load Forecast Summary - load and customer growth, % change in kWh/kW and customer numbers, description of forecasting method(s) used for customer/connection and consumption/demand	**Yes**	Section 1.6.3
16	Rate Base and DSP - major drivers of DSP, rate base for test year, change in rate base from last approved ($ and %), capital expenditures requested for the test year, change in capital expenditures from last approved ($ and %), summary of costs requested for renewable energy connections/expansions, smart grid, and regional planning initiatives, any O.Reg 339/09 planned recovery	**Yes**	Section 1.6.4
16	OM&A Expense - OM&A for test year and change from last approved ($ and %), summary of drivers, inflation assumed, total compensation for test year and change from last approved ($ and %).	**Yes**	Section 1.6.5
16	Cost of Capital - Statement regarding use of OEB's cost of capital parameters; summary of any deviations	**Yes**	Section 1.6.6
16	Cost Allocation & Rate Design - summary of any deviations from OEB methodologies, significant changes proposed to revenue-to-cost ratios and fixed/variable splits and summary of proposed mitigation plans	**Yes**	Section 1.6.7
17	Deferral and Variance Accounts - total disposition (RPP and non-RPP), disposition period, new accounts requested	**Yes**	Section 1.6.8
17	Bill Impacts - total impacts ($ and %) for all classes for typical customers	**Yes**	Section 1.6.9
Customer Engagement			
17	Overview of customer engagement activities; description of plans and how customer needs, preferences and expectations have been reflected in the application.	**Yes**	Section 1.5.5
17	Discussion on how customers were informed of the proposals being considered for inclusion in the application and the value of those proposals to customers i.e. costs, benefits, and the impact on rates	**Yes**	Sections 1.5.2, 1.5.3 and 1.5.4
17	Discussion of any feedback provided by customers and how the feedback shaped the final application	**Yes**	Sections 1.5.2, 1.5.3, 1.5.4, 1.5.5 and 1.5.6
17	Reference to any other communication sent to customers about the application i.e. bill inserts, town hall meetings or other forms of out reach and the feedback received from customers through these engagement activities	**Yes**	Attachment 1-G
17	Complete Appendix 2-AC Customer Engagement Activities Summary - explicit identification of the outcomes of customer engagement in terms of the impacts on the distributor's plans, and how that information has shaped the application	**Yes**	Attachment 1-F
17	All responses to matters raised in letters of comment filed with the OEB	**N/A**	
Performance Measurement			
17 & 18	Discussion of performance for each of the distributor's scorecard measures over the last five years; drivers for its performance, plans for continuous improvement, identify performance improvement targets, forecast of efficiency assessment using the PEG forecasting model for the test year, discussion on how the results obtained from the PEG model has informed the business plan and application	**<u>Yes</u>**	Section 1.4
Financial Information			
18	Non-consolidated Audited Financial Statements for 2 most recent years (i.e. 3 years of historical actuals)	**Yes**	Attachment 1-H
18	Detailed reconciliation of AFS with regulatory financial results filed in the application, with identification of any deviations that are being proposed	**Yes**	Attachment 1-I
18	Annual Report and MD&A for most recent year of distributor and parent company, if applicable	**Yes**	Attachments 1-H and 1-J
18	Rating Agency Reports, if available; Prospectuses, etc. for recent and planned public issuances	**N/A**	
19	Any change in tax status	**Yes**	Section 1.7.5
19	Existing accounting orders and departures from the accounting orders and USoA	**N/A**	
19	Accounting Standards used for financial statements and when adopted	**Yes**	Section 1.7.6
19	Confirmation that accounting treatment of any non-utility business has segregated activities from rate regulated activities	**Yes**	Section 1.7.7
Distributor Consolidation			

2018 Cost of Service Checklist

Essex Powerlines Corporation

EB-2017-0039

Date: August 28th, 2017

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
19	If a distributor has acquired or amalgamated with another distributor, 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 specify whether any commitments made to shareholders are to be funded through rates	N/A	
19	Description of actual savings as a result of consolidation compared to what was in the approved consolidation application and explanation of how savings are sustainable and the efficacy of any rate plan approved as part of the MAADs application	N/A	

2018 Cost of Service Checklist

Essex Powerlines Corporation

EB-2017-0039

Filing Requirement Page # Reference

Date: August 28th, 2017

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
EXHIBIT 2 - RATE BASE			
Overview			
20	Completed Fixed Asset Continuity Schedule (Appendix 2-BA) - in Application and Excel format	**Yes**	Attachment 2-A
20	Opening and closing balances, average of opening and closing balances for gross assets and accumulated depreciation (discussion of methodology if applicant uses an alternative method); working capital allowance (historical actuals, bridge and test year forecast)	**Yes**	Section 2.1.1
20	Continuity statements (year end balance, including interest during construction and overheads). Explanation for any restatement (e.g. due to change in accounting standards) Year over year variance analysis; explanation where variance greater than materiality threshold Hist. OEB-Approved vs Hist. Actual Hist. Act. vs. preceding Hist. Act. Hist. Act. vs. Bridge Bridge vs. Test	**Yes**	Section 2.1.2
20 & 21	Opening and closing balances of gross assets and accumulated depreciation must correspond to fixed asset continuity statements. If not, an explanation must be provided (e.g.. WIP, ARO). Reconciliation must be between net book value balances reported on Appendix 2-BA and balances included in rate base calculation	**N/A**	
Gross Assets - PP&E and Accumulated Depreciation			
21	Breakdown by function and by major plant account; description of major plant items for test year	**Yes**	Section 2.2.1
21	Summary of approved and actual costs for any ICM(s) and/ or ACM approved in previous IRM applications	**N/A**	
21	Continuity statements must reconcile to calculated depreciation expenses and presented by asset account	**Yes**	
21	All asset disposals clearly identified in the Chapter 2 Appendices for all historical, bridge and test years and if any amounts related to gains or losses on disposals have been included in Account 1575 IFRS - CGAAP Transitional PP&E Amount	**N/A**	
Allowance for Working Capital			
22	Working Capital - 7.5% allowance or Lead/Lag Study or Previous OEB Direction	**Yes**	Section 2.4
22	Lead/Lag Study - leads and lags measured in days, dollar-weighted	**N/A**	
22	Cost of Power must be determined by split between RPP and non-RPP customers based on actual data, use most current RPP (TOU) price, use current UTR. Should include SME charge.	**Yes**	Section 2.4.3

2018 Cost of Service Checklist

Essex Powerlines Corporation

EB-2017-0039

Filing Requirement Page # Reference

Date: August 28th, 2017

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
Capital Expenditures			
23	DSP filed as a stand-alone document; a discrete element within Exhibit 2	**Yes**	Attachment 2-C
23	Complete Appendix 2-AB - four historical years must be actuals, forecasts for the bridge and test years; at a minimum, for historical years, applicants must provide actual totals for each DSP category. If no previous plan has been filed, applicants are only required to enter their planned total capital budget in the "plan" column for each historical year and for the bridge year including the OEB-approved amount for the last rebasing year	**Yes**	Attachment 2-D
23 & 24	Complete Appendix 2-AA along with: explanation for variances, including that of actuals v. OEB-approved amounts for last OEB-approved CoS application; for capital projects that have a project life cycle greater than one year, the proposed accounting treatment, including the treatment of the cost of funds for construction work-in-progress	**Yes**	Attachment 2-E
24	Statement that there are no non-distribution activities in the applicant's budget	**Yes**	Section 2.1.1
24	If applicable, details of any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include, initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments	**N/A**	
24	Discussion outlining capital and operating efficiencies realized as a result of the deployment and operationalization of smart meters and related technologies (e.g., AMI communications networks, ODS) in its networks. Qualitative and quantitative description and support should be provided as applicable	**Yes**	Section 2.1.1
24	Description of how incremental conservation initiatives have been considered in order to defer or avoid future infrastructure projects as part of distribution system planning processes	**Yes**	Section 2.1.1
24 & 25	If applying for funding through distribution rates to pursue activities such as energy efficiency programs, demand response programs, energy storage programs etc. the application must include a consideration of the projected affects to the distribution system on a long term basis and the projected expenditures. Distributors should explain the proposed program in the context of the distributors five year Distribution System Plan or explain any changes to its system plans that are pertinent to the program	**N/A**	
26	Changes to capitalization policy since its last rebasing application as a result of the OEB's letter dated July 17, 2012 or for any other reasons, the applicant must identify the changes and the causes of the changes.	**Yes**	Section 2.6.5 and Attachment 2-F
27	Appendix 2-D complete; identification of burden rates and burden rates prior to changes, if any	**Yes**	Attachment 2-G
27	Generation Facilities - If applicable, proposal to divide the costs of eligible investments between the distributor's ratepayers and all Ontario ratepayers per O.Reg. 330/09. Request for rate protection exceeds the materiality threshold in section 2.0.8 of the Filing Requirements - Appendices 2-FA through 2-FC identifying all eligible investments for recovery	**N/A**	
New Policy Options for the Funding of Capital			
28	Distributor may propose ACM capital project coming into service during Price Cap IR (a discrete project documented in DSP). Provide cost and materiality calculations to demonstrate ACM qualification	**Yes**	Section 2.6.8
28	Distributor must establish need for and prudence of these projects based on DSP information; identification that distributor is proposing ACM treatment for these future projects, preliminary cost information	**N/A**	
28	Complete Capital Module Applicable to ACM and ICM	**N/A**	
Addition of ICM Assets to Rate Base			
29	Distributor with previously approved ICM(s) - schedule of ICM amounts proposed to be incorporated into rate base, variances and explanation	**Yes**	Section 2.6.9
29	Balances in Account 1508 sub-accounts, reconciliation with proposed rate base amounts; recalculated revenue requirement should be compared with rate rider revenue	**N/A**	
Service Quality and Reliability Performance			
29 & 30	5 historical years of ESQRs, explanation for any under-performance vs standard and actions taken	**Yes**	Section 2.6.10
30	5 historical years of SAIDI and SAIFI - for all interruptions, all interruptions excluding loss of supply, and all interruptions excluding major events. The applicant should also provide a summary of major events that occurred since last rebasing. For each interruption set out in section 2.1.4.2.5 of the RRR, for the last 5 years, a distributor must report on the following data: name of the Cause of Interruption, number of interruptions that occurred as a result of the Cause of Interruption, Number of Customer Interruptions that occurred as a result of the Cause of Interruption, and the Number of customer-hours of Interruptions that occurred as a result of the Cause of Interruption	**Yes**	Section 2.6.10
30	Explanation for any under-performance vs 5 year average and actions taken	**N/A**	
30	Distributors may propose SAIDI and SAIFI benchmarks different than 5 year average; provide rationale	**N/A**	
30	Completed Appendix 2-G	**Yes**	Attachment 2-H

2018 Cost of Service Checklist

Essex Powerlines Corporation

EB-2017-0039

Filing Requirement Page # Reference

Date: August 28th, 2017

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
Ch 5 p9	Where applicable, explanation for section headings other than Chapter 5 headings; cross reference table	**N/A**	
Ch 5 p9-10	Distribution System Plan Overview - key elements, sources of cost savings, period covered, vintage of information on investment drivers, changes to asset management process since last DSP filing, dependencies	**Yes**	Section 2.1 (5.2.1)
Ch 5 p10-11	Coordinated Planning with 3rd parties - description of consultations - deliverables of the Regional Planning Process, or status of deliverables - OPA letter in relation to REG investments (Ch 5 p8&9) and Dx response letter	**Yes**	Section 2.2 (5.2.2)
Ch 5 p11	Performance Measurement - identify and define methods and measures used to monitor DSP performance - summary of performance and trends over historical period. Must include SAIFI and SAIDI for all interruptions and all interruptions excluding loss of supply - explain how information has affected DSP	**Yes**	Section 2.3 (5.2.3)
Ch5 p12	Asset Management Process Overview - description of AM objectives/corporate goals and how Dx ranks objectives for prioritizing investments	**Yes**	Section 3.1 (5.3.1)
Ch5 p12	Inputs/Outputs of the AM process and information flow for investments; flowchart recommended	**Yes**	Figure 3-4, Section 3.1.2
Ch 5 p13	Overview of Assets Managed - description of service area (including evolution of features in forecast period affecting DSP), - description of system configuration - service profile and condition by asset type (tables and/or figures) - date data compiled - assessment of degree the capacity of system assets is utilized	**Yes**	Section 3.2 (5.3.2)
Ch 5 p13-14	Asset Lifecycle Optimization - description of asset lifecycle optimization policies and practices, including asset replacement and refurbishment, maintenance planning criteria and assumptions - description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation	**Yes**	Section 3.3 (5.3.3)
Ch 5 p14-15	Capital Expenditure Plan Summary for significant projects and activities to be undertaken - capability to connect new load or Gx customers, total annual capex over forecast period by investment category, description of how AMP and Capex planning have affected capital expenditures for each category - list, description and total capital cost of material capital expenditures sorted by category (table recommended) - information related to Regional Planning Process (Needs Assessment Report, Regional Planning Status Letter, Regional Infrastructure Plan - as appropriate) - description of customer engagement - Dx expectations of system development over next 5 years - list, description and total capital cost of projects planned in response to customer preferences, to take advantage of technology based opportunities, to study innovative processes (table recommended)	**Yes**	Section 4.1 (5.4)
Ch 5 p15	Capital Expenditure Planning Process Overview - description of capex planning objectives/criteria/ assumptions, relationship with AM objectives, policy on consideration of non-distribution alternatives, processes used to identify projects in each investment category, customer feedback and impact on plan, method and criteria used to prioritise REG investments	**Yes**	Section 4.2 (5.4.2)
Ch 5 p16	System Capability Assessment for REG - REG applications > 10 kW, number and MW of REG connections for forecast period, capacity of Dx to connect REG, connection constraints	**Yes**	Section 4.3 (5.4.3)
Ch 5 p16-18 **Ch 2 p24**	Capital Expenditure Summary by Investment Category - completed Table 2 of Ch 5 for historical and forecast period, explanation of markedly different variances plan vs actual, explanation of markedly different variances year over year Table 2 of Ch 5 is provided in Excel format in Appendix 2-AB (must provide actual totals for historical years, as a minimum)	**Yes**	Section 4.4 (5.4.4)
Ch5 p19	Overall Plan - comparative expenditures by category over historical period, forecast impact of system investment on O&M, drivers of investments by category, information related to Dx system capability assessment	**Yes**	Section 4.5.1 (5.4.5.1)
Ch 5 p19-25	Material Investments - For each project that meets materiality threshold set in Ch 2 p10 - general information - total capital, customer attachments, dates, risks, variances, REG investments - evaluation criteria - may include: efficiency, customer value, reliability, etc. - category specific requirements for each project - system access, system renewal, system service, general plant (as applicable)	**Yes**	Section 4.5.2 (5.4.5.2)

2018 Cost of Service Checklist

Essex Powerlines Corporation

EB-2017-0039

Filing Requirement Page # Reference

Date: August 28th, 2017

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
EXHIBIT 3 - OPERATING REVENUE			
Load and Revenue Forecasts			
31	Explanation of causes, assumptions and adjustments for volume forecast. Economic assumptions and data sources for customer and load forecasts	**Yes**	Sections 3.2.2, 3.2.3 and Attachment 3-A
31	Explanation of weather normalization methodology	**Yes**	Attachment 3-A
31	Quantification of any impacts arising from the persistence of historical CDM programs as well as the forecasted impacts arising from new programs in the bridge and test years through the current 6-year CDM framework by customer class	**Yes**	Section 3.2.4, 3.2.5 and Attachment 3-A
31	Completed Appendix 2-IB; the customer and load forecast for the test year must be entered on RRWF, Tab 10	**Yes**	Attachment 3-B, RRWF Workform
31 & 32	Multivariate Regression Model - rationale for choice, regression statistics, explanation of weather normalization methodology, sources of data for endogenous and exogenous variables, any binary variables used to either account for individual data points or to account for seasonal or cyclical trends or for discontinuities in the historical data, explanation of any specific adjustments made; data used in load forecast must be provided in Excel format, including derivation of constructed variables	**Yes**	Section 3.2 and Attachment 3-A
32 & 33	NAC Model - rationale for choice, data supporting NAC variables, description of accounting for CDM including licence conditions, discussion of weather normalization considerations	**N/A**	
33	CDM Adjustment - account for CDM in 2018 load forecast. Consider impact of persistence of historical CDM and impact of new programs. Adjustments may be required for IESO reported results which are full year impacts	**Yes**	Section 3.2 and Attachment 3-A
33	CDM savings for 2018 LRAMVA balance and adjustment to 2018 load forecast; data by customer class and for both kWh and, as applicable, kW. Provide rationale for level of CDM reductions in 2018 load forecast	**Yes**	Section 3.2 and Attachment 3-A
33	Completed Appendix 2-I	**Yes**	Attachment 3-B
Accuracy of Load Forecast and Variance Analyses			
33	Completed Appendix 2-IB	**<u>Yes</u>**	Attachment 3-B, RRWF Workform
34	For customer/connection counts - identification as to whether customer/connection count is shown in year end or average format, year-over-year variances in changes of customer/connection counts with explanation of major changes, explanations of bridge and test year forecasts by rate class, for last rebasing variance analysis between last OEB-approved and actuals with explanations for material differences	**<u>Yes</u>**	Section 3.3.2
34	For consumption and demand - explanation to support how kWh are converted to kW for applicable demand-billed classes, year-over-year variances in kWh and kW by rate class and for system consumption overall (kWh) with explanations for material changes in the definition of or major changes over time (should be done for both historical actuals against each other and historical weather-normalized actuals over time), explanations of the bridge and test year forecasts by rate class, variance analysis between the last OEB-approved and the actual and weather-normalized actual results	**<u>Yes</u>**	Section 3.3.2
34	For revenues - calculation of bridge year forecast of revenues at existing rates, calculation of test year forecasted revenues at existing and proposed rates, year-over-year variances in revenues comparing historical actuals and bridge and test year forecasts	**<u>Yes</u>**	Section 3.3.2
35	With respect to average consumption, for each rate class, distributors are to provide weather-actual and weather-normalized average annual consumption or demand per customer as applicable for the rate class for last OEB approved and historical, weather normalized average annual consumption or demand per customer for the bridge and test years, explanation of the net change in average consumption from last OEB-approved and actuals from historical, bridge and test years based on year-over-year variances and any apparent trends in data	**<u>Yes</u>**	Section 3.3.2
Other Revenue			
35	Completed Appendix 2-H	**Yes**	Attachment 3-E
35	Variance analysis - year over year, historical, bridge and test	**Yes**	Section 3.4.2
35	Any new proposed specific service charges, or proposed changes to rates or application of existing specific service charges	**Yes**	Section 3.4.3
35	Revenue from affiliate transactions, shared services, corporate cost allocation. For each affiliate transaction, identification of the service, the nature of the service provided to affiliate entities, accounts used to record the revenue and associated costs (Appendix 2-N)	**Yes**	Section 3.4.4
35	Distributors must identify any discrete customer groups that may be materially impacted by changes to other rates and charges	**N/A**	

2018 Cost of Service Checklist

Essex Powerlines Corporation

EB-2017-0039

Filing Requirement Page # Reference

Date: August 28th, 2017

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
EXHIBIT 4 - OPERATING COSTS			
Overview			
36	Brief explanation of test year OM&A levels, cost drivers, significant changes, trends, inflation rate assumed, business environment changes	**Yes**	Section 4.1.2
Summary and Cost Driver Tables			
36	Summary of recoverable OM&A expenses; Appendix 2-JA	**Yes**	Attachment 4-A
36	Recoverable OM&A cost drivers; Appendix 2-JB	**Yes**	Attachment 4-B
36	Recoverable OM&A Cost per customer and per FTE; Appendix 2-L	**Yes**	Attachment 4-C
37	Identification of change in OM&A in test year in relation to change in capitalized overhead.	**Yes**	Section 4.1.2
36	OM&A variance analysis for test year with respect to bridge and historical years; Appendix 2-D	**Yes**	Section 4.2.3, Attachment 2-G
Program Delivery Costs with Variance Analysis			
37	Completed Appendix 2-JC OM&A Programs Table - completed by program or major functions; include variance analysis limited to variances that are outliers, between test year and last OEB approved and most recent actuals, including an explanation for each significant change whether the change was within or outside the applicant's control and explanation of why	**Yes**	Attachment 4-D
37	For each significant change within the applicant's control describe business decision that was made to manage the cost increase/decrease and the alternatives	**Yes**	Section 4.3.2
Workforce Planning and Employee Compensation			
37	Employee Compensation - completed Appendix 2-K	**Yes**	Attachment 4-G
38	Description of previous and proposed workforce plans, including compensation strategy	**Yes**	Section 4.4.1
38	Discussion of the outcomes of previous plans and how those outcomes have impacted their proposed plans including an explanation of the reasons for all material changes to headcount and compensation. Explanation for all years includes: - year over year variances - basis for performance pay, eligible employee groups, goals, measures, and review process for pay-for-performance plans, - relevant studies (e.g. compensation benchmarking)	**Yes**	Sections 4.4.1, 4.4.2, 4.4.3 and 4.4.4
38	Details of employee benefit programs including pensions for last OEB approved, historical, bridge and test; must agree with tax section	**Yes**	Section 4.4.5
38	Most recent actuarial report on employee benefits, pension and OPEBs	**Yes**	Attachment 4-H
38	Accounting method for pension and OPEBs; if cash method, sufficient supporting rationale. If proposing to change the basis in which pension and OPEB costs included in OM&A, quantification of impact of transition	**Yes**	Sectoin 4.4.5
Shared Services and Corporate Cost Allocation			
39	Identification of all shared services among affiliates and parent company; identification of the extent to which the applicant is a "virtual utility"	**Yes**	Section 4.5.1
39	Allocation methodology for corporate and shared services, list of costs and allocators, including any third party review	**Yes**	Section 4.5.1
39	Completed Appendix 2-N for service provided or received for historical, bridge and test; including reconciliation with revenue included in Other Revenue	**Yes**	Attachment 4-I
39	Shared Service and Corporate Cost Variance analysis - test year vs last OEB approved and most recent actual	**Yes**	Section 4.5.5
39	Identification of any Board of Director costs for affiliates included in LDC costs	**N/A**	
Non-Affiliate Services, One-Time Costs, Regulatory Costs			
39	Purchased Non-Affiliated Services - file a copy of procurement policy (signing authority, tendering process, non-affiliate service purchase compliance)	**Yes**	Section 4.6, Attachment 4-J
39	For material transactions that are not in compliance with procurement policy, or that were undertaken pursuant to exceptions contemplated within the policy, an explanation as to why as well as a summary of the nature and cost of the product, and a description of the specific methodology used for selecting the vendor	**N/A**	
40	Identification of one-time costs in historical, bridge, test; explanation of cost recovery in test (or future years). If no recovery of one-time costs is being proposed in the test year and subsequent IRM term, an explanation must be provided	**Yes**	Section 4.6
40	Regulatory costs - breakdown of actual and forecast, supporting information related to CoS application (e.g. legal fees, consultant fees), proposed recovery (i.e. amortized?) Completed Appendix 2-M	**Yes**	Section 4.7, Attachment 4-K
LEAP, Charitable and Political Donations			
40	LEAP - the greater of 0.12% of forecasted service revenue requirement or $2,000 should be included in OM&A and recovered from all rate classes	**Yes**	Section 4.9
41	Detailed information for all contributions that are claimed for recovery	**Yes**	Section 4.10
41	Charitable Donations - the applicant must confirm that no political contributions have been included for recovery	**Yes**	Section 4.10.2

2018 Cost of Service Checklist

Essex Powerlines Corporation

EB-2017-0039

Filing Requirement Page # Reference

Date: August 28th, 2017

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
Depreciation, Amortization and Depletion			
41	Explanations for any useful lives of an asset that are proposed that are not within the ranges contained in the Kinectrics Report	**N/A**	
41	Depreciation, Amortization and Depletion details by asset group for historical, bridge and test years. Include asset amount and rate of depreciation/amortization. Must agree to accumulated depreciation in Appendix 2-BA under rate base	**Yes**	Section 4.11.1
41	Identification of any Asset Retirement Obligations and associated depreciation, accretion expense	**Yes**	Section 4.11.2
41 & 42	Identification of historical depreciation practice and proposal for test year. Variances from half year rule must be documented and supporting rationale provided	**Yes**	Section 4.11.4
42	Copy of depreciation/amortization policy, or equivalent written description; summary of changes to depreciation/amortization policy since last CoS	**Yes**	Section 4.11.3, Attachment 2-F
42	Explanation of any deviations from the practice of depreciating significant parts or components of PP&E separately	**N/A**	
42	For any depreciation expense policy or asset service lives changes since its last rebasing application: - identification of the changes and detailed explanation for the causes of the changes, including any changes subsequent to those made by January 1, 2013 -use of Kinectrics study or another study to justify changes in useful life - list detailing all asset service lives tied to USoA, detail differences in TUL from Kinectrics and explain differences outside of minimum and maximum TUL range from Kinectrics; Appendix 2-BB -File applicable depreciation appendices as provided in Chapter 2 MIFRS Appendices (Appendix 2-CA to 2-CK)	**Yes**	Attachments 4-L, 4-M
PILs and Property Taxes			
43	Completed version of the PILs model (PDF and Excel); derivation of adjustments for historical, bridge, test years	**Yes**	Attachment 4-O
43	Supporting schedules and calculations identifying reconciling items	**Yes**	Section 4.12.1
43	Most recent federal and provincial tax returns	**Yes**	Attachment 4-N
18 & 43	Financial Statements included with tax returns if different from those filed with application	**N/A**	
43	Calculation of Tax Credits; redact where required (filing of unredacted versions is not required)	**Yes**	Section 4.12.1
43	Supporting schedules, calculations and explanations for other additions and deductions	**Yes**	Section 4.12.1
43	Completion of the integrity checks in the PILs Model	**Yes**	Section 4.14, Attachment 4-O
41	Explanation of how taxes other than income taxes or PILS (e.g. property taxes) are derived	**Yes**	Section 4.12.1
Non-recoverable and Disallowed Expenses			
43	Exclude from regulatory tax calculation any non-recoverable or disallowed expenses	**Yes**	Section 4.13, Attachment 4-O
Conservation and Demand Management			
44 & 45 & 46	LRAMVA - disposition of balance. Distributors must provide new LRAMVA Workform in a working Excel file and provide the following: - statement identifying the year(s) of new lost revenues and prior year savings persistence claimed in the LRAMVA disposition - statement confirming LRAMVA based on verified savings results supported by the distributors final CDM Report and Persistence Savings Report (both filed in Excel format) and a statement indicating use of most recent input assumptions when calculating lost revenue - summary table with principal and carrying charges by rate class and resulting rate riders - statement providing the disposition period; rationale provided for disposing the balance in the LRAMVA if one or more classes do not generate significant rate riders - statement confirming LRAMVA reference amounts, rationale for the distributors circumstances if LRAMVA threshold not used - rationale confirming how rate class allocations for actual CDM savings were determined by class and program (Tab 3-A of LRAMVA Workform) - statement confirming whether additional documentation was provided in support of projects that were not included in distributors final CDM Annual Report (Tab 8 of LRAMVA Workform as applicable) - for OEB-approved programs prior to 2014, a submission of a third party report that provides a review and verification of the LRAM calculation including: confirmation of use of correct input assumptions and lost revenue calculations, participation amounts, net and gross impacts of each program (kW and kWh) by class by year, and verification of any carrying charges requested	**Yes**	Section 4.15, Attachments 4P and 4Q

2018 Cost of Service Checklist

Essex Powerlines Corporation

EB-2017-0039

Filing Requirement Page # Reference

Date: August 28th, 2017

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
EXHIBIT 5 - COST OF CAPITAL AND CAPITAL STRUCTURE			
Capital Structure			
46	Statement that LDC adopts OEB's guidelines for cost of capital and confirms that updates will be done. Alternatively - utility specific cost of capital with supporting evidence	**Yes**	Section 5.1
46	Completed Appendix 2-OA for last OEB approved and test year	**Yes**	Attachment 5-D
46	Completed Appendix 2-OB for historical, bridge and test years	**Yes**	Attachment 5-C
46	Explanation for any changes in capital structure	**Yes**	Section 5.2
Cost of Capital (Return on Equity and Cost of Debt)			
47	Calculation of cost for each capital component	**Yes**	Section 5.2
47	Profit or loss on redemption of debt	**Yes**	Section 5.2.4
47	Copies of promissory notes or other debt arrangements with affiliates	**Yes**	Attachment 5-A, 5-B
47	Explanation of debt rate for each existing debt instrument	**Yes**	Section 5.2
47	Forecast of new debt in bridge and test year - details including estimate of rate	**Yes**	Section 5.2.5, Attachment 5-C
47	If proposing any rate that is different from the OEB guidelines, a justification of the proposed rate(s), including key assumptions	**Yes**	Section 5.2.1
47	Notional Debt - difference between actual debt thickness and deemed debt thickness attracts the weighted average cost of actual long-term debt rate (unless 100% equity financed)	**Yes**	Section 5.2.5
Not-for-Profit Corporations			
48	Not for Profit Corporations - evidence that excess revenue is used to build up operating and capital reserves	**N/A**	
48	Detailed calculation for test year revenue requirement based on its Reserve Requirement	**N/A**	
48	The proposed reserves and rationale for the need to establish each reserve, the time period of building up the reserves, and the procedure and policy of each reserve	**N/A**	
48	Description of the governance of the not-for-profit corporation	**N/A**	
48 & 49	If there are approved reserves from previous OEB decisions provide the following: -any changes to the reserve policies and rationale for the changes since last CoS limits of any capital and/or operating reserves as approved by the OEB and identify decisions -current balances of any established capital and/or operating reserves -list withdrawals from capital and operating reserves, identify amounts and purpose of withdrawal -if limits on capital and operating reserves achieved provide a proposal for utilization of amounts -if limits on reserves not achieved provide rationale and the detail for its forecast of the Reserve Requirement for the test year	**N/A**	
EXHIBIT 6 - REVENUE DEFICIENCY/SUFFICIENCY			
49	Calculation of delivery-related Revenue Deficiency/Sufficiency (excluding cost of power and associated costs): net utility income, rate base, actual return on rate base, indicated rate of return, requested rate of return, deficiency/sufficiency, gross deficiency/sufficiency. Deficiency/sufficiency must also be net of other costs (e.g. LV costs, RSVAs, smart meter or MIST meter expenditures/revenues and other DVA balances).	**Yes**	Section 6.1
49 & 50	Summary of drivers for test year deficiency/sufficiency, how much each driver contributes; references in application evidence mapped to drivers	**Yes**	Section 6.7
50	Impacts of any changes in methodologies to deficiency/sufficiency	**Yes**	Section 6.7
Revenue Requirement Work Form			
50	RRWF - in PDF and Excel. Revenue requirement, def/sufficiency, data entered in RRWF must correspond with other exhibits	**Yes**	Attachment 6-A
50	If the enhanced RRWF cannot reflect a distributor's proposed rates accurately, the distributor must file its rate generator model	**N/A**	

2018 Cost of Service Checklist

Essex Powerlines Corporation

EB-2017-0039

Filing Requirement Page # Reference

Date: August 28th, 2017

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
EXHIBIT 7 - COST ALLOCATION			
Cost Allocation Study Requirements			
51	Completed cost allocation study using the OEB-approved methodology or a comparable model must be filed reflecting future loads and costs and be supported by appropriate explanations and live Excel spreadsheets. Sheets 11 and 12 of the RRWF must also be completed. Live Excel version of 2017 cost allocation model will be filed (updated load profiles or scaled version of HONI CAIF). Model must be consistent with test year load forecast, changes to customer classes and load profiles.	Yes	
51	Explanation provided if a distributor is unable to update its load profiles and confirm that it intends to put plans in place to update its load profiles the next time a cost allocation model is filed	N/A	
52	Description of weighting factors, and rationale for use of default values (if applicable)	Yes	Section 7.3.6, 7.3.9 and 7.3.10
52	Hard copy of sheets I-6, I-8, O-1 and O-2 (first page)	Yes	Attachment 7-A
52 & 53	Host Distributor only - evidence of consultation with embedded Dx - statement regarding embedded Dx support for approach to allocation of costs - if embedded Dx is separate class - class in cost allocation study and RRWF, Sheet 11 - if new embedded Dx class - rationale and supporting evidence (cost of serving, load served, asset ownership information, distribution charges); include in cost allocation study and RRWF, Sheet 11 - if embedded Dx billed as GS customer - , include with the GS class in cost allocation model and Appendix 2-P. Provide cost of serving, load served, asset ownership information, distribution charges, appropriateness of rate class. File Appendix 2-Q.	Yes	Section 7.2.4
53	Unmetered Loads (including Street Lighting) - Confirmation of communication with unmetered load customers when proposing changes to the level of the rates and charges or the introduction of new rates and charges	Yes	Section 7.2.2
53	microFIT - if the applicant believes that it has unique circumstances which would justify a certain rate, appropriate documentation must be provided	Yes	Section 7.2.5
53	Standby Rates - if seeking approval on final basis, provide evidence that affected customers have been advised. If seeking changes to standby charges, provide rationale and evidence that affected customer have been advised.	N/A	
54	New customer class or eliminated customer class - rationale and restatement of revenue requirement from previous CoS	Yes	Section 7.2.1
Class Revenue Requirements			
54	To support a proposal to rebalance rates, the distributor must provide information on the revenue by class that would apply if all rates were changed by a uniform percentage. Ratios must be compared with the ratios that will result from the rates being proposed by the distributor.	Yes	Section 7.5
Revenue to Cost Ratios			
55	If R:C ratios outside deadband based on model - distributors must include cost allocation proposal to bring them within the OEB-approved ranges. In making any such adjustments, distributors should address potential mitigation measures if the impact of the adjustments on the rates of any particular class or classes is significant.	Yes	Section 7.5
55	If Cost Allocation Model other than OEB model used - exclude LV, exclude DVA such as smart meters	N/A	

2018 Cost of Service Checklist

Essex Powerlines Corporation

EB-2017-0039

Filing Requirement Page # Reference

Date: August 28th, 2017

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
EXHIBIT 8 - RATE DESIGN			
56	Monthly fixed charges - 2 decimal places; variable charges - 4 decimal places	**Yes**	
Fixed Variable Proportion			
56	The following is to be provided in relation to the fixed/variable proportion of proposed rates: -Current F/V with supporting info -Proposed F/V proportion with explanation for any changes (billing determinants from proposed load forecast) -Comparison between current and proposed monthly fixed charges with the floor and ceiling as in cost allocation study Analysis must be net of rate adders, funding adders, and rate riders	**Yes**	Section 8.1.2
Rate Design Policy			
57	LDCs must propose changes to residential rates consistent with policy to transition to fully fixed monthly distribution service charge.	**Yes**	Section 8.1.4, Attachment 8-A
57	Proposal follows approach set out in Tab 12 of RRWF	**Yes**	
57	If applicable, distributor with seasonal residential class must propose identical rate design treatment for such a class	**N/A**	
RTSRs			
58	Retail Transmission Service Rate Work Form - PDF and Excel	**Yes**	Attachment 8-C
58	RTSR information must be consistent with working capital allowance calculation	**Yes**	
Retail Service Charges			
58	If proposing changes to Retail Service Charges or introduction of new rates and charges - evidence of consultation and notice	**Yes**	Section 8.9
Regulatory Charges			
58 & 59	Wholesale Market Service Rate - reflect current approved rate in application or justify otherwise	**Yes**	Section 8.5
Specific Service Charges			
59	Specific Service Charge description/purpose/reason for new and revised SSC; calculations to support charges	**Yes**	Section 8.8
59	Identification in the Application Summary all proposed changes that will have a material impact on customers, including charges that may affect a discrete group.	**Yes**	Section 8.8
59	Identification of any rates and charges in Conditions of Service that do not appear on tariff sheet. Explain nature of costs, provide schedule outlining revenues or capital contributions 2012-2015, bridge and test years. Whether these charges should be included on tariff sheet	**Yes**	Section 8.11
59	Ensure revenue from SSCs corresponds with Operating Revenue evidence	**Yes**	
Low Voltage Service Rates			
60	Forecast of LV cost, sum of host distributors charges	**Yes**	Section 8.3.2
60	Low Voltage Cost (historical, bridge, test), variances and explanations for substantive changes	**Yes**	Section 8.3.1
60	Support for forecast LV, e.g. Hydro One Sub-Transmission charges	**Yes**	Section 8.3.3
60	Allocation of LV cost to customer classes (typically proportional to Tx connection revenue)	**Yes**	Section 8.3.3
60	Proposed LV rates by customer class	**Yes**	Section 8.3.3

2018 Cost of Service Checklist

Essex Powerlines Corporation

EB-2017-0039

Filing Requirement Page # Reference

Date: August 28th, 2017

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
Loss Factors			
60	Proposed SFLF and Total Loss Factor for test year	Yes	Section 8.10
60	Statement as to whether LDC is embedded including whether fully or partially	Yes	Section 8.3.1
60	Study of losses if required by previous decision	N/A	
60	3-5 years of historical loss factor data - Completed Appendix 2-R	Yes	Section 8.10
60	If proposed loss factor >5%, explanation and action plan to reduce losses going forward	N/A	
60	Explanation of SFLF if not standard	N/A	
Tariff of Rates and Charges			
60 & 61	Current and proposed Tariff of Rates and Charges filed in the Tariff Schedule/Bill Impacts Model - each change must be explained and supported in the appropriate section of the application	Yes	Attachments 8-E and 8-F
61	Explanation of changes to terms and conditions of service if changes affect application of rates	N/A	
Revenue Reconciliation			
61	Calculations of revenue per class under current and proposed rates; reconciliation of rate class revenue and other revenue to total revenue requirement (i.e. breakout volumes, rates and revenues by rate component etc.)	Yes	Section 8.1.5
61	Completed RRWF - Sheet 13 - rates and charges entered on this sheet should be rounded to the same decimal places as tariff	Yes	
Bill Impact Information			
61	Completed Tariff Schedule and Bill Impacts Model. Bill impacts must identify existing rates, proposed changes to rates, and detailed bill impacts (including % change in distribution excluding pass through costs - Sub-Total A, % change in distribution - Sub-Total B, % change in delivery - Sub-Total C, and $ change in total bill)	Yes	Section 8.13, Attachment 8-F, Attachment 8-G
61	Impact of changes resulting from the as-filed application on representative samples of end-users (i.e. volume, % rate change and revenue). Commodity and regulatory charges held constant	Yes	Section 8.13
61 & 62	Rates and charges input in the tariff schedule and Bill Impacts Model rounded to the decimal places as shown on the existing tariff	Yes	Attachment 8-F
62	Bill impacts provided for typical customers and consumption levels. Must provide residential 750 kWh, residential at the lowest 10th percentile and GS<50 2,000 kWh. Bill impacts must be provided for a range of consumption levels relevant to the service territory.	Yes	Section 8.13, Attachment 8-G
62	If applicable, for certain classes where one or more customers have unique consumption and demand patterns, the distributor must show a typical impact and provide an explanation	N/A	
Rate Mitigation			
62	Evidence showing that the monthly service charge would not rise by more than $4 per year due only to the rate design change, and that the total bill impact, reflecting all proposed changes in the application, will not exceed 10%. If either of these criteria is not met, some form of mitigation may be required (i.e. extending transition period).	Yes	Section 8.13, Attachment 8-G
63	Evaluation of bill impact for residential customer at 10th consumption percentile. Describe methodology for determination of 10th consumption percentile. File mitigation plan for whole residential class if impact >10% for these customers.	Yes	Section 8.13, Attachment 8-G
63	Mitigation plan if total bill increase for any customer class is >10% including: specification of class and magnitude of increase, description of mitigation measures, justification, revised impact calculation. The Tariff Schedule and Bill Impacts Model must reflect any mitigation plan proposed.	N/A	
64	Rate Harmonization Plans, if applicable - including impact analysis	N/A	

2018 Cost of Service Checklist

Essex Powerlines Corporation

EB-2017-0039

Filing Requirement Page # Reference

Date: August 28th, 2017

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS			
64	List of all outstanding DVA and sub-accounts; provide description of DVAs that were used differently than as described in the APH	**Yes**	Sections 9.4 and 9.5
64	Completed DVA continuity schedule for period following last disposition to present - live Excel format	**Yes**	
64	Confirm use of interest rates established by the OEB by month or by quarter for each year	**Yes**	Section 9.2.3
64	Explanation if account balances in continuity schedule differs from trial balance in RRR and AFS	**Yes**	2018 DVA Workform, sheet 3
64	Identification of Group 2 accounts that will continue/discontinue going forward, with explanation	**Yes**	Sections 9.6.2 and 9.6.3
64	Statement as to any new accounts, and justification.	**Yes**	Section 9.6.1
65	Statement whether any adjustments made to DVA balances previously approved by OEB on final basis; explanation, amount of adjustment and supporting documents	**N/A**	
65	Breakdown of energy sales and cost of power by USoA - as reported in AFS mapped and reconciled to USoA. Provide explanation if making a profit or loss on commodity.	**Yes**	Section 9.2.2
65	Statement confirming that IESO GA charge is pro-rated into RPP and non-RPP; provide explanation if not pro-rated.	**Yes**	Section 9.1
One-Time Incremental IFRS Costs			
65 & 66	Request for disposition of Account 1508 sub-account IFRS Transition Costs if balances are still in account and not previously requested for disposition: - completed Appendix 2-YA -statement whether any one time IFRS transition costs are embedded in 2018 revenue requirement, where and why it is embedded, and the quantum - if Account 1508 sub-accounts have been approved for disposition in a prior year, a statement indicating whether prior disposition included forecasted costs -explanation for material variances in Account 1508 sub-account IFRS Transition Costs Variance - explanation on why costs incurred after adoption of IFRS, if any, and the nature of the costs - statement that no capital costs, ongoing IFRS compliance costs are recorded in 1508 sub-account; provide explanation if this is not the case	**Yes**	Section 9.5.1, Attachment 9-C
Account 1575, IFRS-CGAAP Transitional PP&E Amounts			
66 & 67	1575 IFRS-CGAAP PP&E account - Account 1575 and 1576 can't be used interchangeably - breakdown of balance, including explanation for each accounting change; Appendix 2-EA - listing and quantification of drivers - volumetric rate rider to clear 1575; separate rider must be on a fixed basis for the residential class; - rate of return component is to be applied to 1575 but not recorded in 1575 - statement confirming no carrying charges applied to 1575 - explanation for the basis of the proposed disposition period to clear Account 1575 rate rider - show the balance in DVA continuity schedule	**N/A**	
Account 1576, Accounting Changes under CGAAP			
67 & 68	Changes to depreciation and capitalization in 2012 or 2013 - Account 1576 IFRS-CGAAP PP&E - Appendix 2-BA must not be adjusted for 1576 - breakdown of balance related to 1576, Appendix 2-EB or 2-EC - drivers of change in closing net PP&E identified and quantified - volumetric rate rider to clear 1576; the rider for the residential class must be on a fixed basis - rate of return component is to be applied to 1576 but not recorded in 1576 - statement confirming no carrying charges applied to 1576 - explanation for the basis of the proposed disposition period to clear Account 1576 rate rider - show the balance in DVA continuity schedule	**Yes**	Section 9.5.10, Attachment 9-E
Retail Service Charges			
68	Retail Service Charges - material balance in 1518 or 1548 - confirm variances are incremental costs of providing retail services; identify drivers for balances - provide schedule identifying all revenues and expenses listed by USoA for 2013, actual/forecast for bridge and test year - state whether Article 490 of APH has been followed; explanation if not followed	**Yes**	Section 9.5.2
69	Retail Service Charges - zero balance in 1518 or 1548 - state whether Article 490 of APH has been followed; explanation if not followed	**N/A**	

2018 Cost of Service Checklist

Essex Powerlines Corporation

EB-2017-0039

Filing Requirement Page # Reference

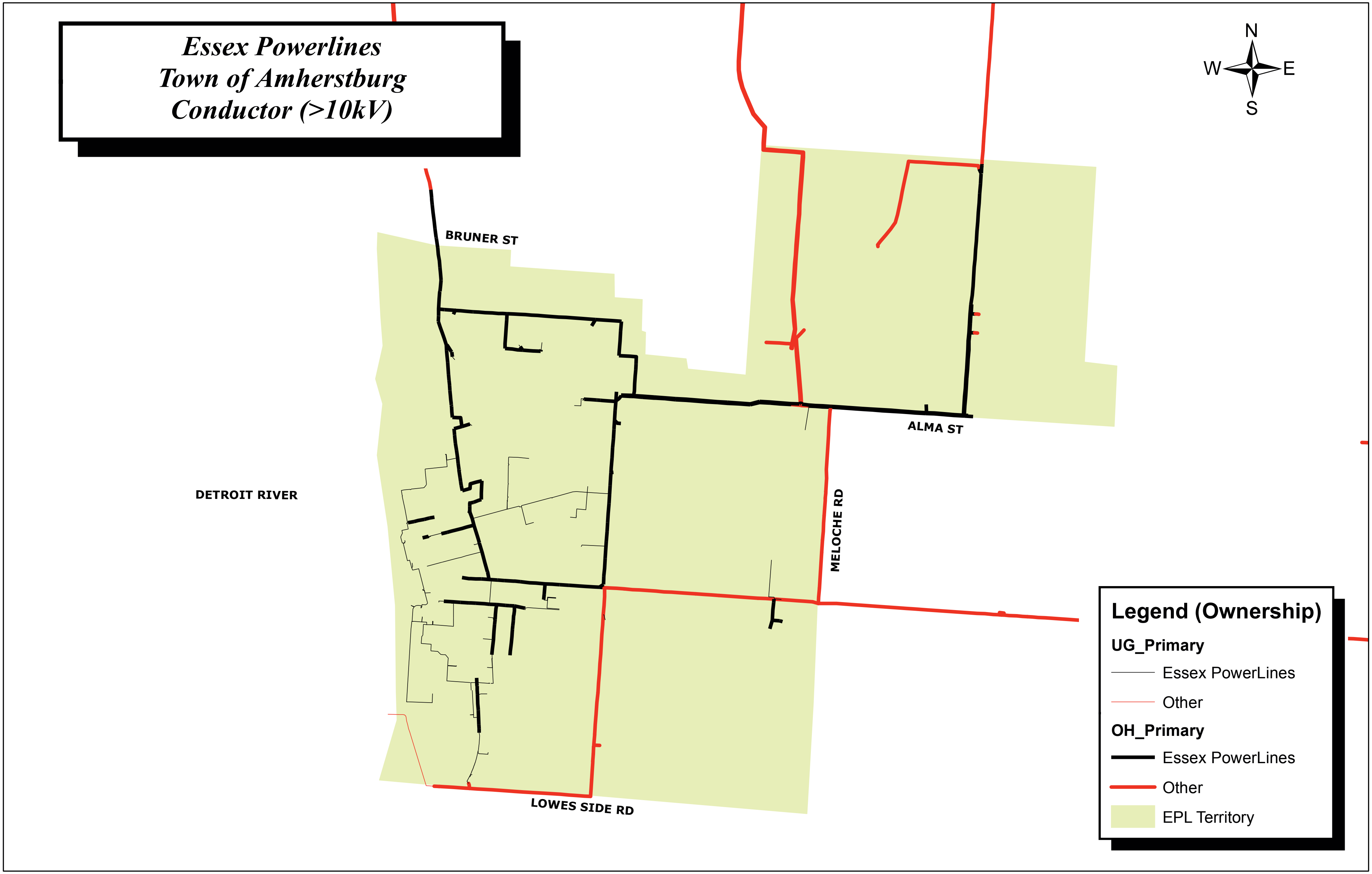
Date: August 28th, 2017

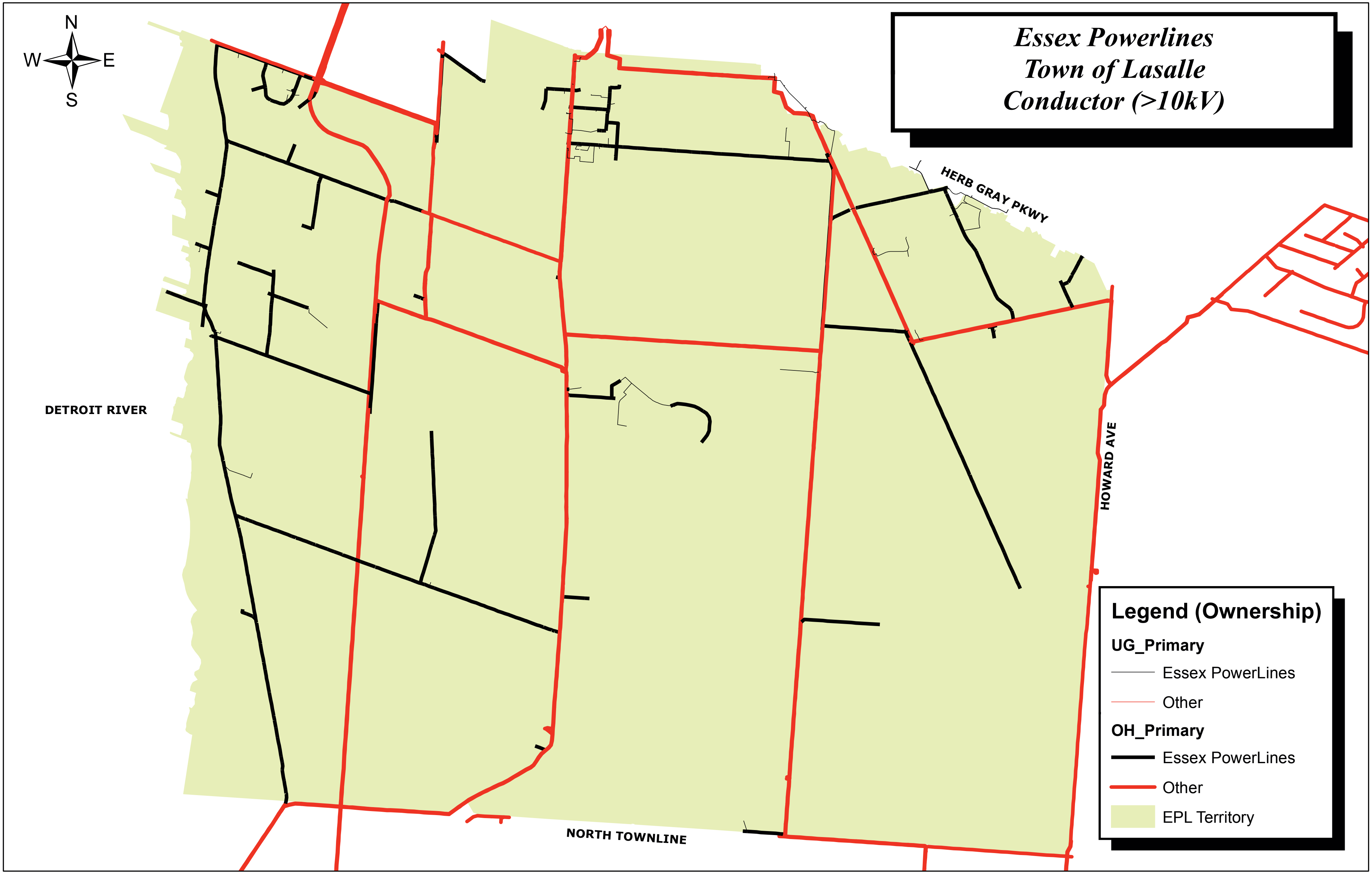
Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
Disposition of Deferral and Variance Accounts			
69	Identify all accounts for which LDC is seeking disposition; identify DVA for which LDC is not proposing disposition and the reasons why	**Yes**	Section 9.3
69	Statement whether DVA balances before forecasted interest match the last AFS; explain any variances	**Yes**	Section 9.2.1
69	Provide an explanation of variance > 5% between amounts proposed for disposition and amounts reported in RRR for each account.	**N/A**	
69	Provide explanations if variances are < 5% threshold if the variances in question relate to: (1) matters of principle (i.e. conformance with the APH or prior OEB decisions, and prior period adjustments); and/or, (2) the cumulative effect of immaterial differences over several accounts total to a material difference between what is proposed for disposition in total before forecasted interest and what is recorded in the RRR filings	**N/A**	
69	For any utility specific accounts requested for disposition, supporting evidence showing how balance is derived and relevant accounting order	**N/A**	
69	Disposition of residual balances for vintage Account 1595 are only done once - distributors expected to seek disposition of the balance a year after a rate rider's sunset date has expired. No further dispositions of these accounts are generally expected unless justified by the distributor	**Yes**	
69 & 70	Proposed mechanisms for disposition with all relevant calculations: allocation of each account (including rationale), billing determinants for recovery purposes in accordance with Rate Design Policy	**Yes**	Section 9.7
70	Rate riders where volumetric rider is $0.0000 for one or more classes not included in the tariff for those classes	**N/A**	
70	Propose rate riders for recovery or refund of balances that are proposed for disposition. The default disposition period is one year; if the applicant is proposing an alternative recovery period must provide explanation.	**Yes**	Section 9.7
70	Establish separate rate riders to recover balances in the RSVA's from Market Participants who must not be allocated the RSVA balances related to charges for which the MP's settle directly with the IESO.	**Yes**	Section 9.7.2
70	Proposed disposition of Account 1580 sub-account CBR Class B in accordance with the CBR Accounting Guidance. - embedded distributors who are not charged CBR (therefore no balance in sub-account CBR Class B) must indicate this is the case for them - In the DVA continuity schedule, applicants must indicate whether they serve any Class A customers during the period where Account 1580 CBR Class B sub-account balance accumulated. - Account 1580 sub-account CBR Class A is not to be disposed through rates proceedings but rather follow the OEB's accounting guidance. - The DVA continuity schedule will allocation the portion of Account 1580 sub-account CBR Class B allocated to customers who transitioned between Class A and Class B based on consumption levels	**Yes**	Section 9.4.5
Global Adjustment			
71	Establishment of a separate rate rider included in the delivery component of the bill that would apply prospectively to Non-RPP Class B customers when clearing balances from the GA Variance Account	**Yes**	Section 9.7
71	RPP Settlement True-Up - distributors to follow guidance in May 23, 2017 letter pertaining to the period that is being requested for disposition for Accounts 1588 and 1589	**Yes**	Section 9.4.8 and 9.4.9
71	GA Analysis Workform in live Excel format- complete GA Analysis Workform; explain discrepancies	**No**	Consistent with Board direction, GA Analysis Workform can be filed shortly after submission. EPLC plans to file this Workform shortly after submission
72	Description of settlement process with IESO or host distributor, specify GA rate used for each rate class, itemize process for providing estimates and describe true-up process, details of method for estimating RPP and non-RPP consumption, treatment of embedded generation/distribution. If distributor uses the actual GA rate to bill non-RPP Class B customers, a proposal must be made to exclude these customer classes from the allocations of the balance of Account 1589 and the calculation of the resulting rate riders	**Yes**	Section 9.4.9
72	Certification by the CEO, CFO or equivalent that distributor has robust processes and internal controls in place for the preparation, review, verification and oversight of account balances being proposed for disposition	**Yes**	Attachment 9-D
Establishment of New Deferral and Variance Accounts			
72 & 73	New DVA - information provided which addresses that the requested DVA meets the following criteria: causation, materiality, prudence; include draft accounting order.	**N/A**	

TOTAL "NO"	**1**	

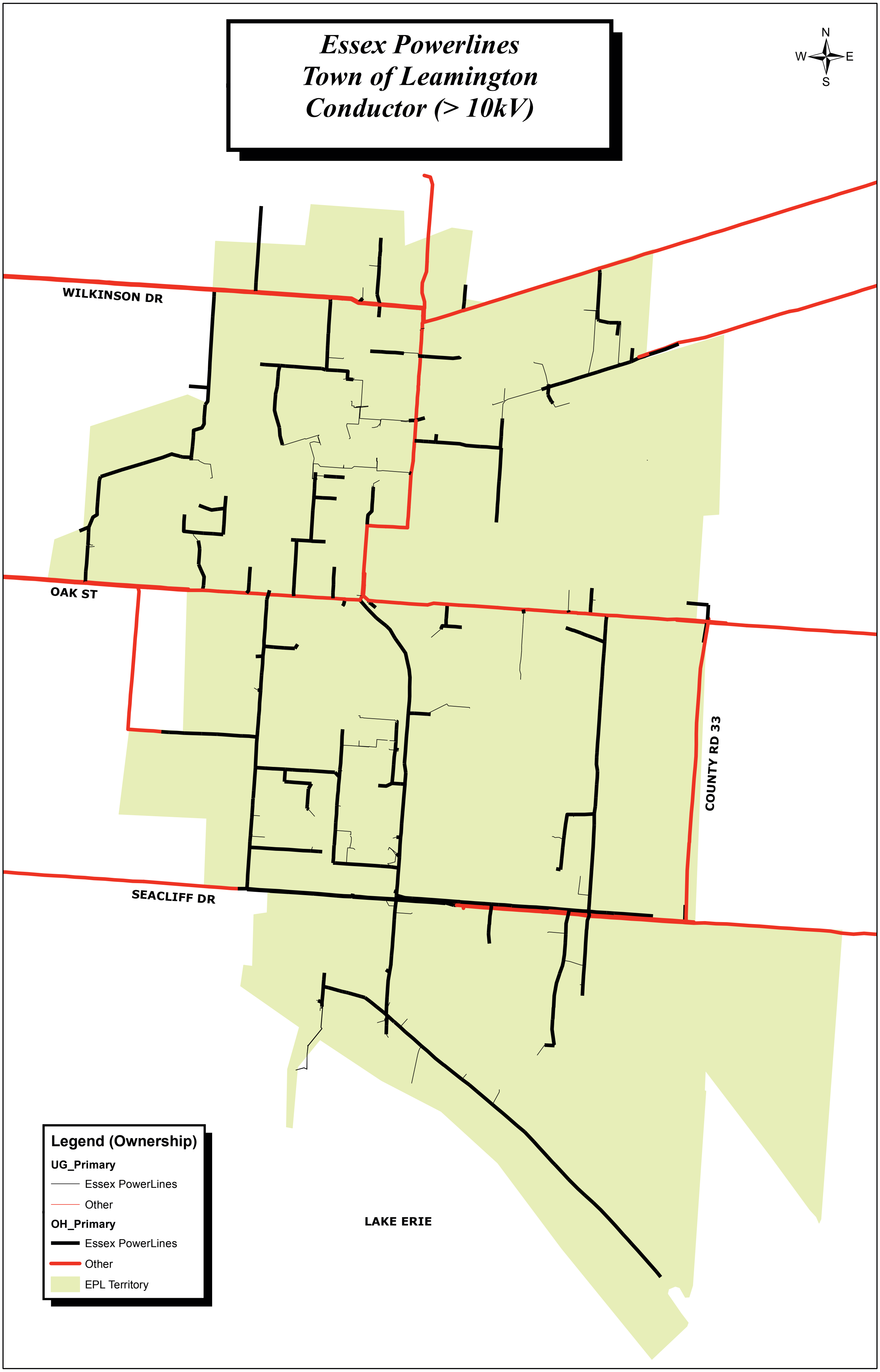
<u>Attachment 1-C</u>

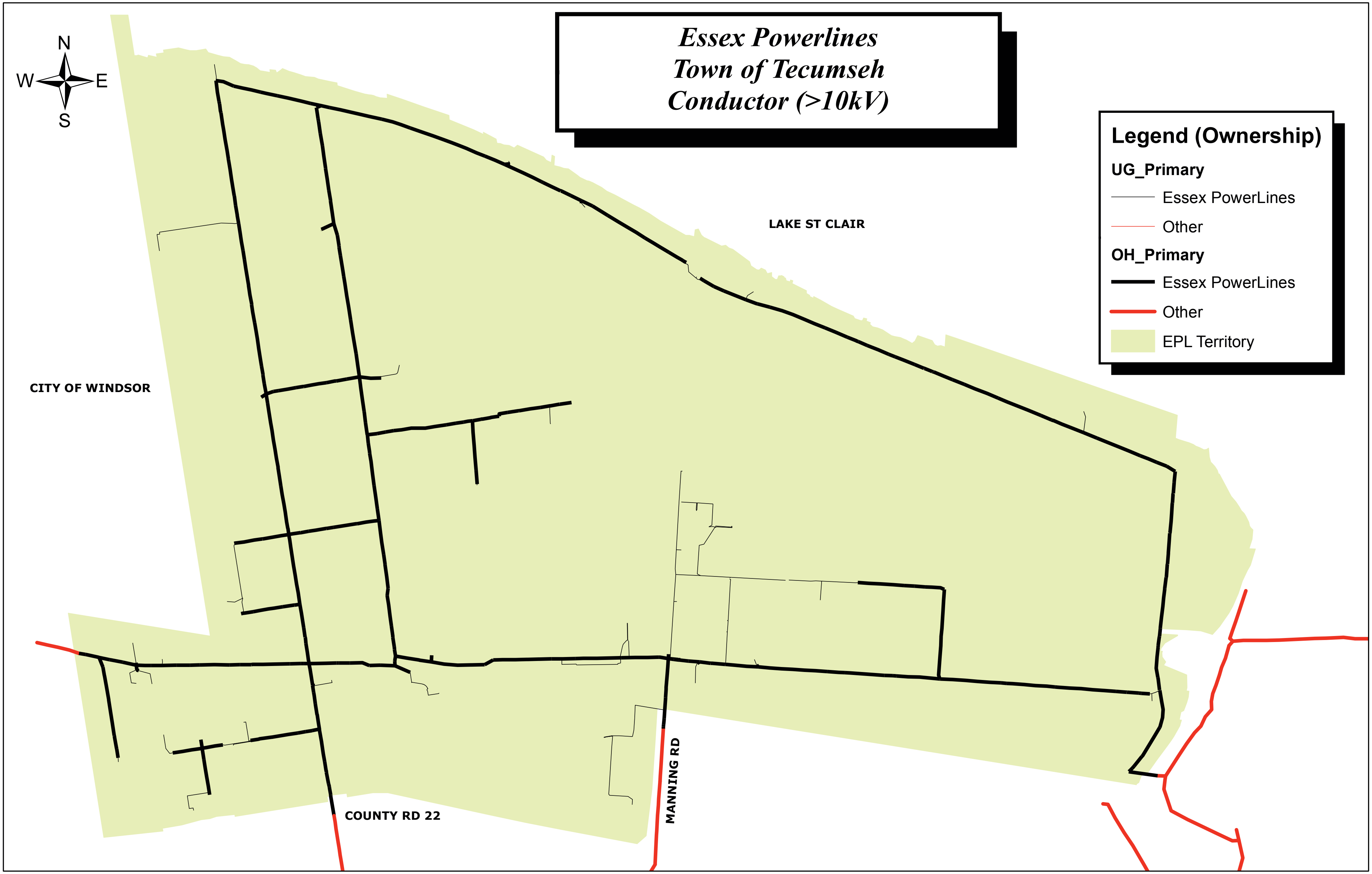
EPLC Service Territory Maps


Essex Powerlines
Town of Amherstburg
Conductor (>10kV)
N
W
E
S
BRUNER ST
ALMA ST
DETROIT RIVER
MELOCHE RD
LOWES SIDE RD
Legend (Ownership)
UG_Primary
Essex PowerLines
Other
OH_Primary
Essex PowerLines
Other
EPL Territory



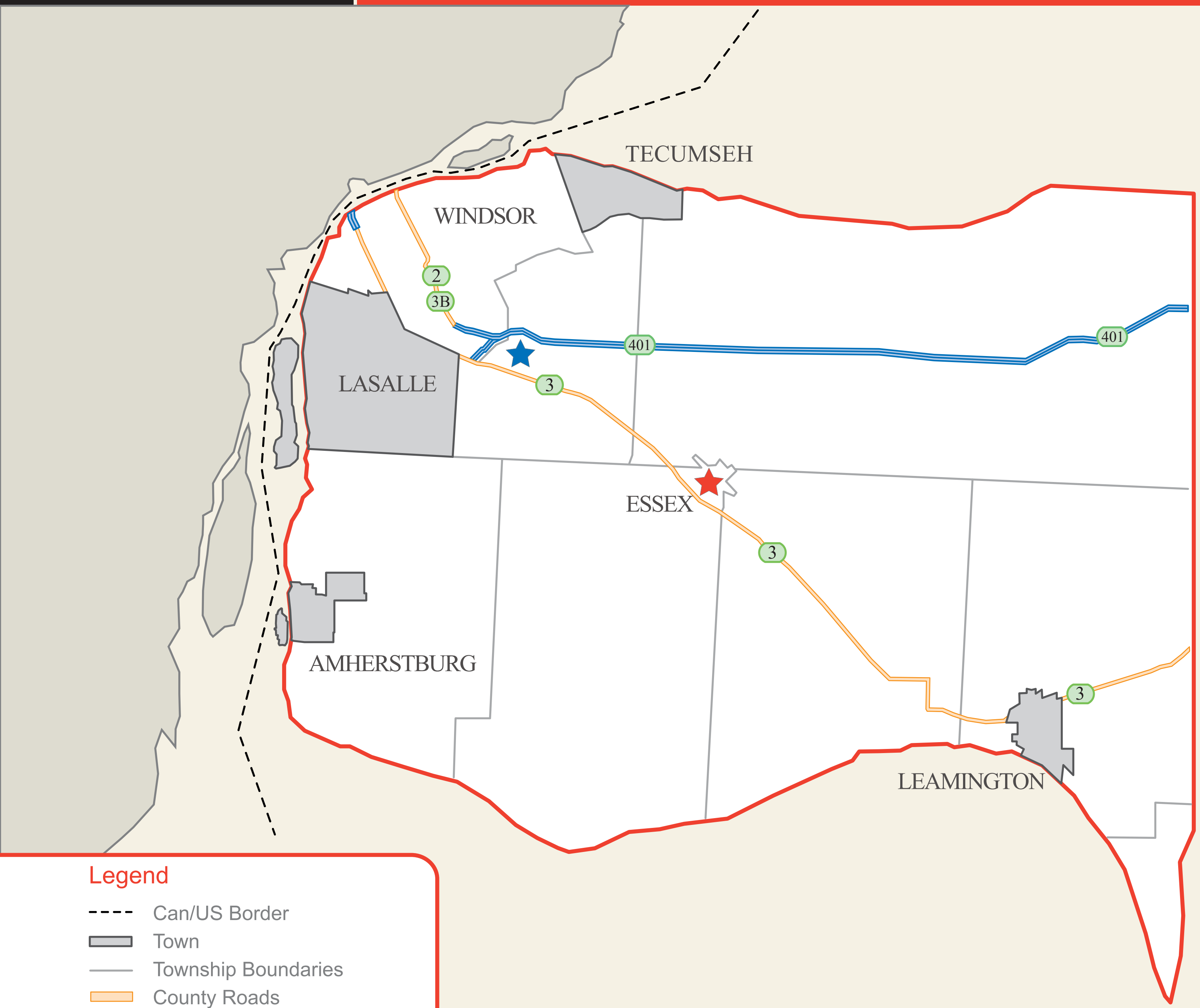
Essex Powerlines
Town of Lasalle
Conductor (>10kV)
N
W
E
S
DETROIT RIVER
HERB GRAY PKWY
HOWARD AVE
NORTH TOWNLINE
Legend (Ownership)
UG_Primary
Essex PowerLines
Other
OH_Primary
Essex PowerLines
Other
EPL Territory


Essex Powerlines
Town of Leamington
Conductor (> 10kV)
N
W
E
S
WILKINSON DR
OAK ST
SEACLIFF DR
COUNTY RD 33
LAKE ERIE
Legend (Ownership)
UG_Primary
Essex PowerLines
Other
OH_Primary
Essex PowerLines
Other
EPL Territory



Essex Powerlines
Town of Tecumseh
Conductor (>10kV)
N
W
E
S
Legend (Ownership)
UG_Primary
Essex PowerLines
Other
OH_Primary
Essex PowerLines
Other
EPL Territory
LAKE ST CLAIR
CITY OF WINDSOR
COUNTY RD 22
MANNING RD

Service Region



Legend

- Can/US Border
- Town
- Township Boundaries
- County Roads
- King's Highway

Point of Interest

- Main Office
- Main Service Center

Attachment 1-D

Green Energy Act Plan

ESSEX POWERLINES CORPORATION

Green Energy Act Plan

Contents

List of Tables

Executive Summary

Essex Powerlines Corporation (Essex) is a medium sized utility in Southwestern Ontario. It serves 4 municipalities and approximately 29,000 customers. The company's mission is to provide safe, reliable, and economical energy supply and services to its customers.

This mission includes connecting renewable generation applications in a timely and efficient manner. Essex predicts that there will be 39 connections in 2016-2018, some of which will require expansion on the current distribution system. All current applications can be accommodated with the current system or with planned expansions. The costs associated with these expansions can be found in Table 1 and Table 2.

Improvements and modifications can be made to the company's distribution system to accommodate the connection of renewable generation facilities. The company has not planned for any of these improvements or modifications within this plan.

The company plans on continuing to develop its smart grid applications over the next few years. This will be accomplished mainly through a demonstration project which was developed by Essex Energy Corporation (EEC). EEC is a wholly owned affiliate of Essex. The demonstration project involves a new software package, SmartMAP, which was awarded a Ministry of Energy Smart Grid Fund, and Essex added in kind contributions to the project. The hardware upgrades outlined in this plan for Essex's distribution system will benefit the software's intelligence by delivering multiple data sources for the software to gather information.

Table 1 - Summary of CAPEX related to GEA Plan

CAPEX	2012	2013	2014	2015	2016	2017	2018
Renewable Expansions	$0	$0	$0	$35,010	$50,000	$65,000	$55,000
Renewable Enabling Investments	$0	$0	$0	$0	$0	$0	$0
Smart Grid Initiatives	$2,833	$85,581	$321,601	$0	$90,072	$50,000	$100,000
Total	$2,833	$85,581	$321,601	$35,010	$140,072	$115,000	$155,000

Table 2 - Summary of OPEX related to GEA Plan

OPEX	2012	2013	2014	2015	2016	2017	2018
Renewable Expansions	$0	$0	$0	$4,901	$8,075	$10,375	$8,900
Renewable Enabling Investments	$0	$0	$0	$0	$0	$0	$0
Smart Grid Initiatives	$0	$46,262	$616	$23,462	$96,748	$99,376	$102,917
Total	$0	$46,262	$616	$28,363	$104,823	$109,751	$111,817

1. Introduction

As a leader in renewable generation connections and smart grid development in Canada, Ontario released the *Green Energy and Green Economy Act, 2009 (GEA)* on September 9, 2009. The *GEA* amended the *Ontario Energy Board Act, 1998*, and the *Electricity Act, 1998*, to emphasize green energy in Ontario and outlines responsibilities of the Ontario Energy Board (OEB) and Ontario's Local Distribution Companies in achieving conservation, promotion of renewable generation, and technological innovation through the smart grid.

As part of a number of initiatives the OEB has created to promote acceptance of *GEA* objectives, the *GEA* act requires that each LDC files a GEA Plan as part of their cost of service rate application.

The purpose of the GEA Plan is three fold:

- Provide information to the Board and interested stakeholders regarding the readiness of a distributor's system to accommodate the connection of renewable generation, as well as the expansion or reinforcement necessary to accommodate renewable generation, and eventually, the development and implementation of smart grid.
- Provide evidence in proceedings for approvals related to infrastructure investments for renewable generation, and smart grid where applicable, and the recovery of the resulting costs from ratepayers; and
- Provide a basis, through the approval of a GEA Plan, by which all of the costs of an expansion to connect renewable generation facilities will be the responsibility of the distributor under the DSC, and therefore also eligible for recovery through the provincial cost recovery mechanism set out in section 79.1 of the *OEB Act*.

When either of the below materiality thresholds are reached, a detailed GEA Plan must be filed according to Section II of the *Filing Requirements*.

1. The total capital costs of all a distributor's planned projects related to the connection of renewable generation and/or the development of a smart grid in any one year:
    - Are more than $100,000 and exceed 3% of the distributor's distribution rate base; or
    - Exceed $5,000,000.
2. The total capital costs of all a distributor's planned projects related to the connection of renewable generation and/or the development of a smart grid over five years:
    - Are more than $100,000 and exceed 6% of the distributor's distribution rate base; or
    - Exceed $10,000,000.

Essex does not reach either of the above materiality thresholds. Essex's rate base can be found in the Cost of Service Application.

This plan has been prepared as a Basic GEA Plan in accordance with OEB's *EB-2009-0397 Filing Requirements; Distribution System Plans.* This plan fulfills submission requirements with the following:

(i) A current assessment of the distribution system
(ii) Information on the planned development of the system to accommodate renewable generation connections
(iii) Activities and expenditures related to the development of the smart grid

This plan details Essex's current and six year GEA plan from 2012 to 2018 and includes a cost summary for the listed projects. Essex is seeking funding for capital expenditure and OM&A costs related to the connection of renewable generation and smart grid development. The costs up to the end of 2015 will be applied for OEB approval deferral accounts as per guidelines, and after will be part of the cost of service filing combined distribution accounts.

2. Current Assessment of the Distribution System

Essex owns and operates a distribution system serving approximately 29,000 residential and business customers in the Town of Amherstburg, the Town of LaSalle, the Municipality of Leamington and the Town of Tecumseh in South-Western Ontario. Essex's 104km^2 service territory consists of 38km^2 of rural territory and 66km^2 of urban territory. Essex currently distributes power through five of Hydro One Networks Incorporated's (HONI) transformer stations; Malden TS, Keith TS Desn1, Kingsville TS, Lauzon TS Desn1 and Lauzon TS Desn2. A mix of overhead and underground 27.6kV primary distribution feeders are run radially from the TS and keep feeder interconnection points normally open, some of which have recently been switched over from a 4kV feeder. The 27.6kV systems contain the largest number of customers and can provide a greater impact on reliability compared to the previous 4kV configurations.

Table 3 - Essex Powerlines Corporation Statistics

	2010	2011	2012	2013	2014	2015
Service Area (km^2)	104	104	104	104	104	104
Metered Customers	28,183	28,281	28,595	28,400	28,640	28,892
Circuit Length (km)	476	466	448	467	461	448
U/G Circuit	259	261	248	272	269	260
O/H Circuit	217	205	200	195	192	188
Substation Transformers	4	4	3	3	1	0
Distribution Transformers	3,074	3,060	3,069	3,089	3,059	3,082
Peak-Summer (kW)	143,420	131,792	122,227	133,124	122,201	109,044
Peak- Winter (kW)	88,536	87,779	78,037	82,181	85,153	78,040
Avg. Peak (kW)	100,033	100,839	89,683	96,572	88,484	81,985
Total kWh Purchased/Delivered[1]	582,070,286	548,867,642	535,233,837	536,939,314	528,334,115	542,447,026

Essex is committed to sustainability and the creation of a green economy and has taken full advantage of new opportunities under the *Green Energy Act*. Essex's mission is to provide safe, reliable, and economical energy supply and services to its customers. Smart meters were installed in virtually all residences and small commercial establishments within Essex Powerlines' distribution system as of December 31, 2010. In accordance with OEB's December 2011 Mandatory Time of Use date for Essex Powerlines, customers were converted to Time-Of-Use (TOU) billing beginning in June 2011.

Essex's renewable generation and smart grid strategy focuses on innovative and cost-effective solutions and Essex takes pride in being at the forefront of implementing new technologies. As a mid-sized utility, Essex plans to leverage the existing smart meters to gain visibility of its

[1] *The total kWh purchased/delivered includes losses for the year*

distribution system; therefore, avoiding investment in the costly SCADA (Supervisory Control And Data Acquisition) solutions. Through the purchase of SmartMAP as well as enhancements to the distribution system, Essex is contributing to the achievement of Ontario's renewable generation and smart grid objectives.

2.1. Renewable Generation Connections

In 2009, the Ontario Power Authority (OPA) launched the Feed-in Tariff (FIT) and microFIT programs to encourage and support renewable generation projects across Ontario. To date, Essex has six FIT contracts and two Renewable Energy Standard Offer Program (RESOP) contracts within its service territory as listed below.

Table 4- Renewable Generation Connected

Feeder	Type	Nameplate Capacity (MW)	Interconnection date
56M26	Solar Rooftop PV	0.5	Nov.24, 2010
23M5	Solar Rooftop PV	0.25	Dec.9, 2011
23M5	Solar Ground PV (RESOP)	10	Aug.15, 2011
23M5	Solar Ground PV(RESOP)	5	Aug.15, 2011
24M9	Solar Rooftop PV	0.25	Sept. 20, 2013
3M6	Solar Rooftop PV	0.25	Sept. 20, 2013
56M26	Solar Rooftop PV	0.25	Sept. 20, 2013
23M5	Solar Rooftop PV	0.25	Jun. 27, 2014
23M5	Solar Rooftop PV	0.2	May. 11, 2015
3M6	Solar Rooftop PV	0.15	Aug. 10, 2015

Table 5 - microFIT Connections

# of Connected Projects	Generation Type	Total Nameplate Capacity (MW)
120	Solar Photovoltaic (Rooftop)	1.35
8	Solar Photovoltaic (Non-Rooftop)	0.075

2.2. *Available Renewable Generation Capacity*

As Essex's distribution system is embedded within HONI's system, Essex has historically been constrained to limitations laid out by the upstream system distributor. Transformer station capacity, as well as feeder capacity, must be taken into account when processing any new renewable generation connections. Limitations on reverse power flow, as well as short circuit capacity of HONI's transformer stations, must be considered. The available capacity on HONI's system is always subject to change as renewable connections from HONI and other distributors increase on a regular basis and affect Essex's available capacity.

Current capacity to accommodate generation from renewable energy generation facilities is limited by HONI's transformer station capacity and feeder capacity as outlined below.

Table 6 - Transformer Station Capacity as of October 30, 2015

Station Name (HONI owned)	Voltage (kV)	HONI Short Circuit Capacity (MVA)	HONI Thermal Capacity (kW)	Minimum Load (MW)
KEITH TS DESN1	27.6	160.6	60,200	20.2
KINGSVILLE TS	27.6	272.2	115,300	55.3
LAUZON TS DESN1	27.6	52.4	64,100	24.1
LAUZON TS DESN2	27.6	55.8	62,400	22.4
MALDEN TS	27.6	173.4	91,600	41.4

Essex uses the Distribution Generation portal and communicates with that team at HONI. In addition to this, Essex has four regional planning meetings with HONI each year to communicate changes and agree upon future improvements. Due to the ongoing complications caused by the presence of HONI's feeders in Essex's service area, Essex is working with HONI to acquire assets within its service area over the next five years. This should allow faster processing and easier connection of renewable generation projects.

As most of the microFIT projects installed by Essex are solar, voltage flicker is a limiting factor. The CSA defines voltage flicker as a perceptible change in voltage due to applying a load or generation, releasing it, and then reapplying it at a later point. A voltage flicker is perceived by humans at a 1% change in voltage and at a frequency of at least once per minute, and less change is required for electrical equipment to be damaged. Due to changes in weather, like clouds, the generated voltage of a solar panel will change perceptibly throughout the day. When connecting a PV panel to an electrical system, the maximum allowable voltage flicker must be taken into account for the system design.

3. Planned Development of the System

Essex will continue to diligently connect renewable generation as requested in the next five years and beyond. Essex prides itself in being a leader in the renewable sector and works hard to promote and ensure customers' successful investment in renewable technologies. Based on the current and anticipated renewable generation applications, Essex has forecasted sufficient capacity on its distribution system to accommodate the requested connections. Essex has found that if there is a need for expansion, the lead time required for approval and connection of a project is long enough to plan and implement appropriate expansion without needing to prioritize the projects. If for some reason the need arose for a prioritization method, Essex will use a first come, first serve basis.

Essex recognizes that the accommodation of renewable generation connections in the future may be restricted by its current distribution system infrastructure. This is why Essex is constantly monitoring connection requests as well as system capacity and assessing where improvements need to be made.

3.1. Anticipated Renewable Generation Connections

Currently, planned and anticipated projects can be accommodated with existing available capacity. In the future, it is assumed that the anticipated lead time will allow capacity to be made available in time for connections when necessary. HONI controls the transformer stations and available capacity so Essex isn't able to increase available capacity directly. With the addition of switching and monitoring hardware described in Section 4.1, Essex could better optimize the existing distribution system for renewable generation.

The anticipated generation connections and capacity is summarized in the following tables and are estimates based on current requests from proponents.

Table 7 - Anticipated Connections

Number of Connections by Year	Currently		2016		2017		2018	
	Number	Gen (MW)	Number	Gen (MW)	Number	Gen (MW)	Number	Gen (MW)
Residential Micro Solar PV (<= 10kw)	144	1.197	20	0.23	11	0.11	8	0.080
Small Solar PV (>10kw, <=250kw)	7	1.6	4	0.734	4	0.74	3	0.584
Small Solar PV (>250kw, <= 500kw)	1	0.5	1	0.265	4	1.605		
Mid Sized Generation (up to 10MW)	2	15						
Total	**154**	**18.3**	**25**	**1.229**	**19**	**2.455**	**11**	**0.664**

3.2. Accommodation of Renewable Generation

The renewable generation applications that are ongoing but not yet connected to Essex's distribution system are identified in Table 8. Where Essex must undertake expansion activities and costs of the expansion are at or below the $90,000/MW threshold, details of expansion project and costs have been detailed in Table 10. Note that past 2016, costs will be placed in another account besides 1531 in accordance with moving towards a combined distribution plan.

Table 8 - FIT Applications

Feeder	Type	Nameplate Capacity (kW)	Expansion Required	Interconnection status	Estimated Connection Year
3M6	Solar Rooftop	265	No	FIT 3 Contract Offered	2016
3M8	Solar Rooftop	146	No	FIT 3 Contract Offered	2016
23M5	Solar Rooftop	135	No	FIT 3 Contract Offered	2016
24M12	Solar Rooftop	250	No	FIT 3 Contract Offered	2016
3M8	Solar Rooftop	105	No	FIT 2 Contract Offered	2017
23M3	Solar Rooftop	200	Yes	FIT 1 Contract Offered	2018
3M8	Solar Rooftop	335	No	FIT 3.x Contact Offered	2017
3M4	Solar Rooftop	500	No	FIT 3.x Contact Offered	2017
3M4	Solar Rooftop	190	No	FIT 3.x Contact Offered	2017
3M6	Solar Rooftop	500	No	FIT 3.x Contact Offered	2017
3M4	Solar Rooftop	90	No	FIT 3.x Contact Offered	2017
23M5	Solar Rooftop	270	No	Under FIT 3.x Review	2018
23M5	Solar Rooftop	200	Yes	Initial Feasibility Stage	2018
24M9	Solar Rooftop	250	No	Initial Feasibility Stage	2018
3M8	Solar Rooftop	134	No	Initial Feasibility Stage	2018
NA	Solar Rooftop 5X250	1250	1 of 5	NA	2016
NA	Solar Rooftop 5X250	1250	1 of 5	NA	2017
NA	Solar Rooftop 5X250	1250	1 of 5	NA	2018

Table 9 - Total microFIT Applications

Being Processed	Generation Type	Total Nameplate Capacity (MW)
24	Solar Photovoltaic (Rooftop)	0.24
0	Solar Photovoltaic (Non-Rooftop)	0

Table 10 - Projects to Accommodate Renewable Generation

Feeder	Type	Name plate Capacity (kW)	Estimated /Actual Expansion Cost	Scope of Work	REI Costs	Renewable Expansion Cost Cap	Total Essex	Estimated Connection Year
23M5	Solar Rooftop	200	$17,401	Transformation & expansion	N/A	$18,000	$17,401	2015
3M6	Solar Rooftop	150	$17,608	Transformation & expansion	N/A	$13,500	$17,608	2015
23M5	Solar Rooftop	200	$25,000	Transformation & expansion	N/A	$18,000	$25,000	2018
3M8	Solar Rooftop	146	$20,000	Transformation & expansion	N/A	$13,500	$20,000	2016
3M6	Solar Rooftop	500	$35,000	Transformation & expansion	N/A	$45,000	$35,000	2017
N/A	Projected	250	$30,000	Transformation & expansion	N/A	$22,500	$30,000	2016
N/A	Projected	250	$30,000	Transformation & expansion	N/A	$22,500	$30,000	2017
N/A	Projected	250	$30,000	Transformation & expansion	N/A	$22,500	$30,000	2018

Table 11- Projected Cost Summary for renewable generation related expansion

Year	2012	2013	2014	2015	2016	2017	2018
Expense	NA	NA	NA	$35,010	$50,000	$65,000	$55,000
					Total		**$205,010**

The OM&A costs associated with the above projects are summarized in the table below. Costs have been estimated based on a percentage of the capital costs along with a set cost per customer connected and per kilometer of line installed. The cost per customer and per kilometer was determined using the current OM&A cost divided by the current number of customers and the current per kilometer cost. Note that past 2016, costs will be placed in another account besides 1532 in accordance with moving towards a combined distribution plan.

Table 12- Projected OM&A Costs

Year	2012	2013	2014	2015	2016	2017	2018
Expense	NA	NA	NA	$4,901	$8,075	$10,375	$8,900
					Total		**$32,251**

3.3. Direct Benefits

Direct Benefits

The OEB decided that the calculation of direct benefits would be either a full inquiry or a standardized percentage using a baseline and then a rolling weighted average. In order to distinguish the requirements of when to do one over the other, it was decided that the materiality thresholds which decide whether to file a detailed GEA plan or basic GEA plan would hold. As Essex does not reach the materiality threshold, the standardized approach to calculating direct benefits can be used, 17% of System Expansion and 6% of Renewable Enabling Improvements. These categories are defined in Section 3.2.30 of the *Distribution Code*. Essex does not have Renewable Enabling Improvements, but they do have System Expansions as described in Table 10, and a cost summary is in Table 11.

Table 13- Direct Benefit Summary

Year	2012	2013	2014	2015	2016	2017	2018
Expense	NA	NA	NA	$35,010	$50,000	$65,000	$55,000
Direct Benefit	NA	NA	NA	$5,952	$8,500	$11,050	$9,350
				Total Direct Benefit		**$34,852**	

4. Smart Grid Development Plan

The smart grid is an intelligent electricity infrastructure that uses technology such as sensors, monitoring, communications, automation and computers to improve the flexibility, reliability and efficiency of the electricity system, particularly for the purposes of:

a) Allowing more renewable generation, such as wind and solar, to be connected to the distribution system
b) Expanding opportunities to provide demand response, price information and load control to customers
c) Enable electric vehicles to be charged conveniently
d) Identify and restore outages more quickly

Innovative smart grid technology has allowed distributors to do more with hardware which is required to run an electrical grid. For instance, smart meters have opened up new possibilities for distributors because meters have the ability to send actual load information to a distributor. The information is data from end points in a network which allows small distribution companies new ways of tracking power flows in their distribution grid without a SCADA system. Since smart grid hardware has built in communications technology, the need for separate automated communications hardware is greatly reduced. Instead of purchasing a large amount of hardware to support a monitoring system, LDCs can purchase basic equipment and still have an idea of what their current system state is. With minimal hardware purchases, visibility into the distribution system skyrockets as things like non-technical losses, fault location, and feeder loading become possible. The new capabilities of hardware and corresponding developing software open up the distribution system monitoring market for more competition from companies who innovate ways to monitor the electrical grid. Innovation and competition amongst vendors will benefit the rate payers by ensuring the best solution for a LDC is implemented.

Some smart gird technology that Essex is intending to install is preemptive in that it will allow for more renewable enabling initiatives to be undertaken in the future. For example, line monitoring units which are going to be installed will be monitoring several renewable generation expansions that Essex will be commissioning over the next few years. Line monitors will assist Essex's renewables by allowing Essex to monitor line loadings and adjust where the generated power is distributed accordingly. The reclosers that are proposed will also allow for the renewable generation to be better utilized by the electrical distribution grid. Since reclosers clear momentary faults and then restore power quickly, the generation will be used more consistently even if a fault does occur. The reclosers will also have the benefit of providing Essex line loadings, just like line monitors. Reclosers and line monitors will also have the added benefit of enabling a self-healing grid. It is Essex's goal to move towards a self-healing grid using available technology to reduce outage times and better the quality of power for all its customers.

4.1. Demonstration Projects

Essex is working with EEC to demonstrate the capabilities and functionality of a new software product, SmartMAP. The SmartMAP solution was awarded a Ministry of Energy Smart Grid Fund due to its innovative use of smart meters and other technology to increase visibility and flexibility of distribution systems. This product has many advantages for small and medium utilities and utilizes smart meters for one of its main information sources.

4.1.1. SmartMAP

As Essex has completed its smart meter installation, the next step is to integrate this "real-time" view of distribution system assets with engineering software. Essex has been using engineering analysis software, Distribution Engineering System Software (DESS), supported by EEC. This software assists engineering in technical system decisions and studies including load flow analysis, protection coordination, system loss calculation, conductor sizing, voltage drop and system loading. Essex will purchase distribution monitoring software, SmartMAP, which will leverage smart meter data and make the information available to key departments within Essex, namely Operations, Engineering and Customer Service, for effective management of renewable generation, outage identification and restoration, and a faster, more cost-effective decision making process.

The implementation of this distribution management system will promote and enable:

- Integration of existing smart meters with the Outage Management System to transmit "last gasp" data in real time, allowing the analysis component to pinpoint exact outage locations, predict causes, and suggest switching changes to restore power faster
- Transformer loading profile (kWh vs. time of day, kVA vs. time of day) aiding in identification of under or overloaded assets
- Reporting of line losses from wholesale meters, transformers and residential meters
- Identification and locating of low voltage conditions which could be signs of failing equipment or wrong transformer tap settings
- Reconciling of loads connected to each transformer to assist in identifying non-technical losses
- Web application available to operations personnel so reporting and problem solving is made quicker and easier
- Ability to send critical alarms and messages about the network to a cellular phone through the use of email or SMS
- Visual monitoring of real time operational data from field devices (fault/line monitors, automated reclosers or switches, and any other field device capable of providing real time feedback) on a graphic display

Alternative solutions have been considered to address Essex's need for a distribution management system, namely installation of a full SCADA solution and other similar products. There are several concerns that arise with a full SCADA system which are too costly for small and medium distributors. The SmartMAP solution has proven to be the most cost effective and is in line with Essex's smart grid strategy.

Table 14- SmartMAP Cost Schedule

Year	2013	2014	2015	2016	2017	2018
Software Setup	$0	$204,476	$0	$0	$0	$0
Yearly Service Fees	$0	$0	$0	$65,000	$66,300	$67,626
				Total Costs	**$403,402**	

4.1.2. Line Monitors

Essex has begun installation of line monitoring units to provide a better understanding of what is happening on the distribution grid in real time, allowing for better operational decisions. The fault monitors/line monitors installed on line feeders support overall grid intelligence, improved operations and maintenance, and security of the distribution grid. Future integration of these monitors with the SmartMAP software will contribute to Essex's smart grid implementation plan by providing useful operational data in real time.

These monitors will give the SmartMAP program a more intimate view of the electrical distribution system. The monitors will allow Essex to see not only endpoints of an area, but current flowing into a section of its territory. Identifying how much current is flowing in a section of line can help to identify non-technical losses, overloaded conductor, and potential for load transfers. The additional data will also allow for even faster response times during an outage event as SmartMAP will not have to wait for meters in an area to be pinged before assessing the extent of a problem because the problem will be identified at the upstream line monitor. Fault currents flowing through a line monitor can assist in identifying which asset is the cause of failure when combined with SmartMAP's intelligent fault current calculations and outage determination system.

Line monitors also have the potential to identify automatic reclosures or momentary outages. SmartMAP will be able to use this information, coupled with its knowledge of the distribution grid and number of customers, to calculate new outage metrics such as Momentary Average Interruption Frequency Index (MAIFI), Customers Experiencing Long Duration Interruptions (CELDI) and Customers Experiencing Multiple Interruptions (CEMI) instead of just System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI).

Description:

The chosen line monitoring unit is powered from the line and does not require any batteries to be changed, nor the use of pole mounted cabinets that require an external power source. This differentiates them from typical fault current indicators (FCI), making installation simple and quick as well as eliminating time consuming battery maintenance. Line monitors also provide much more than just a fault or outage condition, it will provide current data which can be analyzed with SmartMAP to identify areas with non-technical losses. Line monitors will also provide other operations data as seen in the table below.

Table 15 - Features of the Line Monitors

Feature	Benefit
Power Harvesting	• No batteries to replace • Capacitor to keep powered for approximately 5 min. after loss of power • Can be installed on a live line, no customer interruption necessary
Harmonics	• Identify resonance that cause losses and breakdown of equipment
Line Temperature	• Indication of line SAG
Measurements	• Able to measure Max, Min and Ave Line Current, Shell and Line Temperature, Fault Current Value and Direction, Automatic Reclosures, Outages

Outage Detection	• Ability to pinpoint outages, Fault Current Indication (FCI) • Provides data transmission of a failure warning if low power is detected (last gasp)

Implementation:

The proposed locations of line monitor devices have been marked in the single line diagram for each service territory in Appendix A. Each location marked is representing a set of three monitors, one for each phase. The reclosers described in section 4.1.3 will also be able to provide fault data so the placement of the fault/line monitors has been chosen to provide additional data where a recloser is not present to quickly determine the location of a fault. There are a few instances where line monitors are recommended to be installed on HONI owned lines in Essex territory. More detail on the recommended number of line monitors per feeder can be found in Appendix G.

Table 16 - Line Monitoring Installation Schedule

Year	Location	Installation Cost	Hardware Cost	Yearly Total
2012	Units supplied by EEC – TEC	$2,833	$0	$2,833
2013	TEC	$3,009	$0	$3,009
2014	AMH	$10,103	$27,432	$37,535
2015		$0	$0	$0
2016	All of LEA and LAS	$21,675	$68,397	$90,072
		Total 5 Year Implementation Cost:		**$133,449**

Table 17- Overall Line Monitor Costs

	2012	2013	2014	2015	2016	2017	2018	Total
Total # of Line Monitors	36	36	54	54	96	96	96	96
OM&A Costs	$0	$1,262	$616	$0	$1,932	$1,970	$2,010	$7,791
CAPEX Costs	$2,833	$3,009	$37,535	$0	$90,072	$0	$0	$133,449
Support Costs	$0	$0	$0	$8,456	$8,925	$9,104	$9,286	$35,770
Data and Communication Costs	$0	$0	$0	$14,585	$15,394	$15,702	$16,016	$61,697
Total Costs	$2,833	$4,271	$38,151	$23,042	$116,323	$26,776	$26,776	**$238,707**

4.1.3. Switching – Reclosers

Essex's current distribution system contains manual load break switches which do not provide any fault protection, therefore fault protection is provided by a station breaker or upstream recloser. Reclosers are able to automatically trip open on fault, isolating the faulted section and keeping customers upstream from the recloser unaffected. On momentary faults (lightning, animals, etc.) the recloser will trip on a fault and automatically reclose after a few seconds minimizing outage time and eliminating truck rolls.

The reclosers are also able to provide system information to SmartMAP, similar to the line monitors described in the previous section. A recloser action can trigger outage determination in SmartMAP, so Essex can know about an outage very quickly. Momentary outages caused by the reclosers can also be tracked in SmartMAP, contributing to the accuracy of CELDI and CEMI outage statistics. The data will also increase knowledge about power flow within the system, aiding in operations and engineering decisions because voltage and current data will be stored and historical trends can be evaluated. In the event of an outage, SmartMAP has the ability to look at historical data supplied by all of its data sources and determine whether or not it is possible to do a short term load transfer to restore power. This will greatly aid in moving towards a self-healing grid, because having switches which can be triggered remotely and knowledge about whether or not the switches can be operated safely is crucial to making the decision to operate the switch to restore power.

Implementation:

By analyzing the outage data from 2008 to 2012 several feeders have been found with a high SAIDI index. Looking into the data further and filtering out outages that were caused by loss of HONI supply, the numbers improve greatly. These filtered SAIDI values have been used to identify which feeders should be addressed first thereby reducing outage time on those feeders. It is important to note, however, that although filtering out loss of supply outages greatly improves SAIDI results, HONI causes cannot be ignored completely. There is opportunity for changing some switching to restore power to Essex's service area using another feeder while Hydro One addresses the problem.

The placement of reclosers for sectionalizing a feeder is difficult to distinctly identify, however, based on research and white papers, using a combination of sectionalizing a feeder into load sections (3 to 5 MVA) and concentrating on trouble areas based on outage data has provided a strong starting point. The proposed locations of the reclosers have been marked in the single line diagram for each service territory in Appendix A. More detail on the recommended number of reclosers per feeder can be found in Appendix G.

Table 18 – Recloser Costs

	2012	2013	2014	2015	2016	2017	2018	Total
Total # of Reclosers	0	1	1	1	11	15	19	19
Communication Costs	$0	$0	$0	$420	$5,498	$6,300	$7,980	$20,198

4.1.4. Wholesale Meters

With the smart meters already installed, Essex is able to use that data to accurately model loads with SmartMAP and its DESS engine to help identify issues creeping up. Wholesale meter points will be upgraded to ION meters and will use TCP/IP communications to increase reliability of communications and provide multiple communications options and channels that can be used to monitor real time data. The use of this data in real time will help in understanding the loading conditions of feeders within the service territories.

ION meters provide the added benefit of being able to trigger outage detection. The meters send SmartMAP information every five minutes, and if the ION sends either zero current or near zero voltage, SmartMAP triggers outage detection. This is another means by which an outage can be found in SmartMAP, well before a customer has the chance to call in about an outage.

Table 19 - Implementation Schedule and Costs

Year	Wholesale Meter Point Upgrade	Cost	Yearly Total
2013	WM723M3 to ION8600	$20,643	
	WM723M4 to ION8600	$20,643	
	WM723M5 to ION8600	$20,643	
	WM33M6 to ION8600	$20,643	$82,572
2014	WM724M7 to ION8600	$15,918	
	WM724M9 to ION8600	$15,918	
	WM724M10 to ION8600	$15,918	
	WM33M4 to ION8600	$15,918	
	WM33M8 to ION8600	$15,918	$79,590
		Total 5 year Cost:	**$162,162**

Table 20 - Overall Wholesale Meter Costs

	2012	2013	2014	2015	2016	2017	2018	Total
# of Wholesale Meters Installed	0	4	5	0	0	0	0	9
Costs	$0	$82,572	$79,590	$0	$0	$0	$0	**$162,162**

4.1.5. *Self-Healing Grid Study*

Table 21 - Self-Healing Grid Study Costs

	2012	2013	2014	2015	2016	2017	2018
Self-Healing Grid Study Cost	$0	$0	$0	$0	$0	$50,000	$100,000
						Total	**$150,000**

4.2. *Smart Grid Capital Deferral Account*

This account records the capital expenses associated with smart grid demonstration projects. Note that past 2016, costs will be placed in another account besides 1534 in accordance with moving towards a combined distribution plan.

Table 22 – Capital Deferral Account

Year	2012	2013	2014	2015	2016	2017	2018
Hardware Expense	$2,833	$85,581	$321,601	$0	$90,072	$50,000	$100,000
						Total	**$650,087**

4.3. Smart Grid OM&A Deferral Account

This account is for the OM&A directly related to smart grid demonstration, studies, and education and training. Note that past 2016, costs will be placed in another account besides 1535 in accordance with moving towards a combined distribution plan.

Table 23 – OM&A Deferral Account

Year	2012	2013	2014	2015	2016	2017	2018
OM&A Expense	$0	$46,262	$616	$23,462	$96,748	$99,376	$102,917
						Total	**$369,381**

5. References

Hydro One Station Capacity as of October 30st, 2015

Feeder configuration based on GIS model as of August 1st, 2014

Feeder loading based on DESS model as of August 1st, 2014

Outage Data verified as of August 1st, 2014

CAN/CSA-C61000-3-7

6. OPA Letter of Comment

Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority[1] ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

Essex Powerlines Corporation – Distribution System Plan

On February 27, 2015 Essex Powerlines Corporation ("Essex") provided its Renewable Energy Generation Plan ("Plan") to the IESO as part of its 5-year Distribution System Plan. The IESO has reviewed Essex's Plan and has provided its comments below.

OPA FIT/microFIT Applications Received

Tables 4 and 5 of Essex's Plan shows that to date, Essex has connected 6 FIT projects totalling 1.75 MW of capacity, and 123 microFIT projects totalling 1.015 MW of capacity. Additionally, Essex has connected 2 RESOP projects to its distribution system for a total capacity of 15 MW.

Table 8 of Essex's Plan shows that beyond the projects which have already been connected, there are 11 projects in Essex's service territory totalling 2.485 MW which have received FIT contracts but which have not yet been connected.

According to the IESO's information, as of February 28, 2015, the IESO has offered contracts to 123 microFIT projects totalling 1.003 MW of capacity. The IESO has also offered contracts to 17 FIT projects representing a capacity of 4.235 MW, of which 6 FIT projects totalling 1.75 MW of capacity have come into service. In addition, 2 RESOP projects totalling 15 MW have come into service. This comparison shows that the renewable energy generation connections information in Essex's Plan is therefore consistent with that of the IESO.

Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

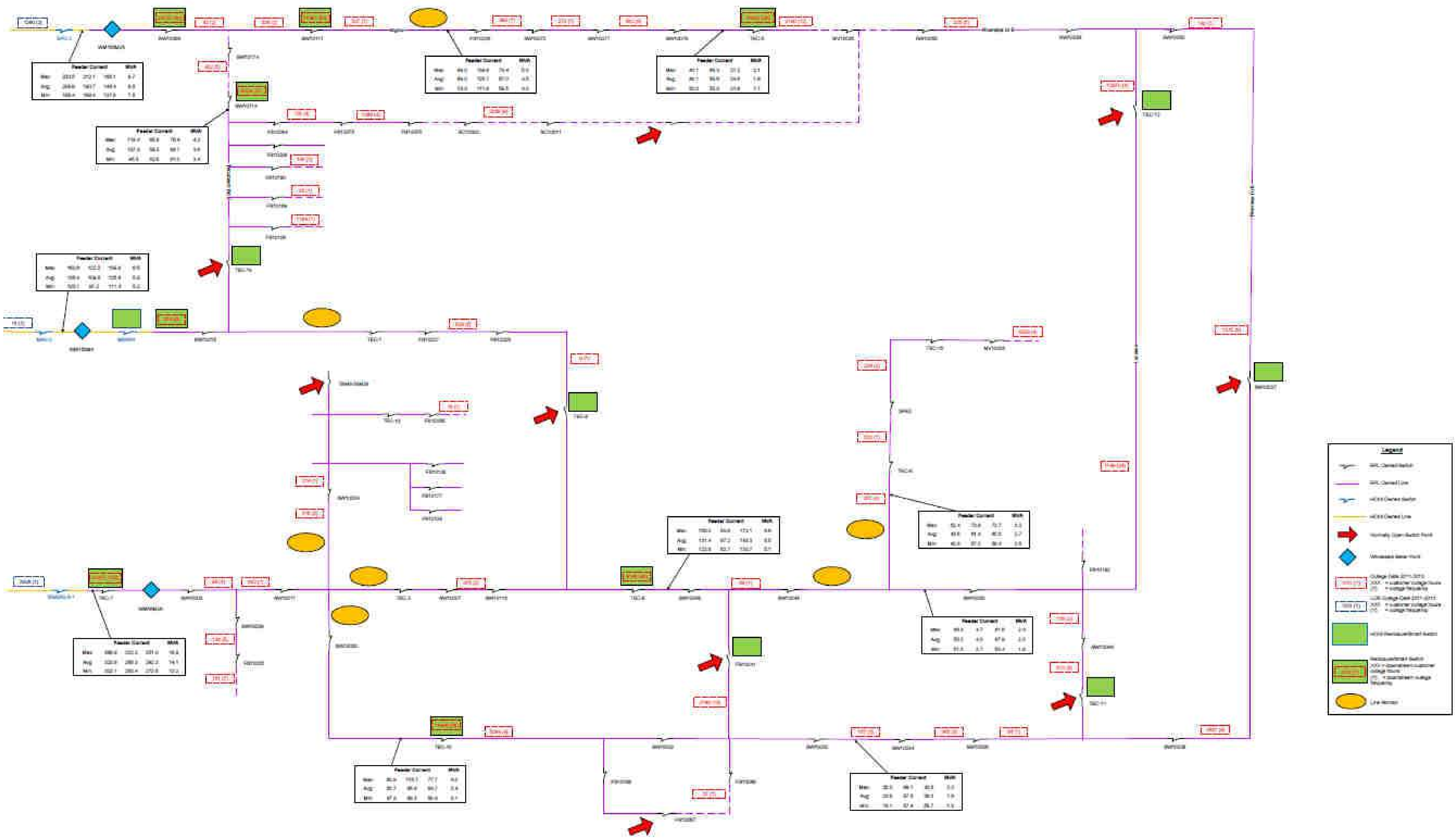
The IESO notes that Essex is part of “Group 1” and the Windsor-Essex Region for regional planning purposes. Essex Powerlines Corporation is one the 5 local distribution companies serving the region and is part of the regional planning Working Group (“Working Group”) for the Integrated Regional Resource Plan (“IRRP”) that is underway in the area. This IRRP that is to be finalized at the end of April, 2015 is being prepared by the IESO on behalf of the Working Group, which includes the following members: Independent Electricity System Operator, Hydro One Networks Inc. (“Hydro One”) (Distribution and Transmission), EnWin Utilities Ltd., Essex Powerlines Corporation, ELK Energy Inc., and Entegrus Inc. As such, Essex has been participating in ongoing planning meetings related to the IRRP and therefore consults regularly with the IESO, the other LDCs and Hydro One on electricity and regional planning related matters. More information on the IRRP may be obtained from the IESO’s website at this link: http://www.powerauthority.on.ca/power-planning/regional-planning/windsor-essex.

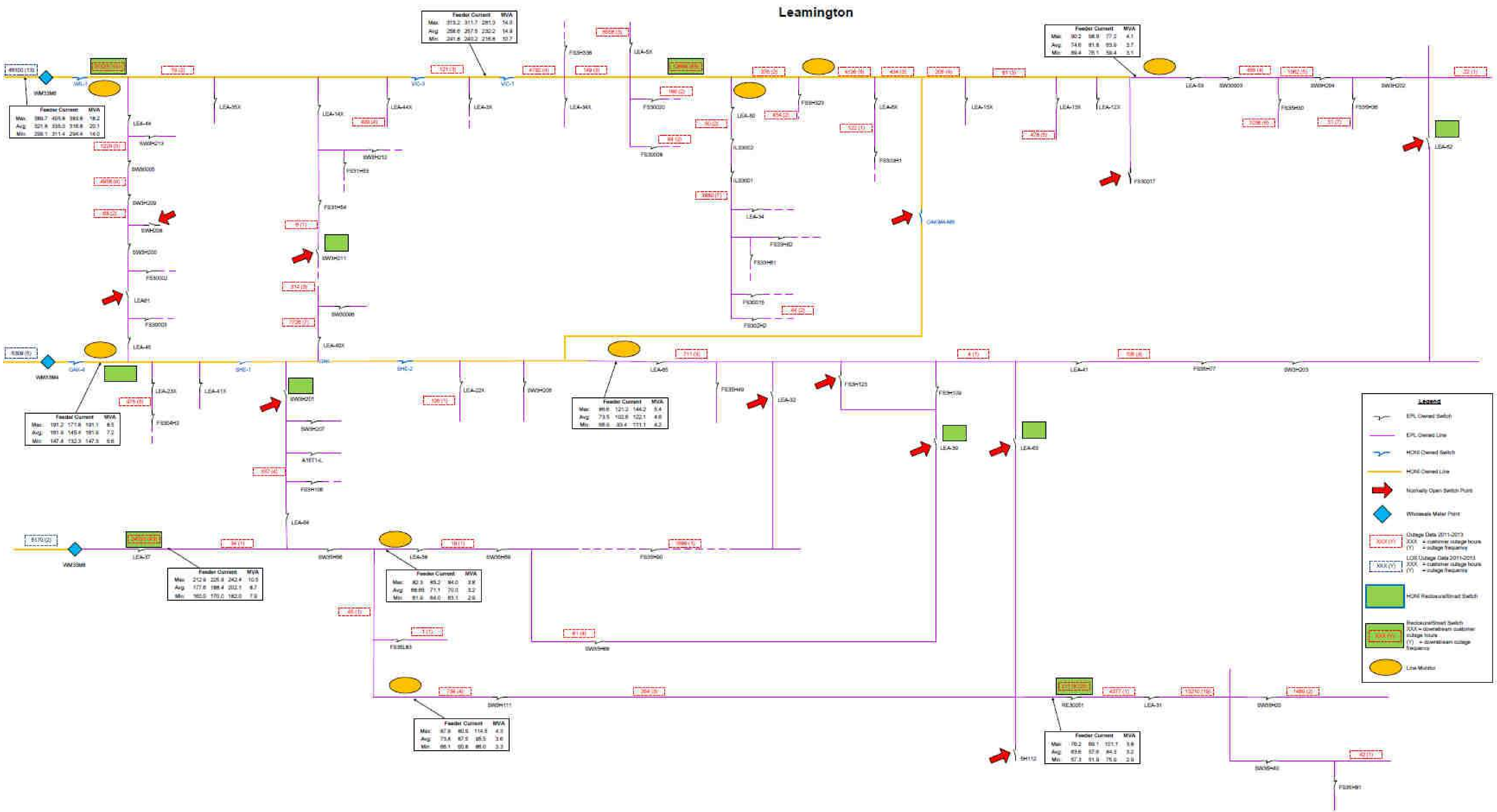
In its Plan, Essex provides a detailed breakdown of currently planned and anticipated REG connections and expects to be able to accommodate this forecast for REG connections with existing available capacity. Essex’s distribution system is embedded within Hydro One’s distribution system. Therefore it is necessary for Essex to co-ordinate regularly with Hydro One to monitor the amount of capacity available on Hydro One’s system to accommodate REG connections on Essex’s system. Future limitations on Hydro One’s system may impact the ability for Essex to connect REG applications.

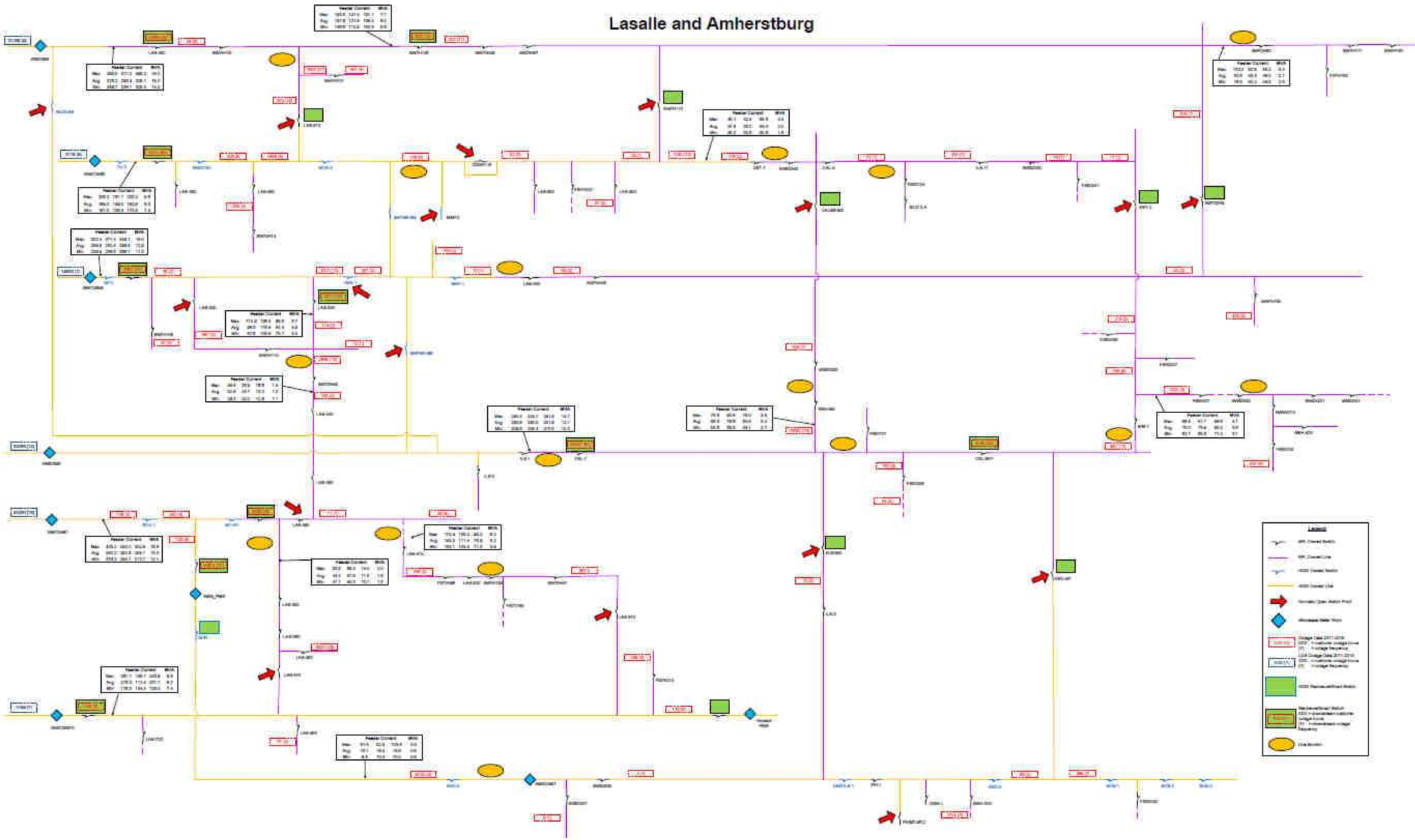
IESO looks forward to continuing its work with Essex Powerlines Corporation throughout the regional planning process in the Windsor-Essex Region and appreciates the opportunity to comment on the information provided as part of its Distribution System Plan at this time.

Appendix A - Single Line Diagrams

Tecumseh




Leamington
Legend
EPL Owned Switch
EPL Owned Line
HONI Owned Switch
HONI Owned Line
Normally Open Switch Point
Wholesale Meter Point
Outage Data 2011-2013
XXX = customer outage hours
(Y) = outage frequency
LOS Outage Data 2011-2013
XXX = customer outage hours
(Y) = outage frequency
HONI Recloser/Smart Switch
Recloser/Smart Switch
XXX = downstream customer outage hours
(Y) = downstream outage frequency
Line Monitor


Lasalle and Amherstburg

Appendix B - Feeder Load Data

Tecumseh

Feeder 56M26

Tec 7

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	389	322	351	16.9
Avg	311	258	281	13.5
Min	194	161	176	8.5

Tec 10

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	61	115	78	4.0
Avg	49	92	62	3.2
Min	30	58	39	2.0

Tec 9

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	158	81	172	6.6
Avg	126	65	138	5.3
Min	79	40	86	3.3

SW10033

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	28	69	44	2.2
Avg	23	55	35	1.8
Min	14	35	22	1.1

SW10050

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	66	5	82	2.4
Avg	53	4	65	1.9
Min	33	2	41	1.2

TEC-6

	Current ph A	ph B	ph C	3ph MVA
Max	52	74	73	3.2
Avg	42	59	58	2.6
Min	26	37	36	1.6

Feeder 56M4

MAN-2

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	151	122	140	6.5
Avg	121	98	112	5.2
Min	75	61	70	3.3

Feeder 56M25

EPC-2

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	234	212	165	9.7
Avg	187	170	132	7.8
Min	117	106	83	4.9

SW10117

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	99	140	74	5.0
Avg	79	112	60	4.0
Min	50	70	37	2.5

SW10114

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	119	66	764	4.2
Avg	96	53	611	3.4
Min	60	33	382	2.1

TEC-5

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	40	66	27	2.1
Avg	32	53	22	1.7
Min	20	33	14	1.1

Leamington

Feeder 3M4

OAK-4

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	191	172	191	8.5
Avg	153	137	153	6.8
Min	96	86	96	4.3

LEA-65

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	87	121	144	5.4
Avg	69	97	115	4.3
Min	43	61	72	2.7

Feeder 3M6

WIL-1

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	390	406	384	18.2
Avg	312	325	307	14.6
Min	195	203	192	9.1

VIC-1

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	313	312	281	14.0
Avg	251	249	225	11.2
Min	157	156	141	7.0

LEA-53

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	90	99	77	4.1
Avg	72	79	62	3.3
Min	45	49	39	2.1

Feeder 3M8

LEA-37

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	213	226	242	10.5
Avg	170	181	194	8.4
Min	106	113	121	5.3

LEA-38

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	82	85	84	3.8
Avg	66	68	67	3.0
Min	41	43	42	1.9

SW3H111

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	88	81	115	4.3
Avg	70	65	92	3.4
Min	44	40	57	2.2

RE30051

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	76	69	101	3.8
Avg	61	55	81	3.0
Min	38	35	51	1.9

Amherstburg

Feeder 23M3

ILS-1

	Current			3ph MVA
	ph A	ph B	ph C	
Max	290	324	292	13.7
Avg	232	259	233	11.0
Min	145	162	146	6.9

REN-M3

	Current			3ph MVA
	ph A	ph B	ph C	
Max	76	91	75	3.6
Avg	60	73	60	2.9
Min	38	45	38	1.8

FS50001

	Current			3ph MVA
	ph A	ph B	ph C	
Max	87	88	99	4.1
Avg	69	70	79	3.3
Min	43	44	49	2.1

Feeder 23M5

DET-1

	Current			3ph MVA
	ph A	ph B	ph C	
Max	46	42	66	2.4
Avg	37	34	53	1.9
Min	23	21	33	1.2

Feeder 24M7

AND-3

	Current			3ph MVA
	ph A	ph B	ph C	
Max	52	52	104	3.3
Avg	41	42	83	2.6
Min	26	26	52	1.7

LaSalle

Feeder 23M4

LAS-340

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	456	311	395	18.0
Avg	364	249	316	14.4
Min	228	156	198	9.0

SW7H106

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	191	147	131	7.1
Avg	152	118	105	5.7
Min	95	74	66	3.6

SW70H62

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	100	53	58	3.3
Avg	80	42	47	2.6
Min	50	26	29	1.7

Feeder 23M5

OJ-2

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	205.2	181.1	223.2	9.6
Avg	164.2	144.9	178.6	7.7
Min	102.6	90.6	111.6	4.8

Feeder 24M10

WM724M10

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	261	136	243	9.8
Avg	209	109	194	7.8
Min	131	68	121	4.9

Feeder 24M7

Bou-1

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	425	323	323	16.6
Avg	340	259	258	13.3
Min	213	162	161	8.3

LAS-350

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	54	58	14	2.0
Avg	43	47	11	1.6
Min	27	29	7	1.0

LAS-410

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	173	135	93	6.3
Avg	139	108	75	5.0
Min	87	68	47	3.2

Feeder 24M9

MT3

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	302	271	349	15.0
Avg	242	217	279	12.0
Min	151	136	175	7.5

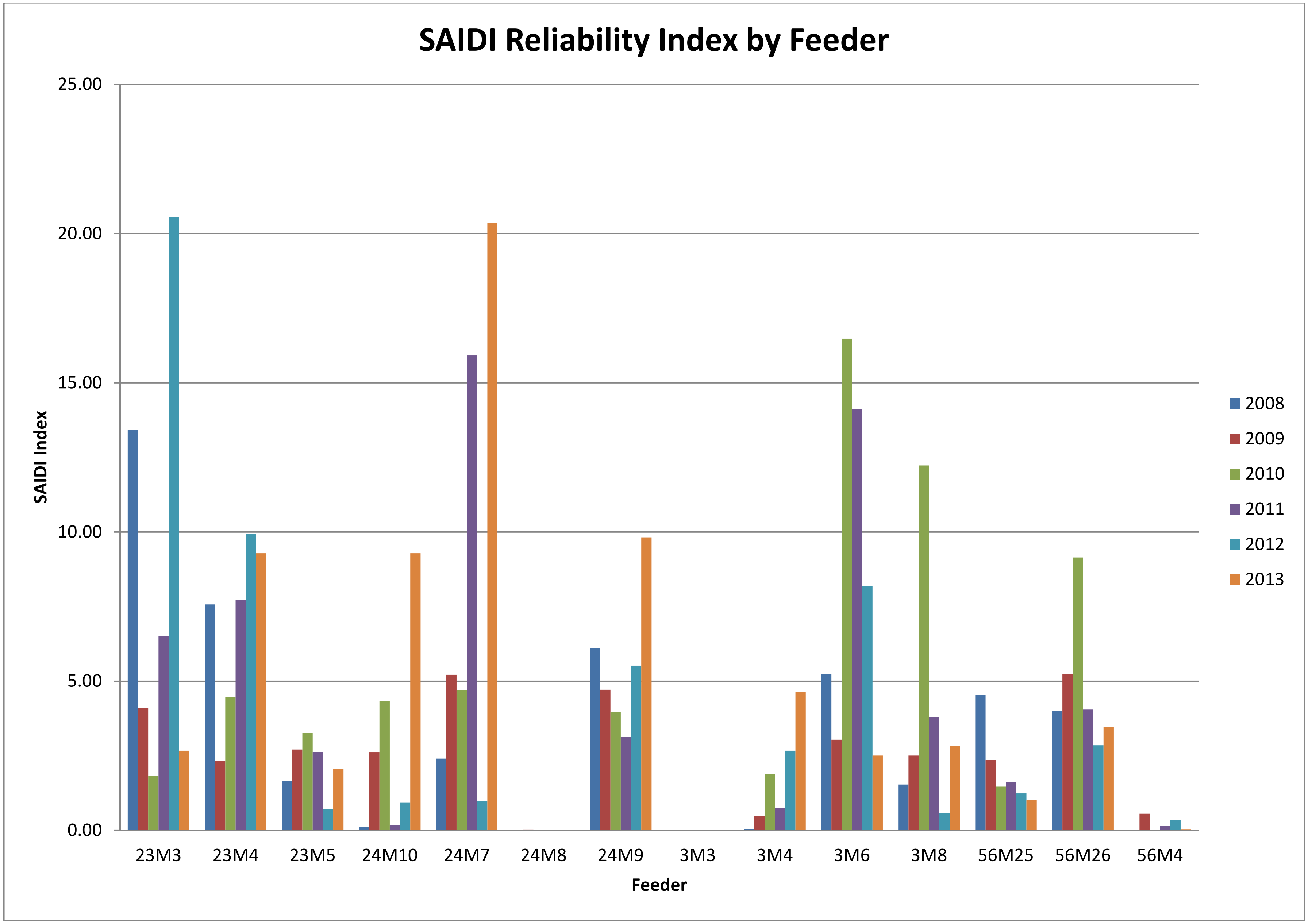
LAS-330

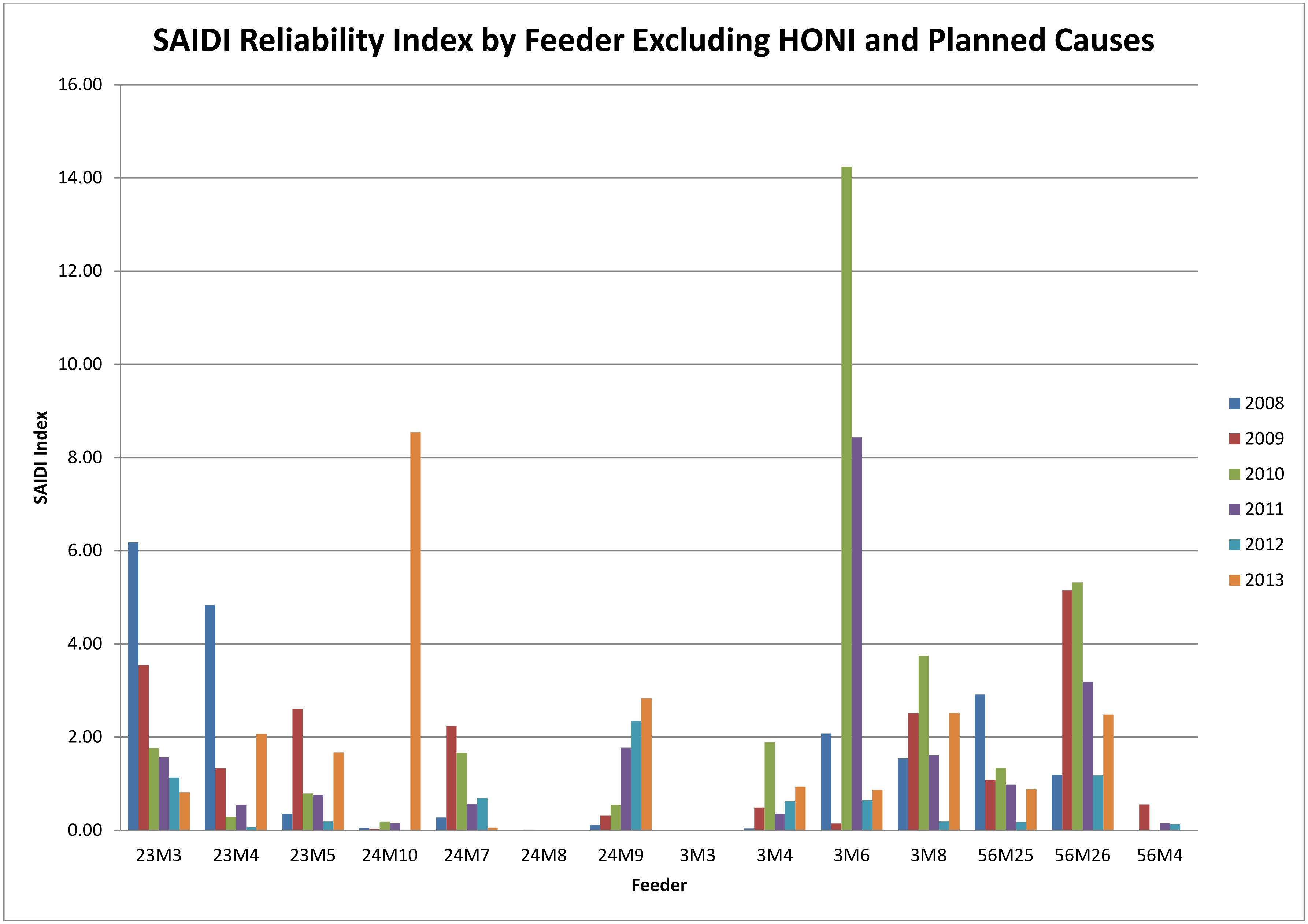
	Current ph A	Current ph B	Current ph C	3ph MVA
Max	115	136	99	5.7
Avg	92	109	79	4.6
Min	57	68	49	2.9

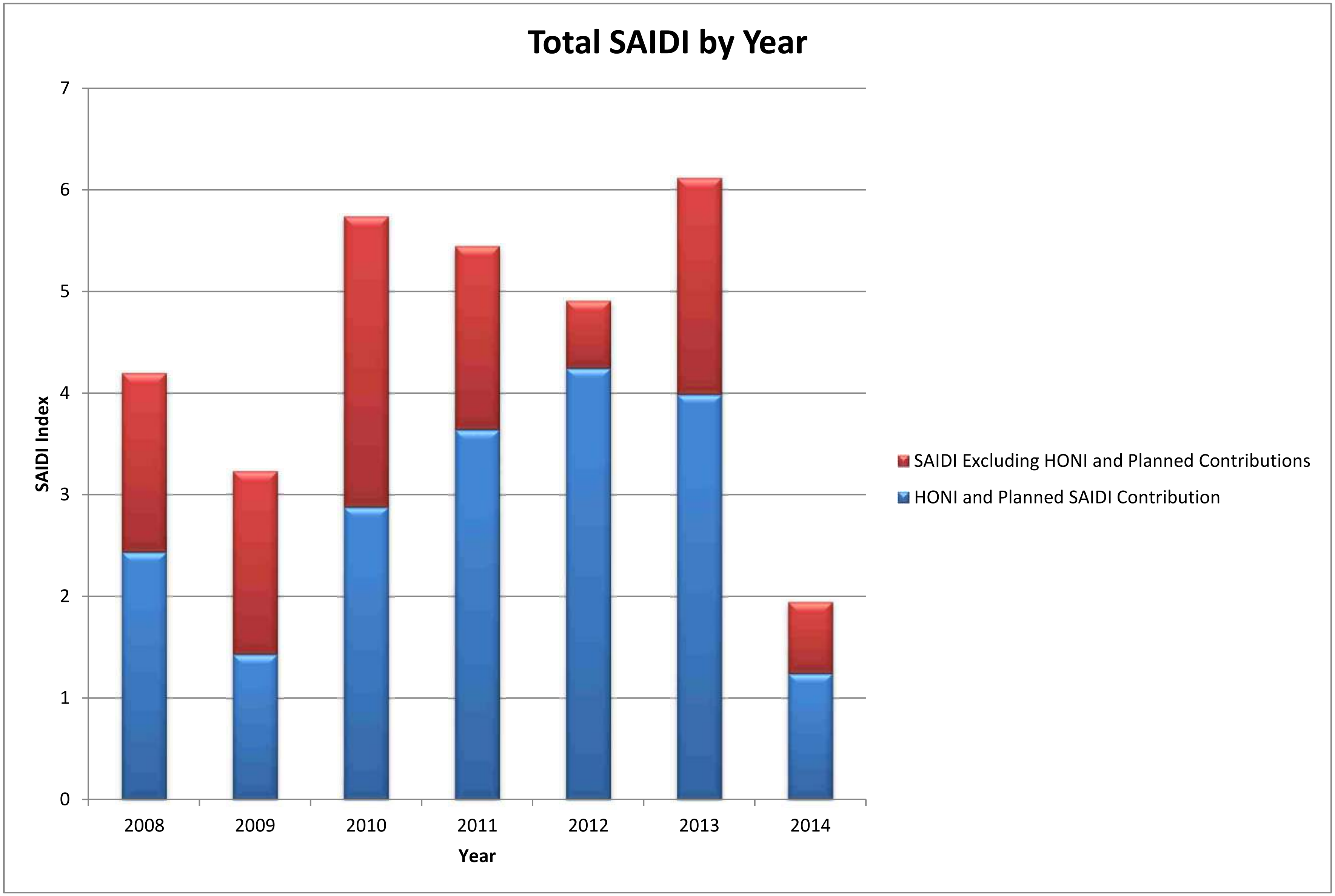
SW70H45

	Current ph A	Current ph B	Current ph C	3ph MVA
Max	38	29	17	1.4
Avg	31	23	13	1.1
Min	19	14	8	0.7

Appendix C - SAIDI Charts


SAIDI Reliability Index by Feeder
SAIDI Index
25.00
20.00
15.00
10.00
5.00
0.00
23M3
23M4
23M5
24M10
24M7
24M8
24M9
3M3
3M4
3M6
3M8
56M25
56M26
56M4
Feeder
2008
2009
2010
2011
2012
2013


SAIDI Reliability Index by Feeder Excluding HONI and Planned Causes
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
SAIDI Index
23M3
23M4
23M5
24M10
24M7
24M8
24M9
3M3
3M4
3M6
3M8
56M25
56M26
56M4
Feeder
2008
2009
2010
2011
2012
2013


Total SAIDI by Year
SAIDI Index
0
1
2
3
4
5
6
7
2008
2009
2010
2011
2012
2013
2014
Year
SAIDI Excluding HONI and Planned Contributions
HONI and Planned SAIDI Contribution

SAIDI Indicator

	Customers	2008	2009	2010	2011	2012	2013	2014
23M3	2540	13.41	4.11	1.82	6.50	20.55	2.67	4.99
23M4	2925	6.58	2.02	3.87	6.70	8.63	8.06	0.28
23M5	1585	2.65	4.34	5.24	4.20	1.16	3.32	1.69
24M10	1746	0.16	3.80	6.30	0.25	1.35	13.52	0.13
24M7	2181	2.80	6.07	5.47	18.53	1.14	23.70	0.46
24M8	14	0.30	3.21	0.00	0.00	2.22	0.10	0.00
24M9	3861	4.01	3.10	2.61	2.06	3.63	6.46	1.74
3M3	4	1.38	0.00	0.00	0.00	1.13	2.45	0.00
3M4	1183	0.10	1.05	4.07	1.60	5.74	9.96	16.33
3M6	3826	3.48	2.02	10.94	9.37	5.43	1.67	0.22
3M8	1774	2.20	3.59	17.51	5.45	0.84	4.04	1.25
56M25	2120	5.43	2.83	1.76	1.92	1.49	1.23	0.09
56M26	4079	2.50	3.26	5.70	2.52	1.78	2.16	1.93
56M4	404	0.07	3.50	0.06	0.95	2.24	0.17	0.86

Modified Values

	Customers	2008	2009	2010	2011	2012	2013	2014
23M3	2540	6.18	3.54	1.76	1.56	1.13	0.82	2.08
23M4	2925	4.20	1.16	0.25	0.48	0.06	1.80	0.01
23M5	1585	0.57	4.17	1.27	1.22	0.30	2.68	0.45
24M10	1746	0.07	0.04	0.26	0.23	0.03	12.42	0.12
24M7	2181	0.31	2.62	1.94	0.66	0.81	0.06	0.44
24M8	14	0.30	3.21	0.00	0.00	0.89	0.09	0.00
24M9	3861	0.07	0.21	0.36	1.17	1.54	1.86	1.02
3M3	4	1.38	0.00	0.00	0.00	0.00	2.45	0.00
3M4	1183	0.08	1.05	4.07	0.76	1.34	2.01	3.75
3M6	3826	1.38	0.10	9.46	5.60	0.43	0.58	0.21
3M8	1774	2.20	3.59	5.36	2.31	0.27	3.60	1.25
56M25	2120	3.49	1.30	1.61	1.17	0.21	1.05	0.07
56M26	4079	0.74	3.21	3.31	1.98	0.73	1.55	0.22
56M4	404	0.07	3.50	0.06	0.95	0.80	0.00	0.63

Notes:

SAIDI is measured in units of time, often minutes or hours. It is usually measured over the course of a year, and according to IEEE Standard 1366-1998 the median value for North American utilities is approximately 1.50 hours.

2014 data is cumulative to August 1st.

Appendix D - Outage Data up to August 1st 2014

Feeder 23M3

outage_id	Restore_Step	from Restore_Device	to_restore_device	Device	Feeder	Cause	DtOut	TmOut	DtRes	TmRes	Duration	NumCust	SubCustMin	AREA_TOWN	Equipment_code	Customer Ho	Modifier	tomer Hours M
A0030	1	ILS-2		None	23M3	Scheduled Outage	23-Jan-08	10:10	23-Jan-08	14:05	235.2	116	27283.2	A5-AMH	1	454.72	0	0.00
A0031	1	U/G service		None	23M3	Equipment failure	29-Jan-08	5:10	29-Jan-08	6:45	94.8	1	94.8	A5-AMH	5.5	1.58	1	1.58
A0032	1	TX50074		None	23M3	Other	05-Feb-08	4:58	05-Feb-08	7:30	151.8	12	1821.6	A5-AMH	5.17	30.36	1	30.36
A0033	1	P142A		Other	23M3	Equipment failure	17-Feb-08	11:30	17-Feb-08	15:30	240	2	480	A5-AMH	5.4	8.00	1	8.00
A0033	2	UG Ped		Other	23M3	Equipment failure	22-Feb-08	13:00	22-Feb-08	14:30	90	2	180	A5-AMH	5.4	3.00	1	3.00
A0035	1	U/G service		None	23M3	Other	05-May-08	20:00	05-May-08	21:00	60	1	60	A5-AMH	5.5	1.00	1	1.00
A0142	1	SEC UG WIRE		Secondary Conductor	23M3	Equipment failure	01-Jun-08	12:55	01-Jun-08	11:50	11455	3	34365	A5-AMH	5.5	572.75	1	572.75
A0112	1	SERVICE		Other	23M3	Tree falling	05-Jun-08	22:23	05-Jun-08	4:30	367	2	734	A5-AMH	3.2	12.23	1	12.23
A0191	1	FS50101+23M3 Feeder		None	23M3	Tree growth	08-Jun-08	17:46	08-Jun-08	23:19	333	2223	740259	A5-AMH	6	12337.65	1	12337.65
A0037	1	All of 23M3		Other	23M3	Other	08-Jun-08	16:46	08-Jun-08	20:38	232.2	2178	505731.6	A5-AMH	2.0	8428.86	0	0.00
A0039	1	All of 23M3		None	23M3	Loss of supply	08-Jun-08	11:00	08-Jun-08	11:20	19.2	2178	41817.6	A5-AMH	2.0	696.96	0	0.00
A0223	1	FS50013		Switch	23M3	Animal	07-Jul-08	18:06	07-Jul-08	20:15	129	35	4515	A5-AMH	9.2	75.25	1	75.25
A0194	1	TX50282		None	23M3	Equipment failure	13-Jul-08	9:43	13-Jul-08	11:00	77	8	616	A5-AMH	5.6	10.27	1	10.27
A0261	1	FS50014		Fused Disconnect	23M3	Tree falling	17-Jul-08	13:30	17-Jul-08	17:00	210	61	12810	A5-AMH	3.1	213.50	1	213.50
A0248C	1	Geo m5 m7		Other	23M3	Loss of supply	08-Aug-08	23:15	09-Aug-08	1:25	130	2396	311480	A5-AMH	2.0	5191.33	0	0.00
A0247	1	Service		Secondary Conductor	23M3	Other	20-Aug-08	21:39	20-Aug-08	22:05	26	1	26	A5-AMH	5.5	0.43	1	0.43
A0246	1	SECONDARY CONNECTION		Secondary Conductor	23M3	Other	23-Aug-08	21:28	23-Aug-08	23:15	107	1	107	A5-AMH	5.5	1.78	1	1.78
0153	1	TX7B459		Transformer Fuse	23M3	Equipment failure	03-Sep-08	20:01	04-Sep-08	0:15	254	1	254	A7-LAS	5.6	4.23	1	4.23
0117	1	FS50002		Other	23M3	Equipment failure	15-Oct-08	14:00	15-Oct-08	15:30	90	1	90	A5-AMH	5.6	1.50	1	1.50
0002	1	FS50101		Fused Disconnect	23M3	Tree falling	29-Nov-08	13:57	29-Nov-08	15:45	108	43	4644	A5-AMH	3.2	77.40	1	77.40
0142	1	ALM 3		Other	23M3	Loss of supply	15-Dec-08	8:00	15-Dec-08	9:30	90	2396	215640	A5-AMH	2.0	3594.00	0	0.00
0258	1	Meter		Other	23M3	Tree falling	27-Dec-08	21:09	28-Dec-08	1:00	231	1	231	A5-AMH	3.1	3.85	1	3.85
A0197	1	FS50012		Fused Disconnect	23M5	Equipment failure	27-Jul-08	7:10	27-Jul-08	11:30	260	27	7020	A5-AMH	5.6	117.00	1	117.00
0188A	1	23M3		Other	23M3	Tree falling	28-Dec-08	5:00	28-Dec-08	6:00	60	2223	133380	A5-AMH	3.2	2223.00	1	2223.00
							Total 2008									**34060.66**	**19.00**	**15694.79**
0404	1	connectors		Other	23M3	Equipment failure	04-Jan-09	9:36	04-Jan-09	11:00	84	1	84	A5-AMH	5.92	1.40	1	1.40
0264	1	Service Wire		Other	23M3	Equipment failure	03-Feb-09	16:45	03-Feb-09	18:30	105	1	105	A5-AMH	5.92	1.75	1	1.75
0605	1	23M3		Other	23M3	Storm	11-Feb-09	18:58	11-Feb-09	22:30	212	2371	502652	A5-AMH	6	8377.53	1	8377.53
0266	1	FS50005		Other	23M3	Storm	11-Mar-09	2:32	11-Mar-09	6:05	213	94	20022	A5-AMH	7	333.70	1	333.70
0268	1	FS50075		Other	23M3	Customer equipment	15-Mar-09	13:36	15-Mar-09	15:09	93	11	1023	A5-AMH	5.24	17.05	1	17.05
0556	1	FS50101			23M3	Equipment failure	03-Apr-09	11:32	03-Apr-09	12:23	51	70	3570	A5-AMH	5.3	59.50	1	59.50
0606	1	insulinks		Other	23M3	Equipment failure	10-Apr-09	11:24	10-Apr-09	12:30	66	1	66	A5-AMH	5.92	1.10	1	1.10
0269	1	Service			23M3	Tree falling	25-Jun-09	18:03	25-Jun-09	20:15	132	1	132	A5-AMH	3.1	2.20	1	2.20
0701	1	TX50P11			23M3	Animal	13-Jul-09	8:00	13-Jul-09	9:00	60	2	120	A5-AMH	9.2	2.00	1	2.00
0427	1	Service		Other	23M3	Equipment failure	21-Aug-09	16:09	21-Aug-09	18:10	121	1	121	A5-AMH	5.92	2.02	1	2.02
0921090824	2	FS50045	TX50149	UG Transformer	23M3	Other	21-Sep-09	8:32	21-Sep-09	8:47	15	71	1065	A5-AMH	5.12	17.75	1	17.75
0921090824	1	TX5140C		UG Transformer	23M3	Other	21-Sep-09	7:12	21-Sep-09	8:47	95	11	1045	A5-AMH	5.12	17.42	1	17.42
1020091016	1	Meter		Meter	23M3	Equipment failure	22-Sep-09	17:27	22-Sep-09	18:50	83	1	83	A5-AMH	5.5	1.38	1	1.38
0929090759	1	SC50190	SC50190	UG Transformer	23M3	Scheduled Outage	30-Sep-09	9:30	30-Sep-09	15:30	360	95	34200	A5-AMH	1	570.00	0	0.00
1006090952	1	FS50003	FS50003	Switch	23M3	Scheduled Outage	08-Oct-09	9:50	08-Oct-09	15:30	340	95	32300	A5-AMH	1	538.33	0	0.00
0114101147	1	TX50102		OH Transformer	23M3	Equipment failure	08-Oct-09	15:30	08-Oct-09	16:45	75	12	900	A5-AMH	5.12	15.00	1	15.00
1008090310	1	TX50102	TX50102	OH Transformer	23M3	Other	08-Oct-09	15:30	08-Oct-09	16:45	75	12	900	A5-AMH	5.12	15.00	0	0.00
1015090114	1	FS50005	FS50005	Switch	23M3	Scheduled Outage	15-Oct-09	13:30	15-Oct-09	13:41	11	94	1034	A5-AMH	1	17.23	0	0.00
1021090832	1	TX5155E	TX5155D	UG Transformer	23M3	Scheduled Outage	22-Oct-09	9:06	22-Oct-09	18:30	564	10	5640	A5-AMH	1	94.00	0	0.00
1110090253	1	SD50004	SD50003	OH Transformer	23M3	Scheduled Outage	16-Nov-09	8:00	16-Nov-09	11:30	210	57	11970	A5-AMH	1	199.50	0	0.00
1223091033	1	Service		Meter	23M3	Equipment failure	22-Nov-09	12:13	22-Nov-09	13:30	77	1	77	A5-AMH	5.92	1.28	1	1.28
1223091048	1	Meter		Meter	23M3	Equipment failure	24-Nov-09	21:36	24-Nov-09	22:40	64	1	64	A5-AMH	5.92	1.07	1	1.07
0559	1	FS50016			23M4	Lightning	09-Apr-09	9:21	09-Apr-09	10:59	98	54	5292	A5-AMH	5.3	88.20	1	88.20
1223090945	1	SD50003		OH Transformer	23M5	Equipment failure	07-Nov-09	16:20	07-Nov-09	18:35	135	25	3375	A5-AMH	5.15	56.25	1	56.25
1223091124	1	service		Meter	23M3	Equipment failure	09-Dec-09	8:40	09-Dec-09	10:00	80	1	80	A5-AMH	5.93	1.33	1	1.33
							Total 2009									**10432.00**	**19.00**	**8997.93**

0106100834	2	FS50005	TX50640	Switch	23M3	Scheduled Outage	08-Jan-10	10:48	08-Jan-10	11:08	20	94	1880	A5-AMH	1	31.33	1	31.33
0106100834	1	FS50005	FS50005	Switch	23M3	Scheduled Outage	08-Jan-10	10:48	08-Jan-10	10:50	2	94	188	A5-AMH	1	3.13	1	3.13
0714101113	1	Service		Service	23M3	Equipment failure	25-Mar-10	16:08	25-Mar-10	19:00	172	1	172	A5-AMH	5.92	2.87	1	2.87
0714101116	1	Service		Service	23M3	Equipment failure	11-May-10	18:27	11-May-10	19:20	53	1	53	A5-AMH	5.5	0.88	1	0.88
0714101120	1	AMH-42X		Unknown	23M3	Equipment failure	17-May-10	20:21	17-May-10	22:35	134	6	804	A5-AMH	5.2	13.40	1	13.40
0714101031	1	meter		Meter	23M3	Equipment failure	19-May-10	15:30	19-May-10	16:15	45	1	45	A5-AMH	5.92	0.75	1	0.75
0714101121	1	CALM5-M3		Unknown	23M3	Equipment failure	20-May-10	12:30	20-May-10	13:58	88	2394	210672	A5-AMH	2	3511.20	1	3511.20
0714101034	1	fs50017		Switch	23M3	Lightning	27-May-10	9:38	27-May-10	10:45	67	25	1675	A5-AMH	4	27.92	1	27.92
0714101035	1	TX5140C		UG Transformer	23M3	Lightning	27-May-10	22:13	28-May-10	0:30	137	11	1507	A5-AMH	4	25.12	1	25.12
0714101037	1	tx5p232		OH Transformer	23M3	Scheduled Outage	28-May-10	8:30	28-May-10	9:15	45	8	360	A5-AMH	1	6.00	0	0.00
0714101122	1	tx50286		OH Transformer	23M3	Equipment failure	02-Jun-10	16:28	02-Jun-10	19:00	152	15	2280	A5-AMH	5.12	38.00	1	38.00
0602100129	1	TX50286	TX50286	OH Transformer	23M3	Lightning	02-Jun-10	13:08	02-Jun-10	15:30	142	15	2130	A5-AMH	4	35.50	1	35.50
0714101124	1	Service		Service	23M3	Equipment failure	07-Jun-10	19:29	08-Jun-10	0:30	301	1	301	A5-AMH	5.5	5.02	1	5.02
0608101145	1	TX50286	TX50286	OH Transformer	23M3	Scheduled Outage	08-Jun-10	11:45	08-Jun-10	12:14	29	15	435	A5-AMH	1	7.25	0	0.00
0615100121	1	TX50153	TX50153	UG Transformer	23M3	Scheduled Outage	15-Jun-10	12:30	15-Jun-10	13:00	30	18	540	A5-AMH	1	9.00	0	0.00
0714101125	1	Service		Service	23M3	Equipment failure	15-Jun-10	17:08	15-Jun-10	19:00	112	1	112	A5-AMH	5.5	1.87	1	1.87
0714101126	1	Service	service	Service	23M3	Equipment failure	22-Jun-10	18:03	22-Jun-10	20:15	132	1	132	A5-AMH	5.5	2.20	1	2.20
0714101127	1	fs50050		Switch	23M3	Lightning	23-Jun-10	23:08	24-Jun-10	6:30	442	19	8398	A5-AMH	4	139.97	1	139.97
072810101201	1	service		Service	23M3	Tree falling	09-Jul-10	1:00	09-Jul-10	1:20	20	1	20	A5-AMH	3.2	0.33	1	0.33
072910013649	1	fs50133		Switch	23M3	Equipment failure	23-Jul-10	19:54	23-Jul-10	22:00	126	136	17136	A5-AMH	5.6	285.60	1	285.60
083010111942	1	fs50133		Switch	23M3	Animal	15-Aug-10	7:30	15-Aug-10	9:45	135	99	13365	A5-AMH	9.2	222.75	1	222.75
092210095440	1	fs50013		Switch	23M3	Other	18-Aug-10	7:40	18-Aug-10	8:55	75	35	2625	A5-AMH	5.6	43.75	1	43.75
092210101050	1	fs50082		Switch	23M3	Other	27-Aug-10	18:55	27-Aug-10	19:35	40	16	640	A5-AMH	0.1	10.67	1	10.67
092210101059	1	tx50019		OH Transformer	23M3	Equipment failure	30-Aug-10	16:30	30-Aug-10	20:00	210	8	1680	A5-AMH	5.14	28.00	1	28.00
090310104020	1	TX50178	TX50178	UG Transformer	23M3	Scheduled Outage	03-Sep-10	10:40	03-Sep-10	11:00	20	11	220	A5-AMH	1	3.67	1	3.67
111710080057	1	tx50045		UG Transformer	23M3	Equipment failure	04-Sep-10	11:45	04-Sep-10	13:15	90	16	1440	A5-AMH	3.2	24.00	1	24.00
092010112920	1	FS50089	FS50089	Switch	23M3	Scheduled Outage	22-Sep-10	9:50	22-Sep-10	12:22	152	46	6992	A5-AMH	1	116.53	0	0.00
111710094700	1	tx50124		OH Transformer	23M3	Human error	27-Sep-10	16:52	27-Sep-10	17:50	58	18	1044	A5-AMH	9.1	17.40	1	17.40
092910012538	1	SECPED	SECPED	Pedestal	23M3	Scheduled Outage	29-Sep-10	13:25	29-Sep-10	14:30	65	1	65	A5-AMH	1	1.08	0	0.00
093010100009	1	SECPED	SECPAD	Pedestal	23M3	Scheduled Outage	30-Sep-10	10:03	30-Sep-10	11:40	97	1	97	A5-AMH	1	1.62	0	0.00
							Total 2010									**4616.80**	**24.00**	**4475.32**
011011110158	1	SERVICE	SERVICE	Service	23M3	Human error	10-Jan-11	8:38	10-Jan-11	13:45	307	1	307	A5-AMH	9.1	5.12	1	5.12
020211024401	1	PMH223	PMH223	UG switch unit	23M3	Equipment failure	02-Feb-11	14:14	02-Feb-11	16:40	146	32	4672	A5-AMH	5.6	77.87	1	77.87
042011011801	1	23m3		Station Breaker	23M3	Loss of supply	10-Apr-11	16:48	10-Apr-11	18:16	88	2394	210672	A5-AMH	2.0	3511.20	0	0.00
042011012532	1	Fs50098		Switch	23M3	Equipment failure	10-Apr-11	6:48	10-Apr-11	9:00	132	49	6468	A5-AMH	5.6	107.80	1	107.80
042011125746	1	TX50188		OH Transformer	23M3	Equipment failure	15-Apr-11	4:30	15-Apr-11	6:10	100	9	900	A5-AMH	5.11	15.00	1	15.00
050511090056	1	FS50005		Switch	23M3	Loss of supply	23-Apr-11	23:24	24-Apr-11	1:50	146	75	10950	A5-AMH	2.0	182.50	1	182.50
050311020534	1	TX50900		OH Transformer	23M3	Equipment failure	23-Apr-11	23:40	24-Apr-11	1:45	125	7	875	A5-AMH	4	14.58	1	14.58
050211094607	1	TX51548		UG Transformer	23M3	Equipment failure	23-Apr-11	15:35	23-Apr-11	17:00	85	8	680	A5-AMH	5.23	11.33	1	11.33
050311020538	1	FS50049		Switch	23M3	Equipment failure	26-Apr-11	14:31	26-Apr-11	16:45	134	14	1876	A5-AMH	5.23	31.27	1	31.27
053011011036	1	TX51548		UG Transformer	23M3	Customer equipment	27-Apr-11	11:12	27-Apr-11	11:43	31	8	248	A5-AMH	5.28	4.13	1	4.13
051611024827	1	FS50010		Switch	23M3	Equipment failure	15-May-11	10:15	15-May-11	11:45	90	23	2070	A5-AMH	5.6	34.50	1	34.50
053011032338	1	Tx50080		OH Transformer	23M3	Tree falling	18-May-11	18:00	18-May-11	19:15	75	15	1125	A5-AMH	3.2	18.75	1	18.75
060611034756	1	FS50011		Switch	23M3	Equipment failure	28-May-11	8:08	28-May-11	9:25	77	97	7469	A5-AMH	4	124.48	1	124.48
062711032351	1	Tx5t185		OH Transformer	23M3	Tree growth	18-Jun-11	17:00	18-Jun-11	18:30	90	11	990	A5-AMH	3.1	16.50	1	16.50
070411012805	1	FS50025	TX50576	Switch	23M3	Equipment failure	28-Jun-11	6:54	28-Jun-11	10:30	216	51	11016	A5-AMH	5.4	183.60	1	183.60
070411012805	2	TX50536	TX50546	Switch	23M3	Equipment failure	28-Jun-11	6:54	28-Jun-11	11:30	276	7	1932	A5-AMH	5.4	32.20	1	32.20
092111090051	1	TX50080		OH Transformer	23M3	Tree falling-weather	02-Jul-11	23:50	03-Jul-11	4:10	260	15	3900	A5-AMH	3.2	65.00	1	65.00
100711031034	1	TX50080		OH Transformer	23M3	Lightning	02-Jul-11	23:51	03-Jul-11	1:30	99	15	1485	A5-AMH	4	24.75	1	24.75
092011022342	1	Service		Service	23M3	Tree falling	03-Jul-11	7:14	04-Jul-11	3:30	1216	1	1216	A5-AMH	3.2	20.27	1	20.27
082211030733	1	Service		Service	23M3	Equipment failure	02-Aug-11	15:00	02-Aug-11	16:35	95	1	95	A5-AMH	5.92	1.58	1	1.58
080911085704	1	FS50005		Switch	23M3	Scheduled Outage	09-Aug-11	8:49	09-Aug-11	10:45	116	94	10904	A5-AMH	7	181.73	0	0.00
080911093641	1	TX50152		UG Transformer	23M3	Other	09-Aug-11	8:05	09-Aug-11	14:34	389	16	6224	A5-AMH	7	103.73	1	103.73
081011122409	1	FS50006		Switch	23M3	Scheduled Outage	10-Aug-11	11:40	10-Aug-11	13:25	105	127	13335	A5-AMH	5.26	222.25	0	0.00
092411023457	1	FS50017		Switch	23M3	Lightning	18-Aug-11	18:37	19-Aug-11	3:20	523	66	34518	A5-AMH	4	575.30	1	575.30
101311090538	1	TX5155D		UG Transformer	23M3	Equipment failure	10-Sep-11	16:28	10-Sep-11	19:00	152	12	1824	A5-AMH	5.23	30.40	1	30.40
090811114124	1	SD50003		Switch	23M3	Scheduled Outage	12-Sep-11	9:00	12-Sep-11	12:18	198	25	4950	A5-AMH	1	82.50	0	0.00
100711100504	1	SC50165		UG switch unit	23M3	Scheduled Outage	16-Sep-11	10:25	16-Sep-11	10:31	6	46	276	A5-AMH	1	4.60	0	0.00
092211082042	1	TX51548		UG Transformer	23M3	Scheduled Outage	22-Sep-11	9:27	22-Sep-11	14:30	303	8	2424	A5-AMH	1	40.40	0	0.00
092611023232	1	Service		Service	23M3	Equipment failure	25-Sep-11	13:30	25-Sep-11	16:00	150	1	150	A5-AMH	5.5	2.50	1	2.50
092711090521	1	FS50049		Switch	23M3	Equipment failure	26-Sep-11	15:30	26-Sep-11	18:10	160	7	1120	A5-AMH	5.23	18.67	1	18.67
092811012901	1	TX51552		UG Transformer	23M3	Scheduled Outage	29-Sep-11	9:00	29-Sep-11	13:35	275	7	1925	A5-AMH	1	32.08	0	0.00
012412110520	1	Service		Service	23M3	Human error	14-Sep-11	14:16	14-Sep-11	16:00	104	1	104	A5-AMH	9.1	1.73	1	1.73
031611092010	1	TX50346		OH Transformer	23M3	Scheduled Outage	16-Mar-11	9:20	16-Mar-11	13:20	240	2	480	A5-AMH	1	8.00	0	0.00
080211082608	1	Service		Service	23M3	Tree falling	11-Jul-11	15:00	11-Jul-11	21:00	360	1	360	A5-AMH	3.2	6.00	0	0.00
081711083156	1	Station Breakers		Station Breaker	23M3	Scheduled Outage	11-Aug-11	14:10	11-Aug-11	14:21	11	4719	51909	A5-AMH	2	865.15	0	0.00
081911011558	1	TX50048		UG Transformer	23M3	Scheduled Outage	19-Aug-11	15:00	19-Aug-11	20:00	300	11	3300	A5-AMH	4	55.00	0	0.00
102811125847	1	Station Breaker		Station Breaker	23M3	Loss of supply	17-Oct-11	1:13	17-Oct-11	3:35	142	2042	289964	A5-AMH	2.0	4832.73	0	0.00
102811125847	2	23M5	CAL-1	Station Breaker	23M3	Loss of supply	17-Oct-11	1:13	17-Oct-11	5:35	262	498	130476	A5-AMH	2.0	2174.60	0	0.00
111711084857	1	FS50014		Switch	23M3	Scheduled Outage	17-Nov-11	9:00	17-Nov-11	13:45	285	65	18525	A5-AMH	1	308.75	0	0.00
111811082238	1	SW50024		Switch	23M3	Scheduled Outage	18-Nov-11	9:00	18-Nov-11	14:20	320	23	7360	A5-AMH	1	122.67	0	0.00
112111021927	1	SD50003		Switch	23M3	Scheduled Outage	22-Nov-11	9:30	22-Nov-11	13:30	240	25	6000	A5-AMH	1	100.00	0	0.00
120811035531	1	CAL-1		Switch	23M3	Equipment failure	04-Dec-11	20:08	04-Dec-11	21:40	92	1480	136160	A5-AMH	5.6	2269.33	1	2269.33
							Total 2011									**16520.57**	**26.00**	**3972.90**

030312023800	1	Station Breaker		Station Breaker	23M3	Loss of supply	18-Feb-12	11:48:00 AM	18-Feb-12	1:45:00 PM	117	3032	354744	A5-AMH	2	5912.40	0	0.00
032112010717	1	FS50133		Switch	23M3	Scheduled Outage	21-Mar-12	1:11:00 PM	21-Mar-12	1:19:00 PM	8	41	328	A5-AMH	1	5.47	0	0.00
032212084817	1	TX5155D		UG Transformer	23M3	Scheduled Outage	22-Mar-12	9:00:00 AM	22-Mar-12	12:30:00 PM	210	7	1470	A5-AMH	1	24.50	0	0.00
032712093923	1	TX50T15		OH Transformer	23M3	Scheduled Outage	27-Mar-12	9:40:00 AM	27-Mar-12	10:10:00 AM	30	9	270	A5-AMH	1	4.50	0	0.00
041412031500	1	TX50T15		OH Transformer	23M3	Lightning	31-Mar-12	4:15:00 PM	31-Mar-12	7:10:00 PM	175	9	1575	A5-AMH	4	26.25	1	26.25
041912104539	1	FS50046		Switch	23M3	Scheduled Outage	19-Apr-12	10:30:00 AM	19-Apr-12	4:00:00 PM	330	64	21120	A5-AMH	5.23	352.00	1	352.00
043012015136	1	FS50081		Switch	23M3	Equipment failure	23-Apr-12	1:54:00 PM	23-Apr-12	4:25:00 PM	151	38	5738	A5-AMH	5.6	95.63	1	95.63
070312110318	1	FS50005		Switch	23M3	Scheduled Outage	03-Jul-12	11:00:00 AM	03-Jul-12	12:04:00 PM	64	79	5056	A5-AMH	4	84.27	1	84.27
070512125549	1	Station Breaker		Station Breaker	23M3	Loss of supply	04-Jul-12	7:53:00 PM	04-Jul-12	10:33:00 PM	160	3071	491360	A5-AMH	2	8189.33	0	0.00
070612021645	1	TX50906		OH Transformer	23M3	Lightning	03-Jul-12	9:18:00 AM	03-Jul-12	12:20:00 PM	182	1	182	A5-AMH	4	3.03	1	3.03
070612025343	1	TX50288		OH Transformer	23M3	Lightning	04-Jul-12	5:39:00 PM	05-Jul-12	1:20:00 AM	461	20	9220	A5-AMH	4	153.67	1	153.67
070912093606	1	TX5T216		OH Transformer	23M3	Scheduled Outage	10-Jul-12	8:32:00 AM	10-Jul-12	8:45:00 AM	13	14	182	A5-AMH	1	3.03	0	0.00
070912113722	1	Station Breaker		Station Breaker	23M3	Loss of supply	05-Jul-12	11:41:00 AM	05-Jul-12	10:49:00 PM	668	3071	2051428	A5-AMH	2	34190.47	0	0.00
071812082821	1	FS50013		Switch	23M3	Other	14-Jul-12	11:30:00 AM	14-Jul-12	2:35:00 PM	185	34	6290	A5-AMH	0.1	104.83	1	104.83
072312013000	1	FS50133		Switch	23M3	Scheduled Outage	23-Jul-12	11:45:00 AM	23-Jul-12	1:45:00 PM	120	41	4920	A5-AMH	9.2	82.00	1	82.00
080712093247	1	Station Breaker		Station Breaker	23M3	Loss of supply	23-Jul-12	11:51:00 AM	23-Jul-12	11:54:00 AM	3	3071	9213	A5-AMH	2	153.55	0	0.00
082712104913	1	Station Breaker		Station Breaker	23M3	Loss of supply	13-Aug-12	1:48:00 AM	13-Aug-12	1:49:00 AM	1	3071	3071	A5-AMH	2	51.18	0	0.00
090712102121	1	TX50159		OH Transformer	23M3	Scheduled Outage	07-Sep-12	8:00:00 AM	07-Sep-12	10:30:00 AM	150	18	2700	A5-AMH	9.2	45.00	1	45.00
091312090528	1	FS50014		Switch	23M3	Equipment failure	08-Sep-12	2:24:00 PM	08-Sep-12	4:55:00 PM	151	65	9815	A5-AMH	5.6	163.58	1	163.58
091412081447	1	23M3		Station Breaker	23M3	Loss of supply	13-Aug-12	1:48:00 AM	13-Aug-12	1:49:00 AM	1	3069	3069	A5-AMH	2	51.15	0	0.00
101612120059	1	FS50030		Switch	23M3	Scheduled Outage	17-Oct-12	6:40:00 AM	17-Oct-12	12:40:00 PM	360	104	37440	A5-AMH	1	624.00	0	0.00
101812030615	1	FS50111	SD50002	Switch	23M3	Equipment failure	13-Oct-12	6:06:00 PM	13-Oct-12	9:00:00 PM	174	71	12354	A5-AMH	5.6	205.90	1	205.90
101812032851	1	FS50111	SD50002	Switch	23M3	Equipment failure	13-Oct-12	10:56:00 PM	14-Oct-12	1:40:00 AM	164	71	11644	A5-AMH	5.6	194.07	1	194.07
101812034019	1	FS50030		Switch	23M3	Equipment failure	14-Oct-12	4:30:00 AM	14-Oct-12	9:00:00 AM	270	31	8370	A5-AMH	5.6	139.50	1	139.50
111412081427	1	SC50160		UG switch unit	23M3	Scheduled Outage	14-Nov-12	9:11:00 AM	14-Nov-12	2:40:00 PM	329	18	5922	A5-AMH	1	98.70	0	0.00
112912032813	1	TX50346		OH Transformer	23M3	Other	29-Nov-12	12:00:00 AM	29-Nov-12	2:40:00 AM	160	2	320	A5-AMH	0.1	5.33	1	5.33
113012081804	1	FS50045		Switch	23M3	Scheduled Outage	30-Nov-12	10:24:00 AM	30-Nov-12	10:46:00 AM	22	74	1628	A5-AMH	1	27.13	0	0.00
122112022328	1	MV50130	FS50001	Switch	23M3	Equipment failure	20-Dec-12	12:00:00 PM	20-Dec-12	2:45:00 PM	165	443	73095	A5-AMH	5.15	1218.25	1	1218.25
							Total 2012									**52208.73**	**15.00**	**2873.32**
11113014229	1	FS50133	NULL	Switch	23M3	Scheduled Outage	11-Jan-13	12:53:00 PM	11-Jan-13	1:30:00 PM	37	91	3367	A5-AMH	9.2	56.12	1	56.12
11513094455	1	FS50133	NULL	Switch	23M3	Animal	12-Jan-13	2:30:00 PM	12-Jan-13	4:30:00 PM	120	82	9840	A5-AMH	9.2	164.00	1	164.00
22813082713	1	TX50170	TX5P111	OH Transformer	23M3	Scheduled Outage	28-Feb-13	10:00:00 AM	28-Feb-13	10:30:00 AM	30	14	420	A5-AMH	1	7.00	0	0.00
22813091848	1	TX50168	TX5P111	OH Transformer	23M3	Scheduled Outage	28-Feb-13	1:45:00 PM	28-Feb-13	2:15:00 PM	30	14	420	A5-AMH	1	7.00	0	0.00
22813092654	1	FS50133	NULL	Switch	23M3	Scheduled Outage	01-Mar-13	9:00:00 AM	01-Mar-13	2:00:00 PM	300	91	27300	A5-AMH	1	455.00	0	0.00
50113083311	1	TX50618	NULL	UG Transformer	23M3	Scheduled Outage	17-Apr-13	9:00:00 AM	17-Apr-13	1:00:00 PM	240	9	2160	A5-AMH	1	36.00	0	0.00
42513113133	1	TX51550	NULL	UG Transformer	23M3	Scheduled Outage	23-Apr-13	9:20:00 AM	23-Apr-13	12:40:00 PM	200	18	3600	A5-AMH	1	60.00	0	0.00
42913082338	1	TX50546	NULL	UG Transformer	23M3	Scheduled Outage	25-Apr-13	9:30:00 AM	25-Apr-13	1:30:00 PM	240	4	960	A5-AMH	1	16.00	0	0.00
42913041818	1	23M3	NULL	Station Breaker	23M3	Loss of supply	25-Apr-13	6:01:00 AM	25-Apr-13	6:03:00 AM	2	3062	6124	A5-AMH	2	102.07	0	0.00
50313073901	1	TX50542	NULL	UG Transformer	23M3	Scheduled Outage	29-Apr-13	9:30:00 AM	29-Apr-13	1:20:00 PM	230	4	920	A5-AMH	1	15.33	0	0.00
50713083155	1	TX50540	NULL	UG Transformer	23M3	Scheduled Outage	01-May-13	9:30:00 AM	01-May-13	1:30:00 PM	240	6	1440	A5-AMH	1	24.00	0	0.00
50913090353	1	TX51550	NULL	UG Transformer	23M3	Scheduled Outage	03-May-13	9:30:00 AM	03-May-13	2:00:00 PM	270	9	2430	A5-AMH	1	40.50	0	0.00
51313072819	1	TX50554	NULL	UG Transformer	23M3	Scheduled Outage	07-May-13	9:30:00 AM	07-May-13	1:22:00 PM	232	7	1624	A5-AMH	1	27.07	0	0.00
51613093511	1	TX50556	NULL	UG Transformer	23M3	Scheduled Outage	09-May-13	9:30:00 AM	09-May-13	1:30:00 PM	240	8	1920	A5-AMH	1	32.00	0	0.00
52313092614	1	TX50558	NULL	UG Transformer	23M3	Scheduled Outage	13-May-13	9:20:00 AM	13-May-13	1:40:00 PM	260	11	2860	A5-AMH	1	47.67	0	0.00
51713080131	1	TX50560	NULL	UG Transformer	23M3	Scheduled Outage	16-May-13	9:30:00 AM	16-May-13	1:20:00 PM	230	7	1610	A5-AMH	1	26.83	0	0.00
52113085006	1	FS50025	NULL	Switch	23M3	Scheduled Outage	17-May-13	9:50:00 AM	17-May-13	10:25:00 AM	35	51	1785	A5-AMH	1	29.75	0	0.00
52813074402	1	TX50576	NULL	UG Transformer	23M3	Scheduled Outage	21-May-13	9:30:00 AM	21-May-13	1:35:00 PM	245	6	1470	A5-AMH	1	24.50	0	0.00
53013081521	1	TX50574	NULL	UG Transformer	23M3	Scheduled Outage	23-May-13	9:30:00 AM	23-May-13	1:20:00 PM	230	8	1840	A5-AMH	1	30.67	0	0.00
53113082733	1	TX50572	NULL	UG Transformer	23M3	Scheduled Outage	29-May-13	9:30:00 AM	29-May-13	1:25:00 PM	235	8	1880	A5-AMH	1	31.33	0	0.00
60613075707	1	TX50570	NULL	UG Transformer	23M3	Scheduled Outage	30-May-13	9:30:00 AM	30-May-13	1:35:00 PM	245	8	1960	A5-AMH	1	32.67	0	0.00
61213012446	1	TX50566	NULL	UG Transformer	23M3	Scheduled Outage	31-May-13	9:00:00 AM	31-May-13	11:20:00 AM	140	8	1120	A7-LAS	1	18.67	0	0.00
61213032733	1	TX50584	NULL	UG Transformer	23M3	Scheduled Outage	06-Jun-13	9:00:00 AM	06-Jun-13	1:30:00 PM	270	9	2430	A5-AMH	1	40.50	0	0.00
61213033140	1	FS50006	NULL	Switch	23M3	Scheduled Outage	12-Jun-13	1:05:00 PM	12-Jun-13	1:45:00 PM	40	128	5120	A5-AMH	1	85.33	0	0.00
61913103159	1	FS50014	NULL	Switch	23M3	Scheduled Outage	14-Jun-13	9:20:00 AM	14-Jun-13	11:15:00 AM	115	64	7360	A5-AMH	1	122.67	0	0.00
61913114212	1	TX50500	NULL	UG Transformer	23M3	Scheduled Outage	17-Jun-13	9:00:00 AM	17-Jun-13	2:00:00 PM	300	8	2400	A5-AMH	1	40.00	0	0.00
61913120141	1	FS50009	NULL	Switch	23M3	Scheduled Outage	19-Jun-13	10:30:00 AM	19-Jun-13	10:41:00 AM	11	213	2343	A5-AMH	1	39.05	0	0.00
62513092359	1	FS50018	NULL	Switch	23M3	Scheduled Outage	19-Jun-13	11:24:00 AM	19-Jun-13	11:28:00 AM	4	254	1016	A5-AMH	1	16.93	0	0.00
70313073712	1	FS50003	NULL	Switch	23M3	Scheduled Outage	19-Jun-13	11:59:00 AM	19-Jun-13	12:25:00 PM	26	74	1924	A5-AMH	1	32.07	0	0.00
72313104641	1	TX50190	NULL	OH Transformer	23M3	Equipment failure	23-Jun-13	7:24:00 AM	23-Jun-13	10:20:00 AM	176	9	1584	A5-AMH	5.12	26.40	1	26.40
80213021354	1	FS50012	NULL	Switch	23M3	Scheduled Outage	03-Jul-13	9:45:00 AM	03-Jul-13	11:29:00 AM	104	29	3016	A5-AMH	1	50.27	0	0.00
91413011126	1	TX5T186	NULL	OH Transformer	23M3	Scheduled Outage	23-Jul-13	10:45:00 AM	23-Jul-13	11:23:00 AM	38	16	608	A5-AMH	1	10.13	0	0.00
100213020147	1	FS50016	NULL	Switch	23M3	Scheduled Outage	06-Aug-13	10:30:00 AM	06-Aug-13	12:00:00 PM	90	55	4950	A5-AMH	1	82.50	0	0.00
100313075558	1	23M3	NULL	Station Breaker	23M3	Loss of supply	12-Sep-13	10:05:00 AM	12-Sep-13	10:07:00 AM	2	1768	3536	A5-AMH	2	58.93	0	0.00
100713013532	1	ILS-1	CALM5-M3	Station Breaker	23M3	Loss of supply	12-Sep-13	10:09:00 AM	12-Sep-13	11:27:00 AM	78	1755	136890	A5-AMH	2	2281.50	0	0.00
100913090105	1	FS50016	NULL	Switch	23M3	Human error	01-Oct-13	3:03:00 PM	01-Oct-13	7:30:00 PM	267	55	14685	A5-AMH	9.1	244.75	1	244.75
100913090105	2	FS50018	NULL	Switch	23M3	Equipment failure	02-Oct-13	1:41:00 PM	02-Oct-13	7:25:00 PM	344	254	87376	A5-AMH	5.4	1456.27	1	1456.27
100913090105	3	FS50016	NULL	Switch	23M3	Scheduled Outage	04-Oct-13	10:16:00 AM	04-Oct-13	10:30:00 AM	14	55	770	A5-AMH	1	12.83	0	0.00
100913041143	1	FS50018	SC50170	UG Transformer	23M3	Scheduled Outage	09-Oct-13	10:30:00 AM	09-Oct-13	10:35:00 AM	5	42	210	A5-AMH	1	3.50	0	0.00
110113021540	1	TX50744	TX50514	UG Transformer	23M3	Scheduled Outage	09-Oct-13	10:30:00 AM	09-Oct-13	10:40:00 AM	10	43	430	A5-AMH	1	7.17	0	0.00
121713080429	1	SC50170	TX50514	UG Transformer	23M3	Scheduled Outage	09-Oct-13	10:30:00 AM	09-Oct-13	1:45:00 PM	195	45	8775	A5-AMH	1	146.25	0	0.00
121813080111	1	TX50516	TX50514	UG Transformer	23M3	Scheduled Outage	10-Oct-13	9:10:00 AM	10-Oct-13	1:35:00 PM	265	16	4240	A5-AMH	1	70.67	0	0.00
121813080457	1	FS50050	NULL	Switch	23M3	Equipment failure	31-Oct-13	5:39:00 PM	01-Nov-13	12:15:00 AM	396	19	7524	A5-AMH	5.23	125.40	1	125.40
121913080425	1	TX50104	NULL	OH Transformer	23M3	Scheduled Outage	17-Dec-13	8:00:00 AM	17-Dec-13	1:04:00 PM	304	12	3648	A5-AMH	1	60.80	0	0.00
10614030745	1	SD50004	NULL	Switch	23M3	Scheduled Outage	18-Dec-13	8:00:00 AM	18-Dec-13	11:35:00 AM	215	62	13330	A5-AMH	1	222.17	0	0.00
22114110631	1	FS50014	NULL	Switch	23M3	Scheduled Outage	18-Dec-13	11:50:00 AM	18-Dec-13	2:10:00 PM	140	66	9240	A5-AMH	1	154.00	0	0.00
30714033323	1	FS50032	NULL	Switch	23M3	Scheduled Outage	19-Dec-13	8:00:00 AM	19-Dec-13	11:39:00 AM	219	23	5037	A5-AMH	1	83.95	0	0.00
32614092539	1	23M3	NULL	Station Breaker	23M3	Loss of supply	20-Dec-13	4:41:00 AM	20-Dec-13	4:42:00 AM	1	1773	1773	A5-AMH	2	29.55	0	0.00
							Total 2013									**6787.75**	**6.00**	**2072.93**

33114095744	1	CALM5-M3	ILS-1	Station Breaker	23M3	Loss of supply	01-Feb-14	8:43:00 PM	01-Feb-14	11:05:00 PM	142	2639	374738	A5-AMH	2	6245.63	0	0.00
40114074713	1	FS50006	NULL	Switch	23M3	Equipment failure	02-Feb-14	11:08:00 AM	02-Feb-14	4:00:00 PM	292	122	35624	A5-AMH	5.23	593.73	1	593.73
40114103303	1	TX50460	NULL	Switch	23M3	Equipment failure	02-Feb-14	11:08:00 AM	02-Feb-14	9:15:00 PM	607	7	4249	A5-AMH	5.23	70.82	1	70.82
40114105427	1	FS50006	NULL	Switch	23M3	Scheduled Outage	03-Feb-14	12:00:00 PM	03-Feb-14	12:35:00 PM	35	129	4515	A5-AMH	1	75.25	0	0.00
41714012015	1	ILS5001	NULL	Switch	23M3	Scheduled Outage	21-Feb-14	11:00:00 AM	21-Feb-14	12:02:00 PM	62	142	8804	A5-AMH	1	146.73	0	0.00
50614021449	1	FS50048	NULL	Switch	23M3	Equipment failure	07-Mar-14	10:08:00 AM	07-Mar-14	12:03:00 PM	115	19	2185	A5-AMH	5.4	36.42	1	36.42
50814014759	1	FS50046	NULL	Switch	23M3	Scheduled Outage	26-Mar-14	10:25:00 AM	26-Mar-14	10:47:00 AM	22	54	1188	A5-AMH	1	19.80	0	0.00
52614122844	1	Service	NULL	Service	23M3	Loss of supply	29-Mar-14	11:58:00 AM	29-Mar-14	10:30:00 PM	632	1	632	A5-AMH	2	10.53	0	0.00
52814031444	1	TX50478	NULL	UG Transformer	23M3	Scheduled Outage	31-Mar-14	10:00:00 AM	31-Mar-14	11:55:00 AM	115	14	1610	A5-AMH	1	26.83	0	0.00
61214043526	1	FS50001	NULL	Switch	23M3	Equipment failure	31-Mar-14	9:39:00 PM	01-Apr-14	1:40:00 AM	241	226	54466	A5-AMH	5.6	907.77	1	907.77
61814030351	1	TX5P152	NULL	UG Transformer	23M3	Equipment failure	01-Apr-14	9:14:00 AM	01-Apr-14	5:00:00 PM	466	1	466	A5-AMH	5.23	7.77	1	7.77
62614073322	1	TX50744	NULL	UG Transformer	23M3	Scheduled Outage	17-Apr-14	1:30:00 PM	17-Apr-14	2:35:00 PM	65	115	7475	A5-AMH	1	124.58	0	0.00
70814111106	1	23M3	NULL	Station Breaker	23M3	Human error	06-May-14	12:03:00 PM	06-May-14	1:20:00 PM	77	2864	220528	A5-AMH	9.1	3675.47	1	3675.47
71014035154	1	FS50133	NULL	Switch	23M3	Scheduled Outage	08-May-14	11:20:00 AM	08-May-14	11:38:00 AM	18	92	1656	A5-AMH	1	27.60	0	0.00
71214114036	1	TX5155B	TX7P112	UG Transformer	23M3	Scheduled Outage	27-May-14	9:00:00 AM	27-May-14	12:45:00 PM	225	11	2475	A5-AMH	1	41.25	0	0.00
70314084702	1	TX5155C	TX5P113	UG Transformer	23M3	Scheduled Outage	29-May-14	9:18:00 AM	29-May-14	12:10:00 PM	172	8	1376	A5-AMH	1	22.93	0	0.00
72514014929	1	TX5155D	TX5P114	UG Transformer	23M3	Scheduled Outage	03-Jun-14	9:38:00 AM	03-Jun-14	1:30:00 PM	232	12	2784	A5-AMH	1	46.40	0	0.00
71914045733	1	TX50155	TX5P115	UG Transformer	23M3	Scheduled Outage	10-Jun-14	9:15:00 AM	10-Jun-14	11:45:00 AM	150	8	1200	A5-AMH	1	20.00	0	0.00
72514014130	1	TX50156	NULL	UG Transformer	23M3	Scheduled Outage	17-Jun-14	8:45:00 AM	17-Jun-14	1:35:00 PM	290	13	3770	A5-AMH	1	62.83	0	0.00
41713084403	1	TX50157	TX5P117	UG Transformer	23M3	Scheduled Outage	24-Jun-14	9:33:00 AM	24-Jun-14	1:15:00 PM	222	15	3330	A5-AMH	1	55.50	0	0.00
42213033236	1	TX50158	NULL	UG Transformer	23M3	Scheduled Outage	26-Jun-14	8:45:00 AM	26-Jun-14	11:45:00 AM	180	8	1440	A5-AMH	1	24.00	0	0.00
91213103143	1	23M3	NULL	Station Breaker	23M3	Loss of supply	27-Jun-14	1:35:00 PM	27-Jun-14	1:38:00 PM	3	3191	9573	A5-AMH	2	159.55	0	0.00
20314093522	1	TX50152	TX5P116	UG Transformer	23M3	Scheduled Outage	03-Jul-14	8:45:00 AM	03-Jul-14	1:31:00 PM	286	16	4576	A5-AMH	1	76.27	0	0.00
20314115303	1	TX50151	TX5P116	UG Transformer	23M3	Scheduled Outage	09-Jul-14	9:00:00 AM	09-Jul-14	12:00:00 PM	180	16	2880	A5-AMH	1	48.00	0	0.00
20514022358	1	TX50150	TX5P119	UG Transformer	23M3	Scheduled Outage	11-Jul-14	8:45:00 AM	11-Jul-14	12:05:00 PM	200	10	2000	A5-AMH	1	33.33	0	0.00
20514022358	2	FS50040	NULL	Switch	23M3	Scheduled Outage	12-Jul-14	8:40:00 AM	12-Jul-14	11:00:00 AM	140	43	6020	A5-AMH	1	100.33	0	0.00
60214041608	1	FS50003	NULL	Switch	23M3	Scheduled Outage	25-Jul-14	1:55:00 PM	25-Jul-14	1:59:00 PM	4	97	388	A5-AMH	1	6.47	0	0.00
61014092246	1	FS50045	NULL	Switch	23M3	Scheduled Outage	25-Jul-14	1:40:00 PM	25-Jul-14	1:47:00 PM	7	62	434	A5-AMH	1	7.23	0	0.00
							To Date 2014									**12673.03**	**6.00**	**5291.97**

Feeder 23M4

outage_id	Restore_Step	from Restore_Device	to_restore_device	Device	Feeder	Cause	DtOut	TmOut	DtRes	TmRes	Duration	NumCust	SubCustMin	AREA_TOWN	Equipment_code	Customer Hours	Modifier	Customer Hours Modified
A0041	1	Insulinks		None	23M4	Equipment failure	22-Jan-08	12:15	22-Jan-08	12:33	18	1	18	A7-LAS	5.17	0.30	1	0.30
A0052	1	Insulinks		None	23M4	Equipment failure	23-Apr-08	19:57	23-Apr-08	23:30	213	1	213	A7-LAS	5.17	3.55	1	3.55
A0190	1	@ LAS-340(opening)-Closing SW700H9		None	23M4	Storm	08-Jun-08	17:45	08-Jun-08	22:10	265	1931	511715	A7-LAS	6	8528.58	1	8528.58
A0140	1	TX7D103		None	23M4	Lightning	15-Jun-08	4:05	15-Jun-08	5:47	102	5	510	A7-LAS	4	8.50	1	8.50
A0187	1	TX70D24		None	23M4	Equipment failure	26-Jun-08	18:52	27-Jun-08	1:05	373	14	5222	A7-LAS	5.5	87.03	1	87.03
A0205	1	NEUTRAL		None	23M4	Tree growth	08-Jul-08	18:30	08-Jul-08	19:50	80	1	80	A7-LAS	3.1	1.33	1	1.33
A0248A	1	SW700H9		Other	23M4	Loss of supply	08-Aug-08	23:15	09-Aug-08	1:30	135	3091	417285	A7-LAS	2.0	6954.75	0	0.00
0155	1	UG wire		Secondary Conductor	23M4	Equipment failure	08-Sep-08	20:10	08-Sep-08	22:22	132	1	132	A7-LAS	5.6	2.20	1	2.20
0061	1	FS70H50		Fused Disconnect	23M4	Tree falling	14-Sep-08	7:30	14-Sep-08	8:55	85	41	3485	A7-LAS	3.2	58.08	1	58.08
0057	1	TX7D261		Other	23M4	Tree falling	14-Sep-08	0:30	14-Sep-08	1:53	83	11	913	A7-LAS	3.2	0.00	0	0.00
0059	1	METER		Other	23M4	Tree growth	18-Sep-08	21:10	18-Sep-08	22:20	70	1	70	A7-LAS	3.1	1.17	1	1.17
0177	1	SERVICE CONNECTION		Other	23M4	Other	15-Oct-08	22:14	16-Oct-08	0:04	110	1	110	A7-LAS	2.0	1.83	1	1.83
0148	1	TX7D114		Transformer Fuse	23M4	Equipment failure	19-Nov-08	8:00	19-Nov-08	9:00	60	8	480	A7-LAS	5.6	8.00	1	8.00
0144	1	SW700H9		Other	23M4	Loss of supply	24-Dec-08	21:50	24-Dec-08	22:35	45	500	22500	A7-LAS	2.0	375.00	1	375.00
0143	1	FS70H16		Other	23M4	Animal	24-Dec-08	16:00	24-Dec-08	17:35	95	231	21945	A7-LAS	9.2	365.75	1	365.75
0188B	1	23M4		Other	23M4	Tree falling	28-Dec-08	5:00	28-Dec-08	6:00	60	2831	169860	A7-LAS	3.2	2831.00	1	2831.00
0261	1	Meter		Other	23M4	Equipment failure	28-Dec-08	13:12	28-Dec-08	17:00	228	1	228	A7-LAS	5.92	3.80	1	3.80
0401	1	O/H Sevice		Other	23M4	Equipment failure	29-Dec-08	10:17	29-Dec-08	11:59	102	1	102	A7-LAS	5.92	1.70	1	1.70
							Total 2008									**19232.58**	**16.00**	**12277.83**
0403	1	FS70825		Other	23M4	Equipment failure	16-Jan-09	2:12	16-Jan-09	3:00	48	51	2448	A7-LAS	5.26	40.80	1	40.80
0751	3	FS70H16		Fused Disconnect	23M4	Animal	03-Feb-09	14:00	03-Feb-09	14:40	40	214	8560	A7-LAS	9.2	142.67	1	142.67
0751	2	FS70H74		Fused Disconnect	23M4	Animal	03-Feb-09	14:00	03-Feb-09	14:30	30	45	1350	A7-LAS	9.2	22.50	1	22.50
0751	1	D648		Fused Disconnect	23M4	Animal	03-Feb-09	14:00	03-Feb-09	14:20	20	9	180	A7-LAS	9.2	3.00	1	3.00
0603	1	TX7B140		Transformer Fuse	23M4	Animal	02-Apr-09	6:57	02-Apr-09	8:30	93	8	744	A7-LAS	9.2	12.40	1	12.40
0559	1	FS50016			23M4	Lightning	09-Apr-09	9:21	09-Apr-09	10:59	98	54	5292	A5-AMH	5.3	0.00	0	0.00
0410	1	TX7D601		Transformer Fuse	23M4	Animal	06-May-09	8:45	06-May-09	9:18	33	14	462	A7-LAS	9.2	7.70	1	7.70
0416	1	TX7D866		Transformer Fuse	23M4	Animal	22-May-09	19:11	22-May-09	20:40	89	18	1602	A7-LAS	9.2	26.70	1	26.70
0418	1	FS70H74			23M4	Animal	24-May-09	10:29	24-May-09	12:08	99	45	4455	A7-LAS	9.2	74.25	1	74.25
0484	1	FS70H74		Other	23M4	Animal	12-Jun-09	8:20	12-Jun-09	9:07	47	45	2115	A7-LAS	9.2	35.25	1	35.25
0270	2	SW7H009		Station Breaker	23M4	Tree falling	11-Jul-09	13:11	11-Jul-09	13:44	33	2912	96096	A7-LAS	2	1601.60	0	0.00
0270	1	LAS340		Station Breaker	23M4	Tree falling	11-Jul-09	13:11	11-Jul-09	13:30	19	2912	55328	A7-LAS	2	922.13	0	0.00
0271	1	TX7D114			23M4	Equipment failure	12-Jul-09	20:50	12-Jul-09	21:40	50	7	350	A7-LAS	0.1	5.83	1	5.83
0616	1	FS7H198		Other	23M4	Animal	18-Jul-09	7:05	18-Jul-09	8:59	114	39	4446	A7-LAS	9.2	74.10	1	74.10
0703	1	pole to house		Secondary Conductor	23M4	Equipment failure	22-Jul-09	17:51	22-Jul-09	21:30	219	1	219	A7-LAS	5.92	3.65	1	3.65
0613	1	TX7B462		Transformer Fuse	23M4	Animal	02-Aug-09	8:32	02-Aug-09	9:50	78	5	390	A7-LAS	9.2	6.50	1	6.50
0925090132	1	TX7D600		OH Transformer	23M4	Scheduled Outage	25-Sep-09	13:30	25-Sep-09	13:45	15	18	270	A7-LAS	1	4.50	1	4.50
1020090836	1	SW7H107		Switch	23M4	Wind	28-Sep-09	4:49	28-Sep-09	8:30	221	8	1768	A7-LAS	6	29.47	1	29.47
0928090942	1	TX7D645		OH Transformer	23M4	Scheduled Outage	28-Sep-09	9:15	28-Sep-09	9:48	33	12	396	A7-LAS	1	6.60	1	6.60
1019091130	1	TX7B428		OH Transformer	23M4	Equipment failure	30-Sep-09	7:30	30-Sep-09	9:00	90	3	270	A7-LAS	5.12	4.50	1	4.50
1102091259	1	23M4	23M4	Service	23M4	Equipment failure	02-Nov-09	10:00	02-Nov-09	11:00	60	2886	173160	A7-LAS	5.17	2886.00	1	2886.00
							Total 2009									**5910.15**	**18.00**	**3386.42**
0322101036	1	TX7B462	TX7B462	UG Transformer	23M4	Scheduled Outage	22-Mar-10	10:30	22-Mar-10	11:40	70	5	350	A7-LAS	1	5.83	1	5.83
0427101238	1	Service		Service	23M4	Equipment failure	02-Apr-10	13:25	02-Apr-10	16:15	170	1	170	A7-LAS	5.92	2.83	1	2.83
0427100802	1	TX70D13		OH Transformer	23M4	Scheduled Outage	27-Apr-10	9:30	27-Apr-10	11:30	120	12	1440	A7-LAS	1	24.00	1	24.00
0428100852	1	FS70H97	FS70H97	Switch	23M4	Scheduled Outage	29-Apr-10	8:55	29-Apr-10	11:15	140	18	2520	A7-LAS	1	42.00	1	42.00
0518100858	1	TX7D311		OH Transformer	23M4	Lightning	05-May-10	17:52	05-May-10	20:00	128	1	128	A7-LAS	4	2.13	1	2.13
0520100116	1	station breaker	LAS310	Station Breaker	23M4	Loss of supply	20-May-10	12:30	20-May-10	15:28	178	1270	226060	A7-LAS	2	3767.67	0	0.00
0520100151	1	station breaker	calm5-m3	Station Breaker	23M4	Loss of supply	20-May-10	12:30	20-May-10	13:15	45	1529	68805	A5-AMH	2	1146.75	0	0.00
0714101004	1	TX7D114		OH Transformer	23M4	Animal	20-Jun-10	21:01	20-Jun-10	23:35	154	8	1232	A7-LAS	9.2	20.53	1	20.53
0714101135	1	TX7D600		OH Transformer	23M4	Equipment failure	24-Jun-10	8:30	24-Jun-10	10:00	90	17	1530	A7-LAS	5.15	25.50	1	25.50
0624100300	1	TX7D600	TX7D600	OH Transformer	23M4	Scheduled Outage	24-Jun-10	8:40	24-Jun-10	10:00	80	18	1440	A7-LAS	1	24.00	0	0.00
072910102510	1	TX7E233	TX7E233	Unknown	23M4	Lightning	23-Jul-10	15:00	23-Jul-10	18:30	210	1	210	A7-LAS	4	3.50	1	3.50
081610121718	1	TX70E34		OH Transformer	23M4	Lightning	28-Jul-10	19:50	28-Jul-10	21:35	105	11	1155	A7-LAS	4	19.25	1	19.25
092210101020	1	tx7d174		OH Transformer	23M4	Animal	29-Aug-10	7:45	29-Aug-10	10:00	135	17	2295	A7-LAS	9.2	38.25	1	38.25
092110020038	1	FS70H16	FS70H16	Switch	23M4	Storm	02-Sep-10	15:05	02-Sep-10	16:35	90	210	18900	A7-LAS	6	0.00	0	0.00
111710075345	1	fs70h16		Switch	23M4	Storm	02-Sep-10	15:05	02-Sep-10	16:35	90	200	18000	A7-LAS	6	300.00	1	300.00
090210031528	1	TX7D648	TX7D648	OH Transformer	23M4	Scheduled Outage	02-Sep-10	15:00	02-Sep-10	21:00	360	9	3240	A7-LAS	1	54.00	0	0.00
111710075706	1	tx7d648		OH Transformer	23M4	Storm	02-Sep-10	15:00	02-Sep-10	21:00	360	9	3240	A7-LAS	6	54.00	1	54.00
090810101431	1	TX7E185	TX7E185	OH Transformer	23M4	Scheduled Outage	08-Sep-10	10:16	08-Sep-10	12:15	119	4	476	A7-LAS	1	7.93	0	0.00
111710094653	1	fs70h41		Switch	23M4	Equipment failure	28-Sep-10	17:00	28-Sep-10	20:00	180	10	1800	A7-LAS	5.6	30.00	1	30.00
111710091844	1	fs7h108		Switch	23M4	Equipment failure	14-Oct-10	3:29	14-Oct-10	5:40	131	68	8908	A7-LAS	5.15	148.47	1	148.47
102510095744	1	TX7D728	TX7D728	OH Transformer	23M4	Animal	22-Oct-10	9:00	22-Oct-10	10:00	60	10	600	A7-LAS	9.2	10.00	1	10.00
011711023924	1	23m4		Station Breaker	23M4	Loss of supply	10-Dec-10	3:26	10-Dec-10	5:20	114	2941	335274	A7-LAS	2	5587.90	0	0.00
		TX7D683		OH Transformer	23M4	Scheduled Outage	02-Sep-10	9:58	02-Sep-10	10:15	17	17	289	A7-LAS	1	4.82	0	0.00
		TX7D683		OH Transformer	23M4	Scheduled Outage	03-Sep-10	13:42	03-Sep-10	14:00	18	17	306	A7-LAS	1	5.10	0	0.00
							Total 2010									**11324.47**	**15.00**	**726.30**

021611085000	1	TX7B462		OH Transformer	23M4	Equipment failure	07-Feb-11	0:30	07-Feb-11	6:15	345	5	1725	A7-LAS	5.11	28.75	1	28.75
030111091849	1	TX7D682		OH Transformer	23M4	Scheduled Outage	01-Mar-11	11:05	01-Mar-11	12:37	92	16	1472	A7-LAS	1	24.53	1	24.53
050511090048	1	FS7H203		Switch	23M4	Animal	29-Apr-11	20:18	29-Apr-11	22:07	109	129	14061	A7-LAS	9.2	234.35	1	234.35
050511090048	2	tx7d915		Switch	23M4	Animal	29-Apr-11	20:18	29-Apr-11	22:50	152	16	2432	A7-LAS	9.2	40.53	1	40.53
051211033603	1	TX7D328		OH Transformer	23M4	Lightning	12-May-11	10:30	12-May-11	12:30	120	2	240	A7-LAS	4	4.00	1	4.00
060611032712	1	tx7b462		OH Transformer	23M4	Equipment failure	28-May-11	7:59	28-May-11	8:45	46	5	230	A7-LAS	5.12	3.83	1	3.83
092011032335	1	23M4 23M3		Station Breaker	23M4	Loss of supply	02-Jul-11	20:00	02-Jul-11	23:20	200	5465	1093000	A7-LAS	2	18216.67	0	0.00
092011020842	1	TX7D153		OH Transformer	23M4	Lightning	03-Jul-11	9:42	03-Jul-11	23:45	843	12	10116	A7-LAS	4	168.60	1	168.60
101111091433	1	Service		Service	23M4	Tree falling-weather	05-Jul-11	10:14	05-Jul-11	13:00	166	1	166	A7-LAS	3.2	2.77	1	2.77
072611082751	1	FS70H40		Switch	23M4	Other	06-Jul-11	8:30	06-Jul-11	9:40	70	10	700	A7-LAS	0.1	11.67	1	11.67
101111092607	1	FS70H13		Switch	23M4	Animal	11-Jul-11	14:01	11-Jul-11	16:00	119	63	7497	A7-LAS	9.2	124.95	1	124.95
101111093842	1	TX70D45		OH Transformer	23M4	Lightning	13-Jul-11	7:59	13-Jul-11	9:00	61	12	732	A7-LAS	4	12.20	1	12.20
080211102949	1	TX7E156		OH Transformer	23M4	Equipment failure	21-Jul-11	19:17	21-Jul-11	20:45	88	15	1320	A7-LAS	5.12	22.00	1	22.00
080211092648	1	TX7B490		OH Transformer	23M4	Lightning	25-Jul-11	19:30	26-Jul-11	9:30	840	13	10920	A7-LAS	4	182.00	1	182.00
072711040757	1	TX7D107		OH Transformer	23M4	Lightning	25-Jul-11	20:00	26-Jul-11	8:30	750	14	10500	A7-LAS	4	175.00	1	175.00
092411033709	1	TX7D169		OH Transformer	23M4	Lightning	18-Aug-11	18:41	18-Aug-11	22:55	254	16	4064	A7-LAS	4	67.73	1	67.73
092411043640	1	TX7E157		OH Transformer	23M4	Lightning	18-Aug-11	18:36	19-Aug-11	1:50	434	6	2604	A7-LAS	4	43.40	1	43.40
092411034149	1	Service		Service	23M4	Tree falling-weather	18-Aug-11	18:29	19-Aug-11	2:30	481	1	481	A7-LAS	3.2	8.02	1	8.02
081911102646	1	TX7D619		OH Transformer	23M4	Scheduled Outage	19-Aug-11	7:30	19-Aug-11	12:00	270	13	3510	A7-LAS	9.2	58.50	1	58.50
082411040205	1	TX7D648		OH Transformer	23M4	Animal	21-Aug-11	7:15	21-Aug-11	9:45	150	9	1350	A7-LAS	9.2	22.50	1	22.50
083011092914	1	TX7D107	TX7D107	OH Transformer	23M4	Scheduled Outage	30-Aug-11	9:25	30-Aug-11	11:48	143	14	2002	A7-LAS	1	33.37	1	33.37
092211124549	1	TX7D328		OH Transformer	23M4	Other	14-Sep-11	15:45	14-Sep-11	18:20	155	2	310	A7-LAS	0.1	5.17	1	5.17
101111110934	2	FS70H41	TX7D622	OH Transformer	23M4	Animal	07-Oct-11	18:31	07-Oct-11	20:20	109	9	981	A7-LAS	9.2	16.35	1	16.35
101111110934	1	FS70H40	FS70H41	OH Transformer	23M4	Animal	07-Oct-11	18:31	07-Oct-11	20:10	99	1	99	A7-LAS	9.2	1.65	1	1.65
012312045449	1	TX7P335		OH Transformer	23M4	Animal	09-Aug-11	15:48	09-Aug-11	16:48	60	10	600	A7-LAS	9.2	10.00	1	10.00
090911095103	1	TX7D866		OH Transformer	23M4	Scheduled Outage	14-Sep-11	9:30	14-Sep-11	14:00	270	18	4860	A7-LAS	1	81.00	1	81.00
112811042223	1	TX70D45		OH Transformer	23M4	Other	25-Nov-11	15:16	25-Nov-11	16:10	54	12	648	A7-LAS	0.1	10.80	1	10.80
							Total 2011									**19610.33**	**26.00**	**1393.67**
020112011132	1	TX7D632		OH Transformer	23M4	Scheduled Outage	01-Feb-12	13:05	01-Feb-12	13:48	43	14	602	A7-LAS	1	10.03	0	0.00
030812125604	1	TX7B429		OH Transformer	23M4	Equipment failure	08-Mar-12	12:40	08-Mar-12	14:00	80	2	160	A7-LAS	5.14	2.67	1	2.67
041412043347	1	FS70H83		Switch	23M4	Equipment failure	02-Apr-12	23:45	03-Apr-12	0:25	40	1	40	A7-LAS	5.6	0.67	1	0.67
041712124335	1	FS70H13		Switch	23M4	Scheduled Outage	17-Apr-12	12:45	17-Apr-12	13:00	15	35	525	A7-LAS	1	8.75	0	0.00
041912090456	1	TX7E176		OH Transformer	23M4	Scheduled Outage	19-Apr-12	9:03	19-Apr-12	9:32	29	8	232	A7-LAS	1	3.87	0	0.00
042312104536	1	FS70H13		Switch	23M4	Scheduled Outage	23-Apr-12	10:44	23-Apr-12	11:14	30	42	1260	A7-LAS	1	21.00	0	0.00
050312102138	1	TX7D300		OH Transformer	23M4	Scheduled Outage	03-May-12	10:21	03-May-12	11:45	84	11	924	A7-LAS	1	15.40	0	0.00
050412091928	1	TX7D300		OH Transformer	23M4	Scheduled Outage	04-May-12	9:19	04-May-12	11:33	134	11	1474	A7-LAS	1	24.57	0	0.00
051012081705	1	TX7D138		OH Transformer	23M4	Equipment failure	09-May-12	16:48	09-May-12	18:35	107	12	1284	A7-LAS	5.14	21.40	1	21.40
061512103721	1	TX70E10		OH Transformer	23M4	Scheduled Outage	15-Jun-12	10:37	15-Jun-12	10:55	18	11	198	A7-LAS	1	3.30	0	0.00
070512010149	1	Station Breaker		Station Breaker	23M4	Loss of supply	04-Jul-12	19:52	04-Jul-12	22:38	166	2739	454674	A7-LAS	2	7577.90	0	0.00
070912013515	1	Station Breaker		Station Breaker	23M4	Loss of supply	05-Jul-12	16:29	05-Jul-12	22:49	380	2739	1040820	A7-LAS	2	17347.00	0	0.00
092512093629	1	TX72012		UG Transformer	23M4	Equipment failure	23-Sep-12	14:51	24-Sep-12	2:30	699	1	699	A7-LAS	5.23	11.65	1	11.65
100512095653	1	FS70H27		Switch	23M4	Scheduled Outage	05-Oct-12	9:56	05-Oct-12	10:20	24	27	648	A7-LAS	1	10.80	0	0.00
101012092830	1	FS50030		Switch	23M4	Scheduled Outage	10-Oct-12	8:17	10-Oct-12	10:15	118	31	3658	A5-AMH	0.1	60.97	0	0.00
103112101416	1	FS70H13		Switch	23M4	Scheduled Outage	31-Oct-12	8:33	31-Oct-12	9:55	82	97	7954	A7-LAS	9.2	132.57	1	132.57
							Total 2012									**25252.53**	**5.00**	**168.95**
10413091850	1	TX7D242	NULL	OH Transformer	23M4	Scheduled Outage	04-Jan-13	9:33	04-Jan-13	11:00	87	7	609	A7-LAS	1	10.15	0	0.00
10713085827	1	TX7E191	NULL	OH Transformer	23M4	Scheduled Outage	07-Jan-13	9:38	07-Jan-13	11:40	122	10	1220	A7-LAS	1	20.33	0	0.00
10813113050	1	TX7E191	NULL	OH Transformer	23M4	Scheduled Outage	07-Jan-13	12:30	07-Jan-13	14:20	110	10	1100	A7-LAS	1	18.33	0	0.00
10813113443	1	TX70023	NULL	OH Transformer	23M4	Scheduled Outage	08-Jan-13	11:41	08-Jan-13	13:40	119	9	1071	A5-AMH	1	17.85	0	0.00
11013100458	1	TX70023	NULL	OH Transformer	23M4	Scheduled Outage	10-Jan-13	9:30	10-Jan-13	11:15	105	10	1050	A7-LAS	1	17.50	0	0.00
11513095148	1	TX7D601	NULL	OH Transformer	23M4	Storm	13-Jan-13	19:15	13-Jan-13	21:45	150	14	2100	A7-LAS	5.92	35.00	1	35.00
20413084634	1	Station Breaker	NULL	Station Breaker	23M4	Loss of supply	20-Jan-13	3:21	20-Jan-13	3:25	4	2752	11008	A7-LAS	2	183.47	0	0.00
12413013859	1	TX7D248	NULL	OH Transformer	23M4	Scheduled Outage	24-Jan-13	13:36	24-Jan-13	14:01	25	10	250	A7-LAS	1	4.17	0	0.00
12513090913	1	TX7D248	NULL	OH Transformer	23M4	Scheduled Outage	25-Jan-13	9:20	25-Jan-13	10:34	74	10	740	A7-LAS	1	12.33	0	0.00
12913012733	1	Station Breaker	NULL	Station Breaker	23M4	Loss of supply	27-Jan-13	21:01	27-Jan-13	21:02	1	2752	2752	A7-LAS	2	45.87	0	0.00
12913013305	1	Station Breaker	NULL	Station Breaker	23M4	Loss of supply	27-Jan-13	21:02	28-Jan-13	2:08	306	2752	842112	A7-LAS	2	14035.20	0	0.00
30713014923	1	TX70E98	NULL	OH Transformer	23M4	Scheduled Outage	07-Mar-13	14:00	07-Mar-13	14:27	27	5	135	A7-LAS	1	2.25	0	0.00
31513074248	1	TX7E128	NULL	OH Transformer	23M4	Equipment failure	14-Mar-13	3:05	14-Mar-13	4:45	100	12	1200	A7-LAS	5.11	20.00	1	20.00
41813125201	1	FS70714	NULL	Switch	23M4	Scheduled Outage	18-Apr-13	12:55	18-Apr-13	13:06	11	50	550	A7-LAS	5.6	9.17	1	9.17
41913031417	1	FS70093	NULL	Switch	23M4	Wind	19-Apr-13	14:14	19-Apr-13	15:50	96	52	4992	A7-LAS	6	83.20	1	83.20
60713115303	1	TX7P446	NULL	UG Transformer	23M4	Equipment failure	05-Jun-13	14:30	05-Jun-13	17:45	195	13	2535	A7-LAS	5.23	42.25	1	42.25
62413094154	1	23M4	NULL	Station Breaker	23M4	Equipment failure	20-Jun-13	19:52	20-Jun-13	21:32	100	2858	285800	A7-LAS	5.93	4763.33	1	4763.33
62513092829	1	FS7H184	NULL	Switch	23M4	Lightning	22-Jun-13	18:25	22-Jun-13	20:35	130	38	4940	A7-LAS	4	82.33	1	82.33
70213030935	1	23M4	NULL	Station Breaker	23M4	Loss of supply	27-Jun-13	13:21	27-Jun-13	13:22	1	2752	2752	A7-LAS	2	45.87	0	0.00
80913091742	1	TX7B425	NULL	OH Transformer	23M4	Equipment failure	17-Jul-13	16:00	17-Jul-13	20:30	270	4	1080	A7-LAS	5.11	18.00	1	18.00
81313012415	1	TX7D724	NULL	OH Transformer	23M4	Storm	18-Jul-13	19:12	18-Jul-13	20:29	77	16	1232	A7-LAS	6	20.53	1	20.53
72913110020	11	TX7D317	NULL	OH Transformer	23M4	Animal	29-Jul-13	9:27	29-Jul-13	11:08	101	9	909	A7-LAS	9.2	15.15	1	15.15
73013020745	1	TX7D682	NULL	OH Transformer	23M4	Animal	05-Aug-13	7:10	05-Aug-13	9:20	130	30	3900	A7-LAS	9.2	65.00	1	65.00
90313124813	1	TX70D81	NULL	OH Transformer	23M4	Equipment failure	30-Aug-13	0:15	30-Aug-13	3:35	200	10	2000	A7-LAS	5.12	33.33	1	33.33
91413122012	1	FS70714	NULL	Switch	23M4	Equipment failure	12-Sep-13	13:33	12-Sep-13	14:40	67	36	2412	A7-LAS	5.93	40.20	1	40.20
111813114043	1	23M4	NULL	Station Breaker	23M4	Loss of supply	17-Nov-13	20:33	17-Nov-13	21:45	72	1773	127656	A7-LAS	2	2127.60	0	0.00
112713111234	1	TX7D247	NULL	OH Transformer	23M4	Equipment failure	26-Nov-13	13:34	26-Nov-13	16:40	186	1	186	A7-LAS	5.14	3.10	1	3.10
120213123012	1	TX70E34	NULL	OH Transformer	23M4	Equipment failure	01-Dec-13	8:15	01-Dec-13	11:45	210	11	2310	A7-LAS	5.12	38.50	1	38.50
121213094313	1	SW700H9	LAS-340	Station Breaker	23M4	Loss of supply	12-Dec-13	9:23	12-Dec-13	10:00	37	2885	106745	A7-LAS	2	1779.08	0	0.00
							Total 2013									**23589.10**	**15.00**	**5269.10**

12014031240	1	TX7D921	NULL	OH Transformer	23M4	Animal	17-Jan-14	17:12	17-Jan-14	19:55	163	6	978	A7-LAS	9.2	16.30	1	16.30
20414025759	1	FS700H2	NULL	Switch	23M4	Equipment failure	31-Jan-14	17:40	31-Jan-14	18:05	25	191	4775	A7-LAS	5.6	79.58	1	79.58
21014093820	1	TX7D224	NULL	OH Transformer	23M4	Scheduled Outage	10-Feb-14	9:40	10-Feb-14	11:00	80	12	960	A7-LAS	1	16.00	0	0.00
21414100758	1	TX7E175	NULL	OH Transformer	23M4	Scheduled Outage	14-Feb-14	10:00	14-Feb-14	10:30	30	8	240	A7-LAS	1	4.00	0	0.00
21414102604	1	TX700E4	NULL	OH Transformer	23M4	Scheduled Outage	14-Feb-14	10:35	14-Feb-14	10:45	10	11	110	A7-LAS	1	1.83	0	0.00
22014100905	1	TX700E6	NULL	OH Transformer	23M4	Scheduled Outage	20-Feb-14	10:10	20-Feb-14	10:28	18	6	108	A7-LAS	1	1.80	0	0.00
22114094336	1	TX700E4	NULL	OH Transformer	23M4	Scheduled Outage	21-Feb-14	9:40	21-Feb-14	10:10	30	11	330	A7-LAS	1	5.50	0	0.00
22414092007	1	TX7D766	NULL	OH Transformer	23M4	Animal	24-Feb-14	8:33	24-Feb-14	9:15	42	17	714	A7-LAS	9.2	11.90	1	11.90
22414041417	1	TX7E185	NULL	OH Transformer	23M4	Scheduled Outage	24-Feb-14	14:00	24-Feb-14	15:00	60	4	240	A7-LAS	1	4.00	0	0.00
30614090003	1	TX7E175	TX70045	OH Transformer	23M4	Scheduled Outage	06-Mar-14	9:30	06-Mar-14	10:41	71	8	568	A7-LAS	1	9.47	0	0.00
31014011930	1	TX700E3	NULL	OH Transformer	23M4	Scheduled Outage	10-Mar-14	13:17	10-Mar-14	13:21	4	12	48	A7-LAS	1	0.80	0	0.00
31714124001	1	TX7D213	NULL	OH Transformer	23M4	Scheduled Outage	17-Mar-14	12:45	17-Mar-14	12:57	12	24	288	A7-LAS	1	4.80	0	0.00
31714010438	1	TX7D630	NULL	OH Transformer	23M4	Scheduled Outage	17-Mar-14	13:00	17-Mar-14	13:33	33	10	330	A7-LAS	1	5.50	0	0.00
31914122006	1	SW70718	NULL	Switch	23M4	Scheduled Outage	19-Mar-14	12:15	19-Mar-14	13:02	47	34	1598	A7-LAS	1	26.63	0	0.00
40814041342	1	TX7B478	TX7B203	OH Transformer	23M4	Scheduled Outage	09-Apr-14	5:00	09-Apr-14	6:30	90	2	180	A7-LAS	1	3.00	0	0.00
41414100405	1	SERVICE	NULL	OH Conductor	23M4	Scheduled Outage	14-Apr-14	10:00	14-Apr-14	11:54	114	3	342	A7-LAS	6	5.70	1	5.70
50114124207	1	TX7B429	TX7B105	OH Transformer	23M4	Scheduled Outage	18-Apr-14	8:11	18-Apr-14	14:30	379	6	2274	A7-LAS	1	37.90	0	0.00
42814084903	1	SW70712	NULL	Switch	23M4	Scheduled Outage	28-Apr-14	9:00	28-Apr-14	10:59	119	39	4641	A7-LAS	1	77.35	0	0.00
50114094246	1	SW70718	TX7D213	Switch	23M4	Scheduled Outage	01-May-14	9:45	01-May-14	11:27	102	24	2448	A7-LAS	1	40.80	0	0.00
50114124454	1	SW70718	TX7D630	Switch	23M4	Scheduled Outage	01-May-14	12:45	01-May-14	13:57	72	10	720	A7-LAS	1	12.00	0	0.00
50514091223	1	TX7D921	NULL	OH Transformer	23M4	Animal	04-May-14	8:29	04-May-14	10:45	136	6	816	A7-LAS	9.2	13.60	1	13.60
52014115004	1	TX7D213	NULL	OH Transformer	23M4	Scheduled Outage	16-May-14	9:45	16-May-14	11:00	75	42	3150	A7-LAS	1	52.50	0	0.00
52014115431	1	FS70093	NULL	Switch	23M4	Scheduled Outage	16-May-14	13:45	16-May-14	14:20	35	122	4270	A7-LAS	1	71.17	0	0.00
52014120854	1	TX7D248	NULL	OH Transformer	23M4	Scheduled Outage	20-May-14	10:30	20-May-14	11:40	70	10	700	A7-LAS	1	11.67	0	0.00
52114040152	1	TX5155A	NULL	UG Transformer	23M4	Scheduled Outage	22-May-14	9:13	22-May-14	14:20	307	10	3070	A5-AMH	1	51.17	0	0.00
52314110314	1	TX7D213	NULL	OH Transformer	23M4	Scheduled Outage	23-May-14	11:04	23-May-14	11:40	36	24	864	A7-LAS	1	14.40	0	0.00
61714103850	1	TX7D635	TX7D173	OH Transformer	23M4	Scheduled Outage	17-Jun-14	11:00	17-Jun-14	11:33	33	13	429	A7-LAS	1	7.15	0	0.00
61714010841	1	TX7B480	NULL	OH Transformer	23M4	Scheduled Outage	17-Jun-14	13:00	17-Jun-14	13:29	29	8	232	A7-LAS	1	3.87	0	0.00
62414104754	1	TX7D173	NULL	OH Transformer	23M4	Scheduled Outage	24-Jun-14	10:35	24-Jun-14	10:56	21	8	168	A7-LAS	1	2.80	0	0.00
62714081437	1	TX72017	NULL	UG Transformer	23M4	Scheduled Outage	27-Jun-14	9:50	27-Jun-14	14:00	250	68	17000	A7-LAS	1	283.33	0	0.00
71414024342	1	TX7P615	NULL	UG Transformer	23M4	Scheduled Outage	15-Jul-14	9:28	15-Jul-14	12:00	152	26	3952	A7-LAS	1	65.87	0	0.00
							To Date 2014									**830.50**	**3.00**	**31.20**

Feeder 23M5

outage_id	Restore_Step	from Restore_Device	to_restore_device	Device	Feeder	Cause	DtOut	TmOut	DtRes	TmRes	Duration	NumCust	SubCustMin	AREA_TOWN	Equipment_code	Customer Hours	Modifier	Customer Hours Modified
A0044	1	TX7E126-FS70H42		Fused Disconnect	23M5	Lightning	05-Feb-08	12:53	05-Feb-08	15:35	162	3	486	A7-LAS	4	8.10	1	8.10
A0045	1	LAS-20X		None	23M5	Equipment failure	10-Feb-08	13:03	10-Feb-08	14:10	67.2	67	4502.4	A7-LAS	5.6	75.04	1	75.04
A0046	1	O/H secondary		Other	23M5	Equipment failure	14-Feb-08	5:58	14-Feb-08	7:15	76.8	1	76.8	A7-LAS	5.17	1.28	1	1.28
A0047	1	LAS-20X		None	23M5	Equipment failure	17-Feb-08	6:30	17-Feb-08	10:05	214.8	124	26635.2	A7-LAS	5.6	443.92	1	443.92
A0055	1	U/G service		None	23M5	Equipment failure	11-May-08	16:16	11-May-08	17:48	91.8	1	91.8	A7-LAS	5.28	1.53	1	1.53
A0056	1	White Phase-LAS27X		Fused Disconnect	23M5	Animal	16-May-08	7:31	16-May-08	9:00	88.8	63	5594.4	A7-LAS	9.2	93.24	0	0.00
A0143	1	UG SEC SERVICE		Secondary Conductor	23M5	Equipment failure	26-May-08	6:58	26-May-08	10:30	212	1	212	A7-LAS	5.5	3.53	1	3.53
A0137	1	FS70H68		None	23M5	Tree falling	09-Jun-08	20:40	09-Jun-08	12:40	960	18	17280	A7-LAS	3.2	288.00	1	288.00
A0118	1	LAS-4X		Fused Disconnect	23M5	Animal	21-Jun-08	7:53	21-Jun-08	10:00	127	24	3048	A7-LAS	9.2	50.80	1	50.80
A0185	1	O/H Service		None	23M5	Other	28-Jun-08	12:00	28-Jun-08	15:00	180	1	180	A5-AMH	6	3.00	1	3.00
A0183	1	O/H Service		None	23M5	Other	28-Jun-08	20:00	28-Jun-08	21:00	60	1	60	A7-LAS	6	1.00	1	1.00
A0197	1	FS50012		Fused Disconnect	23M5	Equipment failure	27-Jul-08	7:10	27-Jul-08	11:30	260	27	7020	A5-AMH	5.6	117.00	0	0.00
A0238	1	SERVICE		Other	23M5	Customer equipment	07-Aug-08	3:30	07-Aug-08	6:30	180	1	180	A5-AMH	8	3.00	1	3.00
A0248B	1	Hydro One Area fixed		Other	23M5	Loss of supply	08-Aug-08	23:15	09-Aug-08	1:40	145	1279	185455	A7-LAS	2	3090.92	0	0.00
0058	1	SERVICE		Other	23M5	Vehicles	16-Sep-08	17:08	17-Sep-08	12:20	1160	1	1160	A7-LAS	9.1	19.33	1	19.33
							Total 2008									**4199.69**	**12.00**	**898.54**
0405	1	TX7D241		Other	23M5	Equipment failure	03-Feb-09	17:21	03-Feb-09	19:30	129	9	1161	A7-LAS	5.14	19.35	1	19.35
0765	1	meter		Secondary Conductor	23M5	Equipment failure	03-Mar-09	5:48	03-Mar-09	9:30	222	1	222	A7-LAS	5.92	3.70	1	3.70
0477	1	New TX		Other	23M5	Equipment failure	28-Apr-09	8:22	28-Apr-09	10:59	157	11	1727	A7-LAS	5.2	28.78	1	28.78
0767	1	LAS-4X		Other	23M5	Equipment failure	12-May-09	8:30	12-May-09	9:00	30	25	750	A7-LAS	5.13	12.50	1	12.50
0424	1	TX7D171			23M5	Customer equipment	21-Jun-09	1:59	21-Jun-09	5:00	181	12	2172	A7-LAS	5.11	36.20	1	36.20
0611	1	O/H Service		Secondary Conductor	23M5	Equipment failure	02-Jul-09	18:15	02-Jul-09	19:45	90	1	90	A7-LAS	5.92	1.50	1	1.50
0425	1	CAL m3 m5		Other	23M5	Loss of supply	13-Jul-09	0:30	13-Jul-09	1:10	40	289	11560	A5-AMH	2	192.67	0	0.00
0704	1	FS7H196 Red Phase		Other	23M5	Animal	09-Aug-09	8:30	09-Aug-09	10:10	100	13	1300	A7-LAS	9.2	21.67	1	21.67
0712	1	TX70D15		Transformer Fuse	23M5	Equipment failure	05-Sep-09	11:52	05-Aug-09	14:15	143	2	286	A7-LAS	5.12	4.77	1	4.77
1001090110	1	TX7D290		OH Transformer	23M5	Animal	01-Oct-09	12:30	01-Oct-09	13:40	70	4	280	A7-LAS	9.2	4.67	1	4.67
0114100256	1	SC35x-6	TX5T238	Switch	23M5	Human error	17-Oct-09	9:10	17-Oct-09	12:17	187	23	4301	A5-AMH	8	71.68	1	71.68
1022091222	1	FS50033	TX5T246	Switch	23M5	Equipment failure	22-Oct-09	10:30	22-Oct-09	22:40	730	34	24820	A5-AMH	1	413.67	1	413.67
1102091247	1	FS70H94	FS70H94	Switch	23M5	Animal	02-Nov-09	12:15	02-Nov-09	13:17	62	98	6076	A7-LAS	9.2	101.27	1	101.27
1223090945	1	SD50003		OH Transformer	23M5	Equipment failure	07-Nov-09	16:20	07-Nov-09	18:35	135	25	3375	A5-AMH	5.15	56.25	0	0.00
1223090127	1	TX50034		OH Transformer	23M5	Animal	07-Nov-09	9:58	07-Nov-09	11:48	110	10	1100	A5-AMH	9.2	18.33	1	18.33
1112090348	1	FS70H42	FS70H42	Switch	23M5	Scheduled Outage	12-Nov-09	15:55	12-Nov-09	17:08	73	14	1022	A7-LAS	1	17.03	0	0.00
1223091018	1	23M5		Station Breaker	23M5	Vehicles	18-Nov-09	22:53	19-Nov-09	3:08	255	1268	323340	A7-LAS	9.1	5389.00	1	5389.00
1222090423	1	SEY-2		Station Breaker	23M5	Vehicles	18-Nov-09	22:53	19-Nov-09	0:32	99	292	28908	A5-AMH	9.1	481.80	1	481.80
1223091059	1	TX70D25		OH Transformer	23M5	Animal	28-Nov-09	14:56	28-Nov-09	16:35	99	5	495	A7-LAS	9.2	8.25	1	8.25
							Total 2009									**6883.08**	**16.00**	**6617.13**
0427101239	1	Service		Unknown	23M5	Equipment failure	06-Apr-10	2:00	06-Apr-10	4:50	170	1	170	A7-LAS	5.92	2.83	1	2.83
0429100329	1	tx72041		UG Transformer	23M5	Equipment failure	21-Apr-10	15:30	21-Apr-10	18:00	150	1	150	A7-LAS	5.2	2.50	1	2.50
0518100909	1	TX7D113		OH Transformer	23M5	Lightning	05-May-10	16:53	05-May-10	19:50	177	10	1770	A7-LAS	4	29.50	1	29.50
0714101130	1	LAS-4X		Unknown	23M5	Animal	16-May-10	8:05	16-May-10	9:25	80	29	2320	A7-LAS	9.2	38.67	1	38.67
0519100256	1	LAS32X	FS70H31	Unknown	23M5	Equipment failure	19-May-10	12:43	19-May-10	14:40	117	60	7020	A7-LAS	5.13	117.00	0	0.00
0714101139	1	LAS-31O	23M5	Station Breaker	23M5	Loss of supply	20-May-10	12:30	20-May-10	15:28	178	1270	226060	A7-LAS	2	3767.67	0	0.00
0714100953	1	LAS-20X		OH Transformer	23M5	Lightning	27-May-10	20:55	27-May-10	22:30	95	74	7030	A7-LAS	4	117.17	1	117.17
072810101129	1	tx70d25		OH Transformer	23M5	Animal	11-Jul-10	23:29	12-Jul-10	1:05	96	3	288	A7-LAS	9.2	4.80	1	4.80
072810101038	1	FS7H194		Switch	23M5	Animal	14-Jul-10	7:04	14-Jul-10	8:30	86	8	688	A7-LAS	9.2	11.47	1	11.47
072610121754	1	FS70H42	FS70H42	Switch	23M5	Storm	23-Jul-10	15:30	23-Jul-10	17:50	140	14	1960	A7-LAS	6	32.67	1	32.67
111710080020	1	tx50068		OH Transformer	23M5	Lightning	02-Sep-10	20:06	02-Sep-10	22:55	169	3	507	A5-AMH	4	8.45	1	8.45
091510095910	1	TX50068	TX50068	OH Transformer	23M5	Lightning	02-Sep-10	20:06	02-Sep-10	22:50	164	3	492	A5-AMH	4	8.20	1	8.20
111710080043	1	23m5		Station Breaker	23M5	Tree falling	03-Sep-10	8:04	03-Sep-10	9:12	68	1270	86360	A7-LAS	3.2	1439.33	1	1439.33
111710080045	1	23m5		Station Breaker	23M5	Tree falling	03-Sep-10	8:04	03-Sep-10	9:12	68	261	17748	A5-AMH	3.2	295.80	1	295.80
111710091910	1	tx50912		OH Transformer	23M5	Other	06-Oct-10	17:23	06-Oct-10	18:30	67	9	603	A5-AMH	0.1	10.05	1	10.05
110310022221	1	TX7D680	TX7D680	OH Transformer	23M5	Animal	03-Nov-10	11:59	03-Nov-10	12:30	31	11	341	A7-LAS	9.2	5.68	1	5.68
121010033848	1	BREAKER	BREAKER	Station Breaker	23M5	Scheduled Outage	10-Dec-10	15:26	10-Dec-10	17:20	114	1270	144780	A7-LAS	1	2413.00	0	0.00
							Total 2010									**8304.78**	**14.00**	**2007.12**

030111122429	1	TX70D46		OH Transformer	23M5	Scheduled Outage	01-Mar-11	12:30	01-Mar-11	13:50	80	10	800	A7-LAS	1	13.33	0	0.00
032911092912	1	tx7e130		OH Transformer	23M5	Equipment failure	22-Mar-11	23:15	23-Mar-11	3:00	225	6	1350	A7-LAS	5.14	22.50	1	22.50
050211094718	1	23M5		Station Breaker	23M5	Loss of supply	06-Apr-11	10:50	06-Apr-11	11:00	10	1270	12700	A7-LAS	2	211.67	0	0.00
050211094713	1	23M5		Station Breaker	23M5	Loss of supply	06-Apr-11	10:50	06-Apr-11	11:00	10	261	2610	A5-AMH	2	43.50	0	0.00
042011011312	1	23M5		Station Breaker	23M5	Loss of supply	10-Apr-11	16:48	10-Apr-11	19:00	132	1270	167640	A7-LAS	2	2794.00	0	0.00
050211094627	1	TX70D25		OH Transformer	23M5	Equipment failure	25-Apr-11	18:00	25-Apr-11	22:45	285	3	855	A7-LAS	5.12	14.25	1	14.25
051611034445	1	FS7H220		Switch	23M5	Equipment failure	07-May-11	18:26	08-May-11	2:00	454	1	454	A7-LAS	5.6	7.57	1	7.57
061311013112	1	LAS76Y		Switch	23M5	Animal	07-Jun-11	6:29	07-Jun-11	7:29	60	113	6780	A7-LAS	9.2	113.00	1	113.00
092111125323	1	SD70010		Switch	23M5	Lightning	02-Jul-11	20:20	04-Jul-11	12:30	2410	34	81940	A7-LAS	4	1365.67	1	1365.67
092011015444	1	TX7B150		OH Transformer	23M5	Lightning	03-Jul-11	0:00	03-Jul-11	23:45	1425	2	2850	A7-LAS	4	47.50	1	47.50
101111095134	1	TX7B459		OH Transformer	23M5	Lightning	18-Jul-11	21:15	19-Jul-11	1:49	274	2	548	A7-LAS	4	9.13	1	9.13
072911043933	1	FS7H196		Switch	23M5	Animal	27-Jul-11	8:45	27-Jul-11	9:50	65	13	845	A7-LAS	9.2	14.08	1	14.08
092411034759	1	LAS-45X		Switch	23M5	Lightning	18-Aug-11	18:29	18-Aug-11	21:20	171	17	2907	A7-LAS	4	48.45	1	48.45
092211092450	1	FS70028		Switch	23M5	Scheduled Outage	22-Sep-11	9:30	22-Sep-11	10:35	65	34	2210	A7-LAS	1	36.83	0	0.00
092211012955	1	FS7H230		Switch	23M5	Scheduled Outage	22-Sep-11	13:27	22-Sep-11	14:02	35	12	420	A7-LAS	1	7.00	0	0.00
092611032035	1	TX72041		UG Transformer	23M5	Other	23-Sep-11	13:00	23-Sep-11	19:05	365	1	365	A7-LAS	0.1	6.08	1	6.08
092611024559	1	Station Breaker		Station Breaker	23M5	Loss of supply	25-Sep-11	3:14	25-Sep-11	3:50	36	1585	57060	A7-LAS	2	951.00	0	0.00
101111103712	1	TX70E16		OH Transformer	23M5	Animal	08-Oct-11	10:41	08-Oct-11	12:40	119	7	833	A7-LAS	9.2	13.88	1	13.88
012312010916	1	FS70H59		Switch	23M5	Animal	28-Dec-11	11:45	28-Dec-11	15:40	235	68	15980	A7-LAS	9.2	266.33	1	266.33
012412111802	1	Station Breaker		Station Breaker	23M5	Loss of supply	15-Sep-11	14:17	15-Sep-11	14:30	13	1576	20488	A7-LAS	2	341.47	0	0.00
021111102804	1	TX7D154		OH Transformer	23M5	Scheduled Outage	11-Feb-11	10:28	11-Feb-11	12:21	113	12	1356	A7-LAS	1	22.60	0	0.00
021411104423	1	TX70D96		OH Transformer	23M5	Scheduled Outage	14-Feb-11	10:44	14-Feb-11	12:30	106	8	848	A7-LAS	1	14.13	0	0.00
082211095115	1	TX70D15		OH Transformer	23M5	Scheduled Outage	22-Aug-11	9:51	22-Aug-11	9:59	8	2	16	A7-LAS	1	0.27	0	0.00
083111092558	1	TX7D676		OH Transformer	23M5	Scheduled Outage	31-Aug-11	9:25	31-Aug-11	9:35	10	11	110	A7-LAS	1	1.83	0	0.00
083111094901	1	TX7D159		OH Transformer	23M5	Scheduled Outage	31-Aug-11	9:43	31-Aug-11	10:27	44	8	352	A7-LAS	1	5.87	0	0.00
083111104310	1	TX7D141		OH Transformer	23M5	Scheduled Outage	31-Aug-11	10:42	31-Aug-11	10:52	10	9	90	A7-LAS	1	1.50	0	0.00
083111105538	1	TX7D140		OH Transformer	23M5	Scheduled Outage	31-Aug-11	10:55	31-Aug-11	11:10	15	5	75	A7-LAS	1	1.25	0	0.00
110711094008	1	SD50004		Switch	23M5	Scheduled Outage	08-Nov-11	9:05	08-Nov-11	14:40	335	50	16750	A5-AMH	1	279.17	0	0.00
111511025607	1	TX70E16		OH Transformer	23M5	Scheduled Outage	15-Nov-11	12:33	15-Nov-11	13:46	73	7	511	A7-LAS	9.2	8.52	1	8.52
111711103726	1	TX7D198		OH Transformer	23M5	Other	16-Nov-11	19:00	16-Nov-11	20:30	90	1	90	A7-LAS	0.1	1.50	1	1.50
120211092913	1	TX70E89		OH Transformer	23M5	Scheduled Outage	02-Dec-11	9:30	02-Dec-11	10:06	36	10	360	A7-LAS	1	6.00	1	6.00
							Total 2011									**6662.38**	**13.00**	**1936.97**
010412014502	1	FS70H59		Switch	23M5	Scheduled Outage	04-Jan-12	13:35	04-Jan-12	13:48	13	68	884	A7-LAS	1	14.73	0	0.00
010412082109	1	FS70H59		Switch	23M5	Scheduled Outage	04-Jan-12	9:01	04-Jan-12	9:40	39	300	11700	A7-LAS	1	195.00	0	0.00
011612082505	1	LAS-460		Switch	23M5	Scheduled Outage	16-Jan-12	9:04	16-Jan-12	12:30	206	12	2472	A7-LAS	1	41.20	0	0.00
011712113500	1	LAS-460		Switch	23M5	Scheduled Outage	17-Jan-12	11:58	17-Jan-12	12:43	45	12	540	A7-LAS	1	9.00	0	0.00
011812090327	1	LAS-460		Switch	23M5	Scheduled Outage	18-Jan-12	9:00	18-Jan-12	14:30	330	15	4950	A7-LAS	1	82.50	0	0.00
012512092438	1	LAS-460		Switch	23M5	Scheduled Outage	25-Jan-12	9:15	25-Jan-12	13:00	225	15	3375	A7-LAS	1	56.25	0	0.00
012612093848	1	LAS-460		Switch	23M5	Scheduled Outage	26-Jan-12	9:36	26-Jan-12	12:55	199	15	2985	A7-LAS	1	49.75	0	0.00
030212035116	1	FS7H132		Switch	23M5	Animal	04-Feb-12	10:53	04-Feb-12	12:35	102	52	5304	A7-LAS	9.2	88.40	1	88.40
041412095943	1	FS72003		Switch	23M5	Equipment failure	13-Mar-12	23:00	14-Mar-12	3:14	254	60	15240	A7-LAS	5.23	254.00	1	254.00
050912035309	1	TX7D680		OH Transformer	23M5	Animal	08-Apr-12	8:20	08-Apr-12	11:45	205	11	2255	A7-LAS	9.2	37.58	1	37.58
061912091500	1	TX7E130		OH Transformer	23M5	Scheduled Outage	19-Jun-12	9:03	19-Jun-12	9:15	12	6	72	A7-LAS	1	1.20	0	0.00
070912011005	1	Station Breaker		Station Breaker	23M5	Loss of supply	05-Jul-12	10:16	05-Jul-12	10:43	27	1606	43362	A7-LAS	2	722.70	0	0.00
070912092422	1	TX7E130		OH Transformer	23M5	Scheduled Outage	09-Jul-12	9:23	09-Jul-12	9:45	22	6	132	A7-LAS	1	2.20	0	0.00
082712014720	1	TX7B459		OH Transformer	23M5	Scheduled Outage	27-Aug-12	13:43	27-Aug-12	14:40	57	2	114	A7-LAS	1	1.90	0	0.00
090412083244	1	FS7H132		Switch	23M5	Scheduled Outage	04-Sep-12	9:56	04-Sep-12	10:52	56	57	3192	A7-LAS	1	53.20	0	0.00
091812081101	1	TX7D904		OH Transformer	23M5	Animal	16-Sep-12	19:05	16-Sep-12	21:15	130	15	1950	A7-LAS	9.2	32.50	0	0.00
100912091014	1	SW7H172		Switch	23M5	Scheduled Outage	03-Oct-12	16:00	03-Oct-12	17:40	100	48	4800	A7-LAS	1	80.00	0	0.00
102312082534	1	FS70H64		Switch	23M5	Scheduled Outage	23-Oct-12	4:56	23-Oct-12	9:00	244	7	1708	A7-LAS	3.2	28.47	1	28.47
111412012537	1	TX70E25		OH Transformer	23M5	Equipment failure	10-Nov-12	9:30	10-Nov-12	13:00	210	12	2520	A7-LAS	5.93	42.00	1	42.00
112712081745	1	TX70010		OH Transformer	23M5	Scheduled Outage	26-Nov-12	14:22	26-Nov-12	15:18	56	7	392	A7-LAS	9.2	6.53	1	6.53
113012092636	1	Station Breaker		Station Breaker	23M5	Loss of supply	26-Nov-12	14:13	26-Nov-12	14:14	1	1606	1606	A7-LAS	2	26.77	0	0.00
121012103644	1	TX7D108		OH Transformer	23M5	Animal	09-Dec-12	13:30	09-Dec-12	15:30	120	6	720	A7-LAS	9.2	12.00	1	12.00
							Total 2012									**1837.88**	**7.00**	**468.98**

11513095927	1	TX70D97	NULL	OH Transformer	23M5	Storm	14-Jan-13	2:15	14-Jan-13	4:30	135	11	1485	A7-LAS	5.15	24.75	1	24.75
12513110317	1	TX7B484	NULL	OH Transformer	23M5	Equipment failure	14-Jan-13	8:16	14-Jan-13	13:30	314	1	314	A7-LAS	5.11	5.23	1	5.23
32513112812	1	23M5	NULL	Station Breaker	23M5	Loss of supply	11-Mar-13	7:38	11-Mar-13	7:39	1	1684	1684	A5-AMH	2	28.07	0	0.00
31113080620	1	23M5	DET-1	Station Breaker	23M5	Equipment failure	11-Mar-13	4:32	11-Mar-13	6:17	105	1485	155925	A7-LAS	5.11	2598.75	1	2598.75
31113080620	2	DET-1	NULL	Station Breaker	23M5	Equipment failure	11-Mar-13	4:32	11-Mar-13	10:00	328	256	83968	A5-AMH	5.11	1399.47	1	1399.47
50913090751	1	23M5	NULL	Station Breaker	23M5	Loss of supply	01-May-13	17:47	01-May-13	17:51	4	1685	6740	A7-LAS	2	112.33	0	0.00
61713091954	1	TX50034	NULL	OH Transformer	23M5	Animal	16-Jun-13	13:07	16-Jun-13	15:00	113	3	339	A5-AMH	9.2	5.65	1	5.65
81913111426	1	TX70D25	NULL	OH Transformer	23M5	Tree growth	15-Aug-13	17:30	15-Aug-13	20:15	165	3	495	A7-LAS	3.1	8.25	1	8.25
80613090624	1	FS70837	NULL	Switch	23M5	Scheduled Outage	07-Aug-13	10:28	07-Aug-13	11:36	68	58	3944	A7-LAS	1	65.73	0	0.00
80713104515	1	FS7H189	NULL	Switch	23M5	Scheduled Outage	07-Aug-13	13:12	07-Aug-13	13:42	30	68	2040	A7-LAS	1	34.00	0	0.00
90613090118	1	LAS-73X	NULL	Switch	23M5	Scheduled Outage	06-Sep-13	9:02	06-Sep-13	9:17	15	133	1995	A7-LAS	1	33.25	0	0.00
91813014728	1	TX70177	NULL	OH Transformer	23M5	Scheduled Outage	18-Sep-13	13:50	18-Sep-13	14:08	18	5	90	A7-LAS	1	1.50	0	0.00
92513101532	1	TX70217	NULL	OH Transformer	23M5	Scheduled Outage	25-Sep-13	10:15	25-Sep-13	10:45	30	8	240	A7-LAS	1	4.00	0	0.00
92713090519	1	FS7H132	NULL	Switch	23M5	Animal	27-Sep-13	8:20	27-Sep-13	9:35	75	60	4500	A7-LAS	9.2	75.00	1	75.00
91813021851	1	TX70667	NULL	OH Transformer	23M5	Scheduled Outage	18-Sep-13	14:21	18-Sep-13	14:45	24	8	192	A7-LAS	1	3.20	0	0.00
101113103307	1	TX70014	NULL	OH Transformer	23M5	Scheduled Outage	11-Oct-13	10:30	11-Oct-13	10:42	12	5	60	A7-LAS	1	1.00	0	0.00
101113105022	1	TX70015	NULL	OH Transformer	23M5	Scheduled Outage	11-Oct-13	10:50	11-Oct-13	10:58	8	6	48	A7-LAS	1	0.80	0	0.00
101113113054	1	TX70016	NULL	OH Transformer	23M5	Scheduled Outage	11-Oct-13	11:15	11-Oct-13	11:28	13	6	78	A7-LAS	1	1.30	0	0.00
111513071317	1	LAS-73X	NULL	Switch	23M5	Scheduled Outage	15-Nov-13	9:56	15-Nov-13	13:57	241	126	30366	A7-LAS	1	506.10	0	0.00
112113034749	1	FS70837	NULL	Switch	23M5	Animal	21-Nov-13	14:15	21-Nov-13	16:06	111	51	5661	A7-LAS	9.2	94.35	1	94.35
120213122020	1	FS7H132	NULL	Switch	23M5	Human error	28-Nov-13	19:05	28-Nov-13	19:45	40	52	2080	A7-LAS	9.1	34.67	1	34.67
120513125603	1	LAS-73X	NULL	Switch	23M5	Scheduled Outage	05-Dec-13	13:00	05-Dec-13	13:25	25	133	3325	A7-LAS	1	55.42	0	0.00
121613082715	1	TX5T226	TX5T227	UG Transformer	23M5	Scheduled Outage	16-Dec-13	8:30	16-Dec-13	14:10	340	30	10200	A5-AMH	1	170.00	0	0.00
							Total 2013									**5262.82**	**9.00**	**4246.12**
10814123649	1	TX50068	NULL	OH Transformer	23M5	Equipment failure	06-Jan-14	18:09	06-Jan-14	21:00	171	4	684	A5-AMH	5.12	11.40	1	11.40
21914104024	1	TX70E79	NULL	Switch	23M5	Vehicles	15-Feb-14	16:46	16-Feb-14	0:04	438	4	1752	A7-LAS	9.1	29.20	1	29.20
21914104024	2	LAS-20X	NULL	Switch	23M5	Vehicles	15-Feb-14	16:46	15-Feb-14	23:45	419	68	28492	A7-LAS	9.1	474.87	1	474.87
70214073003	1	TX7D125	NULL	OH Transformer	23M5	Animal	30-Jun-14	9:24	30-Jun-14	10:26	62	12	744	A7-LAS	9.2	12.40	1	12.40
70614122400	1	TX7E124	NULL	OH Transformer	23M5	Lightning	18-Jun-14	19:18	18-Jun-14	22:30	192	2	384	A7-LAS	4	6.40	1	6.40
73114123654	1	TX70D25	NULL	OH Transformer	23M5	Storm	27-Jul-14	18:14	27-Jul-14	20:30	136	3	408	A7-LAS	6	6.80	1	6.80
71914034922	1	23M5	NULL	Station Breaker	23M5	Loss of supply	08-Jul-14	16:26	08-Jul-14	17:31	65	1816	118040	A7-LAS	2	1967.33	0	0.00
71914041324	1	TX70071	NULL	OH Transformer	23M5	Animal	09-Jul-14	7:07	09-Jul-14	10:30	203	6	1218	A7-LAS	9.2	20.30	1	20.30
71914051534	1	FS70837	NULL	Switch	23M5	Animal	12-Jul-14	7:34	12-Jul-14	10:05	151	58	8758	A7-LAS	9.2	145.97	1	145.97
							To Date 2014									**2674.67**	**8.00**	**707.33**

Feeder 24M10

outage_id	Restore_Step	from Restore_Device	to_restore_device	Device	Feeder	Cause	DtOut	TmOut	DtRes	TmRes	Duration	NumCust	SubCustMin	AREA_TOWN	Equipment_code	Customer Hours	Modifier	Customer Hours Modified
A0043	1	O/H Secondary		None	24M10	Equipment failure	30-Jan-08	12:00	30-Jan-08	13:00	60	1	60	A7-LAS	5.92	1.00	1	1.00
A0042	1	O/H Secondary		Other	24M10	Wind	30-Jan-08	12:00	30-Jan-08	12:40	40.2	1	40.2	A7-LAS	6	0.67	1	0.67
R0020	1	Hot leg		Other	24M10	Equipment failure	17-Feb-08	16:05	17-Feb-08	18:05	120	1	120	A7-LAS	5.17	2.00	1	2.00
A0048	1	O/H Secondary		None	24M10	Equipment failure	24-Feb-08	22:27	24-Feb-08	8:30	633	1	633	A7-LAS	5.92	10.55	1	10.55
A0051	1	FS7H153		Fused Disconnect	24M10	Equipment failure	23-Apr-08	16:31	23-Apr-08	19:30	177.6	2	357.6	A7-LAS	5.6	0.00	0	0.00
A0053	1	Pole		None	24M10	Scheduled Outage	03-May-08	7:25	03-May-08	9:40	135	5	675	A7-LAS	1	11.25	0	0.00
A0057	1	TX7E220		Fused Disconnect	24M10	Animal	19-May-08	9:00	19-May-08	10:30	90	16	1440	A7-LAS	9.2	24.00	1	24.00
A0138	1	TX70D21		None	24M10	Lightning	15-Jun-08	7:19	15-Jun-08	9:30	131	12	1572	A7-LAS	4	26.20	1	26.20
A0117	1	TX70D87		None	24M10	Lightning	21-Jun-08	17:25	21-Jun-08	21:30	245	11	2695	A7-LAS	4	0.00	0	0.00
A0116	1	TX7D210		None	24M10	Lightning	21-Jun-08	21:55	21-Jun-08	23:45	110	7	770	A7-LAS	4	0.00	0	0.00
A0198	1	TX7E218		Transformer Fuse	24M10	Equipment failure	14-Jul-08	6:33	14-Jul-08	7:15	42	13	546	A7-LAS	5.6	9.10	1	9.10
0156	1	BREAKER		Unknown	24M10	Loss of supply	31-Aug-08	18:51	31-Aug-08	18:56	5	1711	8555	A7-LAS	2	142.58	0	0.00
0173	1	LAS-46X		Other	24M10	Scheduled Outage	04-Oct-08	8:00	04-Oct-08	8:30	30	1	30	A7-LAS	1	0.50	0	0.00
0134	1	FS70833		Other	24M10	Equipment failure	26-Dec-08	22:22	26-Dec-08	22:40	18	187	3366	A7-LAS	5.26	56.10	1	56.10
							Total 2008									**283.95**	**8.00**	**129.62**
0137	1	24M10		Other	24M10	Loss of supply	06-Jan-09	20:27	06-Jan-09	22:07	100	1769	176900	A7-LAS	2.6	2948.33	0	0.00
0698	1	LAS40X and FS70H34		Other	24M10	Equipment failure	01-Jun-09	14:45	01-Jun-09	16:20	95	37	3515	A7-LAS	0.1	58.58	1	58.58
0707	1	24M10		Other	24M10	Loss of supply	17-Aug-09	15:15	17-Aug-09	17:15	120	1803	216360	A7-LAS	2	3606.00	0	0.00
0711	1	Service		Other	24M10	Equipment failure	06-Sep-09	18:08	06-Sep-09	20:20	132	1	132	A7-LAS	5.5	2.20	1	2.20
1019091038	1	TX70D85		OH Transformer	24M10	Wind	07-Oct-09	6:35	07-Oct-09	8:30	115	5	575	A7-LAS	6	9.58	1	9.58
1007090840	1	SD70001	SD70001	OH Transformer	24M10	Scheduled Outage	07-Oct-09	9:30	07-Oct-09	11:00	90	6	540	A7-LAS	1	9.00	0	0.00
1223090123	1	Meter		Meter	24M10	Vandalism	21-Nov-09	21:05	21-Nov-09	23:38	153	1	153	A7-LAS	9.3	2.55	1	2.55
							Total 2009									**6636.25**	**4.00**	**72.92**
072810101211	1	24m10		Station Breaker	24M10	Loss of supply	08-Jun-10	9:26	08-Jun-10	9:39	13	1813	23569	A7-LAS	2	392.82	0	0.00
072810101228	1	fs7h210		Switch	24M10	Animal	06-Jul-10	6:36	06-Jul-10	8:20	104	68	7072	A7-LAS	9.2	117.87	1	117.87
0719101130	1	TX7E219	TX7E219	OH Transformer	24M10	Animal	19-Jul-10	11:50	19-Jul-10	12:35	45	21	945	A7-LAS	9.2	15.75	1	15.75
072910015522	1	TX7P453	TX7P453	UG Transformer	24M10	Equipment failure	29-Jul-10	10:38	29-Jul-10	14:00	202	13	2626	A7-LAS	2	43.77	1	43.77
111710101339	1	service		OH Conductor	24M10	Human error	25-Sep-10	12:18	25-Sep-10	14:50	152	1	152	A7-LAS	9.1	2.53	1	2.53
120210020910	1	BREAKER	BREAKER	Unknown	24M10	Other	02-Dec-10	13:37	02-Dec-10	13:40	3	5611	16833	A7-LAS	2	280.55	1	280.55
011711023905	1	24m10		Station Breaker	24M10	Loss of supply	03-Dec-10	13:27	03-Dec-10	13:50	23	1813	41699	A7-LAS	2	694.98	0	0.00
121010114516	1	station breaker	STATION BREAKER	Station Breaker	24M10	Scheduled Outage	10-Dec-10	8:37	10-Dec-10	12:00	203	1813	368039	A7-LAS	2	6133.98	0	0.00
011711023918	1	LAS_320		Station Breaker	24M10	Loss of supply	10-Dec-10	8:51	10-Dec-10	9:46	55	1813	99715	A7-LAS	2	1661.92	0	0.00
121010112809	1	BREAKER	BREAKER	Station Breaker	24M10	Scheduled Outage	10-Dec-10	8:51	10-Dec-10	9:46	55	1813	99715	A7-LAS	1	1661.92	0	0.00
							Total 2010									**11006.08**	**5.00**	**460.47**
051611033318	1	tx7d206		OH Transformer	24M10	Tree growth	07-May-11	11:07	07-May-11	12:07	60	10	600	A7-LAS	3.2	10.00	1	10.00
051611033318	2	tx70d85		OH Transformer	24M10	Tree growth	07-May-11	11:17	07-May-11	12:10	53	5	265	A7-LAS	3.2	4.42	1	4.42
060611025919	1	TX7E109		OH Transformer	24M10	Equipment failure	27-May-11	4:13	27-May-11	5:50	97	10	970	A7-LAS	5.15	16.17	1	16.17
090711035903	1	SD70010		Switch	24M10	Lightning	03-Sep-11	22:08	04-Sep-11	7:15	547	5	2735	A7-LAS	4	45.58	1	45.58
101111095840	1	SD70010		Switch	24M10	Lightning	04-Sep-11	14:16	04-Sep-11	19:30	314	1	314	A7-LAS	4	5.23	1	5.23
092111082718	1	TX7D739		OH Transformer	24M10	Scheduled Outage	21-Sep-11	9:30	21-Sep-11	14:30	300	8	2400	A7-LAS	1	40.00	0	0.00
092611012801	1	TX7D267		OH Transformer	24M10	Animal	25-Sep-11	13:21	25-Sep-11	17:00	219	1	219	A7-LAS	9.2	3.65	1	3.65
092911013253	1	TX7E219		OH Transformer	24M10	Scheduled Outage	29-Sep-11	13:03	29-Sep-11	13:45	42	18	756	A7-LAS	9.2	12.60	1	12.60
100311082628	1	TX7D729		OH Transformer	24M10	Other	30-Sep-11	20:40	30-Sep-11	22:42	122	11	1342	A7-LAS	6	22.37	1	22.37
012312033203	1	FS7H116		Switch	24M10	Animal	27-Dec-11	13:31	27-Dec-11	15:40	129	112	14448	A7-LAS	9.2	240.80	1	240.80
012612010206	1	TX7D729		OH Transformer	24M10	Animal	03-Jul-11	7:03	03-Jul-11	10:00	177	11	1947	A7-LAS	9.2	32.45	1	32.45
091211015708	1	TX7D739		OH Transformer	24M10	Scheduled Outage	12-Sep-11	13:57	12-Sep-11	14:09	12	8	96	A7-LAS	1	1.60	0	0.00
111611013450	1	TX7D214		OH Transformer	24M10	Scheduled Outage	16-Nov-11	13:35	16-Nov-11	13:55	20	4	80	A7-LAS	1	1.33	0	0.00
111711094621	1	TX7D214		OH Transformer	24M10	Scheduled Outage	17-Nov-11	9:30	17-Nov-11	10:33	63	12	756	A7-LAS	1	12.60	0	0.00
121211110649	1	TX70P19		UG Transformer	24M10	Scheduled Outage	12-Dec-11	11:05	12-Dec-11	11:30	25	9	225	A7-LAS	1	3.75	0	0.00
121911103633	1	TX7D297		OH Transformer	24M10	Animal	19-Dec-11	9:59	19-Dec-11	10:27	28	12	336	A7-LAS	9.2	5.60	1	5.60
111610084909	1	TX7D739		OH Transformer	24M10	Scheduled Outage	16-Nov-10	9:30	16-Nov-10	11:15	105	8	840	A7-LAS	1	14.00	0	0.00
							Total 2011									**436.20**	**10.00**	**393.27**

020112100323	1	TX70100		OH Transformer	24M10	Scheduled Outage	01-Feb-12	13:09	01-Feb-12	14:50	101	10	1010	A7-LAS	1	16.83	0	0.00
020712010802	1	FS7H250		Switch	24M10	Scheduled Outage	07-Feb-12	12:35	07-Feb-12	13:02	27	25	675	A7-LAS	1	11.25	0	0.00
020712021048	1	LAS-40X		Switch	24M10	Scheduled Outage	07-Feb-12	14:12	07-Feb-12	14:41	29	82	2378	A7-LAS	1	39.63	0	0.00
030912120131	1	TX7E166		OH Transformer	24M10	Scheduled Outage	09-Mar-12	12:46	09-Mar-12	13:28	42	11	462	A7-LAS	1	7.70	0	0.00
032012124801	1	TX7E166		OH Transformer	24M10	Scheduled Outage	20-Mar-12	12:55	20-Mar-12	13:18	23	11	253	A7-LAS	1	4.22	0	0.00
032312125750	1	TX7D185		OH Transformer	24M10	Scheduled Outage	23-Mar-12	13:00	23-Mar-12	13:48	48	10	480	A7-LAS	1	8.00	0	0.00
041512022243	1	Station Breaker		Station Breaker	24M10	Loss of supply	18-Mar-12	11:04	18-Mar-12	11:08	4	1751	7004	A7-LAS	2	116.73	0	0.00
041712081344	1	LAS34X		Switch	24M10	Scheduled Outage	17-Apr-12	9:33	17-Apr-12	9:54	21	37	777	A7-LAS	1	12.95	0	0.00
041812094435	1	LAS34X		Switch	24M10	Scheduled Outage	18-Apr-12	9:27	18-Apr-12	9:57	30	37	1110	A7-LAS	1	18.50	0	0.00
041812123818	1	TX7D729		OH Transformer	24M10	Scheduled Outage	18-Apr-12	12:47	18-Apr-12	13:20	33	11	363	A7-LAS	1	6.05	0	0.00
042012093613	1	TX7D739		OH Transformer	24M10	Scheduled Outage	20-Apr-12	9:35	20-Apr-12	10:25	50	8	400	A7-LAS	1	6.67	0	0.00
043012111744	1	TX70D21		OH Transformer	24M10	Scheduled Outage	30-Apr-12	11:18	30-Apr-12	12:12	54	14	756	A7-LAS	1	12.60	0	0.00
050112123947	1	LAS-43X		Switch	24M10	Scheduled Outage	01-May-12	12:42	01-May-12	13:15	33	11	363	A7-LAS	1	6.05	0	0.00
050212091127	1	TX70D23		OH Transformer	24M10	Scheduled Outage	02-May-12	11:02	02-May-12	11:09	7	9	63	A7-LAS	1	1.05	0	0.00
050212103526	1	TX7D160		OH Transformer	24M10	Scheduled Outage	02-May-12	10:31	02-May-12	10:49	18	13	234	A7-LAS	1	3.90	0	0.00
051612111040	1	LAS-34X		Switch	24M10	Scheduled Outage	16-May-12	11:09	16-May-12	11:44	35	68	2380	A7-LAS	1	39.67	0	0.00
052512102610	1	Station Breaker		Station Breaker	24M10	Loss of supply	24-May-12	17:57	24-May-12	18:02	5	605	3025	A7-LAS	2	50.42	0	0.00
081512011542	1	SD70009		OH Transformer	24M10	Animal	11-Aug-12	20:05	11-Aug-12	21:15	70	24	1680	A7-LAS	9.2	28.00	1	28.00
082312103549	1	Station Breaker		Station Breaker	24M10	Scheduled Outage	23-Aug-12	9:54	23-Aug-12	13:07	193	605	116765	A7-LAS	2	1946.08	0	0.00
111412094025	1	TX7D739		OH Transformer	24M10	Animal	06-Nov-12	8:00	06-Nov-12	10:00	120	8	960	A7-LAS	9.2	16.00	1	16.00
							Total 2012									**2352.30**	**2.00**	**44.00**
50113040616	1	24M10	NULL	Station Breaker	24M10	Loss of supply	01-May-13	15:45	01-May-13	17:15	90	637	57330	A7-LAS	2	955.50	0	0.00
70813095019	1	FS7H210	NULL	Switch	24M10	Other	07-Jul-13	7:13	07-Jul-13	11:00	227	119	27013	A7-LAS	0	450.22	1	450.22
72513015524	1	24M10	NULL	Station Breaker	24M10	Loss of supply	18-Jul-13	15:22	18-Jul-13	15:23	1	712	712	A7-LAS	2	11.87	0	0.00
72513025041	1	24M10	NULL	Station Breaker	24M10	Loss of supply	19-Jul-13	21:10	19-Jul-13	21:18	8	712	5696	A7-LAS	2	94.93	0	0.00
72513031108	1	24M10	NULL	Station Breaker	24M10	Tree falling-weather	19-Jul-13	20:06	19-Jul-13	23:12	186	6801	1264986	A7-LAS	3.2	21083.10	1	21083.10
92313100130	1	FS7H210	NULL	Switch	24M10	Scheduled Outage	23-Sep-13	10:00	23-Sep-13	12:02	122	115	14030	A7-LAS	1	233.83	0	0.00
92313012327	1	TX7E217	NULL	OH Transformer	24M10	Scheduled Outage	23-Sep-13	13:25	23-Sep-13	13:50	25	14	350	A7-LAS	1	5.83	0	0.00
92413112240	1	FS7H210	NULL	Switch	24M10	Scheduled Outage	24-Sep-13	11:20	24-Sep-13	13:25	125	115	14375	A7-LAS	1	239.58	0	0.00
93013111231	1	24M10	NULL	Station Breaker	24M10	Loss of supply	22-Sep-13	8:12	22-Sep-13	8:14	2	712	1424	A7-LAS	2	23.73	0	0.00
93013035358	1	FS7H210	NULL	Switch	24M10	Scheduled Outage	02-Oct-13	9:45	02-Oct-13	12:30	165	115	18975	A7-LAS	1	316.25	0	0.00
100713013125	1	TX7D188	NULL	OH Transformer	24M10	Scheduled Outage	04-Oct-13	8:37	04-Oct-13	10:15	98	8	784	A7-LAS	1	13.07	0	0.00
102513111211	1	FS700H8	NULL	Switch	24M10	Equipment failure	24-Oct-13	18:04	24-Oct-13	19:30	86	102	8772	A7-LAS	5.8	146.20	1	146.20
110813100314	1	TX7D280	NULL	OH Transformer	24M10	Scheduled Outage	08-Nov-13	9:50	08-Nov-13	11:41	111	6	666	A7-LAS	1	11.10	0	0.00
111113010341	1	TX7D189	NULL	OH Transformer	24M10	Scheduled Outage	08-Nov-13	9:43	08-Nov-13	9:50	7	7	49	A7-LAS	1	0.82	0	0.00
111213124541	1	TX70D85	NULL	OH Transformer	24M10	Animal	06-Nov-13	21:33	07-Nov-13	0:20	167	5	835	A7-LAS	9.2	13.92	1	13.92
							Total 2013									**23599.95**	**4.00**	**21693.43**
42814035008	1	TX70D55	NULL	OH Transformer	24M10	Equipment failure	28-Apr-14	14:39	28-Apr-14	16:45	126	15	1890	A7-LAS	5.14	31.50	1	31.50
50514090022	1	TX70D35	NULL	OH Transformer	24M10	Animal	04-May-14	6:30	04-May-14	8:48	138	12	1656	A7-LAS	9.2	27.60	1	27.60
52614084004	1	FS7H267	NULL	Switch	24M10	Animal	11-May-14	7:22	11-May-14	9:30	128	32	4096	A7-LAS	9.2	68.27	1	68.27
52614084004	2	TX7E218	NULL	Switch	24M10	Animal	11-May-14	7:22	11-May-14	9:50	148	14	2072	A7-LAS	9.2	34.53	1	34.53
73114113832	1	24M10	NULL	Station Breaker	24M10	Loss of supply	31-Jul-14	4:53	31-Jul-14	4:54	1	649	649	A7-LAS	2	10.82	0	0.00
61014125326	1	TX70054	NULL	OH Transformer	24M10	Animal	10-Jun-14	6:36	10-Jun-14	8:45	129	12	1548	A7-LAS	9.2	25.80	1	25.80
61214042307	1	TX7E218	NULL	OH Transformer	24M10	Animal	06-Jun-14	18:41	06-Jun-14	20:45	124	14	1736	A7-LAS	9.2	28.93	1	28.93
							To Date 2014									**227.45**	**6.00**	**216.63**

Feeder 24M7

outage_id	Restore_Step	from Restore_Device	to_restore_device	Device	Feeder	Cause	DtOut	TmOut	DtRes	TmRes	Duration	NumCust	SubCustMin	AREA_TOWN	Equipment_code	Customer Hours	Modifier	Customer Hours Modified
A0036	1	TX52019		Transformer Fuse	24M7	Equipment failure	26-May-08	20:36	26-May-08	22:15	99	3	297	A5-AMH	5.12	4.95	1	4.95
A0126	1	TX7DE38		None	24M7	Equipment Failure	09-Jun-08	21:25	09-Jun-08	1:50	265	8	2120	A7-LAS	6	35.33	1	35.33
A0136	1	TX70D57		None	24M7	Equipment failure	10-Jun-08	21:25	10-Jun-08	2:18	293	7	2051	A7-LAS	4	34.18	1	34.18
A0135	1	TX7E102		None	24M7	Lightning	10-Jun-08	23:21	10-Jun-08	5:07	346	3	1038	A7-LAS	4	17.30	1	17.30
A0139	1	TX7E107		None	24M7	Equipment failure	14-Jun-08	16:51	14-Jun-08	18:40	109	8	872	A7-LAS	5.12	14.53	1	14.53
A0144	1	Hydro Meter		None	24M7	Equipment failure	15-Jun-08	20:25	19-Jun-08	10:45	5180	1	5180	A5-AMH	5.5	86.33	1	86.33
A0195	1	LAS-66X		None	24M7	Equipment failure	19-Jul-08	21:34	23-Jul-08	13:51	5297	1	5297	A7-LAS	5.6	88.28	1	88.28
A0202	1	TX50434		None	24M7	Other	21-Jul-08	18:30	21-Jul-08	20:30	120	1	120	A5-AMH	5.4	2.00	1	2.00
A0224	1	METER		Other	24M7	Equipment failure	26-Jul-08	11:00	26-Jul-08	13:00	120	1	120	A5-AMH	5.4	2.00	1	2.00
0051	1	SERVICE		Other	24M7	Equipment failure	30-Aug-08	22:30	31-Aug-08	1:00	150	1	150	A7-LAS	5.6	2.50	1	2.50
0052	1	SERVICE		Other	24M7	Equipment failure	01-Sep-08	17:17	02-Sep-08	17:00	1423	1	1423	A5-AMH	5.6	23.72	1	23.72
0114	1	POLE MOUNT RECLOSURES		Other	24M7	Other	18-Sep-08	12:57	18-Sep-08	13:50	53	1210	64130	A5-AMH	2	1068.83	0	0.00
0115	1	BREAKER		Unknown	24M7	Loss of supply	18-Sep-08	1:05	18-Sep-08	1:30	25	708	17700	A7-LAS	2	295.00	0	0.00
0163	1	UG SERVICE		Other	24M7	Other	20-Sep-08	8:38	20-Sep-08	10:00	82	1	82	A7-LAS	5.6	1.37	1	1.37
0301	1	TX700D8		Transformer Fuse	24M7	Animal	10-Oct-08	15:20	10-Oct-08	18:20	180	5	900	A7-LAS	9.2	15.00	1	15.00
0176	1	TX7B426		Transformer Fuse	24M7	Equipment failure	15-Oct-08	20:02	16-Oct-08	4:30	508	1	508	A7-LAS	5.6	8.47	1	8.47
0141	1	AMH-22X		Other	24M7	Equipment failure	15-Dec-08	9:30	15-Dec-08	11:30	120	87	10440	A5-AMH	5.4	174.00	1	174.00
0189	1	24M7		Other	24M7	Other	28-Dec-08	5:00	28-Dec-08	7:00	120	2027	243240	A7-LAS	2	4054.00	0	0.00
0057	1	TX7D261		Other	23M4	Tree falling	14-Sep-08	0:30	14-Sep-08	1:53	83	11	913	A7-LAS	3.2	15.22	1	15.22
A0056	1	White Phase-LAS27X		Fused Disconnect	23M5	Animal	16-May-08	7:31	16-May-08	9:00	88.8	63	5594.4	A7-LAS	9.2	93.24	1	93.24
A0051	1	FS7H153		Fused Disconnect	24M10	Equipment failure	23-Apr-08	16:31	23-Apr-08	19:30	177.6	2	357.6	A7-LAS	5.6	5.96	1	5.96
A0117	1	TX70D87		None	24M10	Lightning	21-Jun-08	17:25	21-Jun-08	21:30	245	11	2695	A7-LAS	4	44.92	1	44.92
A0116	1	TX7D210		None	24M10	Lightning	21-Jun-08	21:55	21-Jun-08	23:45	110	7	770	A7-LAS	4	12.83	1	12.83
0187	1	O/H Service		Other	24M7	Vehicles	30-Dec-08	15:00	30-Dec-08	19:45	285	1	285	A7-LAS	9.1	4.75	1	4.75
							Total 2008									**6104.72**	**21.00**	**686.88**
0190	1	TX7D285		Fused Disconnect	24M7	Animal	03-Jan-09	14:34	03-Jan-09	15:40	66	3	198	A7-LAS	9.2	3.30	1	3.30
0267	1	TX7D414		Transformer Fuse	24M7	Animal	13-Mar-09	22:45	14-Mar-09	0:25	100	3	300	A7-LAS	9.2	5.00	1	5.00
0601A	1	Breaker		Other	24M7	Vehicles	26-Mar-09		26-Mar-09	17:55	43	1406	60458	A5-AMH	9.1	1007.63	1	1007.63
0601B	1	Breaker		Other	24M7	Vehicles	26-Mar-09	17:12	26-Mar-09	17:55	43	761	32723	A7-LAS	9.1	545.38	1	545.38
0412	1	Service		Service	24M7	Equipment failure	14-May-09	16:15	14-May-09	18:15	120	2	240	A7-LAS	5.17	4.00	1	4.00
0420	1	24M7		Other	24M7	Loss of supply	01-Jun-09	21:30	01-Jun-09	23:50	140	1448	202720	A5-AMH	2	3378.67	1	3378.67
0201101117	1	SW50027		Switch	24M7	Animal	02-Jun-09	6:58	02-Jun-09	13:00	362	1	362	A5-AMH	9.2	6.03	1	6.03
0272	1	Meter		Secondary Conductor	24M7	Equipment failure	19-Jul-09	9:27	19-Jul-09	11:00	93	1	93	A5-AMH	5.5	1.55	1	1.55
0426	1	FS50096		Other	24M7	Lightning	17-Aug-09	15:00	17-Aug-09	19:00	240	1	240	A5-AMH	4	4.00	1	4.00
1019090239	1	24M7		Station Breaker	24M7	Loss of supply	28-Sep-09	4:30	28-Sep-09	7:30	180	1449	260820	A5-AMH	2	4347.00	0	0.00
1019090240	1	24M7		Station Breaker	24M7	Loss of supply	28-Sep-09	4:30	28-Sep-09	7:30	180	843	151740	A7-LAS	2	2529.00	0	0.00
0928091006	1	LAS-36X		Switch	24M7	Wind	28-Sep-09	8:30	28-Sep-09	11:10	160	1	160	A7-LAS	6	2.67	1	2.67
0930090841	2	SC 35X	TX50645	Switch	24M7	Equipment failure	30-Sep-09	5:09	30-Sep-09	8:45	216	200	43200	A5-AMH	5.4	720.00	1	720.00
0930090841	1	AMH-26X	SC50165	Switch	24M7	Equipment failure	30-Sep-09	5:09	30-Sep-09	8:30	201	6	1206	A5-AMH	5.4	20.10	1	20.10
0930091144	1	TX7E107		OH Transformer	24M7	Scheduled Outage	30-Sep-09	11:30	30-Sep-09	11:51	21	8	168	A7-LAS	1	2.80	0	0.00
0930090200	1	TX7D196		OH Transformer	24M7	Scheduled Outage	30-Sep-09	13:50	30-Sep-09	14:06	16	2	32	A7-LAS	1	0.53	0	0.00
0114101155	1	AMH 48X		Switch	24M7	Scheduled Outage	01-Oct-09	7:30	01-Oct-09	12:00	270	37	9990	A5-AMH	1	166.50	0	0.00
0929090156	1	AMH48X	AMH48X	Switch	24M7	Scheduled Outage	01-Oct-09	7:30	01-Oct-09	12:00	270	37	9990	A5-AMH	1	166.50	0	0.00
1019091129	1	HONI TX		Unknown	24M7	Loss of supply	04-Oct-09	8:30	04-Oct-09	14:00	330	1	330	A7-LAS	2	5.50	0	0.00
1019090215	1	SC50165	SC50165	Switch	24M7	Scheduled Outage	20-Oct-09	9:30	20-Oct-09	15:00	330	59	19470	A5-AMH	1	324.50	0	0.00
1202090157	1	TX7P182	FS70824	UG Transformer	24M7	Scheduled Outage	02-Dec-09	13:45	02-Dec-09	13:50	5	10	50	A7-LAS	1	0.83	0	0.00
1223090210	1	Service		Service	24M7	Tree growth	11-Dec-09	18:20	11-Dec-09	19:45	85	1	85	A7-LAS	3.1	1.42	1	1.42
0114100319	1	FS70H44		Switch	24M7	Human error	14-Dec-09	16:35	14-Dec-09	22:33	358	1	358	A7-LAS	8	5.97	1	5.97
							Total 2009									**13248.88**	**14.00**	**5705.72**
0715101015	1	24M7		Station Breaker	24M7	Loss of supply	05-Apr-10	15:43	05-Apr-10	17:25	102	1342	136884	A5-AMH	2	2281.40	0	0.00
0715101021	1	24M7		Station Breaker	24M7	Loss of supply	05-Apr-10	15:43	05-Apr-10	17:25	102	846	86292	A7-LAS	2	1438.20	0	0.00
0427101237	1	Service		Service	24M7	Equipment failure	07-Apr-10	19:45	07-Apr-10	22:30	165	1	165	A7-LAS	5.92	2.75	1	2.75
0714101114	1	Service		Service	24M7	Equipment failure	08-Apr-10	17:20	08-Apr-10	20:40	200	1	200	A5-AMH	5.5	3.33	1	3.33
0526100205	1	LAS53X	LAS53X	Unknown	24M7	Human error	25-May-10	13:06	25-May-10	13:50	44	2	88	A7-LAS	9.1	1.47	1	1.47
0714101032	1	H1 station		Station Breaker	24M7	Loss of supply	27-May-10	21:00	27-May-10	22:15	75	1342	100650	A5-AMH	2	1677.50	0	0.00
0714101033	1	AMH-22x		Station Breaker	24M7	Lightning	27-May-10	21:00	27-May-10	23:30	150	86	12900	A5-AMH	4	215.00	1	215.00
0607101238	1	FS50073	FS50073	Switch	24M7	Customer equipment	07-Jun-10	10:48	07-Jun-10	21:00	612	34	20808	A5-AMH	5.28	346.80	1	346.80
0715101010	1	24M7		Station Breaker	24M7	Loss of supply	23-Jun-10	23:08	24-Jun-10	0:50	102	1342	136884	A5-AMH	2	2281.40	0	0.00
0715101014	1	24M7		Station Breaker	24M7	Loss of supply	23-Jun-10	23:08	24-Jun-10	0:50	102	846	86292	A7-LAS	2	1438.20	1	1438.20
0714101137	1	H1 breaker st	LAS-390	Unknown	24M7	Storm	23-Jun-10	23:26	24-Jun-10	0:50	84	559	46956	A7-LAS	6	782.60	1	782.60
0714101137	2	LAS-390	sd70002	Unknown	24M7	Storm	23-Jun-10	23:26	24-Jun-10	1:46	140	333	46620	A7-LAS	6	777.00	1	777.00
0714101137	3	sd70002	closed	Unknown	24M7	Storm	23-Jun-10	23:26	24-Jun-10	6:35	429	24	10296	A7-LAS	6	171.60	1	171.60
072810101141	1	tx70d42		OH Transformer	24M7	Equipment failure	10-Jul-10	8:27	10-Jul-10	22:00	813	16	13008	A7-LAS	5.92	216.80	1	216.80
093010025938	1	TX700D8	TX700D8	OH Transformer	24M7	Animal	30-Sep-10	13:11	30-Sep-10	14:00	49	5	245	A7-LAS	9.2	4.08	1	4.08
111710105838	1	pme-224		UG switch unit	24M7	Equipment failure	02-Oct-10	9:00	02-Oct-10	20:00	660	23	15180	A5-AMH	5.5	253.00	1	253.00
111710105858	1	tx70e30		OH Transformer	24M7	Animal	06-Nov-10	8:37	06-Nov-10	10:00	83	12	996	A7-LAS	9.2	16.60	1	16.60
121410084706	1	FS50009	FS50009	Switch	24M7	Scheduled Outage	14-Dec-10	11:37	14-Dec-10	11:42	5	214	1070	A5-AMH	1	17.83	0	0.00
121610093209	1	FS50009	FS50009	Switch	24M7	Scheduled Outage	16-Dec-10	11:26	16-Dec-10	11:30	4	212	848	A7-LAS	1	14.13	0	0.00
							Total 2010									**11939.70**	**13.00**	**4229.23**

010511110129	1	FS50018	FS50018	Switch	24M7	Scheduled Outage	05-Jan-11	11:00	05-Jan-11	12:12	72	10	720	A5-AMH	1	12.00	0	0.00
040111111607	1	MV50110		UG switch unit	24M7	Equipment failure	06-Mar-11	11:40	06-Mar-11	12:48	68	171	11628	A5-AMH	5.6	0.00	0	0.00
050211094556	1	TX50346		OH Transformer	24M7	Scheduled Outage	10-Mar-11	12:12	10-Mar-11	12:40	28	2	56	A5-AMH	1	0.93	0	0.00
050511090052	1	24m7		Station Breaker	24M7	Loss of supply	23-Apr-11	16:13	24-Apr-11	2:00	587	1342	787754	A5-AMH	2	13129.23	0	0.00
050211094612	1	LAS380		Switch	24M7	Equipment failure	27-Apr-11	14:00	27-Apr-11	22:00	480	1	480	A7-LAS	5.6	8.00	1	8.00
062711034102	1	TX7D731		OH Transformer	24M7	Animal	09-May-11	23:45	10-May-11	1:00	75	2	150	A7-LAS	9.2	2.50	1	2.50
051611025411	1	TX70E91		OH Transformer	24M7	Equipment failure	12-May-11	6:04	12-May-11	7:45	101	10	1010	A7-LAS	4	16.83	1	16.83
072811091043	1	TX70D88		OH Transformer	24M7	Lightning	21-Jun-11	22:17	22-Jun-11	0:15	118	9	1062	A7-LAS	4	17.70	1	17.70
100711035348	1	TX50903		OH Transformer	24M7	Other	23-Jun-11	10:45	23-Jun-11	18:30	465	1	465	A5-AMH	0.1	7.75	1	7.75
101111090109	1	TX7D175		OH Transformer	24M7	Other	29-Jun-11	13:58	29-Jun-11	15:00	62	5	310	A7-LAS	5.93	5.17	1	5.17
092011030606	1	24M7 & 24M9		Station Breaker	24M7	Loss of supply	02-Jul-11	20:00	02-Jul-11	22:30	150	6042	906300	A7-LAS	2	15105.00	0	0.00
092111024856	1	FS72008		Switch	24M7	Lightning	03-Jul-11	10:00	05-Jul-11	15:15	3195	1	3195	A7-LAS	4	53.25	1	53.25
080911023545	1	FS50075		Switch	24M7	Scheduled Outage	09-Aug-11	3:30	09-Aug-11	10:10	400	11	4400	A5-AMH	4	73.33	0	0.00
101311095206	1	TX50907		UG Transformer	24M7	Equipment failure	11-Aug-11	16:08	11-Aug-11	18:00	112	2	224	A5-AMH	5.26	3.73	1	3.73
092411041929	1	TX7E168		OH Transformer	24M7	Lightning	18-Aug-11	22:54	18-Aug-11	23:59	65	10	650	A7-LAS	4	10.83	1	10.83
090111015343	1	TX7B102	TX7B102	OH Transformer	24M7	Scheduled Outage	01-Sep-11	13:30	01-Sep-11	14:01	31	1	31	A7-LAS	5.12	0.52	0	0.00
101311091622	1	TX70E47		OH Transformer	24M7	Lightning	10-Sep-11	20:46	10-Sep-11	23:00	134	8	1072	A7-LAS	4	17.87	1	17.87
092211125632	1	Station Breaker		Station Breaker	24M7	Loss of supply	14-Sep-11	20:35	14-Sep-11	21:53	78	7802	608556	A7-LAS	2	10142.60	0	0.00
092611020331	1	TX70E61		OH Transformer	24M7	Lightning	26-Sep-11	2:45	26-Sep-11	5:30	165	9	1485	A7-LAS	4	24.75	1	24.75
101311014902	1	MV50110		UG Transformer	24M7	Scheduled Outage	13-Oct-11	13:40	13-Oct-11	14:00	20	249	4980	A5-AMH	0.1	83.00	0	0.00
010311020145	1	PMH241		UG switch unit	24M7	Scheduled Outage	03-Jan-11	14:01	03-Jan-11	14:21	20	26	520	A5-AMH	1	8.67	0	0.00
010311113426	1	PMH241		UG switch unit	24M7	Scheduled Outage	03-Jan-11	11:34	03-Jan-11	14:21	167	26	4342	A5-AMH	1	72.37	0	0.00
012312035256	1	TX7B426		OH Transformer	24M7	Animal	22-Jul-11	10:29	22-Jul-11	11:28	59	1	59	A7-LAS	9.2	0.98	1	0.98
012412103958	1	TX7D510		OH Transformer	24M7	Animal	11-Aug-11	8:38	11-Aug-11	9:59	81	1	81	A7-LAS	9.2	1.35	1	1.35
012412105323	1	TX7D330		OH Transformer	24M7	Animal	11-Aug-11	14:09	11-Aug-11	15:15	66	2	132	A7-LAS	9.2	2.20	1	2.20
012412121904	1	Station Breaker		Station Breaker	24M7	Loss of supply	16-Sep-11	8:38	16-Sep-11	8:55	17	803	13651	A5-AMH	2	227.52	0	0.00
102111094427	1	TX7E184		OH Transformer	24M7	Animal	21-Oct-11	8:39	21-Oct-11	10:05	86	16	1376	A7-LAS	9.2	22.93	1	22.93
102811024141	1	TX7D321		OH Transformer	24M7	Animal	21-Oct-11	21:08	21-Oct-11	22:35	87	1	87	A7-LAS	9.2	1.45	1	1.45
102811124218	1	FS50042		Switch	24M7	Equipment failure	28-Oct-11	12:27	28-Oct-11	13:38	71	129	9159	A5-AMH	5.93	152.65	1	152.65
110711095022	1	FS50042		Switch	24M7	Other	23-Oct-11	11:00	23-Oct-11	13:40	160	92	14720	A5-AMH	0.1	245.33	1	245.33
110711095022	2	FS50073		Switch	24M7	Other	23-Oct-11	11:00	23-Oct-11	15:14	254	15	3810	A5-AMH	0.1	63.50	1	63.50
110711095022	3	FS50074		Switch	24M7	Other	23-Oct-11	11:00	23-Oct-11	15:15	255	22	5610	A5-AMH	0.1	93.50	1	93.50
120211015823	1	TX50810		UG Transformer	24M7	Scheduled Outage	05-Dec-11	9:00	05-Dec-11	13:30	270	5	1350	A5-AMH	1	22.50	0	0.00
120411040921	1	AMH 30X		Switch	24M7	Equipment failure	30-Nov-11	5:15	30-Nov-11	8:03	168	248	41664	A5-AMH	5.23	694.40	1	694.40
120611081230	1	AMH-26X		Switch	24M7	Scheduled Outage	06-Dec-11	10:48	06-Dec-11	11:02	14	130	1820	A5-AMH	1	30.33	0	0.00
120811123256	1	AMH-26X		Switch	24M7	Scheduled Outage	08-Dec-11	13:45	08-Dec-11	14:17	32	130	4160	A5-AMH	1	69.33	0	0.00
							Total 2011									**40424.02**	**21.00**	**1446.68**
010813084457	1	FS50042		Switch	24M7	Equipment failure	27-Dec-12	2:00	27-Dec-12	5:30	210	151	31710	A5-AMH	5.4	528.50	1	528.50
010813105318	1	MV50130		UG switch unit	24M7	Equipment failure	31-Dec-12	19:00	31-Dec-12	19:45	45	137	6165	A5-AMH	5.24	102.75	1	102.75
020712015326	1	FS7H249		Switch	24M7	Scheduled Outage	07-Feb-12	13:55	07-Feb-12	14:07	12	3	36	A7-LAS	1	0.60	0	0.00
032012114247	1	TX7D135		OH Transformer	24M7	Scheduled Outage	20-Mar-12	11:40	20-Mar-12	11:45	5	18	90	A7-LAS	1	1.50	0	0.00
041412024051	1	TX7D259		OH Transformer	24M7	Other	31-Mar-12	3:30	31-Mar-12	6:30	180	2	360	A7-LAS	0.1	6.00	1	6.00
052512100715	1	Station Breaker		Station Breaker	24M7	Loss of supply	24-May-12	17:57	24-May-12	18:02	5	2890	14450	A7-LAS	2	240.83	0	0.00
062212120412	1	FS50042	PMH180	Switch	24M7	Equipment failure	22-Jun-12	11:45	22-Jun-12	13:15	90	1	90	A5-AMH	5.26	1.50	1	1.50
062212120412	2	PMH180	MV50100	Switch	24M7	Equipment failure	22-Jun-12	13:15	22-Jun-12	15:15	120	122	14640	A5-AMH	5.26	244.00	1	244.00
062212120412	3	MV50110	MV50100	Switch	24M7	Equipment failure	22-Jun-12	15:15	22-Jun-12	15:40	25	95	2375	A5-AMH	5.26	39.58	1	39.58
062212120412	4	FS50042	PMH180	Switch	24M7	Equipment failure	22-Jun-12	15:40	22-Jun-12	15:55	15	94	1410	A5-AMH	5.26	23.50	1	23.50
062612093617	1	TX70E38		OH Transformer	24M7	Other	26-Jun-12	3:15	26-Jun-12	5:18	123	8	984	A7-LAS	0.1	16.40	1	16.40
070512123532	1	Station Breaker		Station Breaker	24M7	Loss of supply	04-Jul-12	19:12	04-Jul-12	19:17	5	2890	14450	A7-LAS	2	240.83	0	0.00
080112075114	1	TX7D318		OH Transformer	24M7	Lightning	27-Jul-12	19:28	27-Jul-12	23:28	240	2	480	A7-LAS	4	8.00	1	8.00
080712093955	1	Station Breaker		Station Breaker	24M7	Loss of supply	23-Jul-12	20:13	23-Jul-12	20:15	2	2890	5780	A7-LAS	2	96.33	0	0.00
080712094838	1	Station Breaker		Station Breaker	24M7	Loss of supply	27-Jul-12	15:22	27-Jul-12	15:23	1	2890	2890	A7-LAS	2	48.17	0	0.00
090612020332	1	TX7D274		OH Transformer	24M7	Other	05-Sep-12	20:40	05-Sep-12	22:30	110	1	110	A7-LAS	0.1	1.83	1	1.83
091412095228	1	Station Breaker		Station Breaker	24M7	Loss of supply	05-Sep-12	15:15	05-Sep-12	15:17	2	2891	5782	A7-LAS	2	96.37	0	0.00
091712093731	1	AMH26X	TX50622	Switch	24M7	Scheduled Outage	13-Sep-12	15:30	13-Sep-12	17:30	120	99	11880	A5-AMH	9.1	198.00	1	198.00
091712093731	2	MV50125	TX51552	Switch	24M7	Scheduled Outage	13-Sep-12	15:30	13-Sep-12	18:45	195	15	2925	A5-AMH	9.1	48.75	1	48.75
092512101206	1	FS7H156		Switch	24M7	Scheduled Outage	24-Sep-12	16:25	25-Sep-12	2:30	605	2	1210	A7-LAS	5.4	20.17	1	20.17
101512085243	1	FS7H156		Switch	24M7	Equipment failure	09-Oct-12	11:06	09-Oct-12	19:01	475	2	950	A7-LAS	5.4	15.83	1	15.83
103112110432	1	AMH-26X		Switch	24M7	Equipment failure	30-Oct-12	6:28	30-Oct-12	8:55	147	20	2940	A5-AMH	5.6	49.00	1	49.00
111312041254	1	FS72008	TX7P130	Switch	24M7	Equipment failure	09-Nov-12	6:45	09-Nov-12	20:45	840	1	840	A7-LAS	5.6	14.00	1	14.00
121012091114	1	FS50042		Switch	24M7	Equipment failure	07-Dec-12	1:30	07-Dec-12	4:30	180	111	19980	A5-AMH	5.4	333.00	1	333.00
121012091114	2	MV50100		Switch	24M7	Equipment failure	07-Dec-12	1:30	07-Dec-12	5:15	225	28	6300	A5-AMH	5.4	105.00	1	105.00
							Total 2012									**2480.45**	**18.00**	**1755.82**

13113084217	1	AMH30X	NULL	Switch	24M7	Scheduled Outage	31-Jan-13	10:00	31-Jan-13	10:50	50	183	9150	A5-AMH	1	152.50	0	0.00
22513114656	1	TX7D599	NULL	OH Transformer	24M7	Equipment failure	24-Feb-13	19:00	24-Feb-13	21:10	130	2	260	A7-LAS	5.14	4.33	1	4.33
32513112831	1	24M7	NULL	Station Breaker	24M7	Loss of supply	23-Mar-13	22:00	23-Mar-13	22:02	2	2858	5716	A7-LAS	2	95.27	0	0.00
40813095126	1	TX50640	NULL	UG Transformer	24M7	Scheduled Outage	08-Apr-13	9:57	08-Apr-13	10:25	28	14	392	A5-AMH	1	6.53	0	0.00
41113082014	1	TX50642	NULL	UG Transformer	24M7	Scheduled Outage	10-Apr-13	9:00	10-Apr-13	12:00	180	6	1080	A5-AMH	1	18.00	0	0.00
41113082633	1	24M7	NULL	Station Breaker	24M7	Loss of supply	10-Apr-13	15:02	10-Apr-13	16:25	83	2858	237214	A5-AMH	2	3953.57	0	0.00
41513075515	1	TX50640	TX50642	UG Transformer	24M7	Scheduled Outage	15-Apr-13	9:00	15-Apr-13	13:00	240	14	3360	A5-AMH	1	56.00	0	0.00
41913112155	1	Tx50622	NULL	UG Transformer	24M7	Scheduled Outage	19-Apr-13	9:30	19-Apr-13	13:30	240	6	1440	A5-AMH	1	24.00	0	0.00
50113080727	1	TX7D285	NULL	OH Transformer	24M7	Animal	30-Apr-13	20:27	30-Apr-13	22:00	93	3	279	A7-LAS	9.2	4.65	1	4.65
60513125400	1	TX70E76	NULL	OH Transformer	24M7	Equipment failure	29-May-13	21:53	30-May-13	0:08	135	5	675	A7-LAS	5.15	11.25	1	11.25
60513011155	1	TX70E86	NULL	OH Transformer	24M7	Animal	03-Jun-13	7:35	03-Jun-13	8:45	70	9	630	A7-LAS	9.2	10.50	1	10.50
61013083227	1	TX7P606	NULL	UG Transformer	24M7	Scheduled Outage	11-Jun-13	9:00	11-Jun-13	11:00	120	5	600	A7-LAS	1	10.00	0	0.00
61313101334	1	TX7P606	NULL	UG Transformer	24M7	Scheduled Outage	19-Jun-13	9:45	19-Jun-13	12:26	161	37	5957	A7-LAS	1	99.28	0	0.00
62513093645	1	TX7D142	NULL	OH Transformer	24M7	Lightning	22-Jun-13	19:14	22-Jun-13	21:30	136	8	1088	A7-LAS	4	18.13	1	18.13
70213010000	1	TX7D133	NULL	OH Transformer	24M7	Lightning	28-Jun-13	13:30	28-Jun-13	14:48	78	2	156	A7-LAS	4	2.60	1	2.60
72513082121	1	24M7	NULL	Station Breaker	24M7	Loss of supply	15-Jul-13	16:11	15-Jul-13	23:19	428	3132	1340496	A7-LAS	2	22341.60	0	0.00
71613015611	1	SW7H100	NULL	Switch	24M7	Scheduled Outage	16-Jul-13	13:55	16-Jul-13	14:08	13	172	2236	A7-LAS	1	37.27	0	0.00
73113103745	1	LAS-420	NULL	Station Breaker	24M7	Loss of supply	18-Jul-13	13:27	18-Jul-13	15:35	128	1678	214784	A7-LAS	2	3579.73	0	0.00
73113103745	2	24M7	NULL	Station Breaker	24M7	Loss of supply	18-Jul-13	13:27	18-Jul-13	21:28	481	1454	699374	A7-LAS	2	11656.23	0	0.00
72513025039	1	24M7	NULL	Station Breaker	24M7	Loss of supply	19-Jul-13	21:06	19-Jul-13	21:18	12	3132	37584	A7-LAS	2	626.40	0	0.00
82913032207	1	24M7	NULL	Station Breaker	24M7	Loss of supply	28-Aug-13	19:29	28-Aug-13	19:30	1	3132	3132	A7-LAS	2	52.20	0	0.00
90313115951	1	FS70H44	NULL	Switch	24M7	Other	30-Aug-13	11:02	30-Aug-13	13:00	118	1	118	A7-LAS	0.1	1.97	1	1.97
90313042756	1	Station Breaker	NULL	Station Breaker	24M7	Loss of supply	30-Aug-13	23:23	30-Aug-13	23:24	1	2858	2858	A7-LAS	2	47.63	0	0.00
90413123639	1	24M7-M7R	NULL	Switch	24M7	Loss of supply	30-Aug-13	23:33	31-Aug-13	3:54	261	865	225765	A5-AMH	2	3762.75	0	0.00
90313125608	1	TX70D87	NULL	OH Transformer	24M7	Storm	31-Aug-13	1:05	31-Aug-13	5:45	280	11	3080	A7-LAS	6	51.33	1	51.33
90413075618	1	TX7D210	NULL	OH Transformer	24M7	Equipment failure	31-Aug-13	17:16	31-Aug-13	19:45	149	7	1043	A7-LAS	5.12	17.38	1	17.38
103013110728	1	TX70E32	NULL	OH Transformer	24M7	Equipment failure	27-Oct-13	8:46	27-Oct-13	10:15	89	13	1157	A7-LAS	5.14	19.28	1	19.28
103113014425	1	24M7	NULL	Station Breaker	24M7	Loss of supply	31-Oct-13	7:08	31-Oct-13	8:49	101	2085	210585	A7-LAS	2	3509.75	0	0.00
103113014425	2	24M7	NULL	Station Breaker	24M7	Loss of supply	31-Oct-13	7:08	31-Oct-13	8:49	101	875	88375	A5-AMH	2	1472.92	0	0.00
111413091840	1	AMH-21X	MV50135	Switch	24M7	Scheduled Outage	14-Nov-13	11:15	14-Nov-13	11:24	9	170	1530	A5-AMH	1	25.50	0	0.00
111413091331	1	PMH237	MV50125	UG switch unit	24M7	Scheduled Outage	14-Nov-13	10:50	14-Nov-13	10:57	7	187	1309	A5-AMH	1	21.82	0	0.00
							Total 2013									**51690.38**	**9.00**	**137.10**
10614014234	1	TX7D260	NULL	OH Transformer	24M7	Equipment failure	04-Jan-14	17:16	04-Jan-14	20:00	164	1	164	A7-LAS	5.12	2.73	1	2.73
12114124338	1	TX7P357	NULL	UG Transformer	24M7	Equipment failure	17-Jan-14	17:21	17-Jan-14	22:45	324	21	6804	A7-LAS	5.23	113.40	1	113.40
12114124338	2	FS7H116	NULL	UG Transformer	24M7	Equipment failure	17-Jan-14	22:00	17-Jan-14	22:45	45	92	4140	A7-LAS	5.23	69.00	1	69.00
31914074849	1	TX7D260	NULL	OH Transformer	24M7	Equipment failure	17-Mar-14	18:51	17-Mar-14	21:00	129	1	129	A7-LAS	5.12	2.15	1	2.15
40814093418	1	MV50200	NULL	UG switch unit	24M7	Equipment failure	05-Apr-14	13:05	05-Apr-14	15:45	160	281	44960	A5-AMH	5.26	749.33	1	749.33
40714101223	1	TX50909	NULL	UG Transformer	24M7	Scheduled Outage	07-Apr-14	10:15	07-Apr-14	10:20	5	13	65	A5-AMH	1	1.08	0	0.00
41714085539	1	TX7D231	NULL	OH Transformer	24M7	Animal	15-Apr-14	7:14	15-Apr-14	9:10	116	5	580	A7-LAS	9.2	9.67	1	9.67
61614022423	1	24M7	NULL	Station Breaker	24M7	Loss of supply	13-Jun-14	1:53	13-Jun-14	1:54	1	2904	2904	A7-LAS	2	48.40	0	0.00
73114011904	1	TX70D62	NULL	OH Transformer	24M7	Lightning	27-Jul-14	19:42	27-Jul-14	22:30	168	6	1008	A7-LAS	6	16.80	1	16.80
							To Date 2014									**1012.57**	**7.00**	**963.08**

Feeder 24M8

outage_id	Restore_Step	from Restore_Device	to_restore_device	Device	Feeder	Cause	DtOut	TmOut	DtRes	TmRes	Duration	NumCust	SubCustMin	AREA_TOWN	Equipment_code	Customer Hours	Modifier	Customer Hours Modified
0178	1	TX70E20		Transformer Fuse	24M8	Animal	27-Oct-08	17:23	27-Oct-08	18:48	85	3	255	A7-LAS	9.2	4.25	1	4.25
							Total 2008									**4.25**	**1.00**	**4.25**
092411041236	1	LAS-21X		Switch	24M8	Lightning	18-Aug-11	18:24	18-Aug-11	22:29	245	11	2695	A7-LAS	4	44.92	1	44.92
							Total 2009									**44.92**	**1.00**	**44.92**
052512101149	1	Station Breaker		Station Breaker	24M8	Loss of supply	24-May-12	17:57	24-May-12	18:02	5	14	70	A7-LAS	2	1.17	0	0.00
070312105522	1	LAS-21X		Switch	24M8	Scheduled Outage	03-Jul-12	8:52	03-Jul-12	10:00	68	11	748	A7-LAS	4	12.47	1	12.47
070512101918	1	Station Breaker		Station Breaker	24M8	Loss of supply	03-Jul-12	8:21	03-Jul-12	9:16	55	14	770	A7-LAS	2	12.83	0	0.00
070912012425	1	Station Breaker		Station Breaker	24M8	Loss of supply	05-Jul-12	10:15	05-Jul-12	10:19	4	14	56	A7-LAS	2	0.93	0	0.00
070912012944	1	Station Breaker		Station Breaker	24M8	Loss of supply	05-Jul-12	10:21	05-Jul-12	10:37	16	14	224	A7-LAS	2	3.73	0	0.00
							Total 2012									**31.13**	**1.00**	**12.47**
42913114404	1	TX7D243	NULL	OH Transformer	24M8	Other	28-Apr-13	12:30	28-Apr-13	13:45	75	1	75	A7-LAS	5.12	1.25	1	1.25
62413100928	1	24M8	NULL	Station Breaker	24M8	Loss of supply	22-Jun-13	16:32	22-Jun-13	16:33	1	12	12	A7-LAS	2	0.20	0	0.00
							Total 2013									**1.45**	**1.00**	**1.25**

Feeder 24M9

outage_id	Restore_Step	from Restore_Device	to_restore_device	Device	Feeder	Cause	DtOut	TmOut	DtRes	TmRes	Duration	NumCust	SubCustMin	AREA_TOWN	Equipment_code	Customer Hours	Modifier	Customer Hours Modified
A0040	1	U/G Service		Secondary Conductor	24M9	Equipment failure	22-Jan-08	10:13	22-Jan-08	11:30	76.8	1	76.8	A7-LAS	5.5	1.28	1	1.28
A0049	1	TX7B111		Transformer Fuse	24M9	Equipment failure	07-Apr-08	8:01	07-Apr-08	9:31	90	2	180	A7-LAS	5.6	0.00	1	0.00
A0050	1	O/H Secondary		None	24M9	Tree falling	19-Apr-08	15:12	19-Apr-08	16:30	78	1	78	A7-LAS	3.2	1.30	1	1.30
A0054	1	FS7H234		Fused Disconnect	24M9	Equipment failure	10-May-08	15:18	10-May-08	18:45	207	1	207	A7-LAS	8	3.45	1	3.45
A0058	1	TX70D65		Transformer Fuse	24M9	Animal	24-May-08	20:59	24-May-08	22:20	81	16	1296	A7-LAS	9.2	21.60	1	21.60
A0061	1	All of 23M4		None	24M9	Loss of supply	08-Jun-08	16:45	08-Jun-08	23:20	394.8	1949	769465.2	A7-LAS	2.0	12824.42	0	0.00
A0059	1	All of 24M9		None	24M9	Other	08-Jun-08	16:39	08-Jun-08	16:41	1.8	4143	7457.4	A7-LAS	2.0	124.29	0	0.00
A0060	1	All of 24M9		Other	24M9	Other	08-Jun-08	18:02	08-Jun-08	18:03	1.8	4143	7457.4	A7-LAS	2.0	124.29	0	0.00
A0065	1	All of 24M9		None	24M9	Loss of supply	08-Jun-08	18:30	08-Jun-08	18:31	1.2	4143	4971.6	A7-LAS	2.0	82.86	0	0.00
A0063	1	All of 24M9		None	24M9	Loss of supply	09-Jun-08	19:39	09-Jun-08	20:06	27	4143	111861	A7-LAS	2.0	1864.35	0	0.00
A0134	1	LAS77X		None	24M9	Lightning	09-Jun-08	21:45	09-Jun-08	23:45	120	48	5760	A7-LAS	4	96.00	1	96.00
A0062	1	All of 24M9		None	24M9	Loss of supply	09-Jun-08	11:11	09-Jun-08	11:12	1.2	4143	4971.6	A7-LAS	2.0	82.86	0	0.00
A0111	1	LAS77X		Fused Disconnect	24M9	Equipment failure	10-Jun-08	5:57	10-Jun-08	8:04	127	48	6096	A7-LAS	5.4	101.60	1	101.60
A0064	1	All of 24M9		None	24M9	Loss of supply	10-Jun-08	4:04	10-Jun-08	4:05	1.2	4143	4971.6	A7-LAS	2.0	82.86	0	0.00
A0193	1	TX70D61		Transformer Fuse	24M9	Equipment failure	21-Jul-08	5:34	21-Jul-08	7:00	86	10	860	A7-LAS	5.6	14.33	1	14.33
A0196	1	TX7D219		Transformer Fuse	24M9	Animal	27-Jul-08	7:41	27-Jul-08	9:50	129	12	1548	A7-LAS	9.2	25.80	1	25.80
A0259	1	FS7H206		OH Transformer	24M9	Scheduled Outage	31-Jul-08	7:30	31-Jul-08	10:20	170	5	850	A7-LAS	1	14.17	0	0.00
A0259	2	TX7P491		OH Transformer	24M9	Scheduled Outage	31-Jul-08	7:30	31-Jul-08	10:28	178	4	712	A7-LAS	1	11.87	0	0.00
A0239	1	TX70D34		Fused Disconnect	24M9	Animal	18-Aug-08	7:30	18-Aug-08	8:40	70	11	770	A7-LAS	9.2	12.83	1	12.83
0063	1	TX7D150		Transformer Fuse	24M9	Animal	05-Sep-08	15:19	05-Sep-08	16:15	56	10	560	A7-LAS	9.2	0.00	1	0.00
							Total 2008									**15490.16**	**11.00**	**278.20**
0414	1	TX7D115			24M9	Animal	23-Apr-09	8:28	23-Apr-09	9:45	77	5	385	A7-LAS	9.2	6.42	1	6.42
0411	1	TX7D695		Other	24M9	Equipment failure	09-May-09	14:40	09-May-09	16:00	80	10	800	A7-LAS	5.14	13.33	1	13.33
0415	1	TX7B465			24M9	Equipment failure	20-May-09	17:38	20-May-09	19:38	120	9	1080	A7-LAS	5.14	18.00	1	18.00
0706	1	TX7D233		Transformer Fuse	24M9	Animal	15-Aug-09	10:15	15-Aug-09	11:17	62	14	868	A7-LAS	9.2	14.47	1	14.47
1007090428	1	HONI Switch On Boundry	LAS-330	Station Breaker	24M9	Storm	17-Aug-09	14:36	17-Aug-09	17:15	159	2320	368880	A7-LAS	2.0	6148.00	0	0.00
1007090428	3	LAS-330	LAS-420	Station Breaker	24M9	Storm	17-Aug-09	14:36	17-Aug-09	19:18	282	1013	285666	A7-LAS	2.0	4761.10	0	0.00
1007090428	2	SW7H114	LAS-320	Station Breaker	24M9	Storm	17-Aug-09	14:36	17-Aug-09	19:10	274	58	15892	A7-LAS	2.0	264.87	0	0.00
0709	1	LAS-6X		Other	24M9	Tree falling	26-Aug-09	16:00	26-Aug-09	18:22	142	9	1278	A7-LAS	3.2	21.30	1	21.30
1022091211	1	TX7D187	TX7D187	OH Transformer	24M9	Equipment failure	29-Sep-09	10:00	29-Sep-09	11:15	75	4	300	A5-AMH	5.3	5.00	1	5.00
0929091121	1	TX7D187		OH Transformer	24M9	Scheduled Outage	29-Sep-09	10:45	29-Sep-09	11:15	30	4	120	A7-LAS	1	2.00	0	0.00
1020091223	1	SW7H108	TX7E145	Switch	24M9	Storm	09-Oct-09	6:15	09-Oct-09	7:55	100	39	3900	A7-LAS	6	65.00	1	65.00
1020091223	2	TX7E145		Switch	24M9	Storm	09-Oct-09	6:15	09-Oct-09	8:25	130	12	1560	A7-LAS	6	26.00	1	26.00
1013091129	1	TX7D273	TX7D273	OH Transformer	24M9	Animal	13-Oct-09	11:30	13-Oct-09	12:30	60	11	660	A7-LAS	9.2	11.00	1	11.00
1222090352	1	Service		Service	24M9	Tree falling	30-Oct-09	16:52	30-Oct-09	18:52	120	2	240	A7-LAS	3.2	4.00	1	4.00
1222090403	1	Service		Service	24M9	Tree falling	31-Oct-09	7:30	31-Oct-09	9:58	148	2	296	A7-LAS	3.2	4.93	1	4.93
1223090807	1	Service		Pole	24M9	Scheduled Outage	17-Nov-09	11:00	17-Nov-09	12:00	60	1	60	A7-LAS	1	1.00	0	0.00
1204090122	1	FS7H137	FS7H137	Switch	24M9	Equipment failure	04-Dec-09	12:04	04-Dec-09	14:45	161	60	9660	A7-LAS	5.12	161.00	1	161.00
1209090904	2	FS70725	TXD65	Switch	24M9	Equipment failure	09-Dec-09	9:30	09-Dec-09	12:30	180	48	8640	A7-LAS	5.12	144.00	1	144.00
1209090904	1	FS70725	FS70725	Switch	24M9	Equipment failure	09-Dec-09	9:30	09-Dec-09	10:45	75	79	5925	A7-LAS	5.12	98.75	1	98.75
0114100346	1	SD70005		Unknown	24M9	Tree falling	13-Dec-09	0:38	13-Dec-09	3:30	172	73	12556	A7-LAS	3.2	209.27	1	209.27
							Total 2009									**11979.43**	**15.00**	**802.47**
0114100914	1	Primary Switch	TX7D612	OH Transformer	24M9	Equipment failure	03-Jan-10	14:24	03-Jan-10	16:30	126	15	1890	A7-LAS	5.17	31.50	1	31.50
0222101059	1	SD70005	SD70005	OH Transformer	24M9	Scheduled Outage	23-Feb-10	9:00	23-Feb-10	15:00	360	73	26280	A7-LAS	1	438.00	0	0.00
0419101001	1	TX7D705	TX7D705	OH Transformer	24M9	Scheduled Outage	19-Apr-10	10:50	19-Apr-10	13:50	180	15	2700	A7-LAS	1	45.00	0	0.00
0518100934	1	TX7D179		OH Transformer	24M9	Animal	30-Apr-10	18:19	30-Apr-10	21:00	161	6	966	A7-LAS	9.2	16.10	1	16.10
0518100904	1	Service		Service	24M9	Tree falling	05-May-10	20:51	06-May-10	7:50	659	1	659	A7-LAS	3.2	10.98	1	10.98
0506100926	1	TX7B110	TX7B110	OH Transformer	24M9	Loss of supply	06-May-10	9:00	06-May-10	18:30	570	2	1140	A7-LAS	2.0	19.00	1	19.00
0622100209	1	TX72033	TX72033	UG Transformer	24M9	Scheduled Outage	23-Jun-10	8:00	23-Jun-10	8:24	24	43	1032	A7-LAS	1	17.20	0	0.00
0714101136	1	FS70726+TX7D233		Switch	24M9	Lightning	24-Jun-10	0:02	24-Jun-10	5:25	323	58	18734	A7-LAS	4	312.23	1	312.23
0714101138	1	fs7h185		Switch	24M9	Animal	27-Jun-10	6:45	27-Jun-10	8:30	105	40	4200	A7-LAS	9.2	70.00	1	70.00
0714100819	2	FS7H151	KENWOOD	Switch	24M9	Scheduled Outage	14-Jul-10	8:15	14-Jul-10	10:40	145	22	3190	A7-LAS	1	53.17	0	0.00
0714100819	1	FS7H151	FS7H111	Switch	24M9	Scheduled Outage	14-Jul-10	8:15	14-Jul-10	9:00	45	33	1485	A7-LAS	1	24.75	0	0.00
0720101128	1	fs70725		OH Transformer	24M9	Equipment failure	20-Jul-10	7:27	20-Jul-10	9:30	123	80	9840	A7-LAS	5.28	164.00	1	164.00
081610015951	1	tx7b585		OH Transformer	24M9	Lightning	23-Jul-10	18:24	24-Jul-10	0:45	381	10	3810	A7-LAS	4	63.50	1	63.50
072910013704	1	fs70h17		Switch	24M9	Lightning	23-Jul-10	8:15	23-Jul-10	9:00	45	33	1485	A7-LAS	4	24.75	1	24.75
080610110548	1	LAS58X	LAS58X	Switch	24M9	Scheduled Outage	06-Aug-10	11:01	06-Aug-10	11:30	29	134	3886	A7-LAS	1	64.77	0	0.00
092210095434	1	tx7d123		OH Transformer	24M9	Animal	18-Aug-10	7:30	18-Aug-10	9:00	90	6	540	A7-LAS	9.2	9.00	1	9.00
082610091015	1	FS7H234	FS7H234	Switch	24M9	Scheduled Outage	26-Aug-10	8:00	26-Aug-10	10:26	146	9	1314	A7-LAS	1	21.90	0	0.00
092210101033	1	tx7b110		OH Transformer	24M9	Animal	29-Aug-10	10:45	29-Aug-10	13:00	135	2	270	A7-LAS	9.2	4.50	1	4.50
111710074712	1	24m9	24m9	Station Breaker	24M9	Loss of supply	02-Sep-10	15:10	02-Sep-10	16:45	95	3798	360810	A7-LAS	2.0	6013.50	0	0.00
111710101305	1	tx7e100		OH Transformer	24M9	Equipment failure	14-Sep-10	6:31	14-Sep-10	8:21	110	3	330	A7-LAS	5	5.50	1	5.50
091510104823	1	TX70D92	TX70D92	OH Transformer	24M9	Scheduled Outage	15-Sep-10	11:00	15-Sep-10	11:20	20	11	220	A7-LAS	1	3.67	0	0.00
092110015223	1	MALDEN STATION	MALDEN STATION	Station Breaker	24M9	Loss of supply	21-Sep-10	15:10	21-Sep-10	16:45	95	306	29070	A7-LAS	2.0	484.50	1	484.50
092210112910	1	FS70725	FS70725	Switch	24M9	Scheduled Outage	22-Sep-10	10:40	22-Sep-10	13:00	140	80	11200	A7-LAS	1	186.67	0	0.00
111710101332	1	fs70725		Switch	24M9	Lightning	22-Sep-10	5:21	22-Sep-10	6:40	79	49	3871	A7-LAS	4	64.52	1	64.52
092810023849	1	TX7D289	TX7D289	OH Transformer	24M9	Scheduled Outage	28-Sep-10	13:12	28-Sep-10	16:24	192	10	1920	A7-LAS	1	32.00	0	0.00
100710101258	1	LAS12X	LAS12X	UG switch unit	24M9	Scheduled Outage	07-Oct-10	10:30	07-Oct-10	10:41	11	48	528	A7-LAS	1	8.80	0	0.00
101210113012	1	TX7D668	TX7D668	OH Transformer	24M9	Scheduled Outage	12-Oct-10	10:51	12-Oct-10	11:22	31	15	465	A7-LAS	1	7.75	0	0.00
102810103801	1	LAS9X	LAS9X	Switch	24M9	Scheduled Outage	28-Oct-10	10:38	28-Oct-10	11:30	52	221	11492	A7-LAS	1	191.53	0	0.00
111510013316	1	TX7B210	TX7B210	OH Transformer	24M9	Scheduled Outage	15-Nov-10	13:34	15-Nov-10	14:18	44	1	44	A7-LAS	1	0.73	0	0.00
111910025125	1	LAS-10X		Switch	24M9	Scheduled Outage	19-Nov-10	14:51	19-Nov-10	15:30	39	111	4329	A7-LAS	1	72.15	0	0.00
120110091230	1	LAS-10X	LAS-10X	Switch	24M9	Scheduled Outage	01-Dec-10	10:45	01-Dec-10	11:14	29	111	3219	A7-LAS	1	53.65	0	0.00
0519100256	1	LAS32X	FS70H31	Unknown	23M5	Equipment failure	19-May-10	12:43	19-May-10	14:40	117	60	7020	A7-LAS	5.13	117.00	1	117.00
011711024609	1	24M9		Station Breaker	24M9	Loss of supply	03-Dec-10	13:27	03-Dec-10	13:50	23	3798	87354	A7-LAS	2.0	1455.90	0	0.00
							Total 2010									**10088.22**	**15.00**	**1397.08**

021611081545	1	tx7d668		OH Transformer	24M9	Animal	29-Jan-11	11:00	29-Jan-11	12:00	60	15	900	A7-LAS	9.2	15.00	1	15.00
021511033629	1	SW7H108	SW7H108	Switch	24M9	Scheduled Outage	15-Feb-11	14:30	15-Feb-11	15:30	60	67	4020	A7-LAS	9.2	67.00	0	0.00
040111122246	1	Las330	Las420	Station Breaker	24M9	Loss of supply	09-Mar-11	2:09	09-Mar-11	3:09	60	1391	83460	A7-LAS	2	1391.00	0	0.00
053011012019	2	FS7H224		Switch	24M9	Customer equipment	23-Apr-11	17:57	23-Apr-11	23:15	318	48	15264	A7-LAS	5.23	254.40	1	254.40
053011012019	1	LAS61X		Switch	24M9	Customer equipment	23-Apr-11	17:57	23-Apr-11	22:25	268	41	10988	A7-LAS	5.23	183.13	1	183.13
062011023035	1	FS7H151		Switch	24M9	Equipment failure	14-Jun-11	12:30	14-Jun-11	14:00	90	193	17370	A7-LAS	5.6	289.50	1	289.50
062011020608	1	fs70h81		Switch	24M9	Equipment failure	14-Jun-11	10:12	14-Jun-11	12:10	118	91	10738	A7-LAS	5.4	178.97	1	178.97
062711033117	1	SD70005		Switch	24M9	Tree falling	23-Jun-11	19:12	23-Jun-11	21:00	108	73	7884	A7-LAS	3.2	131.40	1	131.40
092111093036	1	SD70005		Switch	24M9	Tree falling-weather	02-Jul-11	21:25	03-Jul-11	20:00	1355	61	82655	A7-LAS	3.2	1377.58	1	1377.58
092111011619	1	TX70D78		OH Transformer	24M9	Lightning	02-Jul-11	20:00	03-Jul-11	19:05	1385	13	18005	A7-LAS	4	300.08	1	300.08
092011041320	1	FS70725		Switch	24M9	Other	03-Jul-11	4:19	03-Jul-11	18:30	851	80	68080	A7-LAS	6	1134.67	1	1134.67
092111014326	1	FS70H11		Switch	24M9	Lightning	03-Jul-11	17:10	03-Jul-11	19:05	115	64	7360	A7-LAS	4	122.67	1	122.67
092111021723	1	TX7B464		OH Transformer	24M9	Lightning	03-Jul-11	9:36	04-Jul-11	18:30	1974	1	1974	A7-LAS	4	32.90	1	32.90
072911034127	1	TX7D156		OH Transformer	24M9	Storm	28-Jul-11	1:45	28-Jul-11	10:40	535	8	4280	A7-LAS	6	71.33	1	71.33
081911110735	1	LAS22X		OH Transformer	24M9	Equipment failure	02-Aug-11	7:15	02-Aug-11	8:00	45	82	3690	A7-LAS	5.11	61.50	1	61.50
081911110735	2	TX0D52		OH Transformer	24M9	Equipment failure	02-Aug-11	6:00	02-Aug-11	9:00	180	18	3240	A7-LAS	5.11	54.00	1	54.00
092111030004	1	LAS-54X		Switch	24M9	Equipment failure	09-Aug-11	14:30	09-Aug-11	21:45	435	23	10005	A7-LAS	5.4	166.75	1	166.75
092411035914	1	FS70H35		Switch	24M9	Lightning	18-Aug-11	18:29	18-Aug-11	20:20	111	45	4995	A7-LAS	4	83.25	1	83.25
090811075706	1	TX70D10		OH Transformer	24M9	Animal	03-Sep-11	8:17	03-Sep-11	9:52	95	11	1045	A7-LAS	9.2	17.42	1	17.42
092211121856	1	TX70D52		OH Transformer	24M9	Animal	18-Sep-11	10:53	18-Sep-11	12:15	82	18	1476	A7-LAS	9.2	24.60	1	24.60
092211110839	1	TX7D612		OH Transformer	24M9	Scheduled Outage	22-Sep-11	11:10	22-Sep-11	11:49	39	15	585	A7-LAS	1	9.75	0	0.00
100311104248	1	TX7D610		OH Transformer	24M9	Scheduled Outage	03-Oct-11	11:00	03-Oct-11	12:27	87	10	870	A7-LAS	1	14.50	0	0.00
100311014853	1	TX7D859		OH Transformer	24M9	Scheduled Outage	04-Oct-11	9:45	04-Oct-11	12:07	142	16	2272	A7-LAS	1	37.87	0	0.00
100411095214	1	TX7D611		OH Transformer	24M9	Scheduled Outage	04-Oct-11	9:54	04-Oct-11	10:26	32	13	416	A7-LAS	1	6.93	0	0.00
012612011632	1	Station Breaker		Station Breaker	24M9	Loss of supply	03-Jul-11	2:16	03-Jul-11	2:45	29	3845	111505	A7-LAS	2	1858.42	0	0.00
110111093537	1	TX7D219		OH Transformer	24M9	Scheduled Outage	01-Nov-11	8:54	01-Nov-11	9:20	26	13	338	A7-LAS	9.2	5.63	1	5.63
100710011701	1	LAS-7X		Switch	24M9	Scheduled Outage	07-Oct-10	13:00	07-Oct-10	15:00	120	19	2280	A7-LAS	1	38.00	0	0.00
111610085143	1	TX70D73		OH Transformer	24M9	Scheduled Outage	16-Nov-10	13:00	16-Nov-10	14:30	90	8	720	A7-LAS	1	12.00	0	0.00
111710101927	1	TX7P581		UG Transformer	24M9	Scheduled Outage	17-Nov-10	10:20	17-Nov-10	11:20	60	6	360	A7-LAS	1	6.00	0	0.00
120810113945	1	LAS10X		Switch	24M9	Scheduled Outage	12-Dec-10	5:00	12-Dec-10	11:00	360	100	36000	A7-LAS	1	600.00	0	0.00
							Total 2011									**7940.25**	**19.00**	**4504.78**
020112094404	1	TX7E115		OH Transformer	24M9	Scheduled Outage	01-Feb-12	9:30	01-Feb-12	11:06	96	9	864	A7-LAS	1	14.40	0	0.00
020312083430	1	TX7P588		UG Transformer	24M9	Scheduled Outage	03-Feb-12	9:35	03-Feb-12	10:25	50	300	15000	A7-LAS	1	250.00	0	0.00
041412030059	1	FS70H49		Switch	24M9	Lightning	30-Mar-12	17:09	30-Mar-12	20:20	191	31	5921	A7-LAS	4	98.68	1	98.68
043012015258	1	TX70D73		OH Transformer	24M9	Scheduled Outage	30-Apr-12	13:57	30-Apr-12	14:28	31	8	248	A7-LAS	1	4.13	0	0.00
050612124059	1	Station Breaker		Station Breaker	24M9	Loss of supply	16-Apr-12	2:31	16-Apr-12	2:33	2	3878	7756	A7-LAS	2	129.27	0	0.00
052212102857	1	TX7D920		OH Transformer	24M9	Animal	21-May-12	8:00	21-May-12	9:45	105	13	1365	A7-LAS	9.2	22.75	1	22.75
052512101520	1	Station Breaker		Station Breaker	24M9	Loss of supply	24-May-12	17:57	24-May-12	18:02	5	3900	19500	A7-LAS	2	325.00	0	0.00
052912083333	1	FS7H127		Switch	24M9	Equipment failure	24-May-12	18:02	24-May-12	20:50	168	296	49728	A7-LAS	5.26	828.80	1	828.80
052912111125	1	LAS-26X		Switch	24M9	Scheduled Outage	29-May-12	10:43	29-May-12	11:34	51	37	1887	A7-LAS	4	31.45	1	31.45
053012024721	1	MV70370		UG switch unit	24M9	Equipment failure	28-May-12	17:44	28-May-12	19:45	121	57	6897	A7-LAS	5.23	114.95	1	114.95
061312124658	1	FS70H81		Switch	24M9	Scheduled Outage	13-Jun-12	12:41	13-Jun-12	13:24	43	91	3913	A7-LAS	1	65.22	0	0.00
070512013454	1	Station Breaker		Station Breaker	24M9	Loss of supply	04-Jul-12	19:12	04-Jul-12	19:13	1	3900	3900	A7-LAS	2	65.00	0	0.00
080312120953	1	FS70725		Switch	24M9	Other	03-Aug-12	11:19	03-Aug-12	12:57	98	83	8134	A7-LAS	0.1	135.57	1	135.57
082012114747	1	FS70H11		Switch	24M9	Scheduled Outage	21-Aug-12	9:08	21-Aug-12	14:23	315	77	24255	A7-LAS	1	404.25	0	0.00
082012115142	1	FS70725		Switch	24M9	Scheduled Outage	22-Aug-12	8:30	22-Aug-12	14:30	360	80	28800	A7-LAS	1	480.00	0	0.00
082012115656	1	FS70726		Switch	24M9	Scheduled Outage	23-Aug-12	8:29	23-Aug-12	14:56	387	60	23220	A7-LAS	1	387.00	0	0.00
091712094813	1	TX7D115	Service	Service	24M9	Equipment failure	28-Aug-12	17:41	28-Aug-12	19:00	79	1	79	A7-LAS	9.1	1.32	1	1.32
100412033524	1	TX70D44		OH Transformer	24M9	Animal	01-Oct-12	22:54	02-Oct-12	0:45	111	18	1998	A7-LAS	9.2	33.30	1	33.30
100912095307	1	LAS-10X		Switch	24M9	Animal	08-Oct-12	18:19	08-Oct-12	19:50	91	119	10829	A7-LAS	9.2	180.48	1	180.48
101512091126	1	TX7P546		UG Transformer	24M9	Scheduled Outage	15-Oct-12	9:00	15-Oct-12	12:00	180	9	1620	A7-LAS	1	27.00	0	0.00
121412085802	1	TX7B202		UG Transformer	24M9	Scheduled Outage	14-Dec-12	8:30	14-Dec-12	11:30	180	8	1440	A7-LAS	5.23	24.00	1	24.00
							Total 2012									**14031.87**	**29.00**	**5957.72**

20113030334		1	FS7H151	NULL	Switch	24M9	Other	06-Jan-13	13:30	06-Jan-13	14:15	45	143	6435	A7-LAS		9.2	107.25	1	107.25
20113030334		2	FS70H81	NULL	Switch	24M9	Other	06-Jan-13	13:30	06-Jan-13	14:30	60	83	4980	A7-LAS		9.2	83.00	1	83.00
12913013634		1	Station Breaker	NULL	Station Breaker	24M9	Scheduled Outage	27-Jan-13	23:40	28-Jan-13	2:20	160	3786	605760	A7-LAS		2	10096.00	0	0.00
21213083819		1	FS70H81	NULL	Switch	24M9	Scheduled Outage	12-Feb-13	11:11	12-Feb-13	11:30	19	93	1767	A7-LAS		1	29.45	0	0.00
21413121803		1	FS70H81	NULL	Switch	24M9	Scheduled Outage	14-Feb-13	12:16	14-Feb-13	12:29	13	93	1209	A7-LAS		1	20.15	0	0.00
22113093753		1	SW33L47	NULL	Switch	3M8	Scheduled Outage	21-Feb-13	9:44	21-Feb-13	9:59	15	87	1305	A3-LEA		1	21.75	0	0.00
30713094504		1	TX7D697	NULL	OH Transformer	24M9	Scheduled Outage	07-Mar-13	9:50	07-Mar-13	11:45	115	5	575	A7-LAS		1	9.58	0	0.00
31213080322		1	SW35L96	NULL	Switch	3M8	Scheduled Outage	12-Mar-13	9:20	12-Mar-13	9:36	16	155	2480	A3-LEA		1	41.33	0	0.00
31313081731		1	FS35L87	NULL	Switch	3M8	Scheduled Outage	13-Mar-13	12:50	13-Mar-13	13:15	25	40	1000	A3-LEA		1	16.67	0	0.00
31913121319		1	FS35H81	NULL	Switch	3M8	Scheduled Outage	19-Mar-13	12:40	19-Mar-13	13:55	75	23	1725	A3-LEA		1	28.75	0	0.00
32213020051		1	TX70D75	NULL	OH Transformer	24M9	Scheduled Outage	22-Mar-13	11:08	22-Mar-13	11:44	36	12	432	A7-LAS		1	7.20	0	0.00
32213015705		1	TX7D666	NULL	OH Transformer	24M9	Scheduled Outage	22-Mar-13	10:40	22-Mar-13	11:05	25	9	225	A7-LAS		1	3.75	0	0.00
40513030937		1	TX31445	NULL	OH Transformer	3M8	Animal	03-Apr-13	19:00	03-Apr-13	21:30	150	17	2550	A3-LEA		9.2	42.50	1	42.50
41113102703		1	TX31352	NULL	OH Transformer	3M8	Storm	10-Apr-13	16:30	10-Apr-13	18:30	120	15	1800	A3-LEA		6	30.00	1	30.00
41613101352		1	SW70724	NULL	Switch	24M9	Scheduled Outage	16-Apr-13	10:00	16-Apr-13	10:19	19	2	38	A7-LAS		1	0.63	0	0.00
41713113822		1	TX7D697	NULL	OH Transformer	24M9	Scheduled Outage	17-Apr-13	12:30	17-Apr-13	13:40	70	5	350	A7-LAS		1	5.83	0	0.00
42213032740		1	TX7E186	NULL	OH Transformer	24M9	Scheduled Outage	22-Apr-13	11:40	22-Apr-13	11:52	12	7	84	A7-LAS		1	1.40	0	0.00
42313032801		1	TX7D236	NULL	OH Transformer	24M9	Animal	23-Apr-13	7:43	23-Apr-13	9:05	82	10	820	A7-LAS		9.2	13.67	1	13.67
50913035112		1	TX7D913	NULL	OH Transformer	24M9	Animal	27-Apr-13	8:10	27-Apr-13	9:45	95	22	2090	A7-LAS		9.2	34.83	1	34.83
50213034527		1	24M9	24M10	Station Breaker	24M9	Loss of supply	01-May-13	15:45	01-May-13	17:15	90	3862	347580	A7-LAS		2	5793.00	0	0.00
50713075831		1	Service	NULL	Service	24M9	Scheduled Outage	06-May-13	12:30	06-May-13	13:55	85	4	340	A7-LAS		1	5.67	0	0.00
50813081332		1	FS35H19	NULL	Switch	3M8	Scheduled Outage	08-May-13	9:05	08-May-13	14:20	315	36	11340	A3-LEA		1	189.00	0	0.00
50913091003		1	SW70715	NULL	Switch	24M9	Scheduled Outage	13-May-13	9:30	13-May-13	11:00	90	8	720	A7-LAS		1	12.00	0	0.00
52213014930		1	TX7D918	NULL	OH Transformer	24M9	Other	13-May-13	8:12	13-May-13	9:00	48	9	432	A7-LAS		5.12	7.20	1	7.20
51613091213		1	TX70D75	NULL	OH Transformer	24M9	Scheduled Outage	16-May-13	9:15	16-May-13	11:15	120	12	1440	A7-LAS		1	24.00	0	0.00
52213022915		1	TX7D912	NULL	OH Transformer	24M9	Equipment failure	18-May-13	6:30	18-May-13	9:45	195	20	3900	A7-LAS		5.12	65.00	1	65.00
52113090005		1	SW70715	NULL	Switch	24M9	Scheduled Outage	21-May-13	9:30	21-May-13	11:20	110	8	880	A7-LAS		1	14.67	0	0.00
52413082015		1	TX7D684	NULL	OH Transformer	24M9	Scheduled Outage	24-May-13	9:30	24-May-13	11:30	120	13	1560	A7-LAS		1	26.00	0	0.00
52813084548		1	SERVICE	NULL	Service	3M8	Tree growth	27-May-13	19:54	28-May-13	0:00	246	1	246	A3-LEA		3.1	4.10	1	4.10
60513124410		1	SERVICE	NULL	Service	3M8	Other	29-May-13	6:30	29-May-13	7:30	60	1	60	A3-LEA		7	1.00	1	1.00
53013081940		1	TX7D165	NULL	OH Transformer	24M9	Scheduled Outage	30-May-13	9:00	30-May-13	12:00	180	8	1440	A7-LAS		1	24.00	0	0.00
53113082154		1	TX7D166	NULL	OH Transformer	24M9	Scheduled Outage	31-May-13	9:00	31-May-13	11:30	150	8	1200	A7-LAS		1	20.00	0	0.00
60513115713		1	LAS-37X	NULL	Switch	24M9	Animal	04-Jun-13	9:30	04-Jun-13	11:12	102	44	4488	A7-LAS		9.2	74.80	1	74.80
60713095318		1	TX7D920	NULL	OH Transformer	24M9	Animal	07-Jun-13	8:47	07-Jun-13	9:20	33	14	462	A7-LAS		9.2	7.70	1	7.70
61113125700		1	TX31195	NULL	OH Transformer	3M8	Scheduled Outage	11-Jun-13	12:51	11-Jun-13	13:01	10	15	150	A3-LEA		1	2.50	0	0.00
62613010315		1	SW33L47	TX3P140	Switch	3M8	Scheduled Outage	26-Jun-13	13:00	26-Jun-13	13:15	15	87	1305	A3-LEA		1	21.75	0	0.00
62613084110		1	LAS-10X	NULL	Switch	24M9	Other	26-Jun-13	8:00	26-Jun-13	9:25	85	119	10115	A7-LAS		0	168.58	1	168.58
62713101635		1	TX31142	NULL	OH Transformer	3M8	Scheduled Outage	27-Jun-13	10:45	27-Jun-13	12:30	105	20	2100	A3-LEA		1	35.00	0	0.00
70213010016		1	FS35H55	NULL	Switch	3M8	Lightning	28-Jun-13	15:11	28-Jun-13	18:30	199	60	11940	A3-LEA		4	199.00	1	199.00
70213112008		1	TX70D75	NULL	OH Transformer	24M9	Lightning	28-Jun-13	16:30	28-Jun-13	18:20	110	12	1320	A7-LAS		4	22.00	1	22.00
70213124251		1	TX7D222	NULL	OH Transformer	24M9	Lightning	28-Jun-13	17:15	28-Jun-13	19:00	105	3	315	A7-LAS		4	5.25	1	5.25
71113074049		1	FS35L87	NULL	Switch	3M8	Scheduled Outage	11-Jul-13	9:40	11-Jul-13	13:20	220	40	8800	A3-LEA		1	146.67	0	0.00
71913092809		1	TX31160	TX3P120	OH Transformer	3M8	Scheduled Outage	19-Jul-13	9:00	19-Jul-13	10:45	105	13	1365	A3-LEA		1	22.75	0	0.00
72413024803		1	LEA-31	NULL	Switch	3M8	Storm	19-Jul-13	22:40	20-Jul-13	3:56	316	831	262596	A3-LEA		6	4376.60	1	4376.60
80813111026		1	TX31083	NULL	OH Transformer	3M8	Scheduled Outage	08-Aug-13	10:06	08-Aug-13	12:52	166	7	1162	A3-LEA		1	19.37	0	0.00
80813110250		1	LAS-26X	NULL	Switch	24M9	Scheduled Outage	08-Aug-13	10:20	08-Aug-13	10:50	30	37	1110	A7-LAS		1	18.50	0	0.00
80813105435		1	LAS-28X	NULL	Switch	24M9	Scheduled Outage	08-Aug-13	9:51	08-Aug-13	10:15	24	158	3792	A7-LAS		1	63.20	0	0.00
81213032006		1	LAS-29X	NULL	Switch	24M9	Scheduled Outage	14-Aug-13	9:00	14-Aug-13	16:20	440	27	11880	A7-LAS		1	198.00	0	0.00
81913123146		1	TX31143	NULL	OH Transformer	3M8	Scheduled Outage	21-Aug-13	9:00	21-Aug-13	12:00	180	20	3600	A3-LEA		1	60.00	0	0.00
82013035342		1	LAS-29X	NULL	Switch	24M9	Scheduled Outage	21-Aug-13	9:00	21-Aug-13	16:45	465	27	12555	A7-LAS		1	209.25	0	0.00
82613090017		1	FS33L49	NULL	Switch	3M8	Scheduled Outage	26-Aug-13	10:11	26-Aug-13	10:59	48	105	5040	A3-LEA		1	84.00	0	0.00
90313033326		1	TX7D177	NULL	OH Transformer	24M9	Scheduled Outage	04-Sep-13	9:24	04-Sep-13	13:25	241	4	964	A7-LAS		1	16.07	0	0.00
90313033815		1	TX7D667	TX70667	OH Transformer	24M9	Scheduled Outage	05-Sep-13	9:30	05-Sep-13	13:30	240	8	1920	A7-LAS		1	32.00	0	0.00
91213123726		1	SC35105	NULL	UG switch unit	3M8	Equipment failure	06-Sep-13	19:01	07-Sep-13	21:24	1583	64	101312	A3-LEA		5.24	1688.53	1	1688.53
90313034153		1	TX7D217	TX70217	OH Transformer	24M9	Scheduled Outage	06-Sep-13	9:48	06-Sep-13	12:36	168	12	2016	A7-LAS		1	33.60	0	0.00
90913102753		1	SERVICE	NULL	Service	3M8	Scheduled Outage	09-Sep-13	10:30	09-Sep-13	12:45	135	6	810	A3-LEA		1	13.50	0	0.00
90913103332		1	FS30021	SC35105	Switch	3M8	Scheduled Outage	09-Sep-13	10:22	09-Sep-13	10:37	15	28	420	A3-LEA		1	7.00	0	0.00
101813104637		1	LAS-10X	NULL	Switch	24M9	Animal	18-Oct-13	10:11	18-Oct-13	12:01	110	119	13090	A7-LAS		9.2	218.17	1	218.17
102513094741		1	FS35H78	NULL	Switch	3M8	Animal	25-Oct-13	8:45	25-Oct-13	9:39	54	50	2700	A3-LEA		9.2	45.00	1	45.00
110513115933		1	TX31162	TX31470	OH Transformer	3M8	Scheduled Outage	05-Nov-13	12:30	05-Nov-13	13:15	45	14	630	A3-LEA		1	10.50	0	0.00
111513101218		1	TX31162	TX31470	OH Transformer	3M8	Scheduled Outage	15-Nov-13	9:56	15-Nov-13	11:31	95	14	1330	A3-LEA		1	22.17	0	0.00
120213112323		1	TX7G105	NULL	OH Transformer	24M9	Scheduled Outage	28-Nov-13	4:10	28-Nov-13	8:45	275	7	1925	A7-LAS		1	32.08	0	0.00
120413101120		1	TX31470	TX31162	OH Transformer	3M8	Scheduled Outage	04-Dec-13	10:10	04-Dec-13	12:45	155	24	3720	A3-LEA		1	62.00	0	0.00
120513075607		1	TX7P524	TX7P522	UG Transformer	24M9	Scheduled Outage	05-Dec-13	9:00	05-Dec-13	14:50	350	28	9800	A7-LAS		1	163.33	0	0.00
121113123949		1	FS3H328	NULL	Switch	3M8	Scheduled Outage	12-Dec-13	4:30	12-Dec-13	8:00	210	15	3150	A3-LEA		1	52.50	0	0.00
121713104850		1	TX7E135	NULL	OH Transformer	24M9	Scheduled Outage	17-Dec-13	10:45	17-Dec-13	12:05	80	5	400	A7-LAS		1	6.67	0	0.00
10614075612		1	TX7P528	NULL	UG Transformer	24M9	Scheduled Outage	19-Dec-13	9:10	19-Dec-13	10:20	70	13	910	A7-LAS		1	15.17	0	0.00
								Total 2013										**24932.58**	**20.00**	**7194.18**
10914011115		1	TX70D54	NULL	OH Transformer	24M9	Scheduled Outage	09-Jan-14	13:00	09-Jan-14	14:00	60	8	480	A7-LAS		1	8.00	0	0.00
11514082608		1	24M9	23M5	Station Breaker	24M9	Loss of supply	14-Jan-14	22:47	14-Jan-14	23:05	18	4838	87084	A7-LAS		2	1451.40	0	0.00
11514082608		2	24M7	NULL	Station Breaker	24M9	Loss of supply	14-Jan-14	22:47	14-Jan-14	23:05	18	2966	53388	A7-LAS		2	889.80	0	0.00
21014104803		1	RE30051	NULL	Switch	3M8	Human error	30-Jan-14	2:46	30-Jan-14	5:52	186	559	103974	A3-LEA		8	1732.90	1	1732.90
21314093238		1	TX7D787	NULL	OH Transformer	24M9	Animal	13-Feb-14	8:45	13-Feb-14	9:25	40	13	520	A7-LAS		9.2	8.67	1	8.67
21914110240		1	LAS-49X	LAS-48X	Switch	24M9	Equipment failure	19-Feb-14	10:25	19-Feb-14	12:20	115	80	9200	A7-LAS		5.26	153.33	1	153.33
22514094534		1	LAS-61X	NULL	Switch	24M9	Animal	22-Feb-14	7:15	22-Feb-14	9:32	137	122	16714	A7-LAS		9.2	278.57	1	278.57
31314035805		1	24M9	NULL	Station Breaker	24M9	Loss of supply	12-Mar-14	13:24	12-Mar-14	13:25	1	3116	3116	A7-LAS		2	51.93	0	0.00
32714090837		1	TX7P586	NULL	UG Transformer	24M9	Scheduled Outage	27-Mar-14	9:26	27-Mar-14	10:20	54	15	810	A7-LAS		1	13.50	0	0.00
32814114105		1	ILS-7001	NULL	Switch	24M9	Scheduled Outage	01-Apr-14	8:45	01-Apr-14	14:00	315	31	9765	A7-LAS		1	162.75	0	0.00
32814114532		1	ILS-7002	NULL	Switch	24M9	Scheduled Outage	02-Apr-14	8:45	02-Apr-14	12:12	207	33	6831	A7-LAS		1	113.85	0	0.00
52614104550		1	TX7D233	NULL	OH Transformer	24M9	Tree growth	26-May-14	12:52	26-May-14	16:50	238	14	3332	A7-LAS		3.1	55.53	1	55.53
60414034414		1	FS7H151	NULL	Switch	24M9	Other	31-May-14	6:25	31-May-14	9:44	199	217	43183	A7-LAS		0.1	719.72	1	719.72
60414034414		2	FS7H111	NULL	Switch	24M9	Other	31-May-14	6:25	31-May-14	10:40	255	51	13005	A7-LAS		0.1	216.75	1	216.75
60314102351		1	FS7H111	NULL	Switch	24M9	Scheduled Outage	03-Jun-14	10:23	03-Jun-14	10:50	27	51	1377	A7-LAS		1	22.95	0	0.00
61614022420		1	24M9	NULL	Station Breaker	24M9	Loss of supply	13-Jun-14	1:53	13-Jun-14	1:54	1	2852	2852	A7-LAS		2	47.53	0	0.00
61314094155		1	TX31134	NULL	OH Transformer	3M8	Tree growth	13-Jun-14	6:40	13-Jun-14	9:48	188	13	2444	A3-LEA		3.1	40.73	1	40.73
61814092937		1	FS7H224	TX7P529	Switch	24M9	Equipment failure	18-Jun-14	7:47	18-Jun-14	10:45	178	99	17622	A7-LAS		5.23	293.70	1	293.70
71914032812		1	TX31340	NULL	OH Transformer	3M8	Equipment failure	03-Jul-14	0:47	03-Jul-14	8:43	476	12	5712	A3-LEA		5.11	95.20	1	95.20
70714041209		1	TX7P528	NULL	UG Transformer	24M9	Scheduled Outage	07-Jul-14	10:30	07-Jul-14	10:42	12	8	96	A7-LAS		1	1.60	0	0.00
73114020356		1	TX31134	NULL	OH Transformer	3M8	Equipment failure	20-Jul-14	9:32	20-Jul-14	13:10	218	13	2834	A3-LEA		5.12	47.23	1	47.23
72414095427		1	FS35H55	NULL	Switch	3M8	Lightning	23-Jul-14	3:35	23-Jul-14	7:40	245	42	10290	A3-LEA		6	171.50	1	171.50
72414095427		2	TX3133	NULL	Switch	3M8	Lightning	23-Jul-14	3:35	23-Jul-14	11:15	460	16	7360	A3-LEA		6	122.67	1	122.67
								To Date 2014										**6699.82**	**13.00**	**3936.50**

Feeder 3M3

outage_id	Restore_Step	from Restore_Device	to_restore_device	Device	Feeder	Cause	DtOut	TmOut	DtRes	TmRes	Duration	NumCust	SubCustMin	AREA_TOWN	Equipment_code	Customer Hours	Modifier	Customer Hours Modified
0304	1	LEA-36X		Fused Disconnect	3M3	Scheduled Outage	04-Nov-08	9:30	04-Nov-08	15:00	330	1	330	A3-LEA	2	5.50	1	5.50
							Total 2008									**5.50**	**1.00**	**5.50**
052812111119	1	TX31184		OH Transformer	3M3	Scheduled Outage	28-May-12	11:05	28-May-12	11:20	15	18	270	A3-LEA	1	4.50	0	0.00
							Total 2012									**4.50**	**0.00**	**0.00**
72213025117	1	LEA-36X	NULL	Switch	3M3	Lightning	20-Jul-13	10:11	20-Jul-13	20:00	589	1	589	A3-LEA	4	9.82	1	9.82
							Total 2013									**9.82**	**1.00**	**9.82**

Feeder 3M4

outage_id	Restore_Step	from Restore_Device	to_restore_device	Device	Feeder	Cause	DtOut	TmOut	DtRes	TmRes	Duration	NumCust	SubCustMin	AREA_TOWN	Equipment_code	Customer Hours	Modifier	Customer Hours Modified
A0017	1	O/H Service		Fused Disconnect	3M4	Equipment failure	08-Jan-08	9:05	08-Jan-08	11:06	121.2	1	121.2	A3-LEA	5.13	2.02	1	2.02
A0021	1	O/H Service		None	3M4	Wind	30-Jan-08	7:40	30-Jan-08	9:00	139.8	1	139.8	A3-LEA	6	2.33	1	2.33
A0029	1	FS35H36		Fused Disconnect	3M4	Tree growth	18-May-08	3:02	18-May-08	5:00	118.2	1	118.2	A3-LEA	3.1	0.00	0	0.00
A0127	1	O/H service		None	3M4	Equipment failure	01-Jun-08	13:30	01-Jun-08	15:30	120	1	120	A3-LEA	5.92	2.00	1	2.00
A0131	1	TX31084		None	3M4	Equipment failure	06-Jun-08	2:15	06-Jun-08	4:20	125	6	750	A3-LEA	5.5	0.00	0	0.00
A0131	2	Service		None	3M4	Equipment failure	06-Jun-08	2:15	06-Jun-08	10:45	510	1	510	A3-LEA	5.5	8.50	1	8.50
A0119	1	SERVICE		Other	3M4	Tree growth	08-Jun-08	18:40	08-Jun-08	20:30	110	1	110	A3-LEA	6	1.83	1	1.83
A0237	1	FS35H36		Fused Disconnect	3M4	Animal	10-Aug-08	3:45	10-Aug-08	5:30	105	2	210	A3-LEA	9.2	0.00	0	0.00
0129	1	TX31187		Transformer Fuse	3M4	Equipment failure	01-Nov-08	16:30	01-Nov-08	19:00	150	5	750	A3-LEA	5.6	0.00	0	0.00
A0113	1	TX31345		None	3M6	Tree growth	06-Jun-08	22:30	06-Jun-08	0:45	135	10	1350	A3-LEA	3.1	22.50	0	0.00
0308	1	FS304H8		Fused Disconnect	3M4	Equipment failure	21-Nov-08	11:02	21-Nov-08	1:30	148	32	4736	A3-LEA	5.6	78.93	1	78.93
							Total 2008									**118.12**	**6.00**	**95.62**
0312	1	LEA-22X		Other	3M4	Equipment failure	03-Jan-09	16:30	03-Jan-09	18:45	135	47	6345	A3-LEA	5.3	105.75	1	105.75
0313	1	TX30362		Secondary Conductor	3M4	Animal	11-Jan-09	9:30	11-Jan-09	13:15	225	11	2475	A3-LEA	9.2	41.25	1	41.25
0480	1			Service	3M4	Equipment failure	14-May-09	7:30	14-May-09	14:30	420	1	420	A3-LEA	5.93	7.00	1	7.00
0683	1	LEA-40X		Other	3M4	Lightning	25-Jun-09	5:00	25-Jun-09	8:00	180	345	62100	A3-LEA	4	1035.00	1	1035.00
0805	1	TX31223		Other	3M4	Equipment failure	20-Jul-09	22:26	20-Jul-09	23:45	79	2	158	A3-LEA	5.12	2.63	1	2.63
0710	1	TX31071		Other	3M4	Tree growth	29-Aug-09	17:55	29-Aug-09	20:15	140	20	2800	A3-LEA	3.1	46.67	1	46.67
1020090940	1	Service		Service	3M4	Equipment failure	20-Sep-09	13:31	20-Sep-09	15:30	119	1	119	A3-LEA	5.5	1.98	1	1.98
							Total 2009									**1240.28**	**7.00**	**1240.28**
0714101119	1	Service		Service	3M4	Tree falling	11-May-10	12:09	11-May-10	15:30	201	1	201	A3-LEA	3.2	3.35	1	3.35
0513100927	1	TX31104	TX31104	OH Transformer	3M4	Scheduled Outage	16-May-10	5:30	16-May-10	11:00	330	2	660	A3-LEA	1	0.00	0	0.00
072810012743	1	3M4		Station Breaker	3M4	Storm	06-Jun-10	3:15	06-Jun-10	6:34	199	1163	231437	A3-LEA	6	3857.28	1	3857.28
0610100130	1	TX31292	TX31292	OH Transformer	3M4	Storm	10-Jun-10	13:30	10-Jun-10	16:30	180	11	1980	A3-LEA	6	33.00	1	33.00
0714101044	1	LEA-23X	TX31456	Unknown	3M4	Equipment failure	13-Jun-10	11:00	13-Jun-10	13:10	130	150	19500	A3-LEA	5.6	325.00	1	325.00
0714101109	1	tx31431		OH Transformer	3M4	Equipment failure	24-Jun-10	17:25	24-Jun-10	21:00	215	33	7095	A3-LEA	5.11	118.25	1	118.25
0714101110	1	tx31456		OH Transformer	3M4	Animal	03-Jul-10	22:00	04-Jul-10	1:25	205	1	205	A3-LEA	9.2	3.42	1	3.42
081610020232	1	pole conn		Pole	3M4	Tree falling	23-Jul-10	18:00	24-Jul-10	18:45	1485	1	1485	A3-LEA	6	24.75	1	24.75
081610020310	1	pole conn		Pole	3M4	Tree falling	23-Jul-10	18:00	24-Jul-10	16:00	1320	1	1320	A3-LEA	6	22.00	1	22.00
081610020324	1	pole conn		Pole	3M4	Tree falling	23-Jul-10	18:00	24-Jul-10	14:30	1230	1	1230	A3-LEA	6	20.50	1	20.50
081610020335	1	pole conn		Pole	3M4	Tree falling	23-Jul-10	18:00	24-Jul-10	14:30	1230	1	1230	A3-LEA	6	20.50	1	20.50
081610020317	1	pole conn		Pole	3M4	Tree falling	23-Jul-10	18:00	24-Jul-10	13:00	1140	1	1140	A3-LEA	6	19.00	1	19.00
081610020340	1	pole conn		Pole	3M4	Tree falling	23-Jul-10	18:00	24-Jul-10	12:30	1110	1	1110	A3-LEA	6	18.50	1	18.50
081610020250	1	pole conn		Pole	3M4	Tree falling	23-Jul-10	18:00	24-Jul-10	10:00	960	1	960	A3-LEA	6	16.00	1	16.00
081610020155	1	tx31430		OH Transformer	3M4	Tree falling	23-Jul-10	1:00	23-Jul-10	1:30	30	16	480	A3-LEA	6	8.00	1	8.00
081610020238	1	pole conn		Pole	3M4	Tree falling	23-Jul-10	18:00	23-Jul-10	23:30	330	1	330	A3-LEA	6	5.50	1	5.50
081610020148	1	tx31428		OH Transformer	3M4	Storm	24-Jul-10	8:00	24-Jul-10	11:00	180	1	180	A3-LEA	6	3.00	1	3.00
0427101240	1	LEA23X	Tx31229	OH Transformer	3M6	Equipment failure	02-Apr-10	22:15	03-Apr-10	2:15	240	26	6240	A3-LEA	5.15	104.00	1	104.00
111710091837	1	fs304h4		Switch	3M4	Storm	27-Oct-10	20:00	27-Oct-10	22:45	165	76	12540	A3-LEA	3.2	209.00	1	209.00
							Total 2010									**4811.05**	**18.00**	**4811.05**
020711100934	1	TX31037	TX31531	OH Transformer	3M4	Scheduled Outage	07-Feb-11	10:08	07-Feb-11	11:05	57	8	456	A3-LEA	1	7.60	0	0.00
072511040029	1	Service		Service	3M4	Tree falling-weather	21-Jun-11	22:00	22-Jun-11	13:30	930	1	930	A3-LEA	3.2	15.50	1	15.50
071111124532	1	service		Service	3M4	Tree falling	21-Jun-11	22:00	22-Jun-11	0:35	155	1	155	A3-LEA	3.2	2.58	1	2.58
071111030310	1	LEA-23X		Switch	3M4	Animal	26-Jun-11	21:30	26-Jun-11	22:40	70	150	10500	A3-LEA	9.2	175.00	1	175.00
072711015546	1	TX30582		UG Transformer	3M4	Equipment failure	21-Jul-11	18:45	22-Jul-11	5:30	645	27	17415	A3-LEA	5.23	290.25	1	290.25
082211103659	1	TX31345		OH Transformer	3M4	Lightning	20-Aug-11	19:00	20-Aug-11	22:00	180	10	1800	A3-LEA	4	30.00	1	30.00
010212100505	1	Kingsville TS		Station Breaker	3M4	Loss of supply	08-Aug-11	9:54	08-Aug-11	9:59	5	1187	5935	A3-LEA	2	98.92	0	0.00
101911025248	1	FS35H38		Switch	3M4	Scheduled Outage	10/21/2011	10/28/2011 9:14:00 AM	10/21/2011	10/28/2011 2:12:00 PM	298	180	53640	A3-LEA	1	894.00	0	0.00
110411034914	1	FS35H50		Switch	3M4	Animal	10/23/2011	10:20	10/23/2011	17:30	430	53	22790	A3-LEA	9.2	379.83	1	379.83
							Total 2011									**1893.68**	**6.00**	**893.17**

010213013142	1	LEA23X		Switch	3M4	Equipment failure	25-Dec-12	11:30	25-Dec-12	14:00	150	147	22050	A3-LEA	5.6	367.50	1	367.50
041012084330	1	TX31313		OH Transformer	3M4	Scheduled Outage	10-Apr-12	7:00	10-Apr-12	11:55	295	16	4720	A3-LEA	5.11	78.67	1	78.67
050912030037	1	TX31101		OH Transformer	3M4	Scheduled Outage	09-May-12	14:01	09-May-12	14:57	56	24	1344	A3-LEA	4	22.40	1	22.40
052912094816	1	Station Breaker		Station Breaker	3M4	Scheduled Outage	29-May-12	9:39	29-May-12	10:40	61	1188	72468	A3-LEA	2	1207.80	0	0.00
061812015735	1	TX31345		OH Transformer	3M4	Lightning	17-Jun-12	20:20	17-Jun-12	21:50	90	10	900	A3-LEA	4	15.00	1	15.00
070612030637	1			Service	3M4	Equipment failure	01-Jul-12	10:10	01-Jul-12	18:30	500	1	500	A3-LEA	5.92	8.33	1	8.33
070912031010	1	TX32402		OH Transformer	3M4	Equipment failure	02-Jul-12	22:30	03-Jul-12	5:00	390	27	10530	A3-LEA	5.12	175.50	1	175.50
072012023255	1	PMH3250		UG switch unit	3M4	Other	18-Jul-12	7:10	18-Jul-12	12:30	320	47	15040	A3-LEA	7	250.67	1	250.67
080712012346	1	TX31345		OH Transformer	3M4	Tree growth	05-Aug-12	23:40	06-Aug-12	2:30	170	10	1700	A3-LEA	3.1	28.33	1	28.33
080712013957	1	Service		Service	3M4	Tree growth	05-Aug-12	11:30	05-Aug-12	13:30	120	1	120	A3-LEA	3.2	2.00	1	2.00
100912110052	1	TX31497		OH Transformer	3M4	Other	08-Oct-12	10:53	08-Oct-12	13:30	157	23	3611	A3-LEA	0.1	60.18	1	60.18
100912110101	1	SW30006		Switch	3M4	Equipment failure	08-Oct-12	14:52	08-Oct-12	16:50	118	30	3540	A3-LEA	5.6	59.00	1	59.00
103012021609	1	Service		Service	3M4	Scheduled Outage	30-Oct-12	9:01	30-Oct-12	12:00	179	1	179	A3-LEA	3.2	2.98	1	2.98
110212101953	1	Station Breaker		Station Breaker	3M4	Scheduled Outage	02-Nov-12	9:23	02-Nov-12	10:08	45	5225	235125	A3-LEA	2	3918.75	0	0.00
110912100353	1	Station Breaker		Station Breaker	3M4	Loss of supply	29-Oct-12	22:46	29-Oct-12	22:48	2	1236	2472	A3-LEA	2	41.20	0	0.00
110912100356	1	Station Breaker		Station Breaker	3M4	Loss of supply	30-Oct-12	5:21	30-Oct-12	5:23	2	1236	2472	A3-LEA	2	41.20	0	0.00
111612081705	1	FS34H12		Switch	3M4	Scheduled Outage	16-Nov-12	9:00	16-Nov-12	13:46	286	107	30602	A3-LEA	1	510.03	1	510.03
							Total 2012									**6789.55**	**13.00**	**1580.60**
13113093323	1	TX31226	NULL	OH Transformer	3M4	Equipment failure	30-Jan-13	11:45	30-Jan-13	15:15	210	1	210	A3-LEA	5.11	3.50	1	3.50
60613083705	1	TX31331	NULL	OH Transformer	3M4	Scheduled Outage	06-Jun-13	10:00	06-Jun-13	13:30	210	15	3150	A3-LEA	1	52.50	0	0.00
71613075159	1	SERVICE	NULL	Service	3M4	Tree falling	13-Jul-13	13:28	13-Jul-13	20:15	407	23	9361	A3-LEA	3.2	156.02	1	156.02
72213023310	1	SERVICE	NULL	Service	3M4	Equipment failure	21-Jul-13	17:30	21-Jul-13	19:45	135	1	135	A3-LEA	5.17	2.25	1	2.25
91313083633	1	LEA-32	FS30021	Switch	3M4	Scheduled Outage	17-Sep-13	6:30	17-Sep-13	7:15	45	35	1575	A3-LEA	1	26.25	0	0.00
111913083102	1	TX30582	NULL	UG Transformer	3M4	Scheduled Outage	19-Nov-13	9:00	19-Nov-13	12:30	210	27	5670	A3-LEA	1	94.50	0	0.00
112713115345	1	TX3P138	NULL	UG Transformer	3M4	Scheduled Outage	26-Nov-13	13:00	26-Nov-13	14:35	95	15	1425	A3-LEA	1	23.75	0	0.00
							Total 2013									**11781.67**	**20.00**	**2374.57**
10914014422	1	TX30582	NULL	UG Transformer	3M4	Scheduled Outage	09-Jan-14	13:45	09-Jan-14	14:47	62	27	1674	A3-LEA	1	27.90	0	0.00
12814100024	1	FS3H120	TX30362	Switch	3M4	Equipment failure	28-Jan-14	9:33	28-Jan-14	12:11	158	109	17222	A3-LEA	5.11	287.03	1	287.03
50514092826	1	3M4	NULL	Station Breaker	3M4	Loss of supply	03-May-14	14:17	03-May-14	14:19	2	1253	2506	A3-LEA	2	41.77	0	0.00
50514085257	1	TX31343	NULL	OH Transformer	3M4	Equipment failure	04-May-14	13:37	04-May-14	17:05	208	10	2080	A3-LEA	5.12	34.67	1	34.67
							To Date 2014									**19321.35**	**38.00**	**4438.63**

Feeder 3M6

outage_id	Restore_Step	from Restore_Device	to_restore_device	Device	Feeder	Cause	DtOut	TmOut	DtRes	TmRes	Duration	NumCust	SubCustMin	AREA_TOWN	Equipment_code	Customer Hours	Modifier	Customer Hours Modified
A0022	1	TX31357		None	3M6	Wind	30-Jan-08	8:30	30-Jan-08	11:16	166.2	12	1994.4	A3-LEA	6	33.24	1	33.24
A0018	1	TX31306		None	3M6	Wind	30-Jan-08	2:14	30-Jan-08	3:30	76.2	17	1295.4	A3-LEA	6	21.59	1	21.59
A0019	1	O/H service		None	3M6	Tree falling	30-Jan-08	2:31	30-Jan-08	5:00	148.8	1	148.8	A3-LEA	3.2	2.48	1	2.48
A0020	1	O/H service		None	3M6	Wind	30-Jan-08	4:54	30-Jan-08	6:00	66	1	66	A3-LEA	6	1.10	1	1.10
A0023	1	FS30005		Fused Disconnect	3M6	Animal	09-Feb-08	9:14	09-Feb-08	10:30	76.2	177	13487.4	A3-LEA	9.2	224.79	1	224.79
A0024	1	TX30046		Transformer Fuse	3M6	Equipment failure	11-Feb-08	16:56	11-Feb-08	18:30	94.2	6	565.2	A3-LEA	5.28	9.42	1	9.42
A0026	1	U/G secondary		Secondary Conductor	3M6	Equipment failure	19-Apr-08	9:45	19-Apr-08	11:00	75	1	75	A3-LEA	5.5	1.25	1	1.25
A0027	1	FS35H36		Fused Disconnect	3M6	Equipment failure	21-Apr-08	11:30	21-Apr-08	12:45	75	1	75	A3-LEA	5.6	1.25	1	1.25
A0028	1	U/G secondary		Secondary Conductor	3M6	Equipment failure	27-Apr-08	10:23	27-Apr-08	11:30	67.2	1	67.2	A3-LEA	5.5	1.12	1	1.12
A0113	1	TX31345		None	3M6	Tree growth	06-Jun-08	22:30	06-Jun-08	0:45	135	10	1350	A3-LEA	3.1	0.00	0	0.00
A0121	1	TX31258		None	3M6	Equipment failure	08-Jun-08	13:30	08-Jun-08	15:30	120	8	960	A3-LEA	5.12	16.00	1	16.00
A0130	1	TX31204		None	3M6	Equipment failure	09-Jun-08	18:15	09-Jun-08	9:30	75	16	1200	A3-LEA	5.15	20.00	1	20.00
A0145	1	SERVICE		None	3M6	Scheduled Outage	19-Jun-08	17:50	19-Jun-08	20:30	160	1	160	A3-LEA	1	2.67	1	2.67
A0179	1	SERVICE		None	3M6	Scheduled Outage	19-Jun-08	17:50	19-Jun-08	20:30	160	1	160	A3-LEA	1	2.67	1	2.67
A0114	1	TX31254		None	3M6	Animal	20-Jun-08	8:30	20-Jun-08	10:30	120	8	960	A3-LEA	9.2	16.00	1	16.00
A0125	1	SERVICE		None	3M6	Equipment failure	21-Jun-08	20:30	21-Jun-08	21:30	60	1	60	A3-LEA	5.5	1.00	1	1.00
A0182	1	SERVICE		None	3M6	Equipment failure	01-Jul-08	5:30	01-Jul-08	6:45	75	1	75	A3-LEA	5.28	1.25	1	1.25
A0260	1	FS35H36		Fused Disconnect	3M6	Tree growth	10-Aug-08	3:45	10-Aug-08	5:30	105	4	420	A3-LEA	3.1	7.00	1	7.00
0159	1	SERVICE		Secondary Conductor	3M6	Equipment failure	15-Sep-08	15:45	15-Sep-08	17:40	115	1	115	A3-LEA	5.6	1.92	1	1.92
0108	1	FS31H41		Fused Disconnect	3M6	Tree falling	18-Sep-08	1:40	18-Sep-08	7:30	350	102	35700	A3-LEA	3.1	595.00	1	595.00
0251	1	3M6 Feeder		Other	3M6	Loss of supply	29-Sep-08	19:45	29-Sep-08	22:10	145	3319	481255	A3-LEA	6	8020.92	0	0.00
0253	1	LEA-13X		Fused Disconnect	3M6	Other	14-Oct-08	18:37	14-Oct-08	20:00	83	30	2490	A3-LEA	5.6	41.50	1	41.50
0307	1	TX31172		Other	3M6	Equipment failure	15-Nov-08	14:00	15-Nov-08	16:15	135	2	270	A3-LEA	5.6	4.50	1	4.50
0456	1	SERVICE		Other	3M6	Equipment failure	23-Nov-08	18:40	23-Nov-08	19:15	35	1	35	A3-LEA	5.6	0.58	1	0.58
0457	1	LEA-44X		Other	3M6	Scheduled Outage	01-Dec-08	1:00	01-Dec-08	11:30	630	32	20160	A3-LEA	1	336.00	1	336.00
0459	1	FS35H36		Other	3M6	Animal	17-Dec-08	7:50	17-Dec-08	8:45	55	2	110	A3-LEA	9.2	1.83	1	1.83
0461	1	3M6		Other	3M6	Tree growth	21-Dec-08	10:15	21-Dec-08	11:20	65	3579	232635	A3-LEA	3.1	3877.25	1	3877.25
0461	2	TX31249		Other	3M6	Tree growth	21-Dec-08	10:15	21-Dec-08	12:30	135	21	2835	A3-LEA	3.1	47.25	1	47.25
0465	1	Service		Other	3M6	Equipment failure	27-Dec-08	9:50	27-Dec-08	18:00	490	1	490	A3-LEA	5.92	8.17	1	8.17
0464	1	Service		Other	3M6	Equipment failure	29-Dec-08	9:30	29-Dec-08	11:30	120	1	120	A3-LEA	5.92	2.00	1	2.00
							Total 2008									**13299.74**	**28.00**	**5278.82**
0314	1	TX31263		Other	3M6	Equipment failure	02-Feb-09	6:15	02-Feb-09	7:45	90	8	720	A3-LEA	5.24	12.00	1	12.00
0468	1	3M6		T.S. Breaker	3M6	Loss of supply	12-Feb-09	2:30	12-Feb-09	2:37	7	3912	27384	A3-LEA	2	456.40	0	0.00
0352	1				3M6	Tree falling	23-Mar-09	19:25	23-Mar-09	21:15	110	1	110	A3-LEA	3.1	1.83	1	1.83
0770	1	LEA-10X		Other	3M6	Equipment failure	12-May-09	14:00	12-May-09	14:30	30	73	2190	A3-LEA	5.2	36.50	1	36.50
0482	1	Service		Service	3M6	Equipment failure	13-May-09	16:20	13-May-09	18:30	130	1	130	A3-LEA	5.5	2.17	1	2.17
0687	1	Service		Secondary Conductor	3M6	Tree falling	25-Jun-09	22:00	26-Jun-09	14:00	960	1	960	A3-LEA	3.2	16.00	1	16.00
0803	1	TX37492		Transformer Fuse	3M6	Equipment Failure	25-Jun-09	5:00	25-Jun-09	6:00	60	12	720	A3-LEA	6	12.00	1	12.00
0808	1	3M6		Other	3M6	Loss of supply	02-Aug-09	22:00	02-Aug-09	22:05	5	3915	19575	A3-LEA	2	326.25	0	0.00
0668	1	Service		Other	3M6	Tree growth	08-Sep-09	2:05	08-Sep-09	5:30	205	1	205	A3-LEA	3.1	3.42	1	3.42
0056	1	TX31277		Other	3M6	Equipment failure	09-Sep-09	20:00	09-Sep-09	22:00	120	1	120	A3-LEA	5.15	2.00	1	2.00
0273	1	LEA-13X		Other	3M6	Animal	12-Sep-09	17:45	12-Sep-09	19:30	105	36	3780	A3-LEA	9.2	63.00	1	63.00
0930090907	1	TX30058		UG Transformer	3M6	Equipment failure	16-Sep-09	15:00	16-Sep-09	17:30	150	7	1050	A3-LEA	5.5	17.50	1	17.50
0114101123	1	TX31303		UG Transformer	3M6	Human error	24-Sep-09	16:00	24-Sep-09	20:30	270	8	2160	A3-LEA	8	36.00	1	36.00
1019090343	1	3M6		Station Breaker	3M6	Loss of supply	28-Sep-09	4:00	28-Sep-09	5:45	105	3754	394170	A3-LEA	2	6569.50	0	0.00
1021090153	1	LEA-13X	LEA-13X	Switch	3M6	Animal	21-Oct-09	13:00	21-Oct-09	18:30	330	24	7920	A3-LEA	9.2	132.00	1	132.00
1222090346	1	Meter Base		Meter	3M6	Equipment failure	29-Oct-09	20:32	29-Oct-09	23:00	148	1	148	A3-LEA	5.93	2.47	1	2.47
1223090156	1	TX31306		OH Transformer	3M6	Equipment failure	09-Dec-09	18:25	09-Dec-09	19:45	80	18	1440	A3-LEA	5.12	24.00	1	24.00
1211091032	1	SERVICE	SERVICE	Service	3M6	Other	10-Dec-09	15:30	10-Dec-09	16:40	70	1	70	A3-LEA	5.17	1.17	1	1.17
1223090150	1	Service		Service	3M6	Equipment failure	13-Dec-09	9:30	13-Dec-09	11:30	120	1	120	A3-LEA	5.92	2.00	1	2.00
0114100320	1	TX31261		OH Transformer	3M6	Equipment failure	31-Dec-09	2:45	31-Dec-09	4:00	75	10	750	A3-LEA	5.12	12.50	1	12.50
							Total 2009									**7728.70**	**17.00**	**376.55**

0108101117	1	FS31H49	FS31H49	Switch	3M6	Equipment failure	08-Jan-10	9:15	08-Jan-10	11:45	150	19	2850	A3-LEA	5.6	47.50	1	47.50
0119100100	1	FS35H34	TX30128	UG Transformer	3M6	Equipment failure	19-Jan-10	12:45	19-Jan-10	14:00	75	168	12600	A3-LEA	5.23	210.00	1	210.00
0202100906	1	TX31214		OH Transformer	3M6	Equipment failure	23-Jan-10	9:00	23-Jan-10	12:00	180	5	900	A3-LEA	5.15	15.00	1	15.00
0210101109	1	TX31525		OH Transformer	3M6	Scheduled Outage	10-Feb-10	11:08	10-Feb-10	11:40	32	21	672	A3-LEA	1	11.20	0	0.00
0212101013	1	TX30024	TX30024	UG Transformer	3M6	Scheduled Outage	12-Feb-10	10:30	12-Feb-10	12:00	90	11	990	A3-LEA	1	16.50	0	0.00
0212100112	1	TX30091	SC30110	UG Transformer	3M6	Scheduled Outage	12-Feb-10	13:00	12-Feb-10	13:30	30	4	120	A3-LEA	1	2.00	0	0.00
0217101001	1	TX30077	TX30077	UG Transformer	3M6	Scheduled Outage	17-Feb-10	10:30	17-Feb-10	11:35	65	4	260	A3-LEA	1	4.33	0	0.00
0217100125	1	TX31045	TX31525	OH Transformer	3M6	Scheduled Outage	17-Feb-10	13:15	17-Feb-10	13:35	20	6	120	A3-LEA	1	2.00	0	0.00
0223101024	1	TX30025	TX30025	UG Transformer	3M6	Scheduled Outage	23-Feb-10	10:30	23-Feb-10	11:45	75	9	675	A3-LEA	1	11.25	0	0.00
0322100755	2	TX31366	FS35H25	Switch	3M6	Equipment failure	10-Mar-10	2:50	10-Mar-10	6:05	195	142	27690	A3-LEA	5.24	461.50	1	461.50
0322100755	1	FS35H30	TX31366	Switch	3M6	Equipment failure	10-Mar-10	2:50	10-Mar-10	5:45	175	28	4900	A3-LEA	5.24	81.67	1	81.67
0316101112	1	FS33H65	FS33H65	Switch	3M6	Scheduled Outage	16-Mar-10	10:53	16-Mar-10	13:26	153	35	5355	A3-LEA	1	89.25	0	0.00
0316100304	1	TX31047	TX31047	OH Transformer	3M6	Scheduled Outage	19-Mar-10	9:00	19-Mar-10	11:15	135	14	1890	A3-LEA	1	31.50	0	0.00
0429100328	1	Service	service	Service	3M6	Equipment failure	01-Apr-10	15:30	01-Apr-10	19:30	240	1	240	A3-LEA	5.92	4.00	1	4.00
0427101240	1	LEA23X	Tx31229	OH Transformer	3M6	Equipment failure	02-Apr-10	22:15	03-Apr-10	2:15	240	26	6240	A3-LEA	5.15	0.00	0	0.00
0416100828	1	FS31H58	FS31H58	Switch	3M6	Scheduled Outage	23-Apr-10	9:30	23-Apr-10	12:30	180	25	4500	A3-LEA	1	75.00	0	0.00
0429100330	1	tx31229		OH Transformer	3M6	Equipment failure	25-Apr-10	21:30	26-Apr-10	0:00	150	23	3450	A3-LEA	5.92	57.50	1	57.50
0428100830	1	TX31280	TX31280	OH Transformer	3M6	Scheduled Outage	30-Apr-10	9:00	30-Apr-10	13:10	250	26	6500	A3-LEA	1	108.33	0	0.00
0518100935	1	TX31308		OH Transformer	3M6	Equipment failure	03-May-10	3:00	03-May-10	5:30	150	21	3150	A3-LEA	5.93	52.50	1	52.50
0518100133	1	SERVICE	SERVICE	Service	3M6	Equipment failure	19-May-10	10:00	19-May-10	11:00	60	1	60	A3-LEA	5.17	1.00	1	1.00
0714101005	1	Service	service	Service	3M6	Storm	27-May-10	21:35	28-May-10	3:00	325	1	325	A3-LEA	5.91	5.42	1	5.42
0714101017	1	tx31319		OH Transformer	3M6	Human error	27-May-10	16:20	27-May-10	17:00	40	7	280	A3-LEA	9.1	4.67	1	4.67
0714101030	1	Kingsville breaker		Unknown	3M6	Loss of supply	29-May-10	16:50	29-May-10	19:00	130	184	23920	A3-LEA	2	398.67	0	0.00
0714101045	1	TX31233		OH Transformer	3M6	Equipment failure	16-Jun-10	20:29	17-Jun-10	0:45	256	33	8448	A3-LEA	5.11	140.80	1	140.80
0705100950	1	LEA13X	LEA-13X	Unknown	3M6	Scheduled Outage	07-Jul-10	9:00	07-Jul-10	12:30	210	35	7350	A3-LEA	1	122.50	0	0.00
0722101056	1	TX31233	TX31233	OH Transformer	3M6	Scheduled Outage	22-Jul-10	10:50	22-Jul-10	11:07	17	28	476	A3-LEA	1	7.93	0	0.00
081610020211	1	3M6		Station Breaker	3M6	Tree falling-weather	23-Jul-10	19:30	23-Jul-10	21:15	105	3548	372540	A3-LEA	6	6209.00	1	6209.00
081610020303	1	pole conn		Pole	3M6	Tree falling	23-Jul-10	18:00	24-Jul-10	11:30	1050	1	1050	A3-LEA	6	17.50	1	17.50
081610020204	1	tx31211		OH Transformer	3M6	Tree falling	23-Jul-10	22:30	23-Jul-10	23:00	30	20	600	A3-LEA	6	10.00	1	10.00
081610020244	1	pole conn		Pole	3M6	Tree falling	23-Jul-10	18:00	23-Jul-10	22:45	285	1	285	A3-LEA	6	4.75	1	4.75
081610122145	1	FS31H42		Switch	3M6	Tree growth	24-Jul-10	0:30	24-Jul-10	4:00	210	41	8610	A3-LEA	3.1	143.50	1	143.50
081610020219	1	meter		Meter	3M6	Equipment failure	25-Jul-10	20:00	25-Jul-10	22:00	120	1	120	A3-LEA	5.92	2.00	1	2.00
072710121247	1	PMH32105	PMH32105	UG switch unit	3M6	Equipment failure	27-Jul-10	10:00	27-Jul-10	11:45	105	380	39900	A3-LEA	5.24	665.00	1	665.00
081610121819	1	service		Service	3M6	Equipment failure	27-Jul-10	16:40	27-Jul-10	19:10	150	1	150	A3-LEA	5.92	2.50	1	2.50
081610121636	1	3M6		Station Breaker	3M6	Loss of supply	28-Jul-10	15:30	28-Jul-10	16:43	73	3548	259004	A3-LEA	2	4316.73	0	0.00
081610020139	1	tx31491		OH Transformer	3M6	Animal	31-Jul-10	7:42	31-Jul-10	9:40	118	16	1888	A3-LEA	9.2	31.47	1	31.47
081610020132	1	pmh32105		UG switch unit	3M6	Equipment failure	02-Aug-10	9:35	02-Aug-10	11:15	100	380	38000	A3-LEA	5.7	633.33	1	633.33
081610121750	1	pmh32105		UG switch unit	3M6	Equipment failure	07-Aug-10	9:33	07-Aug-10	13:00	207	380	78660	A3-LEA	5.7	1311.00	1	1311.00
081310093456	1	Pmh32105		UG switch unit	3M6	Equipment failure	13-Aug-10	8:10	13-Aug-10	9:00	50	380	19000	A3-LEA	5.24	316.67	1	316.67
090810103249	1	PMH30125	PMH30125	Unknown	3M6	Equipment failure	24-Aug-10	11:00	24-Aug-10	12:00	60	380	22800	A3-LEA	5.93	380.00	1	380.00
082610094438	1	SC32100	SC32100	UG switch unit	3M6	Scheduled Outage	26-Aug-10	9:45	26-Aug-10	10:00	75	380	28500	A3-LEA	1	475.00	0	0.00
111810015445	3	fs3h320	SC32100	Switch	3M6	Scheduled Outage	26-Aug-10	9:45	26-Aug-10	10:00	15	35	525	A3-LEA	1	8.75	0	0.00
111810014704	2	SC32100	FS3H321	Switch	3M6	Equipment failure	26-Aug-10	9:45	26-Aug-10	10:00	15	34	510	A3-LEA	5.6	8.50	1	8.50
111710091858	1	tx31275		OH Transformer	3M6	Equipment failure	10-Sep-10	8:30	10-Sep-10	15:00	390	6	2340	A3-LEA	5.11	39.00	1	39.00
111710105850	1	lea17x		Switch	3M6	Animal	14-Sep-10	7:00	14-Sep-10	10:00	180	106	19080	A3-LEA	9.2	318.00	1	318.00
111710105844	1	.3m6		Station Breaker	3M6	Equipment failure	20-Sep-10	21:00	20-Sep-10	22:00	60	3732	223920	A3-LEA	5.3	3732.00	1	3732.00
111710105844	2	Lea 44	fs31h43	Station Breaker	3M6	Equipment failure	20-Sep-10	21:00	20-Sep-10	22:45	105	347	36435	A3-LEA	5.3	607.25	1	607.25
111710094710	1	tx30025		UG Transformer	3M6	Equipment failure	25-Sep-10	7:00	25-Sep-10	18:15	675	14	9450	A3-LEA	5.5	157.50	1	157.50
111710105832	1	fs35h36		Switch	3M6	Tree falling	06-Oct-10	3:08	06-Oct-10	5:45	157	2	314	A3-LEA	3.2	5.23	1	5.23
101210030245	1	SERVICE	SERVIC	Meter	3M6	Equipment failure	12-Oct-10	14:00	12-Oct-10	14:30	30	1	30	A1-TEC	5.93	0.50	1	0.50
101410105538	1	TX31248	TX31248	OH Transformer	3M6	Scheduled Outage	14-Oct-10	10:47	14-Oct-10	15:30	283	1	283	A3-LEA	1	4.72	0	0.00
111710091825	1	3m6		Station Breaker	3M6	Tree falling	27-Oct-10	16:00	27-Oct-10	18:00	120	3732	447840	A3-LEA	3.2	7464.00	1	7464.00
011711024003	3	VIC3	LEA-53	Station Breaker	3M6	Equipment failure	20-Dec-10	18:30	20-Dec-10	22:10	220	1747	384340	A3-LEA	5.7	6405.67	1	6405.67
011711024003	2	LEA-62	LEA-53	Station Breaker	3M6	Equipment failure	20-Dec-10	18:30	20-Dec-10	21:50	200	904	180800	A3-LEA	5.7	3013.33	1	3013.33
011711024003	4	LEA-50	LEA-30	Station Breaker	3M6	Equipment failure	20-Dec-10	18:30	21-Dec-10	0:45	375	328	123000	A3-LEA	5.7	2050.00	1	2050.00
011711024003	1	Kings TS	VIC-3	Station Breaker	3M6	Equipment failure	20-Dec-10	18:30	20-Dec-10	20:35	125	753	94125	A3-LEA	5.7	1568.75	1	1568.75
							Total 2010									**41863.67**	**38.00**	**36178.00**

021411032410	1	FS30019		Switch	3M6	Scheduled Outage	14-Feb-11	12:00	14-Feb-11	12:15	15	1	15	A3-LEA	1		0.25	0	0.00
032111093256	1	fs31h41		Switch	3M6	Scheduled Outage	21-Mar-11	8:00	21-Mar-11	15:03	423	119	50337	A3-LEA	1		838.95	0	0.00
032111095628	1	FS3H126		Switch	3M6	Scheduled Outage	21-Mar-11	12:10	21-Mar-11	12:49	39	93	3627	A3-LEA	1		60.45	0	0.00
032911011453	1	FS31H41		Switch	3M6	Scheduled Outage	31-Mar-11	8:00	31-Mar-11	14:30	390	119	46410	A3-LEA	1		773.50	0	0.00
050211094601	1	FS35H32		Switch	3M6	Equipment failure	26-Apr-11	11:00	26-Apr-11	12:15	75	88	6600	A3-LEA		5.23	110.00	1	110.00
060611014305	1	FS35H26		Switch	3M6	Animal	29-May-11	21:45	30-May-11	0:00	135	1	135	A3-LEA	9.2		2.25	1	2.25
062011021727	1	TX31230		OH Transformer	3M6	Other	13-Jun-11	10:20	13-Jun-11	11:00	40	28	1120	A3-LEA	0.1		18.67	1	18.67
071111123217	1	3M6		Station Breaker	3M6	Loss of supply	21-Jun-11	22:00	22-Jun-11	2:05	245	3732	914340	A3-LEA	2		15239.00	1	15239.00
072611073908	1	TX31280		OH Transformer	3M6	Tree falling	21-Jun-11	22:00	22-Jun-11	10:30	750	22	16500	A3-LEA	3.2		275.00	1	275.00
082211034806	1	TX31251		OH Transformer	3M6	Tree falling	21-Jun-11	22:45	22-Jun-11	4:30	345	25	8625	A3-LEA	3.2		143.75	1	143.75
071111014915	1	TX31211		OH Transformer	3M6	Tree growth	21-Jun-11	22:00	22-Jun-11	0:00	120	17	2040	A3-LEA	3.2		34.00	1	34.00
071111122708	1	Service		OH Transformer	3M6	Tree falling	21-Jun-11	22:00	22-Jun-11	2:30	270	1	270	A3-LEA	3.2		4.50	1	4.50
071111011430	1	service		Service	3M6	Tree falling	21-Jun-11	22:00	22-Jun-11	1:30	210	1	210	A3-LEA	3.2		3.50	1	3.50
100511030024	1	TX31211		OH Transformer	3M6	Tree falling-weather	22-Jun-11	22:00	23-Jun-11	11:00	780	17	13260	A3-LEA		3.1	221.00	1	221.00
072611080249	1	FS31H42		Switch	3M6	Equipment failure	26-Jun-11	7:30	26-Jun-11	9:00	90	45	4050	A3-LEA	5.14		67.50	1	67.50
100311033656	1	VIC-1		Switch	3M6	Vehicles	30-Jun-11	19:00	30-Jun-11	20:20	80	2998	239840	A3-LEA	9.1		3997.33	1	3997.33
100311025620	1	Feeder 3M6		Station Breaker	3M6	Vehicles	30-Jun-11	1:45	30-Jun-11	1:55	10	3826	38260	A3-LEA	9.1		637.67	1	637.67
092611035951	1	FS31H43		Switch	3M6	Other	11-Jul-11	17:50	11-Jul-11	21:30	220	1	220	A3-LEA	6		3.67	1	3.67
072811082109	1	FS302H2		Switch	3M6	Lightning	18-Jul-11	20:00	18-Jul-11	20:45	45	11	495	A3-LEA	4		8.25	1	8.25
072911032631	1	TX31259		OH Transformer	3M6	Animal	24-Jul-11	10:00	24-Jul-11	11:45	105	5	525	A3-LEA	9.2		8.75	1	8.75
082211102442	1	FS35H36		Switch	3M6	Lightning	20-Aug-11	19:00	20-Aug-11	21:15	135	2	270	A3-LEA	4		4.50	1	4.50
091211012257	1	TX30298		UG Transformer	3M6	Scheduled Outage	12-Sep-11	11:30	12-Sep-11	16:45	315	16	5040	A3-LEA	9.1		84.00	0	0.00
091211012257	2	TX31421		UG Transformer	3M6	Scheduled Outage	12-Sep-11	16:10	12-Sep-11	16:45	35	14	490	A3-LEA	9.1		8.17	0	0.00
100311015728	1	3M6 Feeder		Station Breaker	3M6	Loss of supply	23-Sep-11	8:50	23-Sep-11	11:45	175	3826	669550	A3-LEA	2		11159.17	0	0.00
100311020609	1	3M6 Feeder		Station Breaker	3M6	Loss of supply	23-Sep-11	14:20	23-Sep-11	14:27	7	3826	26782	A3-LEA	2		446.37	0	0.00
011911010431	1	FS33H61		Switch	3M6	Scheduled Outage	21-Jan-11	15:30	21-Jan-11	16:15	45	74	3330	A3-LEA	1		55.50	0	0.00
101411015459	1	TX31262		OH Transformer	3M6	Equipment failure	27-Jun-11	19:30	27-Jun-11	21:30	120	10	1200	A3-LEA	5.17		20.00	1	20.00
110911031103	1	Kingville TS		Station Breaker	3M6	Loss of supply	02-Nov-11	7:24	02-Nov-11	7:33	9	6783	61047	A3-LEA	2.0		1017.45	0	0.00
110911041807	1	Service		Service	3M6	Equipment failure	17-Oct-11	19:30	17-Oct-11	23:30	240	1	240	A3-LEA	5.5		4.00	0	0.00
112311013342	1	TX31532	TX30005	UG Transformer	3M6	Scheduled Outage	24-Nov-11	9:15	24-Nov-11	13:00	225	15	3375	A3-LEA	1		0.00	0	0.00
112911111909	1	FS31H41		Switch	3M6	Scheduled Outage	29-Nov-11	8:19	29-Nov-11	14:01	342	109	37278	A3-LEA	3.2		621.30	1	621.30
							Total 2011										**35868.43**	**19.00**	**21420.63**
011312115343	1	TX31280		OH Transformer	3M6	Scheduled Outage	13-Jan-12	11:50	13-Jan-12	12:59	69	10	690	A3-LEA	1		11.50	0	0.00
011612083120	1	Service		Service	3M6	Scheduled Outage	16-Jan-12	10:30	16-Jan-12	12:02	92	9	828	A3-LEA	1		13.80	0	0.00
012312105212	1	VIC-1		Station Breaker	3M6	Loss of supply	15-Jan-12	2:31	15-Jan-12	7:51	320	3079	985280	A3-LEA	2		16421.33	0	0.00
030312015552	1	LEA-44X		Switch	3M6	Snow	24-Feb-12	2:30	24-Feb-12	6:30	240	30	7200	A3-LEA	6		120.00	1	120.00
031512083954	1	LAS-7X		Switch	3M6	Scheduled Outage	15-Mar-12	10:10	15-Mar-12	12:45	155	57	8835	A3-LEA	1		147.25	0	0.00
031912101554	1	TX31230		OH Transformer	3M6	Scheduled Outage	19-Mar-12	10:14	19-Mar-12	12:47	153	28	4284	A3-LEA	1		71.40	0	0.00
032012104841	1	TX31087	TX31534	OH Transformer	3M6	Scheduled Outage	20-Mar-12	10:49	20-Mar-12	11:55	66	12	792	A3-LEA	1		0.00	0	0.00
032112104732	1	FS31H52		Switch	3M6	Scheduled Outage	22-Mar-12	9:00	22-Mar-12	11:05	125	24	3000	A3-LEA	1		50.00	1	50.00
041412122229	1	FS35H24		Switch	3M6	Equipment failure	26-Mar-12	16:00	26-Mar-12	20:40	280	23	6440	A3-LEA	5.4		107.33	1	107.33
041512022814	1	Station Breaker		Station Breaker	3M6	Loss of supply	26-Mar-12	19:52	26-Mar-12	19:55	3	3830	11490	A3-LEA	2		191.50	0	0.00
050612104048	1	FS31H42		Switch	3M6	Equipment failure	03-May-12	17:30	03-May-12	20:32	182	45	8190	A3-LEA	5.15		136.50	1	136.50
050612124651	1	Station Breaker		Station Breaker	3M6	Loss of supply	23-Apr-12	11:41	23-Apr-12	11:43	2	3830	7660	A3-LEA	2		127.67	0	0.00
050812010757	1	LEA-10X		Switch	3M6	Scheduled Outage	11-May-12	9:00	11-May-12	10:14	74	62	4588	A3-LEA	1		76.47	0	0.00
051512114747	1	LEA-50		Switch	3M6	Scheduled Outage	15-May-12	11:50	15-May-12	11:51	1	1000	1000	A3-LEA	5.6		16.67	1	16.67
053112095454	1	SEC PED		Pedestal	3M6	Scheduled Outage	31-May-12	10:00	31-May-12	13:45	225	12	2700	A3-LEA	1		0.00	0	0.00
060512024114	1	LEA-9X		Switch	3M6	Scheduled Outage	06-Jun-12	9:30	06-Jun-12	12:42	192	80	15360	A3-LEA	1		256.00	0	0.00
060612011740	1	FS3H126		Switch	3M6	Scheduled Outage	06-Jun-12	13:18	06-Jun-12	13:48	30	98	2940	A3-LEA	5.3		49.00	1	49.00
060812084333	1	FS35H30		Switch	3M6	Other	04-Jun-12	19:43	04-Jun-12	22:20	157	120	18840	A3-LEA	0.1		314.00	1	314.00
062212025625	1	STATION BREAKER		Station Breaker	3M6	Loss of supply	06-May-12	5:06	06-May-12	5:11	5	3802	19010	A3-LEA	2		316.83	0	0.00
062612094638	1	Service		OH Transformer	3M6	Equipment failure	23-Jun-12	10:00	23-Jun-12	12:00	120	1	120	A3-LEA	5.92		2.00	1	2.00
070912030516	1	TX31074		OH Transformer	3M6	Animal	06-Jul-12	16:05	06-Jul-12	19:00	175	1	175	A3-LEA	9.2		2.92	1	2.92
071012021306	1	Service		Service	3M6	Human error	28-Jun-12	18:30	28-Jun-12	22:30	240	1	240	A3-LEA	9.1		4.00	1	4.00
080712013117	1	PMH32110		UG switch unit	3M6	Equipment failure	05-Aug-12	12:54	05-Aug-12	14:15	81	15	1215	A3-LEA	5.24		0.00	1	0.00
082112092828	1	TX31251		OH Transformer	3M6	Scheduled Outage	21-Aug-12	5:30	21-Aug-12	11:34	364	25	9100	A3-LEA	4		151.67	1	151.67
082912123638	1	FS33H61		Switch	3M6	Scheduled Outage	29-Aug-12	13:00	29-Aug-12	13:35	35	256	8960	A3-LEA	1		149.33	0	0.00
091412094335	1	Station Breaker		Station Breaker	3M6	Loss of supply	04-Sep-12	12:32	04-Sep-12	12:34	2	3989	7978	A3-LEA	2		132.97	0	0.00
092012080016	1	LEA7X		Switch	3M6	Scheduled Outage	20-Sep-12	9:35	20-Sep-12	11:06	91	57	5187	A3-LEA	1		86.45	0	0.00
092512092633	1	TX31211		OH Transformer	3M6	Equipment failure	22-Sep-12	14:00	22-Sep-12	17:30	210	17	3570	A3-LEA	5.14		59.50	1	59.50
092512093222	1	TX31337		OH Transformer	3M6	Equipment failure	22-Sep-12	18:30	22-Sep-12	21:00	150	20	3000	A3-LEA	5.14		50.00	1	50.00
100112084319	1	FS35H25		Switch	3M6	Scheduled Outage	01-Oct-12	9:38	01-Oct-12	11:52	134	102	13668	A3-LEA	1		227.80	0	0.00
100912080016	1	LEA-13X		Switch	3M6	Equipment failure	01-Oct-12	22:15	01-Oct-12	22:45	30	33	990	A3-LEA	5.6		0.00	1	0.00
101812084928	1	LEA-10X		Switch	3M6	Scheduled Outage	18-Oct-12	9:32	18-Oct-12	14:00	268	62	16616	A3-LEA	1		276.93	0	0.00
101812090719	1	FS35H34		Switch	3M6	Scheduled Outage	18-Oct-12	12:37	18-Oct-12	14:10	93	170	15810	A3-LEA	1		263.50	0	0.00
102212083953	1	FS31H42		Switch	3M6	Scheduled Outage	22-Oct-12	9:00	22-Oct-12	13:45	285	45	12825	A3-LEA	1		213.75	0	0.00
102512100958	1	TX31529		UG Transformer	3M6	Scheduled Outage	25-Oct-12	9:50	25-Oct-12	13:00	190	14	2660	A3-LEA	1		44.33	0	0.00
102912123516	1	FS35H36		Switch	3M6	Tree growth	28-Oct-12	14:15	28-Oct-12	16:30	135	4	540	A3-LEA	3.1		9.00	1	9.00
103112125039	1	FS35H32		Switch	3M6	Equipment failure	30-Oct-12	13:17	30-Oct-12	17:30	253	76	19228	A3-LEA	5.23		320.47	1	320.47
110212083337	1	TX30079		UG Transformer	3M6	Scheduled Outage	02-Nov-12	9:40	02-Nov-12	13:00	200	8	1600	A3-LEA	1		26.67	0	0.00
110212083915	1	FS35H33		Switch	3M6	Scheduled Outage	02-Nov-12	9:40	02-Nov-12	10:10	30	102	3060	A3-LEA	1		0.00	0	0.00
112112101916	1	Service		Service	3M6	Scheduled Outage	21-Nov-12	10:20	21-Nov-12	14:00	220	4	880	A3-LEA	1		14.67	0	0.00
120412090327	1	FS33L51		OH Transformer	3M6	Animal	29-Nov-12	14:00	29-Nov-12	15:45	105	40	4200	A3-LEA	9.2		70.00	1	70.00
120412090327	2	TX31537		OH Transformer	3M6	Animal	29-Nov-12	14:00	29-Nov-12	15:55	115	25	2875	A3-LEA	9.2		47.92	1	47.92
122112021646	1	TX31306		OH Transformer	3M6	Equipment failure	20-Dec-12	22:15	21-Dec-12	5:00	405	18	7290	A3-LEA	5.11		121.50	1	121.50
H0850	1	Station Breaker		Other	3M6	AUTO RECLOSURE	07-Mar-12	13:33	07-Mar-12	13:34	1	3830	3830	A3-LEA	2		63.83	0	0.00
							Total 2012										**20766.45**	**20.00**	**1632.47**

10313091109	1	TX31056	NULL	OH Transformer	3M6	Scheduled Outage	03-Jan-13	9:00	03-Jan-13	10:26	86	23	1978	A3-LEA	1	32.97	0	0.00
20613021030	1	LEA-9X	NULL	Switch	3M6	Scheduled Outage	06-Feb-13	11:24	06-Feb-13	12:45	81	80	6480	A3-LEA	5.13	108.00	1	108.00
30813030416	1	FS35H34	NULL	Switch	3M6	Scheduled Outage	08-Mar-13	15:30	08-Mar-13	16:00	30	162	4860	A3-LEA	5.23	81.00	1	81.00
41213013534	1	TX3A105	NULL	OH Transformer	3M6	Storm	09-Apr-13	16:00	10-Apr-13	13:30	1290	1	1290	A3-LEA	6	21.50	1	21.50
41113014457	1	3M6	NULL	Station Breaker	3M6	Loss of supply	11-Apr-13	9:05	11-Apr-13	9:10	5	3932	19660	A3-LEA	2	327.67	0	0.00
41613074939	1	3M6	NULL	Station Breaker	3M6	Loss of supply	11-Apr-13	8:56	11-Apr-13	9:06	10	3932	39320	A3-LEA	2	655.33	0	0.00
50813040238	1	TX31542	NULL	OH Transformer	3M6	Animal	06-May-13	6:30	06-May-13	9:00	150	19	2850	A3-LEA	9.2	47.50	1	47.50
52413084124	1	Service	NULL	Service	3M6	Tree falling	23-May-13	19:07	23-May-13	23:00	233	2	466	A3-LEA	3.1	7.77	1	7.77
60513024426	1	SERVICE	NULL	Service	3M6	Tree growth	01-Jun-13	18:15	01-Jun-13	23:15	300	2	600	A3-LEA	3.1	0.00	1	0.00
61713035238	1	TX31249	NULL	OH Transformer	3M6	Animal	08-Jun-13	8:20	08-Jun-13	11:30	190	21	3990	A3-LEA	9.2	66.50	1	66.50
61113124934	1	FS30008	NULL	Switch	3M6	Equipment failure	10-Jun-13	10:51	10-Jun-13	15:30	279	16	4464	A3-LEA	5.24	74.40	1	74.40
70313035821	1	FS35H35	NULL	Switch	3M6	Lightning	28-Jun-13	14:39	28-Jun-13	17:00	141	34	4794	A3-LEA	4	79.90	1	79.90
70413075501	1	TX30035	NULL	UG Transformer	3M6	Lightning	28-Jun-13	20:08	29-Jun-13	0:05	237	10	2370	A3-LEA	4	39.50	1	39.50
70213122025	1	FS35H34	TX30227	Switch	3M6	Lightning	28-Jun-13	13:58	28-Jun-13	17:45	227	170	38590	A3-LEA	4	643.17	1	643.17
70213010239	1	LEA-3X	TX30206	Switch	3M6	Scheduled Outage	02-Jul-13	13:20	02-Jul-13	13:50	30	2	60	A3-LEA	2	1.00	0	0.00
70813033430	1	TX30266	FS3H323	Switch	3M6	Lightning	07-Jul-13	4:49	07-Jul-13	10:00	311	64	19904	A3-LEA	4	331.73	1	331.73
72513120925	1	TX31261	NULL	OH Transformer	3M6	Scheduled Outage	25-Jul-13	12:05	25-Jul-13	13:05	60	9	540	A3-LEA	5.17	9.00	1	9.00
80113085400	1	PMH32110	NULL	UG switch unit	3M6	Scheduled Outage	06-Aug-13	16:00	06-Aug-13	21:15	315	126	39690	A3-LEA	1	661.50	0	0.00
81313030437	1	TX3P116	NULL	UG Transformer	3M6	Scheduled Outage	14-Aug-13	9:00	14-Aug-13	14:00	300	6	1800	A3-LEA	1	30.00	0	0.00
81313030756	1	FS35H29	NULL	Switch	3M6	Scheduled Outage	14-Aug-13	9:00	14-Aug-13	10:00	60	123	7380	A3-LEA	1	123.00	0	0.00
82713014637	1	FS35H32	NULL	Switch	3M6	Scheduled Outage	27-Aug-13	13:45	27-Aug-13	13:59	14	75	1050	A3-LEA	1	17.50	0	0.00
82813103322	1	FS35H32	NULL	Switch	3M6	Scheduled Outage	28-Aug-13	9:53	28-Aug-13	10:29	36	75	2700	A3-LEA	1	0.00	0	0.00
82813104642	1	TX30032	TX3P113	UG Transformer	3M6	Scheduled Outage	29-Aug-13	9:00	29-Aug-13	14:00	300	6	1800	A3-LEA	1	30.00	0	0.00
90313025408	1	FS35H32	NULL	Switch	3M6	Scheduled Outage	03-Sep-13	9:00	03-Sep-13	13:44	284	75	21300	A3-LEA	1	355.00	0	0.00
90413123236	1	SERVICE	NULL	Service	3M6	Scheduled Outage	04-Sep-13	12:30	04-Sep-13	13:53	83	6	498	A3-LEA	1	8.30	0	0.00
90413110401	1	FS35H29	NULL	Switch	3M6	Scheduled Outage	05-Sep-13	9:00	05-Sep-13	14:22	322	129	41538	A3-LEA	1	692.30	0	0.00
90913023901	1	FS35H29	TX3P115	Switch	3M6	Scheduled Outage	10-Sep-13	9:00	10-Sep-13	14:00	300	129	38700	A3-LEA	1	645.00	0	0.00
91313084209	1	TX30034	TX3P115	UG Transformer	3M6	Scheduled Outage	13-Sep-13	9:00	13-Sep-13	14:00	300	29	8700	A3-LEA	1	145.00	0	0.00
91313110238	1	TX30035	TX3P117	UG Transformer	3M6	Scheduled Outage	17-Sep-13	9:00	17-Sep-13	11:30	150	10	1500	A3-LEA	1	25.00	0	0.00
91813114139	1	FS35H35	TX3P118	Switch	3M6	Scheduled Outage	19-Sep-13	9:00	19-Sep-13	12:00	180	35	6300	A3-LEA	1	105.00	0	0.00
92413020013	1	TX30108	TX3P117	UG Transformer	3M6	Scheduled Outage	25-Sep-13	9:00	25-Sep-13	14:00	300	6	1800	A3-LEA	1	30.00	0	0.00
92413020518	1	TX30037	TX3P118	UG Transformer	3M6	Scheduled Outage	26-Sep-13	9:00	26-Sep-13	13:00	240	14	3360	A3-LEA	1	56.00	0	0.00
92413015201	1	TX31143	TX30601	OH Transformer	3M6	Scheduled Outage	01-Oct-13	10:17	01-Oct-13	11:30	73	20	1460	A3-LEA	1	24.33	0	0.00
92713112923	1	TX30143	NULL	UG Transformer	3M6	Scheduled Outage	01-Oct-13	9:00	01-Oct-13	13:36	276	12	3312	A3-LEA	1	55.20	0	0.00
101713012156	1	TX30164	NULL	UG Transformer	3M6	Scheduled Outage	17-Oct-13	13:20	17-Oct-13	13:36	16	7	112	A3-LEA	1	0.00	0	0.00
101813105544	1	TX30164	NULL	UG Transformer	3M6	Scheduled Outage	18-Oct-13	10:24	18-Oct-13	10:47	23	7	161	A3-LEA	1	2.68	0	0.00
102313122928	1	TX31054	NULL	OH Transformer	3M6	Scheduled Outage	23-Oct-13	12:30	23-Oct-13	14:05	95	27	2565	A3-LEA	1	42.75	0	0.00
102413010259	1	TX31054	NULL	OH Transformer	3M6	Scheduled Outage	24-Oct-13	13:00	24-Oct-13	14:00	60	27	1620	A3-LEA	1	27.00	0	0.00
103013075429	1	TX31054	TX3P121	UG Transformer	3M6	Scheduled Outage	29-Oct-13	12:34	29-Oct-13	13:24	50	33	1650	A3-LEA	1	27.50	0	0.00
103013010320	1	TX31048	TX3P121	OH Transformer	3M6	Scheduled Outage	30-Oct-13	13:00	30-Oct-13	13:30	30	15	450	A3-LEA	1	7.50	0	0.00
110413105720	1	TX31208	NULL	OH Transformer	3M6	Animal	02-Nov-13	17:00	02-Nov-13	20:00	180	28	5040	A3-LEA	9.2	84.00	1	84.00
111213112205	1	SERVICE	NULL	Service	3M6	Human error	08-Nov-13	7:45	08-Nov-13	14:00	375	1	375	A3-LEA	8	6.25	1	6.25
111313123718	1	TX31054	TX3P122	OH Transformer	3M6	Scheduled Outage	13-Nov-13	11:01	13-Nov-13	12:33	92	27	2484	A3-LEA	1	41.40	0	0.00
111413095813	1	FS33H61	NULL	Switch	3M6	Animal	14-Nov-13	9:32	14-Nov-13	11:33	121	183	22143	A3-LEA	9.2	369.05	1	369.05
120913102954	1	TX31170	NULL	OH Transformer	3M6	Scheduled Outage	09-Dec-13	10:30	09-Dec-13	10:44	14	27	378	A3-LEA	1	6.30	0	0.00
10614123746	1	TX31283	NULL	OH Transformer	3M6	Equipment failure	21-Dec-13	17:00	22-Dec-13	14:30	1290	11	14190	A3-LEA	5.11	236.50	1	236.50
							Total 2013									**6381.00**	**17.00**	**2205.77**
10814010219	1	TX31283	NULL	OH Transformer	3M6	Scheduled Outage	08-Jan-14	13:05	08-Jan-14	13:28	23	11	253	A3-LEA	1	4.22	0	0.00
11714112938	1	LEA-25X	NULL	Switch	3M6	Animal	17-Jan-14	11:11	17-Jan-14	13:07	116	17	1972	A3-LEA	9.2	32.87	1	32.87
21314114318	1	TX31542	NULL	OH Transformer	3M6	Animal	13-Feb-14	11:29	13-Feb-14	12:08	39	19	741	A3-LEA	9.2	12.35	1	12.35
21914103015	1	TX30257	NULL	UG Transformer	3M6	Equipment failure	16-Feb-14	16:57	17-Feb-14	0:00	423	21	8883	A3-LEA	5.23	148.05	1	148.05
30514101602	1	SERVICE	NULL	Service	3M6	Tree falling	28-Feb-14	13:41	28-Feb-14	18:43	302	1	302	A3-LEA	3.2	5.03	1	5.03
50114034052	1	FS31H42	NULL	Switch	3M6	Scheduled Outage	12-Apr-14	19:27	12-Apr-14	20:02	35	45	1575	A3-LEA	9.1	26.25	1	26.25
41714014737	1	TX3P121	NULL	UG Transformer	3M6	Scheduled Outage	16-Apr-14	12:53	16-Apr-14	13:45	52	20	1040	A3-LEA	1	17.33	0	0.00
50614095222	1	TX31264	NULL	OH Transformer	3M6	Scheduled Outage	06-May-14	9:45	06-May-14	9:58	13	11	143	A3-LEA	1	2.38	0	0.00
50914105201	1	TX31264	NULL	OH Transformer	3M6	Scheduled Outage	09-May-14	11:00	09-May-14	11:20	20	11	220	A3-LEA	1	3.67	0	0.00
51214024340	1	LEA-12X	FS303H7	Switch	3M6	Equipment failure	12-May-14	12:15	12-May-14	15:00	165	174	28710	A3-LEA	5.8	478.50	1	478.50
51214024340	2	FS303H7	TX30202	Switch	3M6	Equipment failure	12-May-14	12:15	12-May-14	17:00	285	1	285	A3-LEA	5.8	4.75	1	4.75
51414040730	1	TX31264	NULL	OH Transformer	3M6	Scheduled Outage	13-May-14	13:14	13-May-14	13:55	41	11	451	A3-LEA	1	7.52	0	0.00
53014041131	1	TX30222	NULL	UG Transformer	3M6	Scheduled Outage	02-Jun-14	9:00	02-Jun-14	10:40	100	10	1000	A3-LEA	1	16.67	0	0.00
70614125933	1	TX31265	NULL	OH Transformer	3M6	Lightning	18-Jun-14	20:13	19-Jun-14	0:20	247	11	2717	A3-LEA	4	45.28	1	45.28
70614011649	1	TX31351	NULL	OH Transformer	3M6	Lightning	18-Jun-14	17:51	18-Jun-14	21:18	207	7	1449	A3-LEA	4	24.15	1	24.15
71014113450	1	TX31263	NULL	OH Transformer	3M6	Animal	09-Jul-14	8:44	09-Jul-14	10:35	111	14	1554	A3-LEA	9.2	25.90	1	25.90
							To Date 2014									**854.92**	**10.00**	**803.13**

Feeder 3M8

outage_id	Restore_Step	from Restore_Device	to_restore_device	Device	Feeder	Cause	DtOut	TmOut	DtRes	TmRes	Duration	NumCust	SubCustMin	AREA_TOWN	Equipment_code	Customer Ho	Modifier	tomer Hours M
A0186	1	Service		None	3M8	Tree growth	28-Jun-08	23:00	29-Jun-08	1:30	150	1	150	A3-LEA	3.1	2.50	1	2.50
A0225	1	TX31134		OH Transformer	3M8	Tree growth	05-Aug-08	7:30	05-Aug-08	8:45	75	12	900	A3-LEA	3.1	15.00	1	15.00
0125	1	RE30051		Other	3M8	Lightning	03-Nov-08	9:00	03-Nov-08	12:00	180	752	135360	A3-LEA	4	2256.00	1	2256.00
0256	1	Georgia Sub		Other	3M8	Lightning	03-Nov-08	9:00	03-Nov-08	13:00	240	387	92880	A3-LEA	4	1548.00	1	1548.00
0128	1	TX30125		Transformer Fuse	3M8	Equipment Failure	03-Nov-08	9:30	03-Nov-08	17:15	465	11	5115	A3-LEA	4	85.25	1	85.25
0455	1	SERVICE		Other	3M8	Equipment failure	16-Nov-08	11:45	16-Nov-08	13:00	75	1	75	A3-LEA	5.6	1.25	1	1.25
0149	1	SERVICE CONNECTION		Other	3M8	Equipment failure	19-Nov-08	8:00	19-Nov-08	11:30	210	1	210	A3-LEA	5.6	3.50	1	3.50
							Total 2008									**3911.50**	**7.00**	**3911.50**
0351	1	TX31459		Fused Disconnect	3M8	Equipment failure	09-Feb-09	8:00	09-Feb-09	9:30	90	16	1440	A3-LEA	5.12	24.00	1	24.00
0802	1	Service		Service	3M8	Tree falling	19-Jun-09	15:30	19-Jun-09	18:00	150	1	150	A3-LEA	3.2	2.50	1	2.50
0682	1	TX30301		Other	3M8	Lightning	25-Jun-09	21:00	26-Jun-09	4:00	420	6	2520	A3-LEA	4	42.00	1	42.00
0807	1	TX31180		Transformer Fuse	3M8	Animal	02-Aug-09	7:45	02-Aug-09	9:45	120	4	480	A3-LEA	9.2	8.00	1	8.00
1223091127	1	FS35H54		Switch	3M8	Equipment failure	18-Nov-09	17:30	18-Nov-09	18:30	60	34	2040	A3-LEA	5.92	34.00	1	34.00
1223090110	1	Service		Meter	3M8	Equipment failure	21-Nov-09	10:00	21-Nov-09	12:15	135	1	135	A3-LEA	5.92	2.25	1	2.25
1204090843	1	Service		Service	3M8	Other	04-Dec-09	12:57	04-Dec-09	14:30	93	1804	167772	A3-LEA	3.1	2796.20	1	2796.20
1209090408	1	3M8	3M8	Service	3M8	Wind	09-Dec-09	16:35	09-Dec-09	18:30	115	1804	207460	A3-LEA	6	3457.67	1	3457.67
1223090205	1	Service		Service	3M8	Wind	10-Dec-09	8:00	10-Dec-09	10:45	165	1	165	A3-LEA	6	2.75	1	2.75
1215091156	1	SERVICE	SERVICE	Service	3M8	Equipment failure	15-Dec-09	10:00	15-Dec-09	13:30	210	1	210	A3-LEA	5.17	3.50	1	3.50
							Total 2009									**6372.87**	**10.00**	**6372.87**
0305100244	1	Service		Service	3M8	Equipment failure	13-Feb-10	9:30	13-Feb-10	11:15	105	1	105	A3-LEA	5.92	1.75	1	1.75
0503101057	1	FS33L41	FS33L41	Switch	3M8	Scheduled Outage	10-May-10	9:00	10-May-10	13:00	240	26	6240	A3-LEA	1	104.00	0	0.00
0714101043	1	Service		Service	3M8	Customer equipment	17-May-10	21:00	17-May-10	23:15	135	1	135	A3-LEA	5.92	2.25	1	2.25
0531101107	1	TX31093	TX31093	OH Transformer	3M8	Scheduled Outage	31-May-10	8:45	31-May-10	9:28	43	18	774	A3-LEA	1	12.90	0	0.00
072810012751	2	LEA-31		Station Breaker	3M8	Storm	06-Jun-10	3:15	06-Jun-10	20:40	1045	250	261250	A3-LEA	6	4354.17	1	4354.17
072810012751	1	LEA-31		Station Breaker	3M8	Storm	06-Jun-10	3:15	06-Jun-10	7:04	229	700	160300	A3-LEA	6	2671.67	1	2671.67
072810012751	3	Fs35h18		Station Breaker	3M8	Storm	06-Jun-10	3:15	07-Jun-10	18:05	2330	35	81550	A3-LEA	6	1359.17	1	1359.17
072810012751	4	fs35l83		Station Breaker	3M8	Storm	06-Jun-10	3:15	07-Jun-10	19:40	2425	15	36375	A3-LEA	6	606.25	1	606.25
0610101112	1	TX31448	TX31448	OH Transformer	3M8	Storm	10-Jun-10	11:26	10-Jun-10	19:00	454	31	14074	A3-LEA	6	234.57	1	234.57
0624101034	1	FS35H55	FS35H55	Switch	3M8	Scheduled Outage	24-Jun-10	10:25	24-Jun-10	11:00	35	59	2065	A3-LEA	1	34.42	0	0.00
0714101108	1	fs35h55		Switch	3M8	Tree growth	24-Jun-10	10:25	24-Jun-10	11:00	35	59	2065	A3-LEA	3.1	34.42	1	34.42
0714101111	1	tx31377		OH Transformer	3M8	Equipment failure	04-Jul-10	4:00	04-Jul-10	7:40	220	14	3080	A3-LEA	5.12	51.33	1	51.33
0714101112	3	tx31377		OH Transformer	3M8	Equipment failure	05-Jul-10	6:30	05-Jul-10	10:15	225	14	3150	A3-LEA	5.11	52.50	1	52.50
0714101112	2	tx31377		OH Transformer	3M8	Equipment failure	05-Jul-10	6:30	05-Jul-10	9:45	195	14	2730	A3-LEA	5.11	45.50	1	45.50
0714101112	1	tx31377		OH Transformer	3M8	Equipment failure	05-Jul-10	6:30	05-Jul-10	7:45	75	14	1050	A3-LEA	5.11	17.50	1	17.50
072810111929	1	tx31336		OH Transformer	3M8	Animal	14-Jul-10	8:00	14-Jul-10	9:15	75	18	1350	A3-LEA	9.2	22.50	1	22.50
072810101055	1	TX31377		OH Transformer	3M8	Equipment failure	14-Jul-10	6:30	14-Jul-10	8:05	95	13	1235	A3-LEA	5.12	20.58	1	20.58
0720100223	1	FS35H18	FS35H18	Switch	3M8	Scheduled Outage	22-Jul-10	9:20	22-Jul-10	12:45	205	66	13530	A3-LEA	1	225.50	0	0.00
081610020227	1	pole conn		Pole	3M8	Tree falling	23-Jul-10	18:00	24-Jul-10	12:30	1110	1	1110	A3-LEA	6	18.50	1	18.50
081610020255	1	pole conn		Pole	3M8	Tree falling	23-Jul-10	18:00	24-Jul-10	11:30	1050	1	1050	A3-LEA	6	17.50	1	17.50
072610082331	1	FS35H53	FS35H53	Switch	3M8	Scheduled Outage	27-Jul-10	8:30	27-Jul-10	11:00	150	31	4650	A3-LEA	1	77.50	0	0.00
080910090739	1	KINGSVILLE STATION	KINGSVILLE STATION	Station Breaker	3M8	Loss of supply	28-Jul-10	15:30	28-Jul-10	17:20	110	7004	770440	A3-LEA	2	12840.67	0	0.00
081610122556	1	3M8		Station Breaker	3M8	Loss of supply	28-Jul-10	15:30	28-Jul-10	17:20	110	1452	159720	A3-LEA	2	2662.00	0	0.00
080510105628	1	FS5H42	FS5H42	Switch	3M8	Scheduled Outage	05-Aug-10	11:00	05-Aug-10	11:50	50	19	950	A3-LEA	1	15.83	0	0.00
092210101039	1	service		Service	3M8	Human error	31-Aug-10	17:24	31-Aug-10	19:00	96	1	96	A3-LEA	9.1	1.60	1	1.60
083110015357	1	SW35H20	SW35H20	Switch	3M8	Scheduled Outage	08-Sep-10	10:00	08-Sep-10	12:00	120	445	53400	A3-LEA	1	890.00	0	0.00
090810105112	1	TX30021	TX30021	UG Transformer	3M8	Scheduled Outage	08-Sep-10	10:00	08-Sep-10	10:15	15	9	135	A3-LEA	1	2.25	0	0.00
110310021136	1	LEA31	LEA31	Unknown	3M8	Scheduled Outage	16-Nov-10	9:00	16-Nov-10	15:00	360	780	280800	A3-LEA	1	4680.00	0	0.00
							Total 2010									**31056.82**	**17.00**	**9511.75**

050211094703	1	Service		Service	3M8	Equipment failure	06-Mar-11	11:30	06-Mar-11	13:30	120	1	120	A3-LEA	5.5	2.00	1	2.00
050211094640	1	FS35L83		Switch	3M8	Other	15-Apr-11	14:10	15-Apr-11	16:22	132	36	4752	A3-LEA	0.1	79.20	1	79.20
051211023350	1	SW35H20		Switch	3M8	Lightning	12-May-11	8:30	12-May-11	11:30	180	468	84240	A3-LEA	4	1404.00	1	1404.00
053011033519	1	FS35H55		Switch	3M8	Other	17-May-11	1:10	17-May-11	2:49	99	60	5940	A3-LEA	0.1	99.00	1	99.00
053011034252	1	Service		Service	3M8	Customer equipment	17-May-11	18:07	17-May-11	19:40	93	1	93	A3-LEA	5.92	1.55	1	1.55
060611012413	1	RE50051		Switch	3M8	Other	28-May-11	23:00	29-May-11	1:50	170	752	127840	A3-LEA	0.1	2130.67	1	2130.67
060611014751	1	fs35h95		Switch	3M8	Lightning	29-May-11	2:00	29-May-11	7:45	345	5	1725	A3-LEA	4	28.75	1	28.75
060611035415	1	Tx30352		UG Transformer	3M8	Lightning	30-May-11	14:06	30-May-11	15:40	94	4	376	A3-LEA	4	6.27	1	6.27
061311013820	1	TX31236		OH Transformer	3M8	Animal	04-Jun-11	19:21	04-Jun-11	21:01	100	3	300	A3-LEA	9.2	5.00	1	5.00
071111033015	1	TX31452		OH Transformer	3M8	Tree growth	21-Jun-11	22:00	22-Jun-11	0:45	165	9	1485	A3-LEA	3.1	24.75	1	24.75
092611042606	1	FS35H19		Switch	3M8	Other	11-Jul-11	15:30	11-Jul-11	22:15	405	36	14580	A3-LEA	6	243.00	1	243.00
082211104701	1	TX31236		OH Transformer	3M8	Other	15-Aug-11	16:35	15-Aug-11	19:35	180	3	540	A3-LEA	0.1	9.00	1	9.00
082411042605	1	TX31287		OH Transformer	3M8	Lightning	24-Aug-11	5:15	24-Aug-11	7:25	130	9	1170	A3-LEA	4	19.50	1	19.50
101111103749	1	ICS		Switch	3M8	Scheduled Outage	11-Oct-11	8:28	11-Oct-11	10:32	124	267	33108	A3-LEA	5.6	551.80	0	0.00
110711090733	1	TX31459		OH Transformer	3M8	Other	11-Mar-11	8:30	11-Mar-11	10:15	105	14	1470	A3-LEA	0.1	24.50	1	24.50
111011124716	1	Station Breaker		Station Breaker	3M8	Loss of supply	11-Sep-11	17:30	11-Sep-11	20:20	170	1775	301750	A3-LEA	2	5029.17	0	0.00
120811034444	1	TX31461		OH Conductor	3M8	Equipment failure	12-May-11	23:00	12-Jun-11	3:45	285	3	855	A3-LEA	5.16	14.25	1	14.25
							Total 2011									**9672.40**	**15.00**	**4091.43**
041312101209	1	FS35H59		Switch	3M8	Scheduled Outage	13-Apr-12	9:37	13-Apr-12	13:41	244	4	976	A3-LEA	1	16.27	0	0.00
041412034102	1	TX31236		OH Transformer	3M8	Lightning	31-Mar-12	13:20	31-Mar-12	15:00	100	3	300	A3-LEA	4	5.00	1	5.00
042412125353	1	FS3H102		Switch	3M8	Scheduled Outage	24-Apr-12	12:51	24-Apr-12	13:30	39	75	2925	A3-LEA	1	48.75	0	0.00
050112110431	1	TX30028		UG Transformer	3M8	Scheduled Outage	01-May-12	10:51	01-May-12	15:17	266	9	2394	A3-LEA	1	39.90	0	0.00
051012032213	1	TX3P104		UG Transformer	3M8	Scheduled Outage	14-May-12	9:30	14-May-12	13:30	240	6	1440	A3-LEA	1	24.00	0	0.00
051812084318	1	TX3P102		UG Transformer	3M8	Scheduled Outage	18-May-12	9:00	18-May-12	12:30	210	7	1470	A3-LEA	1	24.50	0	0.00
052312120726	1	TX3P100		UG Transformer	3M8	Scheduled Outage	23-May-12	9:00	23-May-12	13:30	270	9	2430	A3-LEA	1	40.50	0	0.00
052412010130	1	PED-Rear of 4Rickway		Pedestal	3M8	Scheduled Outage	24-May-12	13:01	24-May-12	14:10	69	10	690	A3-LEA	1	11.50	0	0.00
052512095825	1	TX30016		UG Transformer	3M8	Scheduled Outage	25-May-12	10:00	25-May-12	11:58	118	8	944	A3-LEA	1	15.73	0	0.00
052812094050	1	TX30011		UG Transformer	3M8	Scheduled Outage	28-May-12	9:42	28-May-12	11:46	124	4	496	A3-LEA	1	8.27	0	0.00
052912010121	1	secondary pedestal		Pedestal	3M8	Scheduled Outage	29-May-12	13:01	29-May-12	14:05	64	12	768	A3-LEA	1	12.80	0	0.00
060412011541	1	secondary ped		Pedestal	3M8	Scheduled Outage	04-Jun-12	10:10	04-Jun-12	13:21	191	12	2292	A3-LEA	1	38.20	0	0.00
061812014804	1	TX31241		OH Transformer	3M8	Lightning	17-Jun-12	8:20	17-Jun-12	9:20	60	15	900	A3-LEA	4	15.00	1	15.00
061812021055	1	LEA-31		Switch	3M8	Lightning	17-Jun-12	16:46	17-Jun-12	19:25	159	120	19080	A3-LEA	4	318.00	1	318.00
061912085529	1	FS35H21	TX36100	Switch	3M8	Scheduled Outage	19-Jun-12	9:00	19-Jun-12	12:30	210	1	210	A3-LEA	1	3.50	0	0.00
062212032012	1	STATION BREAKER		Station Breaker	3M8	Loss of supply	05-Jun-12	5:06	05-Jun-12	5:11	5	1686	8430	A3-LEA	2	140.50	0	0.00
070312114034	1	FS3H101		Switch	3M8	Scheduled Outage	03-Jul-12	9:26	03-Jul-12	10:45	79	75	5925	A3-LEA	4	98.75	1	98.75
081512014853	1	TX31353		OH Transformer	3M8	Animal	10-Aug-12	8:30	10-Aug-12	10:00	90	10	900	A3-LEA	9.2	15.00	1	15.00
091312085733	1	TX31452		OH Transformer	3M8	Animal	06-Sep-12	17:30	06-Sep-12	19:45	135	9	1215	A3-LEA	9.2	20.25	1	20.25
092512100759	1	Service		Service	3M8	Scheduled Outage	24-Sep-12	14:23	24-Sep-12	16:40	137	1	137	A3-LEA	5.92	2.28	1	2.28
102312081212	1	FS35H55		Switch	3M8	Scheduled Outage	23-Oct-12	9:00	23-Oct-12	13:12	252	61	15372	A3-LEA	1	256.20	0	0.00
102412083016	1	FS35H18		Switch	3M8	Scheduled Outage	24-Oct-12	9:00	24-Oct-12	14:00	300	66	19800	A3-LEA	1	330.00	0	0.00
							Total 2012									**1484.90**	**7.00**	**474.28**

22113093753	1	SW33L47	NULL	Switch	3M8	Scheduled Outage	21-Feb-13	9:44	21-Feb-13	9:59	15	87	1305	A3-LEA	1			
31213080322	1	SW35L96	NULL	Switch	3M8	Scheduled Outage	12-Mar-13	9:20	12-Mar-13	9:36	16	155	2480	A3-LEA	1			
31313081731	1	FS35L87	NULL	Switch	3M8	Scheduled Outage	13-Mar-13	12:50	13-Mar-13	13:15	25	40	1000	A3-LEA	1			
31913121319	1	FS35H81	NULL	Switch	3M8	Scheduled Outage	19-Mar-13	12:40	19-Mar-13	13:55	75	23	1725	A3-LEA	1	28.75	0	0.00
40513030937	1	TX31445	NULL	OH Transformer	3M8	Animal	03-Apr-13	19:00	03-Apr-13	21:30	150	17	2550	A3-LEA	9.2	42.50	1	42.50
41113102703	1	TX31352	NULL	OH Transformer	3M8	Storm	10-Apr-13	16:30	10-Apr-13	18:30	120	15	1800	A3-LEA	6	30.00	1	30.00
50813081332	1	FS35H19	NULL	Switch	3M8	Scheduled Outage	08-May-13	9:05	08-May-13	14:20	315	36	11340	A3-LEA	1	189.00	0	0.00
52813084548	1	SERVICE	NULL	Service	3M8	Tree growth	27-May-13	19:54	28-May-13	0:00	246	1	246	A3-LEA	3.1	4.10	1	4.10
60513124410	1	SERVICE	NULL	Service	3M8	Other	29-May-13	6:30	29-May-13	7:30	60	1	60	A3-LEA	7	1.00	1	1.00
61113125700	1	TX31195	NULL	OH Transformer	3M8	Scheduled Outage	11-Jun-13	12:51	11-Jun-13	13:01	10	15	150	A3-LEA	1	2.50	0	0.00
62613010315	1	SW33L47	TX3P140	Switch	3M8	Scheduled Outage	26-Jun-13	13:00	26-Jun-13	13:15	15	87	1305	A3-LEA	1	21.75	0	0.00
62713101635	1	TX31142	NULL	OH Transformer	3M8	Scheduled Outage	27-Jun-13	10:45	27-Jun-13	12:30	105	20	2100	A3-LEA	1	35.00	0	0.00
70213010016	1	FS35H55	NULL	Switch	3M8	Lightning	28-Jun-13	15:11	28-Jun-13	18:30	199	60	11940	A3-LEA	4	199.00	1	199.00
71113074049	1	FS35L87	NULL	Switch	3M8	Scheduled Outage	11-Jul-13	9:40	11-Jul-13	13:20	220	40	8800	A3-LEA	1	146.67	0	0.00
71913092809	1	TX31160	TX3P120	OH Transformer	3M8	Scheduled Outage	19-Jul-13	9:00	19-Jul-13	10:45	105	13	1365	A3-LEA	1	22.75	0	0.00
72413024803	1	LEA-31	NULL	Switch	3M8	Storm	19-Jul-13	22:40	20-Jul-13	3:56	316	831	262596	A3-LEA	6	4376.60	1	4376.60
80813111026	1	TX31083	NULL	OH Transformer	3M8	Scheduled Outage	08-Aug-13	10:06	08-Aug-13	12:52	166	7	1162	A3-LEA	1	19.37	0	0.00
81913123146	1	TX31143	NULL	OH Transformer	3M8	Scheduled Outage	21-Aug-13	9:00	21-Aug-13	12:00	180	20	3600	A3-LEA	1	60.00	0	0.00
82613090017	1	FS33L49	NULL	Switch	3M8	Scheduled Outage	26-Aug-13	10:11	26-Aug-13	10:59	48	105	5040	A3-LEA	1	84.00	0	0.00
91213123726	1	SC35105	NULL	UG switch unit	3M8	Equipment failure	06-Sep-13	19:01	07-Sep-13	21:24	1583	64	101312	A3-LEA	5.24	1688.53	1	1688.53
90913103332	1	FS30021	SC35105	Switch	3M8	Scheduled Outage	09-Sep-13	10:22	09-Sep-13	10:37	15	28	420	A3-LEA	1	7.00	0	0.00
90913102753	1	SERVICE	NULL	Service	3M8	Scheduled Outage	09-Sep-13	10:30	09-Sep-13	12:45	135	6	810	A3-LEA	1	13.50	0	0.00
102513094741	1	FS35H78	NULL	Switch	3M8	Animal	25-Oct-13	8:45	25-Oct-13	9:39	54	50	2700	A3-LEA	9.2	45.00	1	45.00
110513115933	1	TX31162	TX31470	OH Transformer	3M8	Scheduled Outage	05-Nov-13	12:30	05-Nov-13	13:15	45	14	630	A3-LEA	1	10.50	0	0.00
111513101218	1	TX31162	TX31470	OH Transformer	3M8	Scheduled Outage	15-Nov-13	9:56	15-Nov-13	11:31	95	14	1330	A3-LEA	1	22.17	0	0.00
120413101120	1	TX31470	TX31162	OH Transformer	3M8	Scheduled Outage	04-Dec-13	10:10	04-Dec-13	12:45	155	24	3720	A3-LEA	1	62.00	0	0.00
121113123949	1	FS3H328	NULL	Switch	3M8	Scheduled Outage	12-Dec-13	4:30	12-Dec-13	8:00	210	15	3150	A3-LEA	1	52.50	0	0.00
							Total 2013									**7164.18**	**8.00**	**6386.73**
21014104803	1	RE30051	NULL	Switch	3M8	Human error	30-Jan-14	2:46	30-Jan-14	5:52	186	559	103974	A3-LEA	8	1732.90	1	1732.90
61314094155	1	TX31134	NULL	OH Transformer	3M8	Tree growth	13-Jun-14	6:40	13-Jun-14	9:48	188	13	2444	A3-LEA	3.1	40.73	1	40.73
71914032812	1	TX31340	NULL	OH Transformer	3M8	Equipment failure	03-Jul-14	0:47	03-Jul-14	8:43	476	12	5712	A3-LEA	5.11	95.20	1	95.20
73114020356	1	TX31134	NULL	OH Transformer	3M8	Equipment failure	20-Jul-14	9:32	20-Jul-14	13:10	218	13	2834	A3-LEA	5.12	47.23	1	47.23
72414095427	1	FS35H55	NULL	Switch	3M8	Lightning	23-Jul-14	3:35	23-Jul-14	7:40	245	42	10290	A3-LEA	6	171.50	1	171.50
72414095427	2	TX3133	NULL	Switch	3M8	Lightning	23-Jul-14	3:35	23-Jul-14	11:15	460	16	7360	A3-LEA	6	122.67	1	122.67
							To Date 2014									**2210.23**	**6.00**	**2210.23**

Feeder 56M25

outage_id	Restore_Step	from Restore_Device	to_restore_device	Device	Feeder	Cause	DtOut	TmOut	DtRes	TmRes	Duration	NumCust	SubCustMin	AREA_TOWN	Equipment_code	Customer Hours	Modifier	Customer Hours Modified
A0002	1	O/H Service		Other	56M25	Scheduled Outage	24-Jan-08	9:00	24-Jan-08	11:00	120	1	120	A1-TEC	1	2.00	0	0.00
A0004	1	U/G Secondary		Secondary Conductor	56M25	Equipment failure	27-Jan-08	11:14	27-Jan-08	12:56	102	1	102	A1-TEC	5.92	1.70	1	1.70
A0013	1	Bad U/G cable		Fused Disconnect	56M25	Equipment failure	09-Mar-08	11:30	09-Mar-08	13:37	127.2	32	4070.4	A1-TEC	5.4	67.84	1	67.84
A0014	1	FS10137	TX10023	Elbow	56M25	Other	02-Apr-08	12:06	02-Apr-08	14:48	162	42	6804	A1-TEC	5.23	113.40	1	113.40
A0014	2	TX10023		Elbow	56M25	Other	02-Apr-08	12:06	02-Apr-08	15:38	212	8	1696	A1-TEC	5.23	28.27	1	28.27
A0132	1	FS10116		None	56M25	Human error	14-May-08	10:30	14-May-08	13:30	180	58	10440	A1-TEC	9.1	174.00	1	174.00
A0141	1	TX10075	TX10072	Other	56M25	Equipment failure	15-Jun-08	0:53	15-Jun-08	3:00	127	29	3683	A1-TEC	5.5	61.38	1	61.38
A0141	2	FS10075	MV110003	Other	56M25	Equipment failure	15-Jun-08	0:53	15-Jun-08	3:30	157	20	3140	A1-TEC	5.5	52.33	1	52.33
A0141	3	MV110003	TX10081	Other	56M25	Equipment failure	15-Jun-08	0:53	15-Jun-08	3:45	172	9	1548	A1-TEC	5.5	25.80	1	25.80
A0242	1	TX70E82		Other	56M25	Auto Reclosure	22-Aug-08	14:14	26-Aug-08	6:59	329	13	4277	A7-LAS	5.6	71.28	1	71.28
0105	1	FS10225		Fused Disconnect	56M25	Equipment failure	03-Sep-08	8:06	03-Sep-08	19:15	669	1	669	A1-TEC	5.6	11.15	1	11.15
0172	1	TX10546		Transformer Fuse	56M25	Equipment failure	26-Sep-08	15:45	26-Sep-08	18:00	135	16	2160	A1-TEC	5.6	36.00	1	36.00
0171	1	SERVICE		Other	56M25	Equipment failure	28-Sep-08	11:15	28-Sep-08	13:00	105	1	105	A1-TEC	5.6	1.75	1	1.75
0255	1	TX10535		Transformer Fuse	56M25	Tree growth	31-Oct-08	16:30	31-Oct-08	19:30	180	6	1080	A1-TEC	3.1	18.00	1	18.00
0204	1	TX10579		Transformer Fuse	56M25	Other	23-Nov-08	11:20	23-Nov-08	12:50	90	13	1170	A1-TEC	5.6	19.50	1	19.50
0150	1	FS10154		Fused Disconnect	56M25	Scheduled Outage	25-Nov-08	12:15	25-Nov-08	14:15	120	49	5880	A1-TEC	1	98.00	0	0.00
A0240	1	TX10579		Fused Disconnect	56M4	Animal	13-Aug-08	7:30	13-Aug-08	9:45	135	13	1755	A1-TEC	9.2	29.25	1	29.25
A0016	1	TX10075		None	56M26	Equipment failure	13-Apr-08	16:30	13-Apr-08	18:30	120	8	960	A1-TEC	5.5	16.00	1	16.00
A0006	1	TEC-7	TEC-12	None	56M26	Tree falling	30-Jan-08	1:14	30-Jan-08	2:29	75	4683	351225	A1-TEC	3.2	5853.75	1	5853.75
A0006	2	TEC-12		None	56M26	Tree falling	30-Jan-08	1:14	30-Jan-08	3:18	124	369	45756	A1-TEC	3.2	762.60	1	762.60
A0008	1	TX10587		None	56M26	Equipment failure	15-Feb-08	11:50	15-Feb-08	15:07	196.8	9	1771.2	A1-TEC	5.11	29.52	1	29.52
A0015	1	FS10144	TX10275	Fused Disconnect	56M26	Equipment failure	03-Apr-08	14:31	03-Apr-08	15:00	29	45	1305	A1-TEC	5.4	21.75	1	21.75
0208	1	SW10066		Other	56M25	Loss of supply	25-Dec-08	0:35	25-Dec-08	3:07	152	1589	241528	A1-TEC	2	4025.47	0	0.00
							Total 2008									**11520.74**	**20.00**	**7395.28**
0216	3	TX10930		Fused Disconnect	56M25	Equipment failure	16-Jan-09	5:08	16-Jan-09	9:30	262	30	7860	A1-TEC	5.28	131.00	1	131.00
0216	2	FS10236		Fused Disconnect	56M25	Equipment failure	16-Jan-09	5:08	16-Jan-09	8:30	202	28	5656	A1-TEC	5.28	94.27	1	94.27
0216	1	FS10174		Fused Disconnect	56M25	Equipment failure	16-Jan-09	5:08	16-Jan-09	7:55	167	33	5511	A1-TEC	5.28	91.85	1	91.85
0220	2	FS10075 w			56M25	Equipment failure	26-Apr-09	1:30	26-Apr-09	2:15	51	90	4590	A1-TEC	5.3	76.50	1	76.50
0220	1	MVI10003 w-2 to MVI10003 r-2			56M25	Equipment failure	26-Apr-09	1:30	26-Apr-09	1:31	1	36	36	A1-TEC	5.3	0.60	1	0.60
0485	1	FS10075		Other	56M25	Equipment failure	04-Jun-09	4:07	04-Jun-09	9:30	323	217	70091	A1-TEC	5.4	1168.18	1	1168.18
0488	1	Service		Secondary Conductor	56M25	Tree growth	01-Aug-09	10:49	01-Aug-09	13:49	180	1	180	A1-TEC	3.1	3.00	1	3.00
0912090929	2	MVI10003	TX10067	Switch	56M25	Scheduled Outage	21-Sep-09	9:07	21-Sep-09	9:40	33	32	1056	A1-TEC	1	17.60	0	0.00
0918091103	2	FS10153	MVI10003	Switch	56M25	Scheduled Outage	21-Sep-09	9:22	21-Sep-09	9:40	18	32	576	A1-TEC	1	9.60	0	0.00
0918091103	1	FS10154	TX10065	Switch	56M25	Scheduled Outage	21-Sep-09	9:22	21-Sep-09	9:30	8	49	392	A1-TEC	1	6.53	0	0.00
0912090929	1	FS10120	TX10066	Switch	56M25	Scheduled Outage	21-Sep-09	9:07	21-Sep-09	9:10	3	33	99	A1-TEC	1	1.65	0	0.00
1020090953	1	Service		Meter	56M25	Equipment failure	27-Sep-09	11:22	27-Sep-09	13:30	128	1	128	A1-TEC	5.5	2.13	1	2.13
0929090254	1	TX10407	TX10407	UG Transformer	56M25	Human error	29-Sep-09	14:45	30-Sep-09	0:25	580	12	6960	A1-TEC	8	116.00	1	116.00
1019090124	1	FS10153	TX10059	Switch	56M25	Scheduled Outage	29-Sep-09	20:35	29-Sep-09	21:15	40	32	1280	A1-TEC	1	21.33	0	0.00
1019091126	1	TX10535		OH Transformer	56M25	Wind	07-Oct-09	1:30	07-Oct-09	11:00	570	8	4560	A1-TEC	6	76.00	1	76.00
1130090157	1	TX10666	TX10666	OH Transformer	56M25	Scheduled Outage	30-Nov-09	14:00	30-Nov-09	14:15	15	9	135	A1-TEC	1	2.25	0	0.00
1223091135	1	Service		Service	56M25	Wind	09-Dec-09	20:31	09-Dec-09	23:40	189	1	189	A1-TEC	6	3.15	1	3.15
1223090220	1	Lauzon Station		Station Breaker	56M25	Loss of supply	15-Dec-09	0:15	15-Dec-09	0:45	30	6380	191400	A1-TEC	2	3190.00	0	0.00
0678	1	TX10579		Other	56M26	Animal	16-Jul-09	13:22	16-Jul-09	14:40	78	13	1014	A1-TEC	9.2	16.90	1	16.90
0222	1	TX10579		Fused Disconnect	56M26	Animal	26-Jul-09	6:45	26-Jul-09	8:15	90	13	1170	A1-TEC	9.2	19.50	1	19.50
1019091127	1	SW10036	White phase at 12280 riverside	Switch	56M26	Vehicles	04-Oct-09	2:45	04-Oct-09	7:43	298	66	19668	A1-TEC	9.1	327.80	1	327.80
1019091127	3	White phase at 12280 riverside	FS10100	Switch	56M26	Vehicles	04-Oct-09	2:45	04-Oct-09	13:10	625	23	14375	A1-TEC	9.1	239.58	1	239.58
1019091127	5	TX10581		Switch	56M26	Vehicles	04-Oct-09	2:45	04-Oct-09	13:34	649	16	10384	A1-TEC	9.1	173.07	1	173.07
1019091127	4	TX10583		Switch	56M26	Vehicles	04-Oct-09	2:45	04-Oct-09	13:14	629	9	5661	A1-TEC	9.1	94.35	1	94.35
1019091127	2	SW10036	White phase at 12280 riverside	Switch	56M26	Vehicles	04-Oct-09	6:45	04-Oct-09	7:43	58	64	3712	A1-TEC	9.1	61.87	1	61.87
1019091127	6	TX10582		Switch	56M26	Vehicles	04-Oct-09	2:45	04-Oct-09	14:26	701	4	2804	A1-TEC	9.1	46.73	1	46.73
1223091138	1	Service	SERVICE	Service	56M25	Equipment failure	23-Dec-09	9:00	23-Dec-09	12:00	180	1	180	A1-TEC	5.17	3.00	1	3.00
							Total 2009									**5994.45**	**20.00**	**2745.48**

0114100218	2	TX10398	TX10065	Switch	56M25	Scheduled Outage	14-Jan-10	9:58	14-Jan-10	10:25	27	20	540	A1-TEC	1	9.00	0	0.00
0114100218	1	FS10154	FS10154	Switch	56M25	Scheduled Outage	14-Jan-10	14:25	14-Jan-10	14:36	11	49	539	A1-TEC	1	8.98	0	0.00
0211100411	1	Tx10524		OH Transformer	56M25	Equipment failure	03-Feb-10	20:26	03-Feb-10	21:45	79	1	79	A1-TEC	5.12	1.32	1	1.32
0416101244	1	FS10120	FS10120	Switch	56M25	Scheduled Outage	19-Apr-10	8:45	19-Apr-10	11:00	135	34	4590	A1-TEC	1	76.50	0	0.00
0714100938	1	tx10556		OH Transformer	56M25	Animal	22-Jun-10	6:50	22-Jun-10	8:10	80	16	1280	A1-TEC	9.2	21.33	1	21.33
072810101120	1	tx10657		UG Transformer	56M25	Equipment failure	10-Jul-10	14:30	10-Jul-10	18:32	242	1	242	A1-TEC	5.23	4.03	1	4.03
081210111657	2	mvi1003		UG Transformer	56M25	Lightning	23-Jul-10	15:15	23-Jul-10	22:20	425	204	86700	A1-TEC	4	1445.00	1	1445.00
081210111645	2	fs10069		UG Transformer	56M25	Lightning	23-Jul-10	15:15	24-Jul-10	0:00	525	34	17850	A1-TEC	4	297.50	1	297.50
081210111657	1	tx10400		UG Transformer	56M25	Lightning	23-Jul-10	15:15	23-Jul-10	22:20	425	20	8500	A1-TEC	4	141.67	1	141.67
081210111645	1	tx10522		UG Transformer	56M25	Lightning	23-Jul-10	15:15	23-Jul-10	19:45	270	9	2430	A1-TEC	4	40.50	1	40.50
081610115834	1	tx10543		OH Transformer	56M25	Lightning	23-Jul-10	14:45	23-Jul-10	18:45	240	3	720	A1-TEC	4	12.00	1	12.00
081210111652	1	tx10544		OH Transformer	56M25	Lightning	23-Jul-10	17:30	23-Jul-10	18:00	30	5	150	A1-TEC	4	2.50	1	2.50
072910101527	1	TX10400	TX10400	UG Transformer	56M25	Lightning	29-Jul-10	15:15	29-Jul-10	22:20	425	20	8500	A1-TEC	4	141.67	1	141.67
080510120345	1	TX10400	TX10400	UG Transformer	56M25	Scheduled Outage	05-Aug-10	11:48	05-Aug-10	13:45	117	20	2340	A1-TEC	1	39.00	0	0.00
081610115843	1	tx10400		UG Transformer	56M25	Equipment failure	07-Aug-10	7:07	07-Aug-10	10:05	178	20	3560	A1-TEC	5.28	59.33	1	59.33
081610115853	1	tx10400		UG Transformer	56M25	Equipment failure	07-Aug-10	12:53	07-Aug-10	15:30	157	20	3140	A1-TEC	5.28	52.33	1	52.33
011711023937	1	FS10153	TX10075	Switch	56M25	Equipment failure	13-Aug-10	16:30	13-Aug-10	21:30	300	32	9600	A1-TEC	5.6	160.00	1	160.00
092210095457	1	service		Service	56M25	Tree falling	21-Aug-10	13:00	21-Aug-10	15:00	120	1	120	A1-TEC	3.1	2.00	1	2.00
082410090748	1	FS10153	FS10153	Switch	56M25	Scheduled Outage	25-Aug-10	9:36	25-Aug-10	9:45	9	31	279	A1-TEC	1	4.65	0	0.00
111710094645	1	fs10120	tx10061	Switch	56M25	Equipment failure	06-Oct-10	6:00	06-Oct-10	9:30	210	35	7350	A1-TEC	5.28	122.50	1	122.50
111710094645	2	fs10120	tx10066	Switch	56M25	Equipment failure	06-Oct-10	8:30	06-Oct-10	9:30	60	35	2100	A1-TEC	5.28	35.00	1	35.00
100610082549	1	tx10061		UG Transformer	56M25	Scheduled Outage	06-Oct-10	6:00	06-Oct-10	9:30	210	9	1890	A1-TEC	0.1	31.50	1	31.50
111910074857	1	fs10074		Switch	56M25	Tree falling	17-Nov-10	0:30	17-Nov-10	5:30	300	95	28500	A1-TEC	3.2	475.00	1	475.00
112610031050	1	TX10902	TX10902	OH Transformer	56M25	Scheduled Outage	26-Nov-10	14:30	26-Nov-10	15:10	40	19	760	A1-TEC	1	12.67	0	0.00
121510115412	1	FS10139	TX10041	Switch	56M25	Scheduled Outage	15-Dec-10	11:01	15-Dec-10	16:50	349	16	5584	A1-TEC	1	93.07	0	0.00
0714100827	1	tx10576		OH Transformer	56M26	Equipment failure	12-Jun-10	8:00	12-Jun-10	10:04	124	17	2108	A1-TEC	5.12	35.13	1	35.13
0714100904	1	tx10915		UG Transformer	56M26	Tree falling	18-Jun-10	10:42	18-Jun-10	13:45	183	19	3477	A1-TEC	3.2	57.95	1	57.95
0714100939	1	TX10579		OH Transformer	56M26	Animal	01-Jul-10	12:15	01-Jul-10	15:30	195	13	2535	A1-TEC	9.2	42.25	1	42.25
092210095426	1	fs10144		Switch	56M26	Equipment failure	18-Aug-10	0:10	18-Aug-10	3:30	200	31	6200	A1-TEC	5.4	103.33	1	103.33
111710101317	2	fs10221		Switch	56M26	Equipment failure	17-Sep-10	17:24	17-Sep-10	19:30	126	16	2016	A1-TEC	5.4	33.60	1	33.60
111710101317	1	fs10144		Switch	56M26	Equipment failure	17-Sep-10	17:24	17-Sep-10	19:20	116	17	1972	A1-TEC	5.4	32.87	1	32.87
111710094720	1	fs10221		Switch	56M26	Equipment failure	24-Sep-10	23:20	25-Sep-10	2:45	205	16	3280	A1-TEC	5.4	54.67	1	54.67
121510115412	2	TX10041	TX10034	Switch	56M25	Scheduled Outage	15-Dec-10	11:01	15-Dec-10	16:55	354	13	4602	A1-TEC	1	76.70	0	0.00
							Total 2010									**3725.55**	**25.00**	**3404.98**
021111104820	1	FS10154	FS10154	Switch	56M25	Scheduled Outage	11-Feb-11	10:37	11-Feb-11	11:00	23	36	828	A1-TEC	9.2	13.80	0	0.00
050211094726	1	FS10153		Switch	56M25	Equipment failure	31-Mar-11	20:05	31-Mar-11	22:05	120	32	3840	A1-TEC	5.6	64.00	1	64.00
040411010032	1	FS10120		Switch	56M25	Scheduled Outage	05-Apr-11	9:05	05-Apr-11	9:17	12	41	492	A1-TEC	1	8.20	0	0.00
051611035021	1	TX10579		OH Transformer	56M25	Animal	06-May-11	13:40	06-May-11	15:00	80	13	1040	A1-TEC	9.2	17.33	1	17.33
062711030533	2	FS10159	TX10300	Switch	56M25	Lightning	10-May-11	8:45	10-May-11	18:30	585	123	71955	A1-TEC	4	1199.25	0	0.00
062711030533	3	FS10158	Tx10286	Switch	56M25	Lightning	10-May-11	8:45	11-May-11	5:00	1215	56	68040	A1-TEC	4	1134.00	1	1134.00
062711030533	4	TX10285		Switch	56M25	Lightning	10-May-11	8:45	11-May-11	20:00	2115	10	21150	A1-TEC	4	352.50	1	352.50
062711030533	1	FS10155	TX10394	Switch	56M25	Lightning	10-May-11	8:45	10-May-11	10:30	105	120	12600	A1-TEC	4	210.00	1	210.00
053011035231	1	Service		Service	56M25	Tree falling	25-May-11	16:05	25-May-11	18:00	115	1	115	A1-TEC	3.2	1.92	1	1.92
060611015239	1	FS10078		Switch	56M25	Other	05-Jun-11	6:10	05-Jun-11	8:00	110	94	10340	A1-TEC	0.1	172.33	1	172.33
062011015906	1	Tx10557		OH Transformer	56M25	Human error	10-Jun-11	7:00	10-Jun-11	7:37	37	8	296	A1-TEC	9.1	4.93	1	4.93
062011014630	1	tx10725		OH Transformer	56M25	Animal	14-Jun-11	6:15	14-Jun-11	6:55	40	19	760	A1-TEC	9.2	12.67	1	12.67
100511024753	1	FS10229		Switch	56M25	Lightning	02-Jul-11	23:39	03-Jul-11	2:00	141	38	5358	A1-TEC	4	89.30	1	89.30
080311014951	1	FS10156		Switch	56M25	Equipment failure	03-Aug-11	11:02	03-Aug-11	13:44	162	36	5832	A1-TEC	5.4	97.20	1	97.20
081911104618	1	TX10568		OH Transformer	56M25	Animal	08-Aug-11	7:45	08-Aug-11	9:00	75	15	1125	A1-TEC	9.2	18.75	1	18.75
101311083930	1	FS10183		Switch	56M25	Equipment failure	07-Oct-11	6:30	07-Oct-11	9:20	170	50	8500	A1-TEC	5.4	141.67	1	141.67
100711112026	1	TX10576		OH Transformer	56M25	Animal	10-Jul-11	11:14	10-Jul-11	12:15	61	17	1037	A1-TEC	9.2	17.28	1	17.28
101311083930	1	FS10183		Switch	56M25	Equipment failure	10-Jul-11	6:30	10-Jul-11	9:20	170	50	8500	A1-TEC	5.26	141.67	1	141.67
110211082305	1	FS10156		Switch	56M25	Scheduled Outage	11-Feb-11	9:07	11-Feb-11	9:20	13	36	468	A1-TEC	1	7.80	0	0.00
110211083233	1	FS10156		Switch	56M25	Scheduled Outage	11-Feb-11	16:15	11-Feb-11	16:20	5	36	180	A1-TEC	1	3.00	0	0.00
111511112456	1	TX10348		UG Transformer	56M25	Scheduled Outage	11/16/2011	9:15	11/16/2011	11:26	131	8	1048	A1-TEC	1	17.47	0	0.00
111811081546	1	TX10348		UG Transformer	56M25	Scheduled Outage	11/18/2011	9:00	11/18/2011	14:00	300	8	2400	A1-TEC	1	40.00	0	0.00
120211125542	1	FS10210		Switch	56M25	Scheduled Outage	12-Jul-11	8:42	12-Jul-11	13:46	304	36	10944	A1-TEC	1	182.40	0	0.00
120811103039	1	FS10156		Switch	56M25	Scheduled Outage	12-Aug-11	12:40	12-Aug-11	13:05	25	36	900	A1-TEC	1	15.00	0	0.00
120911024254	1	TX10277		UG Transformer	56M25	Scheduled Outage	12-Sep-11	9:30	12-Sep-11	14:10	280	11	3080	A1-TEC	1	51.33	0	0.00
120911113049	1	TX10540		OH Transformer	56M25	Scheduled Outage	12-Sep-11	11:28	12-Sep-11	12:58	90	8	720	A1-TEC	1	12.00	0	0.00
120911124025	1	Service		UG Transformer	56M25	Equipment failure	12-May-11	22:15	12-Jun-11	5:40	445	1	445	A1-TEC	5.22	7.42	1	7.42
121311081316	1	TX10276		UG Transformer	56M25	Scheduled Outage	12/13/2011	8:33	12/13/2011	13:13	280	10	2800	A1-TEC	1	46.67	0	0.00
092211082850	1	TX10094		UG Transformer	56M26	Scheduled Outage	22-Sep-11	9:45	22-Sep-11	14:00	255	10	2550	A1-TEC	1	42.50	0	0.00
111610084547	1	FS10120		Switch	56M25	Scheduled Outage	16-Nov-10	9:00	16-Nov-10	11:30	150	67	10050	A1-TEC	1	167.50	0	0.00
							Total 2011									**4079.88**	**16.00**	**2482.97**

011113025602	1	Station Breaker		Station Breaker	56M25	Loss of supply	23-Dec-12	7:53	23-Dec-12	8:28	35	2092	73220	A1-TEC	2	1220.33	0	0.00
021512092844	1	TX10285		UG Transformer	56M25	Scheduled Outage	15-Feb-12	9:27	15-Feb-12	9:46	19	10	190	A1-TEC	1	3.17	0	0.00
040212083229	1	FS10078		Switch	56M25	Scheduled Outage	04-Apr-12	9:20	04-Apr-12	14:12	292	50	14600	A1-TEC	1	243.33	0	0.00
040212084832	1	FS10073		Switch	56M25	Scheduled Outage	05-Apr-12	9:13	05-Apr-12	13:54	281	98	27538	A1-TEC	1	458.97	0	0.00
043012122324	1	TX10568		OH Transformer	56M25	Equipment failure	21-Apr-12	7:30	21-Apr-12	13:00	330	15	4950	A1-TEC	5.12	82.50	1	82.50
052912082239	1	TX10579		OH Transformer	56M25	Animal	26-May-12	7:24	26-May-12	8:50	86	13	1118	A1-TEC	9.2	18.63	1	18.63
060812081120	1	FS10190		Switch	56M25	Equipment failure	07-Jun-12	0:13	07-Jun-12	5:00	287	28	8036	A1-TEC	5.22	133.93	1	133.93
062512095058	1	TX10038		UG Transformer	56M25	Scheduled Outage	26-Jun-12	9:13	26-Jun-12	13:43	270	5	1350	A1-TEC	1	22.50	0	0.00
070912024701	1	FS10153		Switch	56M25	Animal	07-Jul-12	7:30	07-Jul-12	9:30	120	32	3840	A1-TEC	9.2	64.00	1	64.00
070912025944	1	TX10579		OH Transformer	56M25	Animal	08-Jul-12	7:15	08-Jul-12	8:45	90	13	1170	A1-TEC	9.2	19.50	1	19.50
071012021622	1	Service		Service	56M25	Scheduled Outage	28-Jun-12	17:00	28-Jun-12	19:30	150	1	150	A1-TEC	5.5	2.50	1	2.50
071012022027	1	Service		Service	56M25	Tree growth	29-Jun-12	7:00	29-Jun-12	13:30	390	1	390	A1-TEC	3.2	6.50	1	6.50
071212010827	1	TX10723		OH Transformer	56M25	Animal	10-Jul-12	7:35	10-Jul-12	9:15	100	16	1600	A1-TEC	9.2	26.67	1	26.67
072412112500	1	TX10503	TX10505	Switch	56M25	Equipment failure	20-Jul-12	21:25	20-Jul-12	21:55	30	28	840	A1-TEC	5.4	14.00	1	14.00
072512091613	1	TX1P107	MV10005	UG Transformer	56M25	Scheduled Outage	25-Jul-12	9:16	25-Jul-12	9:39	23	84	1932	A1-TEC	1	32.20	0	0.00
072712124338	1	FS10225	Temp Generator	UG Conductor	56M25	Equipment failure	25-Jul-12	22:30	26-Jul-12	15:00	990	1	990	A1-TEC	5.4	16.50	1	16.50
080712094304	1	Station Breaker		Station Breaker	56M25	Loss of supply	25-Jul-12	23:50	25-Jul-12	23:52	2	2088	4176	A1-TEC	2	69.60	0	0.00
092512091620	1	FS10153		Switch	56M25	Scheduled Outage	25-Sep-12	8:46	25-Sep-12	10:33	107	32	3424	A1-TEC	9.1	57.07	1	57.07
110812031605	1	FS10120		Switch	56M25	Scheduled Outage	09-Nov-12	9:14	09-Nov-12	12:05	171	114	19494	A1-TEC	1	324.90	0	0.00
111912023718	1	3/0 Buss		UG Conductor	56M25	Equipment failure	16-Nov-12	23:30	17-Nov-12	3:00	210	2	420	A1-TEC	5.6	7.00	1	7.00
120512081518	1	FS10153		Switch	56M25	Scheduled Outage	05-Dec-12	9:17	05-Dec-12	10:40	83	32	2656	A1-TEC	1	44.27	0	0.00
120512083017	1	FS10120		Switch	56M25	Scheduled Outage	05-Dec-12	9:17	05-Dec-12	14:45	328	34	11152	A1-TEC	1	185.87	0	0.00
121112023654	1	FS10154		Switch	56M25	Scheduled Outage	12-Dec-12	9:00	12-Dec-12	9:23	23	142	3266	A1-TEC	1	54.43	0	0.00
121112023654	2	MV10003	TX10080	Switch	56M25	Scheduled Outage	12-Dec-12	9:23	12-Dec-12	15:09	346	8	2768	A1-TEC	1	46.13	0	0.00
							Total 2012									**3154.50**	**12.00**	**448.80**
11613030219	1	FS10154	NULL	Switch	56M25	Scheduled Outage	17-Jan-13	9:00	17-Jan-13	9:30	30	48	1440	A1-TEC	1	24.00	0	0.00
12513105704	1	FS10154	NULL	UG Transformer	56M25	Scheduled Outage	17-Jan-13	9:30	17-Jan-13	13:40	250	13	3250	A1-TEC	1	54.17	0	0.00
12113100206	1	TX10551	NULL	OH Transformer	56M25	Scheduled Outage	21-Jan-13	10:02	21-Jan-13	10:30	28	4	112	A1-TEC	1	1.87	0	0.00
20513021424	1	FS10154	NULL	Switch	56M25	Scheduled Outage	06-Feb-13	9:38	06-Feb-13	10:46	68	48	3264	A1-TEC	1	54.40	0	0.00
21113082758	1	MV10003	NULL	Switch	56M25	Scheduled Outage	11-Feb-13	9:21	11-Feb-13	11:00	99	33	3267	A1-TEC	1	54.45	0	0.00
21113082758	2	TX1P071	NULL	Switch	56M25	Scheduled Outage	11-Feb-13	9:21	11-Feb-13	13:36	255	8	2040	A1-TEC	1	34.00	0	0.00
21213011120	1	MV10003	NULL	Switch	56M25	Scheduled Outage	13-Feb-13	9:25	13-Feb-13	10:10	45	41	1845	A1-TEC	1	30.75	0	0.00
52813084021	1	TX10557	NULL	OH Transformer	56M25	Animal	26-May-13	6:30	26-May-13	10:00	210	8	1680	A1-TEC	9.2	28.00	1	28.00
60513010000	1	TX10573	NULL	OH Transformer	56M25	Equipment failure	30-May-13	15:45	30-May-13	20:00	255	24	6120	A1-TEC	5.92	102.00	1	102.00
60713091955	1	TX10534	NULL	OH Transformer	56M25	Animal	03-Jun-13	6:30	03-Jun-13	11:30	300	7	2100	A1-TEC	9.2	35.00	1	35.00
60713092001	1	SERVICE	NULL	Service	56M25	Human error	04-Jun-13	19:00	04-Jun-13	23:00	240	1	240	A1-TEC	9.1	4.00	1	4.00
62513104732	1	FS10074	TX10725	Switch	56M25	Equipment failure	23-Jun-13	22:00	24-Jun-13	0:30	150	76	11400	A1-TEC	5.11	190.00	1	190.00
62513104737	1	TX10577	NULL	OH Transformer	56M25	Equipment failure	24-Jun-13	22:00	24-Jun-13	22:45	45	12	540	A1-TEC	5.11	9.00	1	9.00
71113113602	1	TX10556	NULL	OH Transformer	56M25	Lightning	07-Jul-13	8:24	07-Jul-13	14:00	336	17	5712	A1-TEC	4	95.20	1	95.20
72413075903	1	SERVICE	NULL	Service	56M25	Tree falling	20-Jul-13	12:00	20-Jul-13	13:45	105	6	630	A1-TEC	3.2	10.50	1	10.50
80813021535	1	FS10073	NULL	Switch	56M25	Scheduled Outage	09-Aug-13	10:20	09-Aug-13	11:00	40	34	1360	A1-TEC	1	22.67	0	0.00
81313082545	1	TX10575	NULL	OH Transformer	56M25	Equipment failure	11-Aug-13	5:57	11-Aug-13	9:00	183	14	2562	A1-TEC	5.12	42.70	1	42.70
82013034841	1	FS10074	NULL	Switch	56M25	Scheduled Outage	21-Aug-13	9:45	21-Aug-13	12:59	194	19	3686	A1-TEC	1	61.43	0	0.00
101513030400	1	FS10188	MV10003	Switch	56M25	Other	11-Oct-13	21:22	12-Oct-13	1:50	268	265	71020	A1-TEC	0.1	1183.67	1	1183.67
111213103800	1	TX10573	NULL	OH Transformer	56M25	Animal	11-Nov-13	9:30	11-Nov-13	11:50	140	23	3220	A1-TEC	9.2	53.67	1	53.67
111913125753	1	FS10115	TX10524	Switch	56M25	Equipment failure	17-Nov-13	21:25	18-Nov-13	5:25	480	60	28800	A1-TEC	5.93	480.00	1	480.00
111913015256	1	FS10115	FS10116	Switch	56M25	Scheduled Outage	19-Nov-13	13:23	19-Nov-13	13:55	32	50	1600	A1-TEC	1	26.67	0	0.00
							Total 2013									**2598.13**	**12.00**	**2233.73**
12014021850	1	FS10071	TX10539	Switch	56M25	Equipment failure	20-Jan-14	13:50	20-Jan-14	14:51	61	18	1098	A1-TEC	5.14	18.30	1	18.30
12214100013	1	TX10579	NULL	OH Transformer	56M25	Scheduled Outage	22-Jan-14	10:00	22-Jan-14	10:21	21	13	273	A1-TEC	1	4.55	0	0.00
21314012227	1	TX10569	NULL	OH Transformer	56M25	Scheduled Outage	13-Feb-14	13:20	13-Feb-14	13:36	16	21	336	A1-TEC	1	5.60	0	0.00
21414102005	1	TX10569	NULL	OH Transformer	56M25	Scheduled Outage	14-Feb-14	10:20	14-Feb-14	11:22	62	21	1302	A1-TEC	1	21.70	0	0.00
21914101551	1	TX10569	NULL	OH Transformer	56M25	Equipment failure	15-Feb-14	14:26	15-Feb-14	20:31	365	21	7665	A1-TEC	5.11	127.75	1	127.75
61314022856	1	TX10562	NULL	OH Transformer	56M25	Scheduled Outage	13-Jun-14	14:30	13-Jun-14	14:45	15	24	360	A1-TEC	1	6.00	0	0.00
72414102109	1	TX10582	NULL	OH Transformer	56M25	Animal	23-Jul-14	12:04	23-Jul-14	13:38	94	4	376	A1-TEC	9.2	6.27	1	6.27
							To Date 2014									**190.17**	**3.00**	**152.32**

Feeder 56M26

outage_id	Restore_Step	from Restore_Device	to_restore_device	Device	Feeder	Cause	DtOut	TmOut	DtRes	TmRes	Duration	NumCust	SubCustMin	AREA_TOWN	Equipment_code	Customer Hours
A0001	1	FS10018		Fused Disconnect	56M26	Scheduled Outage	06-Jan-08	9:00	06-Jan-08	11:00	120	16	1920	A1-TEC	1	32.00
A0006	1	TEC-7	TEC-12	None	56M26	Tree falling	30-Jan-08	1:14	30-Jan-08	2:29	75	4683	351225	A1-TEC	3.2	5853.75
A0006	2	TEC-12		None	56M26	Tree falling	30-Jan-08	1:14	30-Jan-08	3:18	124	369	45756	A1-TEC	3.2	762.60
A0007	1	O/H Service		None	56M26	Tree growth	01-Feb-08	15:30	01-Feb-08	17:30	120	1	120	A1-TEC	3.1	2.00
A0009	1	All of 56M26		None	56M26	Loss of supply	15-Feb-08	12:27	15-Feb-08	12:32	4.8	4683	22478.4	A1-TEC	2	374.64
A0008	1	TX10587		None	56M26	Equipment failure	15-Feb-08	11:50	15-Feb-08	15:07	196.8	9	1771.2	A1-TEC	5.11	0.00
A0010	1	TX10308,TX10298		Elbow	56M26	Equipment failure	16-Feb-08	7:34	16-Feb-08	12:22	288	119	34272	A1-TEC	5.26	571.20
A0011	1	All of 56M26		None	56M26	Other	16-Feb-08	11:38	16-Feb-08	11:40	1.8	4683	8429.4	A1-TEC	5.6	140.49
A0012	1	FS10169-TX10089		None	56M26	Equipment failure	08-Mar-08	4:30	08-Mar-08	7:45	195	87	16965	A1-TEC	5.4	282.75
A0012	2	TX10089		None	56M26	Equipment failure	08-Mar-08	4:30	08-Mar-08	8:20	230	28	6440	A1-TEC	5.4	107.33
A0015	1	FS10144	TX10275	Fused Disconnect	56M26	Equipment failure	03-Apr-08	14:31	03-Apr-08	15:00	29	45	1305	A1-TEC	5.4	0.00
A0015	2	TX10275		Fused Disconnect	56M26	Equipment failure	03-Apr-08	14:31	03-Apr-08	15:20	49	9	441	A1-TEC	5.4	7.35
A0016	1	TX10075		None	56M26	Equipment failure	13-Apr-08	16:30	13-Apr-08	18:30	120	8	960	A1-TEC	5.5	0.00
E0016	1	Blue Phase - FS10187 - TX10533		Secondary Conductor	56M26	Other	22-Apr-08	4:22	22-Apr-08	6:00	98	20	1960	A1-TEC	6	32.67
A0122	1	FS10038	TX10638	Fused Disconnect	56M26	Animal	02-Jun-08	7:09	02-Jun-08	7:58	49	43	2107	A1-TEC	9.2	35.12
A0122	2	TX10638		Fused Disconnect	56M26	Animal	02-Jun-08	7:09	02-Jun-08	8:27	78	19	1482	A1-TEC	9.2	24.70
A0124	1	FS10169	FS10096	None	56M26	Storm	08-Jun-08	18:00	08-Jun-08	20:13	133	286	38038	A1-TEC	6	633.97
A0115	1	FS10233	TX10124	Fused Disconnect	56M26	Lightning	08-Jun-08	18:00	08-Jun-08	23:30	330	75	24750	A1-TEC	4	412.50
A0124	2	FS10096		None	56M26	Storm	08-Jun-08	18:00	08-Jun-08	20:28	148	28	4144	A1-TEC	6	69.07
A0115	2	TX10124		Fused Disconnect	56M26	Lightning	08-Jun-08	18:00	09-Jun-08	0:30	390	8	3120	A1-TEC	4	52.00
A0123	1	TX10707		None	56M26	Lightning	10-Jun-08	2:42	10-Jun-08	6:08	206	20	4120	A1-TEC	4	68.67
A0189	1	SERVICE		None	56M26	Tree falling	16-Jun-08	15:00	16-Jun-08	18:45	225	1	225	A1-TEC	3.2	3.75
A0181	1	FS10169		None	56M26	Lightning	28-Jun-08	11:19	28-Jun-08	13:30	131	303	39693	A1-TEC	4	661.55
A0200	1	HOUSE SERVICE		None	56M26	Equipment failure	18-Jul-08	18:20	18-Jul-08	22:30	250	1	250	A1-TEC	5.6	4.17
A0201	1	TX10602		None	56M26	Equipment failure	21-Jul-08	8:08	21-Jul-08	9:32	84	6	504	A1-TEC	5.6	8.40
A0203	1	SERVICE		None	56M26	Tree growth	22-Jul-08	22:02	22-Jul-08	0:03	121	1	121	A1-TEC	3.1	2.02
A0204	1	TX10621		None	56M26	Animal	28-Jul-08	8:21	28-Jul-08	9:15	54	2	108	A1-TEC	9.2	1.80
0201	1	TX10624		Transformer Fuse	56M26	Animal	01-Sep-08	14:30	01-Sep-08	15:30	60	16	960	A1-TEC	9.2	16.00
0152	1	@ Breaker		Other	56M26	Equipment failure	03-Sep-08	8:59	03-Sep-08	9:02	3	564	1692	A1-TEC	5.6	28.20
0109	1	SERVICE		Other	56M26	Other	14-Sep-08	16:58	14-Sep-08	18:30	92	1	92	A1-TEC	5.6	1.53
0212	1	Jumpers		Other	56M26	Equipment failure	27-Dec-08	18:46	27-Dec-08	21:40	174	1	174	A1-TEC	5.5	2.90
0213	1	Service Pole		Other	56M26	Other	31-Dec-08	2:32	31-Dec-08	5:10	158	1	158	A1-TEC	9.3	2.63
							Total 2008									**10195.75**
0215	1	TEC-10 to SW10072		Other	56M26	Equipment failure	16-Jan-09	4:15	16-Jan-09	5:10	55	3434	188870	A1-TEC	5.91	3147.83
0215	2	SW10032		Other	56M26	Equipment failure	16-Jan-09	4:15	16-Jan-09	5:36	81	1068	86508	A1-TEC	5.91	1441.80
0215	3	TEC-10 to SW10032		Other	56M26	Equipment failure	16-Jan-09	4:15	16-Jan-09	7:16	181	73	13213	A1-TEC	5.91	220.22
0263	1	TX10382		Other	56M26	Equipment failure	02-Feb-09	19:05	02-Feb-09	22:00	175	9	1575	A1-TEC	5.22	26.25
0752	1	FS10155		Fused Disconnect	56M26	Vehicles	09-Feb-09	17:00	09-Feb-09	18:15	75	119	8925	A1-TEC	9.1	0.00
0755	1	FS10025		Fused Disconnect	56M26	Animal	13-Feb-09	11:26	13-Feb-09	12:25	59	72	4248	A1-TEC	9.2	70.80
0760	1	FS10020			56M26	Equipment failure	09-Mar-09	9:53	09-Mar-09	11:37	104	27	2808	A1-TEC	6	46.80
0191	1	TX10685		Transformer Fuse	56M26	Equipment failure	22-Mar-09	11:24	22-Mar-09	13:00	96	12	1152	A1-TEC	5.12	19.20
0192	1	Service		Service	56M26	Customer equipment	29-Mar-09	20:16	29-Mar-09	23:45	209	1	209	A1-TEC	5.17	3.48
0194	1	Service		Service	56M26	Equipment failure	30-Mar-09	5:00	30-Mar-09	20:00	900	1	900	A1-TEC	5.17	15.00
0761	1	Service		Service	56M26	Equipment failure	09-Apr-09	7:30	09-Apr-09	9:30	120	1	120	A1-TEC	5.5	2.00
0219	1	TX10717		Fused Disconnect	56M26	Equipment failure	11-Apr-09	9:07	11-Apr-09	11:45	158	2	316	A1-TEC	5.12	5.27
0481	1			Unknown	56M26	Equipment failure	13-May-09	13:30	13-May-09	14:30	60	1	60	A1-TEC	5.92	1.00
0483	1	TX10695			56M26	Animal	21-May-09	7:30	21-May-09	8:15	45	21	945	A1-TEC	9.2	15.75
0560	1	FS10194		Other	56M26	Equipment failure	13-Jun-09	4:00	13-Jun-09	6:07	127	58	7366	A1-TEC	5.3	122.77
0221	1	TX10240			56M26	Equipment failure	13-Jun-09	22:00	13-Jun-09	22:15	15	9	135	A1-TEC	5.5	2.25
0423	1	Service		Other	56M26	Tree falling	17-Jun-09	18:30	17-Jun-09	20:30	120	1	120	A1-TEC	3.1	2.00
0139	1	TX10692		Transformer Fuse	56M26	Animal	20-Jun-09	7:45	20-Jun-09	9:45	120	14	1680	A1-TEC	9.2	28.00
0130	1	FS10146		Other	56M26	Animal	28-Jun-09	8:10	28-Jun-09	9:35	85	45	3825	A1-TEC	9.2	63.75
0686	1	Service		Other	56M26	Equipment failure	02-Jul-09	16:30	02-Jul-09	18:00	90	1	90	A1-TEC	5.92	1.50
0678	1	TX10579		Other	56M26	Animal	16-Jul-09	13:22	16-Jul-09	14:40	78	13	1014	A1-TEC	9.2	0.00
0222	1	TX10579		Fused Disconnect	56M26	Animal	26-Jul-09	6:45	26-Jul-09	8:15	90	13	1170	A1-TEC	9.2	0.00
0223	1	TX10686		Other	56M26	Animal	03-Aug-09	19:30	03-Aug-09	21:30	120	12	1440	A1-TEC	9.2	24.00
0676	1	Service		Other	56M26	Equipment failure	03-Aug-09	10:00	03-Aug-09	13:00	180	1	180	A1-TEC	5.92	3.00
0224	1	TX10906		Other	56M26	Equipment failure	30-Aug-09	8:30	30-Aug-09	10:50	140	15	2100	A1-TEC	5.14	35.00
1020090943	1	FS10046		Switch	56M26	Animal	20-Sep-09	15:44	20-Sep-09	16:55	71	16	1136	A1-TEC	9.2	18.93
1020091007	1	Service		Meter	56M26	Equipment failure	03-Oct-09	11:00	03-Oct-09	12:30	90	1	90	A1-TEC	5.92	1.50
1019091127	1	SW10036	riverside	Switch	56M26	Vehicles	04-Oct-09	2:45	04-Oct-09	7:43	298	66	19668	A1-TEC	9.1	0.00
1019091127	3	White phase at 12280 riverside	FS10100	Switch	56M26	Vehicles	04-Oct-09	2:45	04-Oct-09	13:10	625	23	14375	A1-TEC	9.1	0.00
1019091127	5	TX10581		Switch	56M26	Vehicles	04-Oct-09	2:45	04-Oct-09	13:34	649	16	10384	A1-TEC	9.1	0.00
1019091127	4	TX10583		Switch	56M26	Vehicles	04-Oct-09	2:45	04-Oct-09	13:14	629	9	5661	A1-TEC	9.1	0.00
1019091127	2	SW10036	riverside	Switch	56M26	Vehicles	04-Oct-09	6:45	04-Oct-09	7:43	58	64	3712	A1-TEC	9.1	0.00
1019091127	6	TX10582		Switch	56M26	Vehicles	04-Oct-09	2:45	04-Oct-09	14:26	701	4	2804	A1-TEC	9.1	0.00
1019091125	1	Service		Service	56M26	Tree falling	07-Oct-09	2:35	07-Oct-09	9:30	415	1	415	A1-TEC	3.1	6.92
1015090302	1	Service		Meter	56M26	Equipment failure	15-Oct-09	15:30	15-Oct-09	17:30	120	1	120	A1-TEC	5.92	2.00
1222090339	1	FS10059		Switch	56M26	Animal	27-Oct-09	9:32	27-Oct-09	10:55	83	40	3320	A1-TEC	9.2	55.33
1027091000	1	FS10059	FS10059	Switch	56M26	Animal	27-Oct-09	10:15	27-Oct-09	10:55	40	40	1600	A1-TEC	9.2	26.67
1118090305	1	FS10156	FS10156	Switch	56M26	Scheduled Outage	23-Nov-09	10:37	23-Nov-09	13:35	178	36	6408	A1-TEC	1	106.80
1118090307	1	FS10144	FS10144	Switch	56M26	Scheduled Outage	24-Nov-09	10:03	24-Nov-09	12:35	152	36	5472	A1-TEC	1	91.20
1118090311	1	TX10338	TX10338	UG Transformer	56M26	Scheduled Outage	25-Nov-09	9:35	25-Nov-09	12:04	149	9	1341	A1-TEC	1	22.35
0201101116	1	m26rc51	sw10036	Switch	56M26	Equipment failure	08-Dec-09	23:15	09-Dec-09	4:36	321	245	78645	A1-TEC	5.16	1310.75
1223090147	1	TEC-7	TEC-12	Switch	56M26	Tree falling	09-Dec-09	16:08	09-Dec-09	17:22	74	4170	308580	A1-TEC	3.2	5143.00
1223090147	2	TEC-12	TEC-5	Switch	56M26	Tree falling	09-Dec-09	16:08	09-Dec-09	19:11	183	397	72651	A1-TEC	3.2	1210.85
1223090112	1	Service		Service	56M26	Tree falling	09-Dec-09	16:08	09-Dec-09	20:15	247	1	247	A1-TEC	3.1	4.12
							Total 2009									**13298.08**

0202100907	1	service	service	Service	56M26	Equipment failure	18-Jan-10	20:00	18-Jan-10	21:30	90	1	90	A1-TEC	5.92	1.50	1	1.50
0305100339	1	service		Service	56M26	Equipment failure	15-Feb-10	17:15	15-Feb-10	19:15	120	1	120	A1-TEC	5.5	2.00	1	2.00
0316101114	1	FS10147		Switch	56M26	Equipment failure	04-Mar-10	18:32	04-Mar-10	20:40	128	8	1024	A1-TEC	5.24	17.07	1	17.07
0429100326	1	tx10639	tx10639	OH Transformer	56M26	Equipment failure	03-Apr-10	15:55	03-Apr-10	16:00	5	19	95	A1-TEC	5.14	1.58	1	1.58
0414100100	1	FS10232	FS10111	Switch	56M26	Equipment failure	14-Apr-10	13:25	14-Apr-10	13:40	15	92	1380	A1-TEC	5.14	23.00	1	23.00
0415100913	1	TX10620	TX10620	OH Transformer	56M26	Scheduled Outage	18-Apr-10	7:00	18-Apr-10	11:51	291	4	1164	A1-TEC	1	19.40	0	0.00
0518100946	1	Service		Service	56M26	Customer equipment	01-May-10	16:10	01-May-10	20:00	230	1	230	A1-TEC	5.92	3.83	1	3.83
0714100801	1	tx10701		OH Transformer	56M26	Equipment failure	10-May-10	15:20	10-May-10	18:00	160	28	4480	A1-TEC	5.92	74.67	1	74.67
0714100807	1	fs10025		Switch	56M26	Animal	14-May-10	8:45	14-May-10	10:00	75	209	15675	A1-TEC	9.2	261.25	1	261.25
0714101039	1	tx10603		OH Transformer	56M26	Scheduled Outage	28-May-10	9:40	28-May-10	11:50	130	27	3510	A1-TEC	1	58.50	0	0.00
0531100831	1	TX10594	TX10594	OH Transformer	56M26	Scheduled Outage	28-May-10	12:50	28-May-10	13:40	50	10	500	A1-TEC	1	8.33	0	0.00
0714101041	1	tx10588		OH Transformer	56M26	Equipment failure	29-May-10	9:30	29-May-10	11:00	90	2	180	A1-TEC	5.12	3.00	1	3.00
0604100914	1	SERVICE	SERVICE	Service	56M26	Equipment failure	01-Jun-10	12:00	01-Jun-10	13:45	105	1	105	A1-TEC	5.17	1.75	1	1.75
0604101007	1	FS10059	FS10059	Switch	56M26	Animal	04-Jun-10	9:36	04-Jun-10	10:46	70	41	2870	A1-TEC	9.2	47.83	1	47.83
0611101150	1	TX10686	TX10686	OH Transformer	56M26	Scheduled Outage	11-Jun-10	11:41	11-Jun-10	13:34	113	12	1356	A1-TEC	1	22.60	0	0.00
0714100827	1	tx10576		OH Transformer	56M26	Equipment failure	12-Jun-10	8:00	12-Jun-10	10:04	124	17	2108	A1-TEC	5.12	0.00	0	0.00
0714101042	1	FS10038		Switch	56M26	Animal	14-Jun-10	7:30	14-Jun-10	8:00	30	43	1290	A1-TEC	9.2	21.50	1	21.50
0714100757	1	Service	service	Service	56M26	Customer equipment	14-Jun-10	20:09	14-Jun-10	22:05	116	1	116	A1-TEC	5.92	1.93	1	1.93
0714100830	1	fs10040	tx10640	Switch	56M26	Animal	15-Jun-10	18:00	15-Jun-10	20:30	150	49	7350	A1-TEC	9.2	122.50	1	122.50
0714100831	1	fs10040	tx10901	OH Transformer	56M26	Animal	17-Jun-10	15:00	17-Jun-10	16:15	75	22	1650	A1-TEC	9.2	27.50	1	27.50
0617100328	1	TX10901	TX10901	OH Transformer	56M26	Animal	17-Jun-10	15:07	17-Jun-10	16:15	68	22	1496	A1-TEC	9.2	24.93	1	24.93
0714100904	1	tx10915		UG Transformer	56M26	Tree falling	18-Jun-10	10:42	18-Jun-10	13:45	183	19	3477	A1-TEC	3.2	0.00	0	0.00
0714100901	1	Service		Service	56M26	Human error	18-Jun-10	6:15	18-Jun-10	10:30	255	1	255	A1-TEC	9.1	4.25	1	4.25
0714100917	1	Service	service	Service	56M26	Tree falling	19-Jun-10	13:00	19-Jun-10	13:45	45	1	45	A1-TEC	3.2	0.75	1	0.75
0714100932	1	fs10057	fs10059	OH Transformer	56M26	Animal	20-Jun-10	6:15	20-Jun-10	8:15	120	66	7920	A1-TEC	9.2	132.00	1	132.00
0714100932	2	fs10059	tx10683	OH Transformer	56M26	Animal	20-Jun-10	6:15	20-Jun-10	8:16	121	38	4598	A1-TEC	9.2	76.63	1	76.63
0714100820	1	fs10185	tx10584	Switch	56M26	Animal	23-Jun-10	7:30	23-Jun-10	9:33	123	3	369	A1-TEC	9.2	6.15	1	6.15
0714100939	1	TX10579		OH Transformer	56M26	Animal	01-Jul-10	12:15	01-Jul-10	15:30	195	13	2535	A1-TEC	9.2	0.00	0	0.00
072710020212	1	FS10233	FS10233	Switch	56M26	Animal	09-Jul-10	15:35	09-Jul-10	17:25	110	53	5830	A1-TEC	9.2	97.17	1	97.17
072810101110	1	service		Service	56M26	Equipment failure	11-Jul-10	0:30	11-Jul-10	2:25	115	1	115	A1-TEC	5.92	1.92	1	1.92
0715100816	1	SERVICE	SERVICE	Service	56M26	Scheduled Outage	14-Jul-10	14:00	14-Jul-10	17:15	195	1	195	A1-TEC	1	3.25	0	0.00
072810092500	1	56M26		Station Breaker	56M26	Equipment failure	15-Jul-10	17:00	15-Jul-10	19:40	160	4569	731040	A1-TEC	5.6	12184.00	1	12184.00
0715101224	1	FS10144	FS10144	Switch	56M26	Scheduled Outage	15-Jul-10	13:40	15-Jul-10	14:20	40	33	1320	A1-TEC	1	22.00	0	0.00
0719100252	1	FS10144	FS10221	Switch	56M26	Scheduled Outage	20-Jul-10	10:30	20-Jul-10	11:00	30	33	990	A1-TEC	1	16.50	0	0.00
0719100255	1	FS10150	FS10150	Switch	56M26	Scheduled Outage	20-Jul-10	11:20	20-Jul-10	11:40	20	39	780	A7-LAS	1	13.00	0	0.00
080410114158	1	BREAKER	BREAKER	Unknown	56M26	Scheduled Outage	04-Aug-10	11:40	04-Aug-10	12:24	44	4569	201036	A1-TEC	1	3350.60	0	0.00
081010103135	1	FS10162	FS10162	Switch	56M26	Scheduled Outage	10-Aug-10	10:22	10-Aug-10	11:40	78	20	1560	A1-TEC	1	26.00	0	0.00
081110082219	1	TEC-12	TEC-12	Unknown	56M26	Scheduled Outage	11-Aug-10	9:35	11-Aug-10	13:15	220	398	87560	A1-TEC	1	1459.33	0	0.00
083010111934	2	service		Service	56M26	Human error	12-Aug-10	14:00	12-Aug-10	20:00	360	1	360	A1-TEC	9.1	6.00	1	6.00
083010111934	1	service		Service	56M26	Human error	12-Aug-10	16:20	12-Aug-10	20:15	235	1	235	A1-TEC	9.1	3.92	1	3.92
081210113728	1	TX10679	TX10679	OH Transformer	56M26	Scheduled Outage	12-Aug-10	11:33	12-Aug-10	11:37	4	14	56	A3-LEA	1	0.93	0	0.00
081110030937	1	SW10044	SW10044	Switch	56M26	Scheduled Outage	13-Aug-10	10:00	13-Aug-10	13:45	225	212	47700	A1-TEC	1	795.00	0	0.00
081610113437	1	FS10149		Switch	56M26	Scheduled Outage	16-Aug-10	16:30	16-Aug-10	18:10	100	99	9900	A1-TEC	5.6	165.00	0	0.00
092210091026	1	fs10149		Switch	56M26	Switch Overload	16-Aug-10	16:30	16-Aug-10	18:10	100	67	6700	A1-TEC	5.14	111.67	1	111.67
081610085947	1	TEC-6	TEC-6	Unknown	56M26	Scheduled Outage	17-Aug-10	9:30	17-Aug-10	13:30	240	747	179280	A1-TEC	1	2988.00	0	0.00
092210095426	1	fs10144		Switch	56M26	Equipment failure	18-Aug-10	0:10	18-Aug-10	3:30	200	31	6200	A1-TEC	5.4	0.00	0	0.00
081810021610	1	FS10043	FS10043	Switch	56M26	Scheduled Outage	18-Aug-10	14:09	18-Aug-10	15:07	58	49	2842	A1-TEC	1	47.37	0	0.00
081910101456	1	FS10166	FS10166	Switch	56M26	Scheduled Outage	18-Aug-10	12:00	18-Aug-10	12:06	6	124	744	A1-TEC	1	12.40	0	0.00
081810084957	1	FS10107	FS10107	Switch	56M26	Scheduled Outage	18-Aug-10	12:10	18-Aug-10	12:15	5	59	295	A1-TEC	1	4.92	0	0.00
082410104008	1	FS10185	FS10185	Switch	56M26	Scheduled Outage	24-Aug-10	11:14	24-Aug-10	12:05	51	3	153	A1-TEC	1	2.55	0	0.00
111710101257	1	fs10234		Switch	56M26	Animal	11-Sep-10	8:00	11-Sep-10	11:30	210	56	11760	A1-TEC	9.2	196.00	1	196.00
091610105646	1	FS10166	FS10166	Switch	56M26	Scheduled Outage	17-Sep-10	9:45	17-Sep-10	10:40	55	123	6765	A1-TEC	1	112.75	0	0.00
091710081259	1	FS10155	FS10155	Switch	56M26	Scheduled Outage	17-Sep-10	13:30	17-Sep-10	13:50	20	120	2400	A1-TEC	1	40.00	0	0.00
111710101317	2	fs10221		Switch	56M26	Equipment failure	17-Sep-10	17:24	17-Sep-10	19:30	126	16	2016	A1-TEC	5.4	0.00	0	0.00
111710101317	1	fs10144		Switch	56M26	Equipment failure	17-Sep-10	17:24	17-Sep-10	19:20	116	17	1972	A1-TEC	5.4	0.00	0	0.00
091710112143	1	TEC-12	TEC-12	Unknown	56M26	Scheduled Outage	23-Sep-10	9:30	23-Sep-10	12:27	177	48	8496	A1-TEC	1	141.60	0	0.00
091710113559	1	TEC-12	TEC-12	Unknown	56M26	Scheduled Outage	23-Sep-10	9:30	23-Sep-10	9:40	10	48	480	A1-TEC	1	8.00	0	0.00
111710094720	1	fs10221		Switch	56M26	Equipment failure	24-Sep-10	23:20	25-Sep-10	2:45	205	16	3280	A1-TEC	5.4	0.00	0	0.00
102610124808	1	TX10371	TX10371	UG Transformer	56M26	Scheduled Outage	04-Oct-10	11:06	04-Oct-10	14:30	204	8	1632	A1-TEC	1	27.20	0	0.00
100410110902	1	TX10372	TX10372	UG Transformer	56M26	Scheduled Outage	04-Oct-10	9:30	04-Oct-10	9:40	10	9	90	A1-TEC	1	1.50	0	0.00
100510095653	1	TX10369	TX10369	UG Transformer	56M26	Scheduled Outage	05-Oct-10	10:00	05-Oct-10	14:30	270	5	1350	A1-TEC	1	22.50	0	0.00
093010121410	1	TEC-12	TEC-12	Unknown	56M26	Scheduled Outage	06-Oct-10	9:43	06-Oct-10	14:50	307	48	14736	A1-TEC	1	245.60	0	0.00
102510095056	1	FS10126	FS10126	Switch	56M26	Scheduled Outage	25-Oct-10	9:30	25-Oct-10	13:24	234	21	4914	A1-TEC	1	81.90	0	0.00
120910024540	1	FS100400	FS100400	Switch	56M26	Scheduled Outage	09-Dec-10	14:33	09-Dec-10	15:05	32	48	1536	A1-TEC	1	25.60	0	0.00
011711023948	1	wire		UG Conductor	56M26	Equipment failure	26-Dec-10	19:00	26-Dec-10	22:30	210	11	2310	A1-TEC	5.22	38.50	1	38.50
0714100808	1	tx10320		Switch	56M4	Equipment failure	05-Jun-10	14:15	05-Jun-10	16:45	150	8	1200	A1-TEC	5.24	20.00	1	20.00
							Total 2010									**23237.13**	**30.00**	**13514.80**

011911102018	1	station breaker	station breaker	Station Breaker	56M26	Animal	19-Jan-11	10:10	19-Jan-11	10:38	28	4569	127932	A1-TEC	9.2	2132.20	1	2132.20
011411030616	1	FS10097	FS10234	Switch	56M26	Scheduled Outage	19-Jan-11	10:00	19-Jan-11	10:30	30	73	2190	A1-TEC	1	36.50	0	0.00
011411031143	1	fs10144	fs10144	Switch	56M26	Scheduled Outage	19-Jan-11	13:07	19-Jan-11	13:23	16	35	560	A1-TEC	1	9.33	0	0.00
012611082819	1	TX10368	TX10336	UG Transformer	56M26	Equipment failure	26-Jan-11	16:30	26-Jan-11	20:30	240	11	2640	A1-TEC	5.23	44.00	1	44.00
012611082819	2	TX10336	TX10336	UG Transformer	56M26	Equipment failure	26-Jan-11	16:30	26-Jan-11	21:05	275	5	1375	A1-TEC	5.23	22.92	1	22.92
040111110316	1	FS10038		OH Transformer	56M26	Equipment failure	13-Feb-11	15:45	13-Feb-11	18:05	140	43	6020	A1-TEC	5.6	100.33	1	100.33
040111123120	1	tx10679		OH Transformer	56M26	Tree growth	12-Mar-11	11:45	12-Mar-11	13:55	130	14	1820	A1-TEC	3.1	30.33	1	30.33
051211022341	1	TX10901		OH Transformer	56M26	Animal	12-May-11	8:00	12-May-11	9:43	103	22	2266	A1-TEC	9.2	37.77	1	37.77
053011033149	1	TX10708		OH Transformer	56M26	Animal	14-May-11	7:45	14-May-11	8:36	51	20	1020	A1-TEC	9.2	17.00	1	17.00
062711032734	1	Tx10628		OH Transformer	56M26	Equipment failure	31-May-11	13:36	31-May-11	15:30	114	10	1140	A1-TEC	5.92	19.00	1	19.00
070411031114	1	FS10023		Switch	56M26	Human error	11-Jun-11	9:45	11-Jun-11	11:00	75	72	5400	A1-TEC	9.1	90.00	1	90.00
070411031109	1	FS10169		Switch	56M26	Animal	15-Jun-11	14:30	15-Jun-11	15:45	75	193	14475	A1-TEC	9.2	241.25	1	241.25
100311041712	1	TX10692		OH Transformer	56M26	Lightning	30-Jun-11	11:34	30-Jun-11	14:15	161	17	2737	A1-TEC	4	45.62	1	45.62
100511092920	1	FS10232		Switch	56M26	Other	03-Jul-11	17:14	03-Jul-11	22:30	316	92	29072	A1-TEC	6	484.53	1	484.53
100511014607	1	FS10205		Switch	56M26	Tree falling-weather	04-Jul-11	18:41	05-Jul-11	16:00	1279	32	40928	A1-TEC	3.2	682.13	1	682.13
092611050416	1	FS10019		Switch	56M26	Animal	10-Jul-11	8:00	10-Jul-11	8:45	45	29	1305	A1-TEC	9.2	21.75	1	21.75
092611045312	1	TX10679		OH Transformer	56M26	Tree falling	11-Jul-11	15:30	11-Jul-11	20:30	300	14	4200	A1-TEC	6	70.00	1	70.00
092611043629	1	TX10689		OH Transformer	56M26	Animal	15-Jul-11	20:49	15-Jul-11	22:30	101	11	1111	A1-TEC	9.2	18.52	1	18.52
072811075420	1	FS10091	TX10319	Switch	56M26	Lightning	18-Jul-11	14:30	18-Jul-11	17:45	195	163	31785	A1-TEC	4	529.75	1	529.75
081911102209	1	FS10092		Switch	56M26	Tree falling-weather	19-Jul-11	15:00	20-Jul-11	14:30	1410	3	4230	A1-TEC	3.1	70.50	1	70.50
100611104323	1	FS10025		Switch	56M26	Lightning	24-Jul-11	19:41	24-Jul-11	23:50	249	72	17928	A1-TEC	4	298.80	1	298.80
100611104323	3	FS10083		Switch	56M26	Lightning	24-Jul-11	19:41	25-Jul-11	2:16	395	1	395	A1-TEC	4	6.58	1	6.58
100611104323	2	FS10085		Switch	56M26	Lightning	24-Jul-11	19:41	25-Jul-11	1:40	359	1	359	A1-TEC	4	5.98	1	5.98
082211110259	1	Service		Service	56M26	Human error	09-Aug-11	15:50	09-Aug-11	19:15	205	1	205	A1-TEC	9.1	3.42	1	3.42
091311082559	1	FS10169		Switch	56M26	Scheduled Outage	13-Sep-11	9:12	13-Sep-11	9:40	28	205	5740	A1-TEC	1	95.67	0	0.00
091411102240	1	TX10092		UG Transformer	56M26	Scheduled Outage	15-Sep-11	9:39	15-Sep-11	14:35	296	10	2960	A1-TEC	1	49.33	0	0.00
091611124000	1	FS10096		Switch	56M26	Scheduled Outage	16-Sep-11	12:36	16-Sep-11	12:51	15	38	570	A1-TEC	1	9.50	0	0.00
092211082850	1	TX10094		UG Transformer	56M26	Scheduled Outage	22-Sep-11	9:45	22-Sep-11	14:00	255	10	2550	A1-TEC	1	0.00	0	0.00
092611123438	1	FS10144		Switch	56M26	Equipment failure	24-Sep-11	13:50	24-Sep-11	17:00	190	36	6840	A1-TEC	5.4	114.00	1	114.00
092711094954	1	TX10377		UG Transformer	56M26	Scheduled Outage	27-Sep-11	9:40	27-Sep-11	11:40	120	11	1320	A1-TEC	1	22.00	0	0.00
092711094211	1	TX10371		UG Transformer	56M26	Scheduled Outage	27-Sep-11	9:40	27-Sep-11	9:50	10	8	80	A1-TEC	1	1.33	0	0.00
100511093850	1	FS10169	FS10241	Switch	56M26	Scheduled Outage	05-Oct-11	9:46	05-Oct-11	10:00	14	100	1400	A1-TEC	1	23.33	0	0.00
100511125422	1	FS10169	FS10240	Switch	56M26	Scheduled Outage	05-Oct-11	9:40	05-Oct-11	11:03	83	93	7719	A1-TEC	1	128.65	0	0.00
101211083845	1	FS10169		Switch	56M26	Scheduled Outage	12-Oct-11	9:20	12-Oct-11	9:40	20	20	400	A1-TEC	1	6.67	0	0.00
101211083845	2	FS10169	TX10101	Switch	56M26	Scheduled Outage	12-Oct-11	9:20	12-Oct-11	11:41	141	6	846	A1-TEC	1	14.10	0	0.00
101411012112	1	FS10169	FS10239	Switch	56M26	Scheduled Outage	05-Oct-11	12:55	05-Oct-11	13:10	15	18	270	A1-TEC	1	4.50	0	0.00
101711014851	1	FS10241		Switch	56M26	Scheduled Outage	17-Oct-11	13:50	17-Oct-11	14:10	20	75	1500	A1-TEC	1	25.00	0	0.00
101711080950	1	FS10085		Switch	56M26	Lightning	24-Jul-11	19:41	25-Jul-11	1:40	359	104	37336	A1-TEC	4	622.27	1	622.27
101711123444	1	FS10239		Switch	56M26	Scheduled Outage	17-Oct-11	12:42	17-Oct-11	13:29	47	50	2350	A1-TEC	1	39.17	0	0.00
101811011442	1	SW10003		Switch	56M26	Scheduled Outage	18-Oct-11	11:44	18-Oct-11	12:48	64	1243	79552	A1-TEC	0.1	1325.87	0	0.00
102811014623	1	FS10040		Switch	56M26	Other	27-Oct-11	17:05	27-Oct-11	18:55	110	48	5280	A1-TEC	0.1	88.00	1	88.00
111511105953	1	FS10232		Switch	56M26	Equipment failure	12-Nov-11	23:59	13-Nov-11	6:10	371	176	65296	A1-TEC	5.4	1088.27	1	1088.27
112111013346	1	FS10144		Switch	56M26	Scheduled Outage	22-Nov-11	9:00	22-Nov-11	14:04	304	37	11248	A1-TEC	1	187.47	0	0.00
112811083732	1	FS10210		Switch	56M26	Scheduled Outage	28-Nov-11	8:55	28-Nov-11	14:29	334	14	4676	A1-TEC	1	77.93	0	0.00
112811083732	2	FS10210		Switch	56M26	Scheduled Outage	28-Nov-11	8:55	28-Nov-11	9:05	10	22	220	A1-TEC	1	3.67	0	0.00
112811083732	3	FS10210		Switch	56M26	Scheduled Outage	28-Nov-11	14:19	28-Nov-11	14:29	10	22	220	A1-TEC	1	3.67	0	0.00
112911091820	1	FS10242		Switch	56M26	Equipment failure	29-Nov-11	9:13	29-Nov-11	9:30	17	40	680	A1-TEC	5.6	11.33	1	11.33
120211101911	1	FS10232		Switch	56M26	Scheduled Outage	02-Dec-11	10:19	02-Dec-11	11:45	86	92	7912	A1-TEC	1	131.87	0	0.00
062711030533	2	FS10159	TX10300	Switch	56M25	Lightning	10-May-11	8:45	10-May-11	18:30	585	123	71955	A1-TEC	4	1199.25	1	1199.25
120211124137	1	TX10090		UG Transformer	56M26	Scheduled Outage	02-Dec-11	12:42	02-Dec-11	13:04	22	10	220	A1-TEC	1	3.67	0	0.00
							Total 2011									**10294.72**	**28.00**	**8095.50**
010312101910	1	FS10210	FS10156	Switch	56M26	Scheduled Outage	06-Jan-12	9:30	06-Jan-12	10:10	40	36	1440	A1-TEC	1	24.00	0	0.00
010512015259	1	TX10680		OH Transformer	56M26	Scheduled Outage	05-Jan-12	12:35	05-Jan-12	13:50	75	20	1500	A1-TEC	5.14	25.00	1	25.00
021412111152	1	MV110010		UG Transformer	56M26	Scheduled Outage	14-Feb-12	11:12	14-Feb-12	11:38	26	50	1300	A1-TEC	1	21.67	0	0.00
021612104615	1	TX10308		UG Transformer	56M26	Scheduled Outage	16-Feb-12	10:43	16-Feb-12	11:03	20	80	1600	A1-TEC	1	26.67	0	0.00
022112091759	1	MV110005		Switch	56M26	Scheduled Outage	21-Feb-12	9:15	21-Feb-12	9:33	18	90	1620	A1-TEC	1	27.00	0	0.00
030312050209	1	TX10681		OH Transformer	56M26	Equipment failure	28-Jan-12	23:15	29-Jan-12	3:15	240	10	2400	A1-TEC	5.14	40.00	1	40.00
030512012512	1	FS10244		Switch	56M26	Scheduled Outage	05-Mar-12	13:26	05-Mar-12	13:48	22	70	1540	A1-TEC	1	25.67	0	0.00
030512015349	1	FS10240		Switch	56M26	Scheduled Outage	05-Mar-12	14:05	05-Mar-12	14:26	21	51	1071	A1-TEC	1	17.85	0	0.00
030512023036	1	FS10239		Switch	56M26	Scheduled Outage	05-Mar-12	14:28	05-Mar-12	14:44	16	36	576	A1-TEC	1	9.60	0	0.00
030512103554	1	FS10238		Switch	56M26	Scheduled Outage	05-Mar-12	10:36	05-Mar-12	10:59	23	122	2806	A1-TEC	1	46.77	0	0.00
031212095707	1	FS10023		Switch	56M26	Scheduled Outage	12-Mar-12	10:02	12-Mar-12	11:06	64	50	3200	A1-TEC	5.6	53.33	1	53.33
041412035941	1	FS10094	FS10043	Switch	56M26	Lightning	30-Mar-12	3:30	30-Mar-12	4:45	75	25	1875	A1-TEC	4	31.25	1	31.25
041412035941	2	FS10094	FS10094	Switch	56M26	Lightning	30-Mar-12	3:30	30-Mar-12	4:55	85	97	8245	A1-TEC	4	137.42	1	137.42
041612082522	1	TX10527		OH Transformer	56M26	Scheduled Outage	16-Apr-12	10:00	16-Apr-12	12:10	130	18	2340	A1-TEC	1	39.00	0	0.00
043012091804	1	TX10699		OH Transformer	56M26	Animal	26-Apr-12	7:35	26-Apr-12	8:45	70	13	910	A1-TEC	9.2	15.17	1	15.17
060812124447	1	FS10083		Switch	56M26	Animal	07-Jun-12	6:44	07-Jun-12	9:00	136	1	136	A1-TEC	9.2	2.27	1	2.27
061512025807	1	FS10238		Switch	56M26	Animal	09-Jun-12	6:50	09-Jun-12	8:50	120	123	14760	A1-TEC	9.2	246.00	1	246.00
061812020019	1	TX10679		OH Transformer	56M26	Animal	15-Jun-12	20:00	15-Jun-12	22:28	148	14	2072	A1-TEC	9.2	34.53	1	34.53
061812020603	1	Service		UG Conductor	56M26	Human error	16-Jun-12	14:43	16-Jun-12	16:30	107	1	107	A1-TEC	9.1	1.78	1	1.78
062212023745	1	UG Conductor		UG Conductor	56M26	Equipment failure	21-Jun-12	16:30	21-Jun-12	23:00	390	1	390	A1-TEC	5.5	6.50	1	6.50
062612095003	1	TX10627		OH Transformer	56M26	Animal	23-Jun-12	7:30	23-Jun-12	9:45	135	18	2430	A1-TEC	9.2	40.50	1	40.50
070312104119	1	FS10246		Switch	56M26	Scheduled Outage	03-Jul-12	10:05	03-Jul-12	10:14	9	24	216	A1-TEC	4	3.60	1	3.60
070312114552	1	FS10021		Switch	56M26	Scheduled Outage	03-Jul-12	10:31	03-Jul-12	11:36	65	41	2665	A1-TEC	4	44.42	1	44.42
082312020807	1	TX10624		OH Transformer	56M26	Scheduled Outage	23-Aug-12	13:15	23-Aug-12	13:45	30	17	510	A1-TEC	9.2	8.50	1	8.50
092012082956	1	TX10147		UG Transformer	56M26	Equipment failure	18-Sep-12	16:40	18-Sep-12	18:30	110	10	1100	A1-TEC	5.4	18.33	1	18.33
100112094614	1	TX10701		OH Transformer	56M26	Animal	29-Sep-12	15:00	29-Sep-12	17:20	140	27	3780	A1-TEC	9.2	63.00	1	63.00
103012092218	1	FS10026		Switch	56M26	Equipment failure	27-Oct-12	15:15	27-Oct-12	17:40	145	23	3335	A1-TEC	5.6	55.58	1	55.58
103012123251	1	MV10005		Switch	56M26	Scheduled Outage	30-Oct-12	11:40	30-Oct-12	13:57	137	468	64116	A1-TEC	5.6	1068.60	1	1068.60
110812084412	1	FS10187		Switch	56M26	Scheduled Outage	08-Nov-12	9:00	08-Nov-12	13:39	279	19	5301	A1-TEC	1	88.35	0	0.00
121212093812	1	Station Breaker		Station Breaker	56M26	Loss of supply	06-Dec-12	14:11	06-Dec-12	15:07	56	4209	235704	A1-TEC	2	3928.40	0	0.00
121712074516	1	TEC-7		Switch	56M26	Vehicles	07-Dec-12	9:30	07-Dec-12	9:38	8	4209	33672	A1-TEC	9.1	561.20	1	561.20
121712074516	2	SW10004	56M8-56M26	Switch	56M26	Vehicles	07-Dec-12	9:38	07-Dec-12	10:27	49	384	18816	A1-TEC	9.1	313.60	1	313.60
121712074516	3	SW10005		Switch	56M26	Vehicles	07-Dec-12	10:27	07-Dec-12	13:54	207	64	13248	A1-TEC	9.1	220.80	1	220.80
							Total 2012									**7246.35**	**22.00**	**2991.38**

13113090316	1	FS10243	NULL	Switch	56M26	Animal	30-Jan-13	17:55	30-Jan-13	21:15	200	100	20000	A1-TEC	9.2	333.33	1	333.33
40913025116	1	TEC-7	NULL	Switch	56M26	Scheduled Outage	14-Apr-13	6:10	14-Apr-13	6:26	16	4155	66480	A1-TEC	1	1108.00	0	0.00
40913030243	1	SW10005	SW10004	Switch	56M26	Scheduled Outage	14-Apr-13	6:10	14-Apr-13	9:25	195	63	12285	A1-TEC	1	204.75	0	0.00
41513083500	1	TEC-7	NULL	Switch	56M26	Scheduled Outage	14-Apr-13	9:20	14-Apr-13	9:25	5	4155	20775	A1-TEC	1	346.25	0	0.00
42613075422	1	TX10680	NULL	OH Transformer	56M26	Animal	25-Apr-13	6:30	25-Apr-13	7:50	80	20	1600	A1-TEC	9.2	26.67	1	26.67
52413082714	1	TX10526	NULL	OH Transformer	56M26	Scheduled Outage	24-May-13	11:00	24-May-13	12:40	100	20	2000	A1-TEC	1	33.33	0	0.00
52413083818	1	TX10526	NULL	Switch	56M26	Scheduled Outage	24-May-13	9:20	24-May-13	12:40	200	5	1000	A1-TEC	1	16.67	0	0.00
60513024417	1	TX10678	NULL	OH Transformer	56M26	Animal	31-May-13	7:00	31-May-13	8:45	105	18	1890	A1-TEC	9.2	31.50	1	31.50
61713091946	1	TX10633	NULL	OH Transformer	56M26	Animal	15-Jun-13	7:55	15-Jun-13	9:45	110	20	2200	A1-TEC	9.2	36.67	1	36.67
61813092635	1	TX10690	NULL	OH Transformer	56M26	Animal	18-Jun-13	7:30	18-Jun-13	8:55	85	16	1360	A1-TEC	9.2	22.67	1	22.67
62513104726	1	TX10901	NULL	OH Transformer	56M26	Animal	22-Jun-13	8:11	22-Jun-13	10:45	154	22	3388	A1-TEC	9.2	56.47	1	56.47
70313034700	1	TX10609	NULL	OH Transformer	56M26	Lightning	28-Jun-13	13:31	28-Jun-13	14:25	54	16	864	A1-TEC	4	14.40	1	14.40
70313035102	1	TX10610	NULL	OH Transformer	56M26	Lightning	28-Jun-13	14:03	28-Jun-13	14:50	47	2	94	A1-TEC	4	1.57	1	1.57
71113112826	1	SERVICE	NULL	Service	56M26	Tree falling	06-Jul-13	7:15	06-Jul-13	14:45	450	1	450	A1-TEC	3.2	7.50	1	7.50
71713114515	1	FS10043	NULL	Switch	56M26	Other	13-Jul-13	6:45	13-Jul-13	11:15	270	47	12690	A1-TEC	0	211.50	1	211.50
71713114524	1	FS10040	TX10901	Switch	56M26	Other	14-Jul-13	8:50	14-Jul-13	13:30	280	48	13440	A1-TEC	0	224.00	1	224.00
72413075910	1	FS10059	NULL	Switch	56M26	Storm	19-Jul-13	19:30	19-Jul-13	22:10	160	41	6560	A1-TEC	6	109.33	1	109.33
72413084323	1	TX10527	NULL	OH Transformer	56M26	Storm	20-Jul-13	15:00	20-Jul-13	18:25	205	18	3690	A1-TEC	6	61.50	1	61.50
72513075918	1	FS10040	NULL	Switch	56M26	Storm	20-Jul-13	17:15	20-Jul-13	19:15	120	48	5760	A1-TEC	6	96.00	1	96.00
73013015706	1	CONDUCTOR	NULL	OH Conductor	56M26	Tree falling	20-Jul-13	7:53	20-Jul-13	12:00	247	1	247	A1-TEC	3.2	4.12	1	4.12
82313123923	1	MV10005	NULL	UG switch unit	56M26	Equipment failure	21-Aug-13	17:07	22-Aug-13	0:30	443	296	131128	A1-TEC	5.4	2185.47	1	2185.47
82613111322	1	FS10092	NULL	Switch	56M26	Scheduled Outage	23-Aug-13	8:30	23-Aug-13	11:30	180	1	180	A1-TEC	1	3.00	0	0.00
90613041044	1	TX10706	NULL	OH Transformer	56M26	Scheduled Outage	09-Sep-13	13:00	09-Sep-13	14:24	84	19	1596	A1-TEC	1	26.60	0	0.00
92713075625	1	TX10708	NULL	OH Transformer	56M26	Animal	22-Sep-13	8:30	22-Sep-13	12:00	210	20	4200	A1-TEC	9.2	70.00	1	70.00
93013105742	1	FS10099	FS10246	Switch	56M26	Equipment failure	26-Sep-13	20:00	26-Sep-13	22:15	135	24	3240	A1-TEC	5.4	54.00	1	54.00
101513030405	1	FS10040	NULL	Switch	56M26	Other	12-Oct-13	18:34	12-Oct-13	21:57	203	49	9947	A1-TEC	0.1	165.78	1	165.78
101513033026	1	FS10238	NULL	Switch	56M26	Other	15-Oct-13	15:08	15-Oct-13	16:40	92	113	10396	A1-TEC	0.1	173.27	1	173.27
102813014916	1	SERVICE	NULL	Service	56M26	Equipment failure	24-Oct-13	22:05	25-Oct-13	7:00	535	1	535	A1-TEC	5.5	8.92	1	8.92
102913102115	1	MV10005	NULL	UG switch unit	56M26	Scheduled Outage	29-Oct-13	10:15	29-Oct-13	13:30	195	174	33930	A1-TEC	1	565.50	0	0.00
110413105711	1	TX10624	NULL	OH Transformer	56M26	Animal	02-Nov-13	16:45	02-Nov-13	18:00	75	18	1350	A1-TEC	9.2	22.50	1	22.50
110513102212	1	TX10917	NULL	OH Transformer	56M26	Equipment failure	05-Nov-13	8:08	05-Nov-13	11:04	176	23	4048	A1-TEC	5.12	67.47	1	67.47
110613013309	1	MV10015	NULL	UG switch unit	56M26	Scheduled Outage	06-Nov-13	13:08	06-Nov-13	13:37	29	174	5046	A1-TEC	1	84.10	0	0.00
112013105304	1	SW10007	NULL	Switch	56M26	Scheduled Outage	20-Nov-13	10:15	20-Nov-13	12:30	135	51	6885	A1-TEC	1	114.75	0	0.00
10614011604	1	MV10005	NULL	UG switch unit	56M26	Equipment failure	22-Dec-13	0:51	22-Dec-13	5:30	279	223	62217	A1-TEC	5.23	1036.95	1	1036.95
10614011604	2	MV10005	TX10300	UG switch unit	56M26	Equipment failure	22-Dec-13	0:51	22-Dec-13	5:30	279	52	14508	A1-TEC	5.23	241.80	1	241.80
10614011604	3	TX10300	MV10015	UG switch unit	56M26	Equipment failure	22-Dec-13	0:51	22-Dec-13	8:57	486	122	59292	A1-TEC	5.23	988.20	1	988.20
10614021422	1	FS10102	TX10250	Switch	56M26	Equipment failure	27-Dec-13	15:50	27-Dec-13	19:37	227	7	1589	A1-TEC	5.11	26.48	1	26.48
10614021422	2	TX10250	TX10251	Switch	56M26	Equipment failure	27-Dec-13	15:50	27-Dec-13	21:15	325	6	1950	A1-TEC	5.11	32.50	1	32.50
							Total 2013									**8813.50**	**28.00**	**6310.55**
10814125057	1	56M26	NULL	Station Breaker	56M26	Loss of supply	06-Jan-14	22:09	06-Jan-14	22:11	2	4051	8102	A1-TEC	2	135.03	0	0.00
10814125100	1	56M26	NULL	Station Breaker	56M26	Loss of supply	06-Jan-14	22:18	06-Jan-14	22:46	28	4051	113428	A1-TEC	2	1890.47	0	0.00
10814125110	1	TEC-8	56M26	Station Breaker	56M26	Loss of supply	06-Jan-14	22:48	06-Jan-14	23:53	65	4051	263315	A1-TEC	2	4388.58	0	0.00
11514112021	1	TX10624	NULL	OH Transformer	56M26	Animal	14-Jan-14	16:15	14-Jan-14	18:18	123	25	3075	A1-TEC	9.2	51.25	1	51.25
12114114353	1	TX10601	NULL	OH Transformer	56M26	Equipment failure	20-Jan-14	16:17	20-Jan-14	18:30	133	18	2394	A1-TEC	5.12	39.90	1	39.90
12114124724	1	TX10690	NULL	OH Transformer	56M26	Scheduled Outage	21-Jan-14	11:04	21-Jan-14	11:15	11	16	176	A1-TEC	1	2.93	0	0.00
12114125343	1	TX10687	NULL	OH Transformer	56M26	Scheduled Outage	21-Jan-14	11:38	21-Jan-14	11:49	11	7	77	A1-TEC	1	1.28	0	0.00
12114125642	1	TX10689	NULL	OH Transformer	56M26	Scheduled Outage	21-Jan-14	10:32	21-Jan-14	10:44	12	11	132	A1-TEC	1	2.20	0	0.00
12114010034	1	TX10691	NULL	OH Transformer	56M26	Scheduled Outage	21-Jan-14	12:44	21-Jan-14	13:04	20	19	380	A1-TEC	1	6.33	0	0.00
12214103825	1	TX10695	NULL	OH Transformer	56M26	Scheduled Outage	22-Jan-14	10:40	22-Jan-14	11:01	21	21	441	A1-TEC	1	7.35	0	0.00
12214112648	1	TX10696	NULL	OH Transformer	56M26	Scheduled Outage	22-Jan-14	11:25	22-Jan-14	11:40	15	19	285	A1-TEC	1	4.75	0	0.00
12214124604	1	TX10697	NULL	OH Transformer	56M26	Scheduled Outage	22-Jan-14	12:45	22-Jan-14	12:58	13	24	312	A1-TEC	1	5.20	0	0.00
12214011117	1	TX10642	NULL	OH Transformer	56M26	Scheduled Outage	22-Jan-14	13:15	22-Jan-14	13:26	11	18	198	A1-TEC	1	3.30	0	0.00
12214014539	1	TX10641	NULL	OH Transformer	56M26	Scheduled Outage	22-Jan-14	13:42	22-Jan-14	14:01	19	17	323	A1-TEC	1	5.38	0	0.00
12314124316	1	TX10801	NULL	OH Transformer	56M26	Scheduled Outage	23-Jan-14	12:40	23-Jan-14	12:52	12	17	204	A1-TEC	1	3.40	0	0.00
12314010132	1	TX10901	NULL	OH Transformer	56M26	Scheduled Outage	23-Jan-14	13:02	23-Jan-14	13:08	6	39	234	A1-TEC	1	3.90	0	0.00
12314011255	1	TX10640	NULL	OH Transformer	56M26	Scheduled Outage	23-Jan-14	13:11	23-Jan-14	13:25	14	27	378	A1-TEC	1	6.30	0	0.00
12314013019	1	TX10638	NULL	OH Transformer	56M26	Scheduled Outage	23-Jan-14	13:28	23-Jan-14	13:39	11	22	242	A1-TEC	1	4.03	0	0.00
12314014555	1	TX10637	NULL	OH Transformer	56M26	Scheduled Outage	23-Jan-14	13:45	23-Jan-14	14:02	17	21	357	A1-TEC	1	5.95	0	0.00
21314095619	1	TX10515	NULL	UG Transformer	56M26	Scheduled Outage	13-Feb-14	9:30	13-Feb-14	11:31	121	1	121	A1-TEC	1	2.02	0	0.00
22114011848	1	FS10102	TX10251	Switch	56M26	Animal	21-Feb-14	12:40	21-Feb-14	13:41	61	13	793	A1-TEC	9.2	13.22	1	13.22
30514010152	1	TX10527	NULL	OH Transformer	56M26	Scheduled Outage	05-Mar-14	13:00	05-Mar-14	14:13	73	18	1314	A1-TEC	1	21.90	0	0.00
41114092951	1	FS10084	TX10515	Switch	56M26	Scheduled Outage	11-Apr-14	9:30	11-Apr-14	14:10	280	35	9800	A1-TEC	1	163.33	0	0.00
52014120438	1	TX10639	NULL	OH Transformer	56M26	Scheduled Outage	20-May-14	10:30	20-May-14	12:00	90	20	1800	A1-TEC	1	30.00	0	0.00
52614114440	1	FS10040	NULL	Switch	56M26	Animal	23-May-14	8:33	23-May-14	9:55	82	49	4018	A1-TEC	9.2	66.97	1	66.97
53014092710	1	FS10040	NULL	Switch	56M26	Animal	30-May-14	8:13	30-May-14	9:38	85	49	4165	A1-TEC	9.2	69.42	1	69.42
53014040731	1	MV10005	NULL	UG switch unit	56M26	Scheduled Outage	03-Jun-14	9:20	03-Jun-14	11:11	111	129	14319	A1-TEC	1	238.65	0	0.00
53014041615	1	TX10309	NULL	UG Transformer	56M26	Scheduled Outage	03-Jun-14	9:20	03-Jun-14	11:11	111	8	888	A1-TEC	1	14.80	0	0.00
61614012421	1	TX10613	NULL	OH Transformer	56M26	Scheduled Outage	16-Jun-14	13:19	16-Jun-14	14:10	51	27	1377	A1-TEC	1	22.95	0	0.00
62714101135	1	TX10610	NULL	OH Transformer	56M26	Scheduled Outage	27-Jun-14	10:06	27-Jun-14	11:30	84	2	168	A1-TEC	1	2.80	0	0.00
71914111703	1	TX10613	NULL	OH Transformer	56M26	Animal	29-Jun-14	8:44	29-Jun-14	13:00	256	27	6912	A1-TEC	9.2	115.20	1	115.20
63014103159	1	TX10688	NULL	OH Transformer	56M26	Scheduled Outage	30-Jun-14	10:30	30-Jun-14	10:39	9	5	45	A1-TEC	1	0.75	0	0.00
71914123034	1	FS10170	NULL	Switch	56M26	Equipment failure	01-Jul-14	6:18	01-Jul-14	8:48	150	39	5850	A1-TEC	5.11	97.50	1	97.50
71914123034	2	FS10170	TX10706	Switch	56M26	Equipment failure	01-Jul-14	6:18	01-Jul-14	14:15	477	21	10017	A1-TEC	5.11	166.95	1	166.95
70314104205	1	FS10040	NULL	Switch	56M26	Animal	03-Jul-14	8:36	03-Jul-14	10:59	143	49	7007	A1-TEC	9.2	116.78	1	116.78
72114104947	1	TX10110	NULL	UG Transformer	56M26	Equipment failure	21-Jul-14	4:33	21-Jul-14	10:34	361	24	8664	A1-TEC	5.23	144.40	1	144.40
							To Date 2014									**7855.18**	**10.00**	**881.58**

Feeder 56M4

outage_id	Restore_Step	from Restore_Device	to_restore_device	Device	Feeder	Cause	DtOut	TmOut	DtRes	TmRes	Duration	NumCust	SubCustMin	AREA_TOWN	Equipment_code	Customer Hours	Modifier	Customer Hours Modified
A0240	1	TX10579		Fused Disconnect	56M4	Animal	13-Aug-08	7:30	13-Aug-08	9:45	135	13	1755	A1-TEC	9.2	0.00	0	0.00
0203	1	TX10318		Other	56M4	Other	14-Sep-08	2:18	14-Sep-08	4:30	132	13	1716	A1-TEC	5.6	28.60	1	28.60
							Total 2008									**28.60**	**1.00**	**28.60**
1223090924	1	MV10017	TX10925	UG Transformer	56M4	Equipment failure	08-Nov-09	13:12	09-Nov-09	14:14	1502	20	30040	A1-TEC	5.5	500.67	1	500.67
1223090905	1	MV10017	TX10925	UG switch unit	56M4	Customer equipment	09-Nov-09	21:30	10-Nov-09	5:05	455	65	29575	A1-TEC	8	492.92	1	492.92
1223090905	2	TX10925		UG switch unit	56M4	Customer equipment	09-Nov-09	21:30	10-Nov-09	17:30	1200	21	25200	A1-TEC	8	420.00	1	420.00
							Total 2009									**1413.58**	**3.00**	**1413.58**
0714100808	2	fs10140		Switch	56M4	Equipment failure	05-Jun-10	14:15	05-Jun-10	17:00	165	54	1485	A1-TEC	5.24	24.75	1	24.75
0714100808	1	tx10320		Switch	56M4	Equipment failure	05-Jun-10	14:15	05-Jun-10	16:45	150	8	1200	A1-TEC	5.24	0.00	0	0.00
081610110012	1	TX10658	TX10658	OH Transformer	56M4	Animal	13-Aug-10	9:07	13-Aug-10	9:30	23	1	23	A1-TEC	9.2	0.38	1	0.38
							Total 2010									**25.13**	**2.00**	**25.13**
031611034259	1	FS10159		UG Conductor	56M4	Scheduled Outage	16-Mar-11	13:07	16-Mar-11	15:38	151	98	14798	A1-TEC	5.4	246.63	1	246.63
050211094635	1	SW10009		Switch	56M4	Scheduled Outage	25-Apr-11	7:00	25-Apr-11	16:15	555	1	555	A1-TEC	1	9.25	1	9.25
053011034855	1	FS10158		Switch	56M4	Customer equipment	24-May-11	9:15	24-May-11	10:18	63	123	7749	A1-TEC	5.6	129.15	1	129.15
							Total 2011									**385.03**	**3.00**	**385.03**
010412095626	1	TX10205		UG Transformer	56M4	Scheduled Outage	04-Jan-12	9:55	04-Jan-12	12:00	125	11	1375	A1-TEC	1	22.92	0	0.00
022212093340	1	MV110005		Switch	56M4	Scheduled Outage	22-Feb-12	9:34	22-Feb-12	10:22	48	250	12000	A1-TEC	1	200.00	0	0.00
070612023816	1	FS10140		Switch	56M4	Equipment failure	04-Jul-12	6:00	04-Jul-12	10:02	242	80	19360	A1-TEC	5.26	322.67	1	322.67
070612024623	1	FS10227		Switch	56M4	Scheduled Outage	04-Jul-12	6:00	04-Jul-12	10:45	285	67	19095	A1-TEC	1	318.25	0	0.00
080712095225	1	Station Breaker		Station Breaker	56M4	Loss of supply	05-Aug-12	9:21	05-Aug-12	9:24	3	309	927	A1-TEC	2	15.45	0	0.00
090612105624	1	FS10160		UG switch unit	56M4	Scheduled Outage	07-Sep-12	9:10	07-Sep-12	9:25	15	105	1575	A1-TEC	1	26.25	0	0.00
							Total 2012									**905.53**	**1.00**	**322.67**
32613073319	1	FS10160	NULL	Switch	56M4	Scheduled Outage	02-Apr-13	9:40	02-Apr-13	10:20	40	105	4200	A1-TEC	1	70.00	0	0.00
							Total 2013									**70.00**	**0.00**	**0.00**
20414124110	1	TX10913	NULL	UG Transformer	56M4	Customer equipment	02-Feb-14	11:48	02-Feb-14	20:50	542	28	15176	A1-TEC	5.27	252.93	1	252.93
20614101420	1	TX10193	NULL	UG Transformer	56M4	Scheduled Outage	06-Feb-14	9:36	06-Feb-14	9:47	11	28	308	A1-TEC	1	5.13	0	0.00
22114105632	1	TX10913	NULL	UG Transformer	56M4	Scheduled Outage	21-Feb-14	11:00	21-Feb-14	11:08	8	29	232	A1-TEC	1	3.87	0	0.00
61714042941	1	MV10010	TX10655	UG switch unit	56M4	Scheduled Outage	18-Jun-14	4:00	18-Jun-14	6:30	150	32	4800	A1-TEC	1	80.00	0	0.00
71214114017	1	56M4	NULL	Station Breaker	56M4	Loss of supply	22-Jun-14	10:07	22-Jun-14	10:08	1	327	327	A1-TEC	2	5.45	0	0.00
							To Date 2014									**347.38**	**1.00**	**252.93**

Appendix E – SmartMAP Cost Analysis

Smart Grid SCADA Integration Comparison

Assuming that SmartMAP provides approximately 75% of the equivalence of a full control room, the cost of each SCADA system will be reduced to 75% of the quoted price.

Cost for Survalent SCADA

Time required for setup	800
Base Software / Hardware	$ 89,500
Optional Modules:	
ICCP Master to Master Protocol	$ 42,000
WebSurv (includes replicator)	$ 44,680
MultiSpeak Base and Real Time Interface	$ 22,200
Load Curtailment	$ 15,000
Load Estimation	$ 18,000
Short Term Forecasting	$ 18,000
Switch Order Preparation	$ 18,000
Hourly Rate for setup	$80
Hourly Rate for Operator	$61
New Operators	4
Assumptions	
Maintenance Costs	5000

Cost for SmartMAP

Time required for setup	100
Hardware/Setup Fee	$ 235,000
Optional Modules:	
Hourly Rate for setup	$80
Hourly Rate for Operator	$61
New Operators	0
Assumptions	
Maintenance Costs	5000

Cost for Televent SCADA

Time required for setup	480
Base Software / Hardware	$ 200,000
Optional Modules:	
Hourly Rate for setup	$80
Hourly Rate for Operator	$61
New Operators	4
Assumptions	
Maintenance Costs	5000

Survalent SCADA

One Time Costs			
Item:	**Unit Cost**	**Quantity**	**Total Cost**
Hardware			
Base Software / Hardware	$ 89,500	1	$ 89,500
Optional Modules:			
ICCP Master to Master Protocol	$ 42,000	0.75	$ 31,500
WebSurv (includes replicator)	$ 44,680	0.75	$ 33,510
MultiSpeak Base and Real Time Interface	$ 22,200	0.75	$ 16,650
Load Curtailment	$ 15,000	0	$ -
Load Estimation	$ 18,000	0	$ -
Short Term Forecasting	$ 18,000	0	$ -
Switch Order Preparation	$ 18,000	1	$ 18,000
Labour			
Set Up	$ 80	800	$ 64,000
Total:			$ 253,160
Reduction:			$ 63,290
Total Reduced Price:			$ 189,870
Ongoing Costs			
Item:			**Cost per Year:**
Operator	$ 178,120	4	$ 712,480
Operator Administration	$ 10,000	1	$ 10,000
Maintenance Support Package	$ 5,250	1	$ 5,250
WebSurv Maintenance	$ 570	1	$ 570
ICCP Maintenance	$ 570	1	$ 570
Total Yearly:			$ 728,870
Reduction:			$ 182,218
Total Reduced Price:			$ 546,653

SmartMAP

One Time Costs			
Item:	**Unit Cost**	**Quantity**	**Total Cost**
Hardware			
Hardware/Setup Fee	$ 235,000	1	$ 235,000
Optional Modules:			
Labour			
Set Up	$ 80	100	$ 8,000.00
Total:			$ 243,000
Reduction:			$ -
Total Reduced Price:			$ 243,000
Ongoing Costs			
Item:			**Cost:**
Yearly Service Fee	$ 69,480	1	$ 69,480
Total Yearly (after year 2)			$ 69,480
Reduction:			$ -
Total Reduced Price:			$ 69,480

Televent SCADA

One Time Costs			
Item:	**Unit Cost**	**Quantity**	**Total Cost**
Hardware			
Base Software / Hardware	$ 200,000	1	$ 200,000
Optional Modules:			
Labour			
Set Up	$ 80	480	$ 38,400
Total:			$ 238,400
Reduction:			$ 59,600
Total Reduced Price:			$ 178,800
Ongoing Costs			
Item:			**Cost per Year:**
Operator	$ 178,120	4	$ 712,480
Operator Administration	$ 10,000	1	$ 10,000
Maintenance	$ 5,000	1	$ 5,000
Total Yearly:			$ 727,480
Reduction:			$ 181,870
Total Reduced Price:			$ 545,610

Appendix G –Line Monitor Recommendations

Detailed Line Monitor Recommendations

Tecumseh

56M26

This feeder is located in the Tecumseh service area and has an interconnected distribution network with normally open interconnection points. The 56M26 has had a consistently high SAIDI index. Essex owns all of the distribution lines on this feeder within the territory allowing the addition of distribution automation equipment to be placed where it is most effective without ownership restrictions. The approximate locations of three recommended reclosers, five normally open smart switches, and five line monitors have been marked on the single line of Tecumseh in Appendix A.

56M4

This feeder is located in the Tecumseh service area and has an interconnected distribution network with normally open interconnection points. The 56M4 feeder has low SAIDI and the recommended switching adding a recloser, a normally open smart switch, and one line monitor.

56M25

This feeder is located in the Tecumseh service area and has an interconnected distribution network with normally open interconnection points. The 56M25 feeder has had an average SAIDI index. Essex owns all of the distribution lines on this feeder within the territory allowing the addition of distribution automation equipment to be placed where it is most effective without ownership restrictions. The approximate locations of four recommended reclosers, three normally open smart switches, and two line monitors have been marked on the single line of Tecumseh in Appendix A.

Leamington

3M6

This feeder is located in the Leamington service area with a radial distribution network and normally open interconnection points. The 3M6 feeder has had the highest SAIDI index with most customer outage hours and a drastic increase over the last 2 years. HONI owns most of the main feeder running through the service area with Essex owning the lines branching off. This makes it more difficult to add automated switching/reclosers to sectionalize areas. If possible it would be most beneficial if we could install our equipment on HONI owned lines in our territory but this would first have to be arranged with HONI. With this challenge, there are not a lot of recommended additions on this feeder even though it has had a high SAIDI index. The approximate location of three recommended reclosers, two normally open smart switches, and four line monitors have been marked on the single line of Leamington in Appendix A.

3M4

This feeder is located in the Leamington service area with a radial distribution network and normally open interconnection points. The 3M4 feeder has a low SAIDI index and the only switching added would be five normally open smart switches proposed in the other feeders, and two line monitors.

3M8

This feeder is located in the Leamington service area with a radial distribution network and normally open interconnection points. The 3M8 feeder has a SAIDI index that is a little high but the highest year, 2010, was due in large part to a tornado. The approximate locations of two recommended reclosers, three normally open smart switches, and two line monitors have been marked on the single line of Leamington in Appendix A.

LaSalle and Amherstburg

23M3

This feeder is located in the Amherstburg service area with a radial distribution network and normally open interconnection points. The 23M3 feeder has had a SAIDI index higher than desired. Essex owns all of the distribution lines on this feeder within the territory making the addition of distribution automation equipment to be placed where it is most effective without restrictions. The recommended additions of two reclosers, four normally open smart switches, and four line monitors are located on the single line of LaSalle and Amherstburg in Appendix A.

23M4

This feeder is located in the LaSalle service area with a radial distribution network and normally open interconnection points. The 23M4 feeder has a low SAIDI index, but Essex would like to allow for sectionalizing faulted sections by adding switching to the start of the service territory and after the area with the most outages. One reclosers, three normally open smart switches, and two line monitors will be placed as shown in the single line for LaSalle and Amherstburg in Appendix A.

23M5

This feeder is located in the LaSalle and Amherstburg service areas with a radial distribution network and normally open interconnection points. The 23M5 feeder has a low SAIDI index, so two reclosers will be installed, three normally open smart switches, and three line monitors will be added as indicated in the single line for LaSalle and Amherstburg in Appendix A.

24M7

This feeder is located in the LaSalle and Amherstburg service areas with a radial distribution network and normally open interconnection points. The 24M7 feeder has had a decreasing SAIDI index over the last few years, and most of the outage time came from the Amherstburg service area. HONI owns most of the main feeder running through the Amherstburg with Essex owning the lines branching off. Two reclosers, two normally open smart switches, and four line monitors are located on the single line for LaSalle and Amherstburg in Appendix A.

24M9

This feeder is located in the LaSalle service area with a radial distribution network and normally open interconnection points. The 24M9 feeder has had an increasing SAIDI index over the past few years. HONI owns a portion of the main feeder running through the service area with Essex owning the lines branching off. This makes it more difficult to add automated switching/reclosers to sectionalize areas. The addition of one recloser, one normally open smart switch, and two line monitors are located on the single line for LaSalle and Amherstburg in Appendix A.

24M10

This feeder is located in the LaSalle service area with a radial distribution network and normally open interconnection points. The 24M10 feeder has a low SAIDI index and the only recommended switching is one recloser.

<u>**Attachment 1-E**</u>

EPLC Scorecards

Scorecard - Essex Powerlines Corporation

9/24/2014

Performance Outcomes	Performance Categories	Measures		2009	2010	2011	2012	2013	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%	98.60%	98.30%	93.20%	92.70%	↓	90.00%	
		Scheduled Appointments Met On Time		93.50%	94.90%	95.50%	95.70%	94.30%	↑	90.00%	
		Telephone Calls Answered On Time		83.60%	70.60%	67.00%	68.50%	66.40%	↓	65.00%	
	Customer Satisfaction	First Contact Resolution									
		Billing Accuracy									
		Customer Satisfaction Survey Results									
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Public Safety [measure to be determined]									
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted		1.70	3.56	1.01	0.89	2.24	↓		at least within 0.89 - 3.56
		Average Number of Times that Power to a Customer is Interrupted		0.93	1.65	0.52	0.61	1.12	↓		at least within 0.52 - 1.65
	Asset Management	Distribution System Plan Implementation Progress									
	Cost Control	Efficiency Assessment					2	2			
		Total Cost per Customer [1]		$437	$465	$475	$491	$482			
		Total Cost per Km of Line [1]		$26,760	$27,518	$28,669	$30,851	$29,323			
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 Annual Peak Demand Savings (Percent of target achieved) [2]				35.00%	34.00%	46.20%			7.19MW
		Net Cumulative Energy Savings (Percent of target achieved)				38.00%	68.00%	89.70%			21.54GWh
	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%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.70	1.09	1.07	1.00	1.01			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.25	1.30	1.24	1.33	0.96			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)			9.85%	9.85%	9.85%			
			Achieved			10.83%	8.15%	11.20%			

Legend:
- ↑ up
- ↓ down
- flat
- target met
- target not met

Notes:
1. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.
2. The Conservation & Demand Management net annual peak demand savings do not include any persisting peak demand savings from the previous years.

Management Discussion and Analysis for Year 2013

Service Quality

All of the industry standards for service quality have been met. A review of the customer service telephone accessibility is being completed in order to improve the telephone accessibility performance. Customers are encouraged to find information on policies, rates, outages etc. on our website, www.essexpowerlines.ca. Real time information for outages for example, can be found on Twitter as well.(@essexpowerlines)

Customer Satisfaction

The data for First Contact Resolution and Billing Accuracy is currently being collected as these are new measures implemented recently by the Ontario Energy Board. A customer satisfaction survey will be completed in September/October 2014.

Safety

There is nothing to report at this time because the Ontario Energy Board is in the process of developing the requirements and measures for this item.

System Reliability

The performance results are within the reliability standards range. Reliability can be affected by many factors such as weather, equipment, loss of supply, animal and tree contacts etc. There was an increase in weather related events in 2013 compared to 2012 that affected both the number of hours and the number of times that power was interrupted.

Asset Management

There is nothing to report at this time.

Cost Control

Essex Powerlines has been proactive in reducing and containing costs which has resulted in the upper end of the efficiency rating of "2" that means that the actual costs are 10% to 25% below the predicted costs.

Conservation & Demand Management

Essex Powerlines has been successful in achieving our interim conservation and demand management targets for the 2009 to 2014 period.

Connection of Renewable Generation

All targets have been met with respect to the connection of renewable generation within our distribution system.

Financial Ratios

Essex Powerlines has been utilizing effective cash management practices to minimize the timing of the need for long term debt and subsequently minimizing interest expenses. Additional loan facilities are forecasted to be required later in 2014 that will increase both the liquidity and the debt ratios.

Scorecard - Essex Powerlines Corporation

9/28/2015

Performance Outcomes	Performance Categories	Measures		2010	2011	2012	2013	2014	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		98.60%	98.30%	93.20%	92.70%	93.00%	↓	90.00%	
		Scheduled Appointments Met On Time		94.90%	95.50%	95.70%	94.30%	94.70%	↓	90.00%	
		Telephone Calls Answered On Time		70.60%	67.00%	68.50%	66.40%	78.00%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution						99.6%			
		Billing Accuracy						99.84%	→	98.00%	
		Customer Satisfaction Survey Results						81%			
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 [measure to be determined]									
		Level of Compliance with Ontario Regulation 22/04		C	C	C	NI	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		3.56	1.01	0.89	2.24	1.16	↓		at least within 0.89 - 3.56
		Average Number of Times that Power to a Customer is Interrupted		1.65	0.52	0.61	1.12	0.66	↓		at least within 0.52 - 1.65
	Asset Management	Distribution System Plan Implementation Progress						100.8%			
	Cost Control	Efficiency Assessment				2	2	2			
		Total Cost per Customer [1]		$465	$475	$491	$482	$524			
		Total Cost per Km of Line [1]		$27,518	$28,669	$30,851	$29,323	$32,562			
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 Annual Peak Demand Savings (Percent of target achieved) [2]			34.34%	40.61%	58.15%	44.42%			7.19MW
		Net Cumulative Energy Savings (Percent of target achieved)			38.39%	67.93%	89.70%	108.00%			21.54GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%		100.00%	100.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time					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)		1.09	1.07	1.00	1.01	0.91			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.30	1.24	1.33	0.96	0.97			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)		9.85%	9.85%	9.85%	9.85%			
			Achieved		10.83%	8.15%	11.20%	9.73%			

Notes:
1. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.
2. The Conservation & Demand Management net annual peak demand savings include any persisting peak demand savings from the previous years.

Legend: ↑ up ↓ down → flat; target met; target not met

Scorecard MD&A - General Overview

- In 2014, Essex Powerlines Corporation has exceeded all performance targets except for the Net Annual Peak Demand Savings. Essex has seen improvement in some areas from 2013 including system reliability and service quality. System reliability is improving due to Asset Management programs that detect possible system problems that are corrected expeditiously. New smart grid detection programs and equipment are have been implemented in 2014 and 2015 that will assist in increased efficient detection of loss of power areas in our system. This information will be used by line staff to pinpoint the problem that results in faster response and restoration times.

  A large project that affects our distribution system is the Herb Gray Parkway which is a large scale Ontario Ministry of Transportation project to provide an efficient roadway system to a new international Bridge crossing from Canada to the United States through Windsor. This project is due to be completed in 2015. This parkway has required considerable resources from Essex to remove and reconstruct infrastructure to connect new loads that include tunnel lighting and pumping stations.

  Essex completed several customer engagement activities including our first customer satisfaction survey that reflected an overall satisfaction of 81%. We held a public information meeting during the month of November 2014. We also attended council meetings for each of our 4 shareholders to update councils and the public present at those meetings.

  Essex will be upgrading its billing system starting in September 2015 to further address customer needs for information and provide tools for our staff to respond to customer inquiries more efficiently and effectively.

  In 2015, Essex expects to continue to improve its scorecard performance compared to prior years through the implementation of new system monitoring tools, staff training and education and overall system improvements and upgrades.

Service Quality

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

  - All of the service quality measures are above the industry required standard. In 2014, Essex connected 93% of 199 eligible low voltage residential and small business customers within the five day timeline prescribed by the Ontario Energy Board (OEB). There was a decline in the residential/commercial services connected on time in 2012 compared to 2011 and 2010 due to a refinement of the reporting process. The performance for 2012, 2013 and 2014 has been more consistent and continues to be above the industry average of 90%.

- **Scheduled Appointments Met On Time**

  - Essex scheduled 1,167 customer related appointments in 2014 and was able to meet the requested schedule 94.7% of the time. Scheduled appointments met on time has a slight declining trend in 2013 and 2014 but the five year average is approximately 95% which is still consistently over the industry average of 90%.

- **Telephone Calls Answered On Time**

  - Essex received 23,918 calls into its customer service call center or an average of approximately 100 calls per day. An agent answered these calls in 30 seconds or less 78% of the time. Performance of telephone calls answered on time has improved by 12% in 2014 due to an outsourcing of the billing process that freed up more time for Customer Service Representatives to answer customer calls.

Customer Satisfaction

- **First Contact Resolution**

  - Specific customer satisfaction measurements have not been previously defined for the industry prior to 2014. The Ontario Energy Board (OEB) has instructed all electricity distributors to develop measurements in these areas and 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, there may be inconsistencies of performance between distributors until 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 comparisons across electricity distributors.

    For Essex, First Contact Resolution was measured based on calls received and how many required escalation to a supervisor resulting in 99.6% of calls being resolved without escalation to a supervisor.

- **Billing Accuracy**

  - Until July 2014, 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, 2014.

    For the period from October 1, 2014 to December 31, 2014 Essex Powerlines issued more than 94,500 bills and achieved a billing accuracy of 99.8%. This is above the OEB standard of 98%. Essex Powerlines will continue to monitor its billing accuracy and results to find areas of improvement and to ensure adherence to the standard established by the OEB.

- **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.

    Essex Powerlines completed a customer satisfaction survey in 2014 using a third party to conduct the survey that resulted in an overall rating of 81% of customers satisfied with our services. The survey included at a minimum questions relating to 1) power quality and reliability 2) price 3) billing and payment 4) communications and 5) the customer service experience. In addition to the survey, Essex Powerlines also held a public customer engagement meeting in November 2014. The customer engagement meeting included general information about Essex Powerlines, bill components, energy management tools available for customers, planned capital expenditures, operations, maintenance and administration costs projected for 2016. The meeting included interactive questions with the customers that attended. With the satisfaction survey standard established and feedback from the public meeting, Essex will focus on improving our satisfaction rating with our customers.

Safety

- **Public Safety**

  - The Ontario Energy Board (OEB) introduced the Safety measure in 2015. The 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**

  This component of the public safety measure will not have performance data for the 2014 year scorecard because the survey was not required to be completed. The year 2016 will be the first year that the data for this component of measure will be shown on the scorecard for the 2015 results subsequent to the OEB approving the applicable content for a survey and providing sufficient time during 2015 to complete the survey.

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

  - Over the past five year period, Essex Powerlines was found to be compliant 4 out of 5 years with Ontario Regulation 22/04 (Electrical Distribution Safety). This was achieved by our commitment to safety and adherence to company procedures. Ontario Regulation 22/04 – Electrical Distribution Safety established objectives based on 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.

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

  - There were no serious electrical contacts within Essex Powerlines distribution system during the five year period.

System Reliability

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

  - Essex Powerlines variance from year to year in average number of hours that power to a customer was interrupted is based on a number of differing items that occurred during the year. The Asset Management programs, weather, foreign interference, and vegetation will determine these indices. Planned outages to repair, replace, or manage the vegetation related to equipment vary by year and does not exactly follow the same trend as the performance but is similar and accounts for approximately 25% of the indices. Vegetation causing interruptions (10% of the indices) are mainly due to unpreventable incidents where dead (ash) or poor health trees fall over completely or are not within the vicinity of vegetation management. With the vegetation management programs in place, preventable vegetation outages are in a significant downward trend. Weather and lightning and foreign interference represent approximately 30% of the indices. Equipment failures account for approximately 30% of the indices.

Essex Powerlines uses leading edge Asset Investment Strategy tools and processes to improve the indices using: Risk Reduction, Risk Assessments, Optimize Spend based on Strategic Objectives, Keep Reliability Centered Maintenance Statistics within Acceptable Severity/Importance Indices, carry out Cyclical Planned Inspections/Preventative Maintenance & correct findings, Global Information System with full connectivity and asset information, Statistical Data, analysis, and Forecasting Tools, Healthmap – this program provides the health index of assets, alerts of out of range distribution system data, Smartmap – this program provides full integration of voltage, loading, monitoring of line temperature, air temperature, losses, fault current, outages, outage detection upon a system upset.

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

  - Essex Powerlines experienced a reduction in the number of times that power to a customer was interrupted. This reduction was due to the similar reasons as explained in the indices above. There is a significant decrease in the trends with planned outage increasing significantly to approximately 50% of the outages. 26% of the frequency are unpreventable vegetation, lighting, adverse weather, adverse environment, human element and foreign interference. Equipment is approximately 24% with a consistent downward trend.

Asset Management

- **Distribution System Plan Implementation Progress**

  - Distribution system plan implementation progress is a new performance measure by the OEB starting in 2013. The Distribution System Plan (DSP) outlines the forecasted capital expenditures, over the next five (5) years, required to maintain and expand the system to serve its current and future customers. The Distribution System Plan Implementation Progress measure is intended to assess Essex's effectiveness at planning and implementing the DSP. Essex has not yet filed a formal DSP with the OEB due to a delay in filing a full Cost of Service rate application which is now planned to be submitted in April 2016 for OEB review for rates effective January 1. 2017.

    However, Essex Powerlines is continuing to measure the progress of its draft DSP implementation as a ratio of actual total capital expenditures made in a calendar year over the total amount of planned capital expenditures for that calendar year per the DSP. The 2014 measure indicates that Essex slightly exceeded its planned project spending and is on target to complete its five year plan.

Cost Control

- **Efficiency Assessment**

  - The total costs for Ontario Electricity Distributors are evaluated by the Pacific Economics Group LLC (PEG) on behalf of the OEB to produce a single efficiency ranking. PEG has made adjustments to the actual costs to make them more comparable between distributors. The electrical distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. In 2014, for the third year in a row, Essex Powerlines was placed in Group 2, which is the second most efficient grouping of Ontario electrical distributors out of a total of 5 groups with 1 being the most efficient and 5 being the least efficient.

- **Total Cost per Customer**

  - Total cost per customer is calculated as the sum of Essex Powerlines capital and operating costs and dividing this figure by the total number of customers that Essex Powerlines serves. The cost performance for 2014 is $524 per customer which is an 8.7% increase over 2013.

    Essex Powerlines Total cost per customer has increased an average of 2.5% over the five year period of 2010 to 2014. Essex Powerlines has experienced increases in its total costs required to deliver quality, reliable and regulator compliant services to its customers. Essex Powerlines has experienced growth in wage and benefit costs for our employees, as well as investments in new information, financial and operating systems technology and renewal growth of the distribution system. All of these have contributed to increased operating and capital costs. Essex Powerlines has seen additional capital spending on distribution systems to connect the new Herb Gray Parkway which will eventually connect to a new bridge crossing to the United States. This parkway project has affected Essex Powerlines operating and capital costs over the last few years and will be completed in 2015.

    Essex Powerlines will continue to replace distribution assets proactively but pacing the expenditures over several years to avoid any significant increase in costs in any one year. Productivity and improvement initiatives will continue to help offset the costs from inflation and future system improvements and enhancements.

- **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 Essex Powerlines operates to serve its customers. Essex Powerlines rate is $32,562 per Km of line, an 11% increase over 2013. Essex Powerlines has experienced a reduction of 3% or approximately 15 km's of line since 2010. This reduction is due to the Herb Gray Parkway substation conversion that eliminated overhead lines. In addition there has been a low growth rate in the area since 2010 which has limited our ability to fund capital renewal and increased operating costs through customer growth. With these two factors, the cost per km has increased year over year.

Conservation & Demand Management

- **Net Annual Peak Demand Savings (Percent of target achieved)**

  - As shown on the OPA 2014 report below, Essex did not meet its Net Annual Peak Demand Savings and only achieved 44.4% due to the loss of the Heinz Corporation Demand Response contract. Essex's service territory is also primarily residential with only small scale industrial customers. This placed Essex in the lower quartile for all LDC's in the province. This does not affect the overall provincial targets moving forward as they will be based on energy rather than demand.

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

  - As shown below in the draft OPA report, Essex exceeded the Net Cumulative Energy Savings by 8.0% and placed Essex at the very top of the scale in the chart comparison for all LDC's in the province. This was a significant achievement. The two most effective programs for Essex Powerlines were RETROFIT and the HVAC Incentive Program where 9,806,366 kWh and 3,470,981 kWh in savings were realized by our energy conscious customers.

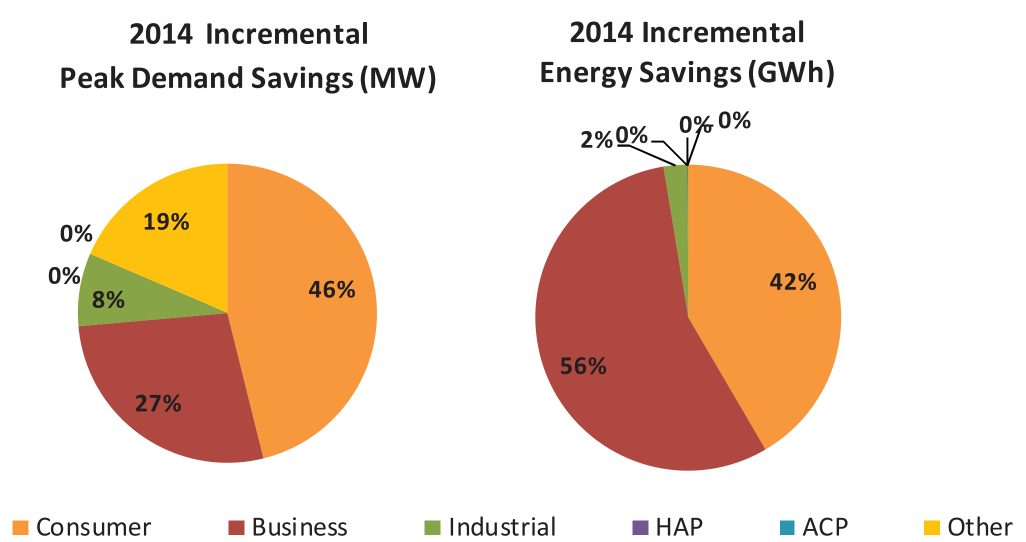
IESO-Contracted Province-Wide CDM Programs: 2011-2014 Final Results Report

LDC: Essex Powerlines Corporation

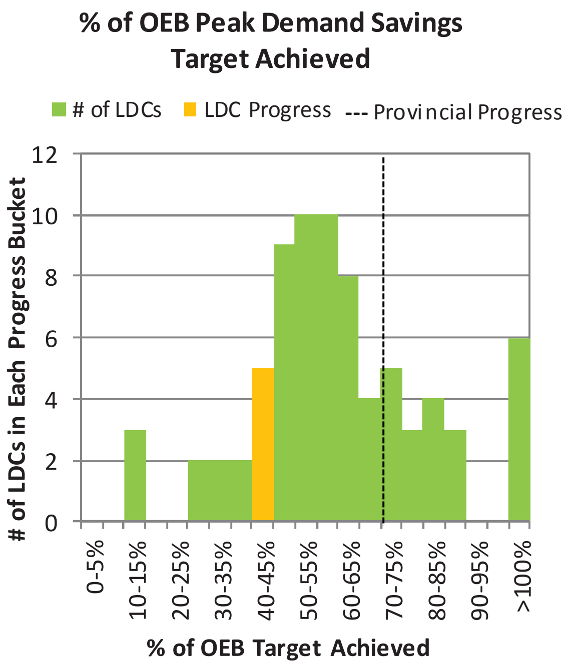
Final 2014 Achievement Against Targets	2014 Incremental	2011-2014 Achievement Against Target	% of Target Achieved
Net Annual Peak Demand Savings (MW)	1.7	3.2	**44.4%**
Net Energy Savings (GWh)	3.8	23.3	**108.0%**

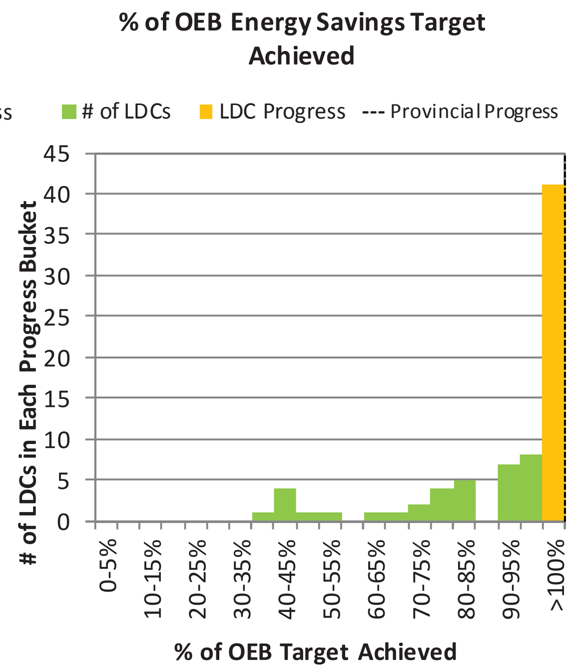
Unless otherwise noted, results are presented using scenario 1which assumes that demand response resources have a persistence of 1year

Achievement by Sector



Comparison: LDC Achievement vs. LDC Community Achievement (Progress to Target)





Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

  - Electricity distributors are required to conduct Connection Impact Assessments (CIA's) within 60 days of receiving authorization from the Electrical Safety Authority. In 2014, Essex Powerlines had two requests for CIA's that were completed within the prescribed time limit. In 2013 there were also two requests that were completed on time. There were no CIA's requested in 2011 and therefore the field is blank.

- **New Micro-embedded Generation Facilities Connected On Time**

  - In 2014, Essex Powerlines connected 12 new micro-embedded generation facilities 100% within the prescribed time frame of 5 business days. The standard is 90% of new micro-embedded generators have to be completed within the five day time frame. Essex Powerlines makes additional effort to meet the connection of these facilities ahead of the standard. There were no micro-embedded generation facilities requested to be connected in 2010, 2011 or 2012 and therefore these fields are blank.

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 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.

    Essex Powerlines ratio for 2014 was .91 compared to 1.01 for 2013. The slight decline is not an indication of financial performance but rather the result of using short term funds to pay for capital expenditures and thereby keeping interest costs down. The plan is to borrow additional long term funds that will increase the current cash available. See the additional explanation under the debt to equity ratio below.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

  - The OEB uses a deemed capital structure of 60% debt and 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 leveraged than the deemed capital structure. A high debt to equity ratio may indicate than 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.

    As indicated above, additional loan facilities will be put in place during 2015. Funding for the new transformer station in Leamington in 2016 will also require additional long term debt to be put in place. These borrowings will increase the debt to equity ratio to be more in line with the approved deemed ratio.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

  - Essex Powerlines current distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity of 9.85% approved by the OEB at our last Cost of Service rate application in 2010. The OEB allows a distributor to earn within +/- 3% of the expected rate of 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**

  - Essex Powerlines regulatory return on equity performance for 2014 was 9.73 and the last four year average is 9.98 which is well within the +/- 3% range established by the OEB.

Note to Readers of 2014 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 judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

Scorecard - Essex Powerlines Corporation

9/29/2016

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		98.30%	93.20%	92.70%	93.00%	92.30%	↓	90.00%	
		Scheduled Appointments Met On Time		95.50%	95.70%	94.30%	94.70%	94.80%	↓	90.00%	
		Telephone Calls Answered On Time		67.00%	68.50%	66.40%	78.00%	79.20%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution					99.6%	99.28			
		Billing Accuracy					99.84%	98.05%	↓	98.00%	
		Customer Satisfaction Survey Results					81%	81%			
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						83.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	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]		1.01	0.89	2.24	1.16	1.34	↓		1.77
		Average Number of Times that Power to a Customer is Interrupted [2]		0.52	0.61	1.12	0.66	0.83	↓		0.91
	Asset Management	Distribution System Plan Implementation Progress					100.8%	107.00			
	Cost Control	Efficiency Assessment			2	2	2	2			
		Total Cost per Customer [3]		$475	$491	$482	$524	$538			
		Total Cost per Km of Line [3]		$28,669	$30,851	$29,323	$32,562	$34,680			
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]						12.15%			31.43 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time			100.00%	100.00%	100.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time				100.00%	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)		1.07	1.00	1.01	0.91	0.87			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.24	1.33	0.96	0.97	0.96			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.85%	9.85%	9.85%	9.85%	9.85%			
			Achieved	10.83%	8.15%	11.20%	9.73%	11.70%			

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

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, Essex Powerlines Corporation has continued to exceed all performance targets set for the industry. Essex has seen improvement in some areas from 2014 including Scheduled Appointments Met on Time, Telephone Calls Answered On Time, consistent trending for all of the safety standards and slight decreases in the areas of system reliability and cost control. Essex has achieved 100% targets for the connection of renewable generation. The financial ratios show a slight decrease in the current ratio and the debt to equity ratio but improvement in the return on equity. New smart grid detection programs and equipment are continued to be implemented in 2014 and 2015 that is resulting in more accurate reporting and increased efficient detection of loss of power in areas within our system.

  A large project that affects our distribution system is the Herb Gray Parkway which is a large scale Ontario Ministry of Transportation project to provide an efficient roadway system to a new international Bridge crossing from Canada to the United States through Windsor. This project was completed in late 2015. This parkway has required considerable resources from Essex to remove and reconstruct infrastructure to connect new loads that include tunnel lighting and pumping stations.

  Essex upgraded its billing system in late 2015 to further address customer needs for information and provide tools for our staff to respond to customer inquiries more efficiently and effectively.

  In 2016, Essex expects to continue to improve its scorecard performance compared to prior years through the implementation of new system monitoring tools, staff training and education and overall system improvements and upgrades.

Service Quality

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

All of the service quality measures are above the industry required standard. In 2015, Essex connected 92.3% of eligible low voltage residential and small business customers within the five day timeline prescribed by the Ontario Energy Board (OEB). This was a slight decline from the 2014 performance of 93% but still above the industry standard of 90%. There has been increased demand in new house connections as the economy in the area begins to improve. There was a decline in the residential/commercial services connected on time in 2012 compared to 2011 due to a refinement of the reporting process. The performance for 2012, 2013, 2014 and 2015 has been more consistent and continues to be above the industry average of 90%.

- **Scheduled Appointments Met On Time**

Essex scheduled 1,315 customer related appointments in 2015 and was able to meet the requested schedule 94.8% of the time. This was an improvement over 2014. Scheduled appointments met on time has a slight declining trend in 2013 and 2014 but the five year average is approximately 95% which is still consistently over the industry average of 90%.

- **Telephone Calls Answered On Time**

Essex received 33,449 calls into its customer service call center or an average of approximately 150 calls per day. An agent answered these calls in 30 seconds or less 79% of the time. Performance of telephone calls answered on time has improved by 1% in 2015 but the number of calls coming into the centre has increased by almost 40% due to new consumer programs such as the Ontario Electricity Savings Program (OESP), increased economic activity in the area such as new home builds and house sales in general. Therefore overall telephone accessibility has improved over 2014.

Customer Satisfaction

- **First Contact Resolution**

Specific customer satisfaction measurements have not been previously defined for the industry prior to 2014. The Ontario Energy Board (OEB) has instructed all electricity distributors to develop measurements in these areas and 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, there may be inconsistencies of performance between distributors until 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 comparisons across electricity distributors.

For Essex, First Contact Resolution was measured based on calls received and how many required escalation to a supervisor resulting in 99.28% of calls being resolved without escalation to a supervisor. This is slightly down from the 2014 performance of

99.6%. This is consistent performance to date for this new measure.

- **Billing Accuracy**

This was a new measure implemented by the Ontario Energy Board in 2014 after consultation with some electricity distributors in the province. For the period from October 1, 2014 to December 31, 2014 Essex Powerlines issued more than 94,500 bills and achieved a billing accuracy of 99.8%. For 2015, Essex issued 354,187 bills and achieved a billing accuracy of 98.05%. This is above the OEB standard of 98% but down from 2014. Essex Powerlines will continue to monitor its billing accuracy and results to find areas of improvement and to ensure adherence to the standard established by the OEB.

- **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.

Essex Powerlines completed a customer satisfaction survey in 2014 using a third party to conduct the survey that resulted in an overall rating of 81% of customers satisfied with our services. The survey included at a minimum questions relating to 1) power quality and reliability 2) price 3) billing and payment 4) communications and 5) the customer service experience. The survey results have demonstrated that Essex Powerlines have the following opportunities to improve the overall customer experience: 1) increased customer knowledge of how bills are calculated, 2) increased familiarity of available online billing tools, 3) identification of new means of communicating with our customer base to keep customers proactively informed.

In addition to the survey, Essex Powerlines also held a public customer engagement meeting in November 2014. The customer engagement meeting included general information about Essex Powerlines, bill components, energy management tools available for customers, planned capital expenditures, operations, maintenance and administration costs projected for 2016. The meeting included interactive questions with the customers that attended. With the satisfaction survey standard established and feedback from the public meeting, Essex will focus on improving our satisfaction rating with our customers.

Essex will be conducting another survey in 2016 and 2017 prior to the submission of its upcoming cost of service.

Safety

- **Public Safety**

  - The Ontario Energy Board (OEB) introduced the Safety measure in 2015. The 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**

    This component of the public safety measure was implemented for 2015. Essex engaged a third party to conduct this survey on its behalf. The survey indicated that 83% of the public are aware of the risks involved with the electricity distribution system. Additional customer education will be conducted in 2016 to increase this percentage.

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

    Over the past five year period, Essex Powerlines was found to be compliant 4 out of 5 years with Ontario Regulation 22/04 (Electrical Distribution Safety). This was achieved by our commitment to safety and adherence to company procedures. Ontario Regulation 22/04 – Electrical Distribution Safety established objectives based on 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.

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

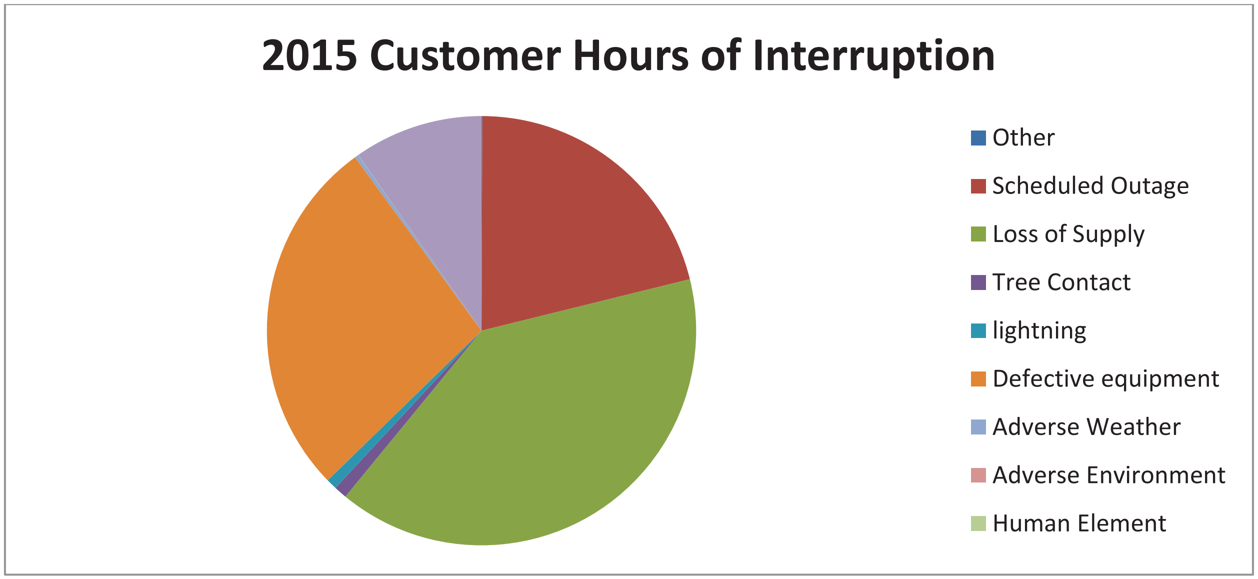
    There were no serious electrical contacts within Essex Powerlines distribution system during the five year period shown on the scorecard.

System Reliability

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

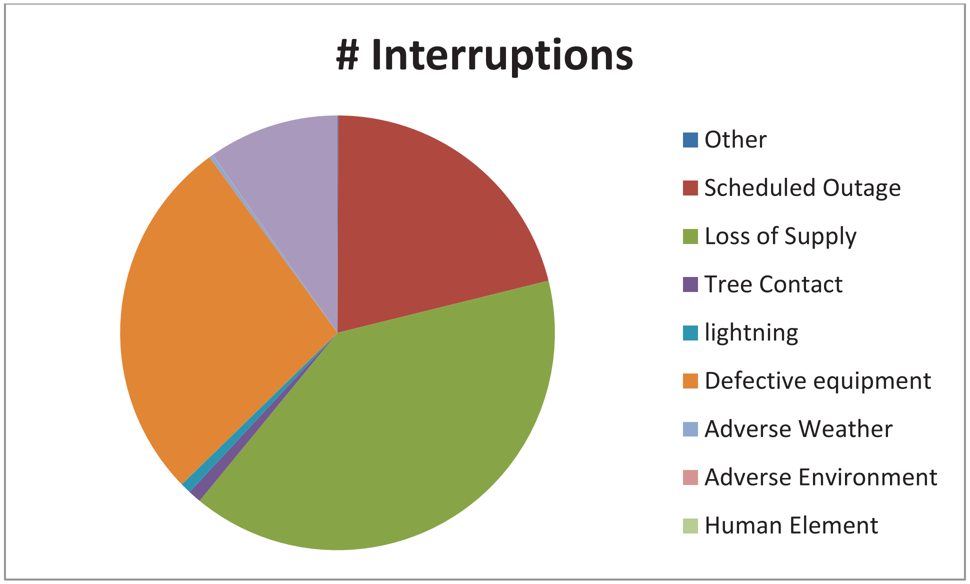
  Essex Powerlines variance from year to year in average number of hours that power to a customer was interrupted is based on a number of differing items that occurred during the year. The Asset Management programs, weather, foreign interference, and vegetation will determine these indices. Planned outages to repair, replace, or manage the vegetation related to equipment vary by year and does not exactly follow the same trend as the performance but is similar and accounts for approximately 25% of the indices. Vegetation causing interruptions (10% of the indices) are mainly due to unpreventable incidents where dead (ash) or poor health trees fall over completely or are not within the vicinity of vegetation management. With the vegetation management programs in place, preventable vegetation outages are in a significant downward trend. Weather and lightning and foreign interference represent approximately 30% of the indices. Equipment failures account for approximately 30% of the indices.

Essex Powerlines uses leading edge Asset Investment Strategy tools and processes to improve the indices using: Risk Reduction, Risk Assessments, Optimize Spend based on Strategic Objectives, Keep Reliability Centered Maintenance Statistics within Acceptable Severity/Importance Indices, carry out Cyclical Planned Inspections/Preventative Maintenance & correct findings, Global Information System with full connectivity and asset information, Statistical Data, analysis, and Forecasting Tools, Healthmap – this program provides the health index of assets, alerts of out of range distribution system data, Smartmap – this program provides full integration of voltage, loading, monitoring of line temperature, air temperature, losses, fault current, outages, outage detection upon a system upset. Essex's average for 2015 was 1.34 hours compared to 1.16 hours in 2014. The 5 year average is 1.77 hours. Essex is overall improving its performance in this area.



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

Essex Powerlines experienced a slight increase in the number of times that power to a customer was interrupted to .83 in 2015 compared to .66 in 2014. This increase is minor and still below the 5 year average of .91. Overall, there is a significant decrease in the trends with planned outage increasing significantly to approximately 61% of the outages. 25% of the frequency are unpreventable vegetation, lighting, adverse weather, adverse environment, human element and foreign interference. Equipment is approximately 14% with a consistent downward trend.



Asset Management

- **Distribution System Plan Implementation Progress**

Distribution system plan implementation progress was a new performance measure added by the OEB starting in 2013. The Distribution System Plan (DSP) outlines the forecasted capital expenditures, over the next five (5) years, required to maintain and expand the system to serve its current and future customers. The Distribution System Plan Implementation Progress measure is intended to assess Essex's effectiveness at planning and implementing the DSP. Essex has not yet filed a formal DSP with the OEB due to a delay in filing a full Cost of Service rate application which is now planned to be submitted in April 2017 for OEB review for rates effective January 1. 2018.

However, Essex Powerlines is continuing to measure the progress of its draft DSP implementation as a ratio of actual total capital expenditures made in a calendar year over the total amount of planned capital expenditures for that calendar year per the DSP. The 2015 measure indicates that Essex slightly exceeded its planned project spending (107%) and is on target to complete its five year plan.

Cost Control

- **Efficiency Assessment**

  The total costs for Ontario Electricity Distributors are evaluated by the Pacific Economics Group LLC (PEG) on behalf of the OEB to produce a single efficiency ranking. PEG has made adjustments to the actual costs to make them more comparable between distributors. The electrical 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 fourth year in a row, Essex Powerlines was placed in Group 2, which is the second most efficient grouping of Ontario electrical distributors out of a total of 5 groups with 1 being the most efficient and 5 being the least efficient.

- **Total Cost per Customer**

  Total cost per customer is calculated as the sum of Essex Powerlines capital and operating costs and dividing this figure by the total number of customers that Essex Powerlines serves. The cost performance for 2014 is $538 per customer which is a 2.7% increase over 2014.

  Essex Powerlines Total cost per customer has increased an average of 2.7% over the five year period of 2011 to 2015. Essex Powerlines has experienced increases in its total costs required to deliver quality, reliable and regulator compliant services to its customers. Essex Powerlines has experienced growth in wage and benefit costs for our employees, as well as investments in new information, financial and operating systems technology and renewal growth of the distribution system. All of these have contributed to increased operating and capital costs. Essex Powerlines has seen additional capital spending on distribution systems to connect the new Herb Gray Parkway which will eventually connect to a new bridge crossing to the United States. This parkway project has affected Essex Powerlines operating and capital costs over the last few years and was completed in 2015.

  Essex Powerlines will continue to replace distribution assets proactively but pacing the expenditures over several years to avoid any significant increase in costs in any one year. Productivity and improvement initiatives will continue to help offset the costs from inflation and future system improvements and enhancements.

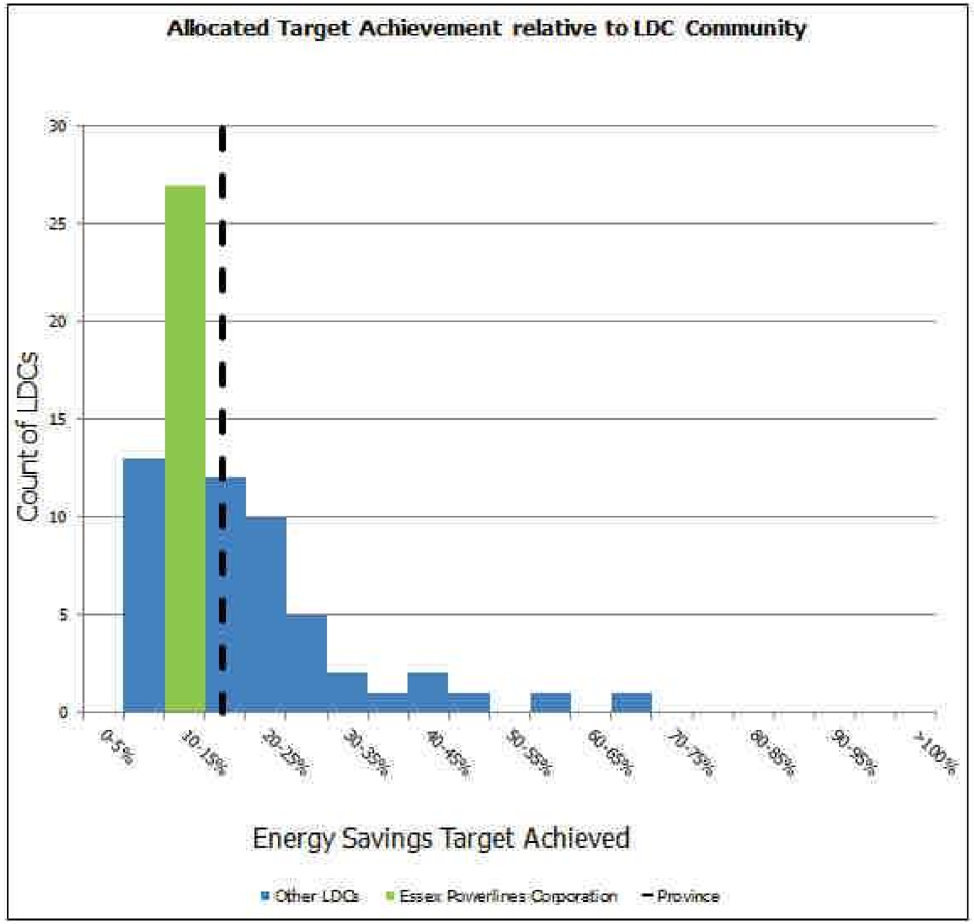
- **Total Cost per Km of Line**

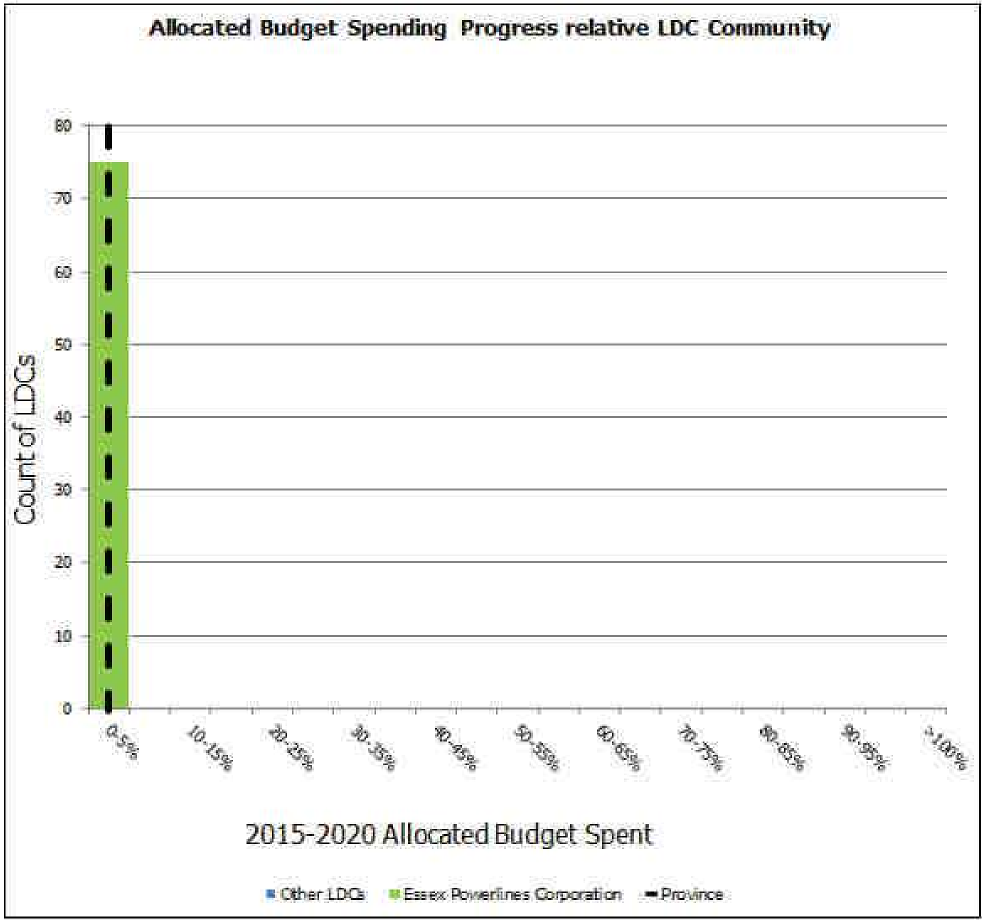
  This measure uses the same total cost that is used in the Cost per customer calculation above. The Total cost is divided by the kilometers of line that Essex Powerlines operates to serve its customers. Essex Powerlines rate is $34,680 per Km of line, a 6.5% increase over 2014 compared to an 11% increase in 2014 over 2013. Essex Powerlines has experienced a reduction of 3% or approximately 15 km's of line since 2010. This reduction is due to the Herb Gray Parkway substation conversion that eliminated overhead lines. In addition there has been a low growth rate in the area since 2010 which has limited our ability to fund capital renewal and increased operating costs through customer growth. With these two factors, the cost per km has increased year over year.

Conservation & Demand Management

- **Net Cumulative Energy Savings**

  Essex Powerlines is tracking to meet our savings target under the 2015-2020 Conservation First Framework. During the first year of the new framework, EPL achieved 12% of its 6 year target while only spending 2% of its allocated budget. EPL is meeting its goal of delivering significant energy savings through its conservation programs, in a manner that is cost effective to ratepayers. This first year performance under the Conservation First Framework positions EPL suitably for achieving even greater energy savings in future program years, as significant conservation projects were identified in 2015 for implementation in 2016.





Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

  - Electricity distributors are required to conduct Connection Impact Assessments (CIA's) within 60 days of receiving authorization from the Electrical Safety Authority. In 2015, Essex Powerlines had four requests for CIA's that were completed within the prescribed time limit. In 2013 there were also two requests that were completed on time. There were no CIA's requested in 2011 and therefore the field is blank.

- **New Micro-embedded Generation Facilities Connected On Time**

In 2015, Essex Powerlines connected 10 new micro-embedded generation facilities 100% within the prescribed time frame of 5 business days. The standard is 90% of new micro-embedded generators have to be completed within the five day time frame. Essex Powerlines makes additional effort to meet the connection of these facilities ahead of the standard. There were no micro-embedded generation facilities requested to be connected in 2011 or 2012 and therefore these fields are blank.

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 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.

Essex Powerlines ratio for 2015 was .87 compared to .91 for 2014. The slight decline is not an indication of financial performance but rather the result of using short term funds to pay for capital expenditures and thereby keeping interest costs down. The plan is to borrow additional long term funds that will increase the current cash available. See the additional explanation under the debt to equity ratio below.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

The OEB uses a deemed capital structure of 60% debt and 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 leveraged than the deemed capital structure. A high debt to equity ratio may indicate than 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.

As indicated above, additional loan facilities will be put in place during 2016 and 2017. Funding for the new transformer station in Leamington in 2017/2018 will also require additional long term debt to be put in place. These borrowings will increase the debt to equity ratio to be more in line with the approved deemed ratio.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

  Essex Powerlines current distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity of 9.85% approved by the OEB at our last Cost of Service rate application in 2010. The OEB allows a distributor to earn within +/- 3% of the expected rate of 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**

  Essex Powerlines regulatory return on equity performance for 2015 was 11.70 compared to 9.73 from 2014 bringing the last five year average to 10.32 which is well within the +/- 3% range established by the OEB.

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 judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

Attachment 1-F

Customer Engagement Activities Summary

File Number:	EB-2017-0039
Exhibit:	1
Tab:	1-F
Page:	1 of 1
Date:	August 28th, 2017

Appendix 2-AC
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.
Customer phone calls related to new accounts, billing inquiries, general inquiries, etc. (Ongoing)	1. Importance of low/affordable rates; 2. Importance of reliability; 3. Importance of customer service and availability of information; 4. Identified the need for assistance with comprehending complexity of electricity sector; 5. Need for social media presence to respond to customer inquries;	1. Continue to focus on realizing efficiencies, keeping any increases in line with inflation; 2. Continue to focus on the Self-Healing Grid and vegetation management initiatives as well as the other programs identified in EPLC's DSP to further reduce customer outages and improve reliability; 3. Enhancements to EPLC's website, bill presentment; 4. Enhancements to EPLC's website, bill presentment and face to face meetings where necessary; 5. Added profiles on Facebook and twitter to better outreach and communicate with customers;
Customer phone calls related to outages, reliability, maintenance projects, vegetation management, conversion work, etc. (Ongoing)	1. Importance of reliability; 2. Importance of availability of information, especially relating to outage information; 3. Need for social media presence to respond to customer inquries;	1. Continue to focus on the Self-Healing Grid and vegetation management initiatives as well as the other programs identified in EPLC's DSP to further reduce customer outages and improve reliability; 2. Enhancements to EPLC's website, update to EPLC's online outage information system where updates are sent via social media to following customers and local stakeholders; 3. Added profiles on Facebook and twitter to better outreach and communicate with customers;
Bill inserts and semi-annual update brochures (Ongoing)	1. Importance of need for assistance with comprehending complexity of electricity sector;	1. Enhancements to EPLC's website, bill presentment;
Community Conservation Events (Ongoing)	1. Importance of low/affordable rates; 2. Importance of reliability; 3. Importance of customer service and availability of information; 4. Importance of need for assistance with comprehending complexity of electricity sector; 5. Need for social media presence to respond to customer inquiries; 6. Identified need to assist customers through the application process for various CDM initiatives;	1. Continue to focus on realizing efficiencies, keeping any increases in line with inflation; 2. Continue to focus on the Self-Healing Grid and vegetation management initiatives as well as the other programs identified in EPLC's DSP to further reduce customer outages and improve reliability; 3. Enhancements to EPLC's website, bill presentment; 4. Enhancements to EPLC's website, bill presentment and face to face meetings where necessary; 5. Added profiles on Facebook and twitter to better outreach and communicate with customers; 6. CDM department now completes applications with or on behalf of customers where requested. Detailed walkthroughs also provided on an as-needed basis;
School / Children Conservation & Electricity Awareness Events (Ongoing)	1. Importance of ongoing education of children and schools about electricity awareness/safety and conservation	1. Implemented ongoing school conservation & electricity awareness campaign that educates children in all grade schools within EPLC shareholder communities about the importance of electrical safety and conservation;
Website & social media (Ongoing)	1. Importance of reliability; 2. Importance of customer service and availability of information; 3. Importance of need for assistance with comprehending complexity of electricity sector; 4. Need for social media presence to respond to customer inquiries;	1. Continue to focus on the Self-Healing Grid and vegetation management initiatives as well as the other programs identified in EPLC's DSP to further reduce customer outages and improve reliability; 2. Enhancements to EPLC's website, bill presentment; 3. Enhancements to EPLC's website, bill presentment and face to face meetings where necessary; 4. Added profiles on Facebook and twitter to better outreach and communicate with customers;
St. Clair College Powerline Maintainer Program (Ongoing)	1. Identified the need for the local community to train and retain skilled people available to the enter the workforce;	1. Received senior management buy-in and support; 2. Promoted the program locally; 3. Hired apprentices from the program;
OEL meetings and channel partner / contractor events (Ongoing)	1. Identified the need to inform local contractors of electrical safety and EPLC's Conditions of Service; 2. Identified the need to inform local contractors of conservation initiatives that available provincially;	1. Continue participating in OEL events and promote EPLC standards and electricity safety; 2. Continue promoting energy conservation initiatives and any relevant updates or changes to programs;
Conservation & Demand Management Outreach - Residential (Ongoing)	1. Importance of low/affordable rates; 2. Importance of reliability; 3. Importance of customer service and availability of information; 4. Importance of need for assistance with comprehending complexity of electricity sector; 5. Need for social media presence to respond to customer inquiries;	1. Continue to focus on realizing efficiencies, keeping any increases in line with inflation; 2. Continue to focus on the Self-Healing Grid and vegetation management initiatives as well as the other programs identified in EPLC's DSP to further reduce customer outages and improve reliability; 3. Enhancements to EPLC's website, bill presentment; 4. Enhancements to EPLC's website, bill presentment and face to face meetings where necessary; 5. Added profiles on Facebook and twitter to better outreach and communicate with customers;
Conservation & Demand Management Outreach - Small Commercial (Ongoing)	1. Importance of low/affordable rates; 2. Importance of reliability; 3. Importance of customer service and availability of information; 4. Importance of need for assistance with comprehending complexity of electricity sector; 5. Need for social media presence to respond to customer inquiries; 6. Need to offer opportunities and incentives to reduce electricity costs;	1. Continue to focus on realizing efficiencies, keeping any increases in line with inflation; 2. Continue to focus on the Self-Healing Grid and vegetation management initiatives as well as the other programs identified in EPLC's DSP to further reduce customer outages and improve reliability; 3. Enhancements to EPLC's website, bill presentment; 4. Enhancements to EPLC's website, bill presentment and face to face meetings where necessary; 5. Added profiles on Facebook and twitter to better outreach and communicate with customers; 6. Continue promoting energy conservation initiatives and any relevant updates or changes to programs;
Conservation & Demand Management Outreach - Larger Commercial & Industrial (Ongoing)	1. Importance of reliability; 2. Importance of power quality; 3. Need to offer opportunities and incentives to reduce electricity costs;	1. Continue to focus on the Self-Healing Grid and vegetation management initiatives as well as the other programs identified in EPLC's DSP to further reduce customer outages and improve reliability; 2. Implementation of EPLC's SmartMAP toolset with active power quality management tools; 3. Continue promoting energy conservation initiatives and any relevant updates or changes to programs;
Annual customer satisfaction survey (2014)	1. Importance of reliability; 2. Importance of low/affordable rates; 3. Importance of customer service and availability of information; 4. Importance of power quality;	1. Continue to focus on the Self-Healing Grid and vegetation management initiatives as well as the other programs identified in EPLC's DSP to further reduce customer outages and improve reliability; 2. Continue to focus on realizing efficiencies, keeping any increases in line with inflation; 3. Enhancements to EPLC's website, bill presentment and face to face meetings, if required; 4. Implementation of EPLC's SmartMAP toolset with active power quality management tools;
Annual customer satisfaction survey (2015)	1. Importance of low/affordable rates; 2. Importance of reliability; 3. Importance of customer service and availability of information; 4. Importance of power quality;	1. Continue to focus on realizing efficiencies, keeping any increases in line with inflation; 2. Continue to focus on the Self-Healing Grid and vegetation management initiatives as well as the other programs identified in EPLC's DSP to further reduce customer outages and improve reliability; 3. Enhancements to EPLC's website, bill presentment and face to face meetings, if required; 4. Implementation of EPLC's SmartMAP toolset with active power quality management tools;
Annual customer satisfaction survey (2016)	1. Importance of low/affordable rates; 2. Importance of reliability; 3. Importance of customer service and availability of information; 4. Importance of power quality;	1. Continue to focus on realizing efficiencies, keeping any increases in line with inflation; 2. Continue to focus on the Self-Healing Grid and vegetation management initiatives as well as the other programs identified in EPLC's DSP to further reduce customer outages and improve reliability; 3. Enhancements to EPLC's website, bill presentment and face to face meetings, if required; 4. Implementation of EPLC's SmartMAP toolset with active power quality management tools;
Community open house meetings (2017)	1. Importance of low/affordable rates; 2. Importance of reliability; 3. Importance of customer service and availability of information; 4. Need to offer opportunities and incentives to reduce electricity costs;	1. Continue to focus on realizing efficiencies, keeping any increases in line with inflation; 2. Continue to focus on the Self-Healing Grid and vegetation management initiatives as well as the other programs identified in EPLC's DSP to further reduce customer outages and improve reliability; 3. Enhancements to EPLC's website, bill presentment and face to face meetings, if required; 4. Continue promoting energy conservation initiatives and any relevant updates or changes to programs;
Innovative DSP customer survey (2017)	1. Importance of low/affordable rates; 2. Importance of reliability; 3. Importance of customer service and availability of information; 4. Importance of power quality;	1. Continue to focus on realizing efficiencies, keeping any increases in line with inflation; 2. Continue to focus on the Self-Healing Grid and vegetation management initiatives as well as the other programs identified in EPLC's DSP to further reduce customer outages and improve reliability; 3. Enhancements to EPLC's website, bill presentment and face to face meetings, if required; 4. Implementation of EPLC's SmartMAP toolset with active power quality management tools;

Note: Use "ALT-ENTER" to go to the next line within a cell

Attachment 1-G

Customer Engagement Studies

(Convergys & Innovative)

2018 RATE APPLICATION REVIEW

Customer Consultation Workbook

ESSEX POWERLINES CORPORATION

For more information, visit www.essexpowerlines.ca/DSP

Essex Powerlines Corporation is the local distribution company responsible for providing reliable and safe power to Amherstburg, LaSalle, Leamington and Tecumseh.

With approximately 44 employees, Essex Powerlines operates and maintains a distribution system serving over 28,000 residential and business customers.

Essex Powerlines is owned by the Town of Tecumseh, Town of LaSalle, Town of Amherstburg and Municipality of Leamington.

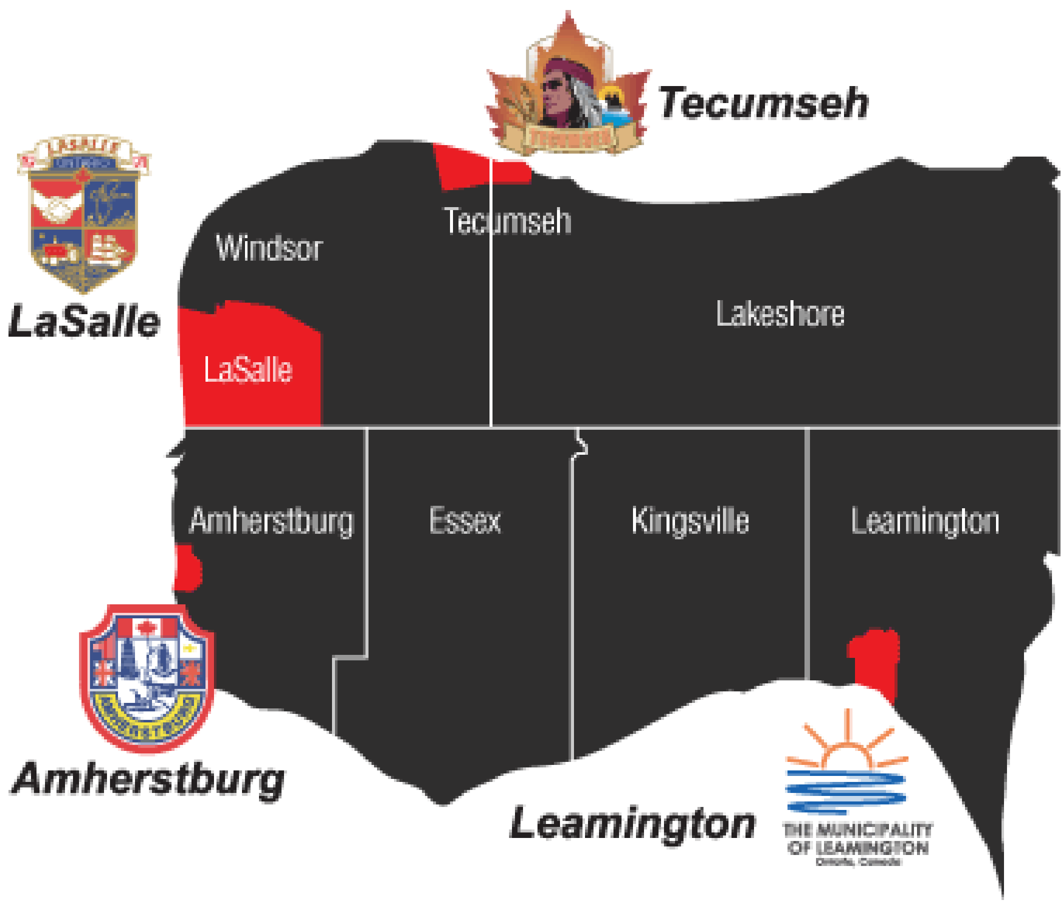


Table of Contents

What Is This Consultation?

The Purpose of this customer consultation is to collect your feedback on Essex Powerlines' investment and spending plan to maintain the local distribution system over the five year period from 2018 to 2022.

Essex Powerlines' goal is to deliver safe and reliable electricity to homes and local businesses as efficiently as possible and at an affordable price. However, there is a balancing act that all utilities must consider when planning for the future; system reliability vs. the cost to consumers. No distribution system delivers perfectly reliable electricity. Generally, the more reliable the system, the more expensive the system is to build and maintain.

This customer consultation is designed to collect your feedback on the reliability of the electricity distribution system and the spending decisions Essex Powerlines will need to make over the next five years. Ultimately, this consultation will help Essex Powerlines ensure alignment between its operational and capital investment plans and customers' needs and preferences.

As an Essex Powerlines customer, this is an opportunity for you to tell Essex Powerlines what you think about the plan and the cost implications for you. This is also an opportunity for Essex Powerlines to explain to its customers the challenges in operating and maintaining the local electricity distribution system, and more importantly how Essex Powerlines intends to meet those challenges.

To participate in this review, you do not need to be an expert. The workbook explains key parts of the electrical distribution system, the challenges facing the system, Essex Powerlines' recent work to maintain the system, and the company's budgetary plan for 2018 to 2022.

Essex Powerlines does not expect you to make electrical engineering decisions. Essex Powerlines wants to hear about the electricity issues that matter most to you and whether or not you feel the company's spending and investing priorities seem reasonable.

This workbook is designed to give you enough background about these issues for you to develop an informed opinion.

ESSEX POWERLINES CORPORATION

What's the Process that Essex Powerlines Must Follow?

How are electricity rates determined in Ontario?

The electricity industry in Ontario is regulated by the Ontario Energy Board (OEB), which recently developed regulatory requirements for electricity distributors, such as Essex Powerlines, to gather customer's preferences on distribution system investments.

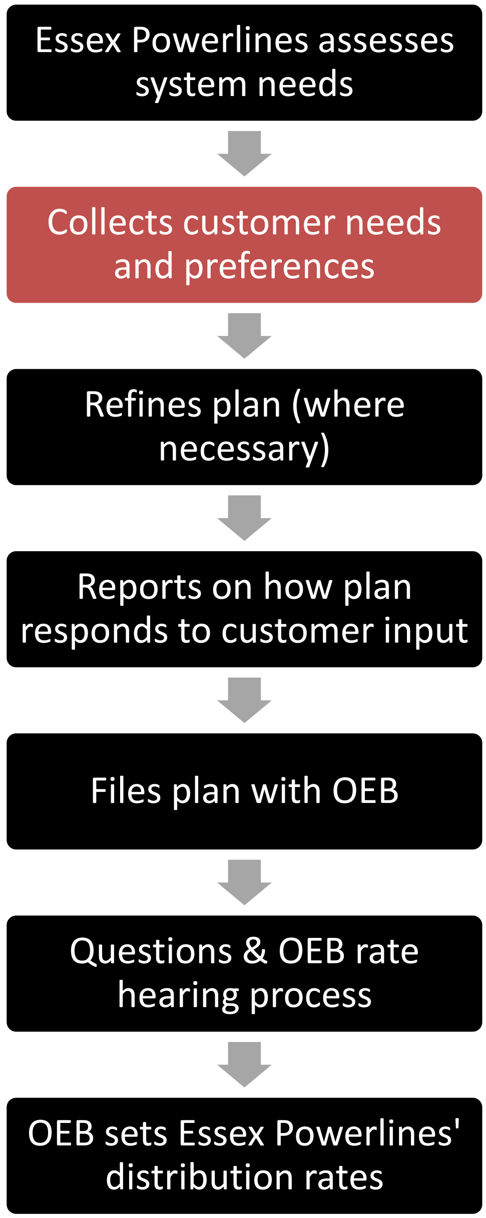
Essex Powerlines is funded by the distribution rates paid by its customers. Periodically, Essex Powerlines is required to file an application with the OEB to determine the funding available to operate and maintain the distribution system. Essex Powerlines must submit evidence to justify the amount of funding it needs to safely and reliably distribute electricity to its customers.

As a customer, how are my interests protected?

Essex Powerlines' evidence is assessed in an open and transparent public process known as a rate hearing. A number of public intervenors with electricity industry expertise submit their own evidence, in some cases challenging Essex Powerlines' plans and assumptions. At the end of the process, the OEB weighs the evidence and decides on the rates Essex Powerlines can charge for distribution.

Why is my feedback important?

Your feedback will be presented to the OEB and public intervenors (who represent various ratepayer groups) when Essex Powerlines files its rate application for 2018-2022. As part of the rate hearing process, the OEB will be reviewing how Essex Powerlines acquired and responded to customer feedback in its planning process.



Consumer Feedback on Ontario's Electricity System

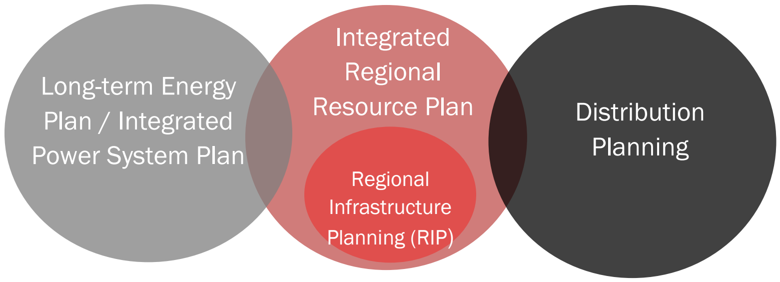
There are a number of ways for consumers to voice their opinions on provincial, regional and local electricity issues. However, this consultation is about your local distribution system and your preferences on how Essex Powerlines Corporation uses your money.

Distribution Planning: This workbook and consultation concentrates on the plan for Essex Powerlines' distribution system over the next five years. The graphic below shows the various planning initiatives ongoing across Ontario's electricity system. In addition to the short-term distribution plan being discussed in this workbook, there are other planning initiatives undertaken to ensure that the distribution system maintains reliability and works efficiently for the benefit of customers.

If you're interested in broader medium- and long-term electricity issues such as Ontario's Long-Term Energy Plan, regional planning, conservation planning and general energy policy in the province, there are other opportunities to provide your feedback.

Ontario's Long Term Energy Plan: The Ontario Government's plan details how electricity will be generated and the longer-term conservation strategy for the province. It can be found at this website: *http://www.energy.gov.on.ca/en/ltep/*

Regional Planning: The Independent Electricity System Operator (IESO) looks ahead to the future electricity needs of your region and how those needs can be addressed through conservation, local generation, and electricity from outside the region. You can follow the IESO's regional planning process at this website: *http://www.powerauthority.on.ca/power-planning/regional-planning*



Provincial System Planning

This involves more long-term planning on how Ontario's electricity system is designed and operated.

This includes planning on:

- Provincial electricity supply mix (e.g. greening the grid and phasing out coal power generation)
- System supply and demand forecasting
- Interconnections and grid design

Regional Planning

Regional planning involves near- and medium-term plans to meet the needs of a region of the province, and ensure all key players (i.e. transmission and distribution operators) are coordinated moving forward.

This planning process is focused on considering whether conservation & local generation options have been considered, in addition to core infrastructure ("wire") solutions.

Distribution System Planning

Distribution planning involves plans, both near- and long-term, to ensure the local distribution system has the adequate infrastructure to meet required reliability and safety standards, and to otherwise meet the needs of customers.

Customer Electricity Bills

Your Electricity Bill: Every item and charge on your bill is mandated by the provincial government or regulated by the OEB. There are two distinct cost areas that make up the “Delivery” charge on your bill: ***distribution*** and ***transmission***. While Essex Powerlines collects both, it remits the transmission charge to Hydro One. The distribution charges are what Essex Powerlines uses to fund its utility needs. Distribution costs make up about 20% of the typical customer’s (750 kWh per month) total electricity bill.

SAMPLE MONTHLY BILL STATEMENT
Essex Powerlines Corporation

Sample Bill
1234 Main St.
Tecumseh, ON X1X 1X1

Billing Summary — Service Address: 1234 Main St.

Previous Balance			$134.89
Payment Received on Mar 02, 2017			$134.89 CR
Balance Forward			$0.00
Your Electricity Charges:			
ON Peak TOU - Winter	72.85 kWh x $0.180000		$13.11
MID Peak TOU - Winter	99.76 kWh x $0.132000		$13.17
OFF Peak TOU - Winter	260.39 kWh x $0.087000		$22.65
Delivery			$28.60
Regulatory Charges			$3.37
Debt Retirement Charge			$0.00
Your Total Electricity Charges:			**$80.90**
Your Municipal Charges:			
Water Base Charge			$13.38
Water Usage - Block 1	1.143200	10.0000	$11.43
Sewer Base Charge			$13.38
Sewer Usage - Block 1	1.185700	10.0000	$11.86
Your Total Municipal Charges:			**$50.05**
HST# 870066529			$10.52
8% Provincial Rebate			$6.47 CR
Total Current Charges			**$135.00**
Total Amount Due			**$135.00**
Debt Retirement Charge Exemption Saved You			$3.03

Bill Date: Mar 17, 2017 **Account Number:** 00000000-00

Read Date	Electric Consumption	Month Total	Day Avg	Off Peak	Mid Peak	On Peak
Mar-1-17		459.00	15.30	276.07	105.77	77.24
Jan-30-17		514.00	19.04	327.09	105.92	81.18
Jan-1-17		631.00	20.35	432.60	103.00	95.23
Dec-1-16		457.00	15.23	276.80	101.55	78.60
Nov-1-16		460.00	14.38	305.28	60.95	93.88
Sep-30-16		518.00	21.58	306.22	91.29	120.93
Sep-1-16		1672.00	53.94	998.58	275.04	398.32
Jul-29-16		1639.00	52.87	1007.69	268.40	362.98
Jun-28-16		1116.00	39.86	699.71	183.89	232.79
May-31-16		405.00	13.97	264.62	62.59	77.79
May-1-16		436.00	14.53	276.06	89.93	69.75
Apr-1-16		508.00	16.39	303.76	114.96	89.13
Feb-29-16		228.00	8.44	149.30	32.22	46.43

Messages:
The Debt Retirement Charge was removed for certain Residential consumption after December 31, 2015. Learn more at Ontario.ca/DRC. The Ontario government is providing a rebate on your electricity costs equal to the provincial portion of HST.

Service Class: RESIDENTIAL Cycle 0009

Essex Powerlines’ distribution rates are subject to the review and approval of the OEB. The revenues collected from customers covered Essex Powerlines’ capital investments and operating expenses. Current monthly distribution charges are approximately $26.16, $59.13, and $453.70 per month for a typical Essex Powerlines customer who consumes 750 kWh, 2,000 kWh, and 40,000 kWh in a month, respectively.

It is estimated that – all things being equal – distribution charges will increase gradually with inflation from 2018 – 2022. This includes the cost of the Essex Powerlines plans to operate, maintain, and modernize its electricity distribution system.

Understanding Essex Powerlines' Role in Ontario's Electricity System

There are three main components to all electricity systems: generation, transmission, and distribution

Where Electricity Comes From

In Ontario, 70% of electricity is generated by Ontario Power Generation (OPG). This provincially-owned organization has generation stations across Ontario that produce electricity from hydroelectric, nuclear and fossil fuel sources.

Once electricity is generated, it must be delivered to urban and rural areas in need of power. This happens by way of high voltage transmission stations and interconnected lines that serve as highways for electricity. The province has more than 30,000 kilometres of transmission lines, owned mostly by Hydro One.

Essex Powerlines Corporation

Essex Powerlines is responsible for the last step of the journey: distributing electricity to customers in the region through our distribution system.

Every distribution system is unique with its own history and challenges. In order to better understand Essex Powerlines' current system, we first have to understand all of the different components and how they impact the way in which you receive electricity when you need it.

Essex Powerlines' power is supplied at high voltage levels to 4 transmission stations (TS) owned by Hydro One. The high voltage electricity is then reduced and connected through 27.6kV feeder circuits. Some of these feeder circuits are used to distribute power to various substations located throughout the communities Essex Powerlines serves. These substations further transform the electricity voltage to lower voltage levels for distribution to the neighbourhoods within the communities. Some customers receive power directly from the 27.6kV system while others receive power via these substations. In either case, additional transformers are located near each customer, and transform the voltage one final time to levels safe to distribute through a home or business.

Essex Powerlines' Overhead System

The overhead system is made up of distribution lines that operate at 4kV, 8kV, or 27.6kV. By 2018, Essex Powerlines' overhead system will be mainly made up of distribution lines that operate at 27.6 kV. Along the line, pole-top transformers step the voltage down. From there, the electricity is delivered to customers.

Essex Powerlines' Underground System

The underground system consists of a complex network of cables, vaults, cable chambers and transformers situated on concrete pads (padmount transformers). In residential areas, underground cables distribute electricity from substations (or TS's as the case may be) to padmount transformers located on customer boulevards. Like the overhead system, these transformers step the electricity down to a lower voltage, and electricity is delivered to customers.

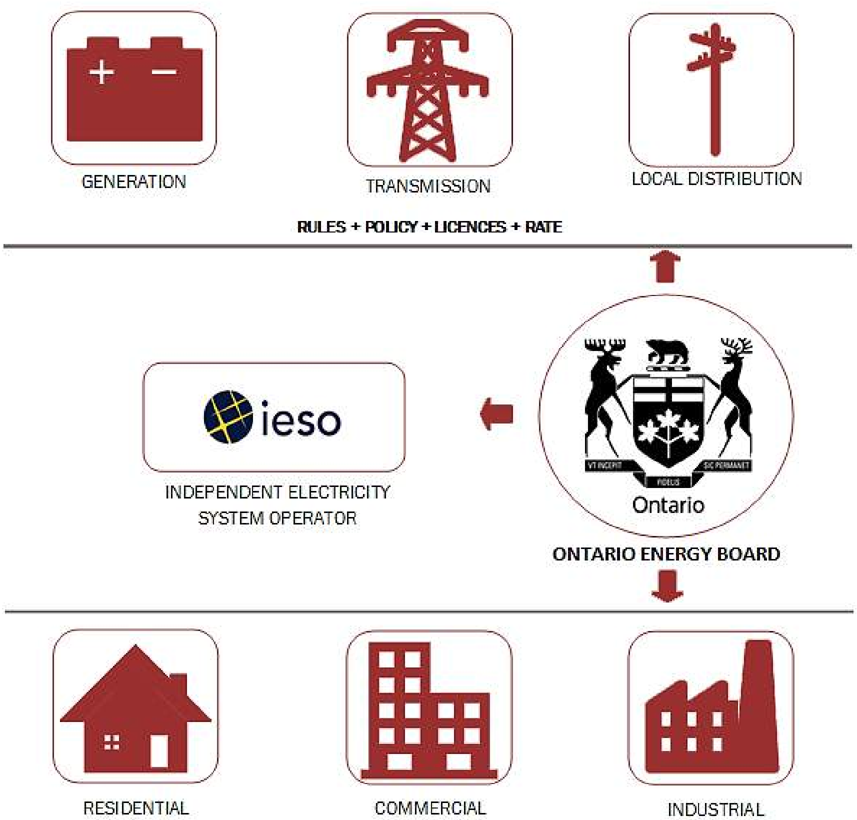
Electricity Grid:
How is Ontario's Electricity System Regulated?

The electricity system in Ontario is regulated by the following bodies:

Ontario Ministry of Energy:
The Ontario Ministry of Energy sets energy policy. It sets the rules and establishes key planning and regulatory agencies through legislation.

Ontario Energy Board:
The mission of the Ontario Energy Board (OEB) is to promote a viable, sustainable and efficient energy sector that serves the public interest and assists consumers to obtain reliable energy services at reasonable cost. It is an independent body established by legislation that sets the rules and regulations for the provincial electricity sector. One of the OEB's roles is to review the distribution plans of all electricity distributors and set their rates.

The Independent Electricity System Operator:
The Independent Electricity System Operator (IESO) is responsible for short, medium and long-term electricity planning to ensure an adequate supply of electricity is available for Ontario residents and businesses. It operates the grid in real-time to ensure that Ontario has the electricity it needs, where and when it needs it. The IESO receives directives from the Ministry of Energy (i.e. energy supply mix, Green Energy Act), but otherwise works at arm's-length from the government.



Customer Feedback

1. Given what you know and what you have read so far, how well do you feel you understand the parts of the electricity system, how they work together and which services Essex Powerlines is responsible for?

   ☐ Very well
   ☐ Somewhat well
   ☐ Not very well
   ☐ I don't understand at all

2. Generally, how satisfied are you with the service you receive from Essex Powerlines?

   ☐ Very satisfied
   ☐ Somewhat satisfied
   ☐ Somewhat dissatisfied
   ☐ Very dissatisfied
   ☐ Not sure

3. Is there anything in particular that Essex Powerlines can do to improve its service to you?

Essex Powerlines' Grid Today

This section describes the construction of Essex Powerlines' distribution grid including its substations, overhead and underground systems. It also explains the company's historical growth and current electrical infrastructure.

Background on Essex Powerlines' Distribution System

Restructuring of the utility industry presented many challenges and opportunities when Bill 35 was passed. Existing public utility commissions had to change to standard Ontario business corporations, owned by the local municipalities. The new corporations answered to the Ontario Energy Board and were responsible for regulatory, rate setting and licensing matters in the electricity market.

The four municipalities of Amherstburg, LaSalle, Leamington and Tecumseh made a strategic decision to pool the resources of their utilities together and avoid many deregulation costs. In the new electricity market new business models would have to be put into place. If the municipalities chose to go alone into the new environment, the local rate base could not have supported the new costs of the business model and the utilities may not have had the expertise and knowledge to become market ready.

On June 1, 2000, the Towns of Amherstburg, LaSalle, Leamington and Tecumseh amalgamated their Utilities to form the Essex Power Group of Companies. Essex Powerlines owns and operates the physical electricity infrastructure in these areas. Essex Powerlines is the default company from which consumers purchase electricity from the provincial grid.

In 2016, Essex Powerlines hired the consulting firm METSCO to help establish a formalized asset management program. Using international engineering standards, METSCO is reviewing all the data Essex Powerlines currently maintains for its assets, evaluating the integrity of that information, recommending additional information for collection, assessing the health of the individual asset classes, and, using a risk-based approach, assisted Essex Powerlines' engineering team in ranking and prioritizing the asset replacement work required in order to minimize Essex Powerlines' operating costs.

This process helped confirm that Essex Powerlines' approach to capital renewal and preventative maintenance was successful in keeping the system up to date. The new approach to asset management will help Essex Powerlines' create better and more focused plans to continue to keep the system updated and deliver a better quality of service.

Every distribution system is unique with its own history and challenges. In order to better understand the current Essex Powerlines system, we first have to understand all of the different components and how they impact the way in which you receive electricity when you need it. The diagram and terms below will help guide you through the system.

Essex Powerlines' distribution system is made up of a number of components which work together to transport electricity to homes and businesses across the communities it serves.

Essex Powerlines' service territory covers 66 square kilometers of urban area, encompassed within a 38 square kilometer geographic area.

The distribution system contains 186 km of overhead lines, 263 km of underground, and 0 municipal substations to step down voltage from 27.6 kV to the remaining old 4 kV and 8 kV systems. (The remainder of the old 4 kV and 8 kV systems will be converted to the 27.6 kV system by 2018.)

Essex Powerlines is served by a total of 4 transmission stations which are owned and operated by Hydro One.

Hydro One's Transmission System

High Voltage Transmission – Connects our distribution system to electricity generating stations across the province.

Transmission Station – Reduces high voltage electricity from transmission lines to medium voltage which is fed into Essex Powerlines' distribution stations.

Essex Powerlines' Distribution System:

Municipal Substations: Municipal substations are a critical element of the electricity distribution system—they are the local hubs from where electricity is distributed to an area. Municipal substations contain:

> **Transformers** – Important pieces of equipment that reduce the voltage of electricity from a high level to a level that can be safely distributed to your area.
>
> **Feeder Circuits** – The wires that connect the transmission station to the broader distribution system in order to deliver electricity to customers.
>
> **Breakers** – Devices that protect the distribution system by interrupting a circuit if a higher than normal amount of electricity is detected.
>
> **Switches** – Control the flow of electricity and steer the current to the correct circuits.

Overhead System: The overhead system includes the wires that are commonly seen across Essex Powerlines' service area. The voltage of the overhead system can range from 4 kV (4,000 volts) to 27.6kV, however, Essex Powerlines is mainly 27.6kV.

> **Wires** – There are 186 km of wire that carry electricity across the overhead distribution system.
>
> **Poles** – Wires are suspended from these, usually wooden (sometimes concrete), poles.
>
> **Pole Top Transformers** – These transformers are mounted near the top of utility poles and are needed to further step-down the voltage from the lines to the final connection to customers.

Underground System: The underground system includes 261 km of cable, which is directly buried and or installed in ducts. At certain intervals, underground service chambers (with manholes) are required to permit cables to be spliced together and to allow underground equipment such as switches to be housed.

An advantage of underground systems is that they are affected to a lesser extent by extreme weather. The disadvantage is that they are more expensive to install and maintain, and when there is a power outage it often takes longer to locate and repair a problem compared to overhead wires.

Underground Cables – Convey the electricity in the underground system. Cables that connect the distribution stations and major industrial users to the distribution station are significantly larger than cables used to connect residential neighbourhoods.

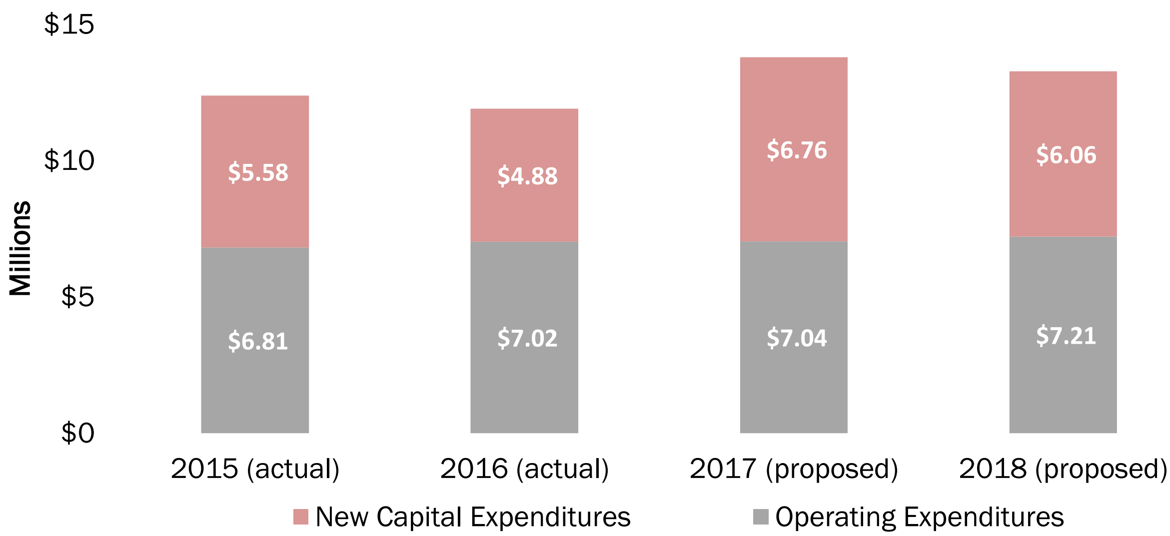
Padmount Transformers – Similar to transformers in the overhead system, these reduce the voltage to a lower level before final connection to customers. In the underground system there are concrete padmounted transformers, which are above ground transformers that are supplied by underground cable, and vault transformers, which are housed in underground chambers.

Paying for the Distribution System?

As anyone who runs their own business would expect, Essex Powerlines' manages its spending in two budgets – an operating budget and a capital budget.

Essex Powerlines' operating budget covers regularly recurring expenses such as the costs of running service vehicles, the payroll for employees, and the maintenance of distribution equipment and buildings.

Its capital budget covers items that, when purchased, do not need to be repurchased for some time and that have lasting benefits over many years. This can include much of the equipment that is part of the distribution system, such as poles, wires and transformers, major computer systems and vehicles.



Managing the distribution system requires millions of dollars in maintenance, system renewable and running the day-to-day operations. In its last fiscal year (2016), Essex Powerlines' operating expenses and capital expenditure totalled $11.9 million.

4. How well do you feel you understand the important parts of the electricity system, how they work together, and which services Essex Powerlines is responsible for?

- ☐ Very well
- ☐ Somewhat well
- ☐ Not very well
- ☐ I don't understand at all

5. The average Essex Powerlines customer experiences one power outage per year. Do you recall how many outages you experiences in the past year?

- ☐ None
- ☐ One
- ☐ Two
- ☐ Three
- ☐ Four
- ☐ More than four
- ☐ Not sure

No system delivers perfectly reliable electricity. There is a balancing act between reliability and the cost of running the system. Please answer the following questions:

6. How acceptable were the number of power outages you experiences over the last 12 months?

- ☐ Very acceptable
- ☐ Somewhat acceptable
- ☐ Not very acceptable
- ☐ Did not have any power outages
- ☐ Not sure

7. How many power outages do you feel are reasonable in a year?

- ☐ No outage is acceptable
- ☐ One
- ☐ Two
- ☐ Three
- ☐ Four
- ☐ More than four
- ☐ Not sure

8. What do you feel is a reasonable duration for a power outage?

- ☐ No outage is acceptable
- ☐ 30 minutes
- ☐ 1 hour
- ☐ 2 hours
- ☐ 3 hours
- ☐ 4 hours or more
- ☐ Not sure

Cost Pressures

From the day-to-day to major storm events, there are a variety of ever-present pressures on Essex Powerlines' operating and capital budget.

Many of these expenditures are items over which Essex Powerlines has little or no control over – major storms, and the implementation of Smart Meters, for example.

Other costs are associated with preventative maintenance like replacing aging equipment. Essex Powerlines has already undertaken several large scale projects, and more are planned.

How does Essex Powerlines determine the appropriate amount of capital spending related to existing infrastructure?

Essex Powerlines monitors the health of its electric infrastructure very closely. As part of its rate application, it must show the OEB third party reviews of the health of its system's assets. These asset health reviews help Essex Powerlines prioritize which parts of its system get upgraded or rebuilt first.

Has Essex Powerlines previously set aside funds for required upgrades?

The OEB does not allow utilities in Ontario (including Essex Powerlines) to create reserve funds. If reserve funds were allowed, a utility would have to charge customers a premium on their rates to set money aside. Under OEB regulation, a utility can only charge customers the rate required to run the distribution system at a reliability standard set by regulatory bodies.

Capital Investment Drivers

Essex Powerlines has developed a list of capital investment drivers and proposes investment programs based on these key drivers.

Reliability: There are two main measures of reliability in the distribution system:

1. How often does the power go out?
2. How long does it stay out?

To achieve maintained or improved reliability, projects are developed to improve asset performance and decrease the frequency and duration of power outages.

Service Requests: Essex Powerlines has a legal obligation to connect customers to its distribution system. This includes both traditional demand customers (new homes and businesses) and distributed generation customers (e.g. micro-FIT customers who have contracts to sell electricity back to the grid such as rooftop solar panels). Requests can also include system modifications to support infrastructure development by government agencies, road authorities and developers.

Support Capacity Delivery: Where there are forecasted changes in demand that will limit the ability of the system to provide consistent service delivery or where it is incapable of meeting the demand requirements, new builds or expansion is required. This is the fundamental infrastructure that allows new customers to be hooked up to the distribution system and is paid for by new customers served over time.

System Efficiency: To provide customers with the best service possible, there is always a need to improve power outage restoration capability.

Mandated Compliance: Compliance with all legal and regulatory requirements and government directives, such as compliance with the Ministry of Energy, the Ontario Energy Board, the Independent Electricity System Operator and other regulations.

Obsolescence: Asset installations that no longer align with Essex Powerlines' current operating practices or current standards. This can include those assets that:

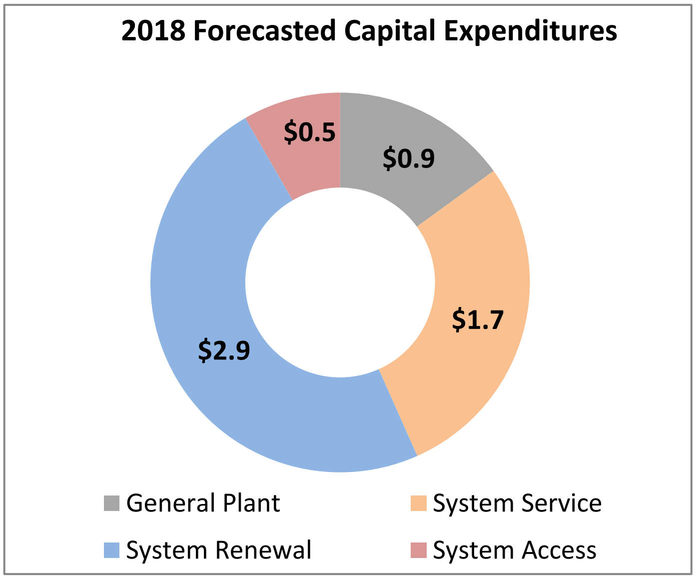
- Are no longer manufactured,
- Lack spare parts,
- Cannot be accessed,
- Lack the ability to have maintenance performed on them,
- Have operational constraints or conflicts, which can result in increased reliability and/or safety related risks.

Aging or Poor Performing Equipment: Where there is the imminent risk of failure due to age or condition deterioration, and these potential failures will result in severe reliability impacts to customers as well as potential safety risks to crew workers or to the public, remediation, through refurbishment or replacement, is required.

Business Support Costs: Essex Powerlines is not just the local electricity distribution system itself, but a company that operates the system. As a company, it needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the system and customer information.

What are the major issues Essex Powerlines needs to address?

Over the years, Essex Powerlines has worked hard to keep its equipment working well beyond its originally expected life, to get maximum value for money. However, Essex Powerlines' key challenge still comes from the need to replace aging equipment.



In 2018, the capital expenditures required to address system renewal, maintain system reliability and invest in other infrastructure priorities are estimated by Essex Powerlines to be $6 million which is consistent with historical spending.

To assist us in prioritizing what needs to be replaced and by when, Essex Powerlines uses an asset management model to drive replacement decisions. Using the information provided by the asset management model, Essex Powerlines plans for four types of capital investment costs:

System Access

Definition: Projects that respond to customer requests for new connections or new infrastructure development. These are usually a high priority, "must do" type of request.

Programs (e.g.): Customer Connections, Relocating assets based on infrastructure needs

System Renewal

Definition: Projects focused on replacing aging equipment in poor condition.

Programs (e.g.): Distribution Station Refurbishment, Voltage Conversion, Underground Cable Replacement, Overhead Wire Replacement

System Service

Definition: Primarily consisting of projects that improve system reliability.

Programs (e.g.): Automated Switches, better distribution system monitoring equipment

General Plant

Definition: Investments in supporting assets, such as tools, vehicles, buildings and information technology (IT) equipment that are needed so that we may perform our task to operate and maintain the distribution system

Programs (e.g.): IT, facilities, fleet

Cost Drivers

Capital Investments

The challenges impacting the Essex Powerlines distribution system can be broken down into 4 broad categories:

1

Aging Infrastructure

- Essex Powerlines completes a variety of field services on a yearly basis to determine the health of its equipment across the four communities that we serve.
- There is a variety of equipment within Essex Powerlines' distribution system that is aging and beyond its useful life requiring replacement ranging from replacements that require immediate action to replacements that need to be addressed in 1-5 years.
- Through its rigorous asset management plan, Essex Powerlines plans to continuously replace aging and equipment in danger of failure through various reactive and preventive maintenance programs.

2

Voltage Conversion

- Essex Powerlines is in the process of finalization its voltage conversion program that will position Essex Powerlines as a single voltage utility in 2017/2018. Instead of supplying electricity at multiple voltages, Essex Powerlines will be supplying its customers with electricity at 27.6kV only. This will reduce inventory, system complexity and system losses; all things that will save Essex Powerlines customers money in the long run.

3

Economic Development

- One of Essex Powerlines' top priorities is to enable economic development in our 4 shareholder communities that we serve through the facilitation of system connection and by keeping our rates at reasonable levels.
- Power quality and reliability has been mentioned by our commercial and industrial customers as a growing concern which is why Essex Powerlines is investing in technology like SmartMAP and the Self-Healing grid to improve visibility of our system and provide faster response times for outages as they incur.

4

Increasing Cost of Electricity

- With energy costs rising and forecasted to continue rising for the foreseeable future, Essex Powerlines has made it a priority to champion Conservation & Demand Management, facilitate customer connection of behind-the-meter generation or simply providing customers with the tools necessary to monitor and control their consumption.

Cost Drivers

Operating Expenses

In addition to its capital budget, Essex Powerlines needs to consider its operating budget which also impacts customer bills.

Cost drivers contributing to the operating budget can largely be attributed to on-going maintenance and management of the distribution system. An example of this cost driver is Essex Powerlines' tree trimming service, designed to lessen the impact of falling tree branches on power lines.

Customer Focus

- It is now an industry requirement for all utilities to demonstrate that they have consulted customers before applying for new rates
- Essex Powerlines embraces this concept and wants to gather ongoing customer feedback and input through website surveys and focus groups.
- Essex Powerlines continues to enhance its online customer service offerings; this has included updating the website as well as increasing social media presence. Essex Powerlines has launched automatic outage updates on our Twitter account. This allows customers to get real-time updates on any outages that they may be experiencing.
- Further, in 2017 Essex Powerlines enhanced the look of the monthly customer bill and made it much easier to read and understand.

Industry Focus

- Industry regulation requires that Essex Powerlines maintain compliance with various regulatory bodies in a complex provincial environment.
- The requirements to implement Smart Meters and to adopt the International Financial Reporting Standard ("IFRS") of accounting are examples of recent industry change.
- Meters are now more complex and require specialized troubleshooting. Essex Powerlines installed many of its Smart Meters in 2009 and 2010. As these meters age, more focus is required on re-verification. Essex Powerlines is now testing groups of these meters at intervals throughout their life span rather than waiting for them to cease operating at end-of-life.
- To ensure that Essex Powerlines is in compliance with all regulatory codes, including new requirements and reporting, additional staffing and support resources have been added since 2010.

Operational Effectiveness & Power Quality

- Consistent with industry best practice, Essex Powerlines has established a formalized asset plan for distribution system assets. This includes asset health assessments and replacement prioritization rules.
- The plan will also include voltage conversion work to modernize the system in order to identify the causes of outages more quickly and reduce line losses.
- Essex Powerlines will incur expenses for additional software and engineering resources as the distribution system plan is continuously updated.

Finding Efficiencies and Cost Savings

Where possible, Essex Powerlines has extended the life of its equipment through rigorous repair and maintenance program in order to get maximum value for money. Some of this aging equipment can be "run to failure", meaning we can replace it after it ceases to function without significant customer impact. However, other end-of-life equipment is more mission critical and cannot be "run to failure" because failure could result in a public safety hazard or an unsupportable economic burden for our customers.

There are several other ways in which Essex Powerlines works to find efficiencies and cost savings in the system:

Enhanced Power Quality Metering: Installing power quality meters at select commercial and industrial sites helps major customers resolve power quality issues so they can better understand and control their energy usage.

Voltage Conversion Program: Converting to a single higher voltage will eliminate antiquated equipment, reduce system losses, and reduce ongoing maintenance costs.

Estimated and Scheduling Tool: A new estimating and scheduling tool means Essex Powerlines can more quickly and more accurately assemble an estimate and lay out work for construction crews.

"Kitting": Warehouse staff pre-assemble parts and equipment needed for specific repairs, which reduces the time needed for crews to complete maintenance and service tasks, thereby reducing costs.

Group Buying Program: Essex Powerlines save money by participating in a group buying program with other local utilities. This means some types of equipment and materials can be purchased much less expensive.

Remote Fault Indication: Allows Essex Powerlines to better diagnose outages before dispatching work crews. Reduces expensive after-hours crew visits.

Labour Saving Equipment: Specialized trucks and other equipment reduce manual labour, which reduces time and costs.

Smart Meter Data: Using Smart Meter data to diagnose outages and power quality issues reduces time and guess work, and helps resolve issues faster.

Targeted Capital Projects: These projects eliminate equipment from the system that is known to be high maintenance.

Outage Management System: Quickly and automatically identifies faults, notifies crews and provides information to help troubleshoot and identify the cause.

SmartMAP: Innovative technology that improves reliability and service and reduces the number of outages as they can be address proactively.

Social Media: Essex Powerlines uses social media to send automated updates to customers about outages and keep them informed about the progress toward restoration.

9. With regards to projects focused on replacing aging equipment in poor condition, which of the following statements best represents your point of view?
   - ☐ Essex Powerlines should invest what it takes to replace the system's aging infrastructure to maintain system reliability, even if that increases my monthly electricity bill by a few dollars over the next few years.
   - ☐ Essex Powerlines should lower its investment in renewing the system's aging infrastructure to lessen the impact of any bill increase, even if that means more or longer power outages.
   - ☐ Not sure

10. As a company, Essex Powerlines needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the system and customer information. Which of the following statements best represents your point of view?
    - ☐ Essex Powerlines should find ways to make do with the buildings, equipment and IT systems it already has.
    - ☐ While Essex Powerlines should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system safely, efficiently and reliably.
    - ☐ Not sure

11. How well do you feel you understand the cost drivers that Essex Powerlines is responding to?
    - ☐ Very well
    - ☐ Somewhat well
    - ☐ Not very well
    - ☐ Not well at all
    - ☐ Not sure

12. How well do you think Essex Powerlines is managing these cost drivers while meeting customer expectations and keeping rates reasonable?
    - ☐ Very well
    - ☐ Somewhat well
    - ☐ Not very well
    - ☐ Not well at all
    - ☐ Not sure

13. How satisfied are you with the efforts Essex Powerlines has made to find efficiencies and cost savings in the distribution system?
    - ☐ Very satisfied
    - ☐ Somewhat satisfied
    - ☐ Not very satisfied
    - ☐ Not at all satisfied
    - ☐ Not sure

What Essex Powerlines Corporation's Plan Means for You

Residential – 750 kWh per month

In 2018, it is anticipated that residential customers with an average monthly consumption of 750 kWh will see a moderate increase on the distribution portion of their electricity bills. It is expected that – all things being equal – distribution rates will increase in line with the rate of inflation.

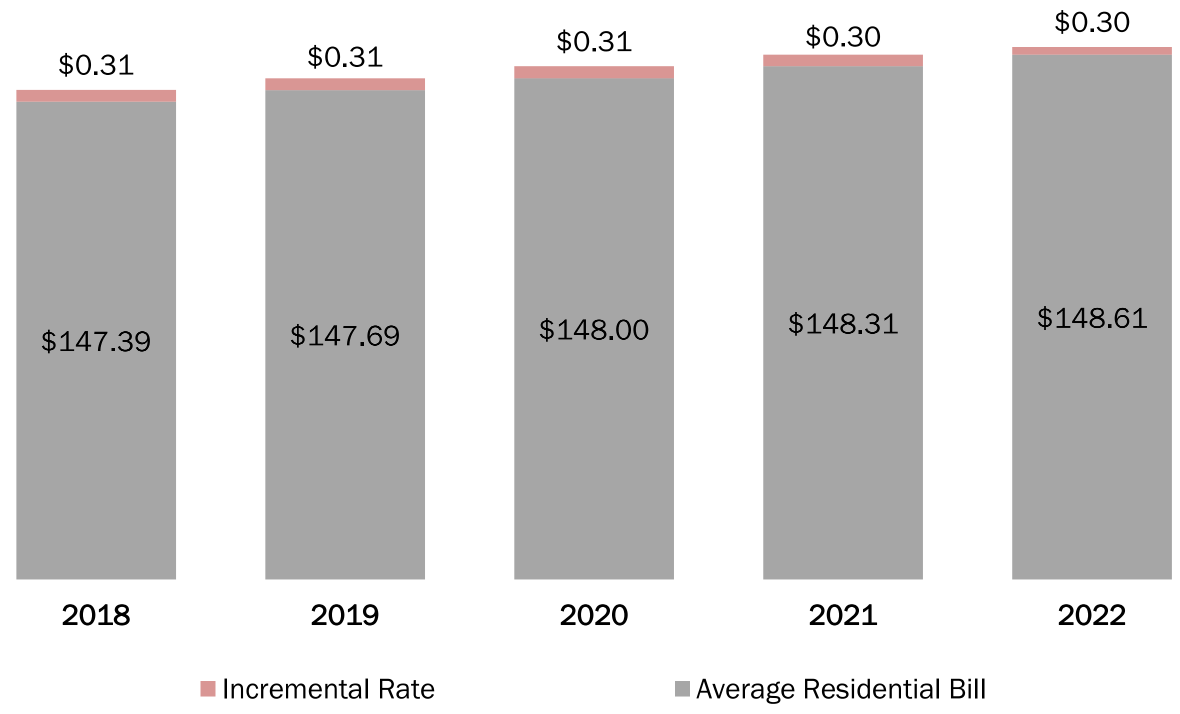
Essex Powerlines considered gradual inflationary increases, consistent with the industry rate-setting process, to determine a one-time rate increase between 2018 until 2022. Essex Powerlines' forecasted increase over the next five years may see an average annual increase of $0.31 per month or 0.2% on the total bill for a residential customer with an average monthly consumption of 750 kWh.

By 2020, Essex Powerlines forecasts that the average residential household will be paying an estimated $1.79 more (6.84%) per month on the distribution portion of their electricity bill; however, this incorporates an average yearly increase of 1.37% each year through 2020.

The illustrations below will provide better understanding of the one-time change in rates.

	Current	Proposed	Increase	5 Year % Increase	Average Yearly Increase
Distribution	$26.16	$27.95	$1.79	6.84%	1.37%
Total Bill	$147.08	$148.61	$1.53	1.04%	0.21%

Estimated Residential Annual Increase in Monthly Bill (5 year forecast)



What Essex Powerlines Corporation's Plan Means for You

GS<50 kW – 2,000 kWh per month

In 2018, it is anticipated that GS<50 kW customers with an average monthly consumption of 2,000 kWh will see a moderate increase on the distribution portion of their electricity bills. It is expected that – all things being equal – distribution rates will increase in line with the rate of inflation.

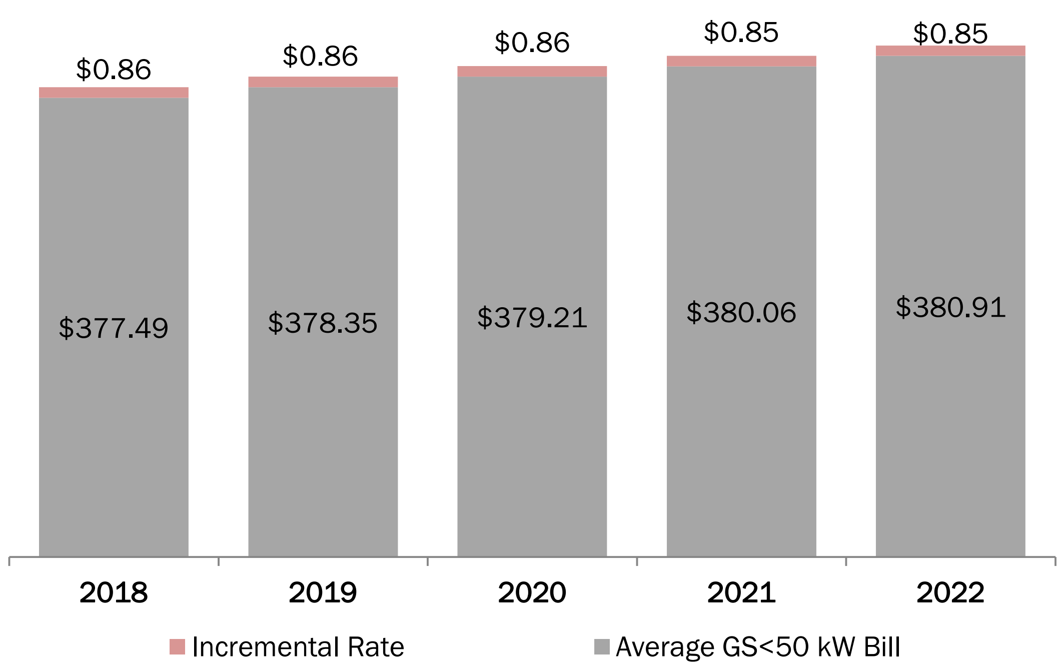
Essex Powerlines considered gradual inflationary increases, consistent with the industry rate-setting process, to determine a one-time rate increase between 2018 until 2022. Essex Powerlines' forecasted increase over the next five years may see an average annual increase of $0.86 per month or 0.2% on the total bill for a GS<50 kW customer with an average monthly consumption of 2,000 kWh.

By 2020, Essex Powerlines forecasts that the average GS<50 kW customer will be paying an estimated $4.92 more (8.32%) per month on the distribution portion of their electricity bill; however, this incorporates an average yearly increase of 1.66% each year through 2020.

The illustrations below will provide better understanding of the one-time change in rates.

	Current	Proposed	Increase	5 Year % Increase	Average Yearly Increase
Distribution	$59.13	$64.05	$4.92	8.32%	1.66%
Total Bill	$376.63	$380.91	$4.28	1.14%	0.23%

Estimated GS<50 kW Annual Increase in Monthly Bill (5 year forecast)



What Essex Powerlines Corporation's Plan Means for You

GS>50 kW – 40,000 kWh & 100 kW per month

In 2018, it is anticipated that GS>50kW customers with an average monthly consumption of 40,000 kWh will see a moderate increase on the distribution portion of their electricity bills. It is expected that – all things being equal – distribution rates will increase in line with the rate of inflation.

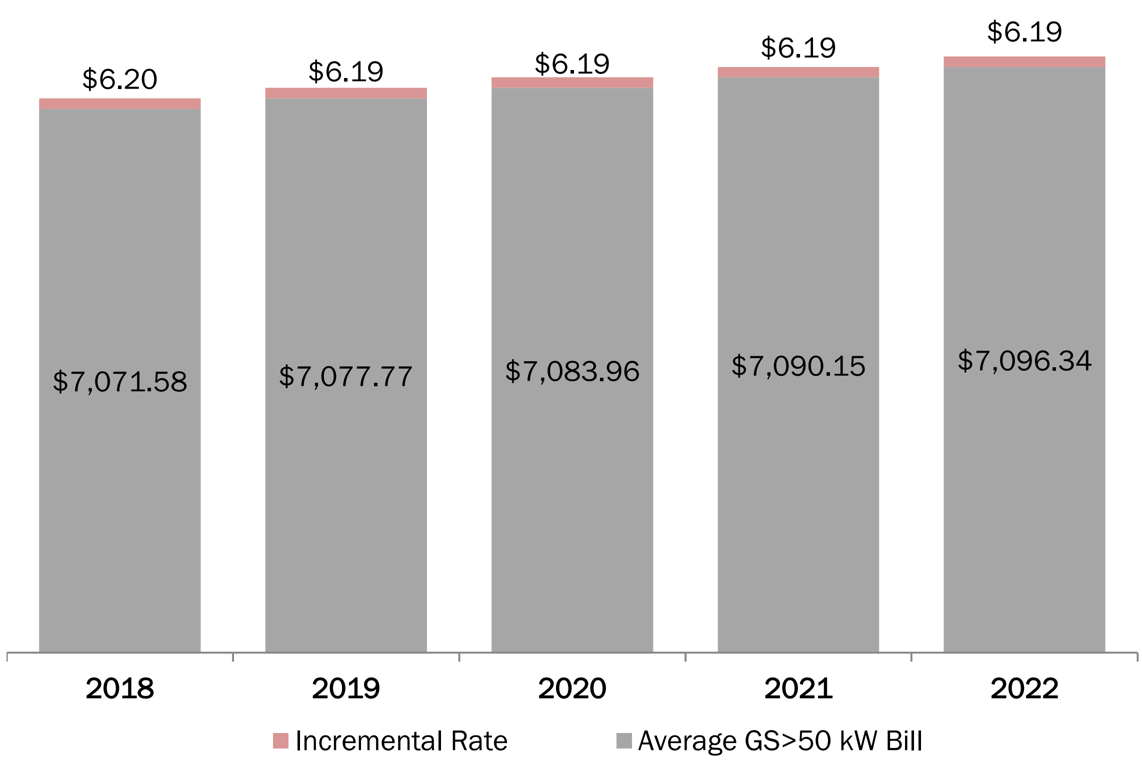
Essex Powerlines considered gradual inflationary increases, consistent with the industry rate-setting process, to determine a one-time rate increase between 2018 until 2022. Essex Powerlines' forecasted increase over the next five years may see an average annual increase of $6.19 per month or 0.08% on the total bill for a GS>50 kW customer with an average monthly consumption of 40,000 kWh.

By 2020, Essex Powerlines forecasts that the average GS>50 kW customer will be paying an estimated $42.67 more (9.40%) per month on the distribution portion of their electricity bill; however, this incorporates an average yearly increase of 1.88% each year through 2020.

The illustrations below will provide better understanding of the one-time change in rates.

	Current	Proposed	Increase	5 Year % Increase	Average Yearly Increase
Distribution	$453.70	$496.37	$42.67	9.40%	1.88%
Total Bill	$7,065.38	$7,096.34	$30.96	0.44%	0.09%

Estimated GS>50 kW Annual Increase in Monthly Bill (5 year forecast)



14. Now that you have a better sense of the operations of Essex Powerlines, including the cost drivers, do you feel the proposed budget is reasonable?
    - ☐ Yes
    - ☐ No
    - ☐ Not sure

15. From what you have read here and what you may have heard elsewhere, does Essex Powerlines' investment plan seem like it is going in the right direction or the wrong direction?
    - ☐ Right direction
    - ☐ Wrong direction
    - ☐ Not sure

16. How well did Essex Powerlines' plan cover the topics you expected?
    - ☐ Very well
    - ☐ Somewhat well
    - ☐ Not very well
    - ☐ Not well at all
    - ☐ Not sure

If not very or not at all, what is missing?

17. How well do you think Essex Powerlines is planning for the future?
    - ☐ Very well
    - ☐ Somewhat well
    - ☐ Not very well
    - ☐ Not well at all
    - ☐ Not sure

18. Considering what you know about the local distribution system, which of the following best represents your point of view?
    - ☐ The rate increase is reasonable and I support it
    - ☐ I don't like it, but I think the rate increase is necessary
    - ☐ The rate increase is unreasonable and I oppose it
    - ☐ Not sure

Final Thoughts

Essex Powerlines values your feedback. This is the first time the utility has conducted a review about its upcoming investment plan in this type of format.

Overall Impression: What did you think about the workbook?

Volume of Information: Did Essex Powerlines provide too much information, not enough, or just the right amount?

Content Covered: Was there any content missing that you would have liked to have seen included?

Outstanding Questions: Is there anything that you would still like answered?

Suggestions for Future Consultations: How would you prefer to participate in these consultations?

Glossary

Breakers: Devices that protect the distribution system by interrupting a circuit if a higher than normal amount on power flow is detected.

Distribution Station: These substations are located near to the end-users. Distribution station transformers change the voltage to lower levels for use by end-users.

Feeder Circuit: Is a wire that connects the transmission station to the broader distribution system in order to deliver electricity to customers.

General Plant: Investments in things like tools, vehicles, buildings and information technology (IT) equipment that are needed to support the distribution system.

Generation Station: A facility designed to produce electric energy from another form of energy, such as fossil fuel, nuclear, hydroelectric, geothermal, solar thermal, and wind.

Kilovolt (kV): 1,000 volts (see volt below).

Kilowatt (kW): 1,000 watts.

Local Distribution Company (LDC): In Ontario, these are the companies that take electricity from the transmission grid and distribute it around a community.

OM&A: Operations, Maintenance and Administration or operating budget.

Substations: Used to change AC voltages from one level to another and to switch generators, equipment and circuits and lines in and out of an electrical system.

Switches: These control the flow of electricity—they direct which supply of electricity is used and which circuits are energized. Distribution systems have switches installed at strategic locations to redirect power flows for load balancing or sectionalizing.

System Access: Projects required to respond to customer requests for new connections or new infrastructure development. These are usually a regulatory requirement to complete.

System Renewal: Projects to replace aging infrastructure in poor condition.

System Service: Primarily projects that improve reliability.

Transmission lines: Transmit high-voltage electricity from the generation source or substation to another substation in the electricity grid.

Transformer: Is an important piece of equipment that reduces the voltage of electricity from a high level to a level that can be safely distributed to your area or to your residence/business.

Underground Cable: A conductor with insulation, or a stranded conductor with or without insulation and other coverings (single-conductor cable), or a combination of conductors insulated from one another (multiple-conductor cable) with an intended use of being buried.

Volt (V): A unit of measure of the force, or 'push,' given the electrons in an electric circuit. One volt produces one ampere of current when acting on a resistance of one ohm.

Watt (W): the unit of electric power, or amount of work (J), done in a unit of time. One ampere of current flowing at a potential of one volt produces one watt of power.

Wire: A conductor wire or combination of wires not insulated from one another, suitable for carrying electric current.

Additional Comments

CONVERGYS
ANALYTICS

ESSEX POWERLINES
Top Down Survey

Wave I Results

November 2016

SURVEY OVERVIEW & METHODOLOGY

Objective

- Gather Customer Satisfaction metrics to be used for OEB and scorecard reporting
- To measure Satisfaction in the following areas: Overall Satisfaction, Service/Brand Performance, Communication, Billing, and Contact Handling

Timing

- Surveying conducted October 3 – October 14, 2016

Methodology

- Telephone Survey conducted by a Convergys live agent

Sampling

- 500 total completed surveys – 400 Residential completes and 100 Business completes

Question Scales & Reporting

- Satisfaction asked on a 5 (Very Satisfied) to 1 (Not at all Satisfied) scale
- Top 3-Box (3, 4 and 5 ratings) reporting used for reporting of survey attributes

CONVERGYS ANALYTICS

OUR OBJECTIVE AS A BUSINESS PARTNER IS TO HELP ESSEX POWERLINES INCREASE CUSTOMER SATISFACTION

Increase customer satisfaction

How we do this…

- Outline what factors have the largest impact on satisfaction
- Identify differences in Business and Residential customer segments
- Identify underperforming areas to target for improvement
- Mine customer comments to determine what common themes reflect opportunities for improvement

Improve customer interactions

How we do this…

- Working smarter to serve customers better by identifying and optimizing self-service opportunities
- Provide recommendations to improve the customer’s experience when they do need to contact customer service

CONVERGYS ANALYTICS

AGENDA

Essex Powerlines Top Down Survey

1 OEB Metric & Satisfaction Overview

2 Key Satisfaction Drivers

3 Touchpoint Satisfaction

4 Recommendations

EXECUTIVE SUMMARY

OEB Metric & Satisfaction Overview

- Overall Satisfaction is high (81%), but there are opportunities to improve service reliability, billing expectations, and customer service
- Business customers are more satisfied (by 8% pts) compared to Residential customers

Key Drivers

- Top Satisfaction drivers for Business customers are Reliability and Power Quality
- Customer Service is a top Satisfaction driver for Residential customers

Touchpoint Satisfaction

- Customers almost exclusively use the phone to contact Essex Powerlines where offering/enhancing self-service capabilities is a prime opportunity to reduce contacts
- Residential customers generally have a preference for mail while Business customers opt for several methods

CONVERGYS ANALYTICS

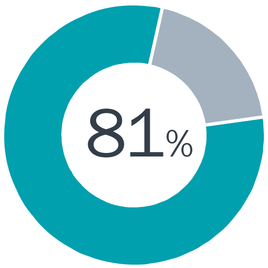
OEB METRIC & SATISFACTION OVERVIEW

THE MAJORITY OF CUSTOMERS ARE HIGHLY SATISFIED WITH ESSEX POWERLINES

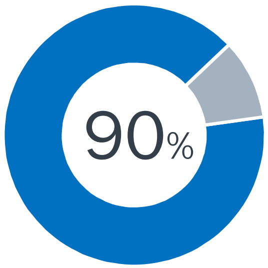
KEY METRIC AND OEB REQUIREMENTS

Top 3 Box

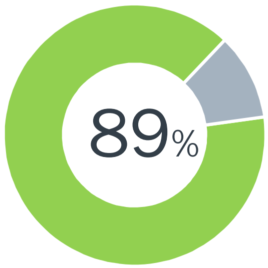
Overall Satisfaction



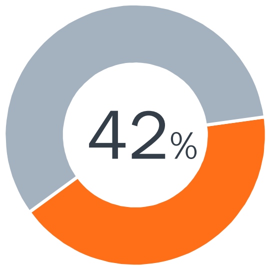
Quality of Power Service



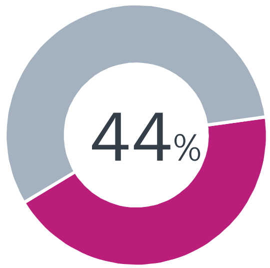
Quality of Customer Service



Affordability of Service



First Contact Resolution*



"Essex Powerlines is always very helpful and has a quick response. It is appropriate for the situation. If I have any questions about the service, Essex Powerlines answers those in a timely manner." ~ '5' Overall Satisfaction rating

"I gave Essex Powerlines a phone call and they were here within a half an hour and my problem was fixed within a few hours." ~ '5' Overall Satisfaction rating

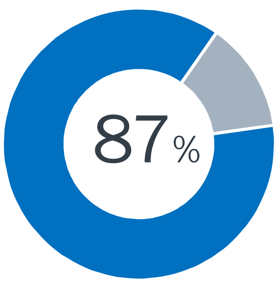
*First Contact Resolution (FCR) = %Yes; Customers contacting Essex by phone and resolved on one contact

OVERALL SATISFACTION IS HIGH, BUT OPPORTUNITIES FOR IMPROVEMENT EXIST, MORE SO FOR RESIDENTIAL CUSTOMERS

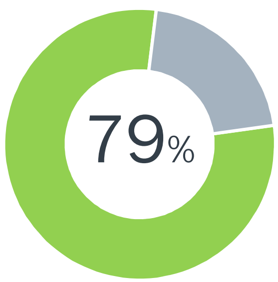
Customer Satisfaction

Top 3 Box

Business



Residential



2016 Reasons for Satisfaction

Positive Mentions

- No Issues/ Reliable
- Good Customer Service
- Good Service/ Satisfied

Negative Mentions

- Service Interruptions
- Price/Cost
- Poor Customer Service

KEY SATISFACTION DRIVERS

WHAT IS A KEY DRIVER ANALYSIS?

Key Drivers represent what is most important to Customers and where to focus efforts to have the greatest impact on Overall Satisfaction.

1 What are the attributes' relationship to Overall Satisfaction?

Action: Calculate each attributes' correlation to Overall Satisfaction

2 If several attributes have a moderate to strong relationship to Overall Satisfaction, how can attributes be prioritized?

Action: Calculate the Relative Importance

3 Once a Relative Importance model is developed, how much does it explain Overall Satisfaction?

Action: Calculate the proportion of variance that explains Overall Satisfaction

BUSINESS CUSTOMERS WANT AN INTERRUPTION-FREE SERVICE WHILE RESIDENTIAL CUSTOMERS PRIORITIZE CARE WITHIN CUSTOMER SERVICE

Key Drivers to Overall Satisfaction

Business		Residential	
26%	Reliability	Customer Service	20%
21%	Power Quality	Value	12%
11%	Promotion of Energy Conservation Programs	Reliability	11%
8%	Customer Service	Power Quality	11%
7%	Leader in Community	Communication	10%

Business: % Variance explained: 61%

Residential: % Variance explained: 56%

Percentages represent the relative impact of each attribute on Overall Satisfaction.

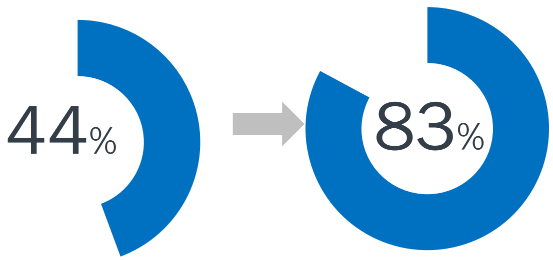
TOUCHPOINT SATISFACTION

CONTACT METHODS AND REASONS ARE SIMILAR FOR BOTH BUSINESS & RESIDENTIAL, HOWEVER, BUSINESS CUSTOMERS CALL MORE OFTEN

Business

Reported Contacts in Past 6 Months

Resolved



Contact Methods

Telephone 98%

Email: 5%

Contact Reasons

n=43

Service Issue 44%

Billing/Payments 40%

Account Change 14%

Call Handling

Residential

Reported Contacts in Past 6 Months

Resolved

Contact Methods

Telephone 97%

Email: 1%

Contact Reasons

n=93

Billing/Payments 39%

Service Issue 37%

Account Change 13%

Total may sum to more than 100% due to multiple responses

Based on customer comments, Q8.

CONVERGYS ANALYTICS

CONTACT HANDLING FINDINGS & OPPORTUNITIES

	Finding	Opportunity	Customer Feedback
Residential	*23% of Customers' inquiries were not resolved*	Follow through with services promised to avoid repeat contacts	*"We've had one issue here and the service through the employee was delayed by hours. We called around 8 and didn't see anyone till around midnight."*
Business & Residential	*Almost half of all customer contacts were for billing and payments*	Increase awareness and enhance online self-service options to reduce the need for contacts	*"I needed to make a payment arrangement."* *"We never received our bill in the mail. I wanted to see if I could receive a copy."*

CUSTOMERS ARE HIGHLY SATISFIED WITH THE TOP DRIVING MEASURES

Business & Residential data breakout in Appendix - Differences ratings are not statistically significant.

SERVICE & BRAND FINDINGS & OPPORTUNITIES

	Finding	Opportunity	Customer Feedback
Business	*Drivers: Power Service & Reliability*	Reduce recurring issues with loss of service	*"Our power seems to go out a lot, interruptions where the power is off for 5 minutes and the computers go off with no explanation."* *"I was looking at the number of times the hydro service was going out. It happens more than it has in previous years."*
Residential	*Driver: Customer Service*	Continue to focus on providing high quality customer service	*"They are very easy to work with and to talk to. They try not to interfere in your life, which to me, all are very good things."* *"They are very helpful with anything I need help with."*
Business & Residential	*Affordability of Service*	Educate Customers on rates and on fees charged	*"The price is too high. Even after we cut down on our hydro consumption it is still pretty high."* *"It is very hard to justify the rates that we have to pay for the services."*

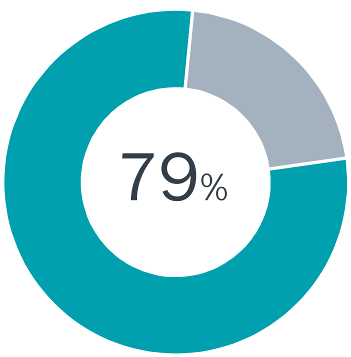
CONVERGYS ANALYTICS

RESIDENTIAL CUSTOMERS STRONGLY PREFER LETTERS; BUSINESS CUSTOMERS ARE LIKELY TO PREFER SEVERAL METHODS SIMILARLY

Business & Residential

Top 3 Box

Communication



Communication Preference

	Business	Residential
Letter in the Mail	41%	53%
Email	27%	24%
Telephone Call	30%	22%

CONVERGYS ANALYTICS

COMMUNICATION FINDINGS & OPPORTUNITIES

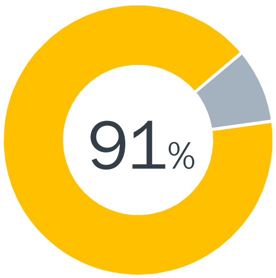
	Finding	Opportunity	Customer Feedback
Business	*Preference several methods – Mail, Email, and Telephone*	Important to leverage all touchpoints for communication	*"I wish they would go back to talking to people, instead of having everything be so automated. It's really annoying needing to talk to someone, and having to combat all these numbers. It's inconvenient for emergencies, but I understand how it's easy for the company."*

THE BILLING PROCESS APPEARS TO BE WELL RECEIVED BY ESSEX POWERLINES CUSTOMERS, BUT HAS ROOM FOR IMPROVEMENT

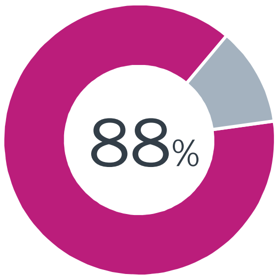
Business & Residential

Top 3 Box

Ease of Accessing Account Information



Billing Accuracy



"A few times, we have an overdue when our bill was already paid."

Continue to ensure billing is understandable and accurate

"Need to do something about the pricing. I have all this green energy but it's not helping anyone with their bill."

Leverage the use of current touchpoints to help Customers better understand how to manage their energy consumption

"I don't agree with people on fixed income having to pay a late fee for paying bill late. I have no control."

Endorse the benefits and feasibility of current payment options

RECOMMENDATIONS

TAKEAWAYS & RECOMMENDATIONS

1 PRIORITIZE KEY DRIVERS OF SATISFACTION

Investing in service reliability and customer service will help minimize the impact of the dissatisfaction triggers

2 PROMOTE SELF-SERVICE SOLUTIONS

Almost all customers are contacting Essex Powerlines via phone and about half are related to billing inquiries; if self-service options and other methods for communication are leveraged, the call center can see a reduction in call volume and costs associated with each call

3 BE PROACTIVE & REACTIVE WHEN COMMUNICATING BILLING

Customers are heavily critiquing their bills due to continuous rate increases; mailing/emailing a bill explanation, posting a bill tutorial to the website, and coaching key agent behaviors (i.e., empathy, clear explanations, etc.) within customer care are ways to effectively communicate billing accuracy and set billing expectations

CONVERGYS

TOOLS TO MANAGE ENERGY CONSUMPTION

Help Customers learn and better understand how to manage their energy consumption by:

Enhance the website. Add visibility and accessibility to "Save Energy" on the home page, and augment the graphics.

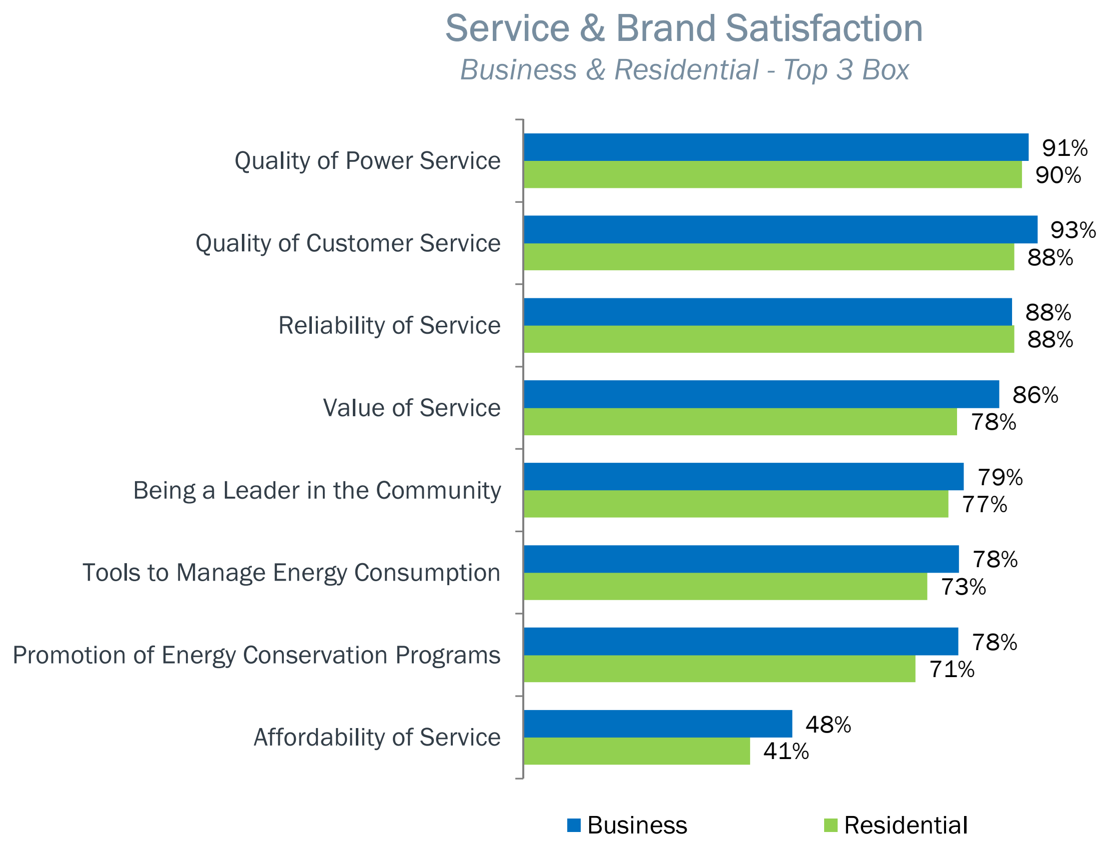
Send information. Send monthly email marketing messages to consenting customers containing tips or postcards that can direct them to more information; also, Customer Service Reps can ask customers if they are interested in learning about managing energy consumption and send them information via email/mailing.

Leverage the social media space. Post information or "how-to" videos online, or create a blog for customers to subscribe to, to learn about managing energy consumption.

Interact with the community. Continue to issue press releases and work with local media (e.g., radio, news, etc.) to share information on managing energy consumption. Host events/seminars at Essex Powerlines so people can come in and learn more or have booths/tables at community events with information on available tools.

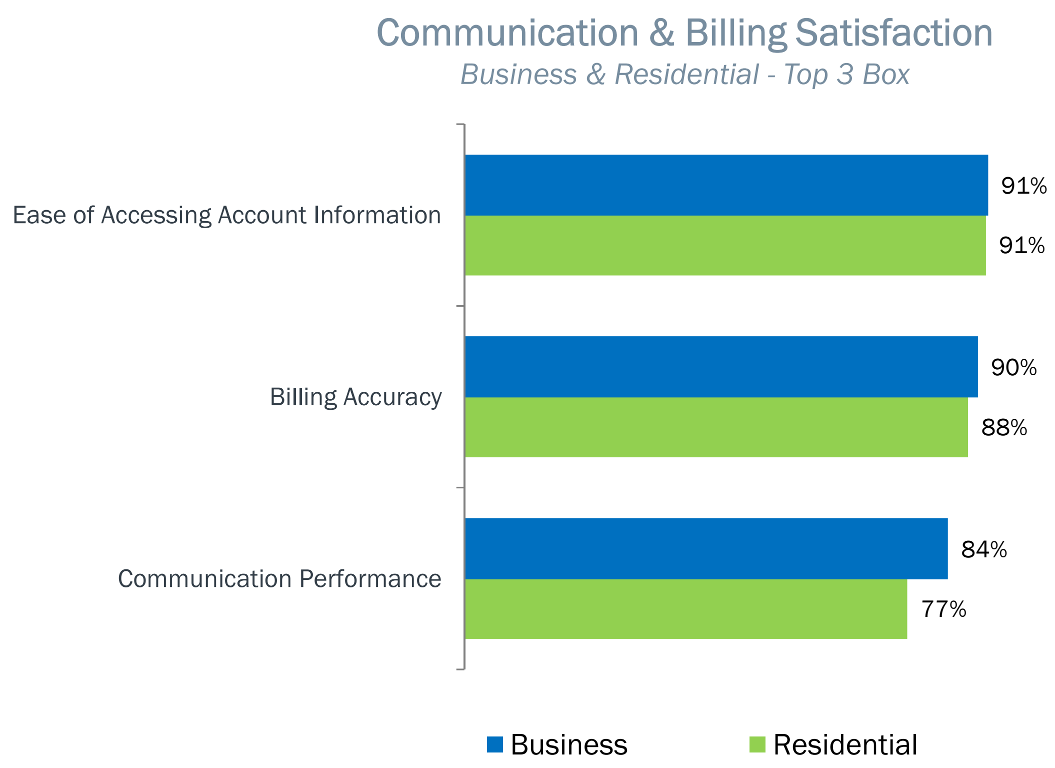
APPENDIX

SERVICE AND BRAND SATISFACTION



Differences in Business & Residential ratings are not statistically significant.

COMMUNICATION AND BILLING SATISFACTION



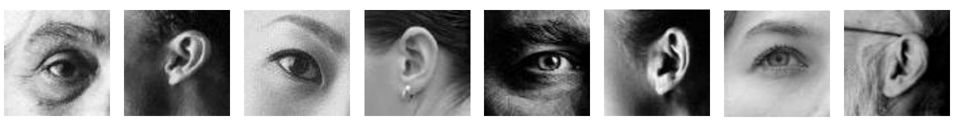
Differences in Business & Residential ratings are not statistically significant.

Prepared by:

Innovative Research Group, Inc.
Toronto • Calgary • Vancouver
www.innovativeresearch.ca

Scorecard Benchmarks

Customer Satisfaction Surveys



Essex Powerlines Corporation
2730 Highway 3
Oldcastle, ON
N0R 1L0

Revised: November 7, 2014

:: Final Report::

Research Objective

Essex Powerlines Corporation commissioned Innovative Research Group (INNOVATIVE) to design and carry out a Customer Outreach Survey as part of the customer satisfaction component of its upcoming Ontario Energy Board (OEB) Scorecard requirements.

Research Goals

Core elements of this research include:

- To ensure compliance with OEB “scorecard” requirement; and
- To identify areas of customer service for continuous improvement.

Meeting OEB Customer Satisfaction Requirement

- Distributors will have discretion to determine how to conduct their customer satisfaction surveys.
- At minimum, surveys will canvass customer satisfaction in the following key areas:
  - a) power quality and reliability;
  - b) price;
  - c) billing and payment;
  - d) communications; and
  - e) the customer service experience.
- In order to fully meet OEB requirements, it is our recommendation that both residential and general service (GS < 50 kW) customers are included in this research.

Methodology

- These surveys were conducted by Innovative Research Group over telephone among **210** randomly-selected residential customers and **98** randomly-selected general service under 50 kWh customers of Essex Powerlines Corporation (EPC), between October 7th and October 16th 2014.

- EPC provided INNOVATIVE with 25,510 residential customer contacts and 1,697 general service customer contacts use to conduct the telephone surveys.

- For residential respondents, only the person who is responsible for paying the electricity bill was eligible to complete this survey.

- For general service respondents, only the person in-charge of managing the electricity bill for their organization was eligible to complete this survey.

- Unweighted probability samples of 210 (residential) and 98 (general service) would have estimated margins of error of **±6.8%** and **±9.8%** percentage points, respectively, 19 times out of 20.

- The margin of error will be larger within each sub-grouping of the sample.

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers.*

Stratified Sample Design

The surveys follow a stratified random sampling methodology. This is a method of sampling that involves the division of a population into smaller groups known as strata. In stratified random sampling, the strata are formed based on members' shared attributes or characteristics (in this case, customer service area or electricity usage). A random sample from each stratum is taken in a number proportional to the stratum's size when compared to the customer population. These subsets of the strata are then pooled to form a random sample.

In this survey, residential and general service customers are divided into strata based on service area populations. Within service area populations, residential customers is then divided in to quartiles based on annual electricity usage to ensure the sample has a proportionate mix of customers from low, medium-low, medium-high, and high electricity usage households or organizations (GS < 50 kWh).

Residential

TARGET	Low	Medium-Low	Medium-High	High	Total
Amherstburg	9	7	8	8	**32**
LaSalle	17	23	19	22	**81**
Leamington	17	8	14	11	**50**
Tecumseh	11	15	12	12	**50**
Total	**54**	**53**	**53**	**53**	**213**

ACTUAL	Low	Medium-Low	Medium-High	High	Total
Amherstburg	9	7	8	8	**32**
LaSalle	16	22	18	22	**78**
Leamington	17	8	14	11	**50**
Tecumseh	11	15	12	12	**50**
Total	**53**	**52**	**52**	**53**	**210**

General Service

TARGET	Low	Medium-Low	Medium-High	High	Total
Amherstburg	4	4	4	4	**16**
LaSalle	7	8	6	7	**28**
Leamington	10	8	10	9	**37**
Tecumseh	4	5	5	5	**19**
Total	**25**	**25**	**25**	**25**	**100**

ACTUAL	Low	Medium-Low	Medium-High	High	Total
Amherstburg	2	5	3	5	**15**
LaSalle	7	6	9	5	**27**
Leamington	8	9	12	9	**38**
Tecumseh	5	7	3	3	**18**
Total	**22**	**27**	**27**	**22**	**98**

Key Findings: Residential

Overall satisfaction ▶▶

- 82% of residents are at least somewhat satisfied with the job Essex Powerlines is doing at running the system, 39% of these are very satisfied

Power quality and reliability ▶▶

- 60% of residents have experienced at least one outage in the last year, half say the outage lasted less than 30 minutes, and 83% say it was only a minor inconvenience or barely any inconvenience
- 9-in-10 (89%) residents are satisfied with Essex Powerlines' reliability and quality of electricity

Price ▶▶

- Half of residential customers say that the price they pay for electricity is reasonable
- However 50% say that it has grown faster than other expenses and 49% were unfamiliar with how much of their bill actually went to Essex Powerlines

Billing and Payment ▶▶

- 85% of residential customers say that they are confident in the accuracy of their bills
- Of households that use e-billing in general, 64% were familiar with the e-billing option from Essex Powerlines

Customer service experience ▶▶

- 37% of residents report having ever contacted Essex Powerlines, of those 55% had contact in the last year. Those most common reasons for contact were to report an outage (30%) and to inquire about a bill (26%)
- Over three quarters of those who had contacted reported that they were satisfied with each of the helpfulness (80%), knowledge (76%), courtesy (86%), and quality of information from (76%) Essex Powerlines' staff

Communications ▶▶

- Half of residential customers (52%) say Essex Powerlines is proactive in communicating changes and issues, while 60% report that they are satisfied with the way Essex communications with them

Key Findings: General Service

Overall satisfaction ▶▶

78% of organizations are at least somewhat satisfied with the job Essex Powerlines is doing at running the system, 38% of these are very satisfied

Power quality and reliability ▶▶

- 57% of organizations have experienced at least one outage in the last year, half say the outage lasted less than 30 minutes, and 75% say it was only a minor inconvenience or barely any inconvenience
- 9-in-10 organizations (90%) are satisfied with Essex Powerlines' reliability and quality of electricity

Price ▶▶

- About 1-in-3 GS customers (37%) say that the price they pay for electricity is reasonable
- However 65% say that it has grown faster than other expenses and 66% were unfamiliar with how much of their bill actually went to Essex Powerlines

Billing and Payment ▶▶

- 73% of GS customers say that they are confident in the accuracy of their bills
- Of businesses that use e-billing in general, 60% were familiar with the e-billing option from Essex Powerlines

Customer service experience ▶▶

- 54% of organizations report having ever contacted Essex Powerlines; of those 89% had contact in the last year. The most common reason for contact was to inquire about a bill (40%)
- Large majorities of those who had contacted reported that they were satisfied with each of the helpfulness (77%), knowledge (77%), courtesy (85%, and quality of information from (73%) Essex Powerlines' staff

Communications ▶▶

- Half of GS customers (51%) say Essex Powerlines is proactive in communicating changes and issues, while 61% report that they are satisfied with the way Essex communications with them

Scorecard: Summary of key benchmarks

Overall

Residential

- **82%** satisfied overall
- **69%** see value for money
- **84%** see high quality of service

General Service

- **78%** satisfied overall
- **62%** see value for money
- **87%** see high quality of service

Key areas

	Power Quality and Reliability	Price	Billing and Payment	Customer service experience	Communications
Key Benchmark	Satisfaction with quality and reliability and electricity service	Reasonableness of price	Accuracy of billing	Resolution of problems	Satisfaction with they way Essex Powerlines communicates
Residential	**82%** satisfied	**50%** reasonable	**85%** confident	**75%** resolved	**60%** satisfied
General Service	**78%** satisfied	**37%** reasonable	**73%** confident	**74%** resolved	**61%** satisfied

Setting the Context

In this section respondents read the following preamble:

"To start, I'd like to ask you a few questions about the electricity system.

As you may know, Ontario's electricity system has three key components: generation, transmission and distribution. **Generating stations** convert various forms of energy into electric power; **Transmission lines** connect the power produced at generating stations to where it is needed across the province; and **Distribution lines** carry electricity to the homes and businesses in our communities.

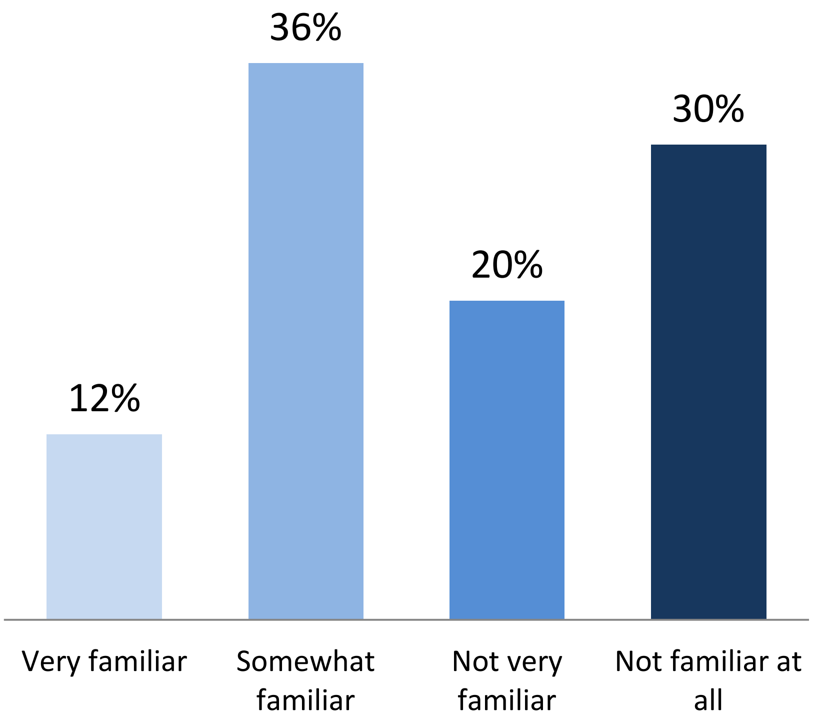
Today we're going to talk about your **local distribution system** which is maintained and operated by **Essex Powerlines**."

INNOVATIVE RESEARCH GROUP

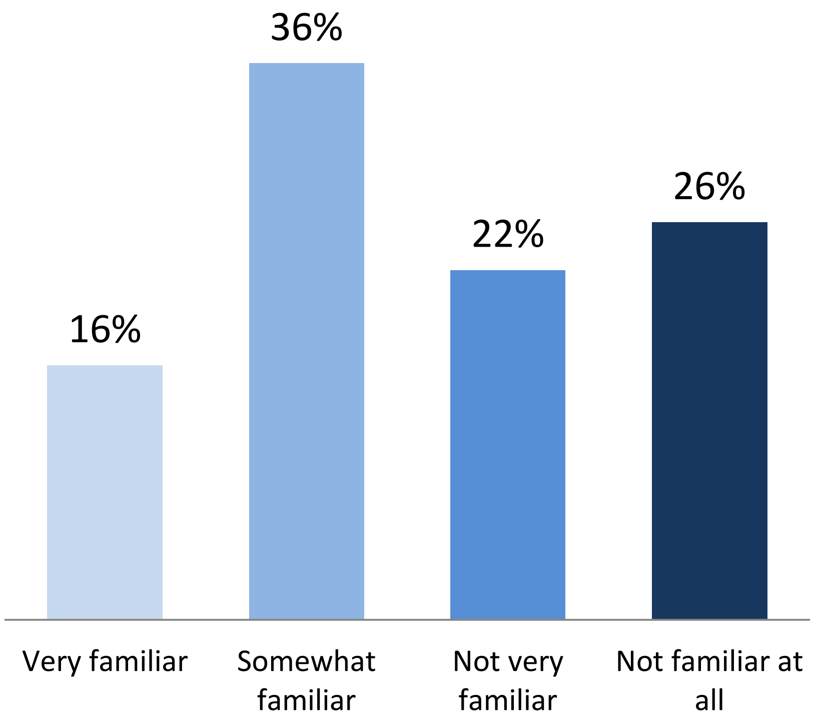
Familiarity with Distribution System: customers have varied level of familiarity with the distribution system

Q How familiar are you with the **local electricity distribution system**? Would you say …

Residential
[asked of all respondents n=210]



General Service
[asked of all respondents n=98]



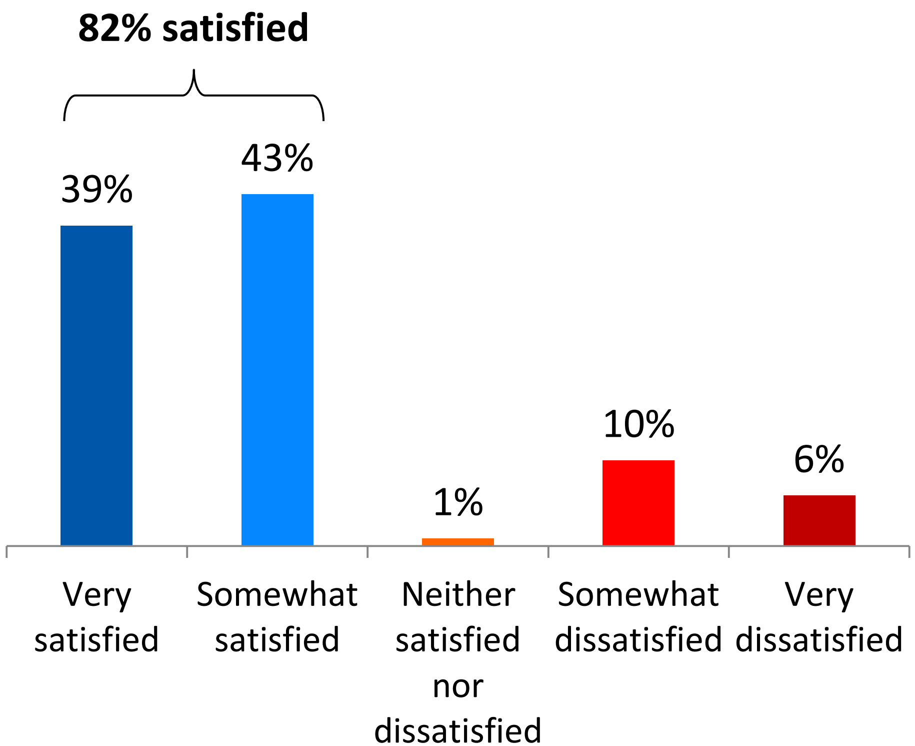
Note: 'Don't Know / Refused' not shown (Res = 1%; GS = 0%)

INNOVATIVE RESEARCH GROUP

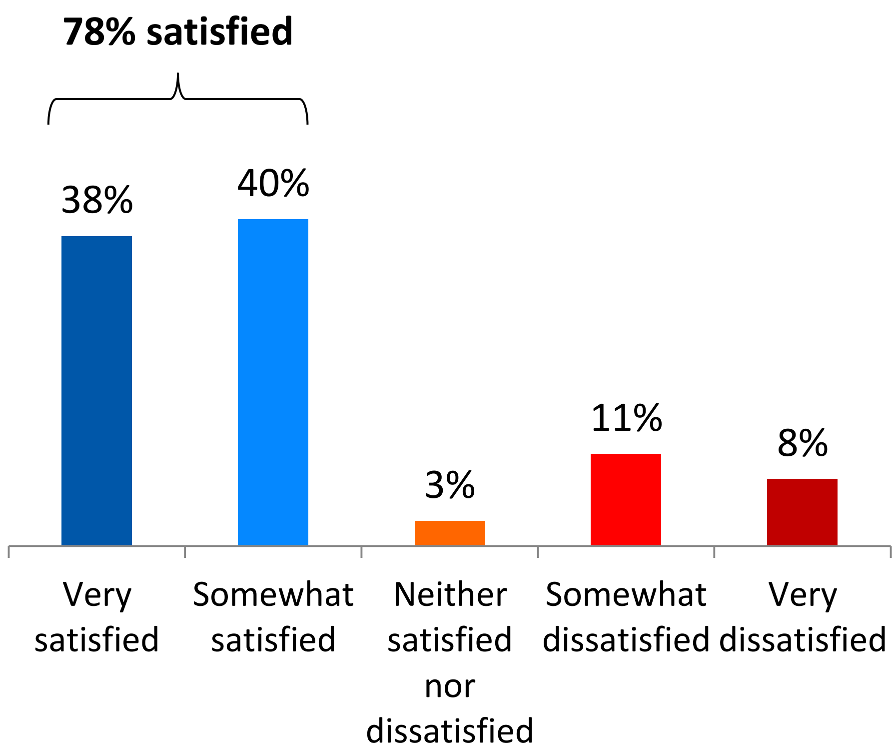
Overall Satisfaction: majority of customers are satisfied with the job Essex is doing at running distribution system

Q Generally speaking, how satisfied are you with the job **Essex Powerlines** is doing at running the local distribution system? Would you say …

Residential
[asked of all respondents n=210]



General Service
[asked of all respondents n=98]



Note: 'Don't Know / Refused ' not shown (Res = 0%; GS = 0%)

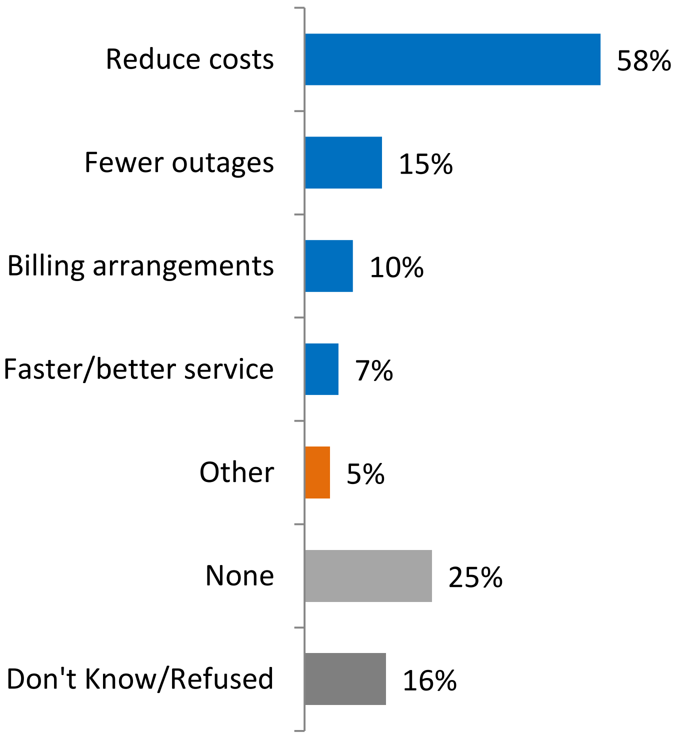
INNOVATIVE RESEARCH GROUP

Service Improvements: cost reductions most commonly cited way to improve service

Q Is there anything in particular **Essex Powerlines** can do to improve their service to you?

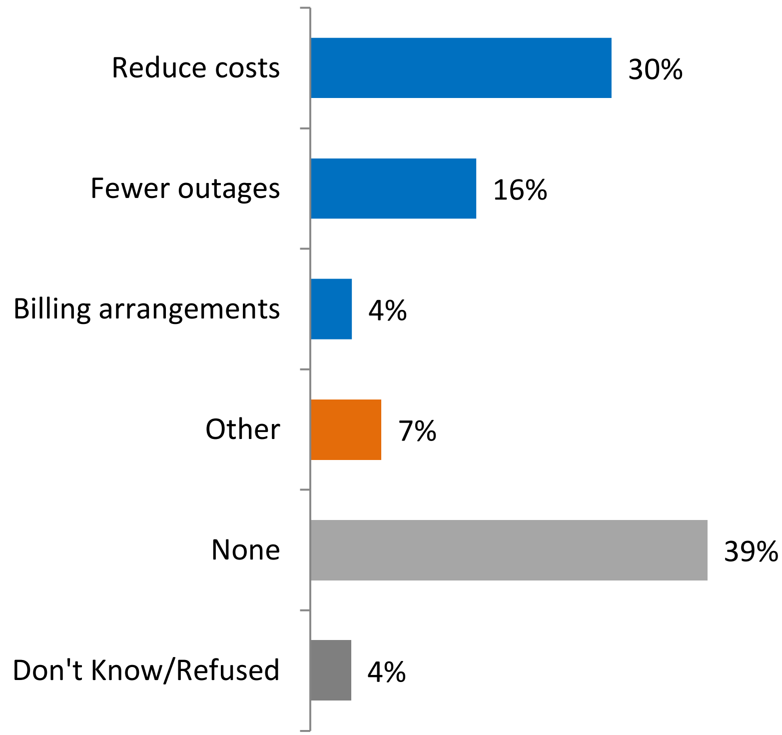
Residential

[asked of all respondents n=210]



General Service

[asked of all respondents n=98]



Power Quality and Reliability

In this section respondents read the following preamble:

Despite best efforts, no electrical distribution system can deliver *perfectly reliable* electricity. As a general rule, the more reliable the system, the more expensive the system is to build and maintain.

With that said –not including **outages caused by extreme weather events**, such as ice storms, powerful winds, or flooding – the average **Essex Powerlines** customer experiences **<u>between one and two power outages</u>** per year.

INNOVATIVE RESEARCH GROUP

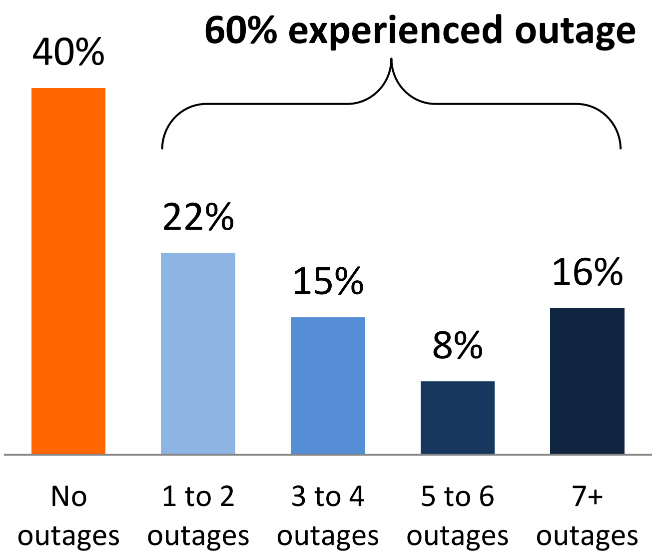
Reliability (residential): 60% of customers had outage in past year; of those, almost half said it lasted < 30 minutes

Residential

Q

Have you **experienced any power outages** – not including those caused by extreme weather events – in the past 12 months, and if so, approximately how many?

[asked of all respondents n=210]

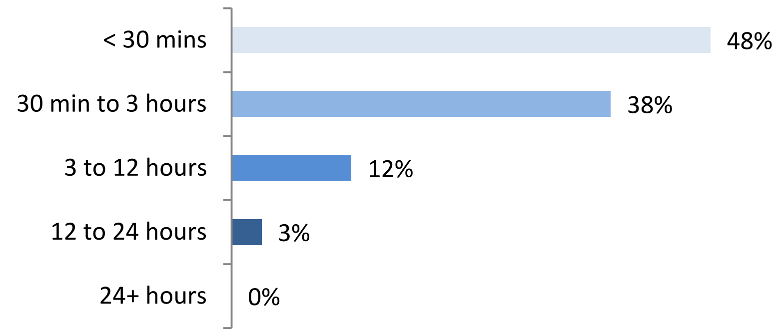


Note: 'Don't Know / Refused' (4%) not shown

Q

Not including outages caused by extreme weather events, approximately **how many minutes** did the most recent power outage last**?**

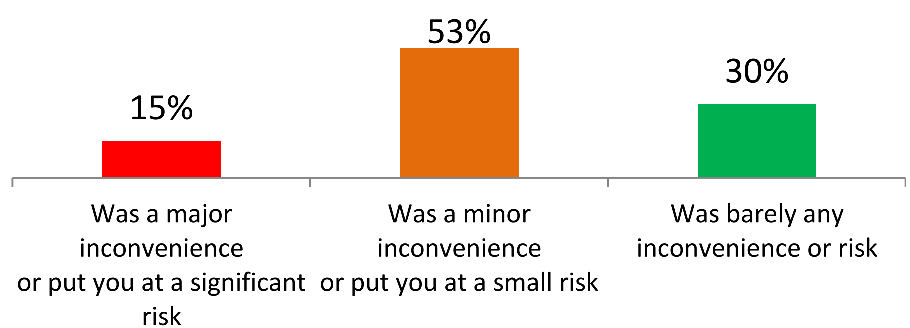
[asked of those reporting at least one outage n=127]



Q

Thinking back to the most recent power outage – again, not including any outages caused by extreme weather – how much were you **inconvenienced** or put at risk by it?

[asked of those reporting at least one outage n=127]



Note: "Don't Know" (2%) not shown

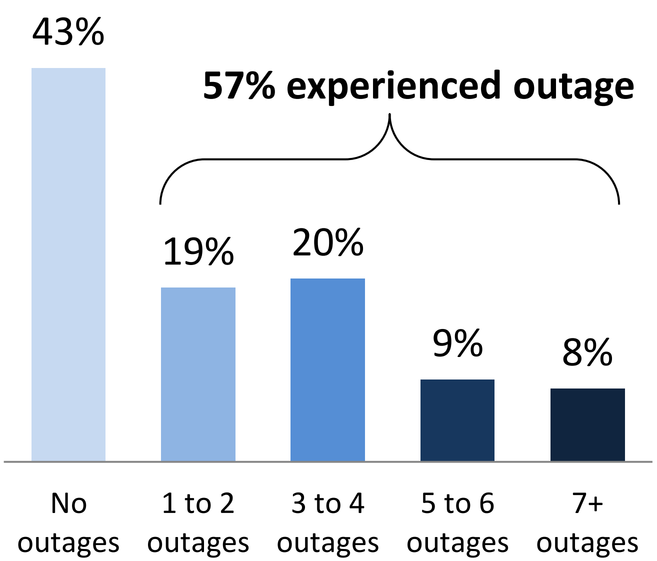
INNOVATIVE RESEARCH GROUP

Reliability (GS): 57% of customers had outage in past year; of those, over half said it lasted < 30 minutes

General Service

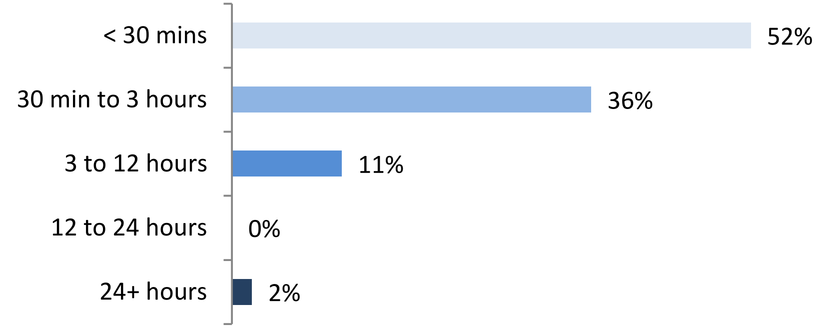
Q Have you **experienced any power outages** – not including those caused by extreme weather events – in the past 12 months, and if so, approximately how many?

[asked of all respondents n=98]



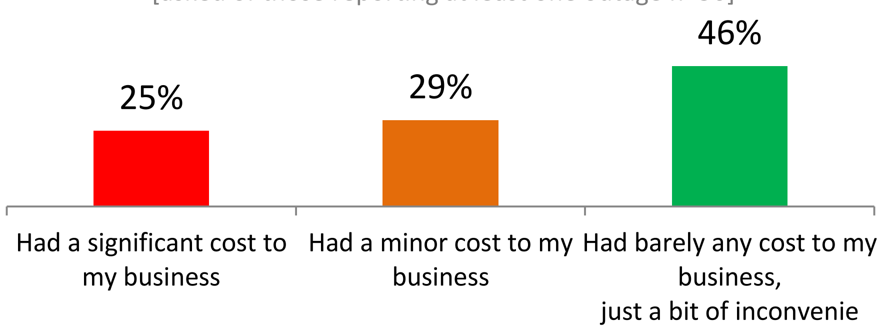
Q Not including outages caused by extreme weather events, approximately **how many minutes** did the <u>most recent power outage</u> last**?**

[asked of those reporting at least one outage n=56]



Q Thinking back to the <u>most recent power</u> outage – again, not including any outages caused by extreme weather – how much were you **inconvenienced** or put at risk by it?

[asked of those reporting at least one outage n=56]



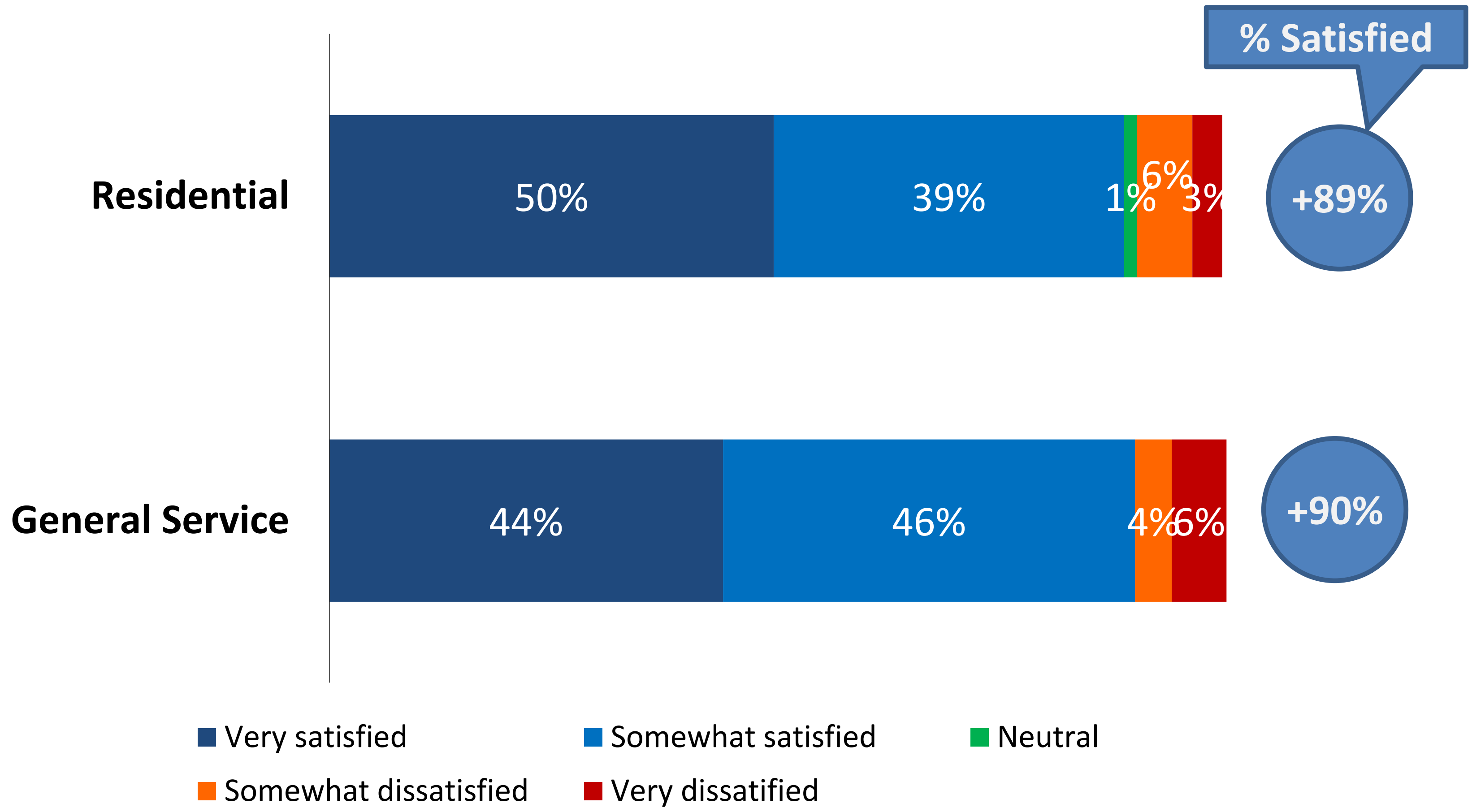
Note: 'Don't Know / Refused' (4%) not shown

Reliability: majority of the customers are satisfied with the reliability and quality provided by Essex Powerlines

Q

Overall, how satisfied are you with the reliability and quality of electricity services provided by **Essex Powerlines**? Would you say you are …

[asked of all respondents; residential n=210; GS n=98]



Price

In this section residential respondents read the following preamble:

"While some customers pay more and other pay less, the **average residential customer pays about $125 a month** for electricity of **which $25 or approximately 20% goes to Essex Powerlines**. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies."

And GS respondents read the following preamble:

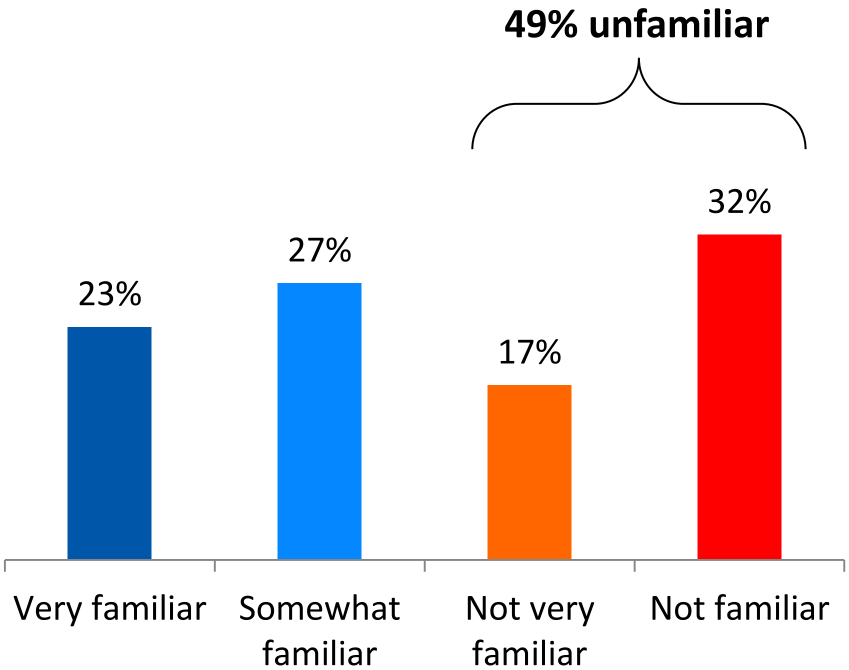
Each month, **approximately 20% of your company's electricity bill goes to Essex Powerlines**. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Cost of Distribution: many customers unfamiliar with the amount of their electricity bill that is remitted to Essex

Q Before this survey, how familiar were you with the amount of your electricity bill that went to **Essex Powerlines**? Would you say …

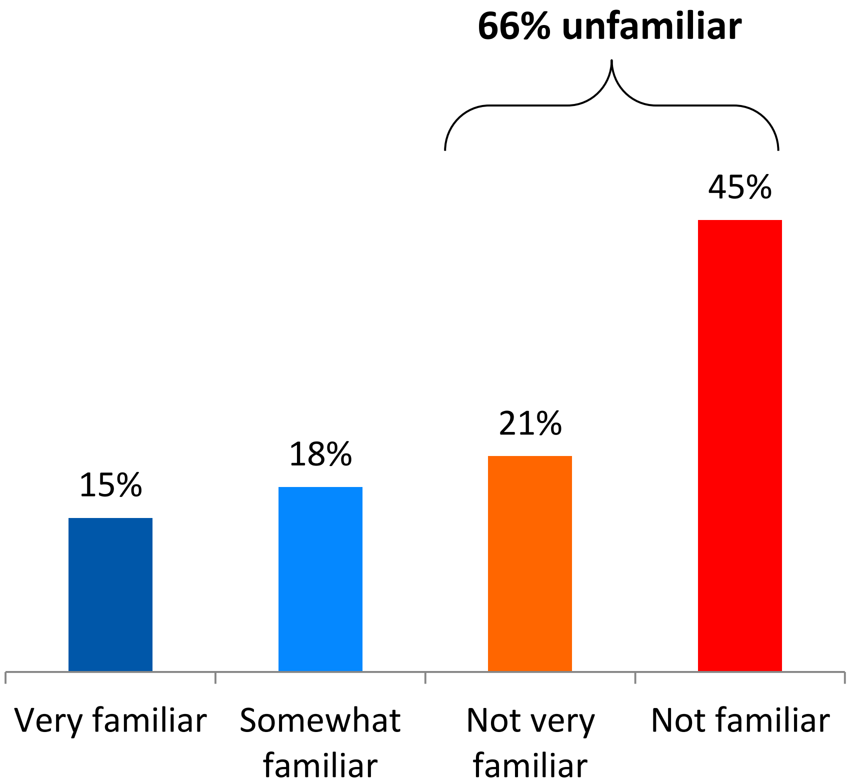
Residential

[asked of all respondents n=210]



General Service

[asked of all respondents n=98]

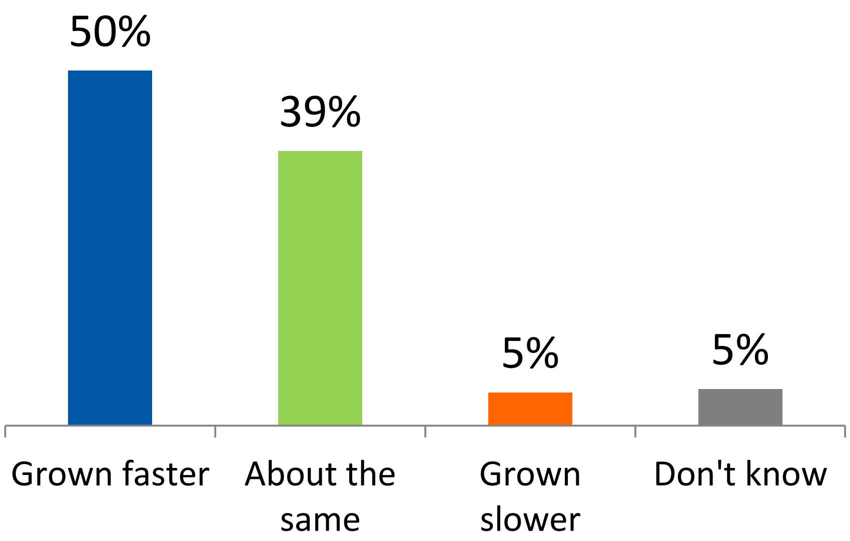


Note: 'Don't Know' not shown (Res = 1%; GS = 0%)

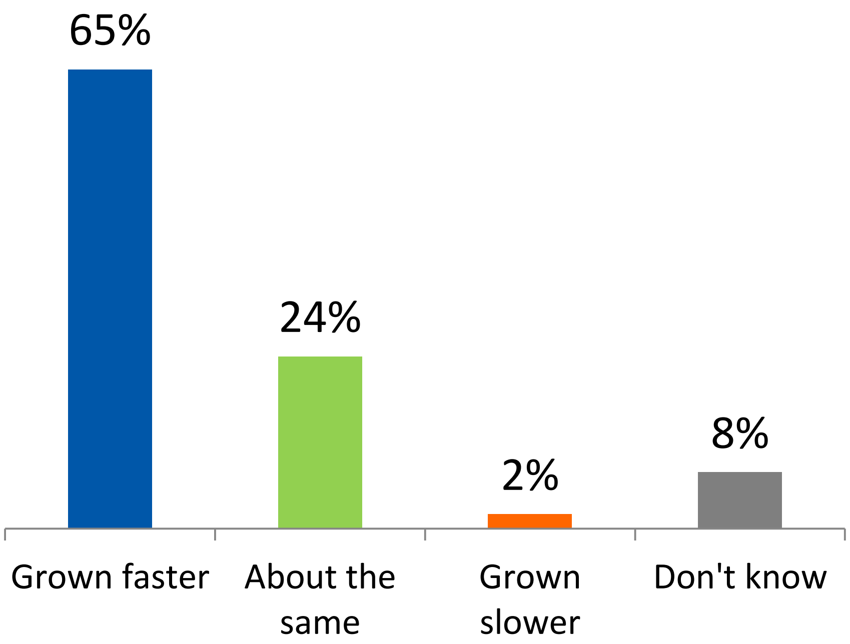
Pace of Price Change: most customers feel the cost of electricity has grown faster than their other expenses

Q Compared to your [your organization's] other bills over the last few years, would you say that the cost of electricity has **grown faster than, slower than, or at about the same rate as** your other household [business] expenses?

Residential
[asked of all respondents n=210]



General Service
[asked of all respondents n=98]

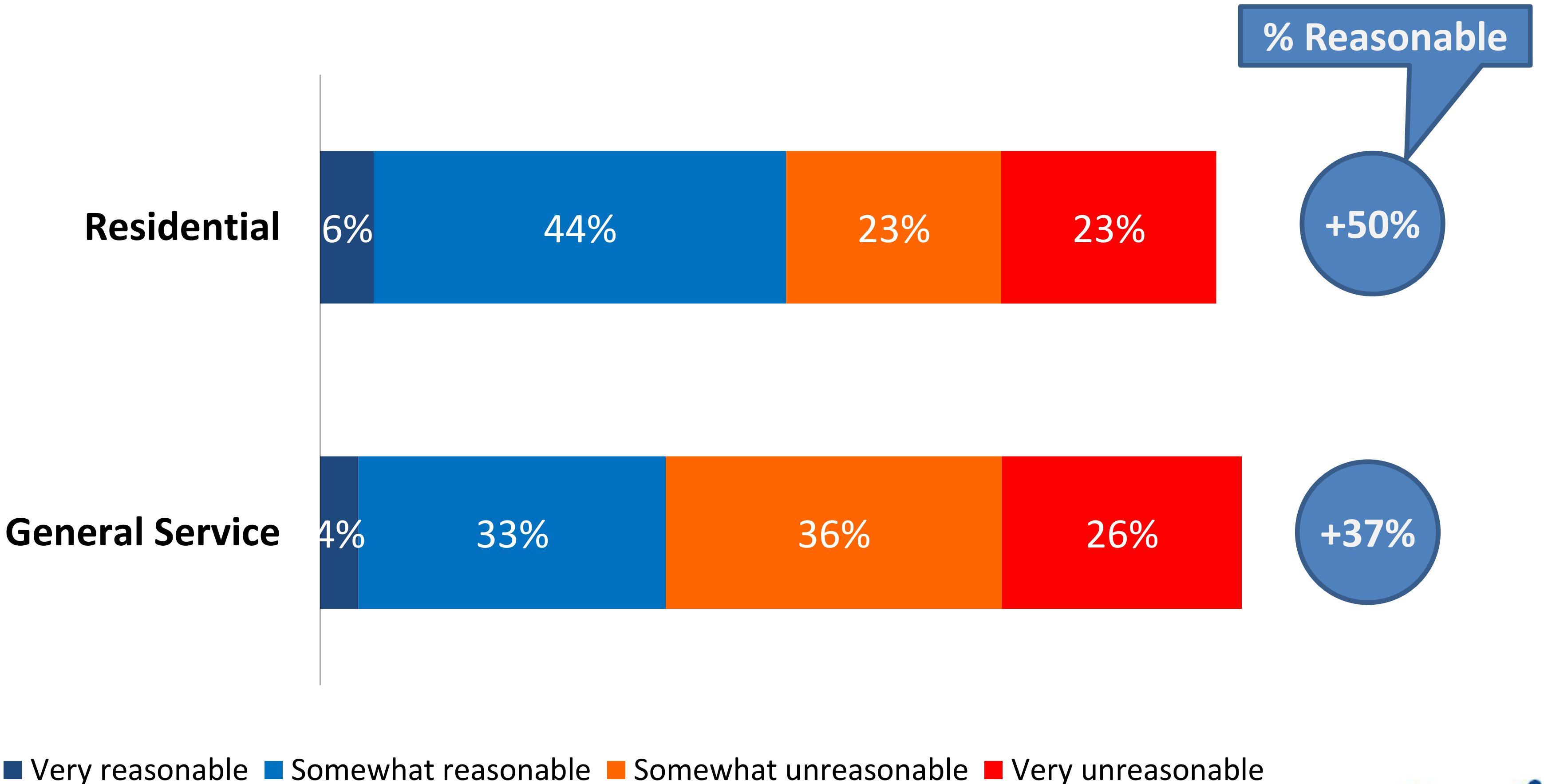


INNOVATIVE RESEARCH GROUP

Price of Electricity: 50% of residential and 37% of GS customers think the price they pay for electricity is reasonable

Q Overall, do you think that **the price you pay [that your organization pays]** for electricity is very reasonable, somewhat reasonable, somewhat unreasonable, or very unreasonable?

[asked of all respondents; residential n=210; GS n=98]



Note: "Don't Know / Refused" not shown (Res = 5%; GS = 2%)

Billing and Payment

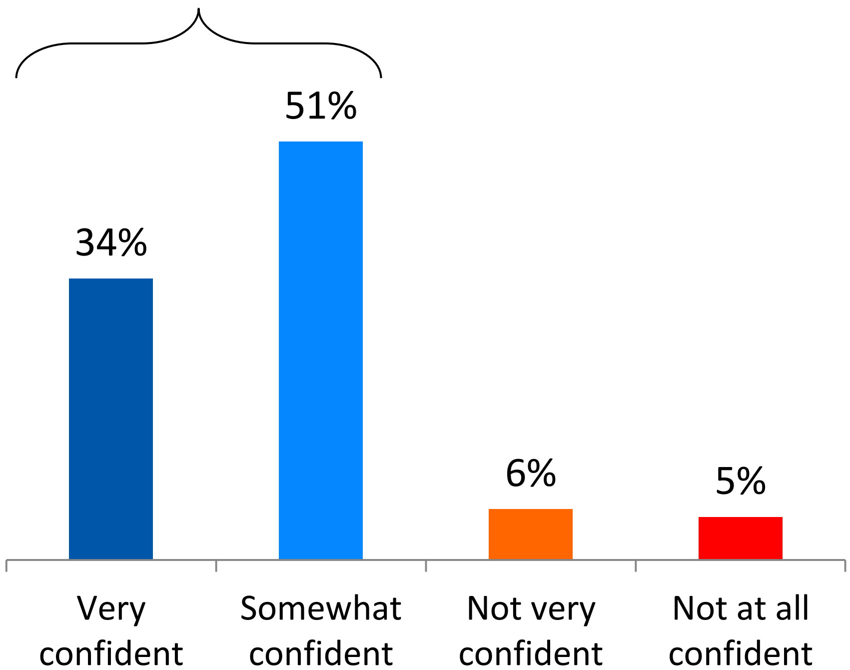
Bill Accuracy: majority of customers are confident in the accuracy of their electricity bills

Q How confident are you in accuracy of electricity bills that you [your organization] receive[s] from **Essex Powerlines**? Would you say …

Residential

[asked of all respondents n=210]

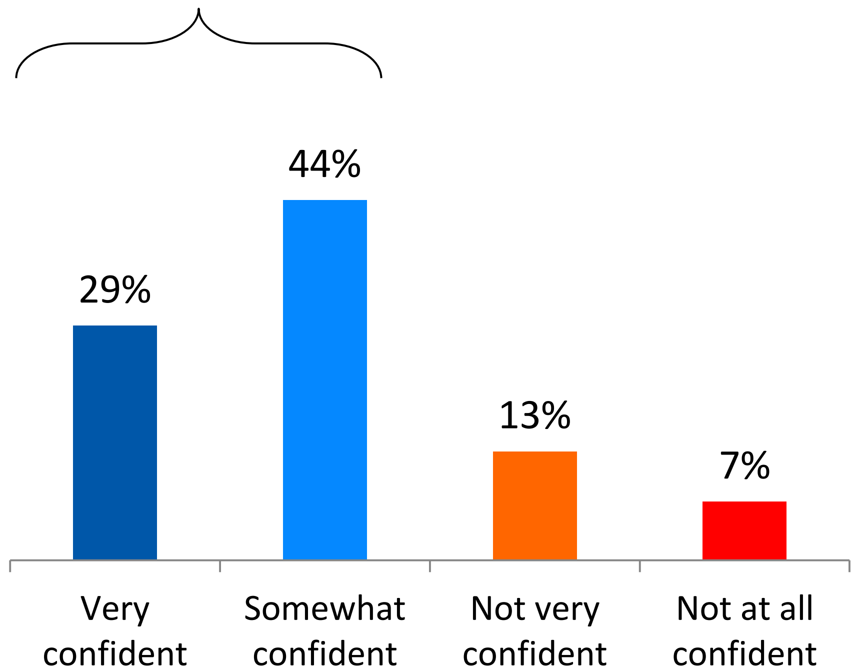
85% of residential customers confident in accuracy of electricity bill



General Service

[asked of all respondents n=98]

73% of GS customers confident in accuracy of electricity bill



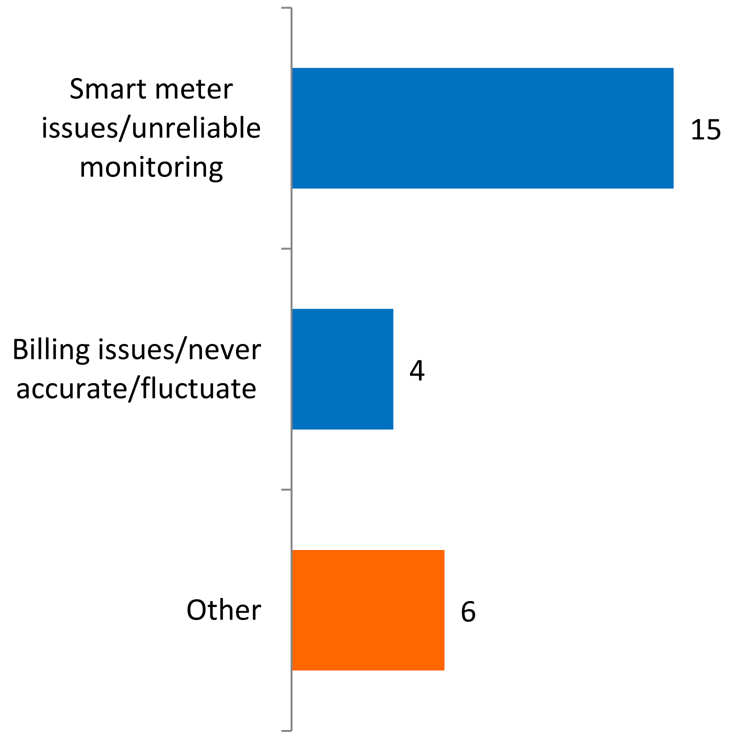
Note: 'Don't Know / Refused' not shown (Res = 3%; GS = 7%)

Perceived issues with *smart meters* most commonly cited reason for lacking confidence in billing accuracy

Q And why is it that you're not confident in the accuracy of your [your organization's] electricity bill from **Essex Powerlines**?

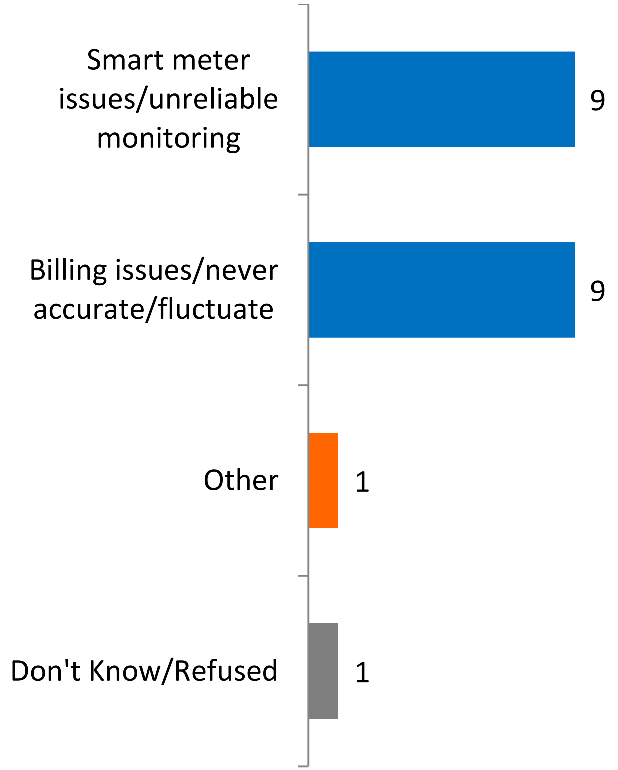
Residential

[asked of all respondents who are not confident in their electricity bill; n=25]



General Service

[asked of all respondents who are not confident in their electricity bill; n=20]



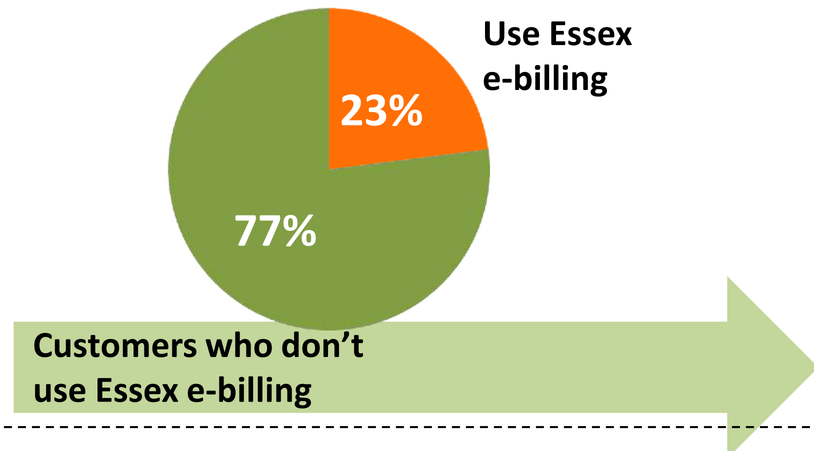
Note: due to small sample size, percentages not shown.

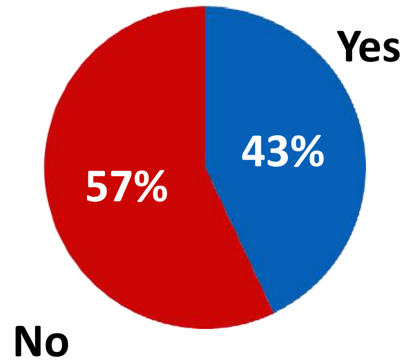
E-billing: Among those who don't use Essex's e-billing, over a third are using other e-billing services

% of customers who use Essex's e-billing services

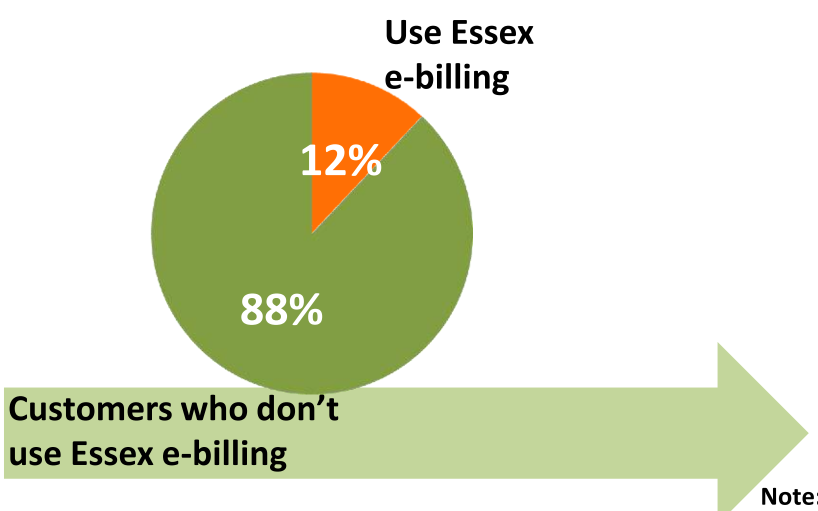
Q Do you currently use electronic billing, or e-billing, to pay any of your household [organization's] bills?
[asked only of customers who do not receive an e-bill from Essex currently: Res n=162; and GS n=86]

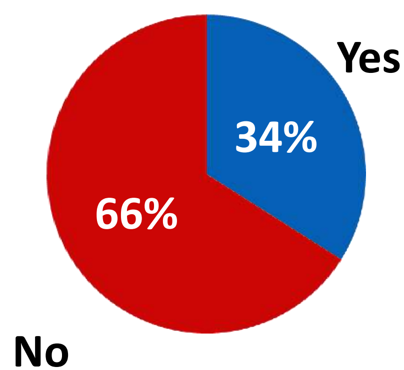
Residential





General Service





Note: 'Don't Know / Refused' not shown (Res = 1%; GS = 0%)

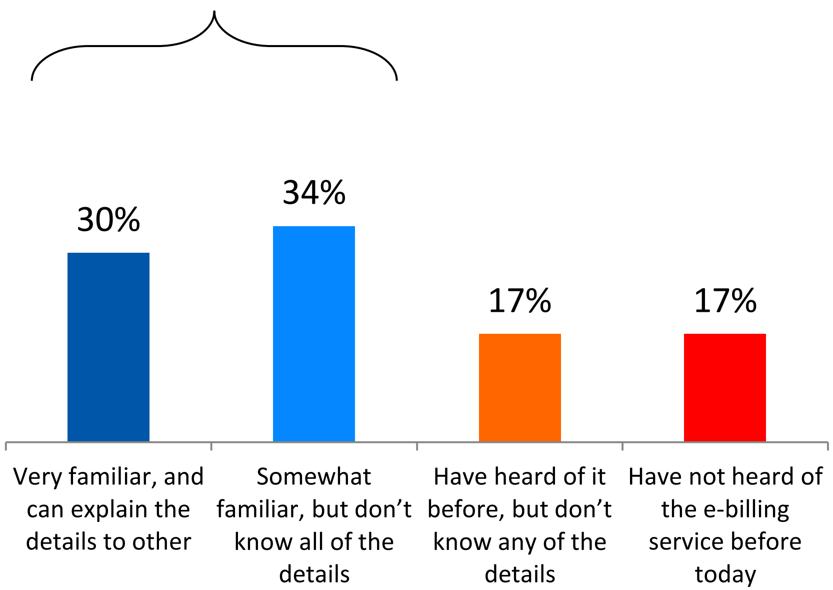
E-billing Familiarity: among customer who use some form of e-billing, a majority are familiar with the Essex's service

Q Essex Powerlines offers an e-billing option which allows customers to view and pay their bill online. How familiar are you with Essex Powerlines' e-billing service? Would you say …

[asked of those who use some form e-billing for household/organizational bills n=70 for residential, n=35 for GS]

Residential

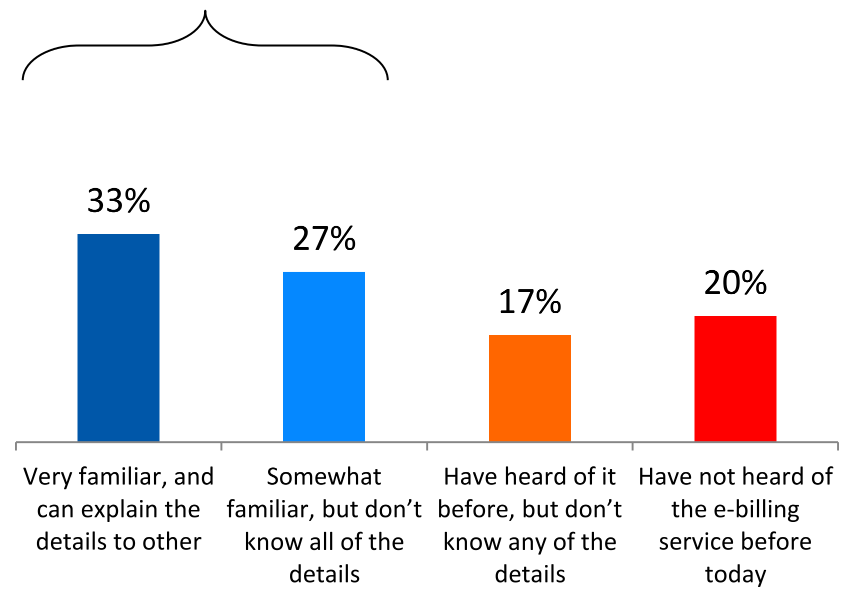
64% of residential customers who do <u>not</u> use Essex Powerlines' e-billing service say that they're say they're at least somewhat familiar with the service



Note: 'Don't Know / Refused' not shown (Res = 1%)

General Service

60% of residential customers who do <u>not</u> use Essex Powerlines' e-billing service say that they're say they're at least somewhat familiar with the service



Note: 'Don't Know / Refused' not shown (GS = 3%)

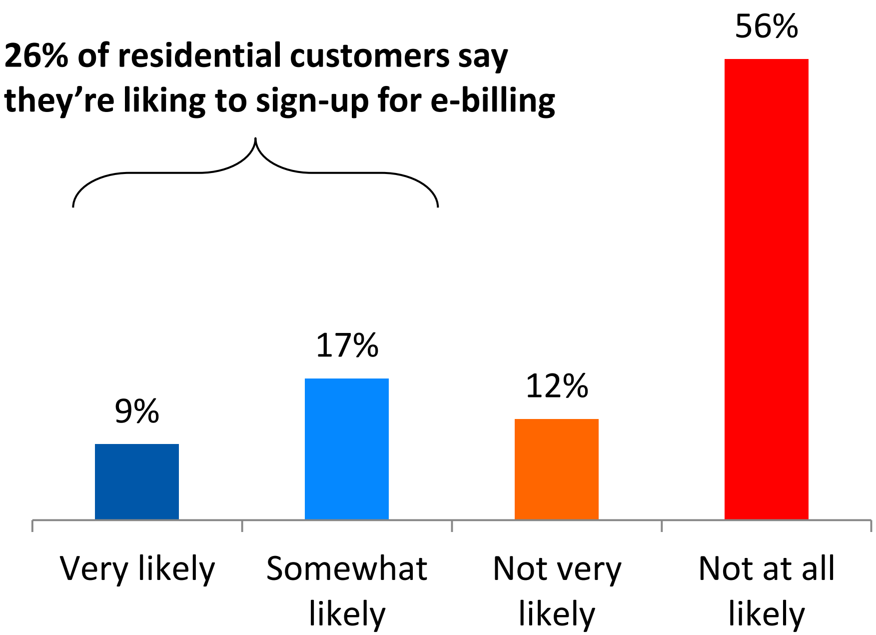
INNOVATIVE RESEARCH GROUP

E-billing Uptake: among customer without EPC e-billing, a quarter say they are likely to sign up in the next year

Q Essex Powerlines offers an e-billing option which allows you to view and pay your bill online. How likely is it that you [your organization] will sign up for e-billing in the next 12 months?

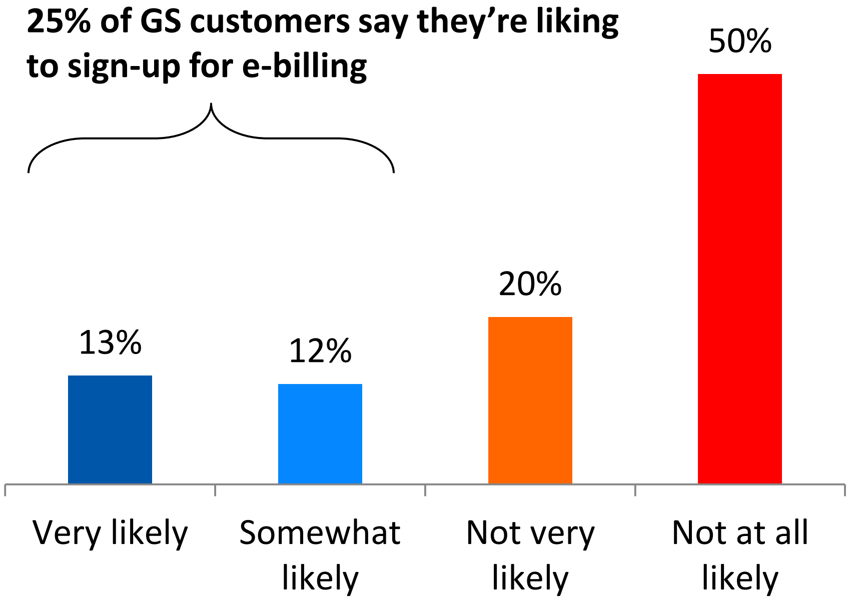
Residential

[asked only of residential respondents who do not currently receive an e-bill from Essex Powerlines; n=162]



General Service

[asked only of residential respondents who do not currently receive an e-bill from Essex Powerlines; n=86]



Note: 'Don't Know / Refused' not shown (Res = 5%)

Note: 'Don't Know / Refused' not shown (GS = 4%)

INNOVATIVE RESEARCH GROUP

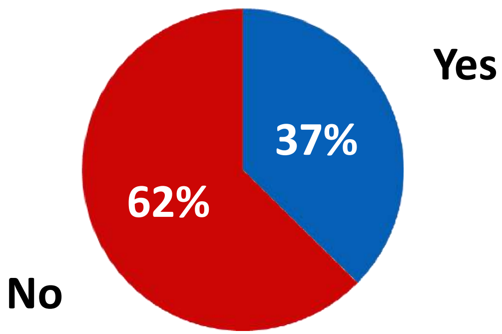
Customer Service Experience

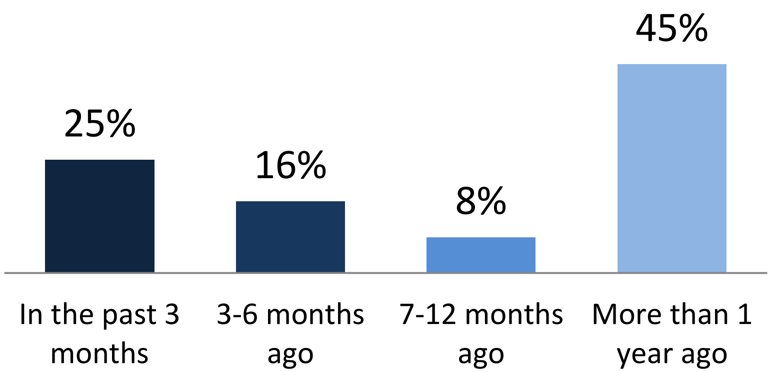
Customer Service Contact: Fewer residential than GS customers have ever contacted Essex

Q Have you [your organization] ever had to contact **Essex Powerlines**?
[asked of all respondents n=210 for residential; n=98 for GS]

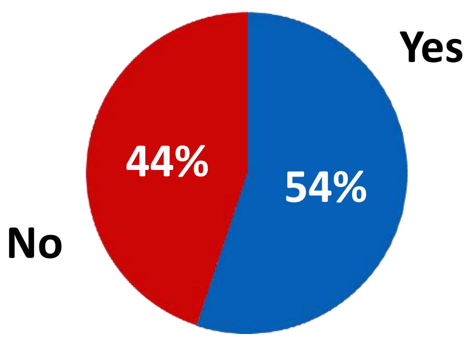
Q When was the **last time** that you [your organization] contacted **Essex Powerlines**? Was it …
[asked of those who had to contact n=77 for residential; n=54 for GS]

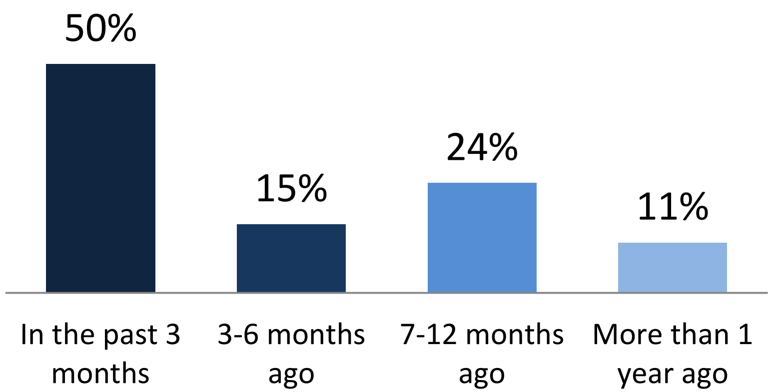
Residential





General Service





Note: 'Don't Know / Refused' not shown (Res =1%; GS = 1%)

Note: 'Don't Know / Refused' not shown (Res =6%; GS = 2%)

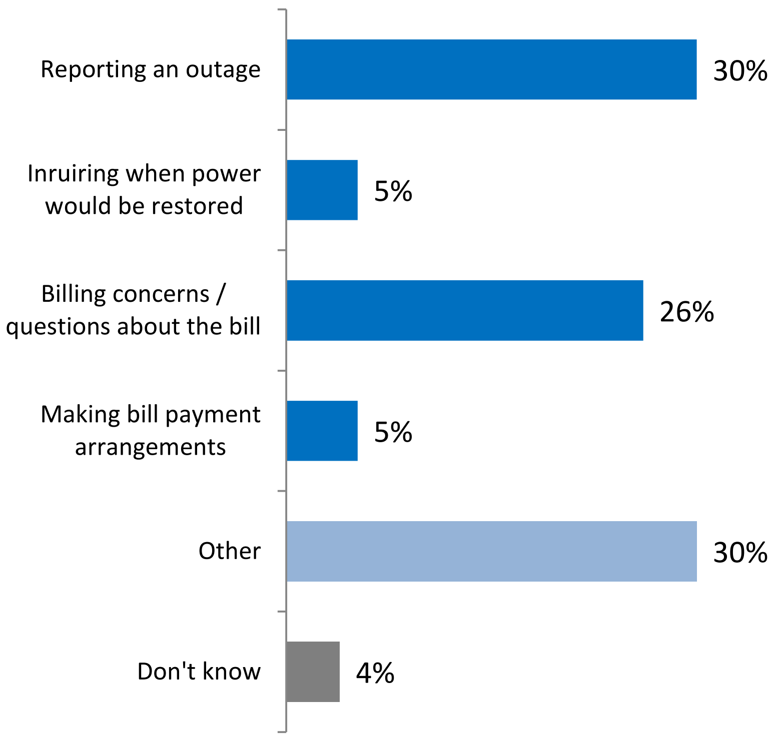
Top reason for contact: reporting an outage (30%) for residential and billing concerns (40%) for General Service

Q

Thinking back to the **last time** you contacted **Essex Powerlines**, what was the reason for this contact? Was it …

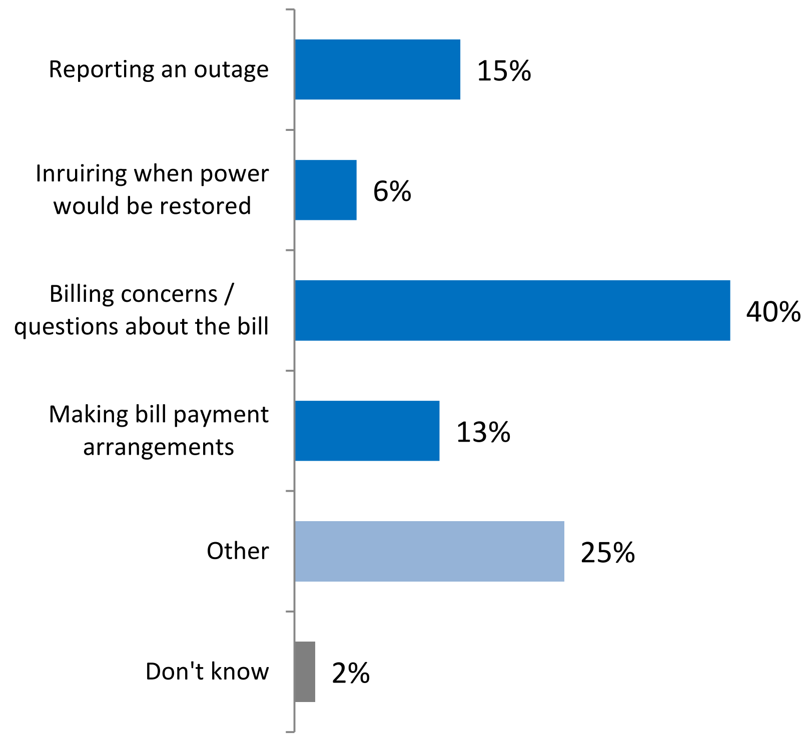
Residential

[asked only of those who have contacted Essex n=77]



General Service

[asked only of those who have contacted Essex n=54]

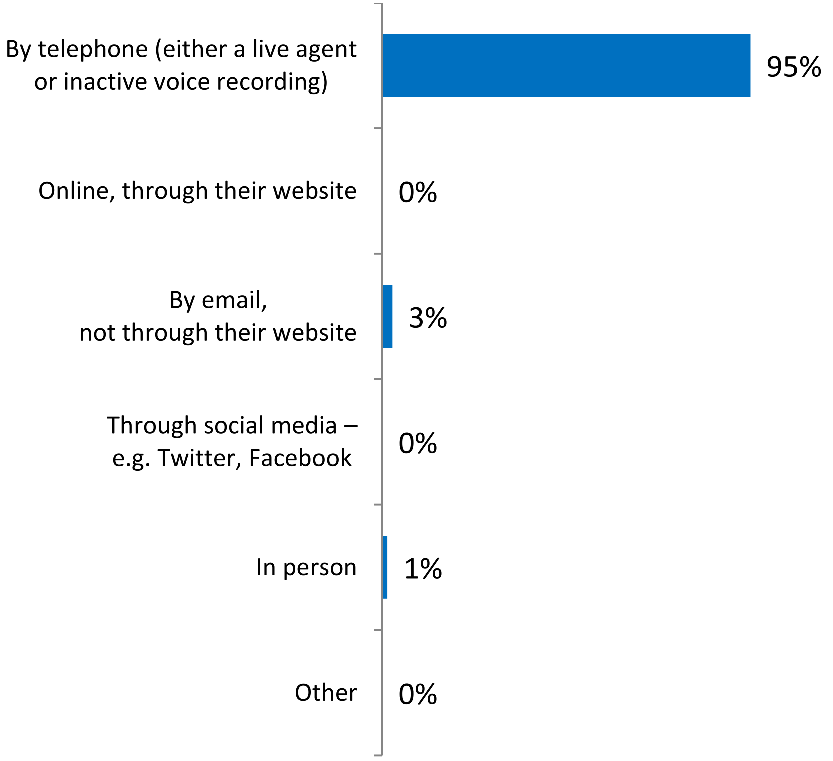


Mode of Contact: Over 90% of both residential and GS customers last contacted Essex by telephone

Q When you [your organization] **last** contacted **Essex Powerlines**, how did you [your organization] contact them?

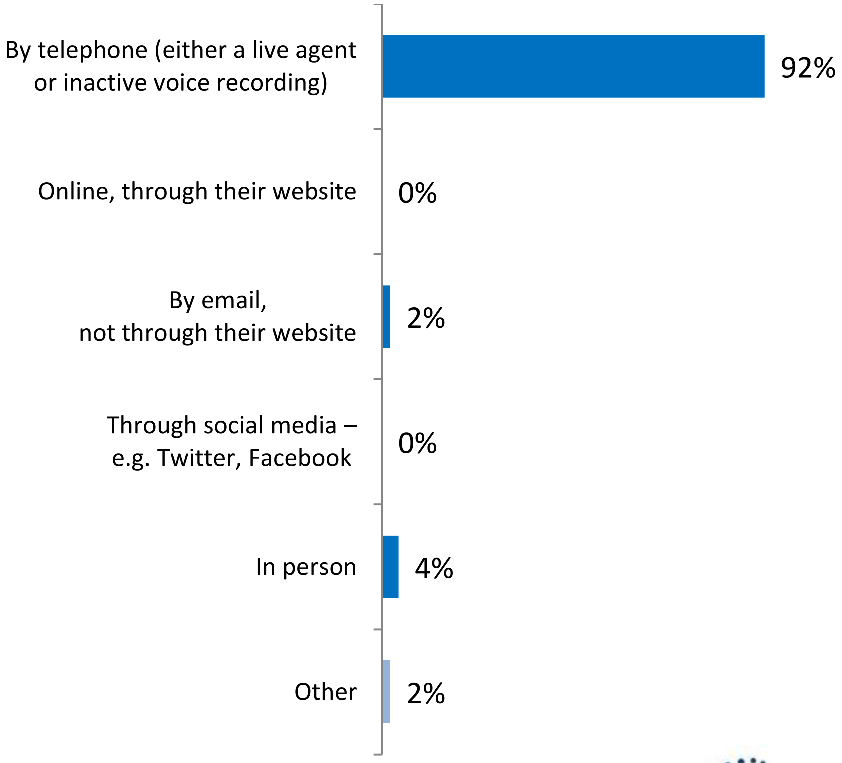
Residential

[asked only of those who have contacted Essex n=77]



General Service

[asked only of those who have contacted Essex n=54]



Note: 'Don't Know / Refused' not shown (Res =1%; GS = 0%)

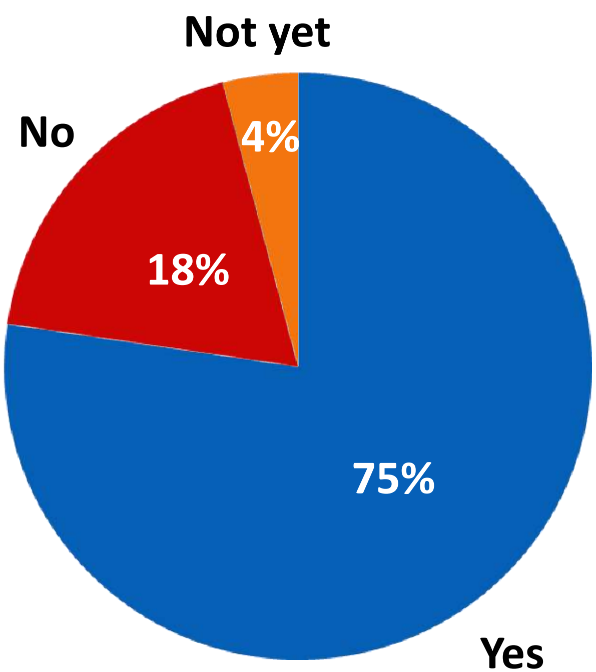
INNOVATIVE RESEARCH GROUP

Resolution: 3-of-4 customers had their questions answered or problem resolved in their last contact with Essex

Q When you **last** contacted Essex Powerlines, was your [your oganization's] question answered or problem resolved to your satisfaction?

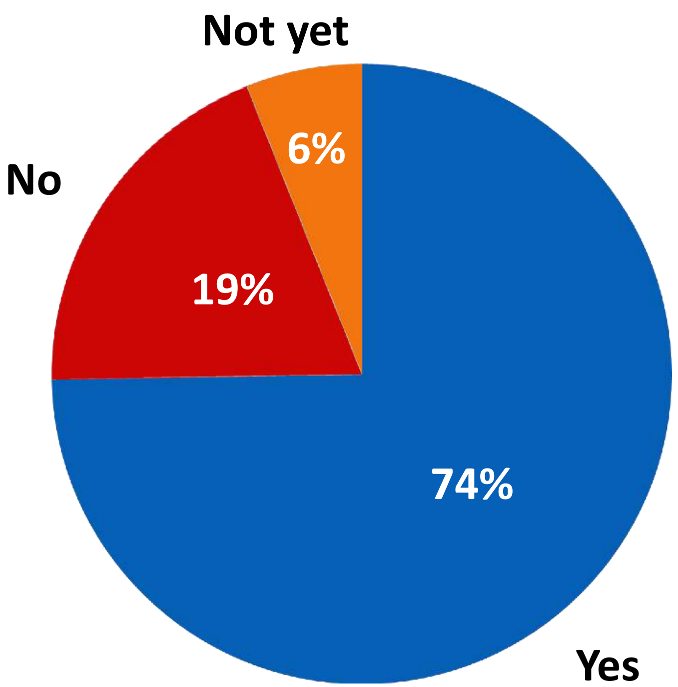
Residential

[asked only of those who have contacted Essex n=77]



General Service

[asked only of those who have contacted Essex n=54]

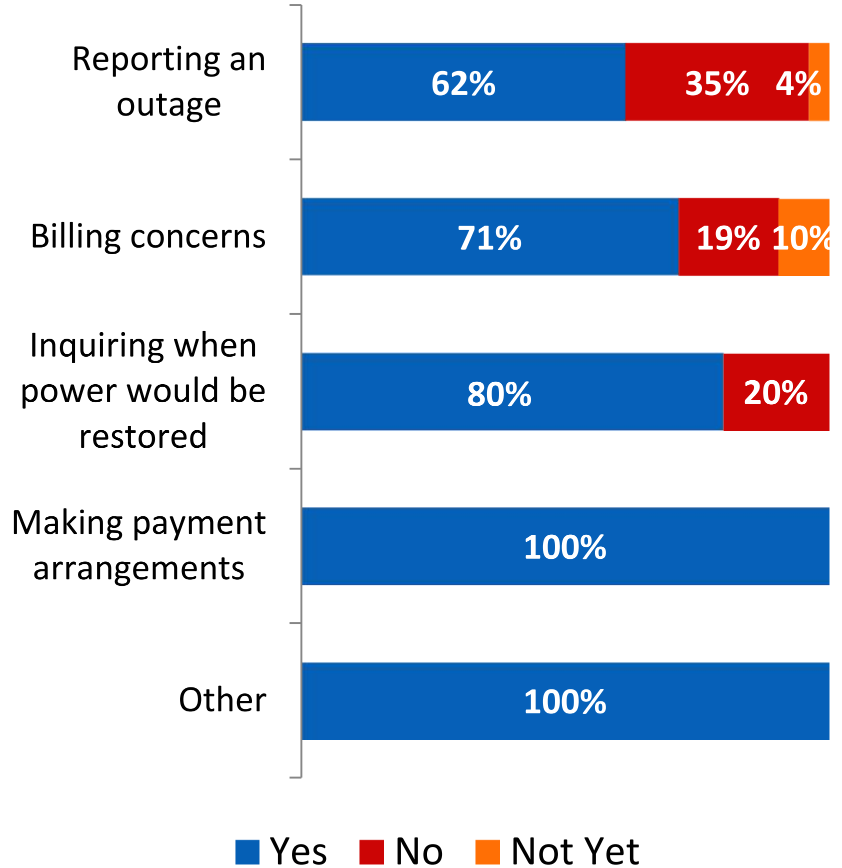


Note: 'Don't Know / Refused' not shown (Res =3%; GS = 2%)

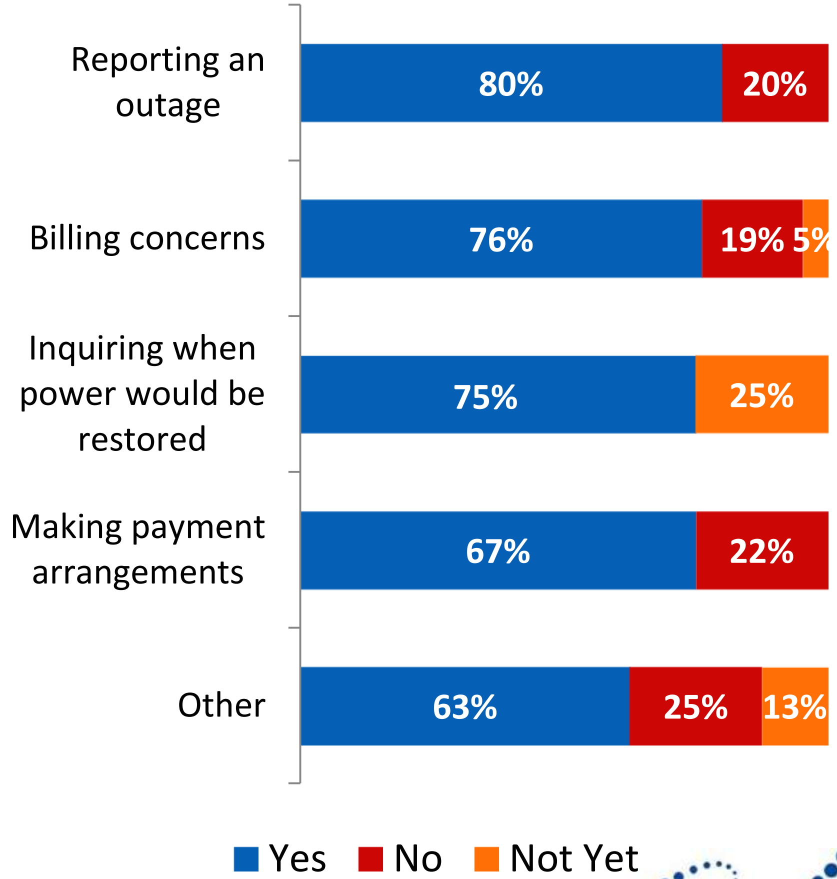
Resolution: residential reporting of an outage were least likely to find resolution, GS were less happy on other issues

Q When you **last** contacted Essex Powerlines, was your [your oganization's] question answered or problem resolved to your satisfaction? **[by kind of inquiry]**

Residential
[asked only of those who have contacted Essex n=77]



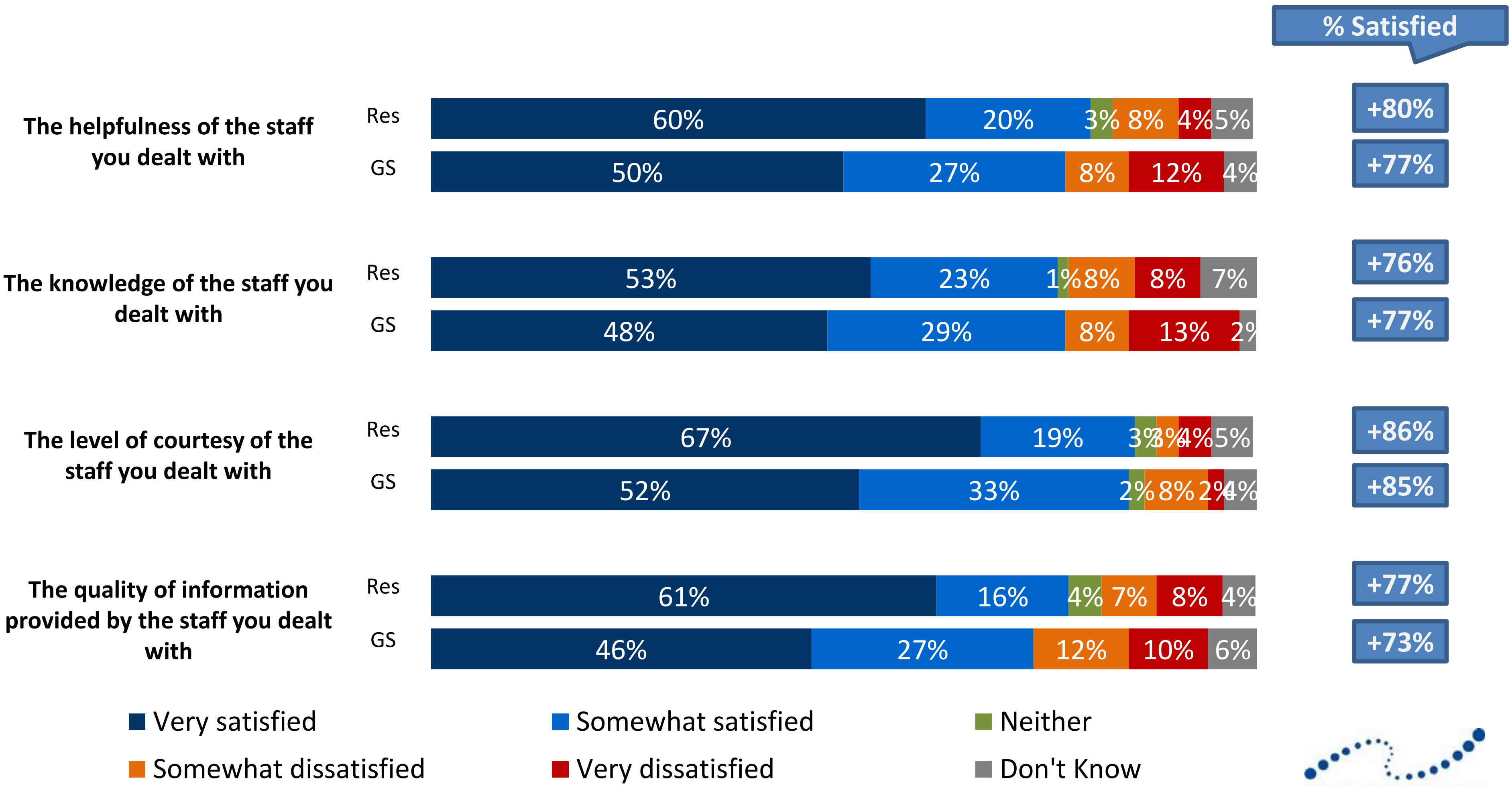
General Service
[asked only of those who have contacted Essex n=54]



Customer Service Satisfaction: customers most satisfied with level of courtesy, followed by the helpfulness of staff

Q

Again, thinking about <u>your last interaction</u> with **Essex Powerlines' customer service staff**, please tell me if you were *very satisfied, somewhat satisfied, somewhat dissatisfied or very dissatisfied* for each of the following.
[asked only among those who have ever had to contact Essex Powerlines; n=77 for residential and n=54 for GS]



Note: 'Don't Know / Refused' not shown

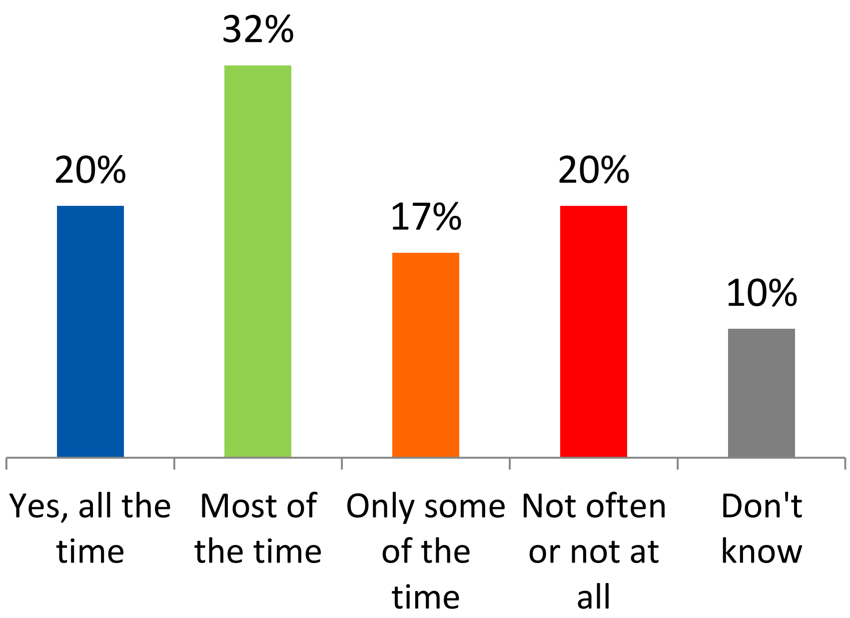
INNOVATIVE RESEARCH GROUP

Communications

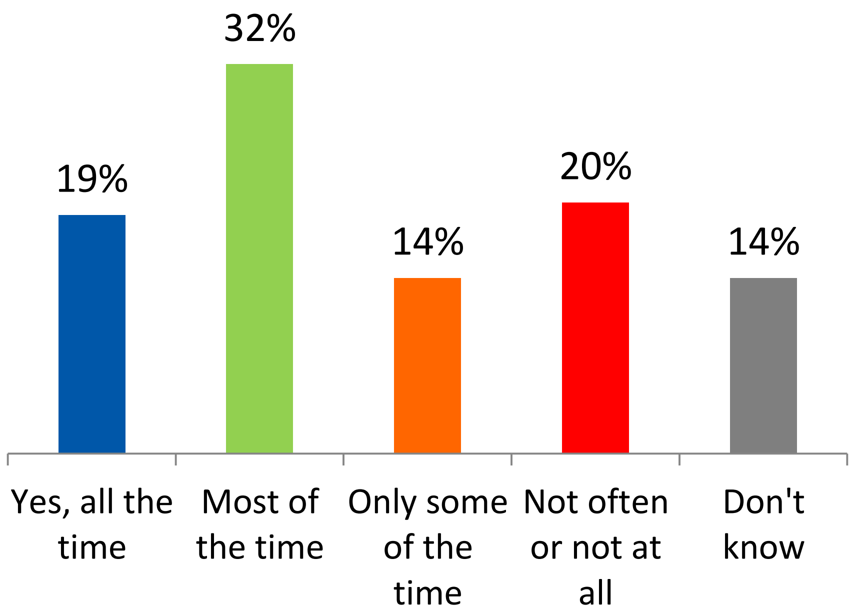
Proactive Communications: majority of customers feel Essex is proactive in communicating at least most of the time

Q Do you feel that **Essex Powerlines is proactive in communicating** changes and issues which may affect customers? Would you say …

Residential
[asked of all respondents n=210]



General Service
[asked of all respondents n=98]

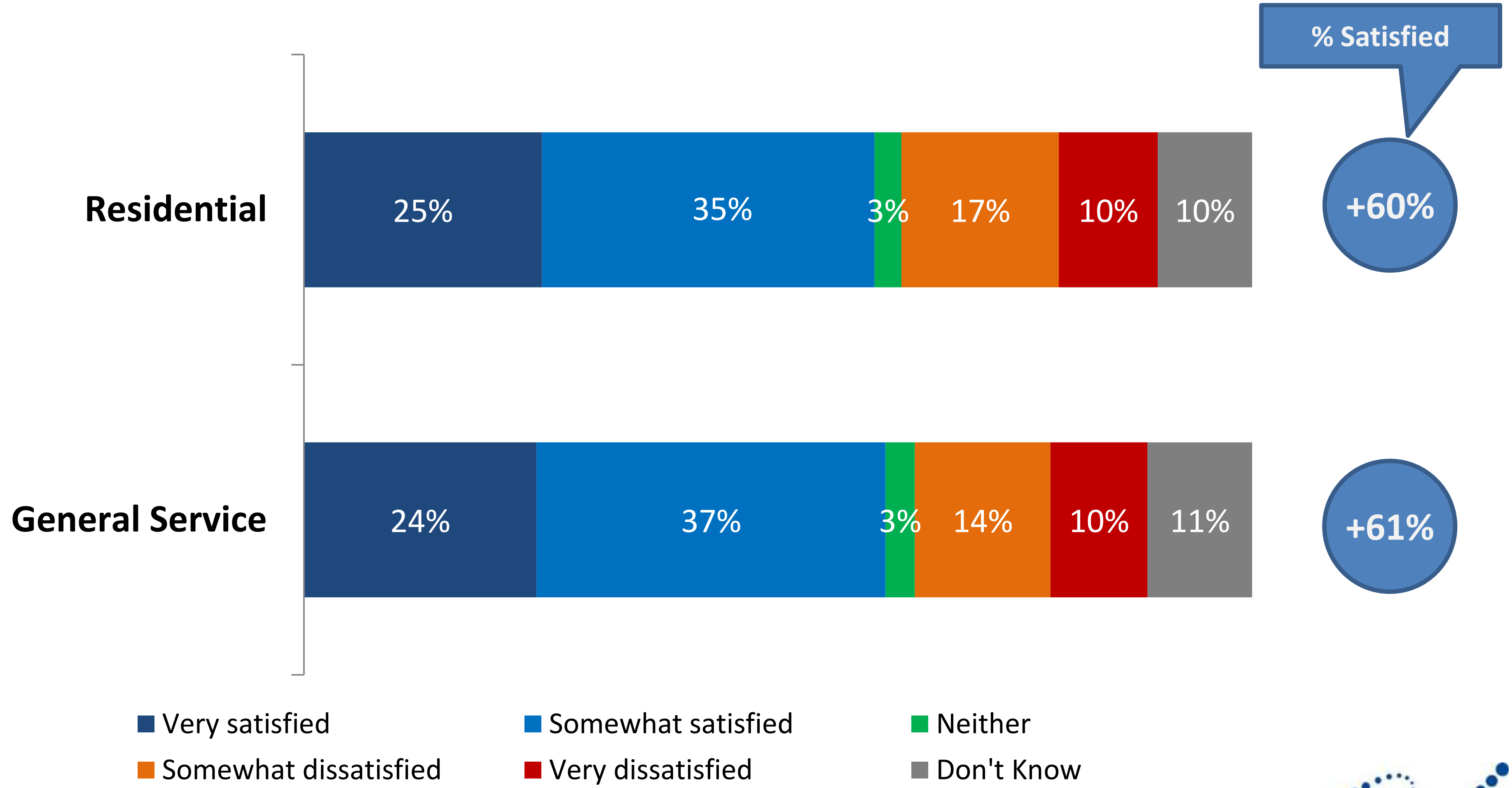


INNOVATIVE RESEARCH GROUP

Power Outage Communications: majority of customers satisfied with the way Essex communicates with them

Q **More specifically**, how satisfied are you with the way that **Essex Powerlines** communicates with you [your organization] regarding power outages? Would you say you are …

[asked of all respondents; residential n=210; GS n=98]

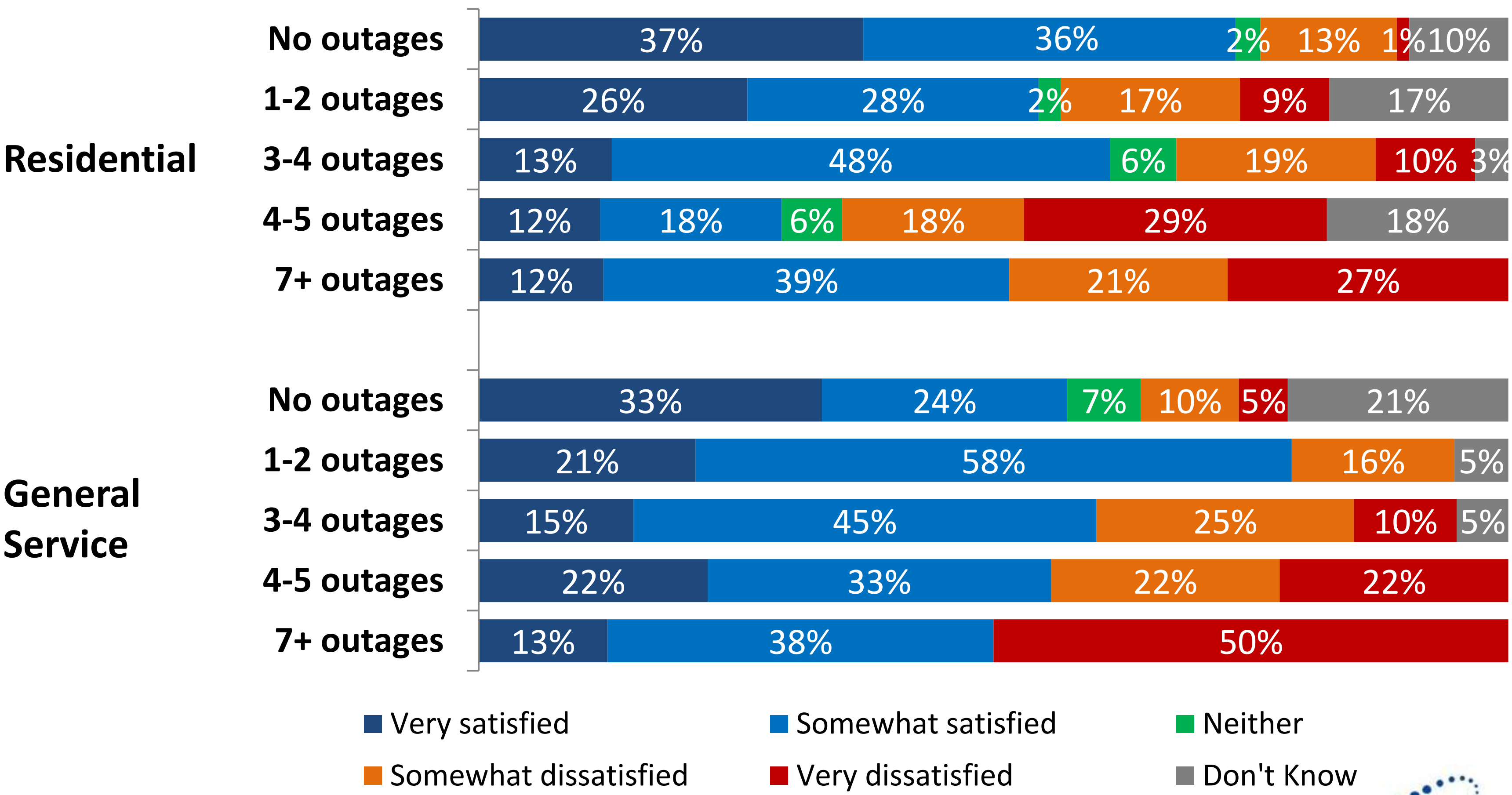


INNOVATIVE RESEARCH GROUP

Communications Satisfaction by # of Power Outages: customers who experience more outages, less satisfied

Q **More specifically**, how satisfied are you with the way that **Essex Powerlines** communicates with you [your organization] regarding power outages? **[BY # of power outages experienced]**

[asked of all respondents; residential n=210; GS n=98]

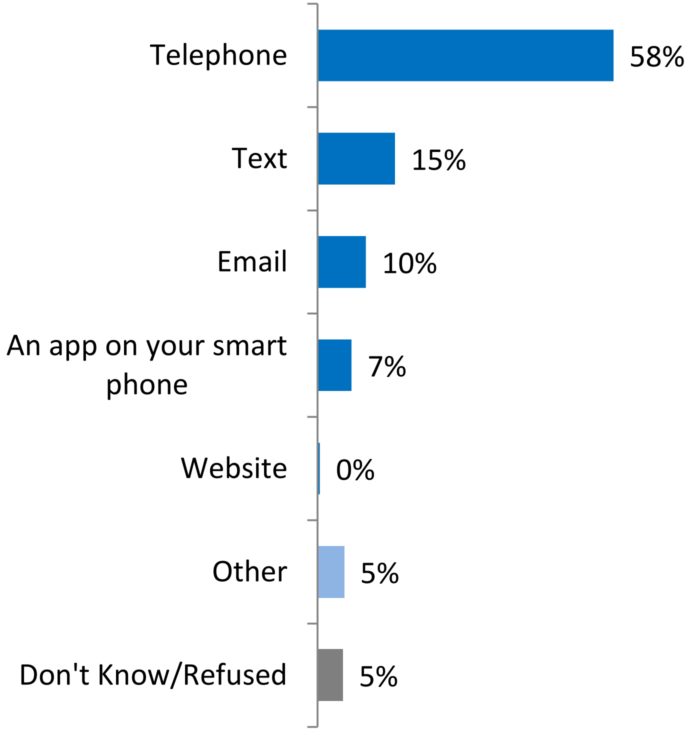


INNOVATIVE RESEARCH GROUP

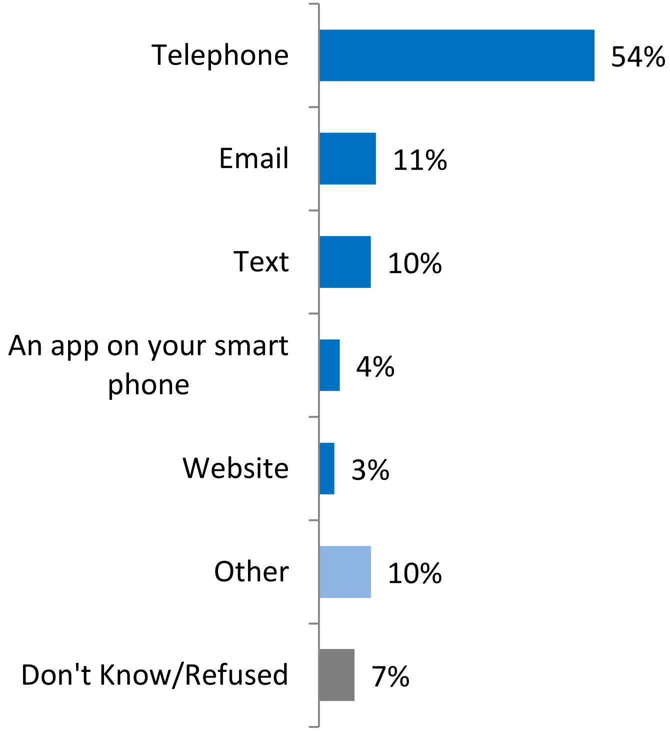
Communications Channels: most customers preferred to be notified about outages by telephone

Q When a power outage occurs, in which way would you prefer to be notified?

Residential
[asked of all respondents n=210]



General Service
[asked of all respondents n=98]



INNOVATIVE RESEARCH GROUP

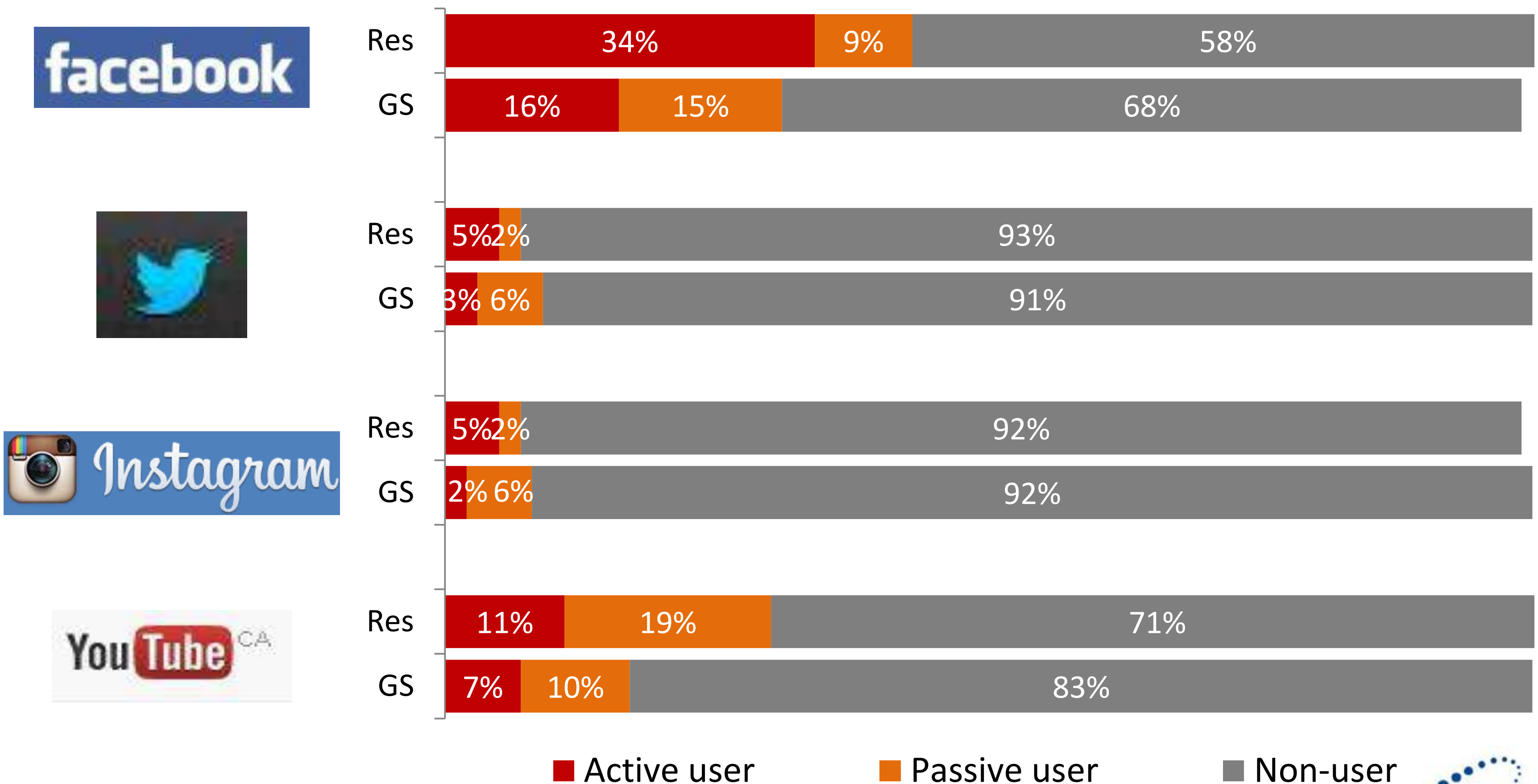
Social Media

Social Media Usage: Facebook, followed by YouTube, most popular among Essex customers

Q

Do you use any of the following social networking sites? → *Yes (user) or No/Don't know (non-user)*
[asked of all respondents]

Did you happen to use [insert name] yesterday? → *Yes (active users) or No/Don't know (passive users)*
[each social media tool only asked of users of the platform]



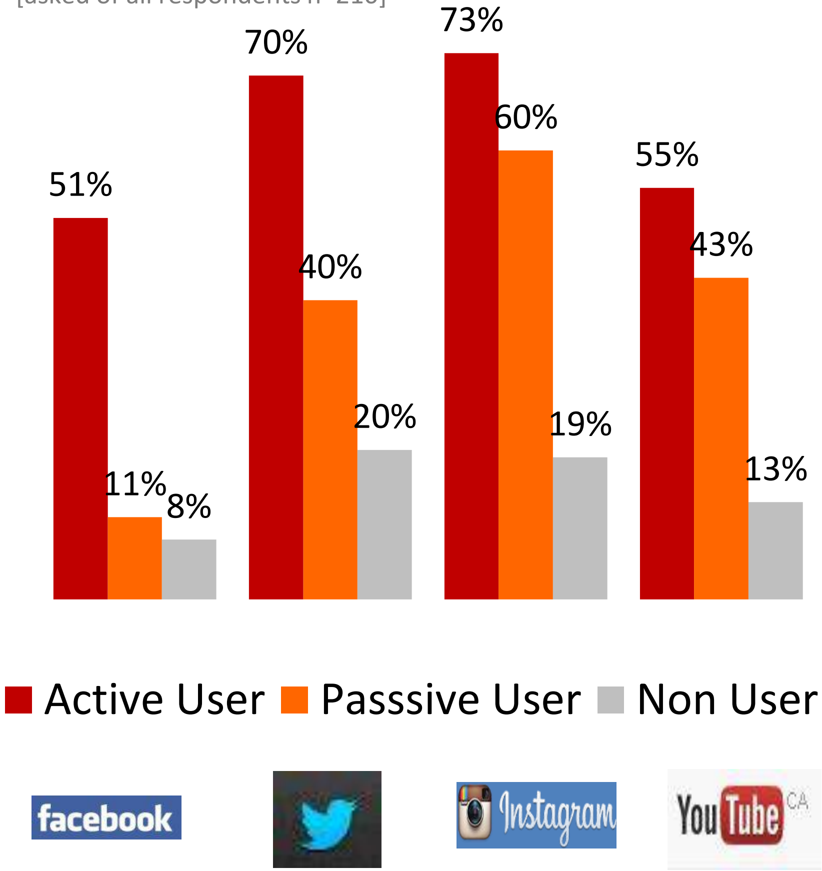
Social Media Notifications: Active Twitter users more likely to say they would make use of social media notifications

Q If **Essex Powerlines** provided notifications about outages and customer service updates using social media, how likely is it that you would make use of such a service?

Percent who say definitely or very likely to use Essex Powerlines' Social Media

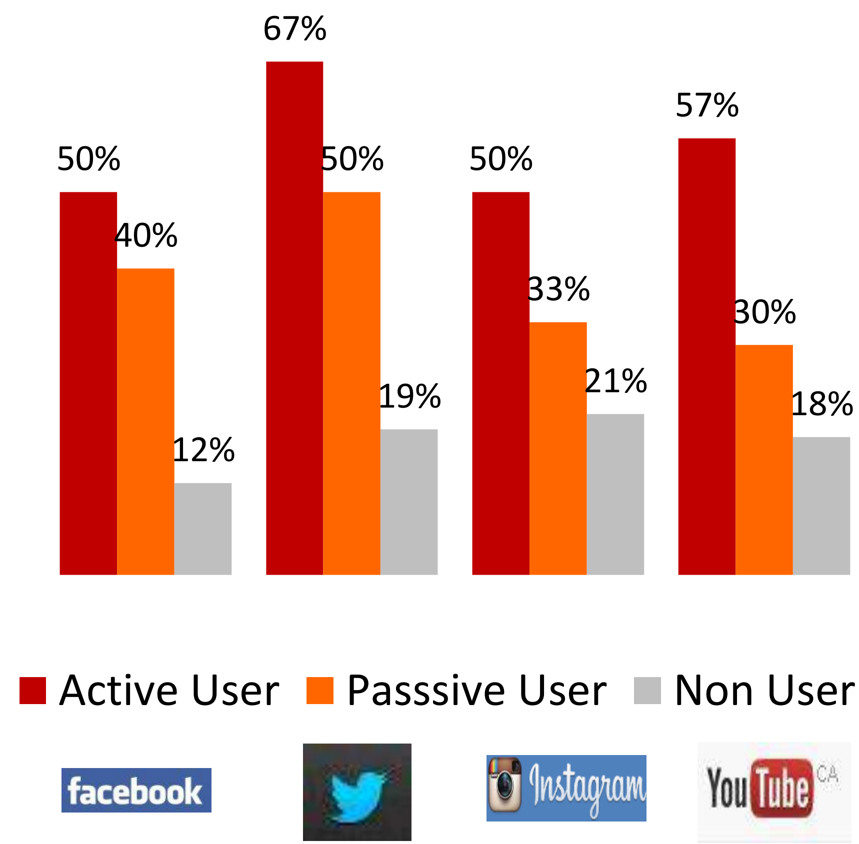
Residential

[asked of all respondents n=210]



General Service

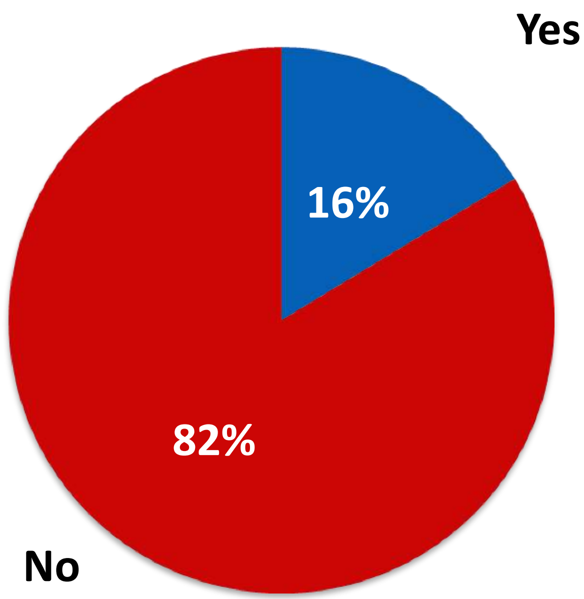
[asked of all respondents n=98]



Website Usage: 16% of residential customers accessed Essex's website in past year; majority found it easy to use

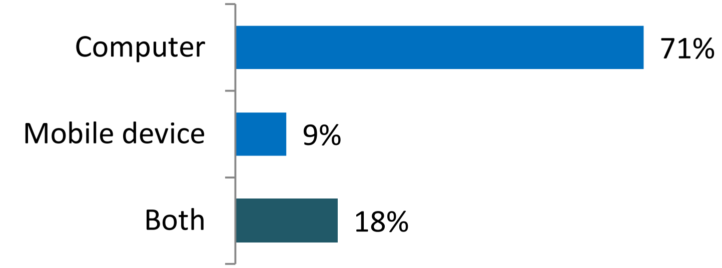
Residential

Q In the past 12 months, have you visited the **Essex Powerlines** website?
[asked of all respondents n=210]



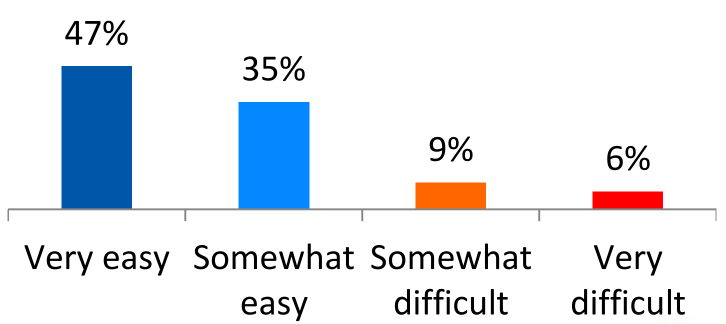
Note: 'Don't Know / Refused' (1%) not shown

Q Did you use a computer to access the site, or a mobile device such as a tablet or smart phone?
[asked of those who visited website in the past 12 months; n=34]



Note: 'Don't Know / Refused' (3%) not shown

Q Overall, how easy did you find it to use the Essex Powerlines website?
[asked of those who visited website in the past 12 months; n=34]



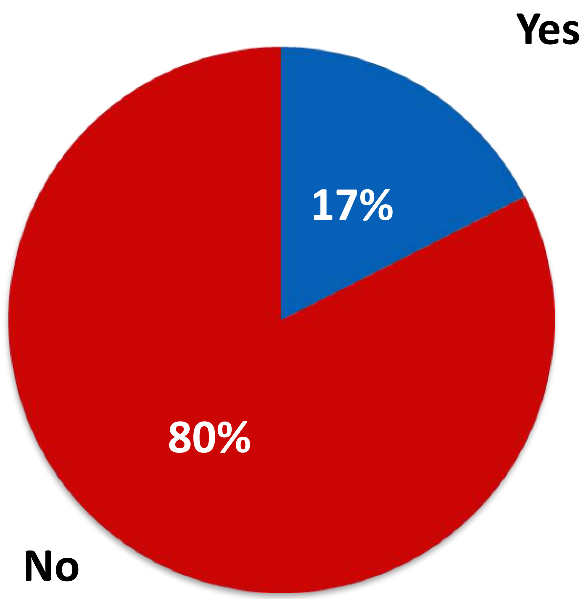
Note: 'Don't Know / Refused' (3%) not shown

INNOVATIVE RESEARCH GROUP

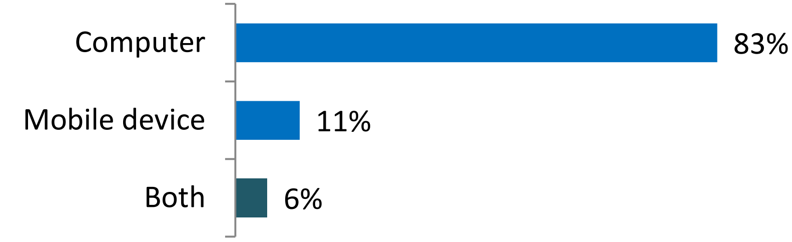
Website Usage: 17% of GS customers accessed Essex's website in past year; majority found it easy to use

General Service

Q In the past 12 months, have you visited the **Essex Powerlines** website?
[asked of all respondents n=98]

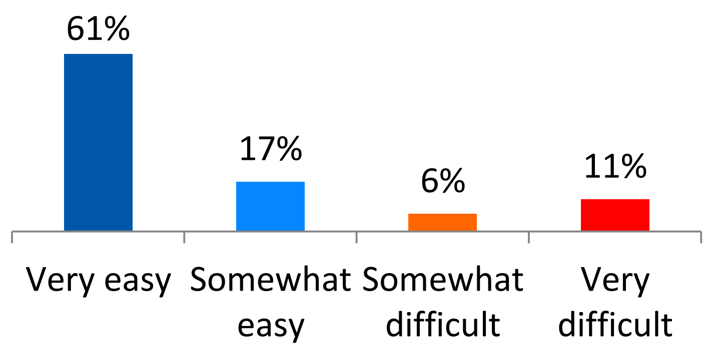


Q Did you use a computer to access the site, or a mobile device such as a tablet or smart phone?
[asked of those who visited website in the past 12 months; n=18]



Note: 'Don't Know / Refused' (0%) not shown

Q Overall, how easy did you find it to use the Essex Powerlines website?
[asked of those who visited website in the past 12 months; n=18]



Note: 'Don't Know / Refused' (3%) not shown

Note: 'Don't Know / Refused' 6%) not shown

INNOVATIVE RESEARCH GROUP

General Satisfaction

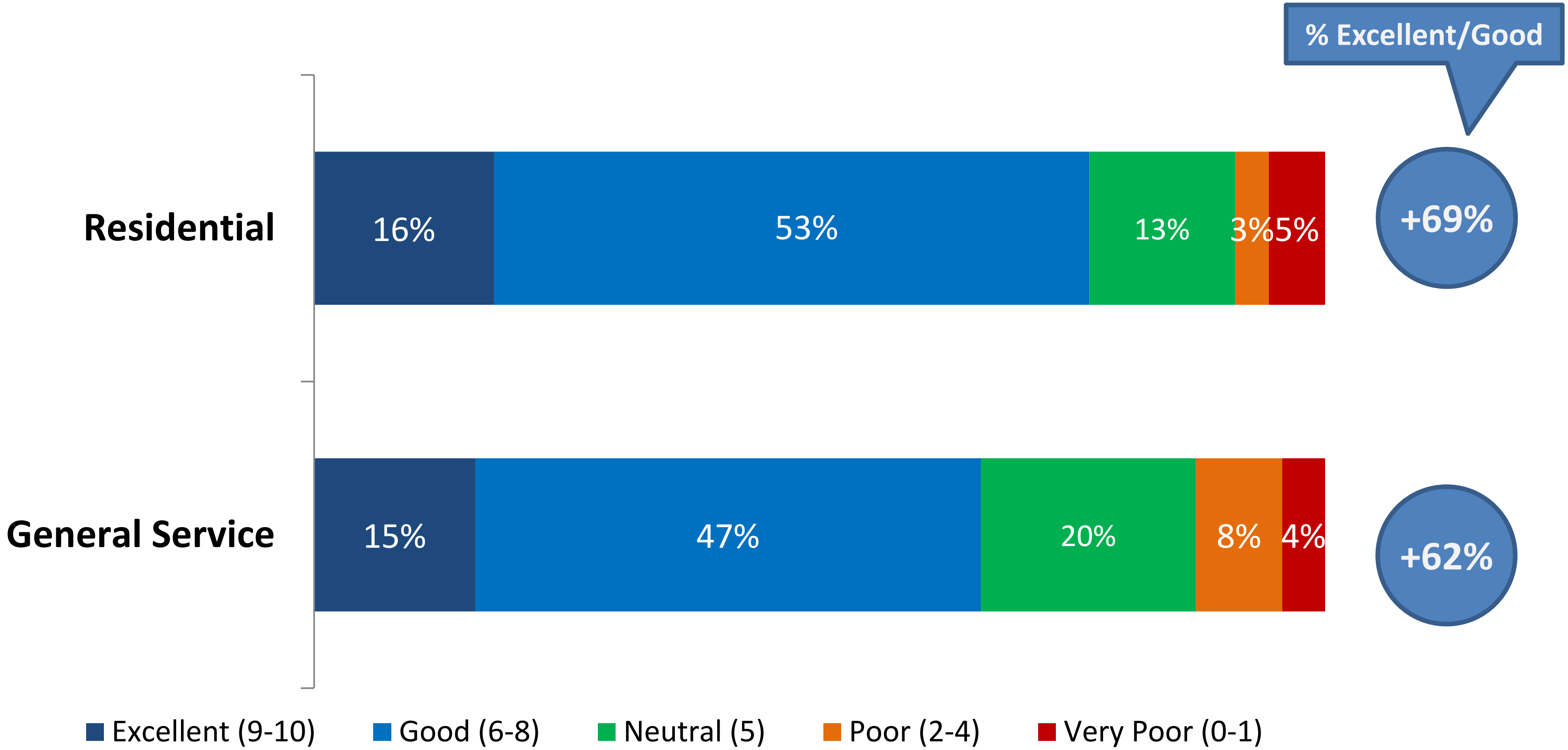
Value for Money: 69% of residential and 62% of GS customers feel Essex offers good *Value for Money*

Q

Based on your [organization's] experience and impressions, on a scale from 0 to 10, where 0 means very poor and 10 mean excellent, how would you rate **Essex Powerlines** in terms of …

The overall value for money it offers to you [your organization] as a customer

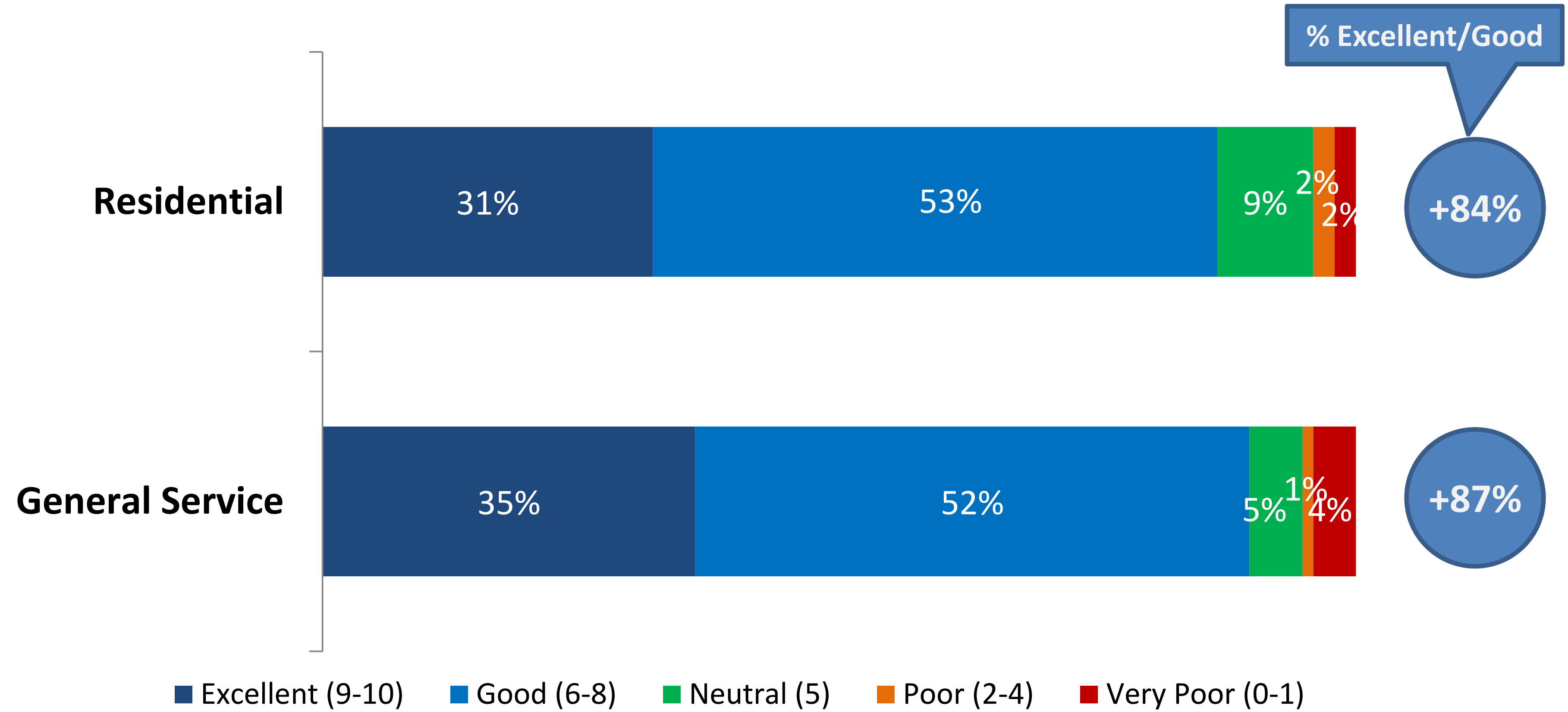
[asked of all respondents; residential n=210; GS n=98]



Quality of Service: a large majority of both types of customers approve of Essex's quality of service

Q

Based on your [organization's] experience and impressions, on a scale from 0 to 10, where 0 means very poor and 10 mean excellent, how would you rate **Essex Powerlines** in terms of …
The overall quality of the service it provides to you [your organization]?
[asked of all respondents; residential n=210; GS n=98]



INNOVATIVE RESEARCH GROUP

Research-based strategic advice.

Public Affairs • Corporate Communications • Fundraising

For more information, please contact:

Jason Lockhart
Vice President
Innovative Research Group Inc.
56 The Esplanade, Suite 310
Toronto ON | M5E 1A7

(t) 416-642-7177
(f) 416-640-5988
(e) jlockhart@innovativeresearch.ca
www.innovativeresearch.ca

Attachment 1-H

Audited Financial Statements

(2010-2016)

Essex Powerlines Corporation

Financial Statements

December 31, 2010

Graham, Setterington, McIntosh, Driedger & Hicks LLP - Chartered Accountants

GRAHAM, SETTERINGTON, McINTOSH, DRIEDGER & HICKS LLP

CHARTERED ACCOUNTANTS

AL W. McINTOSH, CA
PAUL H. DRIEDGER, BSc. CA
R. TYLER HICKS, BBA, CA
HEATHER L. MacPHERSON, BAcc, CA
LINDSAY L. ROUNDING, BAcc, CA

P.O. BOX 189, 49 ERIE ST. N.,
LEAMINGTON, ONTARIO N8H 3W2

TELEPHONE (519) 326-2681
FAX (519) 326-8044

AUDIT REPORT

To the Shareholders of
Essex Powerlines Corporation

We have audited the accompanying financial statements of Essex Powerlines Corporation, which comprise the balance sheet as at December 31, 2010 and the statements of income and expenses, retained earnings and cash flows for the year then ended.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted principles, 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 amount and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not 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.

Basis for Opinion

In our opinion these financial statements present fairly, in all material respects, the financial position of the Essex Powerlines Corporation as at December 31, 2010 and the statements of income and expenses, retained earnings and cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

GRAHAM, SETTERINGTON, McINTOSH, DRIEDGER & HICKS LLP

Graham, Setterington, McIntosh, Driedger & Hicks LLP

Chartered Accountants
Licensed Public Accountants

Leamington, Ontario
March 31, 2011

Essex Powerlines Corporation

Balance Sheet
as at December 31

	2010	2009
Assets		
Current assets		
Cash	**$ 3,328,924**	$ 10,240,908
Accounts receivable	**5,199,985**	4,303,040
Miscellaneous receivables	**1,568,843**	790,590
Prepaid expenses	**177,668**	202,191
Unbilled revenue	**6,173,633**	6,321,145
Income taxes receivable	**19,199**	-
Inventory (note 2)	**60,000**	60,000
	16,528,252	21,917,874
Property, Plant and Equipment (note 2 and 3)	**37,042,304**	31,967,949
Other		
Deferred charges (note 5)	**2,237,720**	2,234,689
Future income taxes (note 2)	**875,893**	2,025,326
	3,113,613	4,260,015
	$ 56,684,169	$ 58,145,838

See Accompanying Notes

Essex Powerlines Corporation

Balance Sheet
as at December 31

	2010	2009
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 10,592,506**	$ 8,932,605
Due to affiliates (note 9)	**30,492**	179,145
Regulatory liabilities (note 4)	**1,404,219**	2,165,881
Income taxes payable	**-**	24,041
Dividends payable	**675,000**	723,258
Current portion of customer deposits (note 6)	**250,000**	250,000
Current portion of long term debt (note 7)	**3,724,979**	2,950,600
	16,677,196	15,225,530
Long term liabilities		
Customer deposits (note 6)	**607,327**	616,936
Long term debt (note 7)	**18,202,843**	19,710,999
Employee future benefits (note 10)	**4,280,137**	4,464,592
	23,090,307	24,792,527
Contingencies (note 16)	**-**	-
Shareholders' Equity		
Capital stock (note 8)	**15,772,801**	15,772,801
Retained earnings	**1,143,865**	2,354,980
	16,916,666	18,127,781
	$ 56,684,169	$ 58,145,838

See Accompanying Notes

Approved by the Board of Directors

______________________________Director

Essex Powerlines Corporation

Statement of Income, Expenses and Retained Earnings
For the years ended December 31

	2010	2009
Electricity Revenue		
Energy sales	**$ 59,856,257**	$ 53,236,461
Cost of Power		
Power purchased	**49,232,444**	43,630,093
Gross Margin on Service Revenue	**10,623,813**	9,606,368
Other Revenue		
Late payment charges	**170,398**	147,660
Miscellaneous revenue	**549,957**	322,561
Pole and light rentals	**102,337**	110,066
Interest income	**87,470**	64,201
Other billing revenue	**907,509**	853,971
	1,817,671	1,498,459
Expenses		
Billing and collecting	**2,077,432**	2,346,304
Administration and general	**2,122,067**	1,780,559
Operations and maintenance	**2,296,797**	2,149,359
Amortization	**2,278,154**	2,145,179
Bank charges and interest expense	**149,056**	174,644
Long term interest	**1,119,878**	596,836
Loss on currency exchange	**36,067**	-
	10,079,451	9,192,881
Income From Operations	**2,362,033**	1,911,946
Other Revenue		
Gain on disposal of property, plant and equipment	**23,879**	22,166
Income Before Income Taxes	**2,385,912**	1,934,112
Income Taxes - Current (note 2 and 17)	**422,027**	582,521
Net Income	**1,963,885**	1,351,591
Retained Earnings at Beginning of Year	**2,354,980**	1,726,647
Dividends	**(3,175,000)**	(723,258)
Retained Earnings at End of Year	**$ 1,143,865**	$ 2,354,980

See Accompanying Notes

Essex Powerlines Corporation

Statement of Cash Flows
For the years ended December 31

	2010	2009
Cash Provided by (Used in):		
Operating Activities		
Net income from operations	$ 1,963,885	$ 1,351,591
Add items not involving cash:		
Amortization of property, plant and equipment	2,171,056	2,111,235
Change in deferred charges	(3,031)	(59,601)
Change in future income taxes	1,149,433	(2,025,326)
Change in regulatory liabilities	(761,664)	609,106
Net changes in non-cash working capital	690,969	1,561,858
	5,210,648	3,548,863
Financing Activities		
Dividends	(3,175,000)	(723,258)
Capital contributions received	1,667,247	453,725
Change in long term debt	(1,702,219)	10,425,201
	(3,209,972)	10,155,668
Investing Activities		
Purchase of property, plant and equipment	(8,936,539)	(3,319,533)
Disposal of property, plant and equipment	23,879	22,166
	(8,912,660)	(3,297,367)
Change in Cash	(6,911,984)	10,407,164
Cash, Beginning of Year	10,240,908	(166,256)
Cash (Bank indebtedness), End of Year	$ 3,328,924	$ 10,240,908

Net Changes in Non-Cash Working Capital		
Accounts receivable	$ (1,546,885)	$ 4,468,020
Other assets	24,523	(78,888)
Current liabilities	2,213,331	(2,827,274)
	$ 690,969	$ 1,561,858

See Accompanying Notes

1. Nature of Business

Business Operations

Essex Powerlines Corporation (EPLC) serves as the rate regulated "local distribution company" (LDC) which provides safe and reliable power to over 27,000 residents and businesses in Amherstburg, LaSalle, Leamington and Tecumseh. Essex Power Corporation holds 100% of the shares of the corporation. The shareholders of Essex Power Corporation include the Town of Amherstburg, the Town of LaSalle, the Municipality of Leamington and the Town of Tecumseh. The municipal owners of Essex Power Corporation also hold debt directly with EPLC (see Note 7)

The Ontario Government enacted the Energy Competition Act, 1998 to introduce competition to the Ontario electricity market. Under the terms of the legislation, the Ontario Energy Board ("OEB") will regulate industry participants by issuing licenses for the right to generate, transmit, distribute or retail electricity. These licenses require compliance with established market rules and codes.

The distribution revenues include a distribution tariff, which is based on OEB approved rates. The distribution tariff rates are set based on an approved revenue requirement that provides cost recovery and includes a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory assets and liabilities over a specified timeframe.

2. Summary of Significant Accounting Policies

Basis of Presentation

The financial statements have been prepared by management in accordance with accounting principles generally accepted in Canada for electric utilities.

Property, Plant and Equipment

Property, plant and equipment is stated at cost less applicable rebates, accumulated amortization and contributions in aid of construction. Cost is comprised of materials, labour, engineering costs and overheads. Amortization is determined on a straight-line basis over the estimated useful lives of the assets.

Transmission and distribution	25 years
Computer hardware and software	5 years
Building	25 years
Office equipment	10 years
Utility equipment and trucks	5-8 years
Land rights	50 years
Solar generation	20 years

2. Summary of Significant Accounting Policies (Cont'd)

Property, Plant and Equipment (cont'd)
In the year of addition a half year of amortization is claimed. When specifically identifiable items are retired or otherwise disposed of, their original cost and accumulated amortization are removed from the accounts and the related gain or loss is included in income in the year of disposal.

Inventory
Inventories consist principally of construction and maintenance materials and are stated at the lower of cost and net realizable value, with cost determined on an average cost basis. The company includes certain major standby equipment as in-service property, plant and equipment and depreciates these assets over their useful lives.

Post Employment Benefits
The corporation pays certain post retirement benefits on behalf of its retired employees. The corporation recognizes these post retirement costs in the period in which the employees rendered the services. The net periodic benefit cost for the year ended December 31, 2010 was determined by actuarial valuation using a discount rate of 5%. The actuarial valuation is required to be completed once every 3 years.

Contributions in Aid of Construction
Contributions in aid of construction are non-refundable contributions of property, plant and equipment made by developers or subdividers which become part of the distribution system. They are recorded as a reduction of the related asset values. These amounts will be amortized on the same basis as the related property, plant and equipment.

Revenue Recognition
In accordance with OEB regulations, the Corporation recognizes as revenue the regulated distribution tariffs associated with energy distributed.

Variances between energy purchase costs and energy billed are recorded as regulatory assets or liabilities for future distribution rate application consideration. The company follows the practice of cycle billing of customers' accounts and revenue is recognized in the period billed. An accrual is made in the accounts at December 31 for power supplied but not billed to customers between the date the meters were last read and the end of the year.

Accounting for Rate Regulated Operations
The Accounting Standards Board (AcSB) accounting guideline 19, Disclosures by Entities Subject to Rate Regulation, is applicable to Essex Powerlines. The guideline requires that we disclose the effect of removing regulatory assets and liabilities and what the effect would be on the financial statements in the absence of rate regulation. The effects will be disclosed in any applicable notes to the financial statements.

2. Summary of Significant Accounting Policies (Cont'd)

Income Taxes - Payments in Lieu

The income taxes are to be calculated in accordance with the rules for computing income, capital and other taxes provided for in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Energy Act and related regulations. After October 1, 2001 the Corporation is required, to compute and remit to the Ontario Electricity Financing Corporation (OEFC) payments in lieu of corporate taxes.

Effective January 1, 2009, the Company adopted amendments to the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3465, Income Taxes and CICA Handbook Section 1100, Generally Accepted Accounting Principles. These amended sections establish new standards for the recognition, measurement, presentation and disclosure of future income tax assets and liabilities of rate regulated enterprises.

For transactions and events that cause temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, the Company recognized future income tax assets and liabilities, and corresponding regulatory liabilities and assets, as a result of adopting these amended standards on January 1, 2009.

Current Income Taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at the amounts receivable or payable from/to the OEFC.

Future Income Taxes

Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely than not that they be realized from taxable profits available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantively enacted by the balance sheet date.

The Company has recognized regulatory assets and liabilities which correspond to future income taxes that flow through the rate-making process.

Measurement Uncertainty

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of financial statements. Certain estimates, also required as regulations which will ultimately determine the actual results, have yet to be finalized and are dependent on the completion of regulatory proceedings or decisions. Due to these uncertainties, actual results might differ from those estimates and the impact will be recorded in the current period when the actual results are known.

2. Summary of Significant Accounting Policies (Cont'd)

Regulatory Accounting

The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. The Company assess the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

3. Property, Plant and Equipment

	Cost	Accumulated Amortization	$ 2010 Net	$ 2009 Net
Land and land rights	**$ 335,598**	**$ 5,000**	**$ 330,598**	$ 298,719
Buildings and fixtures	**1,607,140**	**235,080**	**1,372,060**	1,449,492
Utility equipment and trucks	**1,479,071**	**416,590**	**1,062,481**	840,293
Transmission and distribution equipment	**44,228,741**	**15,006,722**	**29,222,019**	28,550,657
Computer hardware, software and other equipment	**1,289,100**	**552,933**	**736,167**	284,694
Office furniture and equipment	**159,415**	**79,371**	**80,044**	71,710
Construction in progress	**1,197,156**	**-**	**1,197,156**	472,384
Solar generation	**3,041,779**	**-**	**3,041,779**	-
	$ 53,338,000	**$ 16,295,696**	**$ 37,042,304**	$ 31,967,949

4. Regulatory (Assets) Liabilities

Regulatory assets and liabilities are a result of differences between costs charged to Essex Powerlines Corporation and allowed rates charged to customers which are classified as "Retail Settlement Variances". Also included are smart meter costs, deferred payments in lieu and extraordinary event losses. These are referred to as "Non-Retail Settlement Variances".

	2010	2009
A) Retail settlement variances	**$ 1,732,715**	$ 1,777,022
B) Extra event costs - ice storm	**(91,943)**	(55,070)
C) Retail cost and other variances	**(250,395)**	(157,862)
D) Regulatory assets recovered	**1,587,284**	335,920
E) Smart meter variance	**(2,449,335)**	(1,759,455)
F) Future income taxes	**875,893**	2,025,326
	$ 1,404,219	$ 2,165,881

4. Regulatory (Assets) Liabilities (Cont'd)

A) Retail settlement variances represent amounts accumulated since the opening of the electricity market and are comprised of variances between amounts charged by the Independent Electricity System Operator for the operation of the wholesale electricity market and the cost of electricity, amounts from Hydro One for network and line and transformation charges and amounts billed to customers. In the absence of rate regulation income before tax would be lower by $44,307.

B) Extraordinary event costs represent costs incurred to restore services following storms in 2005 and 2010. In the absence of rate regulation income before taxes would be lower by $36,872.

C) Retail cost and other variances represent amounts for costs incurred by the corporation to serve customers that have been enrolled by a commodity retailer, payment in lieu of income taxes, and for miscellaneous other costs that will be recovered from customers. In the absence of rate regulation income before taxes would be lower by $3,363.

D) Regulatory assets recovered represent amounts collected from customers through rates until April 30, 2013. These amounts will be held until approved by the Ontario Energy Board to be refunded to or recovered from customers. In the absence of rate regulation income before taxes would be higher by $1,251,364.

E) The smart meter variance represents costs to install smart meters and interim smart meter recovery amounts paid by customers. These amounts will continue to be recovered from customers until the end of 2010 when an adjustment will be made to include this cost in regular rates. In the absence of rate regulation, net assets would be higher by $3,422,614 and net income would be lower by $689,881.

F) The future income taxes liability is the result of the application of CICA handbook section 3465, Income Taxes, that was amended to require the recognition of future income tax liabilities and assets for regulated enterprises that were previously not subject to these provisions. The future income taxes liability is the amount that will be refunded to customers through future rates. In the absence of rate regulation, net assets would be higher.

5. Deferred Charges

Deferred charges include the excess of the amounts paid to the shareholders less the net assets transferred to Essex Powerlines Corporation. These amounts are being amortized on a straight-line basis over the average remaining service life of the assets transferred. These costs are amortized against revenue as it is earned. The deferred charges also include the Springboard Health & Safety management system development and implementation and miscellaneous deferred debits.

	2010	2009
Deferred charges	**$ 2,813,166**	$ 2,617,075
Less: Accumulated amortization	**575,446**	382,386
	$ 2,237,720	$ 2,234,689

Essex Powerlines Corporation

Notes to Financial Statements
For the years ended December 31

6. Customer Deposits

Customer deposits are amounts received and held as security for energy consumption until the customer's account is closed. Interest is to be paid annually at the average yearly savings interest rate.

7. Long Term Debt

	2010	2009
Related Party Long Term Loan Payable *- is repayable as approved by the Board of Directors not to exceed 20% of the principal lending amount if funds are available as determined each July. Interest is payable at a stated interest rate of 6%. The agreement expires December 31, 2012. The debt is owing to two of the four shareholders of the parent company as follows:*		
Municipality of Leamington	**$ 2,150,296**	$ 2,150,296
Town of Tecumseh	**1,544,408**	1,544,408
Total	**3,694,704**	3,694,704
Mortgage Payable - Woodslee Credit Union *- is repayable in blended monthly payments of $ 8,793 bearing an interest rate of 5.9% and is secured by land and buildings at 2730 Highway #3, RR # 1, Tecumseh. Mortgage matures September 19, 2013.*	**$ 656,713**	$ 721,877
Banker's Acceptance/Interest Rate Swaps - Toronto Dominion Bank/TD Securities *- is a 10 year swap repayable with interest only payments at an effective interest rate of 6.55%. It is the intention of the board of directors that this remain a long term debt. Loan matures June 3, 2013.*	**3,000,000**	3,000,000
Banker's Acceptance/Interest Rate Swaps - Toronto Dominion Bank/TD Securities *- is a 10 year swap repayable with interest only payments at an effective interest rate of 5.44%. It is the intention of the board of directors that this remain a long term debt. Loan matures November 4, 2018.*	**3,300,000**	3,300,000
Fixed Rate Loan - TD Canada Trust *is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $ 39,562, bearing an interest rate of 4.99%. Loan matures November 9, 2019.*	**5,804,859**	5,985,046

7. Long Term Debt (Cont'd)

	2010	2009
Fixed Rate Loan - TD Canada Trust *is a 10 year term loan with a 10 year amortization schedule, repayable in blended monthly payments of $ 62,122, bearing an interest rate of 4.48%. Loan matures November 9, 2019.*	**$ 5,471,546**	$ 5,959,972
	21,927,822	22,661,599
Less: Current portion of long term debt	**3,724,979**	2,950,600
	$ 18,202,843	$ 19,710,999

Approximate long term principal repayments over the next 5 years are as follows:

2011	**$ 3,724,979**
2012	**4,463,920**
2013	**825,439**
2014	**803,919**
2015	**841,854**

8. Capital Stock

			2010	2009
Authorized	*Unlimited*	*Common shares, Class A voting*		
	Unlimited	*Common shares, Class B non-voting*		
Issued	*50*	*Common shares, Class A voting*	**$ 5**	$ 5
Issued	*15,772,796*	*Common shares, Class B non-voting*	**15,772,796**	15,772,796
			$ 15,772,801	$ 15,772,801

9. Related Party Transactions

The Company engages in transactions with its affiliates and parent company. The following is a summary of the related party transactions. These transactions are measured at exchange amount, which is the amount of consideration established and agreed to by the related parties. Essex Powerlines Corporation is affiliated with Essex Power Services Corporation, Essex Energy Corporation and is the subsidiary of Essex Power Corporation.

	2010	2009
Service fees due to affiliate	**$ 12,000**	$ 42,000
Management fees due to parent	**1,204,987**	1,094,915
Amounts due to affiliates	**30,492**	179,145

Related party long term debt payable with the shareholders of Essex Power Corporation is outlined in Note 7. The corporation also was charged interest on the long term debt by the Essex Power Corporation shareholders in the amount of $ 221,682.

10. Employee Future Benefits

Pension Plan

Essex Powerlines Corporation provides a pension plan for its full time employees through Ontario Municipal Employees Retirement System "OMERS". OMERS is a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province for employees of municipalities, local boards and school boards in Ontario. Both participating employers and employees are required to make plan contributions based on participating employees' contributory earnings. The corporation recognized the expense related to this plan as contributions are made. For the year ended December 31, 2010, the corporation's OMERS current service pension costs were $250,776 (2009 - $250,252).

Employee Future Benefits Other Than Pension

Essex Power Corporation pays certain benefits on behalf of its retired employees. Information about the corporation's defined benefit plans is as follows:

	2010	2009
Opening balance	**$ 4,464,592**	$ 4,610,691
Current service and interest expense	**(81,804)**	(105,941)
Benefits paid for the period	**(102,651)**	(40,158)
	$ 4,280,137	$ 4,464,592

The main actuarial assumptions employed for the valuations are as follows:

General Inflation

Future general inflation levels, as measured by changes in the Consumer Price Index ("CPI"), were assumed at 2% in 2010 and thereafter.

Interest (Discount) Rate

The obligation as at December 31, 2010 of the present value of future liabilities and the expense for the year ended December 31, 2010 were determined using a discount rate of 5%. This corresponds to the assumed CPI rate plus an assumed real rate of return of 3%.

Salary Levels

Future general salary and wage levels were assumed to increase at 3.1% per annum.

Medical Costs

Medical costs were assumed to increase at the CPI rate plus a further increase of 9.67% in 2010.

Dental Costs

Dental costs were assumed to increase at the CPI rate plus a further increase of 5% in 2010 and thereafter.

11. Comparative Figures

Certain comparative figures have been reclassified to conform with the current year's presentation.

12. Capital Management

The CICA has adopted Section 1535, "Capital Disclosures", which was effective for the company in 2008. These new accounting standards will require the company to provide additional information about its capital. Essex Powerline's objectives are to maintain access to capital on a long term basis at reasonable rates and to deliver reasonable financial returns to the shareholders.

Essex Powerline's capital structure consists of shareholder's equity, retained earnings, long term debt, cash and cash equivalents. The capital structure as at December 31, 2010 was as follows:

	2010	2009
Long term debt payable within one year	**$ 3,724,979**	$ 2,950,600
Less: Cash and cash equivalents	**3,328,924**	10,240,908
Long term debt	**18,202,843**	19,710,999
	18,598,898	12,420,691
Common shares	**15,772,801**	15,772,801
Retained earnings	**1,143,865**	2,354,980
Total Equity	**16,916,666**	18,127,781
Total Capital	**35,515,564**	30,548,472
Debt to Capital Ratio	**52 %**	41 %

The company is required by TD Canada Trust to maintain a funded debt to capitalization ratio not to exceed 60%. At December 31, 2010, Essex Powerlines is in compliance with all of these covenants and limitations.

13. Financial Instruments

The corporation classifies its cash and cash equivalents as financial assets and liabilities held for trading and accounts receivable and other receivables are classified as loans and receivables each shown at fair value. Accounts payable, accrued liabilities and long term debt are classified as other liabilities and carried at amortized cost. Exposure to market risk, credit risk and liquidity risk arises in the normal course of the company's business.

Market Risk

Market risk refers primarily to the risk of loss that results from commodity prices, foreign exchange rates and interest rates. The company does not have commodity risk but does have foreign exchange risk as we enter into agreements with foreign companies to purchase materials. Essex is also exposed to fluctuations in interest rates from the market compared to interest rates that are allowed by the regulator in our customer rates. At this time this risk is not material.

Credit Risk

Essex is exposed to credit risk with its customers and their ability to pay. Essex's revenue is earned from a broad base of customers in different classes and as such, Essex does not rely on any one single customer for a significant amount of its revenues. As of December 31, 2010, there were no significant balances of accounts receivable owing from any single customer.

13. Financial Instruments (Cont'd)

Liquidity Risk

Liquidity risk refers to the company's ability to meet its financial obligations as they come due. Short term liquidity is provided through cash, cash equivalents and funds from operations. As of December 31, 2010, accounts payable of $ 10.6 million is expected to be paid at their carrying values within the next year. Interest payments owing on long term debt is also expected to be paid within the next year.

14. Supplementary Information

	2010	2009
Interest (paid)	$ (773,438)	$ (663,815)
(Payments) in lieu of corporate income taxes	(920,218)	(528,658)

15. Emerging Accounting Changes

International Financial Reporting Standards (IFRS)

On February 13, 2008, the Canadian Accounting Standards Board confirmed the publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2024. On September 10, 2010, the AcSB decided to permit rate-regulated entities to defer their IFRS implementation date to January 1, 2012. As such, the company will apply IFRS to its financial statements ending December 31, 2011 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2011, for comparative purposes.

16. Contingencies

The Essex Powerlines Corporation subscribes for liability insurance coverage under a self-insurance pool administered by the Municipal Electric Association Reciprocal Insurance Exchange. Under the terms of this co-operative venture the Corporation as a pool member, in addition to its regular policy premiums, is contingently liable for any retroactive reassessment if a deficit originates in a year in which they are a member. The contingent liability for reassessment in respect of any year in which the Corporation is a pool member continues even where the Utility subsequently withdraws from the self-insurance pool. The Corporation will not, however, be subject to reassessment for claims incurred in years in which they are not members of this self-insurance pool.

A letter of credit in the amount of $ 2,725,000 has been issued by the TD Bank to the credit of the Independent Electricity System Operator ("IESO") for the commodity purchases and market services provided. This letter of credit expires April 15, 2011 and is normally renewed annually.

A letter of credit in the amount of $ 32,997 has been issued by the TD Bank to the credit of the Minister of Finance, the Province of Ontario, for the obligations incurred or to be incurred under the Land Transfer Act. This letter of credit was cancelled and returned in February 2011.

16. Contingencies (Cont'd)

This action has been brought under the Class Proceedings Act. 1992. The plaintiff class seeks $500 million in restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities ("LDCs") who received late payment penalties which constitute interest at an effective rate in excess of 60% per year, contrary to section 347 of the Criminal Code. Pleadings have closed in this action. The action has not yet been certified as a class action and no discoveries have been held, as the parties were awaiting the outcome of a similar proceeding brought against Enbridge Gas Distribution Inc. (formerly Consumers Gas).

On April 22, 2004, the Supreme Court of Canada released a decision in the Consumers Gas case rejecting all of the defences which had been raised by Enbridge, although the Court did not permit the Plaintiff class to recover damages for any period prior to the issuance of the Statement of Claim in 1994 challenging the validity of late payment penalties. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge and that settlement was approved by the Ontario Superior Court.

In 2007, Enbridge filed an application to the OEB to recover the Court-approved amount and related amounts from ratepayers. On February 4, 2008 the OEB approved recovery of the said amounts from ratepayers over a five year period.

After the release by the Supreme Court of Canada of its 2004 decision in the Consumers Gas case. the plaintiffs in the LDC late payment penalties class action indicated their intention to proceed with their litigation against the LDCs. The settlement required Essex Powerlines to pay $75,618 to designated low income organizations. On February 22, 2011, the Ontario Energy Board approved the recovery of this amount from ratepayers over a one year period beginning May 1, 2011.

17. Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. The reconciliation between the statutory and effective tax rates is provided as follows:

	2010	2009
Income before provision for PILS	**$ 2,385,912**	$ 1,934,112
Federal and Ontario statutory income tax rate	**31.00 %**	33.00 %
Provision for PILs at statutory rate	**739,633**	638,257
Increase (decrease) resulting from:		
Amortization of deferred charge	**54,396**	57,906
Capital cost allowance in excess of depreciation and amortization	**(309,688)**	(59,251)
Cash payments in excess of employee future benefits other than pension expense.	**(57,181)**	(48,213)
Other	**(5,133)**	(6,178)
Net temporary differences	**(317,606)**	(55,736)
Total income tax provision for PILs	**422,027**	582,521
Effective income tax rate	**17.69 %**	30.12 %

Essex Powerlines Corporation

Financial Statements
December 31, 2011

April 19, 2012

Independent Auditor's Report

To the Shareholders of
Essex Powerlines Corporation

We have audited the accompanying financial statements of Essex Powerlines Corporation, which comprise the balance sheet as at December 31, 2011 and the statements of earnings, retained earnings and cash flows for the year then ended, and the related notes, which comprise 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 Canadian generally accepted accounting principles, 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.

Auditor's responsibility

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

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

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

PricewaterhouseCoopers LLP, Chartered Accountants
245 Ouellette Avenue, Suite 300, Windsor, Ontario, Canada N9A 7J4
T: +1 519 985 8900, F: +1 519 258 5457

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Essex Powerlines Corporation as at December 31, 2011 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Restated comparative information

Without modifying our opinion, we draw attention to note 18 to the financial statements, which explains that certain comparative information for the year ended December 31, 2010 has been restated. The financial statements of Essex Powerlines Corporation for the year ended December 31, 2010 were rep0rted on by another auditor who expressed an unmodified opinion on those financial statements on March 31, 2011.

As part of our audit of the financial statements of Essex Powerlines Corporation for the year ended December 31, 2011, we also audited the adjustments described in note 18 that were applied to restate the financial statements for the year ended December 31, 2010. In our opinion, such adjustments are appropriate and have been properly applied. We were not engaged to audit, review or apply any procedures to the financial statements of Essex Powerlines Corporation for the year ended December 31, 2010 other than with respect to the adjustments and, accordingly, we do not express an opinion or any other form of assurance on the financial statements for the year ended December 31, 2010 taken as a whole.

PricewaterhouseCoopers LLP

Chartered Accountants, Licensed Public Accountants

Essex Powerlines Corporation

Balance Sheet

As at December 31, 2011

	2011 $	Restated (note 18) 2010 $
Assets		
Current assets		
Cash	3,522,510	3,328,924
Accounts receivable	5,630,784	6,768,828
Prepaid expenses	220,818	177,668
Unbilled revenue	6,732,977	6,173,633
Income taxes recoverable	346,199	19,199
Inventory	60,000	60,000
	16,513,288	16,528,252
Property, plant and equipment (note 3)	39,082,804	37,042,304
Deferred charges (note 5)	1,803,428	2,237,720
Future income taxes (note 17 and 18)	2,496,000	3,579,000
	59,895,520	59,387,276
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	9,633,153	10,592,506
Due to affiliates (note 9)	5,412	30,492
Regulatory liabilities (note 4 and 18)	4,093,762	4,107,326
Dividends payable (note 9)	1,006,176	675,000
Current portion of customer deposits (note 6)	250,000	250,000
Current portion of long-term debt (note 7)	4,499,574	3,724,979
	19,488,077	19,380,303
Customer deposits (note 6)	732,195	607,327
Long-term debt (note 7)	16,659,031	18,202,843
Employee future benefits (note 10)	4,017,968	4,280,137
Accrued loss on interest rate swap (note 7 and 18)	711,860	521,045
Shareholder loan (note 9)	373,943	-
	41,983,074	42,991,655
Shareholders' Equity		
Capital stock (note 8)	15,772,801	15,772,801
Retained earnings	1,765,702	622,820
Solar equity reserve (appropriation of retained earnings) (note 9)	373,943	-
	17,912,446	16,395,621
	59,895,520	59,387,276

Contingencies (note 16)

Approved by the Board of Directors

_________________________________ Director _________________________________ Director

Essex Powerlines Corporation

Statement of Earnings

For the year ended December 31, 2011

	2011 $	Restated (note 18) 2010 $
Energy sales	62,303,894	59,856,257
Cost of Power purchased	51,143,998	49,232,444
Gross margin on service revenue	11,159,896	10,623,813
Other revenue from operations		
Solar generation	398,812	-
Miscellaneous revenue	1,617,674	1,730,201
Total other revenue	2,016,486	1,730,201
Expenses		
Billing and collecting	2,026,700	2,077,432
Administration and general	2,262,990	2,122,067
Distribution	2,431,338	2,296,797
Amortization	2,427,255	2,278,154
Bank charges and interest	1,152,689	1,268,934
Solar expense	35,901	-
Loss on currency exchange	41	36,067
Total expenses	10,336,914	10,079,451
Income from operations	2,839,468	2,274,563
Other revenue (expenses)		
Gain on disposal of property, plant and equipment	120,531	23,879
Unrealized loss on interest rate swap (note 7 and 18)	(190,815)	(58,152)
Interest income	136,817	87,470
Income before income taxes	2,906,001	2,327,760
Provision for income taxes		
Current (note 17)	383,000	422,027
Net income for the year	2,523,001	1,905,733

Essex Powerlines Corporation

Statement of Retained Earnings

For the year ended December 31, 2011

	2011 $	Restated (note 18) 2010 $
Retained earnings - Beginning of year	622,820	1,892,087
Net income for the year	2,523,001	1,905,733
Dividends	(1,006,176)	(3,175,000)
Appropriation of retained earnings to solar equity reserve (note 9)	(373,943)	-
Retained earnings - End of year	1,765,702	622,820

Essex Powerlines Corporation

Statement of Cash Flows

For the year ended December 31, 2011

	2011 $	Restated (note 18) 2010 $
Cash provided by (used in):		
Operating activities		
Net income for the year	2,523,001	1,905,733
Add items not involving cash		
Amortization of property, plant and equipment	2,427,255	2,171,058
Decrease (increase) in deferred charges	434,292	(3,031)
Decrease (increase) in future income taxes	1,083,000	(1,553,674)
Gain on disposal of property, plant and equipment	(120,531)	-
Decrease in employee future benefits	(262,169)	(184,455)
Increase (decrease) in regulatory liabilities	(13,564)	1,941,445
Unrealized loss on interest rate swap	190,815	58,152
Net change in non-cash working capital (note 14)	(319,839)	(93,022)
	5,942,260	4,242,206
Financing activities		
Dividends	(1,006,176)	(3,175,000)
Contributions in aid of construction	1,939,672	1,667,247
Decrease in long-term debt	(395,274)	(733,777)
	538,222	(2,241,530)
Investing activities		
Purchase of property, plant and equipment	(6,593,427)	(8,936,539)
Proceeds on disposal of property, plant and equipment	306,531	23,879
	(6,286,896)	(8,912,660)
Increase (decrease) in cash during the year	193,586	(6,911,984)
Cash - Beginning of year	3,328,924	10,240,908
Cash - End of year	3,522,510	3,328,924
Supplementary cash flow information		
Interest paid	1,136,386	773,438
Payments in lieu of corporate income taxes	710,000	920,218

1 Nature of business

Essex Powerlines Corporation (the "Company") serves as the rate regulated "local distribution company" (LDC) which provides safe and reliable power to over 27,000 residents and businesses in Amherstburg, LaSalle, Leamington and Tecumseh. Essex Power Corporation holds 100% of the shares of the Company. The shareholders of Essex Power Corporation include the Town of Amherstburg, the Town of LaSalle, the Municipality of Leamington and the Town of Tecumseh. The municipal owners of Essex Power Corporation also hold debt directly with the Company (see note 7).

The Ontario Government enacted the Energy Competition Act, 1998 to introduce competition to the Ontario electricity market. Under the terms of the legislation, the Ontario Energy Board ("OEB") will regulate industry participants by issuing licenses for the right to generate, transmit, distribute or retail electricity. These licenses require compliance with established market rules and codes.

The distribution revenues include a distribution tariff, which is based on OEB approved rates. The distribution tariff rates are set based on an approved revenue requirement that provides cost recovery and includes a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory assets and liabilities over a specified timeframe.

2 Summary of significant accounting policies

Basis of presentation

The financial statements have been prepared by management in accordance with accounting principles generally accepted in Canada for electric utilities.

Property, plant and equipment

Property, plant and equipment are stated at cost less applicable rebates, accumulated amortization and contributions in aid of construction. Cost is comprised of materials, labour, engineering costs and overheads. Amortization is determined on a straight-line basis over the estimated useful lives of the assets.

Land rights	50 years
Buildings and fixtures	25 years
Transmission and distribution equipment	25 years
Computer hardware, software and other equipment	5 years
Office equipment	10 years
Utility equipment and trucks	5 - 8 years
Solar generation	20 years

In the year of addition, a half year of amortization is claimed. When specifically identifiable items are retired or otherwise disposed of, their original cost and accumulated amortization are removed from the accounts and the related gain or loss is included in income in the year of disposal.

Inventory

Inventories consist principally of construction and maintenance materials and are stated at the lower of cost and net realizable value, with cost determined on an average cost basis. The Company includes certain major standby equipment as in-service property, plant and equipment and depreciates these assets over their useful lives.

Contributions in aid of construction

Contributions in aid of construction are non-refundable contributions of property, plant and equipment made by developers or subdividers which become part of the distribution system. They are recorded as a reduction of the related asset values. These amounts will be amortized on the same basis as the related property, plant and equipment.

Revenue recognition

In accordance with OEB regulations, the Company recognizes as revenue the regulated distribution tariffs associated with energy distributed. Variances between energy purchase costs and energy bills are recorded as regulatory assets or liabilities for future distribution rate application consideration.

The Company follows the practice of cycle billing of customers' accounts and revenue is recognized in the period billed. An accrual is made in the accounts at December 31 for power supplied but not billed to customers between the date the meters were last read and the end of the year.

Accounting for rate regulated operations

The Accounting Standards Board (AcSB) accounting guideline 19 - Disclosures by Entities Subject to Rate Regulation, is applicable to the Company. The guideline requires disclosure of the effect of removing regulatory assets and liabilities and what the effect would be on the financial statements in the absence of rate regulation. The effects will be disclosed in any applicable notes to the financial statements.

Income taxes - payments in lieu

Income taxes are to be calculated in accordance with the rules for computing income, capital and other taxes provided for in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Energy Act and related regulations. After October 1, 2001 the Company is required to compute and remit to the Ontario Electricity Financing Corporation (OEFC) payments in lieu of corporate taxes.

Effective January 1, 2009, the Company adopted amendments to the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3465 - Income Taxes and CICA Handbook Section 1100 - Generally Accepted Accounting Principles. These amended sections establish standards for the recognition, measurement, presentation and disclosure of future income tax assets and liabilities of rate regulated enterprises.

For transactions and events that cause temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, the Company recognized future income tax assets and liabilities, and corresponding regulatory liabilities and assets, as a result of adopting these amended standards on January 1, 2009.

Current income taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at the amounts receivable from or payable to the OEFC.

Future income taxes

Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely that not that they be realized from taxable profits available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantially enacted by the balance sheet.

The Company has recognized regulatory assets and liabilities which correspond to future income taxes that flow through the rate-making process.

Post employment benefits

The Company pays certain post retirement benefits on behalf of its retired employees. The Company recognizes these post retirement costs in the period in which the employees rendered the services. The net periodic benefit cost for the year ended December 31, 2011 was determined by actuarial valuation using a discount rate of 4.75%. The actuarial valuation is required to be completed once every 3 years.

Measurement uncertainty

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of financial statements. Certain estimates also required, as regulations which will ultimately determine the actual results have yet to be finalized and are dependent on the completion of regulatory proceedings or decisions. Due to these uncertainties, actual results might differ from those estimates and the impact will be recorded in the current period when the actual results are known.

Regulatory accounting

The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. The Company assesses the likelihood of recovery of each of its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

3 Property, plant and equipment

			2011
	Cost **$**	**Accumulated amortization** **$**	**Net** **$**
Land and land rights	347,008	7,066	339,942
Buildings and fixtures	1,633,771	299,898	1,333,873
Transmission and distribution equipment	46,552,355	16,735,303	29,817,052
Computer hardware, software and other equipment	1,252,371	725,516	526,855
Office equipment	159,415	94,431	64,984
Utility equipment and trucks	1,740,023	499,985	1,240,038
Construction in progress	1,718,184	-	1,718,184
Solar generation	4,161,535	119,659	4,041,876
	57,564,662	18,481,858	39,082,804

			2010
	Cost **$**	**Accumulated amortization** **$**	**Net** **$**
Land and land rights	335,598	5,000	330,598
Buildings and fixtures	1,607,140	235,080	1,372,060
Transmission and distribution equipment	44,228,741	15,006,722	29,222,019
Computer hardware, software and other equipment	1,289,100	552,933	736,167
Office furniture and equipment	159,415	79,371	80,044
Utility equipment and trucks	1,479,071	416,590	1,062,481
Construction in progress	1,197,156	-	1,197,156
Solar generation	3,041,779	-	3,041,779
	53,338,000	16,295,696	37,042,304

4 Regulatory (assets) liabilities

Regulatory assets and liabilities are a result of differences between costs charged to the Company and allowed rates charged to customers which are classified as "retail settlement variances". Also included are smart meter costs, deferred payments in lieu of income taxes and extraordinary event losses. These are referred to as "non-retail settlement variances".

	2011 $	Restated (note 18) 2010 $
a) Retail settlement variances	2,151,908	1,732,715
b) Extraordinary event costs - ice storm	(91,943)	(91,943)
c) Retail cost and other variances	(98,993)	(250,395)
d) Regulatory assets recovered	1,266,429	1,587,284
e) Smart meter variance	(1,629,639)	(2,449,335)
f) Future income taxes	2,496,000	3,579,000
	4,093,762	4,107,326

a) Retail settlement variances represent amounts accumulated since the opening of the electricity market and are comprised of variances between amounts charged by the Independent Electricity System Operator for the operation of the wholesale electricity market and the cost of electricity, amounts from Hydro One for network and line and transformation charges and amounts billed to customers. In the absence of rate regulation, income before tax would be higher by $419,193.

b) Extraordinary event costs represent costs incurred to restore services following storms in 2005 and 2010. In the absence of rate regulation, income before taxes would not have changed.

c) Retail cost and other variances represent amounts for costs incurred by the Company to serve customers that have been enrolled by a commodity retailer and for miscellaneous other costs that will be recovered from customers. In the absence of rate regulation, income before taxes would be higher by $151,402.

d) Regulatory assets recovered represent amounts collected from customers through rates until April 30, 2013. These amounts will be held until approved by the Ontario Energy Board to be refunded to or recovered from customers. In the absence of rate regulation, income before taxes would be lower by $320,844.

e) The smart meter variance represents costs to install smart meters and interim smart meter recovery amounts paid by customers. These amounts will continue to be recovered from customers until the end of April 2012 when an adjustment will be made to include this cost in regular rates. In the absence of rate regulation, net assets would be higher by $3,262,031 and net income would be higher by $819,696.

f) The future income taxes liability is the result of the application of CICA Handbook Section 3465, Income Taxes, that was amended to require the recognition of future income tax liabilities and assets for regulated enterprises that were previously not subject to these provisions. The future income taxes liability is the amount that will be refunded to customers through future rates. In the absence of rate regulation, net assets would be higher by $2,496,000.

5 Deferred charges

Deferred charges include the excess of the amounts paid to the shareholders less the net assets transferred to the Company. These amounts are being amortized on a straight-line basis over the average remaining service life of the assets transferred. The deferred charges also include the Springboard Health & Safety management system development and implementation and miscellaneous deferred debits.

	2011	**2010**
	$	**$**
Deferred charges	2,885,228	2,813,166
Less: Accumulated amortization	1,081,800	575,446
	1,803,428	2,237,720

6 Customer deposits

Customer deposits are amounts received and held as security for energy consumption. A customer deposit is refunded after a specified period of good payment history. Interest is to be paid annually at the average yearly savings interest rate.

7 Long-term debt

	2011 $	2010 $
Related party long-term loan payable is repayable as approved by the Board of Directors not to exceed 20% of the principal lending amount if funds are available as determined each July. Interest is payable at a stated interest rate of 6%. The agreement expires effective December 31, 2012. The debt is owing to two of the four shareholders of the parent company as follows:		
Municipality of Leamington	2,150,296	2,150,296
Town of Tecumseh	1,544,408	1,544,408
	3,694,704	3,694,704
Mortgage payable - Woodslee Credit Union is repayable in blended monthly payments of $8,793 bearing an interest rate of 5.9% and is secured by land and buildings at 2730 Highway #3, RR# 1, Tecumseh. Mortgage matures September 19, 2013.	587,647	656,713
Banker's acceptance - TD Canada Trust. It is the intention of the Board of Directors that this remain a long-term debt.	3,000,000	3,000,000
Banker's acceptance - TD Canada Trust. It is the intention of the Board of Directors that this remain a long-term debt.	3,300,000	3,300,000
Fixed rate loan - TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $39,562, bearing an interest rate of 4.99%. Loan matures November 9, 2019.	5,615,471	5,804,859
Fixed rate loan - TD Canada Trust is a 10 year term loan with a 10 year amortization schedule, repayable in blended monthly payments of $62,122, bearing an interest rate of 4.48%. Loan matures November 9, 2019.	4,960,783	5,471,546
	21,158,605	21,927,822
Less: Current portion of long-term debt	4,499,574	3,724,979
	16,659,031	18,202,843

Approximate long-term principal repayments over five years are as follows:

	$
2012	4,499,574
2013	825,439
2014	767,919
2015	841,855
2016	880,587

In addition to the Bankers Acceptances with TD Canada Trust, the Company has entered into two interest rate swap agreements with TD Securities. The swap agreements are both 10 year agreements, with the agreement for the notional amount of $3,000,000 maturing on June 3, 2013 and the agreement for the notional amount of $3,300,000 maturing on November 4, 2018. Both of these agreements are “receive variable, pay fixed” swap agreements, which effectively convert variable interest rates on Bankers Acceptances to an effective interest rate of 5.8% and 4.69%, respectively.

The swap agreement entered into with TD Securities do not meet the standards to apply hedge accounting. Accordingly, the interest rate swap contracts are marked to market at year end with the unrealized gain or loss recorded in the statement of earnings. The unrealized loss recorded in 2011 was $190,815 (2010 - $58,152).

8 Capital stock

Authorized

An unlimited number of common shares, Class A, voting.
An unlimited number of common shares, Class B, non- voting.

Issued

	2011 $	2010 $
50 common shares, Class A, voting	5	5
15,772,796 common shares, Class B, non-voting	15,772,796	15,772,796
	15,772,801	15,772,801

9 Related party transactions

The Company engages in transactions with its affiliates and parent company. The following is a summary of the related party transactions. These transactions are measured at exchange amount, which is the amount of consideration established and agreed to by the related parties. The Company is affiliated with Essex Power Services Corporation, Essex Energy Corporation and Utilismart Corporation and is the subsidiary of Essex Power Corporation.

	2011 $	2010 $
Service fees due to affiliate	12,133	12,000
Management fees due to parent	1,142,371	1,204,987
Amounts due to affiliates	5,412	30,492
Dividends payable to parent	1,006,176	675,000

Related party long-term debt payable with the shareholders of Essex Power Corporation is outlined in note 7. The Company was charged interest on the long-term debt by the Essex Power Corporation shareholders in the amount of $223,484.

In the current year, the Company received a non-interest bearing loan from its shareholder for $373,943, with no set repayment terms. The same amount was classified as an appropriation of retained earnings as a solar equity reserve.

10 Employee future benefits

Pension plan

The Company provides a pension plan for its full time employees through Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province for employees of municipalities, local boards and school boards in Ontario. Both participating employers and employees are required to make plan contributions based on participating employees' contributory earnings. The Company recognized the expense related to this plan as contributions are made. For the year ended December 31, 2011, the Company's OMERS current service pension costs were $220,482 (2010 - $250,776).

Employee future benefits other than pension

The Company pays certain benefits on behalf of its retired employees. Information about the Company's defined benefit plans is as follows:

	2011 $	2010 $
Opening balance at beginning of year	4,280,137	4,464,592
Current service and interest expense net of amortization of plan losses (gains)	(139,125)	(81,804)
Contributions made in the period	(123,044)	(102,651)
	4,017,968	4,280,137

The main actuarial assumptions employed for the valuations are as follows:

General inflation
Future general inflation levels, as measured by changes in the Consumer Price Index ("CPI"), were assumed at 2% in 2011 and thereafter.

Interest (discount) rate
The obligation as at December 31, 2011 of the present value of future liabilities and the expense for the year ended December 31, 2011 were determined using a discount rate of 4.75%.

Salary levels
Future general salary and wage levels were assumed to increase at 2% per annum.

Medical costs
Medical costs were assumed to increase at the CPI rate plus a further increase of 4.5% in 2012.

Dental costs
Dental costs were assumed to increase at the CPI rate plus a further increase of 4.5% in 2012.

11 Prior year figures

Certain prior year figures have been reclassified to conform to the financial statement presentation adopted in the current year.

12 Capital management

The Company's objectives are to maintain access to capital on a long-term basis at reasonable rates and to deliver reasonable financial returns to the shareholders.

The Company's capital structure consists of shareholders' equity, retained earnings, solar equity reserve, long-term debt and cash. The capital structure as at December 31, 2011 was as follows:

	2011 $	Restated (note 18) 2010 $
Long-term debt payable within one year	4,499,574	3,724,979
Less: Cash	(3,522,510)	(3,328,924)
Long-term debt	16,659,031	18,202,843
Net long-term debt	17,636,095	18,598,898
Common shares	15,772,801	15,772,801
Retained earnings	1,765,702	622,820
Solar equity reserve	373,943	-
Total equity	17,912,446	16,395,621
Total capital	35,548,541	34,994,519
Debt to capital ratio	50%	53%

The Company is required by TD Canada Trust to maintain a funded debt to capitalization ratio not to exceed 60%. At December 31, 2011, the Company is in compliance with these covenants and limitations.

13 Financial instruments

The Company classifies its cash as held for trading and accounts receivable and other receivables are classified as loans and receivables, with each carried at fair value. Accounts payable, accrued liabilities, amounts due to affiliates, dividends payable, customer deposits and long-term debt are classified as other liabilities and carried at amortized cost. Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market risk

Market risk refers primarily to the risk of loss that results from fluctuations in commodity prices, foreign exchange rates and interest rates. The Company does not have significant commodity risk or foreign exchange risk. The Company is exposed to fluctuations in interest rates from the market compared to interest rates that are allowed by the regulator in customer rates. As further defined in note 7 to these financial statements, the

Company uses derivative financial instruments, primarily interest rate swaps, to manage its interest rate exposure.

The Company has adopted CICA Handbook Sections 3855 and 3861, Financial Instruments for disclosure purposes.

Credit risk

The Company is exposed to credit risk with its customers and their ability to pay. The Company's revenue is earned from a broad base of customers in different classes and as such, the Company does not rely on any one single customer for a significant amount of its revenues. As of December 31, 2011, there were no significant balances of accounts receivable owing from any single customer.

Liquidity risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Short-term liquidity is provided through cash and funds from operations. As of December 31, 2011, accounts payable of $9,633,153, current portion of customer deposits of $250,000 and current portion of long-term debt of $4,499,574 are expected to be paid at their carrying values within the next year. Interest payments owing on long-term debt is also expected to be paid within the next year.

14 Net change in non-cash working capital

The net change in non-cash working capital balances related to operations consists of the following:

	2011 $	2010 $
Decrease (increase) in current assets		
Accounts receivable	1,138,044	(1,675,198)
Prepaid expenses	(43,150)	24,523
Unbilled revenue	(559,344)	147,512
Income taxes recoverable	(327,000)	(19,199)
	208,550	(1,522,362)
Increase (decrease) in current liabilities		
Accounts payable and accrued liabilities	(959,353)	1,659,901
Due to affiliates	(25,080)	(148,653)
Income taxes payable	-	(24,041)
Dividends payable	331,176	(48,258)
Customer deposits	124,868	(9,609)
	(528,389)	1,429,340
	(319,839)	(93,022)

15 Emerging accounting changes

International Financial Reporting Standards (IFRS)

On February 13, 2008, the Accounting Standards Board confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2012. On September 10, 2010, the AcSB decided to permit rate-regulated entities to defer their IFRS implementation date to January 1, 2012. As such, the Company will apply IFRS to its financial statements ending December 31, 2011 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2011, for comparative purposes.

16 Contingencies

The Company subscribes for liability insurance coverage under a self-insurance pool administered by the Municipal Electric Association Reciprocal Insurance Exchange. Under the terms of this co-operative venture, the Company as a pool member, in addition to its regular policy premiums, is contingently liable for any retroactive reassessment if a deficit originates in a year in which they are a member. The contingent liability for reassessment in respect of any year in which the Company is a pool member continues even where the Company subsequently withdraws from the self-insurance pool. The Company will not, however, be subject to reassessment for claims incurred in years in which they are not members of this self-insurance pool.

A letter of credit in the amount of $2,725,000 has been issued by TD Canada Trust to the credit of the Independent Electricity System Operator ("IESO") for the commodity purchases and market services provided. This letter of credit expires April 15, 2012 and is normally renewed annually.

17 Provision for payments in lieu of corporate income taxes

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. The reconciliation between the statutory and effective tax rates is provided as follows:

	2011 **$**
Income before provision for PILs	2,906,001
Federal and Ontario statutory income tax rate	26.50%
Provision for PILs at statutory rate	770,090
Increase (decrease) resulting from:	
Net temporary differences	(435,074)
Amortization of deferred charge	46,500
Other non-temporary differences	1,484
Total income tax provision for PILs	383,000
Effective income tax rate	13.18%

18 Restated comparative information

Certain comparative information for the year ended December 31, 2010 has been restated to correct an error relating to derivative interest rate swap contracts that were not designated as hedges in accordance with the relevant accounting standards. CICA Handbook, Part V, Section 3855: Financial Instruments - Recognition and Measurement requires derivative interest rate swap contracts that were not formally designated as hedges to be recognized in the balance sheet at fair value with changes in fair value between periods recorded through net income.

The comparative information for the year ended December 31, 2010 has also been restated to correct an error relating to future income taxes. Future income tax assets recorded in the comparative financial statements have been increased by $2,703,107 to recognize the future tax effect of the temporary difference relating to employee future benefits, accrued loss on interest rate swap and other temporary differences. A corresponding adjustment has been recorded to restate regulatory liabilities accordingly.

The correction of this error has been applied retrospectively for comparative purposes. The adjustments that have been applied to retained earnings as at December 31, 2009 and to net income, accrued loss on interest rate swap, future income taxes and regulatory liabilities for the year ended December 31, 2010 are as follows:

	$
Retained earnings as at December 31, 2009, as previously reported	2,354,980
Recognition of unrealized loss on interest rate swap	(462,893)
Restated retained earnings as at December 31, 2009	1,892,087
Net income for the year ended December 31, 2010, as previously reported	1,963,885
Recognition of unrealized loss on interest rate swap	(58,152)
Restated net income for the year ended December 31, 2010	1,905,733
Accrued loss on interest rate swap as at December 31, 2010, as previously reported	-
Recognition of accrued loss on interest rate swap	521,045
Restated accrued loss on interest rate swap as at December 31, 2010	521,045
Future income taxes as at December 31, 2010, as previously reported	875,893
Recognition of future tax effect relating to employee future benefits	2,703,107
Restated future income taxes as at December 31, 2010	3,579,000
Regulatory liabilities as at December 31, 2010, as previously reported	1,404,219
Recognition of regulatory liability relating to additional FIT asset	2,703,107
Restated regulatory liabilities as at December 31, 2010	4,107,326

Essex Powerlines Corporation

Financial Statements
December 31, 2012

pwc

April 10, 2013

Independent Auditor's Report

To the Shareholders of
Essex Powerlines Corporation

We have audited the accompanying financial statements of Essex Powerlines Corporation, which comprise the balance sheet as at December 31, 2012 and the statements of earnings, retained earnings and cash flows for the year then ended, and the related notes, which comprise 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 Canadian generally accepted accounting principles, 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.

Auditor's responsibility

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

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

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

PricewaterhouseCoopers LLP
245 Ouellette Avenue, Suite 300, Windsor, Ontario, Canada N9A 7J4
T: +1 519 985 8900, F: +1 519 258 5457

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Essex Powerlines Corporation as at December 31, 2012 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants, Licensed Public Accountants

Essex Powerlines Corporation
Balance Sheet
As at December 31, 2012

	2012 $	2011 $
Assets		
Current assets		
Cash	3,969,160	3,522,510
Accounts receivable	6,158,751	5,630,784
Due from affiliates (note 9)	187,334	-
Prepaid expenses	229,700	220,818
Unbilled revenue	5,002,399	6,732,977
Income taxes recoverable	87,390	346,199
Inventory	60,000	60,000
	15,694,734	16,513,288
Property, plant and equipment (note 3)	42,002,013	39,082,804
Deferred charges (note 5)	1,369,625	1,803,428
Future income taxes (note 4 and 17)	2,266,000	2,496,000
	61,332,372	59,895,520
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	9,376,279	9,633,153
Due to affiliates (note 9)	-	5,412
Regulatory liabilities (note 4)	3,414,393	4,093,762
Dividends payable (note 9)	990,718	1,006,176
Current portion of customer deposits (note 6)	250,000	250,000
Current portion of long-term debt (note 7)	5,121,181	4,499,574
	19,152,571	19,488,077
Customer deposits (note 6)	993,716	732,195
Long-term debt (note 7)	17,232,555	16,659,031
Employee future benefits (note 10)	3,954,070	4,017,968
Accrued loss on interest rate swap (notes 7 and 13)	508,301	711,860
Shareholder loan (note 9)	581,681	373,943
	42,422,894	41,983,074
Shareholders' Equity		
Capital stock (note 8)	15,772,801	15,772,801
Retained earnings	2,554,996	1,765,702
Solar equity reserve (appropriation of retained earnings) (note 9)	581,681	373,943
	18,909,478	17,912,446
	61,332,372	59,895,520

Contingencies (note 16)

Approved by the Board of Directors

______________________ Director ______________________ Director

The accompanying notes are an integral part of these financial statements.

Essex Powerlines Corporation

Statement of Earnings

For the year ended December 31, 2012

	2012 $	2011 $
Energy sales	63,513,633	62,303,894
Cost of power purchased	52,404,547	51,143,998
Gross margin on service revenue	11,109,086	11,159,896
Other revenue from operations		
Solar generation	590,368	398,812
Miscellaneous revenue	1,557,787	1,617,674
Total other revenue	2,148,155	2,016,486
Expenses		
Billing and collecting	2,022,808	2,026,700
Administration and general	2,395,331	2,262,990
Distribution	2,993,439	2,431,338
Amortization	2,722,513	2,427,255
Bank charges and interest	1,222,719	1,152,689
Solar expense	49,173	35,901
Loss on currency exchange	11	41
Total expenses	11,405,994	10,336,914
Income from operations	1,851,247	2,839,468
Other revenue (expenses)		
Gain on disposal of property, plant and equipment	37,915	120,531
Unrealized gain (loss) on interest rate swap (notes 7 and 13)	203,559	(190,815)
Interest income	163,754	136,817
Income before income taxes	2,256,475	2,906,001
Provision for income taxes		
Current income tax expense (note 17)	266,000	383,000
Net income for the year	1,990,475	2,523,001

The accompanying notes are an integral part of these financial statements.

Essex Powerlines Corporation

Statement of Retained Earnings

For the year ended December 31, 2012

	2012 $	2011 $
Retained earnings - Beginning of year	1,765,702	622,820
Net income for the year	1,990,475	2,523,001
Dividends	(993,443)	(1,006,176)
Appropriation of retained earnings to solar equity reserve (note 9)	(207,738)	(373,943)
Retained earnings - End of year	2,554,996	1,765,702

The accompanying notes are an integral part of these financial statements.

Essex Powerlines Corporation

Statement of Cash Flows

For the year ended December 31, 2012

	2012 $	2011 $
Cash provided by (used in):		
Operating activities		
Net income for the year	1,990,475	2,523,001
Add items not involving cash		
Amortization of property, plant and equipment	2,722,513	2,427,255
Decrease in deferred charges	433,803	434,292
Decrease in future income taxes	230,000	1,083,000
Gain on disposal of property, plant and equipment	(37,915)	(120,531)
Decrease in employee future benefits	(63,898)	(262,169)
Decrease in regulatory liabilities	(679,369)	(13,564)
Unrealized (gain) loss on interest rate swap	(203,559)	190,815
Net change in non-cash working capital (note 14)	1,264,439	(651,015)
	5,656,489	5,611,084
Financing activities		
Dividends	(1,008,901)	(675,000)
Contributions in aid of construction	869,852	1,939,672
Increase in long-term debt	2,207,738	373,943
Repayment of long-term debt	(804,869)	(769,217)
	1,263,820	869,398
Investing activities		
Purchase of property, plant and equipment	(6,540,740)	(6,593,427)
Proceeds on disposal of property, plant and equipment	67,081	306,531
	(6,473,659)	(6,286,896)
Increase in cash during the year	446,650	193,586
Cash - Beginning of year	3,522,510	3,328,924
Cash - End of year	3,969,160	3,522,510
Supplementary cash flow information		
Interest paid	1,149,554	1,136,386
Payments in lieu of corporate income taxes	328,000	710,000

The accompanying notes are an integral part of these financial statements.

1 Nature of business

Essex Powerlines Corporation (the Company) serves as the rate regulated "local distribution company" (LDC) which provides safe and reliable power to over 28,000 residents and businesses in Amherstburg, LaSalle, Leamington and Tecumseh. Essex Power Corporation holds 100% of the shares of the Company. The shareholders of Essex Power Corporation include the Town of Amherstburg, the Town of LaSalle, the Municipality of Leamington and the Town of Tecumseh. The municipal owners of Essex Power Corporation also hold debt directly with the Company (see note 7).

The Ontario Government enacted the Energy Competition Act, 1998 to introduce competition to the Ontario electricity market. Under the terms of the legislation, the Ontario Energy Board (OEB) will regulate industry participants by issuing licenses for the right to generate, transmit, distribute or retail electricity. These licenses require compliance with established market rules and codes.

The distribution revenues include a distribution tariff, which is based on OEB approved rates. The distribution tariff rates are set based on an approved revenue requirement that provides cost recovery and includes a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory assets and liabilities over a specified timeframe.

2 Summary of significant accounting policies

Basis of presentation

The financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles for electric utilities.

Property, plant and equipment

Property, plant and equipment are stated at cost less applicable rebates, accumulated amortization and contributions in aid of construction. Cost is comprised of materials, labour, engineering costs and overheads. Amortization is determined on a straight-line basis over the estimated useful lives of the assets.

Land rights	50 years
Buildings and fixtures	25 years
Transmission and distribution equipment	25 years
Computer hardware, software and other equipment	5 years
Office equipment	10 years
Utility equipment and trucks	5 - 8 years
Solar generation	20 years

In the year of addition, a half year of amortization is claimed. When specifically identifiable items are retired or otherwise disposed of, their original cost and accumulated amortization are removed from the accounts and the related gain or loss is included in income in the year of disposal.

Inventory

Inventories consist principally of construction and maintenance materials and are stated at the lower of cost and net realizable value, with cost determined on an average cost basis. The Company includes certain major standby equipment as in-service property, plant and equipment and depreciates these assets over their useful lives.

Contributions in aid of construction

Contributions in aid of construction are non-refundable contributions of property, plant and equipment made by developers or subdividers which become part of the distribution system. They are recorded as a reduction of the related asset values. These amounts will be amortized on the same basis as the related property, plant and equipment.

Revenue recognition

In accordance with OEB regulations, the Company recognizes as revenue the regulated distribution tariffs associated with energy distributed. Variances between energy purchase costs and energy bills are recorded as regulatory assets or liabilities for future distribution rate application consideration.

The Company follows the practice of cycle billing of customers' accounts and revenue is recognized in the period billed. An accrual is made in the accounts at December 31 for power supplied but not billed to customers between the date the meters were last read and the end of the year.

Accounting for rate regulated operations

The Accounting Standards Board (AcSB) accounting guideline 19 - Disclosures by Entities Subject to Rate Regulation, is applicable to the Company. The guideline requires disclosure of the effect of removing regulatory assets and liabilities and what the effect would be on the financial statements in the absence of rate regulation. The effects are disclosed in note 4.

Income taxes - payments in lieu

Income taxes are to be calculated in accordance with the rules for computing income, capital and other taxes provided for in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Energy Act and related regulations. After October 1, 2001 the Company is required to compute and remit to the Ontario Electricity Financing Corporation (OEFC) payments in lieu of corporate taxes.

Effective January 1, 2009, the Company adopted amendments to the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3465 - Income Taxes and CICA Handbook Section 1100 - Generally Accepted Accounting Principles. These amended sections establish standards for the recognition, measurement, presentation and disclosure of future income tax assets and liabilities of rate regulated enterprises.

For transactions and events that cause temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, the Company recognized future income tax assets and liabilities, and corresponding regulatory liabilities and assets, as a result of adopting these amended standards on January 1, 2009.

Current income taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at the amounts receivable from or payable to the OEFC.

Future income taxes

Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely that not that they be realized from taxable profits available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantially enacted by the balance sheet date.

The Company has recognized regulatory assets and liabilities which correspond to future income taxes that flow through the rate-making process.

Post employment benefits

The Company pays certain post retirement benefits on behalf of its retired employees. The Company recognizes these post retirement costs in the period in which the employees rendered the services. The net periodic benefit cost for the year ended December 31, 2012 was determined by actuarial valuation using a discount rate of 4.75%. The actuarial valuation is required to be completed once every 3 years and was last done in December 2011. All actuarial gains and losses are amortized over the employee's average remaining service life which has been determined to be 9.8 years at December 31, 2012. As this liability is only for post employment benefits, there are no plan assets.

Measurement uncertainty

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities. Certain estimates are also required, as regulations which will ultimately determine the actual results have yet to be finalized and are dependent on the completion of regulatory proceedings or decisions. Due to these uncertainties, actual results might differ from those estimates and the impact will be recorded in the current period when the actual results are known.

Regulatory accounting

The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. The Company assesses the likelihood of recovery of each of its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Financial instruments

The Company classifies its cash as held for trading which is carried at fair value and accounts receivable and due from affiliates are classified as loans and receivables, which are initially recognized at fair value and subsequently measured at amortized cost. Accounts payable, accrued liabilities, dividends payable, customer deposits and long-term debt are classified as other liabilities and carried at amortized cost.

The interest rate swap agreements do not meet the criteria to apply hedge accounting. Accordingly, the interest rate swap contracts are marked to market at year-end with the unrealized gain or loss recorded in the statement of earnings. Refer to note 13 for details.

3 Property, plant and equipment

			2012
	Cost **$**	**Accumulated amortization** **$**	**Net** **$**
Land and land rights	353,183	9,473	343,710
Buildings and fixtures	2,394,956	379,580	2,015,376
Transmission and distribution equipment	51,601,861	18,732,642	32,869,219
Computer hardware, software and other equipment	1,492,518	942,773	549,745
Office equipment	180,245	105,977	74,268
Utility equipment and trucks	1,989,536	572,262	1,417,274
Construction in progress	846,344	-	846,344
Solar generation	4,260,595	374,518	3,886,077
	63,119,238	21,117,225	42,002,013

			2011
	Cost $	Accumulated amortization $	Net $
Land and land rights	347,008	7,066	339,942
Buildings and fixtures	1,633,771	299,898	1,333,873
Transmission and distribution equipment	46,552,355	16,735,303	29,817,052
Computer hardware, software and other equipment	1,252,371	725,516	526,855
Office equipment	159,415	94,431	64,984
Utility equipment and trucks	1,740,023	499,985	1,240,038
Construction in progress	1,718,184	-	1,718,184
Solar generation	4,161,535	119,659	4,041,876
	57,564,662	18,481,858	39,082,804

4 Regulatory (assets) liabilities

Regulatory assets and liabilities are a result of differences between costs charged to the Company and allowed rates charged to customers which are summarized below.

	2012 $	2011 $
a) Retail settlement variances	3,105,281	2,151,908
b) Extraordinary event costs - ice storm	(83,110)	(91,943)
c) Retail cost and other variances	(143,211)	(98,993)
d) Regulatory assets recovered	(283,795)	1,266,429
e) Smart meter variance	(1,446,772)	(1,629,639)
f) Future income taxes	2,266,000	2,496,000
	3,414,393	4,093,762

a) Retail settlement variances represent amounts accumulated since the opening of the electricity market and are comprised of variances between amounts charged by the Independent Electricity System Operator for the operation of the wholesale electricity market and the cost of electricity, amounts from Hydro One for network and line and transformation charges and amounts billed to customers. In the absence of rate regulation, income before tax would be higher by $953,373.

b) Extraordinary event costs represent costs incurred to restore services following storms in 2005 and 2010. In the absence of rate regulation, income before taxes would be higher by $8,833.

c) Retail cost and other variances represent amounts for costs incurred by the Company to serve customers that have been enrolled by a commodity retailer and for miscellaneous other costs that will be recovered from customers. In the absence of rate regulation, income before taxes would be lower by $44,218.

d) Regulatory assets recovered represent amounts collected from customers through rates until April 30, 2013. These amounts will be held until approved by the OEB to be refunded to or recovered from customers. In the absence of rate regulation, income before taxes would be lower by $1,550,224.

e) The smart meter variance represents costs to install smart meters and interim smart meter recovery amounts paid by customers. These amounts will continue to be recovered from customers until the end of April 2012 when an adjustment will be made to include this cost in regular rates. In the absence of rate regulation, net assets would be higher by $17,963 and net income would be higher by $249,466.

f) The future income taxes liability is the result of the application of CICA Handbook Section 3465, Income Taxes, that was amended to require the recognition of future income tax liabilities and assets for regulated enterprises that were previously not subject to these provisions. The future income taxes liability is the amount that will be refunded to customers through future rates. In the absence of rate regulation, net assets would be lower by $2,266,000.

5 Deferred charges

Deferred charges include the excess of the amounts paid to the shareholders less the net assets transferred to the Company. These amounts are being amortized on a straight-line basis over the average remaining service life of the assets transferred. The deferred charges also include the Springboard Health & Safety management system development and implementation and miscellaneous deferred debits.

	2012 $	2011 $
Deferred charges	2,586,772	2,885,228
Less: Accumulated amortization	1,217,147	1,081,800
	1,369,625	1,803,428

6 Customer deposits

Customer deposits are amounts received and held as security for energy consumption. A customer deposit is refunded after a specified period of good payment history. Interest is to be paid annually at the prime business rate less 2%.

7 Long-term debt

	2012 $	2011 $
Related party long-term loan payable is repayable as approved by the Board of Directors not to exceed 20% of the principal lending amount if funds are available as determined each March. Interest is payable at a stated interest rate of 4%. The agreement expires effective December 31, 2017. The debt is owing to two of the four shareholders of the parent company as follows:		
Municipality of Leamington	2,150,296	2,150,296
Town of Tecumseh	1,544,408	1,544,408
	3,694,704	3,694,704
Mortgage payable - Woodslee Credit Union is repayable in blended monthly payments of $8,793 bearing an interest rate of 5.9% and is secured by land and buildings at 2730 Highway #3, RR# 1, Tecumseh. Mortgage matures September 19, 2013.	514,543	587,647
Banker's acceptance - TD Canada Trust is repayable with interest only payments at an effective interest rate of 6.55% and is due June 3, 2013.	3,000,000	3,000,000
Banker's acceptance - TD Canada Trust has a 5 year term ending November 4, 2018, and is repayable with interest only payments at an effective interest rate of 5.44%	3,300,000	3,300,000
Fixed rate loan - TD Canada Trust is a 20 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $39,562, bearing an interest rate of 4.99%. Loan matures November 9, 2019.	5,417,206	5,615,471
Fixed rate loan - TD Canada Trust is a 10 year term loan with a 10 year amortization schedule, repayable in blended monthly payments of $62,122, bearing an interest rate of 4.48%. Loan matures November 9, 2019.	4,427,283	4,960,783
Floating rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in monthly principal payments of $8,333, bearing a floating interest rate of prime plus 0%. Loan matures December 2017.	2,000,000	-
	22,353,736	21,158,605
Less: Current portion of long-term debt	5,121,181	4,499,574
	17,232,555	16,659,031

Approximate long-term principal repayments over five years are as follows:

	$
2013	5,121,181
2014	1,642,860
2015	1,680,795
2016	1,719,529
2017	1,762,086

In addition to the Bankers Acceptances with TD Canada Trust, the Company has entered into two interest rate swap agreements with TD Securities. Both of these agreements are "receive variable, pay fixed" swap agreements, which effectively convert variable interest rates on Bankers Acceptances to the effective interest rates mentioned above. Refer to note 13 for details on these swap instruments.

8 Capital stock

Authorized

An unlimited number of common shares, Class A, voting
An unlimited number of common shares, Class B, non-voting

Issued

	2012 $	2011 $
50 common shares, Class A, voting	5	5
15,772,796 common shares, Class B, non-voting	15,772,796	15,772,796
	15,772,801	15,772,801

9 Related party transactions

The Company engages in transactions with its affiliates and parent company. The following is a summary of the related party transactions. These transactions are measured at exchange amount, which is the amount of consideration established and agreed to by the related parties. The Company is affiliated with Essex Power Services Corporation, Essex Energy Corporation and Utilismart Corporation and is the subsidiary of Essex Power Corporation.

	2012 $	2011 $
Service fees due to affiliate	-	12,133
Management fees due to parent	1,000,154	1,142,371
Amounts due to (from) affiliates	(187,334)	5,412
Dividends payable to parent	990,718	1,006,176

Related party long-term debt payable with the shareholders of Essex Power Corporation is outlined in note 7. The Company was charged interest on the long-term debt by the Essex Power Corporation shareholders in the amount of $223,484.

In 2011, the Company received a non-interest bearing loan from its shareholder for $373,943, with no set repayment terms. An additional $207,738 was received during 2012 from its shareholder with no set repayment terms. These same amounts have been classified as an appropriation of retained earnings as a solar equity reserve.

10 Employee future benefits

Pension plan

The Company provides a pension plan for its full time employees through the Ontario Municipal Employees Retirement System (OMERS). OMERS is a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province for employees of municipalities, local boards and school boards in Ontario. Both participating employers and employees are required to make plan contributions based on participating employees' contributory earnings. The Company records the expense related to this plan as contributions are made. For the year ended December 31, 2012, the Company's OMERS current service pension costs were $284,712 (2011 - $220,482).

Employee future benefits other than pension

The Company pays certain benefits on behalf of its retired employees. Information about the Company's defined benefit plans is as follows:

	2012 $	2011 $
Opening balance at beginning of year	4,017,968	4,280,137
Current service and interest expense net of amortization of plan losses (gains)	27,909	(139,125)
Contributions made in the period	(91,807)	(123,044)
	3,954,070	4,017,968

The main actuarial assumptions employed for the valuations are as follows:

General inflation
Future general inflation levels, as measured by changes in the Consumer Price Index (CPI), were assumed at 2% in 2012 and thereafter.

Interest (discount) rate
The obligation as at December 31, 2012 of the present value of future liabilities and the expense for the year ended December 31, 2012 were determined using a discount rate of 4.75%.

Salary levels
Future general salary and wage levels were assumed to increase at 2% per annum.

Medical costs
Medical costs were assumed to increase at the CPI rate plus a further increase of 4.5% in 2013.

Dental costs
Dental costs were assumed to increase at the CPI rate plus a further increase of 4.5% in 2013.

11 Prior year figures

Certain prior year figures have been reclassified to conform to the financial statement presentation adopted in the current year.

12 Capital management

The Company's objectives are to maintain access to capital on a long-term basis at reasonable rates and to deliver reasonable financial returns to the shareholders.

The Company's capital structure consists of shareholders' equity, retained earnings, solar equity reserve, long-term debt and cash. The capital structure as at December 31, 2012 was as follows:

	2012 $	2011 $
Long-term debt payable within one year	5,121,181	4,499,574
Less: Cash	(3,969,160)	(3,522,510)
Long-term debt	17,232,555	16,659,031
Net long-term debt	18,384,576	17,636,095
Common shares	15,772,801	15,772,801
Retained earnings	2,554,996	1,765,702
Solar equity reserve	581,681	373,943
Total equity	18,909,478	17,912,446
Total capital	37,294,054	35,548,541
Debt to capital ratio	49%	50%

The Company is required by TD Canada Trust to maintain a funded debt to capitalization ratio not to exceed 60%. At December 31, 2012, the Company is in compliance with this covenant.

13 Financial instruments

Exposure to market risk, credit risk, liquidity risk and interest rate risk arises in the normal course of the Company's business.

Market risk

Market risk refers primarily to the risk of loss that results from fluctuations in commodity prices, foreign exchange rates and interest rates. The Company does not have significant commodity risk or foreign exchange risk. The Company is exposed to fluctuations in interest rates from the market compared to interest rates that are allowed by the regulator in customer rates. As further defined in note 7 to these financial statements, the Company uses derivative financial instruments, primarily interest rate swaps, to manage its interest rate exposure.

Credit risk

The Company is exposed to credit risk with its customers and their ability to pay. The Company's revenue is earned from a broad base of customers in different classes and as such, the Company does not rely on any one single customer for a significant amount of its revenues. As of December 31, 2012, there were no significant balances of accounts receivable owing from any single customer.

Liquidity risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Short-term liquidity is provided through cash and funds from operations. As of December 31, 2012, accounts payable of $9,376,279, dividend payable of $990,718, current portion of customer deposits of $250,000 and current portion of long-term debt of $5,121,181 are expected to be paid at their carrying values within the next year. Interest payments of $990,000 owing on long-term debt is also expected to be paid within the next year.

Interest rate risk

The Company enters into derivative financial instruments in order to hedge its risk against interest rate fluctuations. The Company has fixed its variable rate long-term borrowing obligations with the following outstanding interest rate swap agreements:

Notional amount $	Interest rate %	Term of agreement	Repricing period
3,000,000	5.30	June 3, 2013	Monthly
3,300,000	4.19	November 4, 2018	Monthly

As at December 31, 2012, the unrealized gain (loss) was $203,559 (2011 - ($190,815)) for these two instruments.

14 Net change in non-cash working capital

The net change in non-cash working capital balances related to operations consists of the following:

	2012 $	2011 $
(Increase) decrease in current assets		
Accounts receivable	(527,967)	1,138,044
Prepaid expenses	(8,882)	(43,150)
Unbilled revenue	1,730,578	(559,344)
Income taxes recoverable	258,809	(327,000)
	1,452,538	208,550
Increase (decrease) in current liabilities		
Accounts payable and accrued liabilities	(256,874)	(959,353)
Due to affiliates	(192,746)	(25,080)
Customer deposits	261,521	124,868
	(188,099)	(859,565)
	1,264,439	(651,015)

15 Emerging accounting changes

International Financial Reporting Standards (IFRS)

On February 13, 2008, the AcSB confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2012. In February 2013, the AcSB decided to permit rate-regulated entities to defer their IFRS implementation date to January 1, 2015. As such, the Company expects to apply IFRS to its financial statements ending December 31, 2015 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2014, for comparative purposes.

16 Contingencies

The Company subscribes for liability insurance coverage under a self-insurance pool administered by the Municipal Electric Association Reciprocal Insurance Exchange. Under the terms of this co-operative venture, the Company as a pool member, in addition to its regular policy premiums, is contingently liable for any retroactive reassessment if a deficit originates in a year in which they are a member. The contingent liability for reassessment in respect of any year in which the Company is a pool member continues even where the Company subsequently withdraws from the self-insurance pool. The Company will not, however, be subject to reassessment for claims incurred in years in which they are not members of this self-insurance pool.

A letter of credit in the amount of $2,900,000 has been issued by TD Canada Trust to the credit of the Independent Electricity System Operator for the commodity purchases and market services provided. This letter of credit expires April 15, 2013 and is normally renewed annually.

17 Provision for payments in lieu of corporate income taxes

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. The reconciliation between the statutory and effective tax rates is provided as follows:

	2012 $	2011 $
Income before provision for PILs	2,256,475	2,906,001
Federal and Ontario statutory income tax rate	26.5%	26.5%
Provision for PILs at statutory rate	598,000	770,090
Increase (decrease) resulting from:		
Net temporary differences	(344,000)	(435,074)
Amortization of deferred charge	47,000	46,500
Rate reduction arising from Ontario small business deduction	(35,000)	-
Other non-temporary differences	-	1,484
Total income tax provision for PILs	266,000	383,000
Effective income tax rate	11.79%	13.18%

Essex Powerlines Corporation

Financial Statements
December 31, 2013

April 7, 2014

Independent Auditor's Report

To the Shareholder of
Essex Powerlines Corporation

We have audited the accompanying financial statements of Essex Powerlines Corporation, which comprise the balance sheet as at December 31, 2013 and the statements of earnings, retained earnings and cash flows for the year then ended, and the related notes, which comprise 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 Canadian generally accepted accounting principles, 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.

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

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

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

PricewaterhouseCoopers LLP
245 Ouellette Avenue, Suite 300, Windsor, Ontario, Canada N9A 7J4
T: +1 519 985 8900, F: +1 519 258 5457

Opinion
In our opinion, the financial statements present fairly, in all material respects, the financial position of Essex Powerlines Corporation as at December 31, 2013 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles

PricewaterhouseCoopers LLP

Chartered Professional Accountants, Licensed Public Accountants

Essex Powerlines Corporation

Balance Sheet

As at December 31, 2013

	2013 $	2012 $
Assets		
Current assets		
Cash	1,481,377	3,969,160
Accounts receivable	5,991,966	6,158,751
Due from affiliates (note 9)	-	187,334
Prepaid expenses	246,639	229,700
Unbilled revenue	7,211,794	5,002,399
Income taxes recoverable	351,594	87,390
Inventory	60,000	60,000
	15,343,370	15,694,734
Property, plant and equipment (note 3)	43,010,825	42,002,013
Deferred charges (note 5)	1,141,653	1,369,625
Future income taxes (note 4 and 17)	1,332,000	2,266,000
	60,827,848	61,332,372
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	11,403,900	9,376,279
Due to affiliates (note 9)	86,467	-
Regulatory liabilities (note 4)	3,448,507	3,414,393
Dividends payable (note 9)	1,030,718	990,718
Current portion of customer deposits (note 6)	270,000	250,000
Current portion of long-term debt (note 7)	2,381,801	5,121,181
	18,621,393	19,152,571
Customer deposits (note 6)	1,348,858	993,716
Long-term debt (note 7)	15,584,514	17,232,555
Employee future benefits (note 10)	3,885,489	3,954,070
Accrued loss on interest rate swap (notes 7 and 13)	306,859	508,301
Shareholder loan (note 9)	581,681	581,681
	40,328,794	42,422,894
Shareholders' Equity		
Capital stock (note 8)	15,772,801	15,772,801
Retained earnings	4,144,572	2,554,996
Solar equity reserve (appropriation of retained earnings) (note 9)	581,681	581,681
	20,499,054	18,909,478
	60,827,848	61,332,372

Commitments and contingencies (note 16)

Approved by the Board of Directors

_______________ Director _______________ Director

The accompanying notes are an integral part of these financial statements.

Essex Powerlines Corporation

Statement of Earnings

For the year ended December 31, 2013

	2013 $	2012 $
Energy sales	62,744,387	57,589,482
Cost of power purchased	51,542,202	46,480,396
Gross margin on service revenue	11,202,185	11,109,086
Other revenue from operations		
Solar generation	586,822	590,368
Miscellaneous revenue	1,153,102	1,557,787
Total other revenue	1,739,924	2,148,155
Expenses		
Billing and collecting	2,259,692	2,022,808
Administration and general	2,674,529	2,395,331
Distribution	2,477,821	2,993,439
Amortization	2,144,849	2,722,513
Solar expense	49,129	49,173
Total expenses	9,606,020	10,183,264
Income from operations	3,336,089	3,073,977
Other revenue (expenses)		
Gain on disposal of property, plant and equipment	79,457	37,915
Unrealized gain on interest rate swap (notes 7 and 13)	201,442	203,559
Interest expense	(896,321)	(1,222,719)
Interest income	283,682	163,754
Gain (loss) on foreign exchange	468	(11)
Income before income taxes	3,004,817	2,256,475
Provision for income taxes		
Current income tax expense (note 17)	384,523	266,000
Net income for the year	2,620,294	1,990,475

The accompanying notes are an integral part of these financial statements.

Essex Powerlines Corporation

Statement of Retained Earnings

For the year ended December 31, 2013

	2013 $	2012 $
Retained earnings - Beginning of year	2,554,996	1,765,702
Net income for the year	2,620,294	1,990,475
Dividends	(1,030,718)	(993,443)
Appropriation of retained earnings to solar equity reserve (note 9)	-	(207,738)
Retained earnings - End of year	4,144,572	2,554,996

The accompanying notes are an integral part of these financial statements.

Essex Powerlines Corporation

Statement of Cash Flows

For the year ended December 31, 2013

	2013 $	2012 $
Cash provided by (used in):		
Operating activities		
Net income for the year	2,620,294	1,990,475
Add items not involving cash		
Amortization of property, plant and equipment	2,144,849	2,722,513
Decrease in deferred charges	227,972	433,803
Decrease in future income taxes	934,000	230,000
Gain on disposal of property, plant and equipment	(79,457)	(37,915)
Decrease in employee future benefits	(68,581)	(63,898)
Increase (decrease) in regulatory liabilities	34,114	(679,369)
Unrealized (gain) on interest rate swap	(201,442)	(203,559)
Net change in non-cash working capital (note 14)	352,811	1,264,439
	5,964,560	5,656,489
Financing activities		
Dividends	(990,718)	(1,008,901)
Contributions in aid of construction	2,191,898	869,852
Increase in long-term debt	-	2,207,738
Repayment of long-term debt	(4,387,421)	(804,869)
	(3,186,241)	1,263,820
Investing activities		
Purchase of property, plant and equipment	(5,345,559)	(6,540,740)
Proceeds on disposal of property, plant and equipment	79,457	67,081
	(5,266,102)	(6,473,659)
Increase in cash during the year	(2,487,783)	446,650
Cash - Beginning of year	3,969,160	3,522,510
Cash - End of year	1,481,377	3,969,160
Supplementary cash flow information		
Interest paid	962,557	1,149,554
Payments in lieu of corporate income taxes	648,727	328,000

The accompanying notes are an integral part of these financial statements.

1 Nature of business

Essex Powerlines Corporation (the Company) serves as the rate regulated "local distribution company" (LDC) which provides safe and reliable power to over 28,000 residents and businesses in Amherstburg, LaSalle, Leamington and Tecumseh. Essex Power Corporation holds 100% of the shares of the Company. The shareholders of Essex Power Corporation include the Town of Amherstburg, the Town of LaSalle, the Municipality of Leamington and the Town of Tecumseh. The municipal owners of Essex Power Corporation also hold debt directly with the Company (see note 7).

The Ontario Government enacted the Energy Competition Act, 1998 to introduce competition to the Ontario electricity market. Under the terms of the legislation, the Ontario Energy Board (OEB) will regulate industry participants by issuing licenses for the right to generate, transmit, distribute or retail electricity. These licenses require compliance with established market rules and codes.

The distribution revenues include a distribution tariff, which is based on OEB approved rates. The distribution tariff rates are set based on an approved revenue requirement that provides cost recovery and includes a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory assets and liabilities over a specified timeframe.

2 Summary of significant accounting policies

Basis of presentation

The financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles for electric utilities.

Property, plant and equipment

Property, plant and equipment are stated at cost less applicable rebates, accumulated amortization and contributions in aid of construction. Cost is comprised of materials, labour, engineering costs and overheads. Amortization is determined on a straight-line basis over the estimated useful lives of the assets.

Land rights	50 years
Buildings and fixtures	50 years
Transmission and distribution equipment	15 - 50 years
Computer hardware, software and other equipment	3 - 5 years
Office equipment	10 years
Utility equipment and trucks	3 - 15 years
Solar generation	25 years

In the year of addition, a half year of amortization is claimed. When specifically identifiable items are retired or otherwise disposed of, their original cost and accumulated amortization are removed from the accounts and the related gain or loss is included in income in the year of disposal.

Property, plant and equipment useful lives were adjusted in 2013 under a policy direction from the Ontario Energy Board (OEB). Regulated companies that have elected to defer adoption of International Financial

Reporting Standards (IFRS) to 2015 are required to change the useful lives to the OEB standard useful life period. These accounting policy changes have been applied prospectively. The financial differences resulting from the application of revised useful lives of assets and the impact on depreciation expense are included in a variance account (note 4) until the Company is approved to settle these changes in the next cost of service rate application for rates effective January 1, 2016.

Inventory

Inventories consist principally of construction and maintenance materials and are stated at the lower of cost and net realizable value, with cost determined on an average cost basis. The Company includes certain major standby equipment as in-service property, plant and equipment and depreciates these assets over their useful lives.

Contributions in aid of construction

Contributions in aid of construction are non-refundable contributions of property, plant and equipment made by developers or subdividers which become part of the distribution system. They are recorded as a reduction of the related asset values. These amounts will be amortized on the same basis as the related property, plant and equipment.

Revenue recognition

In accordance with OEB regulations, the Company recognizes as revenue the regulated distribution tariffs associated with energy distributed. Variances between energy purchase costs and energy bills are recorded as regulatory assets or liabilities for future distribution rate application consideration.

The Company follows the practice of cycle billing of customers' accounts and revenue is recognized in the period billed. An accrual is made in the accounts at December 31 for power supplied but not billed to customers between the date the meters were last read and the end of the year.

Accounting for rate regulated operations

The Accounting Standards Board (AcSB) accounting guideline 19 - Disclosures by Entities Subject to Rate Regulation, is applicable to the Company. The guideline requires disclosure of the effect of removing regulatory assets and liabilities and what the effect would be on the financial statements in the absence of rate regulation. The effects are disclosed in note 4.

Income taxes - payments in lieu

Income taxes are to be calculated in accordance with the rules for computing income, capital and other taxes provided for in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Energy Act and related regulations. After October 1, 2001 the Company is required to compute and remit to the Ontario Electricity Financing Corporation (OEFC) payments in lieu of corporate taxes.

Effective January 1, 2009, the Company adopted amendments to the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3465 - Income Taxes and CICA Handbook Section 1100 - Generally

Accepted Accounting Principles. These amended sections establish standards for the recognition, measurement, presentation and disclosure of future income tax assets and liabilities of rate regulated enterprises.

For transactions and events that cause temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, the Company recognized future income tax assets and liabilities, and corresponding regulatory liabilities and assets, as a result of adopting these amended standards on January 1, 2009.

Current income taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at the amounts receivable from or payable to the OEFC.

Future income taxes

Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax basis used in the computation of taxable profit.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely than not that they be realized from taxable profits available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantially enacted by the balance sheet date.

The Company has recognized regulatory assets and liabilities which correspond to future income taxes that flow through the rate-making process.

Post employment benefits

The Company pays certain post retirement benefits on behalf of its retired employees. The Company recognizes these post retirement costs in the period in which the employees rendered the services. The net periodic benefit cost for the year ended December 31, 2013 was determined by actuarial valuation using a discount rate of 4.75%. The actuarial valuation is required to be completed once every 3 years and was last done in December 2011. All actuarial gains and losses are amortized over the employee's average remaining service life which has been determined to be 8.8 years at December 31, 2013. As this liability is only for post employment benefits, there are no plan assets.

Measurement uncertainty

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities. Certain estimates are also required, as regulations which will ultimately determine the actual results have yet to be finalized and are dependent on the completion of regulatory proceedings or decisions. Due to these uncertainties, actual results might differ from those estimates and the impact will be recorded in the current period when the actual results are known.

Regulatory accounting

The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. The Company assesses the likelihood of recovery of each of its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Financial instruments

The Company classifies its cash as held for trading which is carried at fair value and accounts receivable and due from affiliates are classified as loans and receivables, which are initially recognized at fair value and subsequently measured at amortized cost. Accounts payable, accrued liabilities, dividends payable, customer deposits and long-term debt are classified as other liabilities and carried at amortized cost.

The interest rate swap agreement does not meet the criteria to apply hedge accounting. Accordingly, the interest rate swap contract is marked to market at year-end with the unrealized gain or loss recorded in the statement of earnings. Refer to note 13 for details.

3 Property, plant and equipment

			2013
	Cost $	Accumulated amortization $	Net $
Land and land rights	413,445	12,403	401,042
Buildings and fixtures	2,422,357	422,438	1,999,919
Transmission and distribution equipment	53,787,891	19,801,865	33,986,026
Computer hardware, software and other equipment	1,576,679	1,426,196	150,483
Office equipment	188,609	122,732	65,877
Utility equipment and trucks	2,319,721	752,154	1,567,567
Construction in progress	1,095,450	-	1,095,450
Solar generation	4,357,761	613,300	3,744,461
	66,161,913	23,151,088	43,010,825

			2012
	Cost $	Accumulated amortization $	Net $
Land and land rights	353,183	9,473	343,710
Buildings and fixtures	2,394,956	379,580	2,015,376
Transmission and distribution equipment	51,601,861	18,732,642	32,869,219
Computer hardware, software and other equipment	1,492,518	942,773	549,745
Office equipment	180,245	105,977	74,268
Utility equipment and trucks	1,989,536	572,262	1,417,274
Construction in progress	846,344	-	846,344
Solar generation	4,260,595	374,518	3,886,077
	63,119,238	21,117,225	42,002,013

4 Regulatory (assets) liabilities

Regulatory assets and liabilities are a result of differences between costs charged to the Company and allowed rates charged to customers which are summarized below.

	2013 $	2012 $
a) Retail settlement variances	4,273,814	3,105,281
b) Extraordinary event costs - ice storm	(83,301)	(83,110)
c) Retail cost and other variances	394,069	(143,211)
d) Regulatory assets recovered	(1,494,279)	(283,795)
e) Smart meter variance	(1,439,606)	(1,446,772)
f) Future income taxes	1,332,000	2,266,000
g) Change in useful life estimate	465,810	-
	3,448,507	3,414,393

a) Retail settlement variances are comprised of variances between amounts charged by the Independent Electricity System Operator for the operation of the wholesale electricity market and the cost of electricity, amounts from Hydro One for network line and transformation charges and amounts billed to customers. In the absence of rate regulation, income before tax would be higher by $1,168,533.

b) Extraordinary event costs represent costs incurred to restore services following storms in 2010. In the absence of rate regulation, income before taxes would be lower by $191.

c) Retail cost and other variances represent amounts for costs incurred by the Company to serve customers that have been enrolled by a commodity retailer and for miscellaneous other costs that will be recovered from customers. In the absence of rate regulation, income before taxes would be higher by $537,280.

d) Regulatory assets recovered represent amounts collected from customers through rates until April 30, 2014. These amounts will be held until approved by the Ontario Energy Board to be refunded to or recovered from customers. In the absence of rate regulation, income before taxes would be lower by $1,210,484.

e) The smart meter variance represents costs to install smart meters and interim smart meter recovery amounts paid by customers. Upon approval by the Ontario Energy Board of the installation costs, an adjustment will be made to include this cost in regular rates. In the absence of rate regulation net income before tax would be higher by $7,166.

f) The future income taxes liability is the result of the application of CICA Handbook Section 3465, Income Taxes, that was amended to require the recognition of future income tax liabilities and assets for regulated enterprises that were previously not subject to these provisions. The future income taxes liability is the amount that will be refunded to customers through future rates. In the absence of rate regulation, net assets would be lower by $934,000.

g) The change in useful life estimate variance account is the result of the application of revised useful lives of property, plant and equipment and the subsequent impact on depreciation expense and a reduction of overheads capitalized according to Ontario Energy Board guidelines effective January 1, 2013. The differences in these items are to be included in a variance account until the Company is approved to settle these changes in the next cost of service rate application for rates effective January 1, 2016. In the absence of rate regulation, net assets would be higher by $465,810.

5 Deferred charges

Deferred charges include the excess of the amounts paid to the shareholders less the net assets transferred to the Company. These amounts are being amortized on a straight-line basis over the average remaining service life of the assets transferred. The deferred charges also include the cost of rate rebasing which were amortized over the life of the cost of service and will be fully amortized in April 2014.

	2013 $	2012 $
Deferred charges	2,586,772	2,586,772
Less: Accumulated amortization	1,445,119	1,217,147
	1,141,653	1,369,625

6 Customer deposits

Customer deposits are amounts received and held as security for energy consumption. A customer deposit is refunded after a specified period of good payment history. Interest is to be paid annually at the prime business rate less 2%.

7 Long-term debt

	2013 $	2012 $
Related party long-term loan payable is repayable as approved by the Board of Directors not to exceed 20% of the principal lending amount if funds are available as determined each March. Interest is payable at a stated interest rate of 4.0%. The agreement expires December 31, 2017. The debt is owing to two of the four shareholders of the parent company as follows:		
Municipality of Leamington	2,150,296	2,150,296
Town of Tecumseh	1,544,408	1,544,408
	3,694,704	3,694,704
Mortgage payable - Woodslee Credit Union is repayable in blended monthly payments of $8,793 bearing an interest rate of 5.9% and is secured by land and buildings at 2730 Highway #3, RR# 1, Tecumseh. The mortgage matured September 19, 2013 and was not renewed.	-	514,543
Banker's acceptance - TD Canada Trust is repayable with interest only payments at an effective interest rate of 6.55% and is due June 3, 2013 and was not renewed.	-	3,000,000
Banker's acceptance - TD Canada Trust has a 5 year term ending November 4, 2018, and is repayable with interest only payments at an effective interest rate of 5.44%	3,300,000	3,300,000
Fixed rate loan - TD Canada Trust is a 20 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $39,562, bearing an interest rate of 4.99%. Loan matures November 9, 2019.	5,202,845	5,417,206
Fixed rate loan - TD Canada Trust is a 10 year term loan with a 10 year amortization schedule, repayable in blended monthly payments of $62,122, bearing an interest rate of 4.48%. Loan matures November 9, 2019.	3,868,766	4,427,283
Floating rate loan - TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in monthly principal payments of $8,333, bearing a floating interest rate of prime plus 0%. Loan matures November 30, 2017.	1,900,000	2,000,000
	17,966,315	22,353,736
Less: Current portion of long-term debt	2,381,801	5,121,181
	15,584,514	17,232,555

Approximate long-term principal repayments over five years are as follows:

	$
2014	2,381,801
2015	1,680,795
2016	1,719,529
2017	1,762,085
2018	1,066,721

In addition to the Bankers Acceptances with TD Canada Trust, the Company has entered into an interest rate swap agreement with TD Securities. This agreement is a "receive variable, pay fixed" swap agreement, which effectively convert variable interest rates on Bankers Acceptances to the effective interest rates mentioned above. Refer to note 13 for details on these swap instruments.

8 Capital stock

Authorized

An unlimited number of common shares, Class A, voting
An unlimited number of common shares, Class B, non-voting

Issued

	2013 $	2012 $
50 common shares, Class A, voting	5	5
15,772,796 common shares, Class B, non-voting	15,772,796	15,772,796
	15,772,801	15,772,801

9 Related party transactions

The Company engages in transactions with its affiliates and parent company. The following is a summary of the related party transactions. These transactions are measured at exchange amount, which is the amount of consideration established and agreed to by the related parties. The Company is affiliated with Essex Power Services Corporation, Essex Energy Corporation and Utilismart Corporation (and its subsidiaries) and is the subsidiary of Essex Power Corporation.

	2013 $	2012 $
Management fees due to parent	1,036,741	1,000,154
Amounts due to (from) affiliates	86,467	(187,334)
Dividends payable to parent	1,030,718	990,718

Related party long-term debt payable with the shareholders of Essex Power Corporation is outlined in note 7. The Company was charged interest on the long-term debt by the Essex Power Corporation shareholders in the amount of $147,788.

In 2011, the Company received a non-interest bearing loan from its shareholder for $373,943, with no set repayment terms. An additional $207,738 was received during 2012 from its shareholder with no set repayment terms. These same amounts have been classified as an appropriation of retained earnings as a solar equity reserve.

10 Employee future benefits

Pension plan

The Company provides a pension plan for its full time employees through the Ontario Municipal Employees Retirement System (OMERS). OMERS is a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province for employees of municipalities, local boards and school boards in Ontario. Both participating employers and employees are required to make plan contributions based on participating employees' contributory earnings. The Company records the expense related to this plan as contributions are made. For the year ended December 31, 2013, the Company's OMERS current service pension costs were $320,005 (2012 - $284,712).

Employee future benefits other than pension

The Company pays certain benefits on behalf of its retired employees. Information about the Company's defined benefit plans is as follows:

	2013 $	2012 $
Opening balance at beginning of year	3,954,070	4,017,968
Current service and interest expense net of amortization of plan losses (gains)	27,916	27,909
Contributions made in the period	(96,497)	(91,807)
	3,885,489	3,954,070

The main actuarial assumptions employed for the valuations are as follows:

General inflation
Future general inflation levels, as measured by changes in the Consumer Price Index (CPI), were assumed at 2% in 2013 and thereafter.

Interest (discount) rate
The obligation as at December 31, 2013 of the present value of future liabilities and the expense for the year ended December 31, 2013 was determined using a discount rate of 4.75%.

Medical costs
Medical costs were assumed to increase at the CPI rate plus a further increase of 4.5% in 2013.

Dental costs
Dental costs were assumed to increase at the CPI rate plus a further increase of 4.5% in 2013.

11 Prior year figures

Certain prior year figures have been reclassified to conform to the financial statement presentation adopted in the current year.

12 Capital management

The Company's objectives are to maintain access to capital on a long-term basis at reasonable rates and to deliver reasonable financial returns to the shareholders.

The Company's capital structure consists of shareholders' equity, retained earnings, solar equity reserve, long-term debt and cash. The capital structure as at December 31, 2013 was as follows:

	2013 $	2012 $
Long-term debt payable within one year	2,381,801	5,121,181
Less: Cash	(1,481,377)	(3,969,160)
Long-term debt	15,584,514	17,232,555
Net long-term debt	16,484,938	18,384,576
Common shares	15,772,801	15,772,801
Retained earnings	4,144,572	2,554,996
Solar equity reserve	581,681	581,681
Total equity	20,499,054	18,909,478
Total capital	36,983,992	37,294,054
Debt to capital ratio	45%	49%

The Company is required by TD Canada Trust to maintain a funded debt to capitalization ratio not to exceed 60%. At December 31, 2013, the Company is in compliance with this covenant.

13 Financial instruments

Exposure to market risk, credit risk, liquidity risk and interest rate risk arises in the normal course of the Company's business.

Market risk

Market risk refers primarily to the risk of loss that results from fluctuations in commodity prices, foreign exchange rates and interest rates. The Company does not have significant commodity risk or foreign exchange risk. The Company is exposed to fluctuations in interest rates from the market compared to interest rates that are allowed by the regulator in customer rates. As further defined in note 7 to these financial statements, the Company uses derivative financial instruments, primarily interest rate swaps, to manage its interest rate exposure.

Credit risk

The Company is exposed to credit risk with its customers and their ability to pay. The Company's revenue is earned from a broad base of customers in different classes and as such, the Company does not rely on any one single customer for a significant amount of its revenues. As of December 31, 2013, there were no significant balances of accounts receivable owing from any single customer.

Liquidity risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Short-term liquidity is provided through cash and funds from operations. As of December 31, 2013, accounts payable of $11,403,900, dividend payable of $1,030,718, current portion of customer deposits of $270,000 and current portion of long-term debt of $2,381,801 are expected to be paid at their carrying values within the next year. Interest payments of approximately $1.1 million owing on long-term debt is also expected to be paid within the next year.

Interest rate risk

The Company enters into derivative financial instruments in order to hedge its risk against interest rate fluctuations. The Company has fixed its variable rate long-term borrowing obligations with the following outstanding interest rate swap agreements:

Notional amount $	Interest rate %	Term of agreement	Repricing period
3,300,000	4.19	November 4, 2018	Monthly

As at December 31, 2013, the unrealized gain was $201,442 (2012 - $203,559) for this instrument.

14 Net change in non-cash working capital

The net change in non-cash working capital balances related to operations consists of the following:

	2013 $	2012 $
(Increase) decrease in current assets		
Accounts receivable	166,785	(527,967)
Prepaid expenses	(16,939)	(8,882)
Unbilled revenue	(2,209,395)	1,730,578
Income taxes recoverable	(264,204)	258,809
	(2,323,753)	1,452,538
Increase (decrease) in current liabilities		
Accounts payable and accrued liabilities	2,027,621	(256,874)
Due to affiliates	273,801	(192,746)
Customer deposits	375,142	261,521
	2,676,564	(188,099)
	352,811	1,264,439

15 Emerging accounting changes

International Financial Reporting Standards (IFRS)

On February 13, 2008, the AcSB confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2012. In February 2013, the AcSB decided to permit rate-regulated entities to defer their IFRS implementation date to January 1, 2015. As such, the Company expects to apply IFRS to its financial statements ending December 31, 2015 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2014, for comparative purposes.

16 Commitments and contingencies

The Company subscribes for liability insurance coverage under a self-insurance pool administered by the Municipal Electric Association Reciprocal Insurance Exchange. Under the terms of this co-operative venture, the Company as a pool member, in addition to its regular policy premiums, is contingently liable for any retroactive reassessment if a deficit originates in a year in which they are a member. The contingent liability for reassessment in respect of any year in which the Company is a pool member continues even where the Company subsequently withdraws from the self-insurance pool. The Company will not, however, be subject to reassessment for claims incurred in years in which they are not members of this self-insurance pool.

A letter of credit in the amount of $2,900,000 has been issued by TD Canada Trust to the credit of the Independent Electricity System Operator for the commodity purchases and market services provided. This letter of credit has no term of expiry and is normally renewed annually.

17 Provision for payments in lieu of corporate income taxes

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. The reconciliation between the statutory and effective tax rates is provided as follows:

	2013 $	2012 $
Income before provision for PILs	3,004,817	2,256,475
Federal and Ontario statutory income tax rate	26.5%	26.5%
Provision for PILs at statutory rate	796,276	598,000
Increase (decrease) resulting from:		
Net temporary differences	(418,608)	(297,000)
Rate reduction arising from Ontario small business deduction	(35,000)	(35,000)
Other non-temporary differences	41,855	-
Total income tax provision for PILs	384,523	266,000
Effective income tax rate	12.80%	11.79%

Essex Powerlines Corporation

Financial Statements
December 31, 2014

April 24, 2015

Independent Auditor's Report

To the Shareholder of
Essex Powerlines Corporation

We have audited the accompanying financial statements of Essex Powerlines Corporation, which comprise the balance sheet as at December 31, 2014 and the statements of earnings, retained earnings and cash flows for the year then ended, and the related notes, which comprise 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 Canadian generally accepted accounting principles, 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.

Auditor's responsibility

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

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

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

PricewaterhouseCoopers LLP
245 Ouellette Avenue, Suite 300, Windsor, Ontario, Canada N9A 7J4
T: +1 519 985 8900, F: +1 519 258 5457

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Essex Powerlines Corporation as at December 31, 2014 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles

PricewaterhouseCoopers LLP

Chartered Professional Accountants, Licensed Public Accountants

Essex Powerlines Corporation

Balance Sheet

As at December 31, 2014

	2014 $	2013 $
Assets		
Current assets		
Cash	140,632	1,481,377
Accounts receivable	8,232,113	5,991,966
Prepaid expenses	321,982	246,639
Unbilled revenue	5,513,526	7,211,794
Income taxes recoverable	74,056	351,594
Inventory	60,000	60,000
	14,342,309	15,343,370
Property, plant and equipment (note 3)	44,264,615	43,010,825
Deferred charges (note 5)	1,011,293	1,141,653
Future income taxes (note 4 and 16)	1,286,000	1,332,000
	60,904,217	60,827,848
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	10,299,086	11,403,900
Due to affiliates (note 9)	858,153	86,467
Regulatory liabilities (note 4)	2,345,732	3,448,507
Dividends payable (note 9)	1,016,176	1,030,718
Current portion of customer deposits (note 6)	270,000	270,000
Current portion of long-term debt (note 7)	3,258,617	2,381,801
	18,047,764	18,621,393
Customer deposits (note 6)	972,245	1,348,858
Long-term debt (note 7)	15,809,388	15,584,514
Employee future benefits (note 10)	3,962,578	3,885,489
Accrued loss on interest rate swap (notes 7 and 12)	319,161	306,859
Shareholder loan (note 9)	373,943	581,681
	39,485,079	40,328,794
Shareholders' Equity		
Capital stock (note 8)	15,772,801	15,772,801
Retained earnings	5,272,394	4,144,572
Solar equity reserve (appropriation of retained earnings) (note 9)	373,943	581,681
	21,419,138	20,499,054
	60,904,217	60,827,848

Commitments and contingencies (note 15)

Approved by the Board of Directors

_______________ Director _______________ Director

The accompanying notes are an integral part of these financial statements.

Essex Powerlines Corporation

Statement of Earnings

For the year ended December 31, 2014

	2014 $	2013 $
Energy sales	68,594,460	62,744,387
Cost of power purchased	57,503,389	51,542,202
Gross margin on service revenue	11,091,071	11,202,185
Other revenue from operations		
Solar generation	401,920	586,822
Miscellaneous revenue	1,244,708	1,153,102
Total other revenue	1,646,628	1,739,924
Expenses		
Billing and collecting	2,119,534	2,259,692
Administration and general	2,981,940	2,674,529
Distribution	2,770,765	2,477,821
Amortization	1,726,509	2,144,849
Solar expense	34,807	49,129
Total expenses	9,633,555	9,606,020
Income from operations	3,104,144	3,336,089
Other revenue (expenses)		
Gain on disposal of property, plant and equipment	30,602	79,457
Unrealized (loss) gain on interest rate swap (notes 7 and 12)	(12,302)	201,442
Interest expense	(1,243,067)	(896,321)
Interest income	335,181	283,682
(Loss) gain on foreign exchange	(642)	468
Income before income taxes	2,213,916	3,004,817
Provision for income taxes		
Current income tax expense (note 16)	277,656	384,523
Net income for the year	1,936,260	2,620,294

The accompanying notes are an integral part of these financial statements.

Essex Powerlines Corporation

Statement of Retained Earnings

For the year ended December 31, 2014

	2014 $	2013 $
Retained earnings - Beginning of year	4,144,572	2,554,996
Net income for the year	1,936,260	2,620,294
Dividends	(1,016,176)	(1,030,718)
Appropriation of retained earnings to solar equity reserve (note 9)	207,738	-
Retained earnings - End of year	5,272,394	4,144,572

The accompanying notes are an integral part of these financial statements.

Essex Powerlines Corporation

Statement of Cash Flows

For the year ended December 31, 2014

	2014 $	2013 $
Cash provided by (used in)		
Operating activities		
Net income for the year	1,936,260	2,620,294
Add items not involving cash		
Amortization of property, plant and equipment	1,726,509	2,144,849
Decrease in deferred charges	130,360	227,972
Decrease in future income taxes	46,000	934,000
Gain on disposal of property, plant and equipment	(30,602)	(79,457)
Increase (decrease) in employee future benefits	77,089	(68,581)
(Decrease) increase in regulatory liabilities	(1,102,775)	34,114
Unrealized loss (gain) on interest rate swap	12,302	(201,442)
Net change in non-cash working capital (note 13)	(1,049,425)	352,811
	1,745,718	5,964,560
Financing activities		
Dividends	(1,030,718)	(990,718)
Contributions in aid of construction	1,122,171	2,191,898
Increase in long-term debt	2,000,000	-
Repayment of long-term debt	(1,106,048)	(4,387,421)
	985,405	(3,186,241)
Investing activities		
Purchase of property, plant and equipment	(5,628,968)	(5,345,559)
Proceeds on disposal of property, plant and equipment	1,557,100	79,457
	(4,071,868)	(5,266,102)
Decrease in cash during the year	(1,340,745)	(2,487,783)
Cash - Beginning of year	1,481,377	3,969,160
Cash - End of year	140,632	1,481,377
Supplementary cash flow information		
Interest paid	762,849	962,557
Payments in lieu of corporate income taxes	382,156	648,727

The accompanying notes are an integral part of these financial statements.

1 Nature of business

Essex Powerlines Corporation (the Company) serves as the rate regulated "local distribution company" (LDC) which provides safe and reliable power to over 28,000 residents and businesses in Amherstburg, LaSalle, Leamington and Tecumseh. Essex Power Corporation holds 100% of the shares of the Company. The shareholders of Essex Power Corporation include the Town of Amherstburg, the Town of LaSalle, the Municipality of Leamington and the Town of Tecumseh. The municipal owners of Essex Power Corporation also hold debt directly with the Company (see note 7).

The Ontario Government enacted the Energy Competition Act, 1998 to introduce competition to the Ontario electricity market. Under the terms of the legislation, the Ontario Energy Board (OEB) will regulate industry participants by issuing licenses for the right to generate, transmit, distribute or retail electricity. These licenses require compliance with established market rules and codes.

The distribution revenues include a distribution tariff, which is based on OEB approved rates. The distribution tariff rates are set based on an approved revenue requirement that provides cost recovery and includes a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory assets and liabilities over a specified timeframe.

2 Summary of significant accounting policies

Basis of presentation

The financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles for electric utilities.

Property, plant and equipment

Property, plant and equipment are stated at cost less applicable rebates, accumulated amortization and contributions in aid of construction. Cost is comprised of materials, labour, engineering costs and overheads. Amortization is determined on a straight-line basis over the estimated useful lives of the assets.

Land rights	50 years
Buildings and fixtures	50 years
Transmission and distribution equipment	15 - 50 years
Computer hardware, software and other equipment	3 - 5 years
Office equipment	10 years
Utility equipment and trucks	3 - 15 years
Solar generation	25 years

In the year of addition, a half year of amortization is claimed. When specifically identifiable items are retired or otherwise disposed of, their original cost and accumulated amortization are removed from the accounts and the related gain or loss is included in income in the year of disposal.

Property, plant and equipment useful lives were adjusted in 2013 under a policy direction from the Ontario Energy Board (OEB). Regulated companies that have elected to defer adoption of International Financial

Reporting Standards (IFRS) to 2015 are required to change the useful lives to the OEB standard useful life period. These accounting policy changes have been applied prospectively. The financial differences resulting from the application of revised useful lives of assets and the impact on depreciation expense are included in a variance account (note 4) until the Company is approved to settle these changes in the next cost of service rate application for rates effective January 1, 2016.

Inventory

Inventories consist principally of construction and maintenance materials and are stated at the lower of cost and net realizable value, with cost determined on an average cost basis. The Company includes certain major standby equipment as in-service property, plant and equipment and depreciates these assets over their useful lives.

Contributions in aid of construction

Contributions in aid of construction are non-refundable contributions of property, plant and equipment made by developers or subdividers which become part of the distribution system. They are recorded as a reduction of the related asset values. These amounts will be amortized on the same basis as the related property, plant and equipment.

Revenue recognition

In accordance with OEB regulations, the Company recognizes as revenue the regulated distribution tariffs associated with energy distributed. Variances between energy purchase costs and energy bills are recorded as regulatory assets or liabilities for future distribution rate application consideration.

The Company follows the practice of cycle billing of customers' accounts and revenue is recognized in the period billed. An accrual is made in the accounts at December 31 for power supplied but not billed to customers between the date the meters were last read and the end of the year.

Accounting for rate regulated operations

The Accounting Standards Board (AcSB) accounting guideline 19 - Disclosures by Entities Subject to Rate Regulation, is applicable to the Company. The guideline requires disclosure of the effect of removing regulatory assets and liabilities and what the effect would be on the financial statements in the absence of rate regulation. The effects are disclosed in note 4.

Income taxes - payments in lieu

Income taxes are to be calculated in accordance with the rules for computing income, capital and other taxes provided for in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Energy Act and related regulations. After October 1, 2001 the Company is required to compute and remit to the Ontario Electricity Financing Corporation (OEFC) payments in lieu of corporate taxes.

Current income taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at the amounts receivable from or payable to the OEFC.

Future income taxes

Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax basis used in the computation of taxable profit.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely than not that they be realized from taxable profits available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantially enacted by the balance sheet date.

The Company has recognized regulatory assets and liabilities which correspond to future income taxes that flow through the rate-making process.

Post employment benefits

The Company pays certain post-retirement benefits on behalf of its retired employees. The Company recognizes these post retirement costs in the period in which the employees rendered the services. The net periodic benefit cost for the year ended December 31, 2014 was determined by actuarial valuation using a discount rate of 4%. The actuarial valuation is required to be completed once every 3 years and was last done in December 2011. All actuarial gains and losses are amortized over the employee's average remaining service life which has been determined to be 8.9 years at December 31, 2014. As this liability is only for post-employment benefits, there are no plan assets.

Measurement uncertainty

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities. Certain estimates are also required, as regulations which will ultimately determine the actual results have yet to be finalized and are dependent on the completion of regulatory proceedings or decisions. Due to these uncertainties, actual results might differ from those estimates and the impact will be recorded in the current period when the actual results are known.

Regulatory accounting

The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. The Company assesses the likelihood of recovery of each of its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Financial instruments

The Company classifies its cash as held for trading which is carried at fair value and accounts receivable and due to affiliates are classified as loans and receivables, which are initially recognized at fair value and subsequently measured at amortized cost. Accounts payable, accrued liabilities, dividends payable, customer deposits and long-term debt are classified as other liabilities and carried at amortized cost.

The interest rate swap agreement does not meet the criteria to apply hedge accounting. Accordingly, the interest rate swap contract is marked to market at year-end with the unrealized gain or loss recorded in the statement of earnings. Refer to note 12 for details.

3 Property, plant and equipment

			2014
	Cost $	Accumulated amortization $	Net $
Land and land rights	428,516	16,082	412,434
Buildings and fixtures	2,422,357	449,539	1,972,818
Transmission and distribution equipment	58,371,057	20,972,193	37,398,864
Computer hardware, software and other equipment	1,694,894	1,506,374	188,520
Office equipment	190,108	140,711	49,397
Utility equipment and trucks	2,687,100	883,482	1,803,618
Construction in progress	380,863	-	380,863
Solar generation	2,613,191	555,090	2,058,101
	68,788,086	24,523,471	44,264,615

			2013
	Cost $	Accumulated amortization $	Net $
Land and land rights	413,445	12,403	401,042
Buildings and fixtures	2,422,357	422,438	1,999,919
Transmission and distribution equipment	53,787,891	19,801,865	33,986,026
Computer hardware, software and other equipment	1,576,679	1,426,196	150,483
Office equipment	188,609	122,732	65,877
Utility equipment and trucks	2,319,721	752,154	1,567,567
Construction in progress	1,095,450	-	1,095,450
Solar generation	4,357,761	613,300	3,744,461
	66,161,913	23,151,088	43,010,825

4 Regulatory (assets) liabilities

Regulatory assets and liabilities are a result of differences between costs charged to the Company and allowed rates charged to customers which are summarized below.

	2014 $	2013 $
a) Retail settlement variances	161,818	4,273,814
b) Extraordinary event costs - ice storm	(83,301)	(83,301)
c) Retail cost and other variances	343,650	394,069
d) Regulatory assets recovered	1,368,616	(1,494,279)
e) Smart meter variance	(1,354,075)	(1,439,606)
f) Future income taxes	1,286,000	1,332,000
g) Change in useful life estimate	623,024	465,810
	2,345,732	3,448,507

a) Retail settlement variances are comprised of variances between amounts charged by the Independent Electricity System Operator for the operation of the wholesale electricity market and the cost of electricity, amounts from Hydro One for network line and transformation charges and amounts billed to customers. In the absence of rate regulation, income before tax would be lower by $4,111,996.

b) Extraordinary event costs represent costs incurred to restore services following storms in 2010. In the absence of rate regulation, income before taxes would not change.

c) Retail cost and other variances represent amounts for costs incurred by the Company to serve customers that have been enrolled by a commodity retailer and for miscellaneous other costs that will be recovered from customers. In the absence of rate regulation, income before taxes would be lower by $50,419.

d) Regulatory assets recovered represent amounts collected from customers through rates until April 30, 2014. These amounts will be held until approved by the Ontario Energy Board to be refunded to or recovered from customers. In the absence of rate regulation, income before taxes would be higher by $2,862,895.

e) The smart meter variance represents costs to install smart meters and interim smart meter recovery amounts paid by customers. Upon approval by the Ontario Energy Board of the installation costs, an adjustment will be made to include this cost in regular rates. In the absence of rate regulation net income before tax would be higher by $85,531.

f) The future income taxes liability is the result of the application of CPA Handbook Section 3465, Income Taxes, that was amended to require the recognition of future income tax liabilities and assets for regulated enterprises that were previously not subject to these provisions. The future income taxes liability is the amount that will be refunded to customers through future rates. In the absence of rate regulation, net assets would be lower by $46,000.

g) The change in useful life estimate variance account is the result of the application of revised useful lives of property, plant and equipment and the subsequent impact on depreciation expense and a reduction of overheads capitalized according to Ontario Energy Board guidelines effective January 1, 2013. The differences in these items are to be included in a variance account until the Company is approved to settle these changes in the next cost of service rate application for rates effective January 1, 2016. In the absence of rate regulation, net assets would be higher by $157,214.

5 Deferred charges

Deferred charges include the excess of the amounts paid to the shareholders less the net assets transferred to the Company. These amounts are being amortized on a straight-line basis over the average remaining service life of the assets transferred. The deferred charges also include the cost of rate rebasing which were amortized over the life of the cost of service and were fully amortized in April 2014.

	2014 $	2013 $
Deferred charges	2,649,383	2,586,772
Less: Accumulated amortization	1,638,090	1,445,119
	1,011,293	1,141,653

6 Customer deposits

Customer deposits are amounts received and held as security for energy consumption. A customer deposit is refunded after a specified period of good payment history. Interest is to be paid annually at the prime business rate less 2%.

7 Long-term debt

	2014 $	2013 $
Related party long-term loan payable is repayable as approved by the Board of Directors not to exceed 20% of the principal lending amount if funds are available as determined each March. Interest is payable at a stated interest rate of 4.0%. The agreement expires December 31, 2017. The debt is owing to two of the four shareholders of the parent company as follows:		
Municipality of Leamington	2,150,296	2,150,296
Town of Tecumseh	1,544,408	1,544,408
	3,694,704	3,694,704
Banker's acceptance - TD Canada Trust has a 5 year term ending November 4, 2018, and is repayable with interest only payments at an effective interest rate of 5.44%	3,300,000	3,300,000
Fixed rate loan - TD Canada Trust is a 20 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $39,562, bearing an interest rate of 4.99%. Loan matures November 9, 2019.	4,988,343	5,202,845
Fixed rate loan - TD Canada Trust is a 10 year term loan with a 10 year amortization schedule, repayable in blended monthly payments of $62,122, bearing an interest rate of 4.48%. Loan matures November 9, 2019.	3,284,958	3,868,766
Floating rate loan - TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in monthly principal payments of $8,333, bearing a floating interest rate of prime plus 0%. Loan matures November 30, 2017.	1,800,000	1,900,000
Floating rate loan - TD Canada Trust is a 5 year term loan with a 20 year amortization schedule, repayable in monthly principal payments of $8,333, bearing a floating interest rate of prime plus 0%. Loan matures December 19, 2019.	2,000,000	-
	19,068,005	17,966,315
Less: Current portion of long-term debt	3,258,617	2,381,801
	15,809,388	15,584,514

Approximate long-term principal repayments over five years are as follows:

	$
2015	3,258,617
2016	1,819,414
2017	1,860,484
2018	1,167,504
2019	1,199,248

In addition to the Bankers Acceptances with TD Canada Trust, the Company has entered into an interest rate swap agreement with TD Securities. This agreement is a "receive variable, pay fixed" swap agreement, which effectively convert variable interest rates on Bankers Acceptances to the effective interest rates mentioned above. Refer to note 12 for details on these swap instruments.

8 Capital stock

Authorized

An unlimited number of common shares, Class A, voting
An unlimited number of common shares, Class B, non-voting

Issued	2014 $	2013 $
50 common shares, Class A, voting	5	5
15,772,796 common shares, Class B, non-voting	15,772,796	15,772,796
	15,772,801	15,772,801

9 Related party transactions

The Company engages in transactions with its affiliates and parent company. The following is a summary of the related party transactions. These transactions are measured at exchange amount, which is the amount of consideration established and agreed to by the related parties. The Company is affiliated with Essex Power Services Corporation, Essex Energy Corporation (and its subsidiaries) and Utilismart Corporation (and its subsidiaries) and is the subsidiary of Essex Power Corporation.

	2014 $	2013 $
Management fees due to parent	1,071,227	1,036,741
Amounts due to (from) affiliates	858,153	86,467
Dividends payable to parent	1,016,176	1,030,718

Related party long-term debt payable with the shareholders of Essex Power Corporation is outlined in note 7. The Company was charged interest on the long-term debt by the Essex Power Corporation shareholders in the amount of $147,788.

In 2011, the Company received a non-interest bearing loan from its shareholder for $373,943, with no set repayment terms. An additional $207,738 was received during 2012 from its shareholder with no set repayment terms.

In 2014, the Company sold a Solar Panel asset to Essex Energy Corporation for total consideration of $1,510,000. The related shareholder loan associated with this asset which had a value of $207,738 was also transferred to Essex Energy Corporation.

10 Employee future benefits

Pension plan

The Company provides a pension plan for its full time employees through the Ontario Municipal Employees Retirement System (OMERS). OMERS is a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province for employees of municipalities, local boards and school boards in Ontario. Both participating employers and employees are required to make plan contributions based on participating employees' contributory earnings. The Company records the expense related to this plan as contributions are made. For the year ended December 31, 2014, the Company's OMERS current service pension costs were $339,033 (2013 - $320,005).

Employee future benefits other than pension

The Company pays certain benefits on behalf of its retired employees. Information about the Company's defined benefit plans is as follows:

	2014 $	2013 $
Opening balance at beginning of year	3,885,489	3,954,070
Current service and interest expense net of amortization of plan losses	201,248	27,916
Contributions made in the period	(124,159)	(96,497)
	3,962,578	3,885,489

The main actuarial assumptions employed for the valuations are as follows:

General inflation
Future general inflation levels, as measured by changes in the Consumer Price Index (CPI), were assumed at 2% in 2014 and thereafter.

Interest (discount) rate
The obligation as at December 31, 2014 of the present value of future liabilities and the expense for the year ended December 31, 2014 was determined using a discount rate of 4%.

Medical costs
Medical costs were assumed to increase at the CPI rate plus a further increase of 4.5% in 2014.

Dental costs
Dental costs were assumed to increase at the CPI rate plus a further increase of 4.5% in 2014.

11 Capital management

The Company's objectives are to maintain access to capital on a long-term basis at reasonable rates and to deliver reasonable financial returns to the shareholders.

The Company's capital structure consists of shareholders' equity, retained earnings, solar equity reserve, long-term debt and cash. The capital structure as at December 31, 2014 was as follows:

	2014 $	2013 $
Long-term debt payable within one year	3,258,617	2,381,801
Less: Cash	(140,632)	(1,481,377)
Long-term debt	15,809,388	15,584,514
Net long-term debt	18,927,373	16,484,938
Common shares	15,772,801	15,772,801
Retained earnings	5,272,394	4,144,572
Solar equity reserve	373,943	581,681
Total equity	21,419,138	20,499,054
Total capital	40,346,511	36,983,992
Debt to capital ratio	47%	45%

The Company is required by TD Canada Trust to maintain a funded debt to capitalization ratio not to exceed 60%. At December 31, 2014, the Company is in compliance with this covenant.

12 Financial instruments

Exposure to market risk, credit risk, liquidity risk and interest rate risk arises in the normal course of the Company's business.

Market risk

Market risk refers primarily to the risk of loss that results from fluctuations in commodity prices, foreign exchange rates and interest rates. The Company does not have significant commodity risk or foreign exchange risk. The Company is exposed to fluctuations in interest rates from the market compared to interest rates that are allowed by the regulator in customer rates. As further defined in note 7 to these financial statements, the Company uses derivative financial instruments, primarily interest rate swaps, to manage its interest rate exposure.

Credit risk

The Company is exposed to credit risk with its customers and their ability to pay. The Company's revenue is earned from a broad base of customers in different classes and as such, the Company does not rely on any one single customer for a significant amount of its revenues. As of December 31, 2014, there were no significant balances of accounts receivable owing from any single customer.

Liquidity risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Short-term liquidity is provided through cash and funds from operations. As of December 31, 2014, accounts payable and accrued liabilities of $10,299,086, dividend payable of $1,016,176, due to affiliates of $858,153, current portion of customer deposits of $270,000 and current portion of long-term debt of $3,258,617 are expected to be paid at their carrying values within the next year. Interest payments of approximately $800,000 owing on long-term debt is also expected to be paid within the next year.

Interest rate risk

The Company enters into derivative financial instruments in order to hedge its risk against interest rate fluctuations. The Company has fixed its variable rate long-term Banker's acceptance with the following outstanding interest rate swap agreements:

Notional amount $	Interest rate %	Term of agreement	Repricing period
3,300,000	4.19	November 4, 2018	Monthly

As at December 31, 2014, the unrealized (loss) gain was ($12,302) (2013 - $201,442) for this instrument.

13 Net change in non-cash working capital

The net change in non-cash working capital balances related to operations consists of the following:

	2014 $	2013 $
(Increase) decrease in current assets		
Accounts receivable	(2,240,147)	166,785
Prepaid expenses	(75,343)	(16,939)
Unbilled revenue	1,698,268	(2,209,395)
Income taxes recoverable	277,538	(264,204)
	(339,684)	(2,323,753)
Increase (decrease) in current liabilities		
Accounts payable and accrued liabilities	(1,104,814)	2,027,621
Due to affiliates	771,686	273,801
Customer deposits	(376,613)	375,142
	(709,741)	2,676,564
	(1,049,425)	352,811

14 Emerging accounting changes

International Financial Reporting Standards (IFRS)

On February 13, 2008, the AcSB confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2012. In February 2013, the AcSB decided to permit rate-regulated entities to defer their IFRS implementation date to January 1, 2015. As such, the Company expects to apply IFRS to its financial statements ending December 31, 2015 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2014, for comparative purposes.

15 Commitments and contingencies

The Company subscribes for liability insurance coverage under a self-insurance pool administered by the Municipal Electric Association Reciprocal Insurance Exchange. Under the terms of this co-operative venture, the Company as a pool member, in addition to its regular policy premiums, is contingently liable for any retroactive reassessment if a deficit originates in a year in which they are a member. The contingent liability for reassessment in respect of any year in which the Company is a pool member continues even where the Company subsequently withdraws from the self-insurance pool. The Company will not, however, be subject to reassessment for claims incurred in years in which they are not members of this self-insurance pool.

A letter of credit in the amount of $2,900,000 has been issued by TD Canada Trust to the credit of the Independent Electricity System Operator for the commodity purchases and market services provided. This letter of credit has no term of expiry and is normally renewed annually.

Regulatory (assets) liabilities

The regulatory (assets) liabilities represent certain amounts receivable from future customers or refundable to future customers. These amounts have been deferred for accounting purposes because it is probable that they will be recovered or refunded in future rates. The Ontario Energy Board (OEB) regulates the amounts in these accounts and determines the amounts receivable and refundable to customers through an Incentive Rate Mechanism (IRM) process annually and a Cost of Service (COS) process every 5 years.

During the IRM process to determine 2015 customer rates, errors were discovered that affected the determination of rates for 2014. The errors affecting the deferral variance account rate rider were disclosed to the Ontario Energy Board and a rate order was issued to discontinue the rate rider as of February 1, 2015. The process to determine the outcome of the error correction that may affect customer rates is before the OEB for consideration and resolution of this issue. The OEB may or may not approve the correction of the errors that would result in amounts receivable back from customers and amounts to be refunded to customers. The amounts receivable from customers could be at risk for collection pending OEB approval.

At this time, it cannot be determined if the resolution is probable or not. An adverse decision by the OEB will be appealed by the Company. If management determines that it is no longer probable that the OEB will allow the collection of the amounts receivable from customers in future rates, the applicable carrying amount of the regulatory asset will be reflected in the results of operations in the period that the judgment is made by management.

16 Provision for payments in lieu of corporate income taxes

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. The reconciliation between the statutory and effective tax rates is provided as follows:

	2014 $	2013 $
Income before provision for PILs	2,213,916	3,004,817
Federal and Ontario statutory income tax rate	26.5%	26.5%
Provision for PILs at statutory rate	586,688	796,276
Increase (decrease) resulting from:		
Net temporary differences	(31,959)	(418,608)
Rate reduction arising from Ontario small business deduction	-	(35,000)
Other non-temporary differences	(277,073)	41,855
Total income tax provision for PILs	277,656	384,523
Effective income tax rate	12.54%	12.80%

Financial Statements of

Essex Powerlines Corporation

Year ended December 31, 2015
(Expressed in thousands of dollars)

pwc

May 19, 2016

Independent Auditor's Report

To the Shareholders of
Essex Powerlines Corporation

We have audited the accompanying financial statements of Essex Powerlines Corporation, which comprise the statement of financial position as at December 31, 2015 and December 31, 2014 and January 1, 2014 and the statements of comprehensive income, changes in equity and cash flows for the years ended December 31, 2015 and December 31, 2014, and the related notes, which comprise 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.

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

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

PricewaterhouseCoopers LLP
245 Ouellette Avenue, Suite 300, Windsor, Ontario, Canada N9A 7J4
T: +1 519 985 8900, F: +1 519 258 5457

Opinion
In our opinion, the financial statements present fairly, in all material respects, the financial position of Essex Powerlines Corporation as at December 31, 2015 and December 31, 2014 and January 1, 2014 and its statements of comprehensive income and changes in equity and its cash flows for the years ended December 31, 2015 and December 31, 2014 in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Professional Accountants, Licensed Public Accountants

ESSEX POWERLINES CORPORATION

Statements of Financial Position
(In thousands of dollars)

	Note		December 31, 2015		December 31, 2014		January 1, 2014
Assets							
Current assets							
Cash and cash equivalents	5	$	2,482	$	141	$	1,481
Accounts receivable	6		6,763		8,232		5,992
Due from related parties	19		17		---		---
Unbilled revenue			6,345		5,514		7,212
Income taxes receivable			---		74		352
Materials and supplies			60		60		60
Prepaid expenses			287		322		247
Total current assets			15,954		14,343		15,344
Non-current assets							
Property, plant and equipment	7		51,648		47,375		45,274
Intangible assets	8		265		313		302
Deferred charges			915		1,011		1,142
Deferred tax assets	9		1,144		176		1,273
Total non-current assets			53,972		48,875		47,991
Total assets			69,926		63,218		63,335
Regulatory balances	10		42,323		39,925		34,156
Total assets and regulatory balances		$	112,249	$	103,143	$	97,491

See accompanying notes to the financial statements.

ESSEX POWERLINES CORPORATION

Statements of Financial Position
(in thousands of dollars)

	Note		December 31, 2015		December 31, 2014		January 1, 2014
Liabilities							
Current liabilities							
Accounts payable and accrued liabilities	11	$	13,163	$	10,299	$	11,404
Due to related parties	19		---		858		87
Long-term debt due within one year	12		4,116		3,259		2,382
Income Taxes Payable			155		---		---
Customer deposits			1,213		1,242		1,618
Dividend Payable			1,016		1,016		1,030
Total current liabilities			19,663		16,674		16,521
Non-current liabilities							
Long-term debt	12		16,896		15,809		15,585
Sub debt payable – shareholder	19		374		374		582
Post-employment benefits	13		2,915		2,563		3,600
Non-hedging financial derivatives			316		319		307
Deferred revenue			2,304		875		---
Deferred tax liabilities	9		505		470		760
Total non-current liabilities			23,310		20,410		20,834
Total liabilities			42,973		37,084		37,355
Equity							
Share capital	14		15,773		15,773		15,773
Solar Equity Reserve (appropriation of retained earnings)			374		374		582
Retained earnings			6,772		4,766		3,404
Accumulated other comprehensive income (loss)			749		967		171
Total equity			23,668		21,880		19,930
Total liabilities and equity			66,641		58,964		57,285
Regulatory balances	10		45,608		44,179		40,206
Total liabilities, equity and regulatory balances		$	112,249	$	103,143	$	97,491

See accompanying notes to the financial statements.

On behalf of the Board:

____________________ Director   ____________________ Director

ESSEX POWERLINES CORPORATION

Statements of Income and Comprehensive Income
Years ended December 31, 2015 and 2014
(in thousands of dollars)

	Note	2015	2014
Revenue			
Sale of energy		$ 59,140	$ 58,511
Distribution revenue		13,763	11,091
Solar		390	402
Other	15	1,518	1,492
		74,811	71,496
Operating expenses			
Cost of energy purchased		61,785	59,297
Operating expenses	16	8,130	8,068
Solar Expenses		41	35
Depreciation and amortization		2,139	2,211
		72,095	69,611
Income from operating activities		2,716	1,885
Finance income	17	99	335
Finance costs	17	(911)	(1,135)
Income before income taxes		1,904	1,085
Current tax expense	9	442	278
Future tax expense (recovery)	9	(591)	433
Net income for the year		**2,053**	**374**
Net movement in regulatory balances, net of tax	10	969	1,796
Net income for the year and net movement in regulatory balances		**3,022**	**2,170**
Other comprehensive income			
Items that will not be reclassified to profit or loss:			
Remeasurements of post-employment benefits	13	(326)	1,170
Tax on remeasurements	9	108	(374)
Other comprehensive income for the year		(218)	796
Total comprehensive income for the year		$ **2,804**	$ **2,966**

See accompanying notes to the financial statements.

ESSEX POWERLINES CORPORATION

Statements of Changes in Equity
Years ended December 31, 2015 and 2014
(in thousands of dollars)

	Share capital	Solar Equity	Retained earnings	Accumulated other comprehensive income (loss)	Total
Balance at January 1, 2014	$ 15,773	$ 582	$ 3,404	$ 171	$ 19,930
Net Income and net movement in regulatory balances	---	---	2,170	---	2,170
Other comprehensive income	---	---	---	796	796
Appropriation of retained earnings To solar equity reserve (reversed)	---	(208)	208	---	---
Dividends	---	---	(1,016)	---	(1,016)
Balance at December 31, 2014	$ 15,773	$374	$ 4,766	$ 967	$ 21,880
Balance at January 1, 2015	$ 15,773	$374	$ 4,766	$ 967	$ 21,880
Net income and net movement in regulatory balances	---	---	3,022	---	3,022
Other comprehensive income	---	---	---	(218)	(218)
Dividends	---	---	(1,016)	---	(1,016)
Balance at December 31, 2015	$ 15,773	$ 374	$ 6,772	$ 749	$ 23,668

See accompanying notes to the financial statements.

ESSEX POWERLINES CORPORATION

Statements of Cash Flows
Years ended December 31, 2015 and 2014
(in thousands of dollars)

		2015		2014
Operating activities				
Net Income and net movement in regulatory balances	$	3,022	$	2,170
Adjustments for:				
Depreciation and amortization		2,139		2,211
Amortization of deferred revenue		(19)		(247)
Post-employment benefits		26		133
Losses (gain) on disposal of property, plant and equipment		105		(30)
Unrealized (gain) loss on non-hedging financial derivatives		(3)		12
Decrease in deferred charges		96		131
Net finance costs		812		800
Income tax expense		(149)		711
Change in non-cash operating working capital		2,633		(1,327)
Net movement in regulatory balances		(969)		(1,796)
Income tax paid		(447)		---
Interest paid		(911)		(1,135)
Interest received		99		335
Net cash from operating activities		6,434		1,968
Investing activities				
Purchase of property, plant and equipment and intangibles		(6,469)		(5,850)
Proceeds on disposal of property, plant and equipment		---		1,557
Contributions received from customers		1,448		1,122
Net cash used by investing activities		(5,021)		(3,171)
Financing activities				
Dividends paid		(1,016)		(1,030)
Proceeds from long-term debt		3,000		2,000
Repayment of long-term debt		(1,056)		(1,107)
Net cash from financing activities		928		(137)
Change in cash and cash equivalents		2,341		(1,340)
Cash and cash equivalents, beginning of year		141		1,481
Cash and cash equivalents, end of year	$	2,482	$	141

See accompanying notes to the financial statements.

1. Reporting entity

Essex Powerlines Corporation (the "Corporation") is a rate regulated, municipally owned "local distribution company" (LDC) incorporated under the laws of Ontario, Canada. The Corporation is located in Oldcastle, Ontario. The address of the Corporation's registered office is 2730 Highway 3, Oldcastle, ON N0R 1L0.

The Corporation delivers electricity and related energy services to over 28,000 residential and commercial customers in Amherstburg, LaSalle, Leamington and Tecumseh. The Corporation is wholly owned by Essex Power Corporation. The shareholders of Essex Power Corporation include the Town of Amherstburg, the Town of LaSalle, the Municipality of Leamington and the Town of Tecumseh.

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 25.

The financial statements were approved by the Board of Directors on May 18, 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 thousand.

2. Basis of presentation (continued)

(e) Use of estimates

i) Assumptions and 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 including changes as a result of future decisions made by the OEB and IESO.

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) Note 3(e) – estimation of useful lives of its property, plant and equipment and intangible assets
(iii) Note 3(j) – recognition and measurement of regulatory balances
(iv) Note 13 – measurement of defined benefit obligations: key actuarial assumptions

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 21 – adoption of IFRS: policy choices and exemptions

(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 September 28, 2009 for rates effective May 1, 2010 to April 30, 2011. The GDP IPI-FDD for 2015 is 2.1%, the Corporation's productivity factor is 0% and the stretch factor is 0.15%, resulting in a net adjustment of 1.95% to the previous year's rates.

The Corporation has decided to next apply to have rates rebased by April 2017 for rates effective January 1, 2018. In the interim, the Corporation will continue to file annual IRMs to adjust 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 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(g). Cash and cash equivalents are measured at fair value. The Corporation holds interest rate swaps and measures them at fair value.

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.

Unbilled revenue

Unbilled revenue is recorded based on an estimated amount of electricity delivered and not yet billed. The estimate is calculated by using the customers' actual consumption data up to year end to arrive at the unbilled revenue accrual.

3. Significant accounting policies (continued)

(c) Revenue recognition (continued)

Other revenue

Revenue earned from the provision of services is recognized as the service is rendered or contract milestones are achieved. Amounts received in advance of these milestones are presented as deferred revenue.

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.

(d) 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 a weighted 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.

(e) 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 21(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.

3. Significant accounting policies (continued)

(e) Property, plant and equipment (continued)

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 and fixtures	50
Land	Indefinite
Computer hardware, and other equipment	5 -10
Office equipment	10
Utility Equipment and trucks	7-10
Distribution Equipment	15 -50
Solar Generation	20

3. Significant accounting policies (continued)

(f) 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 21(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.

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
Land rights	50

(g) 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)

(g) 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.

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.

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.

(h) Customer deposits

Customer deposits represent cash deposits from electricity distribution customers and retailers to guarantee the payment of energy bills. Interest is paid annually on customer deposits at a rate of prime business rate less 2%.

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.

(i) 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)

(j) 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)

(k) 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. The last actuarial valuation was done as of December 31, 2014.

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, net interest expense on post-employment benefits and impairment losses on financial 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.

Rate-regulated accounting requires the recognition of regulatory balances and related deferred tax assets and liabilities for the amount of deferred taxes expected to be refunded to or recovered from customers through future electricity distribution rates. A gross up to reflect the income tax benefits associated with reduced revenues resulting from the realization of deferred tax assets is recorded within regulatory credit balances. Deferred taxes that are not included in the rate-setting process are charged or credited to the consolidated statements of income.

4. Standards issued but not yet adopted

Future accounting changes

There are new standards, amendments to standards and interpretations which are not yet effective for the year ended December 31, 2015 and have not been applied in preparing these financial statements.

The Corporation is still evaluating the adoption of the following new and revised standards along with any subsequent amendments.

4. Standards issued but not yet adopted (continued)

Revenue Recognition

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers* ("IFRS 15"), which replaces existing revenue recognition guidance, including IAS 18 Revenue and IFRIC 18 *Transfers of Assets from Customers* ("IFRIC 18"). IFRS 15 replaces IAS 11 Construction Contracts, IAS 18 Revenue and various interpretations and establishes principles regarding the nature, amount, timing and uncertainty of revenue arising from contracts with customers. The standard requires entities to recognize revenue for the transfer of goods or services to customers measured at the amounts an entity expects to be entitled to in exchange for those goods or services. In July 2015, the IASB announced a one-year deferral of the effective date of IFRS 15 to annual periods beginning on or after January 1, 2018. The Corporation is assessing the impact of IFRS 15 on its results of operations, financial position, and disclosures.

Financial Instruments

In July 2014, the IASB issued a new standard, IFRS 9 *Financial Instruments*, which will replace IAS 39 Financial Instruments: Recognition and Measurement. The replacement of IAS 39 is a multi-phase project with the objective of improving and simplifying the reporting for financial instruments. The issuance of IFRS 9 is part of the first phase of this project. IFRS 9 is effective for annual periods beginning on or after January 1, 2018 and must be applied retrospectively with some exceptions. The Corporation is assessing the impact of IFRS 9 on its results of operations, financial position, and disclosures.

Property, Plant, and Equipment and Intangible Assets

In May 2014, the IASB issued amendments to IAS 16, *Property, Plant and Equipment* and IAS 38 *Intangible Assets*, which are effective for years beginning on or after January 1, 2016. The amendments clarify when revenue-based depreciation methods are permitted. The Corporation is assessing the impact of the amendments on its results of operation, financial positions, and disclosures.

Leases

In January 2016, IASB issued IFRS 16 to establish principles for the recognition, measurement, presentation, and disclosure of leases, with the objective of ensuring that lessees and lessors provide relevant information that faithfully represents those transactions. IFRS 16 replaces IAS 17 and it is effective for annual periods beginning on or after January 1, 2019 and will be applied retrospectively with some exceptions. Early adoption is permitted if IFRS 15 has been adopted. The Corporation is assessing the impact of IFRS 16 on its results of operations, financial positions, and disclosures.

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.

(in thousands of dollars)

5. Cash and cash equivalents

	December 31, 2015	December 31, 2014	January 1, 2014
Bank balances	$ 2,482	$ 141	$ 1,481
Cash and cash equivalents in the statements of cash flows	$ 2,482	$ 141	$ 1,481

6. Accounts receivable

	December 31, 2015	December 31, 2014	January 1, 2014
Trade receivables	$ 5,867	$ 7,213	$ 5,172
Other receivables	803	871	713
Billable work	93	148	107
	$ 6,763	$ 8,232	$ 5,992

ESSEX POWERLINES CORPORATION

Notes to Financial Statements
Years ended December 31, 2015 and 2014
(In thousands of dollars)

7. 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	**$**	**2,190**	**$**	**42,525**	**$**	**4,057**	**$**	**381**	**$**	**49,153**
Additions		49		5,110		1,095		183		6,437
Transfers		---		---		---		---		---
Disposals/retirements		---		(158)		---		---		(158)
Balance at December 31, 2015	$	2,239	$	47,477	$	5,152	$	564	$	55,432
Balance at January 1, 2014	$	2,190	$	36,600	$	5,389	$	1,095	$	45,274
Additions		---		5,211		549		---		5,760
Transfers		---		714		---		(714)		---
Disposals/retirements		---		---		(1,881)		---		(1,881)
Balance at December 31, 2014	$	2,190	$	42,525	$	4,057	$	381	$	49,153
Accumulated depreciation										
Balance at January 1, 2015	$	27	$	1,655	$	96	$	---	$	1,778
Depreciation		41		1,540		478		---		2,059
Disposals/retirements		---		(53)		---		---		(53)
Balance at December 31, 2015	$	68	$	3,142	$	574	$	---	$	3,784
Balance at January 1, 2014	$	---	$	---	$	---	$	---	$	---
Depreciation		27		1,655		450		---		2,132
Disposals/retirements		---		---		(354)		---		(354)
Balance at December 31, 2014	$	27	$	1,655	$	96	$	---	$	1,778
Carrying amounts										
At December 31, 2015	$	2,171	$	44,335	$	4,578	$	564	$	51,648
At December 31, 2014		2,163		40,870		3,961		381		47,375
At January 1, 2014		2,190		36,600		5,389		1,095		45,274

At December 31, 2015 land and buildings with a carrying amount of $2,171 (December 31, 2014 - $2,163; January 1, 2014 - $2,190) are subject to a general security agreement.

(In thousands of dollars)

8. Intangible assets

	Computer software	Land rights	Total
Cost or deemed cost			
Balance at January 1, 2015	$ 214	$ 178	$ 392
Additions	17	15	32
Balance at December 31, 2015	231	193	424
Balance at January 1, 2014	139	163	302
Additions	75	15	90
Balance at December 31, 2014	$ 214	$ 178	$ 392
Accumulated amortization			
Balance at January 1, 2015	$ 75	$ 4	$ 79
Amortization	76	4	80
Balance at December 31, 2015	151	8	159
Balance at January 1, 2014	---	---	---
Amortization	75	4	79
Balance at December 31, 2014	$ 75	$ 4	$ 79
Carrying amounts			
At December 31, 2015	$ 80	$ 185	$ 265
At December 31, 2014	139	174	313
At January 1, 2014	139	163	302

9. Income tax expense

Current tax expense

	2015	2014
Current tax expense	$ 442	$ 278
Deferred tax expense	(591)	433
	$ (149)	$ 711

(in thousands of dollars)

9. Income tax expense (continued)

Reconciliation of effective tax rate

	2015	2014
Income before taxes	$ 1,904	$ 1,085
Canada and Ontario statutory Income tax rates	26.5%	26.5%
Expected tax provision on income at statutory rates	505	288
Increase (decrease) in income taxes resulting from:		
Other	(654)	423
Income tax expense	$ (149)	$ 711

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	$ (20)	$ (871)	$ (143)
Post-employment benefits	1,050	932	1,305
Other	114	115	111
	$ 1,144	$ 176	$ 1,273

	December 31, 2015	December 31, 2014	January 1, 2014
Deferred tax liabilities:			
Non-regulated solar assets	$ 505	$ 470	$ 760

(in thousands of dollars)

ESSEX POWERLINES CORPORATION

10. 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
Group 1 deferred accounts	$	9,980	$	(7,794)	$	(644)	$	1,542	---
Extraordinary event costs		83		---		---		83	---
Regulatory settlement account		5,254		(1,724)		8,088		11,618	1-3
Other regulatory accounts		24,608		(977)		5,449		29,080	---
	$	39,925	$	(10,495)	$	12,893	$	42,323	

Regulatory deferral account debit balances		January 1, 2014		Additions		Recovery/ reversal		December 31, 2014	Remaining years
Group 1 deferred accounts	$	1,628	$	8,942	$	(590)	$	9,980	---
Extraordinary event costs		83		---		---		83	---
Regulatory settlement account		14,704		(1,360)		(8,090)		5,254	1
Other regulatory accounts		17,741		1,409		5,458		24,608	---
	$	34,156	$	8,991	$	(3,222)	$	39,925	---

Regulatory deferral account credit balances		January 1, 2015		Additions		Recovery/ reversal		December 31, 2015	Remaining years
Group 1 deferred accounts	$	(10,142)	$	5,915	$	(37)	$	(4,264)	---
Regulatory transition to IFRS		(623)		---		---		(623)	---
Regulatory settlement account		(7,166)		(5)		(2,880)		(10,051)	1-3
Other regulatory accounts		(25,603)		220		(3,782)		(29,165)	---
Income tax		(645)		(860)		---		(1,505)	---
	$	(44,179)	$	5,270	$	(6,699)	$	(45,608)	

Regulatory deferral account credit balances		January 1, 2014		Additions		Recovery/ reversal		December 31, 2014	Remaining years
Group 1 deferred accounts	$	(5,902)	$	(9,774)	$	5,534	$	(10,142)	---
Regulatory transition to IFRS		(466)		(157)		---		(623)	---
Regulatory settlement account		(13,477)		1,338		4,973		(7,166)	---
Other regulatory accounts		(18,993)		(901)		(5,709)		(25,603)	---
Income tax		(1,368)		723		---		(645)	---
	$	(40,206)	$	(8,771)	$	4,798	$	(44,179)	---

10. 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.

Typically, settlement of the Group 1 deferral accounts is done on an annual basis through application to the OEB. EPL did not apply to recover its Group 1 Deferral and Variance accounts since balances were below the OEB materiality threshold for eligibility to apply for recovery. The OEB is conducting an audit of these Group 1 accounts and an application to recover the accounts is pending the outcome of this audit. Once approval is received, the approved account balance will be moved to the regulatory settlement account as required by the regulator.

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 recovered from/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 between 1.10% and 1.47%.

Group 1 deferred accounts are comprised of variances between amounts charged by the Independent Electricity System Operator for the operation of wholesale electricity market and the cost of electricity, the amounts from Hydro One for network line and transformation charges and amounts billed to customers.

Extraordinary event costs represent costs incurred to restore services following storms in 2010.

Regulatory settlement accounts represent amounts collected from customers through rates. These amounts will be held until approved by the Ontario Energy Board to be refunded to or recovered from customers.

Other regulatory accounts represent amounts for costs incurred by the Corporation to serve customers that have been enrolled by a commodity retailer and for miscellaneous other costs that will be recovered from customers.

Regulatory transition to IFRS represents changes in estimates and other variances arising from the transition to IFRS which will be held until approved by the Ontario Energy Board to be refunded to or recovered from customers.

Income tax represents an amount of a future tax liability which will be refunded to customers through future rates.

(in thousands of dollars)

11. Accounts payable and accrued liabilities

	December 31, 2015	December 31, 2014	January 1, 2014
Accounts payable – energy purchases	$ 2,860	$ 1,143	$ 2,358
Debt retirement charge payable to OEFC	277	261	306
Payroll payable	269	184	218
Other	9,757	8,711	8,522
	$ 13,163	$ 10,299	$ 11,404

12. Long-term debt

	2015	2014	January 1, 2014
Related party long-term loan payable is repayable as approved by the Board of Directors not to exceed 20% of the principal lending amount if funds are available as determined each March. Interest is payable at a stated interest rate of 4.0%. The agreement expires December 31, 2017. The debt is owing to two of the four shareholders of the parent company as follows:			
Municipality of Leamington	2,150	2,150	2,150
Town of Tecumseh	1,545	1,545	1,545
	3,695	3,695	3,695
Banker's acceptance - TD Canada Trust has a 5 year term ending November 4, 2018, and is repayable with interest only payments at an effective interest rate of 5.03%	3,300	3,300	3,300
Fixed rate loan - TD Canada Trust is a 20 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $40, bearing an interest rate of 4.99%. Loan matures November 9, 2019.	4,757	4,988	5,203
Fixed rate loan - TD Canada Trust is a 10 year term loan with a 10 year amortization schedule, repayable in blended monthly payments of $62, bearing an interest rate of 4.48%. Loan matures November 9, 2019.	2,674	3,285	3,869
Fixed rate loan - TD Canada Trust is a 5 year term loan with a 20 year amortization schedule, repayable in monthly payments of $10, bearing an interest rate of 2.47%. Loan matures October 24, 2020.	1,704	1,800	1,900
Fixed rate loan - TD Canada Trust is a 5 year term loan with a 20 year amortization schedule, repayable in monthly payments of $10, bearing an interest rate of 2.47%. Loan matures October 19, 2020.	1,902	2,000	-

(in thousands of dollars)

Fixed rate Loan - TD Canada Trust is a 5 year term loan with a 10 year amortization schedule, repayable in monthly principal payments of $16 bearing an interest rate of 2.47%. Loan matures on October 19, 2020	2,980	-	-
	21,012	19,068	17,967
Less: Current portion of long-term debt	4,116	3,259	2,382
	16,896	15,809	15,585

Approximate long-term principal repayments over the next five years and thereafter are as follows:

	$
2016	4,116
2017	1,948
2018	1,263
2019	4,964
2020	5,421
Thereafter	3,300
	21,012

In addition to the Bankers Acceptances with TD Canada Trust, the Company has entered into an interest rate swap agreement with TD Securities. This agreement is a "receive variable, pay fixed" swap agreement, which effectively convert variable interest rates on Bankers Acceptances to the effective interest rates mentioned above. Refer to note 20 for details on these swap instruments.

13. 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 $326 to OMERS (2014 - $339), of which $150 (2014 - $115) has been capitalized as part of PP&E and the remaining amount of $176 (2014 - $224) has been recognized in profit or loss. The Corporation estimates that a contribution of $350 to OMERS will be made during the next fiscal year.

As at December 31, 2015, OMERS had approximately 461,000 members, of whom 42 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 $7,000,000. This unfunded liability is likely to result in future payments by participating employers and members.

(in thousands of dollars)

(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.

Reconciliation of the obligation		2015		2014
Defined benefit obligation, beginning of year	$	2,563	$	3,600
Included in profit or loss				
Current service cost		87		76
Interest cost		103		181
		2,753		3,857
Included in OCI				
Actuarial (gains) losses arising from:				
changes in demographic assumptions		252		(1,417)
changes in financial assumptions—discount rate		74		247
		326		(1,170)
Benefits paid		(164)		(124)
Defined benefit obligation, end of year	$	2,915	$	2,563

Actuarial assumptions	2015	2014
General inflation	2.00%	2.00%
Discount (interest) rate	3.75%	4.00%
Medical Costs	7.50%	8.00%
Dental Costs	4.50%	4.50%

(b) Post-employment benefits other than pension (continued)

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing by $281. A 1% decrease in the assumed discount rate would result in the defined benefits obligation increasing by $329.

A 1% increase in the assumed trend rate would result in the defined benefit obligation increasing by $287. A 1% decrease in the assumed trend rate would result in the defined benefit obligation decreasing by $249.

(in thousands of dollars)

14. Share capital

	2015	2014
Authorized:		
Unlimited number of common shares, Class A, voting		
Unlimited number of common shares, Class B, non-voting		
Issued:		
50 common shares, Class A, voting	$ -	$ -
15,772,796 common shares, Class B, non-voting	15,773	15,773
	$ 15,773	$ 15,773

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 $0.06 per share (2014 - $0.06), which amount to total dividends paid in the year of $1,016 (2014 - $1,016).

15. Other revenue

	2015	2014
Rental revenue for joint use of poles	$ 115	$ 130
Billing services to ultimate shareholders	1,014	1,014
Deferred revenue recognized	19	247
Gain (loss) from retirement of assets	(105)	30
Other	475	71
	$ 1,518	$ 1,492

16. Operating expenses

	2015	2014
Contract/consulting	$ 1,318	$ 1,260
Materials and supplies	1,073	888
Salaries, wages and benefits	3,035	3,074
Post-employment benefit plans	190	256
Vehicles	130	168
Other	2,384	2,422
	$ 8,130	$ 8,068

(in thousands of dollars)

17. Finance income and costs

		2015		2014
Finance income				
Interest income on bank deposits	$	99	$	335
Finance costs				
Interest expense on long-term debt		748		687
Interest expense on customer deposits		3		3
Other		160		445
		911		1,135
Net finance costs recognized in profit or loss	$	812	$	800

18. Commitments and contingencies

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 Company subscribes for liability insurance coverage under a self-insurance pool administered by the Municipal Electric Association Reciprocal Insurance Exchange. Under the terms of this co-operative venture, the Company as a pool member, in addition to its regular premiums, is contingently liable for any retroactive reassessment if a deficit originates in a year in which they are a member. The contingent liability for reassessment in respect of any year in which the Company is a pool member continues even where the Company subsequently withdraws from the self-insurance pool. The Company will not, however, be subject to reassessment for claims incurred in years in which they are not members of this self-insurance pool. As at December 31, 2015 no assessments have been made.

Regulatory Assets/Liabilities

The regulatory assets and liabilities represent certain amounts receivable or refundable to future customers. These amounts have been deferred for accounting purposes because it is probable that they will be recovered or refunded in future rates. The Ontario Energy Board (OEB) regulates Essex Powerlines Corporation and determines the amounts receivable and refundable to customers through an Incentive Rate Mechanism (IRM) and/or a Cost of Service (COS) rate application rate proceedings.

In February 2015, Essex Powerlines requested that the OEB issue an order to cease the 2014 Deferral and Variance Account rate riders, in order to mitigate any further impacts of errors, until such time as the OEB determines an appropriate remedy. On February 27, 2015 the OEB ordered Essex Powerlines to cease the 2014 Deferral and Variance Account rate riders. This action was intended to limit the impact of the error which Essex Powerlines estimates to be approximately $3,600. Essex Powerlines made adjustments in its books and records to correct this error; although more adjustments may be required as a result of the current OEB audit process. The 2013 related DVA balances have not yet been disposed on a final basis.

During the IRM rate application proceeding process to determine the 2015 rates for Essex Powerlines' customers, a number of errors were discovered that resulted in the OEB's Decision and Order ("Decision and Order") EB-2014-0301 EB-2014-0072 issued by the OEB on June 9, 2015.

The Decision and Order stated that the errors made by Essex Powerlines were not minor and impacted its customers in a material way. In addition, the OEB raised its concern about Essex Powerlines' regulatory accounting controls. As part of the Decision and Order, the OEB ordered an audit of all Essex Powerlines deferral and variance accounts (except smart meter accounts 1555 and 1556), procedures and controls. The OEB audit commenced on January 15, 2016 and as at the date of the audited financial statements is still on-going. The conclusion of the OEB audit may lead to making adjustments by Essex Powerlines to the DVA account balances in the Essex Powerlines' 2016 financial statements.

One of the errors was related to a misallocation between two Group 1 Deferral and Variance Accounts; Account 1588 – RSVA Power, and Account 1589 – RSVA Global Adjustment, and incorrect cost allocation in 2011, 2012 and 2013 between all customers (including Regulated Price Plan (RPP) customers) and non-RPP customers. The 2011 and 2012 DVA balances of approximately $5,200 had previously been approved by the OEB and disposed on a final basis and a new rate rider commenced in 2014. As a result, August 10, 2015 the OEB self-initiated a Motion to Review, EB-2015-0240 ("Motion to Review") regarding the above-noted Decision and Order. At the time of issuance of these audited financial statements, the outcome of the Motion to Review has not yet been determined by the OEB.

Letter of Credit

A letter of credit in the amount of $2,900 has been issued by TD Canada Trust to the credit of the Independent Electricity System Operator for the commodity purchases and market services provided. This letter of credit has no term of expiry and is normally renewed annually.

19. Related party transactions and balances

(a) Parent and jointly controlling shareholders

The sole shareholder of the Corporation is Essex Power Corporation, which in turn is wholly-owned by the Towns of Amherstburg, LaSalle and Tecumseh, and the Municipality of Leamington. The Towns and Municipality produce financial statements that are available for public use.

(in thousands of dollars)

(b) Outstanding balances with related parties

	2015	2014	January 1, 2014
Balances due to:			
Essex Power Corporation	$ 3	$ 886	$ 104
Essex Energy Corporation	224	268	108
Essex Power Services Corporation	4	-	2
Utilismart Corporation	29	-	20
Municipality of Leamington	86	-	-
Town of Tecumseh	64	-	-
	$ 410	**$ 1,154**	**$ 234**
Balances due from:			
Town of Amherstburg	35	34	34
Essex Power Services Corporation	46	-	27
Utilismart Corporation	11	-	-
Town of LaSalle	23	40	51
Town of Tecumseh	25	41	47
Municipality of Leamington	31	32	62
	$ 171	**$ 147**	**$ 221**

All balances due from and due to related parties listed above are included within accounts receivable and accounts payable respectively. Amounts are non-interest bearing with repayment terms similar to other trade accounts receivable and accounts payable. The amounts disclosed separately as due from related parties or due to related parties, as well as the sub debt payable – shareholder are non-interest bearing with no specified repayment terms.

(c) Transactions with parent

During the year the Corporation paid management fees to its parent in the amount of $1,132 (2014 - $1,072).

(d) Transactions with ultimate jointly controlling shareholders

The Corporation had the following significant transactions with its ultimate parents, government entities: the Towns of Amherstburg, LaSalle and Tecumseh, and the Municipality of Leamington.

The Corporation delivers electricity to these entities throughout the year for the electricity needs of the Towns and Municipality. Electricity delivery charges are at prices and under terms approved by the OEB. The Corporation also provides additional services to the Towns and Municipality, including billing and customer care services. The total revenues related to these services for 2015 were $1,014 (2014 - $1,014).

(in thousands of dollars)

(e) Key management personnel

The key management personnel of the Corporation have been defined as members of its board of directors and senior management team members. The compensation paid or payable is as follows:

		2015		2014
Directors' fees	$	6	$	---
Salaries and bonuses		305		259
	$	311	$	259

20. 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.

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 Towns of Amherstburg, LaSalle, Tecumseh and the Municipality of Leamington. No single customer accounts for a balance in excess of 1.72% of total accounts receivable.

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 $188 (2014 - $137). An impairment loss of $190 (2014 - $136) 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 $419 (2014 - $395) is considered 60 or more days past due. The Corporation has over 29,000 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 $1,213 (2014 - $1,242).

(in thousands of dollars)

(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.

(c) Interest Rate Risk

The Company enters into derivative financial instruments in order to hedge its risk against interest rate fluctuations. The Company has fixed its variable rate long-term Banker's acceptance with the following outstanding interest rate swap agreements:

Notional amount	Interest rate	Term of Agreement	Repricing Period
$3,300	4.19%	November 4, 2018	Monthly

As at December 31, 2015, the unrealized loss was $3 (2014 – gain of $12).

A 1% variation the interest rate at December 31, 2015 would increase or decrease this loss by $33, assuming all other variables remain constant.

(d) 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 $4,000 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, no amounts had been drawn under the Corporation's credit facility.

The Corporation also has a bilateral facility for $2,900 (the "LC" facility) for the purpose of issuing letters of credit mainly to support the prudential requirements of the IESO, of which none has been drawn and posted with the IESO during 2015 or 2014.

The majority of accounts payable, as reported on the statement of financial position, are due within 30 days. Customer deposits are due on demand. Scheduled repayments associated with long-term debt is described within note 12.

(e) 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 $23,668 (December 31, 2014 - $21,880; January 1, 2014 - $19,930) and long-term debt amounts to $21,012 (December 31, 2014 - $19,068; January 1, 2014 - $17,967). The Corporation's debt agreement includes restrictive covenants such as limitations on additional indebtedness, and restrictions on mergers, amalgamations or consolidations.

21. 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 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 determined that certain debit and credit balances arising from rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with IFRS 14 and have elected to apply this Standard in its first IFRS financial statements.

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.

IFRS Mandatory exceptions

IFRS 1 states that estimates made in accordance with IFRS at the date of transition should be consistent with estimates made under previous GAAP. Accordingly, estimates previously made under CGAAP were not revised at the date of transition except where necessary to reflect changes in accounting policies.

IFRS 1 Optional exemptions

(a) Transfer of assets from customers

The corporation has elected to apply the transitional provisions in IFRIC 18 *Transfers of Assets from Customers,* which allows a first-time adopter to apply IFRIC 18 prospectively to transfers of assets from customers received on or after the date of transition. This provision states that the effective date of this standard should be July 1, 2019 or the date of transition to IFRS whichever is the later.

(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 quality 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 $45,274 for PP&E and $302 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.

(in thousands of dollars)

21. 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
Cash and cash equivalents		1,481	-	-	1,481
Accounts receivable		5,992	-	-	5,992
Unbilled revenue		7,212	-	-	7,212
Income taxes receivable		352	-	-	352
Materials and supplies		60	-	-	60
Prepaid expenses		247	-	-	247
Total current assets		15,344	-	-	15,344
Deferred charges		1,142	-	-	1,142
Property, plant and equipment	a, h	43,011	2,263	-	45,274
Intangible assets	a, h	-	302	-	302
Deferred tax assets	e, g, j	1,332	-	(59)	1,273
Total assets		60,829	2,565	(59)	63,335
Regulatory balances	f	-	34,156	-	34,156
Total assets and regulatory balances		60,829	36,721	(59)	97,491
Accounts payable and accrued liabilities		11,404	-	-	11,404
Dividends Payable		1,030	-	-	1,030
Due to related parties		87	-	-	87
Long-term debt due within a year		2,382	-	-	2,382
Customer deposits	g	270	1,348	-	1,618
Regulatory liabilities	f	3,449	(3,449)	-	-
Total current liabilities		18,622	(2,101)	-	16,521
Non-hedging financial derivatives		307	-	-	307
Customer deposits	g	1,348	(1,348)	-	-
Long-term debt		15,585	-	-	15,585
Sub debt payable- shareholder		582	-	-	582
Post-employment benefits	e	3,885	-	(285)	3,600
Deferred tax liabilities	j	-	-	760	760
Total liabilities		40,329	(3,449)	475	37,355
Share capital		15,773	-	-	15,773
Solar Equity (appropriated from retained earnings)		582	-	-	582
Retained earnings	g, j	4,145	-	(741)	3,404
Accumulated OCI	e	-	-	171	171
Total liabilities and equity		60,829	(3,449)	(95)	57,285
Regulatory balances	f	-	40,170	36	40,206
Total liabilities, equity and regulatory balances		60,829	36,721	(59)	97,491

ESSEX POWERLINES CORPORATION

Notes to Financial Statements
Years ended December 31, 2015 and 2014
(in thousands of dollars)

21. 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
Cash and cash equivalents		141	-	-	141
Accounts receivable		8,232	-	-	8,232
Unbilled revenue		5,514	-	-	5,514
Income taxes receivable		74	-	-	74
Material and supplies		60	-	-	60
Prepaid expenses		322	-	-	322
Total current assets		14,343	-	-	14,343
Deferred charges		1,011	-	-	1,011
Property, plant and equipment	a, c, h	44,264	3,111	-	47,375
Intangible assets	a, h	-	313	-	313
Deferred tax assets	g, j	1,286	-	(1,110)	176
Total assets		60,904	3,424	(1,110)	63,218
Regulatory balances	f	-	39,925	-	39,925
Total assets and regulatory balances		60,904	43,349	(1,110)	103,143
Accounts payable and accrued liabilities		10,299	-	-	10,299
Dividends Payable		1,016	-	-	1,016
Due to related parties		858	-	-	858
Long-term debt due within one year		3,259	-	-	3,259
Customer deposits	g	270	972	-	1,242
Regulatory balances	f	2,346	(2,346)	-	-
Total current assets		18,048	(1,374)	-	16,674
Non-hedging financial derivatives		319	-	-	319
Customer deposits	g	972	(972)	-	-
Long-term debt		15,809	-	-	15,809
Sub debt payable		374	-	-	374
Post-employment benefits	e	3,963	-	(1,400)	2,563
Deferred revenue	c	-	875	-	875
Deferred tax liabilities	j	-	-	470	470
Total liabilities		39,485	(1,471)	(930)	37,084
Share capital		15,773	-	-	15,773
Solar Equity (appropriated from retained earnings)		374	-	-	374
Retained earnings	g, j	5,272	-	(506)	4,766
Accumulated OCI	e	-	-	967	967
Total liabilities and equity		60,904	(1,471)	(469)	58,964
Regulatory balances	f	-	44,820	(641)	44,179
Total liabilities, equity and regulatory balances		60,904	43,349	(1,110)	103,143

(in thousands of dollars)

21. Explanation of transition to IFRS (continued)

Reconciliation of net income for 2014

	Note	CGAAP	Presentation differences	Measurement & recognition differences	IFRS
Revenue					
Sale of energy	g, k	68,594	(10,083)	-	58,511
Distribution revenue	k	-	11,091	-	11,091
Solar		402	-	-	402
Other	c	1,245	247	-	1,492
		70,241	1,255	-	71,496
Operating expenses					
Cost of energy purchased	g	57,503	1,794	-	59,297
Operating expenses	f	7,872	141	55	8,068
Solar expenses		35	-	-	35
Depreciation and amortization	c, g	1,727	484	-	2,211
		67,137	2,419	55	69,611
Income from operating activities		3,104	(1,164)	(55)	1,885
Finance income	j	-	335	-	335
Finance costs	j	-	(1,135)	-	(1,135)
		-	(800)	-	(800)
Other revenue (expenses)	j	(890)	890	-	-
Income before income taxes		2,214	(1,074)	(55)	1,085
Income tax expense current		278	-	-	278
Income tax expense future	e	-	34	399	433
		278	34	399	711
Net income for the year		1,936	(1,108)	(454)	374
Net movement in regulatory balances, net of tax	g	-	1,108	688	1,796
Net income and net movement in regulatory balances		1,936	-	234	2,170
Other comprehensive income					
Remeasurement of post-employment benefits	f	-	-	1,170	1,170
Tax on remeasurements	f	-	-	(374)	(374)
Total comprehensive income for the year		1,936	-	796	2,966

21. Explanation of transition to IFRS (continued)

Notes to the reconciliations

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 $22,025 and $1,126 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 $875 at December 31, 2014; to increase PP&E by $875 at December 31, 2014 and to increase other revenue and depreciation expense by $247 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. There have been no losses incurred as a result of such removals.

e. In previous years, deferred taxes related to unregulated solar assets were grouped with deferred taxes for regulated assets. The treatment and presentation has been revised in accordance with rate regulation recovery practices.

21. Explanation of transition to IFRS (continued)

f. 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 decreased post-employment benefits by $285, decreased deferred tax assets by $95, increased opening accumulated other comprehensive income by $171 and increased retained earnings by $18 at January 1, 2014. As at December 31, 2014 the impact of these recognition and measurement differences is a decrease to post-employment benefits of $1,400, a decrease in deferred tax assets of $469, an increase in opening accumulated other comprehensive income of $171, an increase to opening retained earnings of $18, an increase to other comprehensive income of $779 net of tax, an increase to operating expenses of $55.

g. IFRS 14 permits a rate-regulated entity to continue to apply its previous GAAP accounting policies for the recognition, measurement, impairment and derecognition of regulatory balances. However, all regulatory balances and related deferred tax amounts are reclassified to a new and separate section of the consolidated balance sheet. As well, the net income effect of all changes in regulatory balances must be segregated in a new separate section of the consolidated statement of income. Amounts that are permitted or required to be recognized under another IFRS are excluded from the regulatory balances.

   For the Corporation, the impact of IFRS 14 at January 1, 2014 was to transfer the smart meter capital expenditures to PP&E, and to transfer all regulatory debit and credit balances to separate lines below what was formerly known as "Total assets" and "Total liabilities and equity", respectively. The impact of this change as at January 1, 2014 was to reduce current regulatory liabilities by $3,449, and increase PP&E by $2,565, regulatory debit balances by $34,156 and regulatory credit balances by $40,170.

   As at December 31, 2014, the impact was to reduce current regulatory liabilities by $2,346, and increase PP&E by $2,351, regulatory debit balances by $39,925 and regulatory credit balances by $44,820. For the year ended December 31, 2014, the impact was to increase sale of energy by $1,008, increase cost of power purchased by $1,794, distribution expense by $141, increase depreciation and amortization expense by $214, increase future income tax expense by $34, and net movements in regulatory balances, net of tax by $1,108.

h. Customer deposits at January 1, 2014 of $1,348 and at December 31, 2014 of $972 which were previously classified as long-term liabilities were reclassified as current liabilities since they are due on demand.

i. Intangible assets at January 1, 2014 of $302 and at December 31, 2014 of $313 which were previously classified within PP&E were reclassified as intangible assets on the balance sheet.

j. Finance income of $355 previously included in other income/expense for the year ended December 31, 2014 was reclassified to Finance income within the statement of income and other comprehensive income. Finance expense of $1,135 previously included in other income/expense for the year ended December 31, 2014 was reclassified to Finance expense within the statement of income and other comprehensive income.

k. Distribution revenue of $11,091 previously included in sale of energy for the year ended December 31, 2014 was reclassified to Distribution revenue within the statement of income and comprehensive income.

Explanation of material adjustments to the statement of cash flows for 2014:

Reclassification of capital contributions received to finance additions to PP&E from investing activities to operating activities, and inclusion of amortization of deferred revenue related to capital contributions in operating activities. Under CGAAP, capital contributions were treated as a reduction of PP&E and associated cash flows were classified as investing activities. Under IFRS, the Corporation treats capital contributions as deferred revenue and classifies the associated cash flows as operating activities;

Presentation of income taxes paid and interest paid within the body of the statements of cash flows as part of operating and financing activities, respectively, whereas they were previously disclosed as supplementary information; and

Reclassification of adjustments relating to regulatory balances within operating activities to "Net movements in regulatory balances" in the application of IFRS 14.

Financial Statements of

Essex Powerlines Corporation

Year ended December 31, 2016
(Expressed in thousands of dollars)

pwc

April 27, 2017

Independent Auditor's Report

To the Shareholders of
Essex Powerlines Corporation

We have audited the accompanying financial statements of Essex Powerlines Corporation, which comprise the statement of financial position as at December 31, 2016 and December 31, 2015 and the statements of comprehensive income, changes in equity and cash flows for the years ended December 31, 2016 and December 31, 2015, and the related notes, which comprise 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.

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

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

PricewaterhouseCoopers LLP
245 Ouellette Avenue, Suite 300, Windsor, Ontario, Canada N9A 7J4
T: +1 519 985 8900, F: +1 519 258 5457

Opinion
In our opinion, the financial statements present fairly, in all material respects, the financial position of Essex Powerlines Corporation as at December 31, 2016 and December 31, 2015 and its statements of comprehensive income and changes in equity and its cash flows for the years ended December 31, 2016 and December 31, 2015 in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Professional Accountants, Licensed Public Accountants

ESSEX POWERLINES CORPORATION

Statements of Financial Position
(in thousands of dollars)

	Note	December 31, 2016	December 31, 2015
Assets			
Current assets			
Cash and cash equivalents	5	$ ---	$ 2,482
Accounts receivable	6	7,794	6,763
Due from related parties	19	130	17
Unbilled revenue		6,601	6,345
Income taxes receivable		287	---
Materials and supplies		643	60
Prepaid expenses		182	287
Total current assets		15,637	15,954
Non-current assets			
Property, plant and equipment	7	53,774	51,648
Intangible assets	8	412	265
Deferred charges		682	915
Deferred tax assets	9	481	1,144
Total non-current assets		55,349	53,972
Total assets		70,986	69,926
Regulatory balances	10	39,824	42,323
Total assets and regulatory balances		$ 110,810	$ 112,249

See accompanying notes to the financial statements.

ESSEX POWERLINES CORPORATION

Statements of Financial Position
(in thousands of dollars)

	Note		December 31, 2016		December 31, 2015
Liabilities					
Current liabilities					
Bank indebtedness	5	$	527	$	---
Accounts payable and accrued liabilities	11		15,411		13,163
Long-term debt due within one year	12		4,944		4,116
Income Taxes Payable			---		155
Customer deposits			1,431		1,213
Dividend Payable			1,046		1,016
Total current liabilities			23,359		19,663
Non-current liabilities					
Long-term debt	12		15,908		16,896
Sub debt payable – shareholder	19		374		374
Post-employment benefits	13		3,006		2,915
Non-hedging financial derivatives			198		316
Deferred revenue			3,133		2,304
Deferred tax liabilities	9		541		505
Total non-current liabilities			23,160		23,310
Total liabilities			46,519		42,973
Equity					
Share capital	14		15,773		15,773
Solar Equity Reserve (appropriation of retained earnings)			374		374
Retained earnings			8,832		6,772
Accumulated other comprehensive income			749		749
Total equity			25,728		23,668
Total liabilities and equity			72,247		66,641
Regulatory balances	10		38,563		45,608
Total liabilities, equity and regulatory balances		$	110,810	$	112,249

See accompanying notes to the financial statements.

On behalf of the Board:

Director

Director

ESSEX POWERLINES CORPORATION

Statements of Income and Comprehensive Income
Years ended December 31, 2016 and 2015
(in thousands of dollars)

	Note	2016	2015
Revenue			
Sale of energy		$ 72,553	$ 59,140
Distribution revenue		10,803	13,763
Solar generation		395	390
Other	15	1,538	1,518
		85,289	74,811
Operating expenses			
Cost of energy purchased		74,762	61,785
Operating expenses	16	8,256	8,130
Solar expenses		51	41
Depreciation and amortization		2,249	2,139
		85,318	72,095
Income from operating activities		(29)	2,716
Finance income	17	54	99
Finance costs	17	(896)	(911)
Income (loss) before income taxes		(871)	1,904
Current tax expense	9	170	442
Future tax expense (recovery)	9	699	(591)
Net income (loss) for the year		**(1,740)**	**2,053**
Net movement in regulatory balances, net of tax	10	4,325	969
Net income for the year and net movement in regulatory balances		**2,585**	**3,022**
Other comprehensive income			
Items that will not be reclassified to profit or loss:			
Remeasurements of post-employment benefits	13	---	(326)
Tax on remeasurements	9	---	108
Other comprehensive income for the year		---	(218)
Total comprehensive income for the year		**$ 2,585**	**$ 2,804**

See accompanying notes to the financial statements.

ESSEX POWERLINES CORPORATION

Statements of Changes in Equity
Years ended December 31, 2016 and 2015
(in thousands of dollars)

	Share capital	Solar Equity	Retained earnings	Accumulated other comprehensive income (loss)	Total
Balance at January 1, 2015	$ 15,773	$374	$ 4,766	$ 967	$ 21,880
Net Income and net movement in regulatory balances	---	---	3,022	---	3,022
Other comprehensive income (loss)	---	---	---	(218)	(218)
Dividends	---	---	(1,016)	---	(1,016)
Balance at December 31, 2015	$ 15,773	$ 374	$ 6,772	$ 749	$ 23,668
Balance at January 1, 2016	$ 15,773	$374	$ 6,772	$ 749	$ 23,668
Regulatory adjustments	---	---	521	---	521
Net income and net movement in regulatory balances	---	---	2,585	---	2,585
Dividends	---	---	(1,046)	---	(1,046)
Balance at December 31, 2016	$ 15,773	$ 374	$ 8,832	$ 749	$ 25,728

See accompanying notes to the financial statements.

ESSEX POWERLINES CORPORATION

Statements of Cash Flows
Years ended December 31, 2016 and 2015
(in thousands of dollars)

		2016		2015
Operating activities				
Net Income and net movement in regulatory balances	$	2,585	$	3,022
Adjustments for:				
Depreciation and amortization		2,249		2,139
Amortization of deferred revenue		(102)		(19)
Post-employment benefits		91		26
(Gain) loss disposal of property, plant and equipment		(19)		105
Unrealized (gain) loss on non-hedging financial derivatives		(118)		(3)
Decrease in deferred charges		233		96
Net finance income		842		812
Income tax expense		869		(149)
Change in non-cash operating working capital		588		2,633
Net movement in regulatory balances		(4,325)		(969)
Regulatory adjustments (net)		300		---
Income tax paid		(612)		(447)
Interest paid		(896)		(911)
Interest received		54		99
Net cash from operating activities		1,739		6,434
Investing activities				
Purchase of property, plant and equipment and intangibles		(4,503)		(6,469)
Net cash used by investing activities		(4,503)		(6,469)
Financing activities				
Dividends paid		(1,016)		(1,016)
Contributions in aid of construction		931		1,448
Proceeds from long-term debt		1,000		3,000
Repayment of long-term debt		(1,160)		(1,056)
Net cash from financing activities		(245)		2,376
Change in cash and cash equivalents		(3,009)		2,341
Cash and cash equivalents, beginning of year		2,482		141
(Bank indebtedness) Cash and cash equivalents, end of year	$	(527)	$	2,482

See accompanying notes to the financial statements.

1. Reporting entity

Essex Powerlines Corporation (the "Corporation") is a rate regulated, municipally owned "local distribution company" (LDC) incorporated under the laws of Ontario, Canada. The Corporation is located in Oldcastle, Ontario. The address of the Corporation's registered office is 2730 Highway 3, Oldcastle, ON N0R 1L0.

The Corporation delivers electricity and related energy services to over 28,000 residential and commercial customers in Amherstburg, LaSalle, Leamington and Tecumseh. The Corporation is wholly owned by Essex Power Corporation. The shareholders of Essex Power Corporation include the Town of Amherstburg, the Town of LaSalle, the Municipality of Leamington and the Town of Tecumseh.

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) The financial statements were approved by the Board of Directors on April 26, 2017.

(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 thousand.

2. Basis of presentation (continued)

(e) Use of estimates

i) Assumptions and 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 including changes as a result of future decisions made by the OEB and IESO.

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) Note 3(e) – estimation of useful lives of its property, plant and equipment and intangible assets
(iii) Note 3(j) – recognition and measurement of regulatory balances
(iv) Note 13 – measurement of defined benefit obligations: key actuarial assumptions

(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, and 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 certain 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 usually 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 September 28, 2009 for rates effective May 1, 2010 to April 30, 2011. The GDP IPI-FDD for 2016 is 2.10%, the Corporation's productivity factor is 0% and the stretch factor is 0.15%, resulting in a net adjustment of 1.95% to the previous year's rates.

The Corporation has decided to next apply to have rates rebased by August 2017 for rates effective May 1, 2018. In the interim, the Corporation will continue to file annual IRMs to adjust 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 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(g). Cash and cash equivalents are measured at fair value. The Corporation holds interest rate swaps and measures them at fair value.

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.

Unbilled revenue

Unbilled revenue is recorded based on an estimated amount of electricity delivered and not yet billed. The estimate is calculated by using the customers' actual consumption data up to year end to arrive at the unbilled revenue accrual.

3. Significant accounting policies (continued)

(c) Revenue recognition (continued)

Other revenue

Revenue earned from the provision of services is recognized as the service is rendered or contract milestones are achieved. Amounts received in advance of these milestones are presented as deferred revenue.

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.

(d) 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 a weighted 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.

(e) 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, 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.

3. Significant accounting policies (continued)

(e) Property, plant and equipment (continued)

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 and fixtures	50
Land	Indefinite
Computer hardware, and other equipment	5 -10
Office equipment	10
Utility Equipment and trucks	7-10
Distribution Equipment	15 -50
Solar Generation	20

3. Significant accounting policies (continued)

(f) Intangible assets

Intangible assets used in rate-regulated activities and other intangible assets measured at cost less accumulated amortization.

Computer software that is acquired or developed by the 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.

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
Land rights	50

(g) 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)

(g) 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.

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.

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.

(h) Customer deposits

Customer deposits represent cash deposits from electricity distribution customers and retailers to guarantee the payment of energy bills. Interest is paid annually on customer deposits at a rate of prime business rate less 2%.

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.

(i) 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)

(j) 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)

(k) 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. The last actuarial valuation was done as of December 31, 2014.

(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, regulatory debit balances, cash equivalents and dividend income.

Finance costs comprise interest expense on borrowings, regulatory credit balances, net interest expense on post-employment benefits and impairment losses on financial assets.

3. Significant accounting policies (continued)

(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.

Rate-regulated accounting requires the recognition of regulatory balances and related deferred tax assets and liabilities for the amount of deferred taxes expected to be refunded to or recovered from customers through future electricity distribution rates. A gross up to reflect the income tax benefits associated with reduced revenues resulting from the realization of deferred tax assets is recorded within regulatory credit balances. Deferred taxes that are not included in the rate-setting process are charged or credited to the consolidated statements of income.

4. Standards issued but not yet adopted

Future accounting changes

There are new standards, amendments to standards and interpretations which are not yet effective for the year ended December 31, 2016 and have not been applied in preparing these financial statements.

The Corporation is still evaluating the adoption of the following new and revised standards along with any subsequent amendments.

Revenue Recognition

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers* ("IFRS 15"), which replaces existing revenue recognition guidance, including IAS 18 Revenue and IFRIC 18 *Transfers of Assets from Customers* ("IFRIC 18"). IFRS 15 replaces IAS 11 Construction Contracts, IAS 18 Revenue and various interpretations and establishes principles regarding the nature, amount, timing and uncertainty of revenue arising from contracts with customers.

(in thousands of dollars)

4. Standards issued but not yet adopted (continued)

The standard requires entities to recognize revenue for the transfer of goods or services to customers measured at the amounts an entity expects to be entitled to in exchange for those goods or services. In July 2015, the IASB announced a one-year deferral of the effective date of IFRS 15 to annual periods beginning on or after January 1, 2018. The Corporation is assessing the impact of IFRS 15 on its results of operations, financial position, and disclosures.

Financial Instruments

In July 2014, the IASB issued a new standard, IFRS 9 *Financial Instruments*, which will replace IAS 39 Financial Instruments: Recognition and Measurement. The replacement of IAS 39 is a multi-phase project with the objective of improving and simplifying the reporting for financial instruments. The issuance of IFRS 9 is part of the first phase of this project. IFRS 9 is effective for annual periods beginning on or after January 1, 2018 and must be applied retrospectively with some exceptions. The Corporation is assessing the impact of IFRS 9 on its results of operations, financial position, and disclosures.

Leases

In January 2016, IASB issued IFRS 16 to establish principles for the recognition, measurement, presentation, and disclosure of leases, with the objective of ensuring that lessees and lessors provide relevant information that faithfully represents those transactions. IFRS 16 replaces IAS 17 and it is effective for annual periods beginning on or after January 1, 2019 and will be applied retrospectively with some exceptions. Early adoption is permitted if IFRS 15 has been adopted. The Corporation is assessing the impact of IFRS 16 on its results of operations, financial positions, and disclosures.

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. Cash and cash equivalents (bank indebtedness)

		2016		2015
Restricted bank balances, held for customer deposits	$	1,159	$	1,159
Unrestricted bank balances		---		1,323
		1,159		2,482
Bank indebtedness		(1,686)		---
	$	(527)	$	2,482

(in thousands of dollars)

6. Accounts receivable

	2016	2015
Trade receivables	$ 7,045	$ 5,867
Other receivables	622	803
Billable work	127	93
	$ 7,794	$ 6,763

7. Property, plant and equipment

	Land and buildings	Distribution equipment	Other fixed assets	Construction -in-Progress	Total
Cost					
Balance at January 1, 2016	**$ 2,239**	**$ 47,477**	**$ 5,152**	**$ 564**	**$ 55,432**
Reclassification	48	(48)	---	---	---
Additions	42	3,909	338	---	4,289
Transfers	---	334	---	(334)	---
Disposals/retirements	(12)	(148)	---	---	(160)
Balance at December 31, 2016	$ 2,317	$ 51,524	$ 5,490	$ 230	$ 59,561
Balance at January 1, 2015	$ 2,190	$ 42,525	$ 4,057	$ 381	$ 49,153
Additions	49	5,110	1,095	183	6,437
Transfers	---	---	---	---	---
Disposals/retirements	---	(158)	---	---	(158)
Balance at December 31, 2015	$ 2,239	$ 47,477	$ 5,152	$ 564	$ 55,432
Accumulated depreciation					
Balance at January 1, 2016	$ 68	$ 3,142	$ 574	$ ---	$ 3,784
Depreciation	42	1,653	487	---	2,182
Disposals/retirements	(12)	(22)	(145)	---	(179)
Balance at December 31, 2016	$ 98	$ 4,773	$ 916	$ ---	$ 5,787
Balance at January 1, 2015	$ 27	$ 1,655	$ 96	$ ---	$ 1,778
Depreciation	41	1,540	478	---	2,059
Disposals/retirements	---	(53)	---	---	(53)
Balance at December 31, 2015	$ 68	$ 3,142	$ 574	$ ---	$ 3,784
Carrying amounts					
At December 31, 2016	$ 2,219	$ 46,751	$ 4,574	$ 230	$ 53,774
At December 31, 2015	2,171	44,335	4,578	564	51,648

At December 31, 2016 land and buildings with a carrying amount of $2,219 (December 31, 2015 - $2,171) are subject to a general security agreement.

(in thousands of dollars)

8. Intangible assets

	Computer software	Land rights	Total
Cost			
Balance at January 1, 2016	$ 231	$ 193	$ 424
Additions	212	2	214
Balance at December 31, 2016	443	195	638
Balance at January 1, 2015	214	178	392
Additions	17	15	32
Balance at December 31, 2015	$ 231	$ 193	$ 424
Accumulated amortization			
Balance at January 1, 2016	$ 151	$ 8	$ 159
Amortization	63	4	67
Balance at December 31, 2016	214	12	226
Balance at January 1, 2015	75	4	79
Amortization	76	4	80
Balance at December 31, 2015	$ 151	$ 8	$ 159
Carrying amounts			
At December 31, 2016	$ 229	$ 183	$ 412
At December 31, 2015	80	185	265

9. Income tax expense

Current tax expense

	2016	2015
Current tax expense	$ 170	$ 442
Future tax expense (recovery)	699	(591)
	$ 869	$ (149)

(in thousands of dollars)

9. Income tax expense (continued)

Reconciliation of effective tax rate

		2016		2015
Income before taxes	$	(871)	$	1,904
Canada and Ontario statutory Income tax rates		26.5%		26.5%
Expected tax provision on income at statutory rates		(231)		505
Increase (decrease) in income taxes resulting from:				
Other		1,100		(654)
Income tax expense (recovery)	$	869	$	(149)

Significant components of the Corporation's deferred tax balances

		2016		2015
Deferred tax assets (liabilities):				
Property, plant and equipment	$	(673)	$	(20)
Post-employment benefits		1,084		1,050
Other		70		114
	$	481	$	1,144

		2016		2015
Deferred tax liabilities:				
Non-regulated solar assets	$	541	$	505

(in thousands of dollars)

10. Regulatory balances

Reconciliation of the carrying amount for each class of regulatory balances

Regulatory deferral account debit balances	January 1, 2016	Regulatory Adjustments	Additions	Recovery/ reversal	December 31, 2016	Remaining recovery/ reversal years
Group 1 deferred accounts	$ 1,542	$ (171)	$ 2,899	$ ---	$ 4,270	
Extraordinary event costs	83	---	4	---	87	
Regulatory settlement account	11,618	(11,833)	3,930	1,631	5,346	1
Other regulatory accounts	29,080	2	467	572	30,121	
	$ 42,323	$(12,002)	$ 7,300	$ 2,203	39,824	

Regulatory deferral account debit balances	January 1, 2015	Regulatory Adjustments	Additions	Recovery/ reversal	December 31, 2015	Remaining recovery/ reversal years
Group 1 deferred accounts	$ 9,980	$ ---	$ (7,794)	$ (644)	$ 1,542	
Extraordinary event costs	83	---	---	---	83	
Regulatory settlement account	5,254	---	(1,724)	8,088	11,618	1-3
Other regulatory accounts	24,608	---	(977)	5,449	29,080	
	$ 39,925	$ ---	(10,495)	$ 12,893	$ 42,323	

Regulatory deferral account credit balances	January 1, 2016	Regulatory Adjustments	Additions	Recovery/ reversal	December 31, 2016	Remaining recovery/ reversal years
Group 1 deferred accounts	$ (4,264)	$ 731	$ (1,004)	$ ---	$ (4,537)	
Regulatory transition to IFRS	(623)	(735)	---	---	(1,358)	
Regulatory settlement account	(10,051)	11,961	(3,892)	---	(1,982)	1
Other regulatory accounts	(29,165)	266	(323)	(622)	(29,844)	
Income tax	(1,505)	---	663	----	(842)	
	$ (45,608)	$ 12,223	$ (4,556)	$ (622)	$ (38,563)	

Regulatory deferral account credit balances	January 1, 2015	Regulatory Adjustments	Additions	Recovery/ reversal	December 31, 2015	Remaining recovery/ reversal years
Group 1 deferred accounts	$ (10,142)	$ ---	$ 5,915	$ (37)	$ (4,264)	
Extraordinary event costs	(623)	---	---	---	(623)	
Regulatory settlement account	(7,166)	---	(5)	(2,880)	(10,051)	1-3
Other regulatory accounts	(25,603)	---	220	(3,782)	(29,165)	
Income tax	(645)	---	(860)	---	(1,505)	
	$ (44,179)	$ ---	$ 5,270	$ (6,699)	$ (45,608)	

10. Regulatory balances (continued)

Regulatory adjustments arose as a result of an audit conducted by the OEB as further described in note 18.

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.

Typically, settlement of the Group 1 deferral accounts is done, as required, through application to the OEB. EPL plans to recover its Group 1 Deferral and Variance accounts in a COS application for 2018 rates. The approved account balances will be moved to the regulatory settlement account as required by the regulator.

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 recovered from/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 between 1.10% and 1.10%.

Group 1 deferred accounts are comprised of variances between amounts charged by the Independent Electricity System Operator for the operation of wholesale electricity market and the cost of electricity, the amounts from Hydro One for network line and transformation charges and amounts billed to customers.

Extraordinary event costs represent costs incurred to restore services following storms in 2010.

Regulatory settlement accounts represent amounts collected from customers through rates. These amounts will be held until approved by the Ontario Energy Board to be refunded to or recovered from customers.

Other regulatory accounts represent amounts for costs incurred by the Corporation to serve customers that have been enrolled by a commodity retailer and for miscellaneous other costs that will be recovered from customers.

Regulatory transition to IFRS represents changes in estimates and other variances arising from the transition to IFRS which will be held until approved by the Ontario Energy Board to be refunded to or recovered from customers.

Income tax represents an amount of a future tax liability which will be refunded to customers through future rates.

(in thousands of dollars)

11. Accounts payable and accrued liabilities

	December 31, 2016	December 31, 2015
Accounts payable – energy purchases	$ 8,536	$ 3,087
Debt retirement charge payable to OEFC	122	277
Payroll payable	280	269
Water and waste water billings due to Ultimate Shareholders	4,070	4,100
Other accounts payable and accrued liabilities	2,403	5,430
	$ 15,411	$ 13,163

12. Long-term debt

	2016	2015
Related party long-term loan payable is repayable as approved by the Board of Directors not to exceed 20% of the principal lending amount if funds are available as determined each March. Interest is payable at a stated interest rate of 4.0%. The agreement expires December 31, 2017. The debt is owing to two of the four shareholders of the parent company as follows:		
Municipality of Leamington	2,150	2,150
Town of Tecumseh	1,545	1,545
	3,695	3,695
Banker's acceptance - TD Canada Trust has a 5 year term ending November 4, 2018, and is repayable with interest only payments at an effective interest rate of 5.03%.	3,300	3,300
Fixed rate loan - TD Canada Trust is a 10 year term loan with a 10 year amortization schedule, repayable in blended monthly payments of $40, bearing an interest rate of 4.99%. Loan matures November 9, 2019.	4,515	4,757
Fixed rate loan - TD Canada Trust is a 10 year term loan with a 10 year amortization schedule, repayable in blended monthly payments of $62, bearing an interest rate of 4.48%. Loan matures November 9, 2019.	2,036	2,674
Fixed rate loan - TD Canada Trust is a 5 year term loan with a 17 year amortization schedule, repayable in blended monthly payments of $10, bearing an interest rate of 2.47%. Loan matures October 24, 2020.	1,622	1,704

(in thousands of dollars)

Fixed rate loan - TD Canada Trust is a 5 year term loan with a 19 year amortization schedule, repayable in blended monthly payments of $10, bearing an interest rate of 2.47%. Loan matures October 19, 2020.	1,822	1,902
Fixed rate Loan - TD Canada Trust is a 5 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $16, bearing an interest rate of 2.42%. Loan matures on October 26, 2020.	2,862	2,980
Fixed rate Loan - TD Canada Trust is a 5 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $5, bearing an interest rate of 2.19%. Loan matures on December 2, 2021.	1,000	---
	20,852	21,012
Less: Current portion of long-term debt	4,944	4,116
	15,908	16,896

Approximate long-term principal repayments over the next five years and thereafter are as follows:

	$
2017	4,944
2018	4,604
2019	5,006
2020	5,465
2021	833
	20,852

In addition to the Bankers Acceptances with TD Canada Trust, the Company has entered into an interest rate swap agreement with TD Securities. This agreement is a "receive variable, pay fixed" swap agreement, which effectively convert variable interest rates on Bankers Acceptances to the effective interest rates mentioned above. Refer to note 20 for details on these swap instruments.

13. 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 $342 to OMERS (2015 - $326), of which $82 (2015 - $150) has been capitalized as part of PP&E and the remaining amount of $260 (2015 - $176) has been recognized in profit or loss. The Corporation estimates that a contribution of $340 to OMERS will be made during the next fiscal year.

(in thousands of dollars)

As at December 31, 2016, OMERS had approximately 470,000 members, of whom 41 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 \$6,200,000. 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.

Reconciliation of the obligation		2016		2015
Defined benefit obligation, beginning of year	$	2,915	$	2,563
Included in profit or loss				
Current service cost		94		87
Interest cost		109		103
		3,118		2,753
Included in OCI				
Actuarial (gains) losses arising from:				
changes in demographic assumptions		--		252
changes in financial assumptions—discount rate		--		74
		--		326
Benefits paid		(112)		(164)
Defined benefit obligation, end of year	$	3,006	$	2,915

Actuarial assumptions	2016	2015
General inflation	2.00%	2.00%
Discount (interest) rate	3.75%	3.75%
Medical Costs	7.00%	7.50%
Dental Costs	4.50%	4.50%

(b) Post-employment benefits other than pension (continued)

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing by \$282. A 1% decrease in the assumed discount rate would result in the defined benefits obligation increasing by \$331.

A 1% increase in the assumed trend rate would result in the defined benefit obligation increasing by \$289. A 1% decrease in the assumed trend rate would result in the defined benefit obligation decreasing by \$250.

(in thousands of dollars)

14. Share capital

	2016	2015
Authorized:		
Unlimited number of common shares, Class A, voting		
Unlimited number of common shares, Class B, non-voting		
Issued:		
50 common shares, Class A, voting	$ -	$ -
15,772,796 common shares, Class B, non-voting	15,773	15,773
	$ 15,773	$ 15,773

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 $0.066317 per share (2015 - $0.064425), which amount to total dividends declared in the year of $1,046 (2015 - $1,016).

15. Other revenue

	2016	2015
Rental revenue for joint use of poles	$ 117	$ 115
Billing services to ultimate shareholders	1,014	1,014
Deferred revenue recognized	102	19
Loss from retirement of assets	(85)	(105)
Other	390	475
	$ 1,538	$ 1,518

16. Operating expenses

	2016	2015
Contract/consulting	$ 1,354	$ 1,318
Materials and supplies	733	1,073
Salaries, wages and benefits	2,928	3,035
Cost of billing services for ultimate shareholders	942	948
Post-employment benefit plans	203	190
Vehicles	112	130
Other	1,984	1,436
	$ 8,256	$ 8,130

(in thousands of dollars)

17. Finance income and costs

		2016		2015
Finance income				
Interest income on bank deposits	$	54	$	99
Finance costs				
Interest expense on long-term debt		756		748
Interest expense on customer deposits		3		3
Interest expense on		137		160
		896		911
Net finance costs recognized in profit or loss	$	842	$	812

18. Commitments and contingencies

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 Company subscribes for liability insurance coverage under a self-insurance pool administered by the Municipal Electric Association Reciprocal Insurance Exchange. Under the terms of this co-operative venture, the Company as a pool member, in addition to its regular premiums, is contingently liable for any retroactive reassessment if a deficit originates in a year in which they are a member. The contingent liability for reassessment in respect of any year in which the Company is a pool member continues even where the Company subsequently withdraws from the self-insurance pool. The Company will not, however, be subject to reassessment for claims incurred in years in which they are not members of this self-insurance pool. As at December 31, 2016 no assessments have been made.

Regulatory Assets/Liabilities

The regulatory assets and liabilities represent certain amounts receivable or refundable to future customers. These amounts have been deferred for accounting purposes because it is probable that they will be recovered or refunded in future rates. The Ontario Energy Board (OEB) regulates Essex Powerlines Corporation and determines the amounts receivable and refundable to customers through an Incentive Rate Mechanism (IRM) and/or a Cost of Service (COS) rate application rate proceedings.

(in thousands of dollars)

As part of a recent OEB Decision and Order (EB-2014-0301, EB-2014-0072), the OEB ordered an audit of all Essex Powerlines deferral and variance accounts (except smart meter accounts 1555 and 1556), procedures and controls. The OEB issued a final audit report on March 21, 2017 which resulted in regulatory adjustments and other reclassifications within regulatory balances.

Letter of Credit

A letter of credit in the amount of $2,900 has been issued by TD Canada Trust to the credit of the Independent Electricity System Operator for the commodity purchases and market services provided. This letter of credit has no term of expiry and is normally renewed annually.

19. Related party transactions and balances

(a) Parent and jointly controlling shareholders

The sole shareholder of the Corporation is Essex Power Corporation, which in turn is wholly-owned by the Towns of Amherstburg, LaSalle and Tecumseh, and the Municipality of Leamington. The Towns and Municipality produce financial statements that are available for public use.

(b) Outstanding balances with related parties

	2016	2015
Balances due to:		
Essex Power Corporation	$ -	$ 3
Essex Energy Corporation	131	224
Essex Power Services Corporation	45	4
Utilismart Corporation	51	29
Municipality of Leamington	942	986
Town of Tecumseh	672	713
Town of Amherstburg	906	958
Town of LaSalle	611	574
	$ 3,358	$ 3,491
Balances due from:		
Essex Power Corporation	128	-
Essex Energy Corporation	2	-
Essex Power Services Corporation	34	46
Utilismart Corporation	12	11
Town of LaSalle	24	23
Town of Tecumseh	99	25
Town of Amherstburg	94	35
Municipality of Leamington	232	31
	$ 625	$ 171

(in thousands of dollars)

All balances due from and due to related parties listed above are included within accounts receivable and accounts payable respectively. Amounts are non-interest bearing with repayment terms similar to other trade accounts receivable and accounts payable. The amounts disclosed separately as due from related parties or due to related parties, as well as the sub debt payable – shareholder are non-interest bearing with no specified repayment terms.

(c) Transactions with parent

During the year the Corporation paid management fees to its parent in the amount of $1,085 (2015 - $1,132).

(d) Transactions with ultimate jointly controlling shareholders

The Corporation had the following significant transactions with its ultimate parents, government entities: the Towns of Amherstburg, LaSalle and Tecumseh, and the Municipality of Leamington.

The Corporation delivers electricity to these entities throughout the year for the electricity needs of the Towns and Municipality. Electricity delivery charges are at prices and under terms approved by the OEB. The Corporation also provides additional services to the Towns and Municipality, including billing and customer care services. The total revenues related to these services for 2016 were $1,014 (2015 - $1,014).

(e) Key management personnel

The key management personnel of the Corporation have been defined as members of its board of directors and senior management team members. The compensation paid or payable is as follows:

		2016		2015
Directors' fees	$	6	$	6
Salaries and bonuses		302		305
	$	308	$	311

20. 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.

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.

(in thousands of dollars)

(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 Towns of Amherstburg, LaSalle, Tecumseh and the Municipality of Leamington. No single customer accounts for a balance in excess of 6% of total accounts receivable.

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 $193 (2015 - $188). An impairment loss of $150 (2015 - $190) 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 $390 (2015 - $419) is considered 60 or more days past due. The Corporation has over 29,000 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 $1,172 (2015 - $1,213).

(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.

(c) Interest Rate Risk

The Company enters into derivative financial instruments in order to hedge its risk against interest rate fluctuations. The Company has fixed its variable rate long-term Banker's acceptance with the following outstanding interest rate swap agreements:

Notional amount	Interest rate	Term of Agreement	Repricing Period
$3,300	4.19%	November 4, 2018	Monthly

As at December 31, 2016, the unrealized loss was $198 (2015 - $316).

A 1% variation the interest rate at December 31, 2016 would increase or decrease this loss by $33, assuming all other variables remain constant.

(d) 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 $6,000 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, $2,139 had been drawn under the Corporation's credit facility.

The Corporation also has a bilateral facility for $2,900 (the "LC" facility) for the purpose of issuing letters of credit mainly to support the prudential requirements of the IESO, of which none has been drawn and posted with the IESO during 2016 or 2015.

The majority of accounts payable, as reported on the statement of financial position, are due within 30 days. Customer deposits are due on demand. The scheduled repayments associated with long-term debt are described within note 12.

(e) 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 $25,728 (December 31, 2015 - $23,668) and long-term debt amounts to $20,852 (December 31, 2015 - $21,012). The Corporation's debt agreement includes restrictive covenants such as limitations on additional indebtedness, and restrictions on mergers, amalgamations or consolidations.

21. Comparative figures

Certain of the comparative figures have been reclassified to conform to the presentation adopted in the current year.

<u>Attachment 1-I</u>

Reconciliation of Audited Financial Statements to RRR Trial Balances

2.1.13 **ESSEX POWERLINES RECONCILIATION OF AUDITED FINANCIAL STATEMENTS TO OEB TRIAL BALANCE FILING 2014**

Audited Financial Statements (AFS)		Per OEB Trial Balance Filing		Variance	
BALANCE SHEET					
Current Assets					
Cash	$ 140,632				
Accounts receivable	$ 8,232,113				
Due from affiliates	$ -	Current assets	$ 12,974,427	$ 1,307,882	AFS shows the due to affiliates as a liability ($858,153); AFS includes Commodity taxes in the Accounts Receivable figure ($449,730)
Prepaid expenses	$ 321,982				
Unbilled revenue	$ 5,513,526				
Income taxes recoverable	$ 74,056				
Inventory	$ 60,000	Inventory	$ 60,000	$ -	
Property, plant & equipment	$ 44,264,615	Capital assets	$ 68,788,086	-$ 0	
		Accumulated Amortization	-$ 24,523,471		
Deferred charges	$ 1,011,293	Other assets & deferred charges	-$ 997,119	$ 3,294,412	AFS have regulatory assets coded as current liability $(1,059,732) / AFS includes $(948,680) which represents the excess of the shares issued to the shareholders versus the net assets transferred to Essex Powerlines Corporation that our auditors agreed that this is a ligitimate accounting entry, however the OEB auditors disagreed so it has been removed from the OEB filing / AFS includes the debit portion of Future Taxes ($1,286,000)
Future income taxes	$ 1,286,000				
		Non-Current Assets	$ -	$ -	
	$ 60,904,217		**$ 56,301,922**	**$ 4,602,295**	
Liabilities					
Current Liabilities					
Accounts payable & accrued liabilities	$ 10,299,086				
Due to Affiliates	$ 858,153				
Dividends payable	$ 1,016,176	Current liabilities	-$ 14,394,149	$ 1,307,883	AFS shows the due to affiliates as a liability $858,153 / AFS includes Commodity taxes in the Accounts Receivable figure $449,730
Income Taxes Payable	$ -				
Current portion of customer deposits	$ 270,000				
Current portion of long-term debt	$ 3,258,617				
Regulatory liabilities	$ 2,345,732			$ 2,345,732	AFS have regulatory assets coded as current liability $1,059,732 / AFS includes the debit portion of Future Taxes $1,286,000
Customer deposits	$ 972,245	Non-current liabilities	-$ 4,934,823		
Employee future benefits	$ 3,962,578				
Long-term debt	$ 15,809,388				
Accrued loss on interest rate swap	$ 319,161	Other liabilities deferred credit & LTD	-$ 16,502,492		
Shareholder loan	$ 373,943				
Shareholders' Equity					
Capital stock	$ 15,772,801				
Retained earnings (AFS incl. $1,299,624.54)	$ 5,272,394	Shareholders equity	-$ 20,470,458	$ 948,680	See Other Asset explanation regarding excess shares $948,680
Solar equity reserve	$ 373,943				
	$ 60,904,217		**-$ 56,301,922**	**$ 4,602,295**	
	$ -		-	0	
INCOME STATEMENT					
Energy sales	$ 68,594,460	Sales of electricity	-$ 57,503,389	-$ 0	
		Revenues from services	-$ 11,091,071		
Cost of power purchased	$ 57,503,389	Other power supply expenses	$ 57,503,389	$ 0	
Gross margin on service revenue	**$ 11,091,071**				
Other revenue from operations					
Solar Generation	$ 401,920	Other Operating Revenues	-$ 541,108		AFS inlcudes B&C exp for water and sewer in B&C expense $947,979/AFS inlcudes Solar Expense $34,807 / AFS shows Investment income ($335,181), Gain on sale of asset ($30,602), Gain on Foreign Exchange $642 below the line
		Invesstment income	-$ 335,181	$ 617,645	
Miscellaneous revenue	$ 1,244,708	Other Income/Deductions	-$ 152,694		
Total other revenue	**$ 1,646,628**				
Expenses					
Billing and collecting	$ 2,119,534	Billing and collecting	$ 1,158,128	-$ 961,406	AFS includes B&C W&S expenses in account 4380 ($947,979), also includes Leap Expenses ($13,427)
Administration and general expense	$ 2,981,940	Admin general expense	$ 2,948,703	-$ 33,237	AFS inlcude account 6105 property taxes in A&G ($44,568) / AFS includes the amortization of excess of the shares issued to the shareholders versus the net assets transferred to Essex Powerlines Corporation that our auditors agreed that this is a ligitimate accounting entry, however the OEB auditors disagreed so it has been removed from the OEB filing ($175,472) / AFS includes Community Relations in A&G ($7,645), Advertising ($2,371), Property Taxes $184,534, ESA Fees $12,286
		Sales expense	$ 2,371	$ 2,371	AFS includes Advertising in A&G $2,371
		Community relations	$ 7,645	$ 7,645	AFS includes Community Relations in A&G $7,645
Distribution	$ 2,770,765	Distribution expense	$ 2,573,946	-$ 196,819	AFS inlcudes property maintenance ($184,534) / AFS inlcudes ESA fees ($12,286)
Amortization	$ 1,726,509	Amortization expense	$ 1,726,509	-$ 0	
Bank charges and interest	$ -	Interest expense	$ 1,243,067	$ 1,243,067	AFS shows this below the income from operations line $1,243,067
Solar expense	$ 34,807			-$ 34,807	Included in Other Income/Deductions in OEB Trial Balance ($34,807)
Total expenses	**$ 9,633,555**				
Income from operations	**$ 3,104,144**				
Other revenue (expenses)					
		Other Deductions	$ 13,427	$ 13,427	AFS includes Leap expense in Billing & Collecting $13,427
Gain on disposal of property, plant & equipment	$ 30,602			$ 30,602	Included in Other Income/Deductions in OEB trial balance $30,602
Loss on currency exchange	$ (642)			-$ 642	Included in Other Income/Deductions in OEB trial balance ($642)
Unrealized gain (loss) on interest rate swap	$ (12,302)	Extraordinary Item	$ 12,302	$ -	
Interest Expense	$ (1,243,067)			-$ 1,243,067	AFS shows this below the income from operations line ($1,243,067)
Interest income	$ 335,181			$ 335,181	See other Income $335,181
Income before taxes	**$ 2,213,916**				
Provision for income taxes					
Current income tax expense	$ 277,656	Taxes	$ 322,225	$ 44,569	AFS inlcude property taxes in A&G ($44,569)
Net income for the year	**$ 1,936,260**	Profit/Loss	-$ 2,111,733	$ 175,473	

Essex Powerlines

IFRS audited FS line descriptions	12/31/15 - AFS (IFRS Accounting Standard) Audited by PWC	To reverse Jan 1 2014 gain on future benefit revaluation and related tax, as well to record OCI and expense impact	To reverse year 2014 gain on future benefit revaluation and related tax, as well to record OCI and expense impact	To reverse year 2015 loss on future benefit revaluation and related tax, as well to record OCI and expense impact	Smart Meter Amort catch-up of $1,116,679 per OEB disposition June 2015	2015 Reverse amortization of deferred revenue n/a for CGAAP (local ledger)	Reverse capital contributions received in 2014 from deferred revenue & related amortization PP&E	Reclass 2015 contributed capital from deferred revenue (local ledger)	Record 2015 amortization of contributed capital (local ledger)	Add admin OH layer to 2015 capital spend (local ledger)	Increase 2015 Deprec Exp and Accumulated Deprec for higher values and shorter lives (local ledger)	Reclass 2015 Solar Asset Deprec Exp to Admin	Mapping Commodity taxes payable to AR - current	Combine intangibles with PP&E on BS	Inventory Spares reclassed to PP&E from Inventory on BS	Reclass solar expenses to other revenue on IS	Reclass Non Rate-Regulated expenses to Other Income/Deductions on IS	Reclass non-recoverable expenses (GL 8000) from Operating Expenses to Other revenue on IS	Reclass interest on swaps from Non-hedging derivatives to LT debt on BS	Reverse IFRS Reclass of Long Term Customer Deposits on BS - per IFRS	Reclass OCI to retained earnings for prior year 2014	Move adjustments to RSVAs included in service revenue or cost of power to net movement in regulatory balances	Gross up customer billings and costs included in deferral and variance accounts to the Statement of Operations	2014 drawdown - Solar assets tax adjustment	Orig 2009 FMV increment reclassed to R/E per OEB (local ledger)	Amort of FMV not allowed per OEB (local ledger)	PWC Presentation differences & rounding differences	Recombine settlement variance debits and credits	OEB Audit Adjustments (Revised in RRR 2015; included in external financials in 2016)	Total IFRS AFS Adjusted back to CGAAP	OEB TB RRR 2.1.7 - mapped from detailed TB to the right	Variance
	2015																															
STATEMENT OF FINANCIAL POSITION	in 000's																															
Current assets																																
Cash	2,482																													2,482	2,482	-
Accounts receivable (incl -0567 HST GL)	6,763												(303)																	6,460	6,460	-
Unbilled revenue	6,345																												102	6,447	6,447	0
PILs receivable																														-		-
Due from affiliated companies	17																													17	17	-
Inventories	60														818															878	878	-
Prepaid expenses	287																													287	287	-
	15,954	-	-	-		-		-	-	-	-	-	(303)	-	818	-	-	-	-	-	-	-	-	-	-	-	-	-	102	16,571	16,571	
																																-
PPE	51,648						(875)	(1,448)	552	521	(1,677)			265	(818)									574					816	49,558	47,088	2,470
Intangibles	265													(265)																-		-
Future PILs Asset	1,144	95	374	(108)																							(1)			1,504	1,504	-
Deferred Charges	915																								(2,177)	1,404	(1)		(58)	83	83	(0)
Special deposits																														-		-
Investment																														-		-
Regulatory assets	42,323																											(42,323)		-		-
																																-
Total assets	112,249	95	374	(108)	-	-	(875)	(1,448)	552	521	(1,677)	-	(303)	-	-	-	-	-	-	-	-	-	-	574	(2,177)	1,404	(2)	(42,323)	860	67,716	65,246	
																																-
Current liabilities																																-
Line of Credit																														-		-
Demand instalment loans																														-		-
Customer Deposits	(1,213)																			843										(370)	(370)	-
Dividends payable	(1,016)																													(1,016)	(1,016)	-
Current portion of long-term debt	(4,116)																													(4,116)	(4,116)	-
Accounts payable and accr liab(incl Other & Swap)	(13,163)												303														4		(450)	(13,306)	(13,306)	(0)
Income Tax Payable (current Tax Pay)	(155)																										1			(154)	(154)	-
Due to affiliated companies	-																													-		-
	(19,663)	-	-	-	-	-	-	-	-	-	-	-	303	-	-	-	-	-	-	843	-	-	-	-	-	-	5	-	(450)	(18,962)	(18,962)	
																																-
Long-term debt (incl Sub-Debt)	(17,270)																		(316)											(17,586)	(17,586)	-
Regulatory Liabilities																								580				(3,285)	(293)	(2,998)	(2,999)	1
Employee future benefits	(2,915)	(285)	(1,115)	326																							(1)			(3,990)	(3,990)	-
Accrued loss on interest rate swap	(316)																		316											-	-	-
Deferred tax liabilities (future tax)	(505)																													(505)	(505)	-
Deferred revenue	(2,304)					(18)	875	1,448																			(1)			-		-
Customer Deposits																				(843)										(843)	(843)	-
Note payable																														-		-
S/H Equity:																														-		-
Share capital	(15,773)																													(15,773)	(15,773)	-
Solar equity reserve (appropriation of RE)	(374)																													(374)	(374)	-
Paid-up capital																														-		-
Accumulated OCI	(749)	172	775	(219)																	19						2			-		-
Retained earnings	(6,772)	18	(34)	1		18			(552)	(521)	1,677	-									(19)			(1,154)	2,177	(1,404)	(3)		(116)	(6,684)	(6,685)	1
	(23,668)	190	741	(218)	-	18	-	-	(552)	(521)	1,677	-	-	-	-	-	-	-	-	-	-	-	-	(1,154)	2,177	(1,404)	(1)	-	(116)	(22,831)	(22,832)	
Regulatory balances	(45,608)																											45,608		-		-
Total Liabilities and S/H Equity, and regulatory balances	(112,249)	(95)	(374)	108	-	-	875	1,448	(552)	(521)	1,677	-	303	-	-	-	-	-	-	-	-	-	-	(574)	2,177	(1,404)	2	42,323	(860)	(67,716)	(67,717)	
STATEMENT OF OPERATIONS AND RETAINED EARNINGS																																
Revenue																																-
Sale of Energy	(59,140)																					(4,321)	1,199							(62,262)	(62,262)	-
Distribution Revenue	(13,763)																													(13,763)	(13,763)	-
Solar	(390)																													(390)	(390)	-
Other	(1,518)															41	1,134	167												(176)	(176)	-
	(74,811)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	41	1,134	167	-	-	-	(4,321)	1,199	-	-	-	-	-		(76,591)	(76,591)	
Operating Expenses																																
Cost of power purchased	61,785																					(178)	629							62,236	62,236	-
Operating Expenses	8,130			1						(521)		166					(1,134)	(167)				(41)					369			6,803	6,803	-
Solar Expenses	41										-	-				(41)														-		-
Depreciation and amortization	2,139				1,117	-			(552)			(166)																		2,538	2,538	-
	72,095	-	-	1	1,117	-	-	-	(552)	(521)	-	-	-	-	-	(41)	(1,134)	(167)	-	-	-	(219)	629	-	-	-	369	-		71,577	71,577	
Income from operating activities	(2,716)	-	-	1	1,117	-	-	-	(552)	(521)	-	-	-	-	-	-	-	-	-	-	-	(4,540)	1,828	-	-	-	369	-		(5,014)	(5,014)	
Finance income	(99)																													(99)	(99)	-
Finance costs	911																										(5)			906	906	-
Income before income taxes	(1,904)	-	-	1	1,117	-	-	-	(552)	(521)	-	-	-	-	-	-	-	-	-	-	-	(4,540)	1,828	-	-	-	364	-		(4,207)	(4,207)	
Current tax expense	442																													442	442	-
Future tax expense (recovery)	(591)																										626			35	35	-
Net Income for the year	(2,053)	-	-	1	1,117	-	-	-	(552)	(521)	-	-	-	-	-	-	-	-	-	-	-	(4,540)	1,828	-	-	-	990	-		(3,730)	(3,730)	
Net movement in regulatory balances, net of tax	(969)				(1,117)																	4,540	(1,828)				(626)			-		-
Net income for the year and net movement in regulatory balances	(3,022)	-	-	1	-	-	-	-	(552)	(521)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	364	-		(3,730)	(3,730)	
Other comprehensive income																																
Remeasurement of post-employment benefits	326			(326)																										-		-
Tax on remeasurements	(108)			108																										-		-
Other comprehensive income for the year	218	-	-	(218)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	
Total comprehensive income for the year	(2,804)	-	-	(217)	-	-	-	-	(552)	(521)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	364	-		(3,730)	(3,730)	
Retained Earnings, beginning	(4,766)																													(4,766)	(3,970)	
Prior Period Adjustment to RE	-	18	(34)																		(19)			(1,154)	2,177	(1,404)	(367)		(116)	(899)		
Net income for the year and net movement in regulatory balances	(3,022)	-	-	1		-		-	(552)	(521)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	364	-		(3,730)	(3,730)	-
2015 adjustments made in local ledger for OEB						18					1,677																			1,695		
Dividends	1,016																													1,016	1,016	
Retained Earnings, end	(6,772)	18	(34)	1		18		-	(552)	(521)	1,677	-	-	-	-	-	-	-	-	-	(19)	-	-	(1,154)	2,177	(1,404)	(3)	-	(116)	(6,684)	(6,684)	

Essex Powerlines Corporation 2016

Opening balance IFRS restatement	12/31/16 - AFS (IFRS Accounting Standard) Audited by PWC	To reverse prior years loss on future benefit related tax, as well as OCI and expense impact	Reverse 2016 amortization of deferred revenue n/a for CGAAP (LOCAL ledger)	Reclass prior years net deferred revenue to net Contr Capital on BS (LOCAL ledger)	Reclass 2016 contributed capital from deferred revenue on BS (LOCAL ledger)	Record 2016 amort of contrib capital (LOCAL ledger)	Reverse original year 2009 FMV increment reclassed to R/E on BS per OEB (LOCAL ledger)	Reverse prior years Amort of excess FMV increment not allowed per OEB (LOCAL ledger)	Reverse 2016 Amort of excess FMV not allowed per OEB (LOCAL ledger)	Add 2015 year MIFRS adjustment to 1576 (LOCAL ledger)	Add 2016 year MIFRS adjustment to 1576 (LOCAL ledger)	Reclass 2016 Intangibles to PP&E on BS (LOCAL ledger)	Reclass 2016 Solar expense to other revenue on IS	Reclass 2016 Solar Asset Deprec Exp to Other Rev/Exp on IS	Reclass cumulative Acct. 1531 Renewable Connection from PP&E to Deferred Charges on BS	Reclass PILs Tax Receivable to Accounts Receivable on BS	Reclass Sub-Debt to L T Debt on BS	Reclass Non-hedging derivates (SWAP liability) to LT debt on BS	Reclass IFRS presentation of Long-term Customer Deposits out of current on BS	Move RSVAs included in Sale of Energy, Distrib Revenue & Cost of power classed as Net Movement back to cost/income accounts on IS	Move other recoveralbe cost/income classed as Net Movement for IFRS back to cost/income accounts on IS	Reclass other Life to date Net Movement activity back to IS or BS	Reclass Future Tax provision on Non Rate-Regulated Solar activities to Other Income/Ded on IS	Rounding differences	Recombine settlement variance (debits and credits) presentation on BS	Total IFRS AFS Adjusted back to CGAAP	OEB TB RRR 2.1.7 - mapped from detailed TB in Column AG	Rounding Variance
STATEMENT OF FINANCIAL POSITION	in 000's																											
Current assets																												
Cash	-																									-	-	-
Accounts receivable (incl -0567 HST GL)	7,794															287								1		8,082	8,082	-
Due from affiliated companies	130																									130	130	-
Unbilled revenue	6,601																									6,601	6,601	-
PILs receivable	287															(287)										-		-
Inventories (Materials & Supplies)	643																									643	643	-
Prepaid expenses	182																									182	182	-
	15,637	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		1	-	15,638	15,638	-
PPE	53,774			(2,099)	(931)	590						412			(70)							(749)				50,927	50,927	-
Intangibles	412											(412)														-	-	-
Future PILs Asset	481	360																								841	841	-
Deferred Charges	682						(2,177)	1,404	175						70											154	154	-
Regulatory assets	39,824									(419)	(782)											526			(38,563)	586	586	-
Total assets	110,810	360	-	(2,099)	(931)	590	(2,177)	1,404	175	(419)	(782)	-	-	-	-	-	-	-	-	-	-	(223)		1	(38,563)	68,146	68,146	-
Current liabilities																												-
Bank Indebtedness (Line of Credit)	(527)																									(527)	(527)	-
Demand instalment loans																										-		-
Accounts payable and accr liab(incl Other & Sw	(15,411)																							2		(15,409)	(15,409)	-
Current portion of long-term debt	(4,944)																									(4,944)	(4,944)	-
Income Tax Payable (current Tax Pay)	-																									-	-	-
Customer Deposits	(1,431)																		1,061							(370)	(370)	-
Dividends payable	(1,046)																									(1,046)	(1,046)	-
Due to affiliated companies	-																									-		-
	(23,359)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,061	-	-	-		2	-	(22,296)	(22,296)	-
Long-term debt	(15,908)																(374)	(198)								(16,480)	(16,480)	-
Sub-Debt Payable Shareholder	(374)																374									-	-	-
Regulatory Liabilities																									-	-	-	-
Employee future benefits	(3,006)	(1,076)																						1		(4,081)	(4,081)	-
Accrued loss on interest rate swap	(198)																	198								-	-	-
Deferred revenue	(3,133)		103	2,099	931																					-	-	-
Deferred tax liabilities (future tax)	(541)																									(541)	(541)	-
Customer Deposits																			(1,061)							(1,061)	(1,061)	-
S/H Equity:																										-		-
Share capital	(15,773)																									(15,773)	(15,773)	-
Solar equity reserve (appropriation of RE)	(374)																									(374)	(374)	-
Retained earnings	(8,832)	(35)	(103)			(590)	2,177	(1,404)	(175)	419	782			-								223		(2)		(7,540)	(7,540)	-
Accumulated OCI	(749)	751																						(2)		-	-	-
	(25,728)	716	(103)	-	-	(590)	2,177	(1,404)	(175)	419	782	-	-	-	-	-	-	-	-	-	-	223		(4)	-	(23,687)	(23,687)	
Regulatory balances	(38,563)																								38,563	-	-	-
Total Liabilities and S/H Equity, and regulatory b	(110,810)	(360)	-	2,099	931	(590)	2,177	(1,404)	(175)	419	782	-	-	-	-	-	-	-	-	-	-	223		(1)	38,563	(68,146)	(68,146)	
STATEMENT OF OPERATIONS AND RETAINED EARNINGS																												
Revenue																												
Sale of Energy	(72,553)																			951	-					(71,602)	(71,601)	(1)
Distribution Revenue	(10,803)																			(1,300)						(12,103)	(12,103)	-
Solar	(395)																									(395)	(395)	-
Other	(1,538)		(103)										51	165								2,120	(36)			659	659	-
	(85,289)	-	(103)		-	-	-	-	-	-	-	-	51	165		-	-	-	-	(349)	-	2,120		-	-	(83,441)	(83,440)	
Operating Expenses																												
Cost of power purchased	74,762																			(3,161)	-					71,601	71,601	-
Operating Expenses	8,256	-							(175)		782									520	(51)	(2,429)				6,903	6,903	-
Solar Expenses	51									-			(51)	-												-	-	-
Depreciation and amortization	2,249		-			(590)								(165)												1,494	1,494	-
	85,318	-	-		-	(590)	-	-	(175)	-	782	-	(51)	(165)		-	-	-	-	(2,641)	(51)	(2,429)		-	-	79,998	79,998	
Loss (Income) from operating activities	29	-	(103)		-	(590)	-	-	(175)	-	782	-	-	-		-	-	-	-	(2,990)	(51)	(309)		-	-	(3,443)	(3,442)	
Finance income	(54)																				(87)					(141)	(141)	-
Finance costs	896																				50					946	946	-
Income before income taxes	871	-	(103)		-	(590)	-	-	(175)	-	782	-	-	-		-	-	-	-	(2,990)	(88)	(309)		-	-	(2,638)	(2,637)	
Current tax expense	170																									170	170	-
Future tax expense (recovery)	699																					(663)	(36)			-	-	-
Net Income for the year	1,740	-	(103)		-	(590)	-	-	(175)	-	782	-	-	-		-	-	-	-	(2,990)	(88)	(972)		-	-	(2,468)	(2,467)	
Net movement in regulatory balances, net of tax	(4,325)																			2,990	88	1,247				-	-	-
Net income for the year and net movement in re	(2,585)	-	(103)		-	(590)	-	-	(175)	-	782	-	-	-		-	-	-	-	-	-	275	-	-	-	(2,468)	(2,467)	
Other comprehensive income																												
Remeasurement of post-employment benefits	-	-																								-		-
Tax on remeasurements	-	-																								-		-
Other comprehensive income for the year	-	-	-		-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-		-	-	-	-	-
Total comprehensive income for the year	(2,585)	-	(103)		-	(590)	-	-	(175)	-	782	-	-	-		-	-	-	-	-	-	275	-	-	-	(2,468)	(2,467)	
Retained Earnings, beginning	(6,772)																							0		(6,772)	(6,120)	
Prior Period Adjustment to RE	-	(17)	-	-	-	-	2177	(1,404)																(2)		754		
OEB Audit adjustments to RE (prior periods)	(521)									419																(102)		
Net income for the year and net movement in re	(2,585)	(18)	(103)	-	-	(590)	-	-	(175)	-	782	-	-	-	-	-	-	-	-	-	-	223	-	-	-	(2,466)	(2,466)	
Dividends	1,046																									1,046	1,046	
Retained Earnings, end	(8,832)	(35)	(103)	-	-	(590)	2,177	(1,404)	(175)	419	782	-	-	-	-	-	-	-	-	-	-	223	-	(2)	-	(7,540)	(7,540)	

<u>Attachment 1-J</u>

EPC Annual Reports (2015-2016)

2015 ANNUAL REPORT

ESSEX POWER CORPORATION

EMPOWERING CUSTOMERS TO HELP BUILD OUR SUSTAINABLE COMMUNITIES

OUR CORPORATE PHILOSOPHY

MISSION

Essex Power Corporation is a dynamic energy company that provides safe, reliable and economical energy supply and services to our customers. Our commitment to innovation, performance management and leading by example has built the foundation at Essex Power and our affiliates to establish a diverse set of energy products and services that are valued by our customers. At Essex Power, "Your Power is Our Priority."

VISION

Essex Power Corporation's vision is to be an Energy Provider that utilizes "best in class" people, processes, and technology to lead the market place in sustainable energy solutions. Our customers will receive the greatest value by integrating an economic and environmental balance to the products and services we will deliver to them. As an Energy Provider we will be a community leader in ensuring that environmental stewardship is a vital component of our services to increase customer awareness of proper energy utilization and management.

TABLE OF CONTENTS

BOARD CHAIR & CEO MESSAGE

EMPOWERING CUSTOMERS TO HELP BUILD OUR SUSTAINABLE COMMUNITIES

At Essex Power, we believe the stakes are high when it comes to “our environment” and we must work as a team with our communities to help them become sustainable leaders and serve as a standard for others to follow.

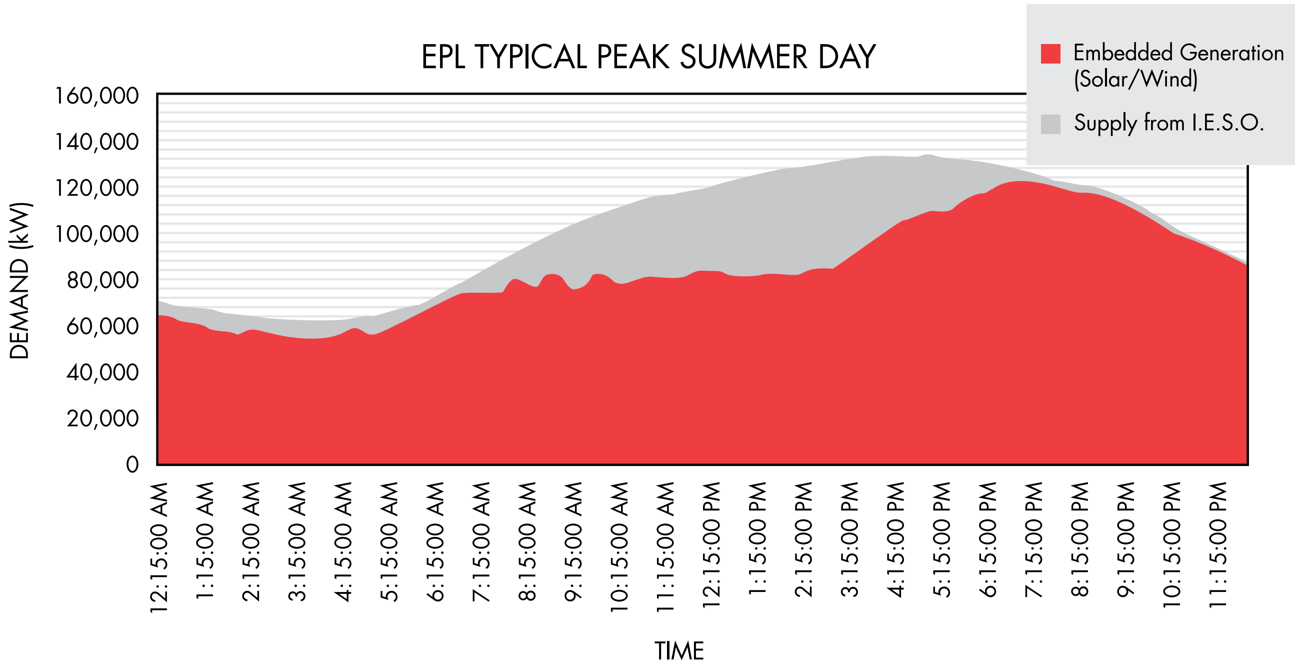
Gary McNamara, Chair, Essex Power Corp and President, AMO and Ray Tracey, President and CEO, Essex Power, and Chair, Electricity Distributors Association

As the world confronts the increasing challenges of Global Warming, we believe it will be the sustainable communities that will have the greatest effect in reducing and hopefully reversing the negative impacts that threaten our environment and our way of life in our communities.

At Essex Power, we are empowering our customers to help build these more sustainable communities. Reducing the carbon footprint of the community requires the engagement of everyone and as a key stakeholder, Essex Power’s role is to enable new technologies and spark new innovation to help reduce our communities’ reliance on carbon based technologies.

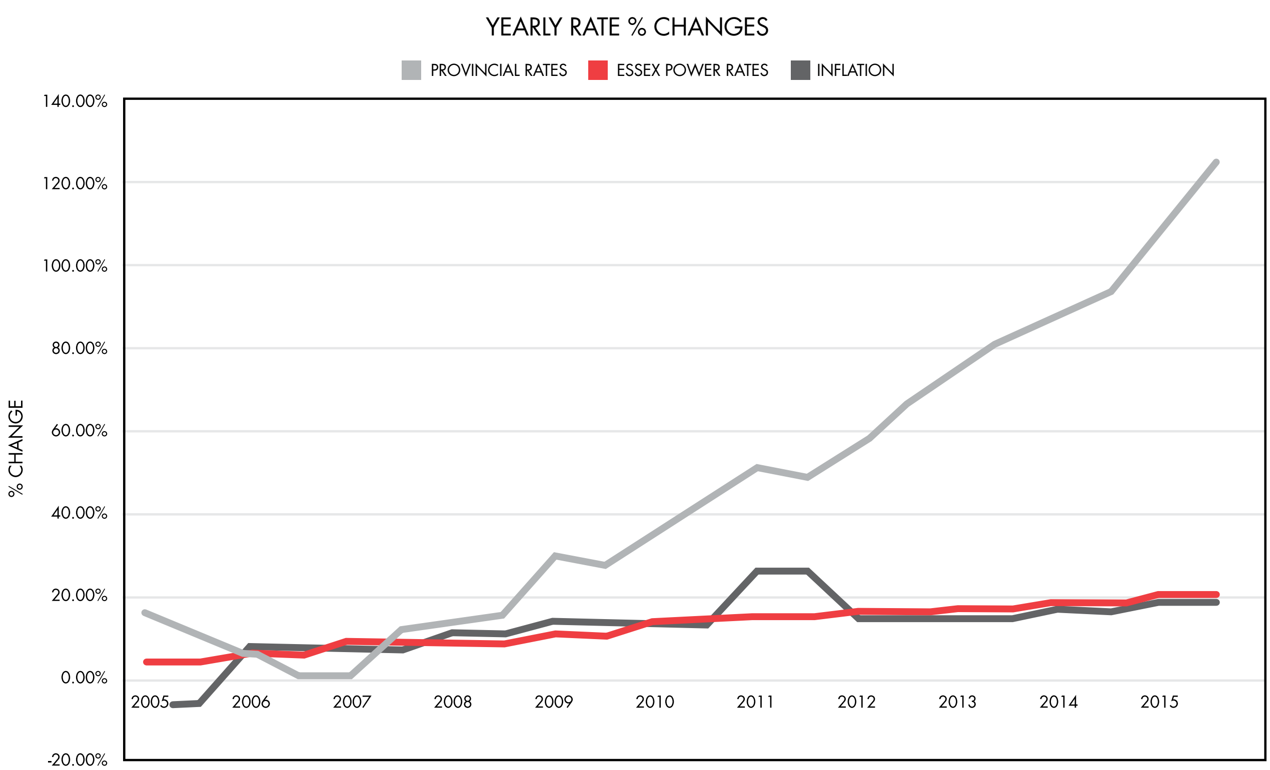
While the Province and the Ontario electricity sector have made huge strides in significantly reducing carbon utilization across the Generation mix that supplies Ontario by eliminating coal and introducing new renewable generation resources such as solar and wind, there is still more to do.

The following power demand curve for Essex Powerline’s aggregated summer peak day shows that local embedded renewable generation (in grey) is now playing a major role in contributing to the overall supply mix of servicing our four service territories in Amherstburg, LaSalle, Leamington and Tecumseh. During the mid-day peak period as much as 33% percent of our needed supply is bring produced locally through mostly renewable resources!



Essex Powerlines, Essex Power's regulated Local Distribution Company (LDC), continues to play a pivotal role in providing tools to our **30,000** customers through Conservation and Demand Management programs to reduce energy usage or usage patterns that can reduce their overall electricity bill cost. This makes good business sense but more important it is good for our environment.

Reducing the carbon footprint of the Generation supply mix for Ontario has come at a price for Ontarians. While Essex Powerlines' local distribution cost increases have remained at or below inflation, the rest of the provincial charges for electricity have clearly risen at rates that are pushing the boundaries of "utility affordability".



Essex Power remains committed to finding new ways of helping our customers to deal with the price pressures they are feeling. We are looking at "behind the meter" opportunities for residents and businesses to use less or even self-generate their own power needs more affordably.

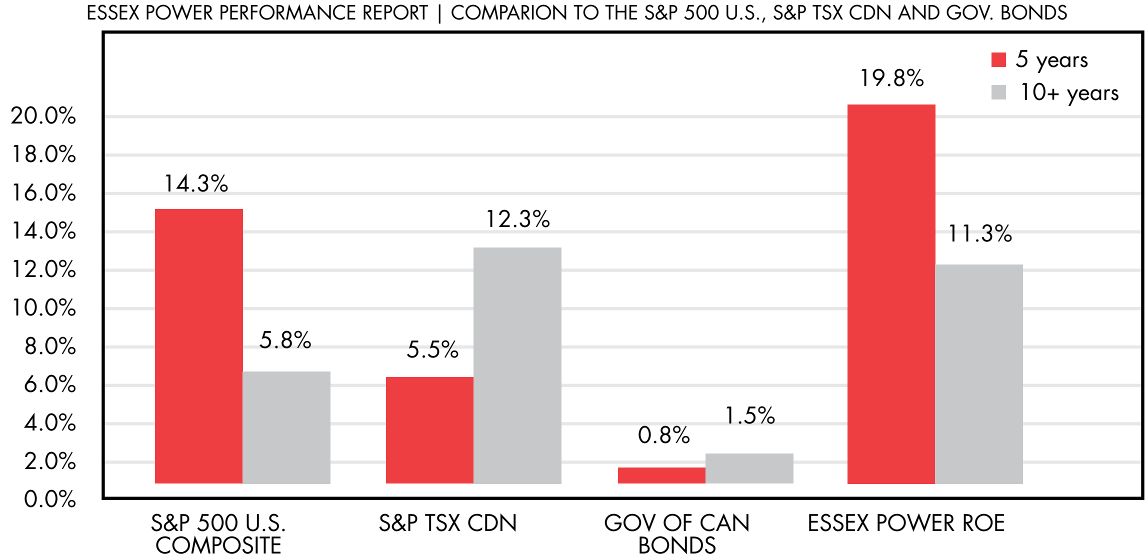
Essex Power has committed to 21st century technologies to enhance customer choice and allow for more technology and innovation to exist across the grid. Essex Powerlines and Essex Energy will be collaborating with the IESO and new storage provider partners to install grid level storage capacity within our distribution system. This will allow us to more effectively balance our load curve and take full advantage of both embedded renewable generation and off-peak lower energy prices.

Essex Power is also developing and installing a grid level intelligence system to enable a vast array of new technologies to be connected to the grid or behind the meter. The joint project between Essex Powerlines and Essex Energy will allow us to communicate with smart devices such a, smart meters, electric cars and their charging stations, intelligent thermostats like NEST, grid storage, automated switching devices, embedded generation and many other new technologies. We will use this grid level intelligence to help optimize how the grid can be managed in the most effective way to balance the supply-load mix to maximize efficiency and the reduction of carbon in the supply mix of electricity needed by our power our customers' needs.

At the same time, we will be helping residents and businesses reduce the impacts on their electricity bills. We will be providing choice and enabling them to decide what technologies will best help them to reduce their electricity costs.

Essex Power's 2015 corporate performance remains very strong yet at the same time we maintained responsible and affordable distribution rates. Essex Powerlines distribution charge as part of the overall utility bill has dropped from 25% down to **19%** over the last ten years. Essex Power maintains this strong corporate performance through a balance business approach by having operating interest in both regulated and unregulated sectors. As our local communities begin to rebound and grow out of the recession, Essex Power is well prepared to service this growth with capital reinvestments now reaching **$38 M** and the modernization of the entire distribution system across ALL four service areas to a single distribution voltage of 27.6 kV thus eliminating our entire end of life step down substations and substantially upgrading distribution lines and transformers. This has resulted in a much more reliable grid and with increased capacity to serve both our load and embedded generation customers.

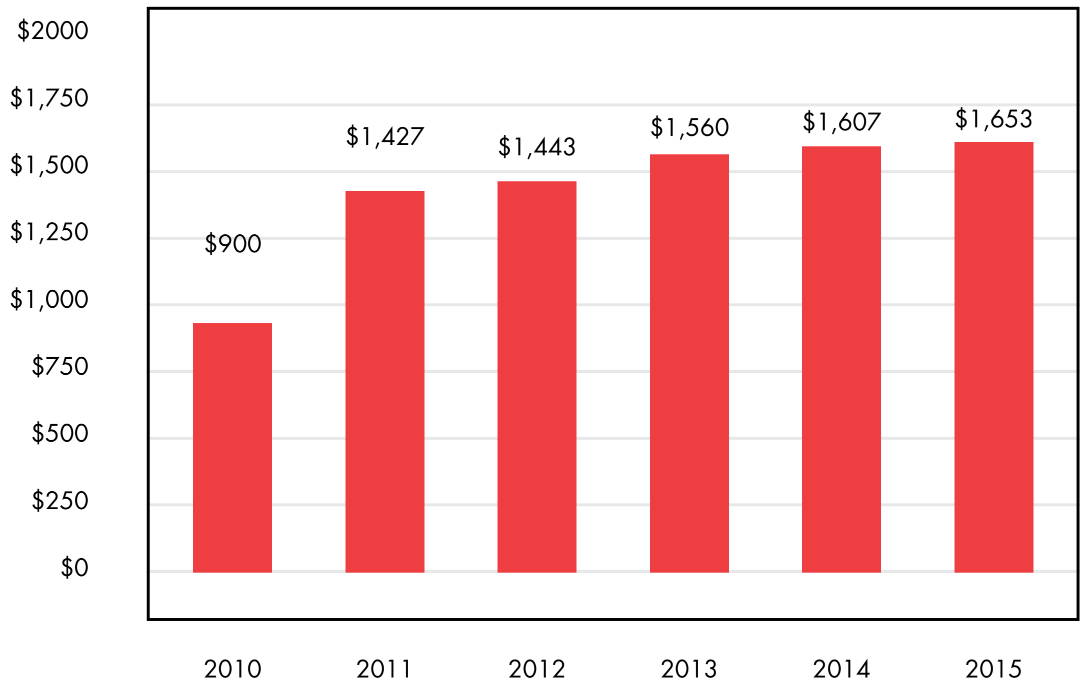
ESSEX POWER PERFORMANCE REPORT | COMPARION TO THE S&P 500 U.S., S&P TSX CDN AND GOV. BONDS



Essex Powerlines dividend stream and corporate returns remain very strong and continue to outperform market investments comparisons. Shareholder equity has grown substantially as a result of this consistent corporate performance. Outperforming the market in corporate performance and maintaining fair and reasonable distribution rates allows Essex Power Shareholders' to have a Win-Win situation as a local owner of an integrated Energy business.

Essex Power issued **$1,591,000** cash dividend in 2015 which is a **3% increase** from last year and the overall corporate return was **16.8 %**. The past five year dividend cash flow to our shareholders has been **$7,690,000** enabling our Shareholders to strategically re-invest and build our sustainable communities even stronger.

COMMON SHARES AND SPECIAL SHARES DIVIDENDS (THOUSANDS)



As Canada's most renowned astronaut **Chris Hadfield** said:

> *Ultimately, leadership is not about glorious crowning acts. It's about keeping your team focused on a goal and motivated to do their best to achieve it, especially when the stakes are high and the consequences really matter.*

Raymond J. Tracey, P. Eng.
President & C.E.O, Essex Power Corporation

Gary McNamara
Chair, Essex Power Corporation

2015 FAST FACTS

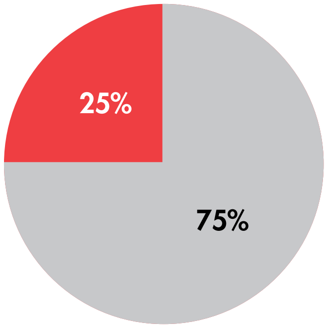
Essex Powerlines (Regulated)

$47,589,018 ASSETS

Total Assets	$47,589,018
Overhead lines	188 km
Underground cable	261 km
Transformers	3,074
Poles	6,276
Fleet Vehicles	24
Summer Peak Demand	121,803 kW
Winter Peak Demand	80,880 kW

ELECTRICITY BILL BREAKDOWN - 2005

PROVINCIALLY CONTROLLED ESSEX POWERLINES CONTROLLED

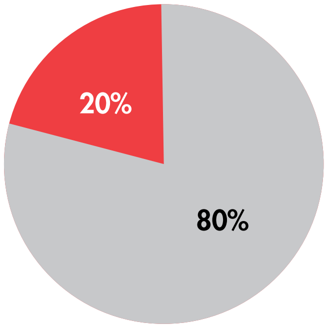


28,949 CUSTOMERS

Total Electricity Customers	28,949
Total Electricity Consumed	488,521,550 kWh
Number of Residential Customer Accounts	26,713
Total Electricity Consumption	246,568,730 kWh
Number of Commercial & Industrial Accounts	2,236
Total Electricity Consumption	236,952,820 kWh

ELECTRICITY BILL BREAKDOWN - 2015

PROVINCIALLY CONTROLLED ESSEX POWERLINES CONTROLLED



$1,591,000 TOTAL COMMON DIVIDENDS

Common Dividends for Year	2015	2014	2013	2012
Amherstburg	226,877	220,317	213,900	199,640
LaSalle	529,007	513,712	498,750	465,500
Leamington	414,456	402,472	390,750	364,700
Tecumseh	420,660	408,498	396,600	370,160
Total Common Dividends	1,591,000	1,545,000	1,500,000	1,400,000

Community Renewable Energy Projects

$61,709 TOTAL SPECIAL DIVIDENDS

Special Dividends (GS) for Year	2015	2014	2013	2012
Amherstburg	17,804	17,804	17,804	
LaSalle	17,729	17,729	15,870	14,542
Tecumseh	26,176	26,176	26,176	26,176
Total Special Dividends	61,709	61,709	58,850	40,718

ESSEX ENERGY HIGHLIGHTS

In 2015, Essex Energy commissioned over **1430kW** of solar PV generation capacity in Ontario. As of the end of 2015, the cumulative total of clean, emission-free energy that has been produced by renewable generators developed by Essex Energy surpassed **8.2 GWh** including over **145 sites**. This is a great accomplishment by the dedicated and socially responsible staff of the company.

The effort to carbon neutralize three large quarries in the Muskoka region through the deployment of 1.8MW of solar PV facilities that began in 2014 continued in 2015 as Essex Energy completed engineering and broke ground on the sites.

To complement Essex Energy's renewable generation fleet, the company has moved in to the grid-tied energy storage sector. In 2015, Essex Energy, in partnership with others, was awarded a contract through Ontario's Independent Electrical System Operator to construct flow battery storage technology facilities totaling 3,000 kW's in the Essex County region and in Essex Powerlines service territory. This is an exciting accomplishment for the Essex Power Group and will ensure the corporation stays at the leading edge of Distributed Energy Resource technology in the province.

Essex Energy's efforts to contribute to the region's economic development were strong in 2015. One significant example of this is the work that the company did in the greenhouse sector to explore options with Provincial Agencies to make more efficient use of the county's rural grid in order to enable more connections for lighting facilities that will result in competitive gains for the industry.

Finally, in 2015, Essex Energy, in partnership with Utilismart Corporation, completed its first major Ontario launch of its industry leading smart grid software suite – SmartMAP. The launch was an overwhelming success and has served as a reference project as Essex Energy and Utilistmart Corporation expand sales of this and other cloud-based software in the greater North American market.

SOLAR HIGHLIGHTS

In 2015, Essex Energy Corporation commissioned solar PV sites at Marmora, Atlas Tube Centre, Lakeshore 34 and CFC Warehouse. With just our large systems, we have saved enough kilowatt hours to power **995** homes for a year!

Project Name	Commissioned Date	Number of Days Running	kWh Savings	Homes Powered per Year
Tecumseh Arena	October 22, 2010	1,899	2,882,446	324
Vollmer Arena	December 21, 2011	1,474	1,579,744	178
Amherstburg Arena	November 19, 2012	1,140	2,470,975	278
Marmora	April 1, 2015	277	244,183	27
Atlas Tube Centre	November 26, 2015	38	26,209	3

In December, Essex Energy Corporation was the recipient of the Fronius SnapINverter Reference Project Competition for the 600kW DC solar PV system at the Atlas Tube Centre. The Atlas Tube Centre was one of the few contracts awarded by the OPA based on the Unconstructed Rooftop Solar Pilot Project.

ESSEX POWERLINES HIGHLIGHTS

In 2015, the focus was on ensuring that Essex Powerlines will continue to be an industry leader with respect to 21st Century Utility processes, systems and technological integration. In addition to continuing towards putting the necessary pieces in place that will allow for a "self-healing" distribution system that can automatically reroute power during an outage and in turn reduce the length of the outage and the cost of rolling trucks out, the main focus was on preparing to empower all our employees through technology, including the use of cutting edge technology such as SmartMap.

In 2015, Essex Powerlines became a single voltage utility. Furthermore, we continued to invest in distribution system capital that will provide increased reliability for our customers. These achievements will enable us to achieve our goals of maximizing shareholder value, improving customer satisfaction and maintaining regulatory compliance.

For 2016 and beyond, EPL will continue developing both short and long term labour strategies that align the needs of our asset replacement and repair with a compliment of line and metering resources.

UTILISMART HIGHLIGHTS

Utilismart is a Meter Data Management company providing data collection, processing, storage and web-presentment services to engineering, operations, finance and customer service of utilities and municipalities, as well as data for use by the end consumers of electricity, water and natural gas.

Since 2000, Utilismart Corporation has been providing Distribution Utilities, Municipalities, Commercial and Industrial customers with the data that they require to operate efficiently and effectively.

In 2015, Utilismart was successful in upgrading their Information Security Management System to ISO 27001:2013, which exhibits the commitment to data security, reliability and privacy.

Utilismart is also revolutionizing Utility application with the adoption of SmartMAP, a cutting edge Distribution Management System. SmartMAP has been very well received in the market and provides tremendous value to Utilities that have deployed Advanced Metering Infrastructure (AMI).

Utilismart has acquired 12 new customers, stabilized the UDM product, and has launched an expansion into cellular services in Ontario.

ISO

utilismart™ CORPORATION

bsi. ISO/IEC 27001:2013 Information Security Management

smartmap

GRI REPORT CONTENT

The Global Reporting Initiative (GRI) is an internationally recognized standardized framework for disclosing an organization's environmental, social and economic performance.

This is Essex Power's fourth filing with the GRI framework and we are proud to say that as a result of our commitment to social sustainability, we have transitioned from a Level C to a Level B. We are happy with our improvements thus far but we are committed to building upon our current successes in order to improve in the future.

REPORT SCOPE & BOUNDARIES

Our regulated electricity distribution company, Essex Powerlines, is accountable for providing a safe, reliable and cost effective supply of electricity to the municipalities of all our stakeholders and communities. The scope of this report and GRI submission includes all of the Essex Power Group of Companies.

To measure our success and progress in sustainability, we have defined key areas that we see of great importance to achieving success. Essex Power has made sustainability a core foundation for all decision making and has initiated best practices for managing operational and environmental risk. This report will analyze and measure Essex Power's performance within the three pillars of sustainability.

Environmental stewardship is evaluated by our success in energy conservation, renewable energy investment, waste management, and environmental risk mitigation of our operations.

Social responsibility is evaluated by how we ensure the safety and wellness of people including our employees, our contractors, and our communities. We are committed to providing a safe and respectful workplace where employees are highly valued, treated fairly, provided with challenging and meaningful work and benefit from opportunities for knowledge growth and career development.

Economic Performance is evaluated by the value we create for our stakeholders while facilitating the economic growth of the communities we serve.

B
GRI REPORT
GRI CHECKED

The GRI G3.1 Content Index for Application Level B and the Electric Utilities Supplement Content index are available on our website at: **www.essexpower.ca**

We welcome your feedback on our Sustainability Report.

Comments can be directed to: **sustainability@essexpower.ca**

CONSERVATION & DEM

In 2015, the IESO and Ontario's Local Distribution Companies transitioned from the former 2011-2014 Conservation framework to the new 2015-2020 Conservation First Framework. Through diligent efforts and engagement with the community and customer base, Essex Powerlines Corporation achieved 108% of its mandated conservation target at the end of 2014. The 2015 year saw a significant change in the structure of how Conservation programs are designed, administered, managed and delivered.

Under the 2015-2020 Conservation First Framework, Ontario's LDCs have greater flexibility, autonomy, and responsibility in pursuit of the challenging conservation targets mandated in the Framework. As of the end of 2015, Essex Powerlines had successfully transitioned to the new Conservation First Framework and is on track to achieve its Conservation targets.

MAND MANAGEMENT

$1,709,211 IN INCENTIVES

Essex Power offered energy retrofit programs to local businesses that injected over **$1,709,211** into the economy, representing investments made by local residents, businesses and industry in conservation.

Comfort INN

LEAMINGTON

$16,256 total incentives

2.32 kW saved

14,913.52 kWh saved

28 lightbulbs turned off for a year

DIAGEO

$20,951.75 total incentives

47.8 kW saved

419,035 kWh saved

797 light bulbs turned off for a year

reaume
CHEVROLET • BUICK • GMC
www.ReaumeChev.com

$13,064 total incentives

8.82 kW saved

40,657 kWh saved

77 light bulbs turned off for a year

SOCIAL PERFORMANCE

Essex Power employees engaged in a friendly "food fight" between two of our sites with the winner being one of our local food banks. St. Andrew's LaSalle Food Bank received 1918 cans. We are also proud of our employees at Utilismart who donated 90 lbs to the London Food Bank.

COMMUNITY INVOLVEMENT

Some of the local organizations that received our support include:
St. Andrew's LaSalle Community Food Bank
Amherstburg Food & Fellowship Mission
Leamington & District Ministerial Food Bank
Tecumseh Goodfellows
Erie Shores Hospice
Windsor & Essex County Crime Stoppers
Taste of Tecumseh
8th Annual LaSalle Fishing Tournament
Bursary for Communications Tech Graduate at General Amherst High School
Law Enforcement Torch Ride – Special Olympics
Amherstburg Minor Soccer Association
St. Anne's High School 2015 AAAA OFSAA Girls Volleyball
Holy Names High School – Knight Vision Robotics

COMMUNITY INVOLVEMENT

In 2015, Essex Power continued the support of our communities through various charitable donations and employee involvement. 2015 was the second year of our "Youth in Community Fund" with our Shareholders supporting organizations offering activities and projects to the youth in our communities. Once again, each of our Shareholders was provided with **$10,000** in funding to be used towards youth oriented programing and initiatives Essex Power provided financial support to those programs in our communities that serve as food banks, Amherstburg Food & Fellowship Mission, LaSalle St Andrew's Anglican Church Food Bank, Leamington & District Ministerial Food Bank and the Tecumseh Good fellows. We are proud that our employees are on board with contributing to our communities as well, as an additional **$800+** employee funded donation was given to the food banks. We had staff active as volunteers in the community including the Goodfellows Paper Drive in Tecumseh. There are numerous organizations throughout our service area EPC continues to support. Essex Power continued

SHAREHOLDERS

to support the annual community festivals in our municipalities through sponsorships and we continue to provide $5,000 in in-kind services to each of our Shareholders. We participated in the Co Operative Education programs with Universities and Colleges and offered a bursary to local high schools.

In Ray Tracey's role as Chair of the EDA Western District, we worked closely with South Western LDCs to hold the 3rd Annual EDA Western District Charity Golf Tournament following the Annual General Meeting. The beneficiary of the tournament Chatham-Kent Hospice is in the process of building a new, first for the community, 10 bed residence. The EDA Western District was thrilled to surpass our fundraising expectations with a final donation of **$63,000**.

CORPORATE OWNERSHIP STRUCTURE

Committed to strong corporate governance and accountability, the **Board of Directors** brings a depth of experience to governing Essex Power Corporation in the best interests of customers and the community.

SHAREHOLDERS

ESSEX POWER CORPORATION

(Holdco)
President & CEO Raymond J. Tracey

BOARD OF DIRECTORS
Gary McNamara Chair
Aldo DiCarlo
Frank C. Ricci
Joe Graziano
John Paterson
Ken Antaya
Tom Burton
William Wark

ESSEX POWERLINES CORPORATION

REGULATED

BOARD OF DIRECTORS

Ken Antaya, Chair
Aldo DiCarlo
Robert Pula
(Independent Member)

General Manager
Joe Barile

Master Service

Agreement for resources for street lights and other third party projects

ESSEX POWER SERVICES CORPORATION

UNREGULATED

BOARD OF DIRECTORS*

Tom Burton

General Manager
Steve Ray

third parties

CONTRACTS FOR SERVICES

ESSEXENERGY CORPORATION

UNREGULATED

BOARD OF DIRECTORS

Joe Graziano, Chair
Tom Burton
John Paterson

General Manager
Steve Ray

utilismart™ CORPORATION

BOARD OF DIRECTORS

Marie Campagna, Chair
Ray Tracey
Gary McNamara
Joe Graziano
President
John Avdoulos

WattsWorth the energy analysis people

NOTES

Essex Power Corporation is a dynamic energy company that provides safe, reliable and economical energy supply and services to our customers. Our commitment to innovation, performance management and leading by example has built the foundation for Essex Power and our affiliates to establish a diverse set of energy products and services that are valued by our customers.

Essex Powerlines Corporation, a regulated company, provides reliable and safe power to over 28,000 residents and businesses in Amherstburg, LaSalle, Leamington and Tecumseh. Essex Powerlines provides safe, reliable and economical electrical distribution and service to 28,000 customers within four municipalities of Essex County, and has system voltages of 4.16 kV, 8 kV and 27.6 kV. At Essex Powerlines, our corporate vision is to provide the communities of Amherstburg, LaSalle, Leamington, and Tecumseh with safe, reliable, and economical energy supply and service. The foundation to empower our vision is based on a dynamic and progressive workforce that will be industry leaders in providing 'best of class' business solutions in the delivery of service to our customers.

Since 2000 EPS has been a key streetlight service provider for our communities. Being ISO 9001:2008 certified our Quality Management System ensures proper business operation utilizing best practices. Essex Power Services was registered with IESO as a MSP (Metering Service Provider) in 2012 and currently maintains a total of 23 wholesale metering installations.

Essex Energy Corporation is a dynamic group of more than 20 engineers, business professionals, certified energy managers and LEED accredited individuals ready to provide your organization with a suite of energy management services. Among a wide array of other energy sector related activities, Essex Energy is directly responsible for the reduction of more than 252,000,000 lifecycle kWh through our conservation initiatives and has built some of Canada's largest solar photovoltaic rooftop systems Essex Energy is uniquely positioned to assist you in realizing your own triple bottom line.

Since 2002, Utilismart has been the industry leader in providing settlement services to utilities throughout Ontario. Our services are built on industry expertise and an in-depth understanding of both the settlement processes in the marketplace and the needs of the customer. Our hosted solutions offer customers an economical, efficient settlement service that has build-in reporting and analysis tools. Our knowledge in this area allows for seamless integration into CIS, Financial, and other customer systems requiring settlement data.

As a Canadian company based in Ontario, WattsWorth offers a variety of energy management services to participants in the Ontario market. Our clients include large industrial/commercial companies, electric utilities, electricity generators and municipalities. WattsWorth has over1billon kWh consumed annually. In addition to technical expertise and a highly specialized and robust infrastructure, WattsWorth makes a commitment to listen to our clients' requirements and tailor solutions that respect their objectives. WattsWorth has a business manner that reflects high standards of professionalism, attention to detail, and a logical approach to problem solving.

Essex Power 2015 Financial Statements are available on our website
www.essexpower.ca

Printed copies of this report may be requested by sending an email to
sustainability @essexpower.ca

ESSEX POWER CORPORATION

2199 Backacre Drive Suite 200 Oldcastle, Ontario N0R 1L0
Phone: 519.946.2002 Fax: 1.866.291.5317 Email: info@essexpower.ca

Essex Power's 2015 Annual Report and Financial Statements are printed on recycled paper.

EMPOWERING

INNOVATION

ESSEX POWER CORPORATION

2016 ANNUAL REPORT | EMPOWERING INNOVATION

OUR CORPORATE PHILOSOPHY

MISSION

Essex Power Corporation is a dynamic energy company that provides safe, reliable and economical energy supply and services to our customers. Our commitment to innovation, performance management and leading by example has built the foundation at Essex Power and our affiliates to establish a diverse set of energy products and services that are valued by our customers. At Essex Power, "*Your Power is Our Priority.*"

VISION

Essex Power Corporation's vision is to be an Energy Provider that utilizes "*best in class*" people, processes, and technology to lead the market place in sustainable energy solutions. Our customers will receive the greatest value by integrating an economic and environmental balance to the products and services we will deliver to them. As an Energy Provider we will be a community leader in ensuring that environmental stewardship is a vital component of our services to increase customer awareness of proper energy utilization and management.

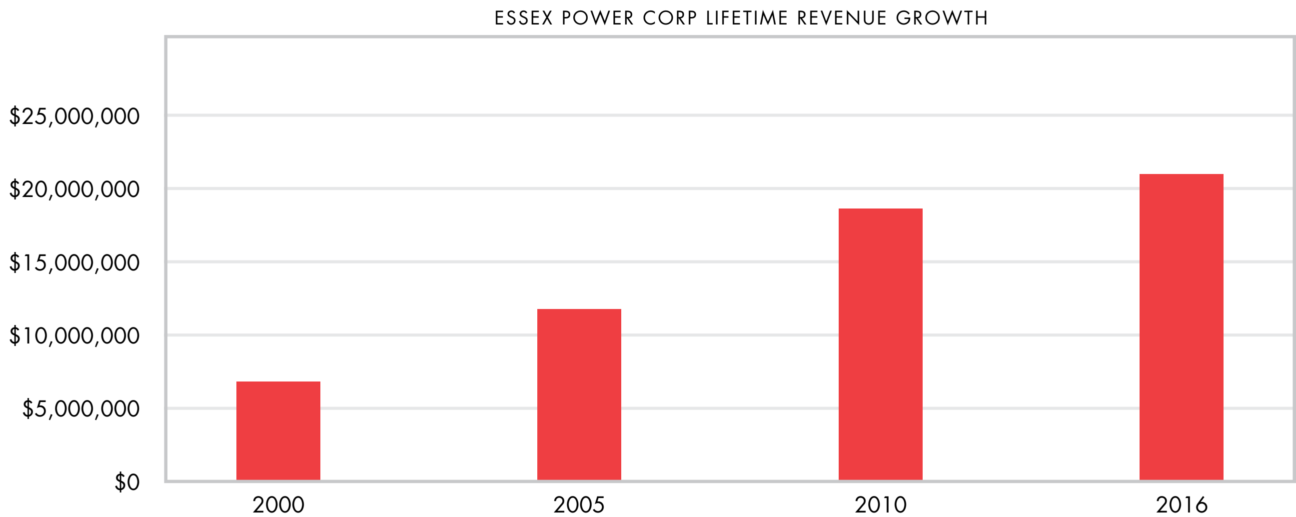
TABLE OF CONTENTS

BOARD CHAIR & CEO MESSAGE

Gary McNamara, Chair, Essex Power Corp and Ray Tracey, President and CEO, Essex Power Corp

Essex Power Corp. is very pleased to present our corporate results and recognize our industry acknowledgments that we received in 2016. Essex Power's diversified portfolio of business activities that spread across both regulated and non-regulated sides of the energy sector has allowed us to consistently deliver strong operational and financial performance to our shareholders and our customers. We are fully committed to the communities in which we serve and we continue to play a local leadership role in supporting the social fabric that makes southwest Ontario such a great place to work, live and play.

While we pride ourselves in delivering such a consistency of strong performance, we also realize that the fast pace of innovation growth within the Energy sector means change. We need to embrace the opportunities that can be realized by leading the energy transformation that is occurring across this industry. As a result, Essex Power is taking a leadership role through grid modernization. We have upgraded our distribution assets to a single high level voltage, we have added intelligent monitoring and switching devices throughout our networks and are now able to operate it with complete grid intelligence. We plan, engineer and operate from a common system that operates 24-7 and provides full transparency of grid performance from the end-use meter to transmission stations.



Essex Power, using an innovative spirit across its group of companies, built and commercialized a technology called **ODS 2.0** and **SmartMap** in 2016 and partnered with Essex Powerlines and Collus Powerstream as our first two pilots using this new technology.

We were extremely proud when both Essex Powerlines and Collus Powerstream received the Utility Innovation Award from the Electricity Distributors Association for piloting and implementing this leading edge grid intelligence technology.

This is the second time that Essex Power has been recognized as an industry leader. In 2011, Essex Powerlines was recognized as Utility of the Year as a result of our overall performance in Operations, Safety and Quality of Service.

The world has now embraced alternative energy resources and we see even stronger signs of potential new investments. Our focus will be to develop local and regional sustainable energy resources within the communities we serve and across Ontario where the actual energy is needed. Autonomous vehicles, electrification of transformation towards electric vehicles and EV charging stations along with large scale storage will be the next era of new technologies.

Renewable technologies such as wind, solar, bio-gas and hydro have become the mainstream technology of choice to expand electricity capacity within a region.

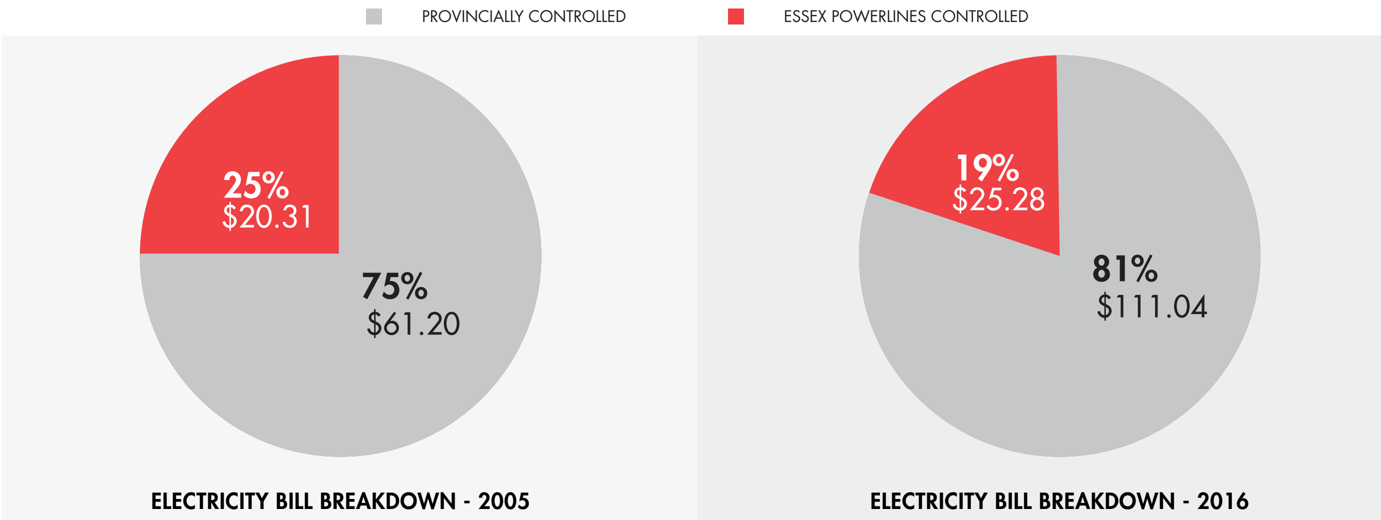
At Essex Power, the clear trend is towards more local resources providing the supply capacity needs of our customers. Our electricity grid has become the "two way highway" and as such more intelligence is needed to facilitate the supply-demand balance locally using more embedded generation and new technology, such as storage. Customers are now investing at record levels in "*Behind the Meter*" technologies in order to reduce their consumption, fully displace it or even export excess power. New potential provincial programs such a Net and Virtual metering will only enhance the growth of new technologies at the customer's premise

At Essex Powerlines the distribution portion of the bill has become an even smaller portion of the overall bill. Thus, our customer's attention has turned towards lowering the energy supply side of the bill. This has the potential of creating new opportunity for us as an overall energy provider.

Essex Power plans to work very closely with stakeholders and serve as a catalyst for developing local distributed energy resources across our grid whether they are connected directly to it or behind the meter at our customers' sites.

Essex Power and Collus Powerstream employees accepting the EDA Innovation Award

WHAT PORTION OF THE OVERALL BILL DOES EPL REPRESENT?

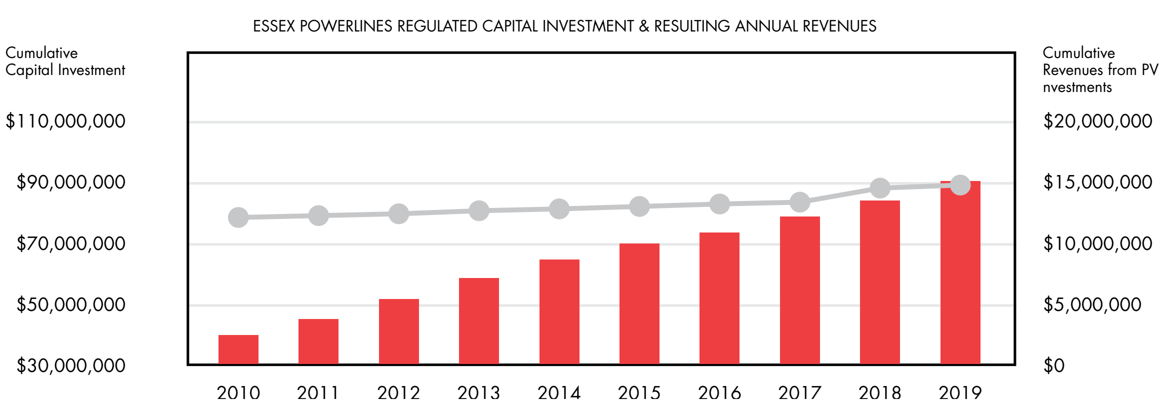


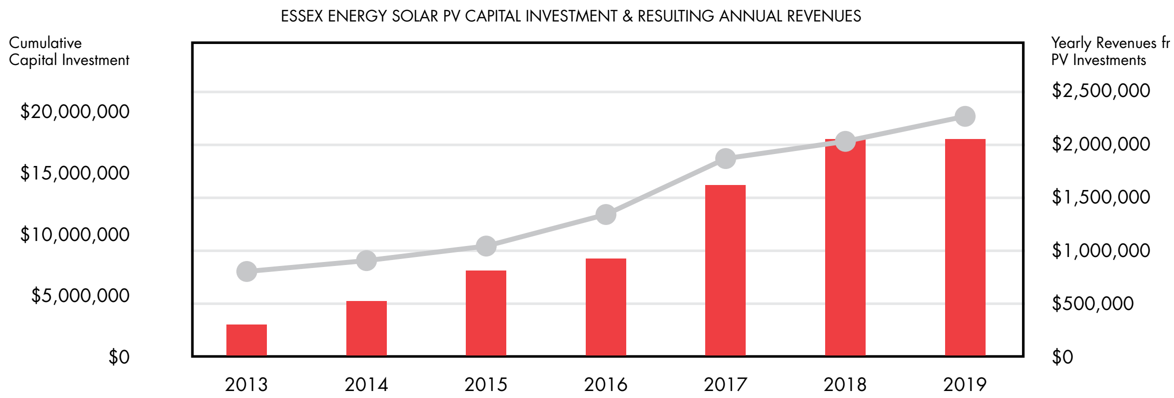
For a typical Essex Powerlines residential electricity bill (800kWh/month), EPL's portion of the bill increased **$5.29** while the provincial portion increased **$49.84** over the last 11 years.

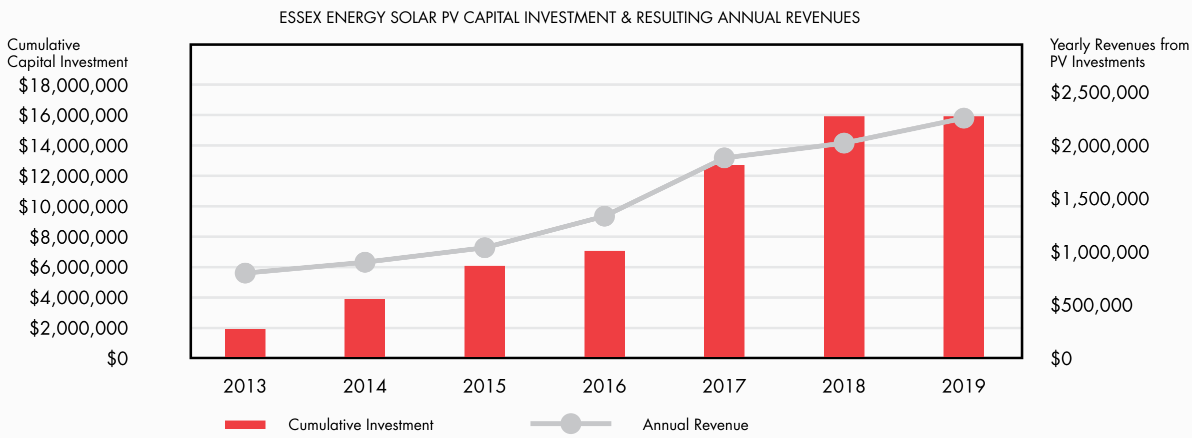
Essex Power's investment portfolio commitment in new technologies in order to grow revenue remains strong. We also have increased our spending to make our local distribution systems smarter, more efficient and adaptable to new technologies. Our unregulated entities will continue to develop new smart grid software technologies as well build more sustainable technologies locally.

While we continue to make prudent investments, we also continue to provide our shareholders a strong dividend return with increased growth year over year. The EPC Board recommended and approved an increased dividend of **$1,639,000** to be issued to the Shareholders; this is **3%** increase from the previous year. This will represent a dividend payment that provides a cash return on common share equity of **9.1%**.

Our commitments to the community remain as strong as ever. We continue to participate and host many local fundraising events and are focused on helping others in need. Essex Power provided financial support to those programs in our communities that serve as food banks, Amherstburg Food & Fellowship Mission, LaSalle St Andrew's Anglican Church Food Bank, Leamington & District Ministerial Food Bank and the Tecumseh Good fellows.







While Essex Power cannot fully predict our future, we do know that opportunity lies with those that never stop seeking it. Essex Power's group of diversified companies allows us to look at every opportunity in the energy sector from a different set of lenses. This also allows us to focus on those that can deliver solutions that benefit our customers, our local communities and our Shareholders.

> *When one door closes another door opens; but we so often look so long and so regretfully upon the closed door, that we do not see the ones which open for us.*
> **- Alexander Graham Bell**, inventor of the telephone

Raymond J. Tracey, P. Eng.
President & C.E.O, Essex Power Corporation

Gary McNamara
Chair, Essex Power Corporation

2016 FAST FACTS

$53,773,779 ASSETS

Essex Powerlines (Regulated)

Total Assets	$53,773,779
Overhead Lines	186 km
Underground Cable	263 km
Transformers	3,081
Poles	6,264
Fleet Vehicles	23
Summer Peak Demand	129,367 kW
Winter Peak Demand	74,705 kW

29,095 CUSTOMERS

Total Electricity Customers	29,095
Total Electricity Consumed	505,521,588 kWh
# of Residential Customer Accounts	27,131
Total Electricity Consumption	255,480,799 kWh
# of Commercial & Industrial Accounts	5,401
Total Electricity Consumption	250,040,789 kWh

$1,639,000 TOTAL COMMON DIVIDENDS

Common Dividends for Year	2016	2015	2014	2013
Amherstburg	233,721	226,877	220,317	199,640
LaSalle	544,968	529,007	513,712	465,500
Leamington	426,959	414,456	402,472	364,700
Tecumseh	433,352	420,660	408,498	370,160
Total Common Dividends	1,639,000	1,591,000	1,545,000	1,400,000

$61,709 TOTAL SPECIAL DIVIDENDS

Community Renewable Energy Projects

Special Dividends (GS) for Year	2016	2015	2014	2013
Amherstburg	17,804	17,804	17,804	17,804
LaSalle	17,729	17,729	17,729	15,870
Tecumseh	26,176	26,176	26,176	26,176
Total Special Dividends	61,709	61,709	61,709	58,850

ESSEX ENERGY HIGHLIGHTS

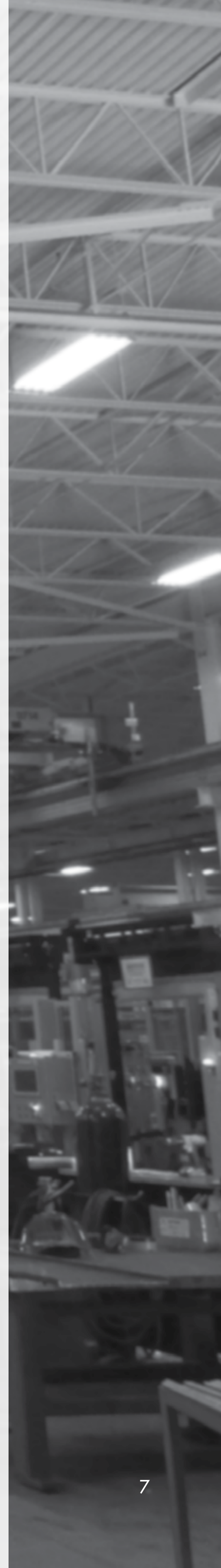
2016 marked another successful year for Essex Energy Corporation (*EE*). During this past year, EE reinforced its social commitment to the environment as it continued the construction of **1.8MW** of renewable generation at three quarry sites in the Muskoka Region, in partnership with First Nations. These projects are uniquely complex given the terrain and promise to neutralize the carbon footprint of the quarries. In addition to the quarry sites, Essex Energy also acquired a Solar Photovoltaic facility located in Vaughan, Ontario, thus extending its PV fleet to greater than 6MW of capacity across nine sites in the province.

In years to come, Net Metering and Virtual Net Metering will replace existing renewable energy programs and will present EE with new and innovative opportunities related to generation and community power projects involving shareholders.

Also, as technology in the energy sector advances on all fronts, EE has been successful in realizing many opportunities that have resulted. For example, EE qualified for and was chosen by the province (Ministry of Energy) to conduct a detailed research study regarding the benefits of distribution-connected energy storage in Ontario. This study will set the pace for energy storage as it may be adopted in the province's Long Term Energy Plan. It is EE's intention to continue to monitor storage technologies and actively deploy assets as the market evolves. Asset deployment will begin in 2017 with **3MW** of flow battery technology that has been contracted with the Independent Electricity System Operator (*IESO*) under their "*Phase II*" procurement. Exciting times!

In 2016, EE's smart grid business evolved from engineering, conservation, and complex software services (which still thrive) to the design and installation of Electric Vehicle (*EV*) charging stations – soon to be integrated with renewable power and storage systems (mini-micro grids). EE applied for, and was awarded, a grant to install a level 3 EV charger at Amherstburg's recreation complex. A successful project! As more Distributed Energy Resources find their way to the energy sector, EE's ability to integrate technologies will lead to more "*1st of its kind*"-type projects.

Essex Energy's current and future success is a direct result of the hard work of its great employees who continue to push the boundaries of an exciting sector!



SOLAR HIGHLIGHTS

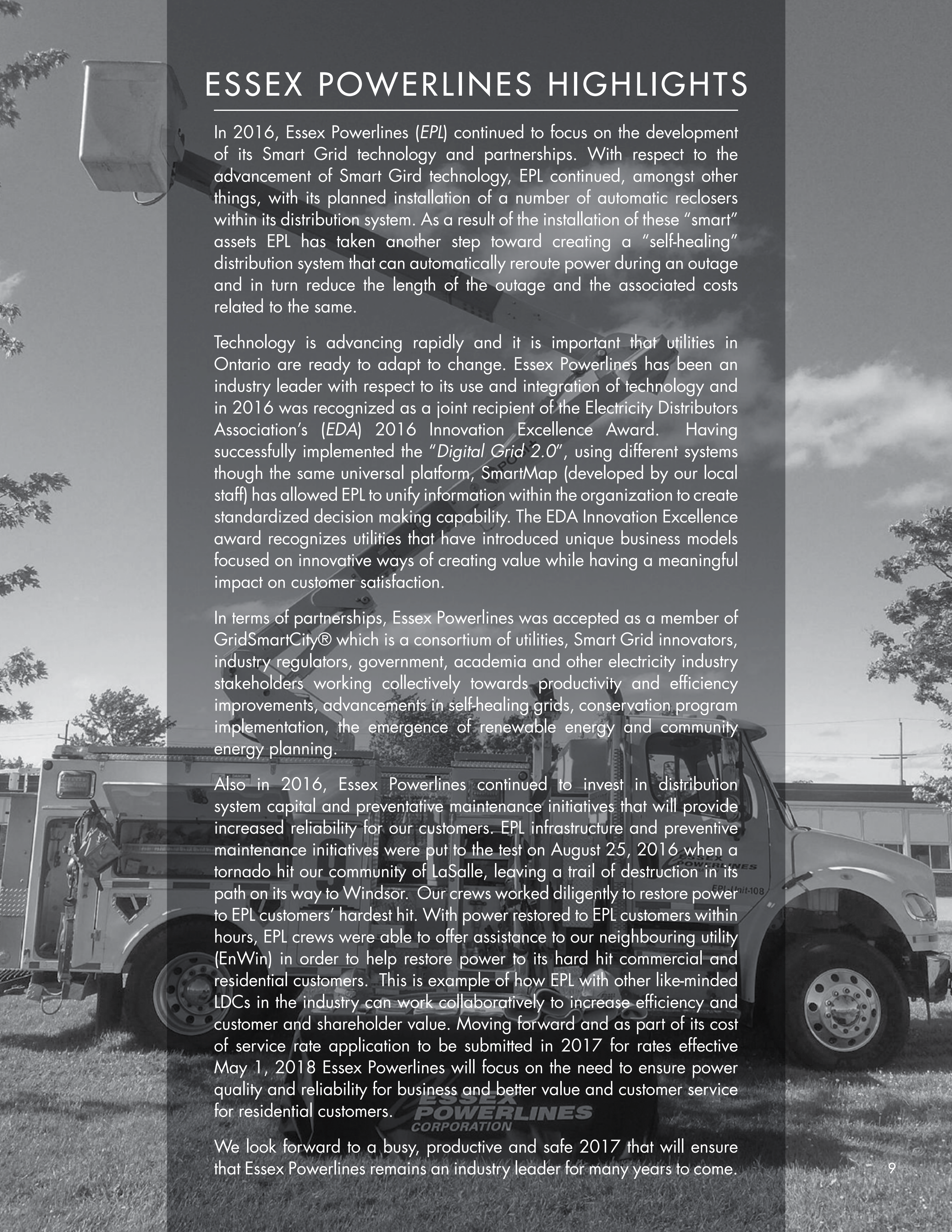
In 2016, Essex Energy Corporation acquired the ASI SPE 106 Solar Site in Thornhill, ON and we began construction of the Ullswater site which is scheduled to be commissioned in Q1 2017. With just our large systems, we have saved enough kilowatt hours to power **1,332** homes for a year!

Project Name	Commissioned Date	Number of Days Running	kWh Savings	Homes Powered per Year
Tecumseh Arena	October 22, 2010	2,468	3,736,841	420
Vollmer Arena	December 21, 2011	2,043	2,268,270	255
Amherstburg Arena	November 19, 2012	1,709	3,725,833	419
Marmora	April 1, 2015	846	652,611	73
Atlas Tube Centre	November 26, 2015	599	1,208,327	136
ASI SPE 106 Inc.	June 1, 2016	420	524,379	29

EV CHARGING STATION

The Town of Amherstburg, in partnership with Essex Energy Corporation, is thrilled to announce the launch of a Level 3 EV charging station at the Libro Credit Union Centre.

This charging station has been made possible due to a grant awarded by the Ministry of Transportation through the Electric Vehicle Chargers Ontario (EVCO) Program. The Town of Amherstburg was among **24** public and private partners selected in 2016 to help create an expanded network of fast-charging electric vehicle stations across Ontario in 2017. The goal of the Program was to create a network of optimally distributed public EVSEs that enable EV drivers to travel between and within cities and support the implementation of charging infrastructure to enable city and apartment dwellers to access much needed charging infrastructure.



ESSEX POWERLINES HIGHLIGHTS

In 2016, Essex Powerlines (*EPL*) continued to focus on the development of its Smart Grid technology and partnerships. With respect to the advancement of Smart Gird technology, EPL continued, amongst other things, with its planned installation of a number of automatic reclosers within its distribution system. As a result of the installation of these "smart" assets EPL has taken another step toward creating a "self-healing" distribution system that can automatically reroute power during an outage and in turn reduce the length of the outage and the associated costs related to the same.

Technology is advancing rapidly and it is important that utilities in Ontario are ready to adapt to change. Essex Powerlines has been an industry leader with respect to its use and integration of technology and in 2016 was recognized as a joint recipient of the Electricity Distributors Association's (*EDA*) 2016 Innovation Excellence Award. Having successfully implemented the "*Digital Grid 2.0*", using different systems though the same universal platform, SmartMap (developed by our local staff) has allowed EPL to unify information within the organization to create standardized decision making capability. The EDA Innovation Excellence award recognizes utilities that have introduced unique business models focused on innovative ways of creating value while having a meaningful impact on customer satisfaction.

In terms of partnerships, Essex Powerlines was accepted as a member of GridSmartCity® which is a consortium of utilities, Smart Grid innovators, industry regulators, government, academia and other electricity industry stakeholders working collectively towards productivity and efficiency improvements, advancements in self-healing grids, conservation program implementation, the emergence of renewable energy and community energy planning.

Also in 2016, Essex Powerlines continued to invest in distribution system capital and preventative maintenance initiatives that will provide increased reliability for our customers. EPL infrastructure and preventive maintenance initiatives were put to the test on August 25, 2016 when a tornado hit our community of LaSalle, leaving a trail of destruction in its path on its way to Windsor. Our crews worked diligently to restore power to EPL customers' hardest hit. With power restored to EPL customers within hours, EPL crews were able to offer assistance to our neighbouring utility (EnWin) in order to help restore power to its hard hit commercial and residential customers. This is example of how EPL with other like-minded LDCs in the industry can work collaboratively to increase efficiency and customer and shareholder value. Moving forward and as part of its cost of service rate application to be submitted in 2017 for rates effective May 1, 2018 Essex Powerlines will focus on the need to ensure power quality and reliability for business and better value and customer service for residential customers.

We look forward to a busy, productive and safe 2017 that will ensure that Essex Powerlines remains an industry leader for many years to come.

UTILISMART HIGHLIGHTS

In 2016 Utilismart continued to look forward and remained an industry leader. The team evaluated opportunities for growth and implemented processes to drive long term value for shareholders.

A partnership agreement was announced and finalized between First Derivatives and Utilismart to create a Big Data Solution. This will be built on First Derivative's Kx for Sensors database platform and is set for 2017 completion date. In preparation for this, we sundowned Utilismart Smart Metering System and moved all customers onto Central Data Repository (CDR).

In addition to creating a Big Data Solution, we also made some other system enhancements. We successfully upgraded our Energy Axis system to the latest version which improves the user experience for those customers with Elster meters.

Adding to our portfolio, Rogers Cellular Services business was launched, on boarded eight new customers and continued ISMS certification, without using third party resources.

During 2016, Project Management Office (PMO) responsibilities were defined and PMO workflows were created. Adding these vital pieces to our organization only promises improved project quality, consistency and allows for confident decision making from the team.

Utilismart was awarded round three Smart Grid Funding by the Ministry of Energy for the "*21st Century Utility: Universal Translation Engine*" project in the amount of $1M. This is amazing opportunity for the entire Utilismart team.

Innovation was blended into our annual Customer Appreciation Day in 2016 which featured speakers from the Ministry of Energy and Independent Electricity System Operator (IESO), entertainment and a golf tournament. Every year, we use this opportunity to donate to a local charity. The 2016 event raised **$10,000** and was presented to The Heart and Stroke Foundation.

WATTSWORTH HIGHLIGHTS

WattsWorth Analysis Inc. enjoyed an exciting year in 2016. At its core, WattsWorth helps large energy users and generators to maximize their potential given the province's market construct. Energy markets and associated regulatory requirements in Ontario continued to change rapidly over the past twelve months, thus playing well into WattsWorth's strengths.

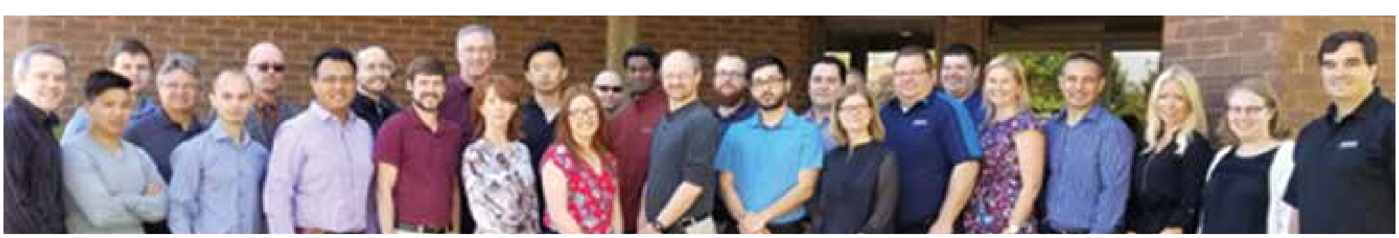
More specifically, the areas of focus and growth for WattsWorth in 2016 were:

Industrial Conservation Initiative ("ICI") adoption in the public, commercial, and agricultural sectors. WattsWorth helped clients save significant electricity costs through its energy market services

Renewable generation settlement support. WattsWorth helped clients navigate the complicated market settlement process associated with large wind and solar farms

Retail Settlement Variance Account ("RSVA") verification for Local Distribution Companies ("LDC"). WattsWorth developed a software tool that will assist LDCs and error proof the critical processes associated with settling RSVA's. The tool will be rolled out in 2017 in collaboration with Utilismart Corporation

WattsWorth is becoming well known in the province as a one-stop-shop for all energy market-related needs. This has been a result of the hard work and expertise of its staff. As a consulting firm, WattsWorth's success is directly linked to the performance of its employees. The future looks very bright for WattsWorth.



GRI REPORT CONTENT

The Global Reporting Initiative (GRI) is an internationally recognized standardized framework for disclosing an organization's environmental, social and economic performance.

The GRI is a simple tool that is becoming a common framework used by many utilities within Ontario, Canada as well as around the world.

This is Essex Power's fifth filing with the GRI G3.1 framework. When we first began our commitment to social sustainability, we reported as a Level C. Last year, we were able to transition to a **Level B** and we have successfully maintained that standing for the 2016 year. We are happy with our improvements thus far but we are committed to building upon our current successes in order to improve in the future.

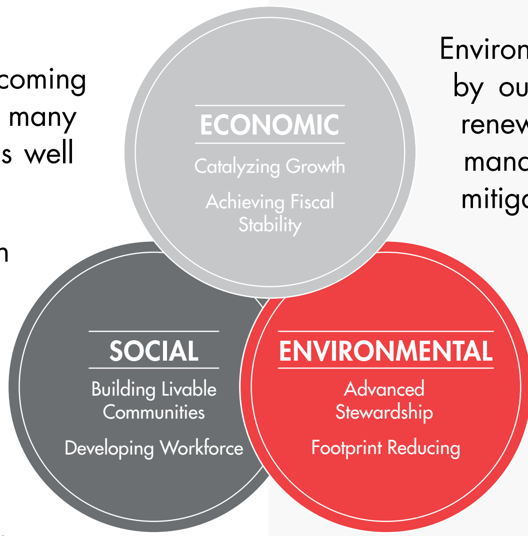
In 2017, we will be following the new G4 reporting guidelines in order to maintain our success and be able to build upon it in future years.

ESSEX POWER RATED B TWO YEARS IN A ROW

REPORT SCOPE & BOUNDARIES

Our regulated electricity distribution company, Essex Powerlines, is accountable for providing a safe, reliable and cost effective supply of electricity to the municipalities of all our stakeholders and communities. The scope of this report and GRI submission includes all of the Essex Power Group of Companies.

To measure our success and progress in sustainability, we have defined key areas that we see of great importance to achieving success. Essex Power has made sustainability a core foundation for all decision making and has initiated best practices for managing operational and environmental risk. This report will analyze and measure Essex Power's performance within the three pillars of sustainability.



Environmental stewardship is evaluated by our success in energy conservation, renewable energy investment, waste management, and environmental risk mitigation of our operations.

Social responsibility is evaluated by how we ensure the safety and wellness of people including our employees, our contractors, and our communities. We are committed to providing a safe and respectful workplace where employees are highly valued, treated fairly, provided with challenging and meaningful work and benefit from opportunities for knowledge growth and career development.

Economic Performance is evaluated by the value we create for our stakeholders while facilitating the economic growth of the communities we serve. The GRI G3.1 Content Index for Application Level B and the Electric Utilities Supplement Content index are available on our website at: www.essexpower.ca. We welcome your feedback on our Sustainability Report. Comments can be directed to: sustainability@essexpower.ca

CONSERVATION &

In 2016, Essex Powerlines continued its progress towards meeting the required conservation target under the 2015-2020 Conservation First Framework. Through diligent efforts and engagement with the community and customer base, Essex Powerlines achieved approximately **7,232 MWh** of gross energy savings through the various residential and business programs. To support these efforts, Essex Powerlines is actively collaborating with other regional LDCs to further drive program efficiency and to introduce new opportunities to our customers. Essex Powerlines is on track towards achieving its target of **31,430 GWh** conserved by **December 31, 2020.**

$637,765

IN TOTAL INCENTIVES

THE CORPORATION OF THE MUNICIPALITY OF LEAMINGTON | STREETLIGHT CONVERSION

1,188,878 kWh total savings | **$178,837** incentive | **1,221** Tonnes of CO_2 emissions prevented per year

DEMAND MANAGEMENT

THE CORPORATION OF THE TOWN OF TECUMSEH | STREETLIGHT CONVERSION
926,960 kWh total savings | **$139,378** incentive *(from Essex Power)* | **952** Tonnes of CO_2 emissions prevented per year

CENTRELINE WINDSOR LTD. | HIGH BAY CONVERSION
196,992 kWh total savings | **$10,944** incentive | **202** Tonnes of CO_2 emissions prevented per year

SOCIAL PERFORMANCE

In 2016, Essex Power donated a used Radial Boom Derrick truck to the Powerline Technician program at St. Clair College Thames Campus. This donation is intended to be a useful tool for the students and to give them hands on practice to prepare them for their future as a Powerline Technician. We are committed to being a good corporate citizen and we are proud to see this donation bring great opportunities to the students.

SOME OF THE LOCAL ORGANIZATIONS THAT RECEIVED OUR SUPPORT INCLUDE:

LaSalle Firefighters Fishing Tournament
St Andrew's LaSalle Community Food Bank
OPP Torch Run – Ontario Special Olympics
Tecumseh Goodfellows
Amherstburg Food & Fellowship Mission
Leamington Salvation Army
St Andrew's LaSalle Community Food Bank
London Food Bank
St Clair Beach Optimist Club

Amherstburg Harvest Festival
Amherstburg Rotary – Rib Fest
LaSalle Strawberry Festival
Tecumseh Corn Festival
Leamington Sip and Savour Festival
John McGivney Children's Centre
Heart & Stroke Foundation
MySafeWork

In 2016 Essex Power continued our support of our communities through various charitable donations and employee involvement. This was the third year of our "*Youth in Community Fund*" with our Shareholders supporting organizations offering activities and projects to the youth in our communities. Once again, each of our Shareholders was given **$10,000** in funding to be used towards youth oriented programing and initiatives.

Essex Power provided financial support to those programs in our communities that serve as food banks including Amherstburg Food & Fellowship Mission, LaSalle St Andrew's Anglican Church Food Bank, Leamington & District Ministerial Food Bank and the Tecumseh Good fellows. We are proud that our employees are on board with contributing to our communities as well, as an additional **$900+** employee funded donation was given to the food banks. Our employees rode the "*Big Bike*", donating to the Heart and Stroke Foundation, and being able to raise awareness at the same time!

Additionally, there was the employee driven campaign to support "*Movember*" providing funding for men's health. Essex Power also continued to support the annual community festivals in our municipalities through sponsorships and we continue to provide **$5,000** in kind services to each of our Shareholders. We participated in the Co-Operative Education programs with Universities and Colleges and offered a bursary to local high schools.

Essex Power worked closely with our EDA Western District utilities to host and organize the 4th Annual EDA Western District Charity Golf Tournament. The beneficiary of the tournament was the United Way. The EDA Western District was thrilled with a final donation of close to **$30,000**. And we are equally proud that through Utilismart's Annual Customer Conference and Golf Day, we were able to donate **$10,000** to the Heart and Stroke Foundation.

In October, representatives of the EPC Wellness Committee attended "*The Gord Smith Healthy Workplace Awards*" ceremony, sponsored by the Go for Health and the Windsor Essex County Health Unit. We are very pleased and proud to announce that Essex Power Corp received the "*DIAMOND*" award, given to companies who demonstrate a commitment to improve the health and wellness of all employees. We are proud of our Wellness Committee members for taking the lead in organizing wellness initiatives, and to all employees for their participation and to our senior leaders that support these activities. In 2016, Essex Power staff continues to support "*Partners for Life*" with the Canadian Red Cross; and exceeded our pledged amount **20 units** per year!

Essex Power is proud to be a good corporate neighbour to our communities and look forward to supporting many worthy causes in 2017.

CORPORATE OWNERSHIP STRUCTURE

Committed to strong corporate governance and accountability, the **Board of Directors** brings a depth of experience to governing Essex Power Corporation in the best interests of customers and the community.

SHAREHOLDERS

AMHERSTBURG

La Salle

TECUMSEH

ESSEX POWER CORPORATION

(Holdco)
President & CEO Raymond J. Tracey

BOARD OF DIRECTORS
Gary McNamara Chair
Aldo DiCarlo
Frank C. Ricci
Joe Graziano
John Paterson
Ken Antaya
Tom Burton
William Wark

ESSEX POWERLINES CORPORATION

REGULATED

BOARD OF DIRECTORS
Ken Antaya, Chair
Aldo DiCarlo
Robert Pula
(Independent Member)

General Manager
Joe Barile

Master Service

Agreement for resources for street lights and other third party projects

ESSEX POWER SERVICES CORPORATION

UNREGULATED

BOARD OF DIRECTORS*
Tom Burton

General Manager
Steve Ray

third parties

CONTRACTS FOR SERVICES

ESSEX ENERGY CORPORATION

UNREGULATED

BOARD OF DIRECTORS
Joe Graziano, Chair
Tom Burton
John Paterson

General Manager
Steve Ray

utilismart™ CORPORATION

BOARD OF DIRECTORS
Marie Campagna, Chair
Ray Tracey
Gary McNamara
Joe Graziano
President
John Avdoulos

WattsWorth the energy analysis people

*1 Member Board with Powers Divested to Holdco Board of Directors

Essex Power Corporation is a dynamic energy company that provides safe, reliable and economical energy supply and services to our customers. Our commitment to innovation, performance management and leading by example has built the foundation for Essex Power and our affiliates to establish a diverse set of energy products and services that are valued by our customers.

Essex Powerlines Corporation, a regulated company, provides reliable and safe power to over 28,000 residents and businesses in Amherstburg, LaSalle, Leamington and Tecumseh. Essex Powerlines provides safe, reliable and economical electrical distribution and service to 28,000 customers within four municipalities of Essex County, and has system voltages of 4.16 kV, 8 kV and 27.6 kV. At Essex Powerlines, our corporate vision is to provide the communities of Amherstburg, LaSalle, Leamington, and Tecumseh with safe, reliable, and economical energy supply and service. The foundation to empower our vision is based on a dynamic and progressive workforce that will be industry leaders in providing 'best of class' business solutions in the delivery of service to our customers.

Since 2000 EPS has been a key streetlight service provider for our communities. Being ISO 9001:2008 certified our Quality Management System ensures proper business operation utilizing best practices. Essex Power Services was registered with IESO as a MSP (Metering Service Provider) in 2012 and currently maintains a total of 23 wholesale metering installations.

Essex Energy Corporation is a dynamic group of more than 20 engineers, business professionals, certified energy managers and LEED accredited individuals ready to provide your organization with a suite of energy management services. Among a wide array of other energy sector related activities, Essex Energy is directly responsible for the reduction of more than 252,000,000 lifecycle kWh through our conservation initiatives and has built some of Canada's largest solar photovoltaic rooftop systems Essex Energy is uniquely positioned to assist you in realizing your own triple bottom line.

Since 2002, Utilismart has been the industry leader in providing settlement services to utilities throughout Ontario. Our services are built on industry expertise and an in-depth understanding of both the settlement processes in the marketplace and the needs of the customer. Our hosted solutions offer customers an economical, efficient settlement service that has build-in reporting and analysis tools. Our knowledge in this area allows for seamless integration into CIS, Financial, and other customer systems requiring settlement data.

As a Canadian company based in Ontario, WattsWorth offers a variety of energy management services to participants in the Ontario market. Our clients include large industrial/commercial companies, electric utilities, electricity generators and municipalities. WattsWorth has over 1-billon kWh consumed annually. In addition to technical expertise and a highly specialized and robust infrastructure, WattsWorth makes a commitment to listen to our clients' requirements and tailor solutions that respect their objectives. WattsWorth has a business manner that reflects high standards of professionalism, attention to detail, and a logical approach to problem solving.

ESSEX POWER CORPORATION

2199 Backacre Drive Suite 200 Oldcastle, Ontario N0R 1L0
519.946.2002 | Fax: 1.866.291.5317 | info@essexpower.ca

Essex Power's 2016 Annual Report and Financial Statements are printed on recycled paper.

Attachment 1-K

Corporate Governance

Documentation

Insert Date

XXX Board Member
123 Main Street,
Your Town, ON, N*N 4#4

Dear Board Member

Congratulations on your appointment to the Essex Power Corporation Board of Directors. We anticipate your expertise will greatly enhance the make-up of our dynamic board and we look forward to a successful relationship.

The following items are attached for your information:

1. Corporate Structure
2. Current Board Governance
3. Essex Power Group of Companies
4. Corporate Governance Review Report;
5. Regulatory Summary
6. 201X Business Plan;
7. 201X Annual Report; and
8. Directors' Liabilities

Board of Director Meetings and Agenda Material

Essex Power Corporation regular Board Meetings are held quarterly, the fourth Wednesday of the month, typically at 4:00 PM, so as not to interfere with County Council Meetings. The next EPC scheduled Board Meetings are as follow:

1. Wednesday, April X, 201X, 4 PM
2. Wednesday, July X, 201X, 4 PM
3. Wednesday, October X, 201X, 4 PM
4. Wednesday, December X, 201X, 4 PM

The board agenda meeting material is posted on a secure web site the Friday preceding the meeting. Please find included instructions for accessing the Board of Directors Web Portal.

Subsidiary Board and Committee Meetings are also scheduled quarterly, or on as a needed basis. The subsidiary Board Meetings will be scheduled once the subsidiary Board Directors are known.

Board of Directors' Nominations and Elections

The appointments of Chair, Vice Chair, Boards and Committees are for a two year term.

At the XXX Date EPC Board of Directors' Meeting, the following nominations and elections will take place.

- **Essex Power Corp Board (EPC)** – Chair and Vice Chair
    - **Audit Committee** – Members (3)
    - **HR & Governance** Committee (3)
- **Essex Powerlines Corp Board (EPL)** – Directors (2), + 1 Independent Representative (Robert Pula)

The position of Chair for the subsidiary Boards (EPL) and Committees (Audit, HR) will be held at the relative meetings.

Director Remuneration

Please complete and return the following forms in the enclosed preaddressed and stamped envelope.

1. Direct Deposit Authorization Form and Void Cheque – The annual salary is paid monthly, typically the last Thursday of the month. Meeting fees and expenses accrued for the month will also be automatically deposited on the last Thursday of the month.
2. Personnel Information Sheet – Includes emergency contact information, and information for payroll set up.

Board Compensation is as follows

Board	Number of Members	Annual Salary	Meeting Fee**	***Committee Fee	Conference Call
EPC	8	$6,000 Chair $4,000 Director	$500	$250	$125
EPL	3 (2 from EPC, 1 independent)	$4,000 **Independent Member*** $1000 additional to the Chair	$500	$250	$125

*An Independent Member, is one who does not sit on the EPC Board of Directors, or is an employee of EPC or any of its affiliates

**Meeting Fee may be prorated for "Special" Meeting; President & C.E.O to determine what constitutes a special meeting. For example, one specific agenda item. Meeting Fee Range is $250-$500

*** Committee Fee – There is no additional fee provided to the Chair of a committee. ($250)

Note: If a committee or board meeting is held immediately preceding a regular full Board Meeting, there is no additional meeting fee paid except for the independent EPL Board Member who receives the $500.00 meeting fee. (Resolution February 26, 2002)

Should you have any questions or concerns at any time, please feel free to contact either myself at 226 252 6261 or my assistant Janis McVittie, Board Secretary at 226 252 6259

Yours truly

Raymond J Tracy
C.E.O & President

RJT/jm
Encls.

2199 Blackacre Dr | Suite 200 | Oldcastle, ON | N0R 1L0
Office: 519-946-2002| Fax: 1-866-291-5317

Governance Policy

Essex Power Corporation Board of Directors

Table of Contents

TOPIC: GOVERNANCE PHILOSOPHY STATEMENT		POLICY NO.: BD#1	
Originator of Policy: Board of Directors	**Approved By:** Board of Directors	**Signature of Chair:**	**Date Approved:** September 26, 2001

ACCOUNTABILITY:
The Board of Directors of The Essex Power Corporation acts on behalf of the Corporation and represents the interests of the municipal shareholder groups who in turn represent the community.

BOARD'S ROLE:
The Board's governing style will emphasize outward vision, strategic leadership, excellence, integrity, and development of the confidence and trust of our owners and customers.

The Board will focus chiefly on the intended long-term impacts (ends), not the administrative means of achieving those effects. It recognizes that its role is in governance of the organization as well as advocating for its many stakeholders. The Board is an initiator of policy and is committed to persistent due diligence through monitoring policy implementation.
The Board of Directors is to be the primary force pressing the organization to:

- meet the energy supply needs of the community
- provide best value for the customers
- protect the environment
- create positive financial return for the shareholders
- meet regulatory requirements
- establish strategic alliances where appropriate

BOARD EFFECTIVENESS:
The Board of Directors is committed to functioning in a manner that continuously enhances confidence and trust in Essex Power Corporation. The Board will speak with one voice once Board decisions have been passed.

The Board ensures that it maintains a structure and process that enhances its effectiveness. It is committed to evaluating performance, at least annually, in fulfilling its mandate and goals. The Board's committee structure and membership will be reviewed annually.

INDIVIDUAL BOARD MEMBER ROLE:
The primary role of each Board member is to assist Essex Power Corporation in achieving its mission. This responsibility will take clear precedence over any other role an individual Board member may have. Board members will be proactive (not reactive) in industry change and will bring a knowledgeable and enthusiastic approach to the organization.
Board members have a responsibility to enhance their skills and knowledge related to the Corporation's mission and mandate, through Board member continuing education. The Board will ensure that a process is in place to facilitate their learning and to orientate new Board members.
A Board member will declare a conflict of interest if a personal or business gain could result from membership on the Board of Directors.

ROLE OF CHAIR:
The Chair of the Board will ensure that the Board of Directors fulfils its responsibility for the governance of the Essex Power Corporation. He/she will have a responsibility to see that the relationship between the Board and the CEO is optimised. The Chair is the official spokesperson for the Board.

RELATIONSHIP WITH THE CEO:
The Board ensures that The Essex Power Corporation and its subsidiaries are well managed. The Board will achieve this by selecting, supporting, and measuring the performance of an effective President. The Board will establish policies and set objectives within the business environment and monitor their timely achievement.

SPECIFIC RESPONSIBILITIES:
<u>POLICY MAKING</u>

- set the strategic plan of the Corporation including the mission, vision, strategic objectives and methodology of the Corporation.
- determine the role and responsibilities of the Board, its officers, committees and task forces
- assign the President’s responsibility and authority.

<u>MONITORING:</u>

- determine and articulate Board information needs and reporting requirements
- periodic review of milestones achieved

<u>LINKING:</u>

- promote and develop linkages to the ownership
- ensure that the decisions of the Board take into account the values and perspectives of the ownership
- collaborate with the Board of Directors of other Power Corporations

<u>OTHER MANDATED REQUIREMENTS</u>:

- approve annual reports to the Ontario Energy Board
- approve business plans, annual budgets and financial statements
- others as required

TOPIC: Strategic Plan		POLICY NO.: BD#2	
Originator of Policy: Board of Directors	**Approved By:** Board of Directors	**Signature of Chair:**	**Date Approved:** September 26, 2001

Mission Statement:
The Essex Power Corporation will provide safe, reliable and economical energy supply and services to its customers.

Guiding Values:
1. Demonstrated leadership in electricity industry.
2. Progressive, positive work environment.
3. Fiscally responsible.
4. Build on core business activities, ensuring market share of industry.
5. Pursue new markets and opportunities, where appropriate.
6. Market and industry readiness.
7. Value to shareholders.

Strategic Objectives:
1. <u>Safe and Reliable Energy Supply</u>

People can live, work, and flourish within our service jurisdiction due to our safe and reliable energy supply.

Service delivery will be exceptional in power supply, billing, collections, and troubleshooting.

New and leading edge information and knowledge about energy supply will be achieved through our ongoing research and development. This will produce information on how best to use new technology, equipment and process.

2. <u>Economical Energy Supply</u>

Our efficient and forward-looking systems will produce stable rates for our customers over the long term.

Our customers will receive exceptional value in our service to price relationship.

Our shareholders will receive stable and substantial dividends as well as solid growth in the value of the company.

3. <u>Healthy Environment</u>

The environment will remain healthy from an energy delivery perspective based on the work of Essex Power Corporation.

4. <u>Sound Resource for Participating Communities</u>

Essex Power Corporation will be developed and managed to become a solid asset for the communities who own the company.

Sufficient capital and net revenues will be generated to ensure ongoing renewal and investment in Essex Power Corporation such that it has the ongoing capability to thrive in the future.

Well-planned expansion will occur through service diversification and customer base expansion, which will result in real growth of the company.

These strategic priorities will be evident in the following perspectives:

Customer

- Meet energy delivery needs of the communities served
- Customer value through product and service availability, reliability, and price
- Reliable, cost-effective delivery of energy

Finance and Growth

- Ensure financial viability / sustainability
- Ensure sufficient funds are allocated to maintain assets, facilities and future products and services
- Return profit / dividends to shareholders
- Create profits which can be used to sustain the organization
- Create profits which can be used to grow the organization
- Corporate diversification through re-investment

Environment

- Minimize environmental impact from the energy delivery system

Innovation, Research and Development

- Utilize new technology, equipment and processes to enhance our energy supply and related services
- Growth – create opportunities

Employees

- Provide safe and challenging employment opportunities
- Invest in employee skills and abilities

Essex Power Corporation is a dynamic energy company that provides safe, reliable and economical energy supply and services to our customers. Our commitment to innovation, performance management and leading by example has built the foundation for Essex Power and our affiliates to establish a diverse set of energy products and services that are valued by our customers.

Essex Powerlines Corporation, a regulated company, provides reliable and safe power to over 28,000 residents and businesses in Amherstburg, LaSalle, Leamington and Tecumseh. Essex Powerlines provides safe, reliable and economical electrical distribution and service to 28,000 customers within four municipalities of Essex County, and has system voltages of 4.16 kV, 8 kV and 27.6 kV. At Essex Powerlines, our corporate vision is to provide the communities of Amherstburg, LaSalle, Leamington, and Tecumseh with safe, reliable, and economical energy supply and service. The foundation to empower our vision is based on a dynamic and progressive workforce that will be industry leaders in providing 'best of class' business solutions in the delivery of service to our customers.

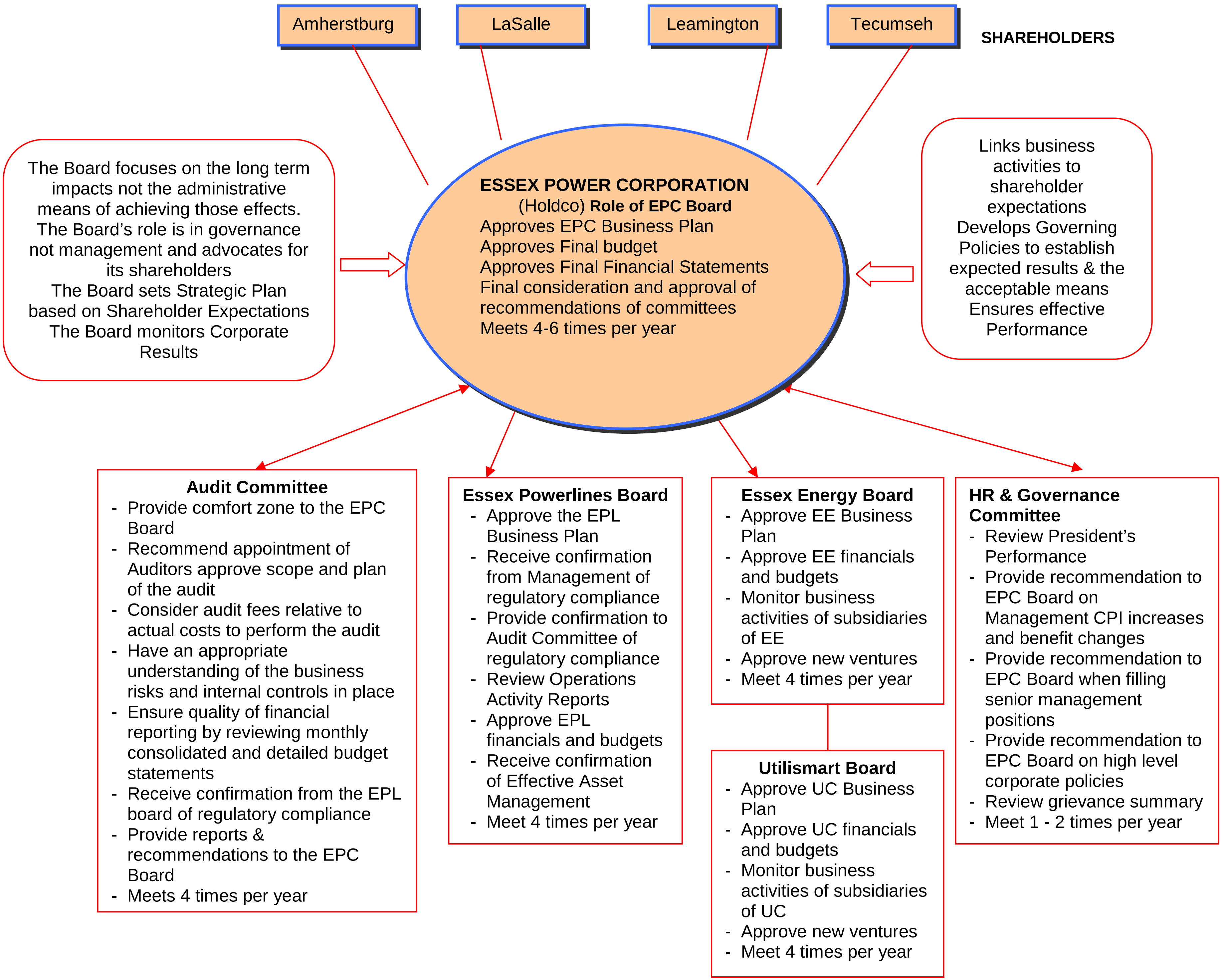
Since 2000 EPS has been a key streetlight service provider for our communities. Being ISO 9001:2008 certified our Quality Management System ensures proper business operation utilizing best practices. Essex Power Services was registered with IESO as a MSP (Metering Service Provider) in 2012 and currently maintains a total of 23 wholesale metering installations.

Essex Energy Corporation is a dynamic group of more than 20 engineers, business professionals, certified energy managers and LEED accredited individuals ready to serve your public agency with Ontario's Green Energy Act. Among a wide array of other energy sector related activities, Essex Energy is directly responsible for the reduction of more than 252,000,000 lifecycle kWh through our conservation initiatives and has built some of Canada's largest solar photovoltaic rooftop systems, Essex Energy is uniquely positioned to assist you in realizing your own triple bottom line.

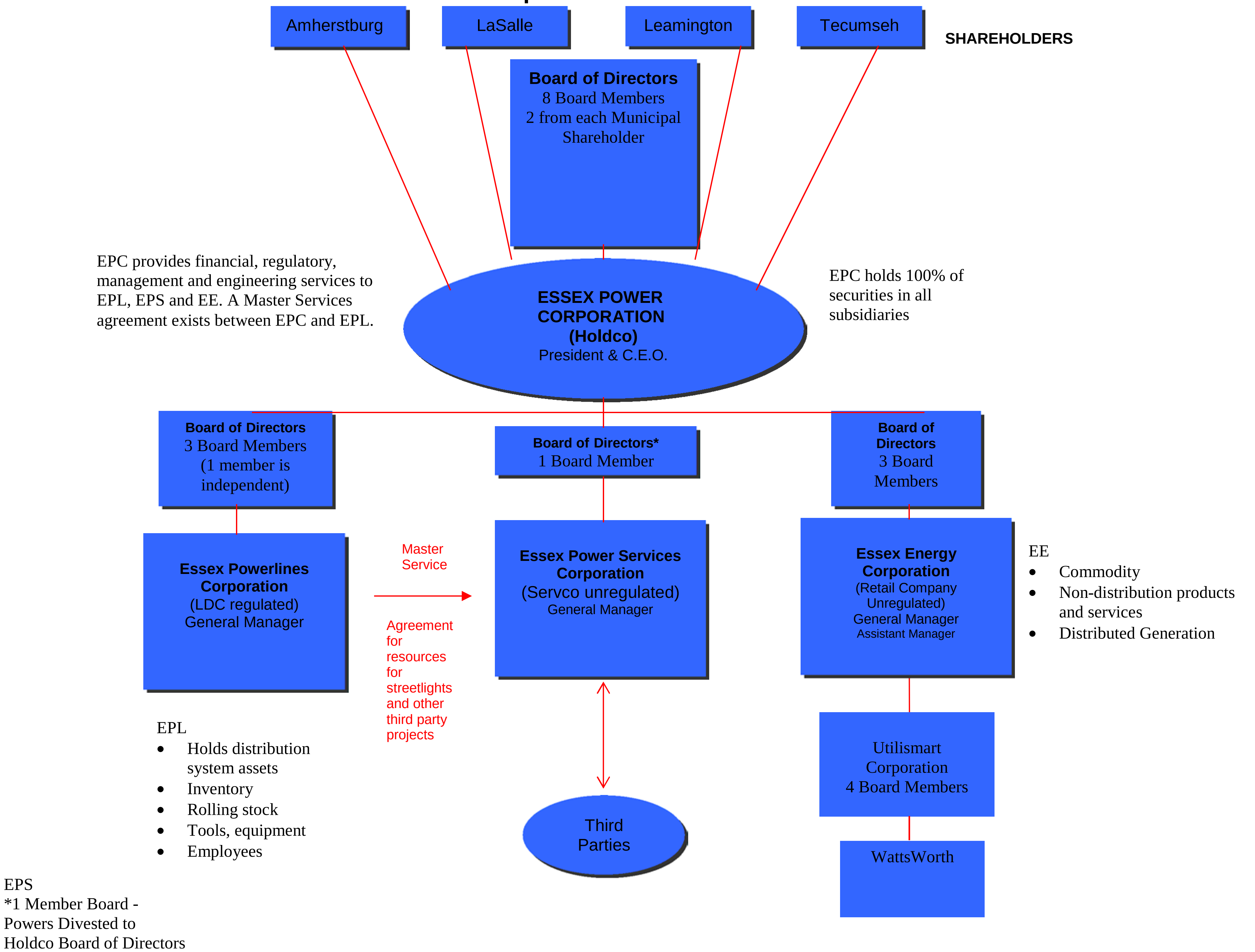
Since 2002, Utilismart has been the industry leader in providing settlement services to utilities throughout Ontario. Our services are built on industry expertise and an in-depth understanding of both the settlement processes in the marketplace and the needs of the customer. Our hosted solutions offer customers an economical, efficient settlement service that has built-in reporting and analysis tools. Our knowledge in this area allows for seamless integration into CIS, Financial, and other customer systems requiring settlement data.

As a Canadian company based in Ontario, WattsWorth offers a variety of energy management services to participants in the Ontario market. Our clients include large industrial/commercial companies, electric utilities, electricity generators and municipalities. WattsWorth has over 1-billon kWh consumed annually. In addition to technical expertise and a highly specialized and robust infrastructure, WattsWorth makes a commitment to listen to our clients' requirements and tailor solutions that respect their objectives. WattsWorth has a business manner that reflects high standards of professionalism, attention to detail, and a logical approach to problem solving.

Current Board Governance



Corporate Structure



DIRECTORS' LIABILITIES: AN OVERVIEW

January 25, 2007

Goodmans LLP Barristers & Solicitors

TABLE OF CONTENTS

1. INTRODUCTION

Broadly stated, the law considers directors to be agents of the corporation for which they act and, accordingly, directors are subject to general laws governing the principal-agency relationship. The material aspect of that relationship is the fiduciary character of the obligations owed by an agent to its principal. All powers entrusted to directors must be exercised in that capacity. Directors must exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances, while acting in the best interest of the corporation.

This principle, as well as other specific rules regulating the conduct of corporations and their directors, has now been largely codified in a series of federal and provincial statutes and regulations. In fact, there are more than 200 federal and Ontario statutes which impose liabilities on directors. Many of these are either industry-specific (for example, the *Credit Unions and Caisses Populaires Act* (Ontario)) or are unlikely to be of real concern to most directors, such as liability for donating food which is unfit for human consumption under the *Donation of Food Act* (Ontario) or selling an appliance which does not meet the appropriate efficiency standard pursuant to the *Energy Efficiency Act* (Canada).

What follows is a list of some of the more important of these statutes together with a brief summary of the relevant provisions which create liability for directors. The information contained in this memorandum is a summary only, and should not be relied upon as a complete guide with respect to the liabilities of directors in Ontario.

2. LIABILITIES ARISING IN THE ORDINARY COURSE

The most significant exposures to liability faced by directors are those arising in the ordinary course. These are the types of liabilities which the director faces in the everyday running of business. These liabilities can arise either under statute or at common law.

(a) Standard of Performance

The standard of behaviour required of directors as set out in the corporate statutes is based on a common law standard requiring that a director act honestly and in good faith with a view to the best interests of the corporation and to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. This statutory standard can be broken down into two parts - the fiduciary duty and the duty of care.

(i) Fiduciary duty

The fiduciary duty requires that directors act in the best interest of the corporation. In this regard, the corporation's interest is synonymous with the interest of the shareholders (as a whole, and not just one particular class). While the directors may consider other stakeholders when making corporate decisions, ultimately the best interests of the shareholders cannot be compromised.

The primary obligations faced by a director in discharging this duty are: (1) a duty to avoid or disclose conflicts of duty and interest; and (2) a duty not to usurp opportunities belonging to the corporation.

With respect to the conflict of duty and interest, the director must ensure that he/she does not place him/herself in a situation where there is, or may appear to be, a conflict between his/her personal objectives, and those of the corporation. Examples of a conflict of interest include a situation where the board of directors is voting on a contract in which the director has a material interest; a situation where the board of directors is considering a share provision and the director is a major shareholder; and a situation where the directors take actions in the face of a take-over bid that are motivated by a desire to protect their own vested interests rather than the interests of the company. A director who encounters this type of situation should immediately declare his/her conflict to the board of directors, and (with certain exceptions) refrain from engaging in the decision regarding that issue. When holding multiple directorships, directors must also be aware of the possibility of conflict between the interests of the different corporations.

The duty not to usurp corporate opportunities has been interpreted very strictly by the courts. In essence, this duty means that a director cannot take personal advantage of an opportunity which comes to the director's attention through his/her role as a director, even when the corporation is unable to take advantage of it. This aspect of a director's duties to the corporation has been held to continue past the point in time that the director's association with the corporation is discontinued.

The legal standards governing the fiduciary duties of directors of financially troubled companies are still uncertain and developing. The practical reality is that actions taken when a company is insolvent or facing possible insolvency will receive heightened scrutiny in the aftermath of a loss. A duty is owed to the shareholders of financially troubled corporations, and the oppression remedy may be used by creditors whose interests were unfairly prejudiced or disregarded by the directors. Directors of financially troubled companies must therefore be careful to consider the concerns of each constituency interested in the corporation and comply with all statutory obligations, so as to ensure that their fiduciary obligations are met.

(ii) Duty of care, diligence and skill

The statutory duty to "exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances" is vague and does not provide much guidance to directors in discharging their duties. However, it is possible to gain some insight by examining each of the three elements of this duty separately.

The standard of care is objective: directors will be measured against what a reasonably prudent person would do in comparable circumstances. Directors will not be liable for mere errors in business judgment, so long as they have exercised due diligence in forming and acting upon their business judgment. Directors must ask for, and are entitled to receive, detailed information regarding the issues under consideration before them. The board must not merely "rubber stamp" management proposals. A director should actively question management and advisors of the corporation, and encourage the retention of independent advisors, where necessary. A director will be exonerated for good faith reliance on professional advice, or on incorrect information if it would be reasonable for the director to believe the veracity of the information. Meeting the standard of diligence will provide directors with a defence to most types of liability.

Although the standard of skill required is not judged in reference to any particular level of education or professional designation, courts have imposed different standards of conduct on different types of board members. "Inside directors" and members of board committees must use specialized information which is in their possession when making decisions to which such specialized information would apply. A member of the audit committee will be held to a higher standard of care with respect to an error in the corporation's financial statements than will a member of the board who is not on the audit committee. Directors who have certain professional qualifications (lawyers, accountants, engineers, etc.) may not ignore such knowledge when making decisions in areas which encompass their professional knowledge.

(b) Torts

Directors may incur tortious liability for acts of the corporation, including: (a) inducing breach of contract; (b) participating in a breach of trust; (c) negligence; (d) fraud or nuisance; (e) negligent misrepresentation; (f) breach of confidence; and (g) conspiracy.

For the corporate veil to be lifted and the director be held personally liable: (1) there must be control by the director; (2) the control must be exercised to commit fraud, wrong, or breach of duty; and (3) this misconduct must be the proximate cause of the plaintiff's injury or loss. Essentially, directors who take the reins of control in a designated part of the company's business will assume the personal liability that goes with that control, but they will not be responsible for matters beyond their limited field. It should be noted that the corporate veil may be pierced in order to hold a parent company liable for the action of its subsidiary where the parent company has the requisite level of control so as to make it the "alter ego" of the subsidiary. It is not unimaginable therefore, that a director of a parent company may be held responsible for the wrongdoings of a subsidiary.

The following is a brief discussion of the above-mentioned categories of tortious liability:

(i) Inducing breach of contract

In general, a claim for inducing breach of contract will be successful where it can be shown that the party inducing the breach knew of the contract and intended to procure the breach, and the party breaching the contract had no justification for such breach. With respect to an action against a director personally, courts have imposed the additional qualification that the director must either have acted outside the scope of his/her authority, or breached another one of his/her duties to the corporation in some other way, since a corporation can only act through its officers.

(ii) Participation in a breach of trust

In most cases, liability for participation in a breach of trust by a corporation will arise where there is a commingling and misapplication of trust monies. A director (i.e. a stranger to the trust) will be held liable, as a constructive trustee, for participating in such a breach where the director knowingly directs, authorizes, assents to or acquiesces in, or was wilfully blind or reckless to, the action which amounts to a breach of trust by the corporation. The nature of the breach must be fraudulent or dishonest in the sense that it involved a risk to the property to the prejudice of the beneficiary.

(iii) Negligence

A director can be found liable in negligence for the action/inaction of the corporation where he/she independently meets the test for negligence.

(iv) Fraud or nuisance

Directors can be held liable for fraudulent actions and nuisances carried on by the corporation where it can be fairly stated that they were the architects of the actions at issue. As such, an action alleging these wrongdoings must show that the director had personal knowledge of the events complained of and authorized, directed, assented to or acquiesced in their commencement or continuation.

(v) Negligent misrepresentation

Personal liability of a director or officer for a corporate debt may arise out of a negligent misrepresentation. There are five general requirements:

- there must be a duty of care based on a special relationship between the representor and the representee;
- the representation in question must be untrue, inaccurate, or misleading;
- the representor must have acted negligently in making the misrepresentation;
- the representee must have reasonably relied on the misrepresentation; and
- damages must have resulted to the representee.

A director will be liable for all reasonably foreseeable economic loss suffered by any reasonably proximate plaintiff as a result of any negligent misrepresentation, even if the director gained nothing personally from the transaction.

(vi) Breach of confidence

A director may be liable when confidential information is revealed. The test for whether there has been a breach of confidence is composed of three elements: (1) the information revealed to the other party must have the necessary quality of confidence about it; (2) that information must have been imparted in circumstances creating an obligation of confidence; and (3) there must be an unauthorized use of that information to the detriment of the party from whom it originated.

(vii) Conspiracy

By implicating a director in the commission of a tort, a corporate creditor opens the door to attaching personal liability to the director for the tort of conspiracy. A tort claim can be recognized, whether the means used by the director were lawful or unlawful, where the predominant purpose of the director's conduct was to cause injury to the plaintiff, or where the conduct of the director was unlawful, the conduct was directed towards the plaintiff (alone or together with others), and the director should have known in the circumstances that injury to the plaintiff was likely to and did result.

3. LIABILITY UNDER THE *BUSINESS CORPORATIONS ACT* (ONTARIO) ("OBCA") AND OTHER CORPORATE LEGISLATION

(a) The OBCA

The OBCA requires that each director, in exercising his or her powers and discharging his or her duties, must act honestly and in good faith with a view to the best interests of the corporation, and exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. To meet the duties of care, diligence and skill required, directors would be well advised to: (a) avoid a pattern of absence from board meetings; (b) obtain and review prior to the meeting copies of all reports and documents which are relevant to matters to be considered at the board or committee meeting; (c) carefully review all minutes of meetings including minutes of meetings at which the director was not in attendance; (d) keep a record book containing personal notes of the meetings; (e) keep a record book containing copies of all minutes and other documents relating to the company; (f) require the board or the applicable committee to obtain written legal advice on important issues being considered; and (g) require written opinions from other professional advisors upon whose advice the board is acting. For further discussion, see Appendix "A".

Under the OBCA, directors are jointly and severally liable to the corporation for amounts improperly distributed in the context of certain transactions, which include:

- Issuing shares for property or past services which have a fair market value less than the money the corporation would have received if it had issued the shares for money;
- Purchase, redemption, retraction or other acquisition of shares of the corporation in contravention of the statutory solvency tests;
- Payment of a dividend in contravention of the statutory solvency tests;
- Payment of an amount to a shareholder who has exercised statutory dissent rights.

Since directors only incur liability for these transactions if they vote for or consent to the resolution authorizing the transaction, they should understand that they will be deemed to have consented to a resolution unless they dissent in the manner and within the time prescribed by the statute.

The OBCA also provides for various offences that, if committed by the corporation, will create liability for a director if he or she knowingly authorizes, permits or acquiesces in such wrongful acts. Examples include making untrue statements of material facts in any public document or material filed or submitted under the OBCA, using a list of securities holders other than as allowed by the Act, failing to file insider reports, failing to appoint an auditor, and, in general, failing to comply with the OBCA or the regulations without reasonable cause.

The OBCA allows shareholders and "complainants" to challenge corporate conduct that prejudices or disregards their interests. As a result, in certain cases, the courts will intervene to force directors not to act in disregard of a minority shareholder's interest.

Directors cannot avoid responsibility for corporate action by absenting themselves from directors' meetings. Directors can be held responsible for resolutions passed or actions taken at meetings at which they refrain from voting or at which they are not present, if they do not record their dissent within seven days after they become aware of the resolution or action. In addition, directors cannot be absolved of their duties and liabilities under the OBCA by contract or otherwise.

(b) The *Corporations Information Act* (Ontario)

A director who authorizes, acquiesces in or permits a false or misleading statement in any document or information required under this Act is guilty of an offence and, on conviction, liable to a fine of up to $2,000 and/or a one-year jail term.

(c) The *Business Names Act* (Ontario)

A corporation which carries on business or identifies itself to the public under a name other than its corporate name or a name which it has registered under this Act is guilty of an offence. A director who authorizes, acquiesces in or permits such an offence may be liable, on conviction, of a fine of up to $2,000.

(d) The *Limited Partnerships Act* (Ontario)

A director who authorizes, acquiesces in or permits any contravention of this Act or its regulations, or makes any false or misleading statement in any document or information submitted or required by the Act, is guilty of an offence and, on conviction, is liable to a fine of up to $2,000.

4. THE *PROVINCIAL OFFENCES ACT* (ONTARIO)

In Ontario, the *Provincial Offences Act* ("POA"), sets out a specific procedure for the Crown to follow when prosecuting provincial offences. The POA applies to nearly all laws, including municipal by-laws, in the Province of Ontario which are not federal laws. Under the POA, it is possible for a director to be charged with an offence committed by the corporation even where the statute under which the corporation is charged does not contemplate individual liability, due to the fact that the POA contains a section which ascribes liability to parties to an offence. In the event that the court determines that the director is a party to the offence committed by the corporation, the director is subject to the same penalty as set out in the statute under which the corporation is liable.

5. LIABILITY UNDER TAXATION STATUTES

(a) The *Income Tax Act* (Canada)

The *Income Tax Act* (Canada) ("ITA") sets out requirements for withholding amounts from payments made to taxpayers, and remitting such amounts to the Receiver General. In particular, the ITA requires that an employer withhold and remit income tax deducted from salaries and wages paid to employees. Furthermore, a Canadian corporation is required to withhold and remit a portion of certain payments of passive income (for example, interest, dividends, rents and royalties) made to non-residents. Where a corporation fails to withhold and remit such amounts, the persons who were directors at the time of the failure to remit or withhold are jointly and severally liable for the amounts which should have been withheld or remitted plus related interest and penalties. This liability does not arise, however, unless the Canada Revenue Agency has been unsuccessful in attempting to collect from the corporation, as evidenced by either: (i) an unsatisfied execution for the amount certified as a debt in the Federal Court; (ii) liquidation or dissolution proceedings; or (iii) an assignment or receiving order under the *Bankruptcy and Insolvency Act* (Canada). No action to recover an amount owed by the corporation can be initiated against a person more than two years after the person ceased to be a director of the corporation. In addition, a director will not be liable if he or she has "exercised the degree of care, diligence and skill to prevent the failure to withhold and remit that a reasonably prudent person would have exercised in comparable circumstances".

In addition to liability for taxes and penalties owed by the corporation, a director may also be found criminally liable if the corporation commits an offence under the ITA where he/she directed, authorized, assented to, acquiesced in or participated in the commission of the offence. A director can be found guilty, regardless of whether or not the corporation has been charged or convicted. Examples of offences under the ITA include: failure to file a tax return; failure to keep adequate books and records; failure to assist representatives of the Minister of Revenue; making false or deceptive statements in a tax return; destroying or altering records; and tax evasion. The penalty to which a director may be subject varies depending on the section of the ITA breached by the corporation. For example, the penalty for failure to file a tax return is a fine ranging from $1,000 to $25,000 and may also include imprisonment for up to 12 months; the penalty for making false statements on a tax return or altering account books to evade tax can be a fine equal to 100% to 200% of the amount of tax in question and imprisonment for up to 5 years, if the Crown proceeds by indictment.

In addition, a director may, in certain situations where the director can be considered the legal representative of the corporation and the corporation has outstanding tax obligations, be subject to liability for distributing property (whether or not the corporation is insolvent) without first having received a clearance certificate from the Canada Revenue Agency. Breaching this provision of the ITA renders the director liable for the taxes owing by the corporation, up to the value of the property disposed.

(b) *Excise Tax Act* (Canada) - Goods and Services Tax

Under the *Excise Tax Act* (Canada) (the "ETA"), where a corporation fails to remit an amount of net tax payable for goods or services ("GST"), any person who was a director of the corporation at the time the corporation was required to remit the amount is jointly and severally liable, together with the corporation, to pay that amount and any interest or penalties relating thereto. This liability does not arise, however, unless the Canada Revenue Agency has been unsuccessful in attempting to collect from the corporation, as evidenced by either: (i) an unsatisfied execution for the amount certified as a debt in the Federal Court; (ii) liquidation or dissolution proceedings; or (iii) an assignment or receiving order under the *Bankruptcy and Insolvency Act* (Canada). Even then, a director will not be liable for unremitted GST if he or she can establish that they exercised the degree of care, diligence and skill that a reasonably prudent person would have exercised in comparable circumstances. No action to recover an amount owed by the corporation can be initiated against a person more than two years after the person ceased to be a director of the corporation.

In addition to liability for taxes and penalties owed by the corporation, a director may be found criminally liable for any offence under the ETA committed by the corporation, if he/she directed, authorized, assented to, acquiesced in or participated in the commission of the offence. A director can be found guilty and be subject to the penalty or punishment prescribed by the relevant section of the ETA, regardless of whether the corporation has been prosecuted or convicted. The penalty varies with the offence: for example, the penalty for failure to file a return is a fine ranging from $1000 to $25,000 and may also include imprisonment for up to 12 months; the penalty for failure to pay, collect, or remit taxes is a maximum fine of $1000 plus 20% of the amount of tax in question, and may also include imprisonment for up to 6 months. More serious penalties, including imprisonment for up to 5 years, are possible for other offences.

(c) The *Retail Sales Tax Act* (Ontario)

Under the *Retail Sales Tax Act* (Ontario) (the "RSTA"), where a corporation has failed to collect or remit retail sales tax ("RST"), persons who were directors of the corporation at the time of the failure to collect or remit are jointly and severally liable, together with the corporation, to pay such amounts and any interest and penalty relating thereto. This liability does not arise, however, unless the Canada Revenue Agency has been unsuccessful in attempting to collect from the corporation, as evidenced by either: (i) an execution for the amount of the debt returned unsatisfied by the sheriff; (ii) liquidation or dissolution proceedings, or similar proceedings; or (iii) the corporation has become bankrupt due to an assignment or receiving order or by notice of intent to file a proposal under the *Bankruptcy and Insolvency Act* (Canada). Even then, if a director has exercised the degree of care, diligence and skill to prevent the failure that a reasonably prudent person would have exercised in comparable circumstances, the director will not be held liable for the amounts owing by the corporation. No action to recover an amount owed by the corporation can be initiated against a person more than two years after the person ceased to be a director of the corporation.

A director is criminally liable for any offence under the RSTA committed by the corporation if he/she directed, authorized, assented to, acquiesced in, or participated in the offence. The penalties vary depending on the provision breached. For example: failure to file a return carries a fine of not less than $50 per day for each day during which the default continues; the penalty for failure to collect tax is a fine equal to the amount of tax that should have been collected, plus an additional fine of between $50 and $2000. Imprisonment of up to one year can be imposed on a person who fails to pay a fine under the RSTA.

(d) Other Acts

Offences similar to those in the *Income Tax Act* (Canada) regarding director liability may also be found in the *Income Tax Act* (Ontario), the *Canada Pension Plan Act*, the E*mployment Insurance Act* (Canada), the *Corporations Tax Act* (Ontario) and the *Customs Act* (Canada).

(e) The *Employer Health Tax Act* (Ontario)

Pursuant to the provisions of the *Employer Health Tax Act* (Ontario) (the "EHTA"), employers are required to pay the Ontario Employer Health Tax for their employees based on the employees' earnings. If a corporation is guilty of an offence under the EHTA, an officer or director is personally guilty of that offence if he or she directed, authorized, assented to, acquiesced in, or participated in the commission of the offence.

6. LIABILITIES ARISING OUT OF BANKRUPTCY OR INSOLVENCY

(a) The *Bankruptcy and Insolvency Act* (Canada) and the *Winding Up and Restructuring Act* (Canada)

Under the *Winding Up and Restructuring Act* (Canada) and the *Bankruptcy and Insolvency Act* (Canada) (the "BIA"), directors may be held jointly and severally liable for the corporation's payment of cash dividends, the acquisition or redemption of its own shares, or, in the case of the BIA, the provision of financial assistance to other companies or individuals, within the 12 month period prior to its bankruptcy or winding up, if the payment or acquisition occurred at a time when the corporation was insolvent, or if the corporation was rendered insolvent thereby, and the directors directed, authorized, assented to, acquiesced in or participated in its commission. A director will not be held liable if he or she protests against the payment, acquisition or redemption.

Under the BIA, a director may also be liable for a fine not exceeding $10,000 or to imprisonment for up to three years or both, if he or she directed, authorized, condoned or participated in certain actions by the corporation after or within the 12 month period immediately preceding the bankruptcy of the corporation, including obtaining any credit or property by false representation; concealing, destroying, falsifying, or making an omission in a book or document relating to the affairs of the corporation with intent to conceal the state of the corporation's affairs; making any fraudulent disposition of property before or after bankruptcy; pawning, pledging or otherwise disposing of any property which the corporation has obtained on credit and has not paid for; and generally failing to perform all duties imposed by the BIA.

(b) Labour Law Considerations

The exposure of directors of an insolvent corporation to labour law liability arises in respect of making payments on behalf of the insolvent corporation. In this regard, directors face three major types of exposure: (a) wages, vacation pay and severance pay under the OBCA; (b) payments due under the *Employer Health Tax Act* (Ontario); and (c) payments due under the *Pension Benefits Act* (Ontario).

(c) Tax Considerations

See paragraph on distribution of property without a clearance certificate under the ITA (Section 5).

7. LIABILITY UNDER EMPLOYMENT-RELATED STATUTES

(a) The *Employment Standards Act* (Ontario)

The *Employment Standards Act* (Ontario) (the "ESA") regulates conditions relating to an employee's work and ensures that they receive overtime pay, compensation for unpaid wages, vacation pay, holiday pay, termination pay and severance pay. The ESA provides for a fine of up to $50,000 and/or imprisonment for a term of not more than twelve months for directors, officers and agents of employers who authorize, permit or acquiesce in a contravention of the ESA. The Minister of Labour may recover such amounts via the personal liability of directors in the event that recovery against the corporation itself is impossible or improbable. The corporation need not be charged with a contravention of the ESA for the director to be found guilty.

Directors are personally liable under the ESA for up to the value of six months of wages and twelve months vacation pay (but not termination pay or severance pay) that are payable or accrue during the period that they serve as a director, plus interest thereon determined in accordance with the ESA. A director cannot contract out of this liability. Since directors' liability for unpaid wages ends when the directorship ends, it is critical that a record is made of when the director ceased to hold office. Failure to change the public record may expose a director to claims for the corporation's debt to its employees for wages that became payable after a departure from office. Resigning directors would therefore be well advised to take steps to ensure that they meet all the necessary requirements for resignation under the relevant corporate statute and take all available steps to ensure that the corporation properly files a notice of change of directors with the appropriate authorities.

The ESA provides that an employer may indemnify a director or former director against all costs, charges and expenses incurred to satisfy orders under the Act reasonably incurred, if the director acted honestly and in good faith with a view to the best interests of the employer and, in the case of a proceeding or action that is enforced by a monetary penalty, the director had reasonable grounds for believing that his or her conduct was lawful.

Of course, civil remedies that former employees may have against an employer and/or its directors (such as inducing breach of contract) are not limited by the ESA, and a director can be held personally responsible, along with the company, where the director was the "directing mind and will" behind the breach. In a recent case in which this was applied, the director and company were ordered to pay the full amount of a prearranged termination package. However, since the company was by then defunct, the director was ordered to pay the full award.

(b) The *Labour Relations Act* (Ontario)

The *Labour Relations Act* (Ontario) (the "LRA") is designed to regulate the relationships between employers and employees (unions in particular). Directors who assent to the commission of an offence committed by a corporation under the LRA will be deemed to be 'parties' to and guilty of the offence. Contravention of the LRA includes interfering in the formation, selection or administration of a trade union, contributing financial support to a trade union, engaging in strike-related misconduct and, where a trade union is entitled to represent the employees in a bargaining unit, bargaining with any other person or trade union. The maximum penalty to a director for an offence under the LRA is a fine of $2,000. However, each day that the conditions giving rise to the offence continue constitutes a separate offence.

(c) The *Pension Benefits Act* (Ontario)

Any director who causes, authorizes, permits, acquiesces, or participates in the commission of an offence by a corporation, or who fails to take all reasonable care to prevent the corporation from committing an offence, under the *Pension Benefits Ac*t (Ontario) is guilty of an offence and is liable to a fine of not more than $100,000 on a first conviction and not more than $200,000 on each subsequent conviction, whether or not the corporation has been prosecuted for or convicted of an offence under the circumstances.

In addition to the fine indicated above, a director who is convicted of an offence relating to the failure to pay funds to a pension fund or insurance company may also be ordered to pay the amount due to the fund or insurance company.

The Crown must commence proceedings for an offence within five years of the date the offence occurred or is alleged to have occurred.

(d) The *Pay Equity Act* (Ontario)

The *Pay Equity Act* (Ontario) (the "PEA") is designed to redress gender discrimination. Any person who contravenes or fails to comply with the provision of the PEA relating to the intimidation of a person who is attempting to exercise their rights under the PEA, the provision respecting the hindrance, obstruction or interference with a review officer in the carrying out of his or her duties under the PEA, or an order of the Hearings Tribunal is liable to a fine of not more than $5,000. Any officer, official or agent (which may include a director) of the employer who authorizes, permits, or acquiesces in a contravention of the PEA, is liable to the penalty provided for the offence, whether or not the corporation has been prosecuted or convicted.

(e) The *Occupational Health and Safety Act* (Ontario)

The *Occupational Health and Safety Act* (the "OHSA") sets forth a number of regulations designed to ensure that workers are able to carry out their duties in a relatively safe environment. Any act or neglect of an officer or director of a corporation is considered to be the act or neglect of the corporation, and upon conviction a corporation may be charged with a maximum fine of $500,000. Any person (including a director and/or officer) who contravenes or fails to comply with a provision of the OHSA or regulations is guilty of an offence and on conviction is liable to a fine of not more than $25,000 and/or to imprisonment for a term of not more than twelve months. The Crown must commence a prosecution within one year of the offence.

A director may be held liable for fatal or critical injury to workers, high risk of critical or fatal injury to workers, conscious or gross disregard for the OHSA and its regulations and failure to comply with orders, or a history of orders issued for similar infractions. Employer corporations (and their directors) can even be liable for the acts and negligence of independent contractors, who must therefore be supervised for compliance with the OHSA.

To minimize potential liability, directors should consider the creation of a joint committee on health and safety of employees and employer, regular work place inspections, identification of any designated substances and implementation of any required programs for designated substances and the appropriate training of workers.

(f) The *Construction Lien Act* (Ontario)

The *Construction Lien Act* (Ontario) provides that certain funds received by the corporation must be held in trust for specified individuals (contractors, etc.). Directors may be liable for the amount of any such funds which the corporation fails to hold in trust where that director assents to or acquiesces in conduct that he or she knows, or reasonably ought to know, constitutes a breach of trust by the corporation.

8. LIABILITY UNDER ENVIRONMENTAL LAW STATUTES

There are six basic types of offences which can be committed under the environmental legislation listed below: pollution; failure to report a spill; failure to promptly clean up a spill; failure to comply with an administrative order; failure to properly dispose of waste; and failure to comply with notice/manifest requirements. Most of these offences relate to causing or permitting a discharge. Broadly speaking, the courts have found that lower level employees will be guilty of causing discharges while upper level management (including directors) will be guilty of permitting discharges. However, the liability imposed on directors in some of the legislation goes even further. Both the *Environmental Protection Act* (Ontario) and the *Ontario Water Resources Act* (Ontario) impose a positive duty on directors to prevent the discharge of contaminants into the natural environment. Thus, it is possible for a director to be found guilty of breaching the environmental statutes despite the fact that no discharge has yet occurred.

Directors may be found guilty as a party to the corporation's offence under one of the above-noted statutes where the director "authorized, directed, assented to, acquiesced in or participated in" the offence. Note that maximum fines may be increased by the amount of any profit earned as a result of undertaking the activity which breaches the statute. There have been a number of cases where directors have been imprisoned for their corporations' contravention of an environmental statute. The following are examples of potential liability under Ontario and Federal environmental legislation:

(a) Federal Environmental Legislation

The *Canadian Environmental Protection Act* (Canada) ("CEPA") provides that a director who directs, authorizes, assents to, acquiesces in or participates in the commission of an offence under CEPA is guilty of the offence and is liable to the punishment provided by CEPA. The offences provided for by CEPA apply to any person who "owns" or "has the charge, management or control of" a toxic substance or waste material before its release into the environment.

CEPA provides for significant punishment for the commission of offences under such Act. For example, CEPA provides that a court may make an order directing the offender to pay such money as may be necessary to ensure compliance with any order of the court, or directing the offender to compensate the Minister for any preventative action taken. A court may also require the offender to comply with conditions that will secure the offender's good conduct and prevent the offender from committing the same offence again. This is a concern because it may allow a court to restrict the corporation from compensating (through indemnification or insurance) directors for offences under CEPA.

(b) The *Ontario Water Resources Act* (Ontario)

The *Ontario Water Resources Act* (Ontario) (the "OWRA") provides that every director or officer of a corporation who engages in an activity that might result in the discharge of any material so as to impair the quality of water resources has a duty to take all reasonable care to prevent the corporation from causing or permitting such unlawful discharge. Failure to comply with this duty is an offence and may be prosecuted regardless of whether a prosecution has been undertaken against the corporation. Generally, on a first conviction, offences under the OWRA carry fines for individuals not exceeding $50,000 for each day the offence occurs, and on a subsequent conviction, a fine not exceeding $100,000 and/or imprisonment of not more than a year. However, for more serious offences, every individual convicted of an offence is liable to pay a fine of not less than $5,000 and not more than $4,000,000 on a first conviction; not less than $10,000 and not more than $6,000,000 on a second conviction; and not less than $20,000 and not more than $6,000,000 for each subsequent conviction. As well, every individual convicted of a more serious offence may also be subject to imprisonment for up to 5 years, or may receive imprisonment as the only penalty. The corporate fines are substantially higher than those imposed on individuals, and an order to protect and restore the environment can also be issued.

(c) The *Environmental Protection Act* (Ontario)

A director who contravenes a provision of this Act, fails to comply with any order or the terms of any certificate, or who engages in an activity which *may* result in the discharge of a contaminant into the natural environment (i.e. even if the discharge did not occur), is guilty of an offence and liable to a fine of up to $50,000 on a first conviction and up to $100,000 on a subsequent conviction and/or a jail term of up to one year. If a director is found guilty of actually polluting the environment or of non-compliance with a stop order, then the fines increase to $4 million and $6 million, respectively, and the prison term increases to 5 years.

Note that liability under this Act is not tied to participation in a corporate act. Each director has a duty to maintain the environment that is independent of corporate liability. A due diligence defence does exist under the EPA for the liability to compensate for damages if the director or officer can show that he or she has exercised all reasonable care and diligence to prevent the offence and also, in the case of the director or officer complying in good faith with an order or duty under the EPA, he or she may have a defence to an offence committed while doing so.

(d) Civil Liability

A further source of liability for directors and officers is the possibility of being sued personally for their acts or omissions committed on behalf of the corporation. Civil claims against an officer or a director of a corporation would most likely be based on nuisance or negligence. These claims are rarer as corporations are better able to pay (so long as it is solvent) a damage claim or make an offer to settle and given the nature of decision-making in corporations, it is often difficult to allocate fault to specific individuals within a corporation. However, there have been cases in which a director was found personally liable in nuisance for an environmental problem caused by a corporation where the director or officer had knowledge of the existence or continuance of the nuisance and had control over the operation of the facility causing the nuisance. Directors and officers also become civilly liable by virtue of being joint tortfeasors with the corporation. Further, the EPA and CEPA provide a civil cause of action for loss or damage which arises as a result of conduct contrary to the provisions of such statutes.

(e) Insurance

General liability insurance has become restricted with regards to pollution liability, and most general policies include a standard pollution exclusion clause. Policies should therefore be carefully tailored and structured so as to provide as much protection as possible.

9. OTHER ACTS IMPOSING LIABILITY ON DIRECTORS

(a) The *Consumer Protection Act* (Ontario)

This Act requires that "executory" contracts (i.e. either delivery of the goods or services, or payment is not made at the time the contract is entered into) must be in writing and contain certain specified information. It also sets out certain requirements for credit transactions. A director who knowingly concurs in a contravention of this Act or its regulations is guilty of an offence and, on conviction, is liable for a fine of up to $25,000 and/or a one-year jail term.

10. CIVIL LIABILITY FOR CORPORATE ACTS

Directors have been held personally liable (for example for environmental liability) for civil wrongs under common law or pursuant to civil rights of action contained in particular statutes where: (i) they know of an existing contract or obligation and intend to procure a breach of that contract or obligation without justification; (ii) where they acted with a lack of good faith, outside the scope of their powers, in bad faith and/or fraudulently; and (iii) where they personally benefited from the wrongful action. In many of these situations, where a court has imposed personal liability on directors and officers, a high degree of control has been exercised by the defendant individual. Therefore, in these cases, the acts were inspired, directed and/or authorized by the defendant individual. Examples would include inducing the breach of an employment contract, breach of trust, negligent misrepresentation and stripping corporate assets so as to leave the corporation unable to meet its liabilities to shareholders and creditors.

11. INDEMNIFICATION OF DIRECTORS BY THE CORPORATION

(a) Permissible Indemnification

Pursuant to the OBCA, a corporation may indemnify a current or former director or officer of the corporation or any subsidiary for liability and monetary penalties arising out of any civil, criminal or administrative proceeding if the director or officer acted honestly and in good faith with a view to the best interests of the corporation and he or she had reasonable grounds for believing that his or her conduct was lawful. Thus, indemnification is generally available for the specific statutory liabilities outlined above, as well as for common law liability, for amounts paid in settlement of a claim and for costs relating to lawyers, accountants and other advisors incurred in defence of a claim or in responding to a governmental investigation. It should be noted that there is no requirement that the director or officer achieve complete success as a defendant, only substantial success.

Notwithstanding the foregoing, there are restrictions on indemnification contained in particular statutes which create liability for directors (such as the ESA and environmental legislation outlined above). Further, there are problems in the application of the authorizing provision of the OBCA since there are no standardised tests for whether a director acted "honestly" and in "good faith" with a view to the best interests of the corporation.

In any event, approval of indemnification would have to be made by a disinterested quorum of the board, perhaps on the basis of an opinion from independent legal counsel and perhaps with shareholder ratification. Alternatively, the corporation could apply for court approval of the indemnification, as discussed below.

(b) Derivative Action

A derivative action is an action brought by a security holder, current or former director or officer, or other stakeholder in the name of and on behalf of the corporation, dealing with such matters as seizing a business opportunity which the corporation could have pursued, self-dealing, unreasonable reimbursement of expenses, insider trading and other actions which involve a breach of duty to the corporation (such as the director's fiduciary duty and duty of competence). In a derivative action, the corporation may indemnify a current or former director or officer against all reasonable costs of his or her defence, whether or not the director or officer was successful in the defence, if the director or officer acted honestly and in good faith with a view to the best interests of the corporation and he or she had reasonable grounds for believing that his or her conduct was lawful, and if a court approves of such payment. If a director is substantially successful on the merits in a derivative action, he or she may be entitled to indemnification in respect of his or her defence costs, as indicated below. Directors would have to fund their interim defence costs, however.

(c) Mandatory Indemnification

A director or officer is entitled, as a matter of right, to an indemnity if he or she was substantially successful on the merits in his or her defence of any civil, criminal or administrative proceedings and indemnification would have been permitted under (1) above.

Note that directors cannot require indemnification if they settle an action, but can make any settlement conditional on approval of the settlement and indemnification by the corporation and the relevant court. Further, a director or officer cannot require the corporation to fund his or her interim defence costs until the conclusion of the action (and, unless there is a decision on the merits, cannot require the corporation to fund professional fees relating to governmental investigation proceedings). These matters may, however, be the subject of permissive indemnification. The existence of a strong corporate by-law requiring interim indemnification and requiring the corporation to apply to the court would certainly be of considerable benefit to the director in obtaining an order for pre-judgment indemnification in this context.

(d) Court Approval

There is provision under the OBCA for an application to the court for approval of proposed indemnification, which may be brought by either a director or officer seeking indemnification or by the corporation. These applications are brought whenever there is uncertainty as to whether indemnification is allowable or proper and the payer (which could be the corporation's board of directors or a receiver appointed by a secured creditor) wishes protection from liability for having made the payments.

(e) Indemnification Contracts

The creation of an indemnity in favour of directors or officers is generally effected by by-law. However, a corporate by-law does not constitute a contract between a corporation and its directors and officers that can be enforced by them. Further, by-laws can be changed or repealed, which is particularly relevant to former directors and officers. Accordingly, as there are many matters in respect of which a director or officer cannot compel a corporation to provide indemnification, directors should consider whether, as a condition of serving as a director, they wish to require an agreement pursuant to which the corporation contractually agrees to indemnify him or her to the full extent permitted by the OBCA. Indemnification contracts may be sought from the corporation, from a parent corporation and a guaranty can be obtained from a majority shareholder. By doing so, a director converts the permitted indemnity (discussed under (1) above) into a mandatory indemnity enforceable by him or her. For further discussion, see Appendix "B".

12. DIRECTORS' AND OFFICERS' LIABILITY INSURANCE

Viewed pragmatically, the protection afforded by an indemnity, whether mandatory, permissible or contractual, is limited according to the ability of the corporation to meet its obligations. An indemnity would primarily be relevant in circumstances where a corporation is in financial difficulty, but this offers little protection as any claim under the indemnity would rank subsequent to the claims of any secured and preferred creditors in the event of bankruptcy. Further, there are legal limits on permissible indemnification contained in the OBCA and other statutes (such as the ESA and environmental legislation). Therefore directors should consider obtaining a directors' and officers' liability insurance policy (a "D & O policy").

Directors should be aware of the extent of coverage and the extent of exclusions in any insurance policy. D & O policies are typically negotiable and directors should consider obtaining independent legal advice and advice from independent insurance brokers as to policy endorsements and exclusions; often additional coverage which is particularly relevant for the industry in which the corporation operates can only be obtained by endorsements at extra cost. Such professional advisors will be able to confirm what additional coverages are available.

Counsel and independent insurance brokers will also be able to advise the board as to special coverage that may be required by professional advisors who also serve as directors and as to the extent of deductibles, percentage co-insurance requirements applicable to the directors and officers and aggregate policy limits, so that an informed decision as to the worthiness of a particular policy can be made. In this regard, note that unlike most comprehensive general liability policies, policy limits on D & O policies constitute aggregate limits for the entire year and not just maximum limits with respect to any one particular claim. Therefore, if a large claim is pending, the directors may be underinsured or uninsured for the balance of the year.

Further advice should be obtained as to the timing of claims and the policy period. D & O policies are now written on a "claims made" basis; that is, the policy covers claims made during the policy period even though the occurrence which led to the claim may have been prior to the policy period. The policy period is generally one to three years. In the event that coverage is not to be renewed with a particular carrier or a particular carrier is refusing to renew coverage, it is essential that notice be given to the insurer prior to the termination of the policy period of any possible or potential claims that the directors and officers or corporation may be aware of. This will result in protection under the policy being provided if an actual claim later results.

Directors will also wish to ensure that the D & O policy does not provide that they have to fund interim defence costs up to the deductible amount or pursue the corporation for such interim defence costs and, further, that they are presumed innocent of claims concerning matters for which coverage is not provided under the policy, again, so that the insurer is obligated to fund interim defence costs.

13. TAX CONSIDERATIONS: INDEMNIFICATION AND INSURANCE

It is the Canada Revenue Agency's view that where a corporation purchases an insurance policy indemnifying the directors or officers of the company for any liability arising in their official capacities, neither the insurance premiums nor the proceeds of insurance will be considered a taxable benefit to the director or officer, provided that the risks covered by the policy are inherent and normal occurrences in the carrying out of the duties of the insured as a director or officer of the corporation. Of course, indemnities paid where the directors were not acting in good faith would be taxable.

Where a contractual indemnity is contained in an employment contract (for example, in the case of senior officers) or is a pre-condition to becoming a director, the Canada Revenue Agency may argue that the indemnification provision was part of the consideration for taking the position, something that is expressly taxable under the ITA. The problem may be dealt with by having a "gross-up clause" in the indemnification agreement. In this way, the extra tax liability can be satisfied through additional payments to directors and officers by the corporation.

14. CONCLUSION

This memorandum does not deal with the liability of a director in respect of matters occurring prior to his or her appointment, or prior to the incorporation of the corporation, nor liabilities under the *Securities Act* (Ontario). In addition, although we have not addressed matters relating to the laws of other provinces, the laws of other provinces may apply to a particular corporation to the extent that it carries on business in such other provinces.

The purpose of this memorandum is to point out specific provisions which create a liability for directors, so that a risk management program can be formulated and implemented. Like a bullet-proof vest, having a risk management program is no guarantee that no harm will come to the owner. It is, however, a way of ensuring that all reasonable measures have been taken to minimize the danger. In today's legislative climate, no qualified directors should be expected to serve without a full knowledge of the hazards involved, and without the best protection individual directors and their corporations can provide.

APPENDIX "A"

MEASURES TO REDUCE THE POTENTIAL LIABILITY OF DIRECTORS

Ideally, a risk management program should consist of three components: (a) measures undertaken by corporations; (b) measures undertaken by the board of directors; and (c) measures undertaken by individual directors.

1. Measures corporations should take to protect their directors:

   (a) Keep directors informed about legal statutes that may apply to them, and about the dollar value of potential liability. This should be done in writing by independent legal counsel. Environmental issues should be dealt with separately, since potential liability in this area can run into astronomical figures.

   (b) Provide directors with formal assurance that liabilities are being recorded and paid.

   (c) Have in place an orientation program for new directors, and a continuing educational process throughout their tenure.

   (d) Provide directors with background material in time to do their homework before board meetings. Make sure independent experts are available during the discussions of particularly complex issues.

   (e) Report regularly on risk areas. The agenda of every board meeting should include a report on issues that involve potential personal liability, such as compliance issues and steps taken by management to mitigate risk.

   (f) Obtain indemnification and liability insurance, including coverage of directors' legal costs.

   (g) Remunerate directors to cover the work required. Fees should be sufficient to compensate directors for their growing responsibilities and for the substantial time required for preparation and attendance at board meetings.

   (h) Remember the statute of limitations. Legal action can be launched within two years of the cause of the damage complained of, however, the limitation period might not begin to run until several years after the occurrence of the event due to the principle of discoverability. The ultimate limitation period is 15 years and thus insurance should also cover past directors.

2. Measures the board of directors should take to protect itself:

   (a) Put an appropriate system in place to ensure that income tax deductions and other crown remittances are made. Note that even if these deductions are not made, directors may well avoid personal liability if they have implemented an appropriate system for deductions and remittances and receive regular reports as to the compliance with such system. If directors are aware that the company is experiencing financial difficulties, they should either attempt to obtain from the company's bank an enforceable undertaking to pay all payroll deductions, GST, PST and similar payments when due, or establish separate trust accounts for such remittances. For example, a payroll trust account could be created to hold funds for subsequent disbursement to employees and the Crown.

(b) In the case of material acquisitions, dispositions or corporate reorganizations, it is important for directors to obtain a proper valuation from an investment dealer or other valuation expert. The expert should provide copies of the analysis and comparative data to the board so that it is clear that an informed decision has been reached as to the proposed transaction.

(c) The board should also establish, in conjunction with the company's counsel, both a general policy statement and some form of monitoring system concerning compliance with environmental, health and safety and other legislation applicable to the corporation. Consideration should be given to requiring those responsible for these areas to regularly complete and forward a questionnaire to the directors which is designed to deal with all principal areas of concern and to attend board meetings to answer questions.

(d) The corporation's auditors and lawyers are a source of independent information about potential director liability issues and such professionals can be asked to attend board meetings to report directly to the board as to matters potentially resulting in director liability. So long as professional advisors do not withhold information from management there is no conflict in their reporting directly to the board. In the case of a company in financial difficulty, it would be advisable for the directors to request that the corporation's counsel and the auditors attend board meetings and report directly to the entire board with respect to matters such as the corporation's potential duties to creditors, the solvency of the corporation, remittances to the Crown and the accounting principles applicable to interim financial statements.

(e) The board may delegate to specialized committees of the board responsibility for the overview of areas in which the committee members would have and/or develop expertise. Depending upon the size of the board and the nature of the corporation's obligations, a committee structure may enable more active oversight of an area by the board by permitting more frequent contact with management and quicker response to management. However, members of committees may be held to a higher standard of care with respect to the matters within their mandate.

3. Measures individual directors should take to protect themselves:

(a) Obtain an effective contractual indemnity from the corporation (and, if the corporation is in financial difficulty, a guarantee of this indemnity from a major shareholder).

(b) Insist that the duties and responsibilities as a director be spelled out in written job description. Without it, a director has no way of knowing by what standards his or her performance may be judged.

(c) Examine the quality and makeup of the board, including independent directors with a background in finance, accounting and marketing, and information systems.

(d) Consider trusts, letters of credit or acceleration of payments. Where a company is in financial difficulty, a director should insist that steps be taken to ensure that funds are segregated and available to discharge known liabilities such as taxes, unpaid wages etc.

(e) Keep proper documentation, including detailed records of matters discussed and decisions taken at board meeting. A director should make sure the minutes record any dissenting votes or abstentions.

(f) Demand access to first-class professional expertise. Review the credentials and performance of accountants, lawyers, tax experts and other outside advisers to the company.

(g) Use audits and an audit committee. Where appropriate, a director should insist on an audit even through it may not be required by law. Any audit committee of the board can focus attention on financial and accounting issues raised by the auditors.

(h) Say "why" as often as "yes". Understanding the reasons behind management decisions is both a director's right and duty. A director should ask questions that help him or her understand key issues.

(i) Exercise the right and duty to dissent. A positive obligation to dissent has been imposed on directors; this obligation has clearly increased the liability exposure of outside, non-management directors, who are the least likely to be actively involved in the corporation's affairs. Even a director who takes practically no interest in his or her corporation nonetheless receives board minutes and, therefore, will in the normal course become aware of board resolutions and acts. The director may file the written dissent with the person acting as secretary, or send the dissent by registered mail to the corporation. A further copy must be sent by registered mail to the Minister in charge of the Administration of the OBCA. It should be noted that the registration of dissent will not necessarily exonerate a director from all liability, but unless such a director registers his or her dissent to a resolution passed or act taken that is later impugned by a plaintiff, there is little if anything that defence counsel can do to avoid the statutory imputation of the resolution or act to that director.

(j) Be prepared to resign. If a director is uncomfortable with the company, its board or practices, or unable to devote the time and effort required to discharge his or her fiduciary responsibility, he or she should step down. However, simple resignation from the board cannot insulate a director from liability for conduct that has violated the corporate fiduciary duty. Further, the court may hold directors responsible for corporate actions taken after their resignation - actions that the departing directors neither considered nor approved.

APPENDIX "B"

INDEMNIFICATION CHECKLIST

1. In view of the expanding scope of potential liability, prudence dictates that directors and officers ensure that all appropriate measures to achieve the maximum possible protection by way of indemnification and insurance coverage be taken. What follows is a checklist of considerations which should be taken into account when acting as a director or officer:

2. Review the requisite corporation authorization, whether by way of Articles of Incorporation or by way of corporate by-law, to ensure that the corporation is authorized to indemnify and to ascertain the terms of the permitted indemnification, particularly with a view to any limitations therein;

3. Enter into a specific contract of indemnification setting out the right to be indemnified, the terms of the indemnification and the authorization of the corporation to enter into the contract of indemnification;

4. Ensure that appropriate directors' and officers' liability insurance is secured and maintained by the corporation either by seeking distinct remuneration in the requisite premium amount or requiring notice of default to be given directly to the director and officer;

5. As security for the obligation to indemnify, obtain the covenant of principal shareholders and related corporate entities;

6. Ensure that the indemnification obligation of the corporation is applicable to the particular position of the director or officer;

7. Generally, the wording of a contractual indemnity provision and the corporate authorizing provision should be in the broadest possible terms and should not be limited or made referable only to the statutory provisions;

8. Ensure that the right to be indemnified, and any resolution of the board of directors in that respect, specifically permits indemnification before, and regardless of, the outcome of any relevant proceedings;

9. If interim funding (versus indemnification) is to be obtained, there must be a specific right in this regard;

10. Ensure that the indemnification provisions apply specifically to indemnification for a settlement before judgment both as to costs and as to any other amounts paid;

11. The provision of the indemnity contract or authorizing by-law should ensure that there is full coverage of solicitor and client costs irrespective of whether there ultimately is a right of indemnity;

12. Since litigation in many instances is extremely time consuming and disruptive, directors and officers should seek to include a provision calling for a reasonable rate of remuneration for their involvement in litigation which will become the subject to indemnification, over and above indemnification for their costs and expenses;

13. The right of indemnity should be expressed to survive the director or officer ceasing to hold office, at least for a period sufficient to cover any limitation periods;

14. Ensure that the indemnification provisions oblige the corporation to apply for approval if demanded by the director or officer;

15. Allow the corporation to bring the application for indemnification as opposed to the director and officer;

16. When seeking court approval for indemnification, ensure that there is an authorizing resolution of the board of directors comprised of independent directors.

Attachment 1-L

Unanimous Shareholder Agreement

ARTICLE III
OPERATION OF HOLDCO

3.01 Initial Structure

Until such time as the circumstances described in Section 3.02 apply, a Shareholder shall be entitled to nominate one-quarter of the members of the board of directors of Holdco, which until July 1, 2000 shall initially consist of four directors and be constituted as follows:

Director	Nominator
Tony Tiefenbach	Amherstburg
William Varga	LaSalle
David Wilkinson	Leamington
Gary McNamara	Tecumseh

and which after July 1, 2000 shall consist of eight directors. All decisions of the board of directors of Holdco shall be made by a majority of directors voting thereon. Until July 1, 2000, three (3) directors in attendance at a meeting of the board of directors shall constitute a quorum. Thereafter, six (6) directors in attendance at a meeting of the board of directors shall constitute a quorum.

3.02 Altered Structure of Holdco Board

If, at any time, Shareholder(s) who are not original signatories to this Agreement ("New Shareholders") and who have become Shareholders in the circumstances described in Section 6.01, own, as a result of the operation of Section 6.01, (a) more than from twenty-five percent, but less than forty-five percent of all Shares, or (b) forty-five percent of all Shares, the other Shareholders shall nominate five of the members of the board of directors of Holdco and the New Shareholder(s) shall nominate three members of the board of directors of Holdco.

3.03 Meetings of Directors of Holdco

Meetings of the board of directors of Holdco shall be held quarterly in January, April, July and October in each calendar year at a time and place to be determined by the Chairman of Holdco. At least 15 Business Days before each quarterly meeting of the directors, each director shall receive a written notice from the Secretary of Holdco indicating the time and place of the meeting. At least 5 Business Days before each quarterly meeting of the directors, each director shall receive a written summary of the matters to be considered at the meeting. Additional meetings of the board of directors may be called by any director by the delivery of a written notice to every other director at least 5 Business Days before such meeting indicating the time and place of the meeting and providing a written summary of the matters to be considered. A director may waive notice of a meeting by an instrument in writing delivered to the Chairman of Holdco at or prior to the meeting and the attendance of a director at a meeting shall constitute a waiver of notice of the meeting (except where a director attends a meeting for the express

TW C

purpose of objecting to the transaction of business on the grounds that the meeting is not properly called).

3.04 **Material Decisions**

No Material Decisions shall be implemented by a Company without the prior approval of the directors of Holdco, and no Material Decision referred to in clauses (iv), (xvi) or (xi) of the definition of that term, or any sale of all or substantially all of the assets of a Company, shall be implemented unless first approved by Special Resolution.

3.05 **Appointment of Directors**

The Shareholders shall take all actions that may be required to ensure the election or appointment as directors of Holdco of the nominees contemplated by this Article. On the appointment or election of each director, the Secretary of Holdco shall make note of the nominator, and the nominator shall, subject to the Act, be entitled by direction in writing from time to time to remove its nominee and nominate a successor who shall, promptly upon the resignation of the existing director, be elected a director to replace the individual previously nominated. Each Shareholder shall ensure at all times that one of its nominees is an elected municipal representative, and that the other nominee is a non-elected member of the business community.

3.06 **Indemnification of the Directors**

Holdco shall indemnify and save the directors harmless from and against any and all liability, damages, costs (including reasonable counsel fees and disbursements), charges and expenses arising out of or related to any act or omission done or permitted by them to be done in connection with the execution of the duties of their office as directors of Holdco or by reason of their being or having been directors of Holdco, including (without limitation):

(a) any amounts paid to settle an action or satisfy a judgment, that the directors may sustain or incur in respect of any civil, criminal or administrative action, suit, proceeding, claim, or demand, that is proposed, asserted, commenced or made against them and/or against Holdco;

(b) all liability for wages to employees and for income, corporation or other taxes, and fines or penalties arising out of any prosecution in connection therewith; and

(c) all liability for failure by Holdco to comply fully with the provisions of the Act or any other applicable law and fines or penalties arising out of any prosecution in connection therewith;

provided such indemnity shall not extend to liabilities, damages, costs, charges or expenses attributable to the deliberate misconduct or reckless disregard by the director of his or her duties as a director of Holdco. These rights are in addition to and not in substitution for any and all other indemnities to which the director may be entitled.

TPS

Holdco's directors shall be entitled to cause Holdco to obtain and maintain directors' and officers' liability insurance in such amounts and on such terms as they deem prudent.

3.07 **Officers**

The officers of each Company shall be designated and appointed from time to time by the directors.

3.08 **Books of Account**

Proper books of account and records shall be kept by Holdco at its registered office and entries shall be made therein in accordance with generally accepted accounting principles. Each of the Shareholders, the directors of Holdco and their respective representatives shall have access at all reasonable times to examine and copy such books of account and records, provided that any confidential information which is obtained from their examinations shall not be disclosed to Persons who are not directors of Holdco, Shareholders or directors of Shareholders and shall not be used for any improper purpose.

3.09 **Budget**

At least four weeks before the beginning of each Fiscal Year, Holdco shall send to each director and Shareholder a profit forecast, annual budget and business and marketing plan for each Company, providing, among other things, a detailed breakdown of projected cash flow, capital expenditures and income. The Budget for each Company shall be effective upon being approved by the directors of Holdco, with such changes as they determine to be necessary.

3.10 **Periodic Reports**

Within ten Business Days after the end of each calendar quarter, the chief financial officer of Holdco shall send to each director and Shareholder :

(a) an income statement, balance sheet and cash flow statement for each Company on a cumulative, quarterly basis compared to corresponding periods in the previous Fiscal Year;

(b) an income instatement and balance sheet and cash flow statement for each Company on a cumulative quarterly basis compared to corresponding periods in the previous Fiscal Year and compared to the Budget; and

(c) cumulative year to date statistics.

3.11 **Distributions**

All funds received by a Company shall be paid and distributed in the following order:

(a) the payment of all debts and liabilities of such Company which are due and payable from time to time to Persons dealing at arm's length, as that term is

TB S

construed for the purposes of the *Income Tax Act* (Canada), with all of the parties to this agreement;

(b) the establishment of such reserves as may be:

(i) required by the auditors of Holdco in accordance with generally accepted accounting principles, and/or

(ii) approved by the directors of Holdco;

(c) the repayment of interest owing on the First Tier Loans owed by such Company pro rata in accordance with accrued interest;

(d) the repayment of principal owing on the First Tier Loans owed by such Company pro rata in accordance with the principal amounts owing;

(e) the repayment of interest owing on the Second Tier Loans owed by such Company pro rata in accordance with the principal amounts owing;

(f) the repayment of principal owing on the Second Tier Loans owed by such Company pro rata in accordance with the principal amounts owing;

(g) the repayment of all other Shareholder Loans owed by such Company; and

(h) the payment of dividends, provided that no such dividends shall be declared or paid except to the extent that they can be satisfied by a Company without incurring any additional liabilities. Additionally, no dividend shall be paid if precluded by any loan agreement to which a Company is a party; provided the amount that would have been paid as dividends but for the loan agreement shall be paid when a Company may legally do so.

ARTICLE IV
FINANCING MATTERS

4.01 Recourse Borrowing

No plan or arrangement shall be implemented which requires any of the Shareholders to contribute or lend funds to a Company or would require any of the Shareholders to guarantee or secure any debts or obligations of a Company or its Subsidiaries unless all of the Shareholders agree in writing to the implementation of such plan or arrangement.

4.02 Non-Recourse Borrowing

The Shareholders agree to use all commercially reasonable efforts to cause Essex Powerlines Corporation to obtain financing from a financial institution or other lender in a principal amount equal to the aggregate principal amount of the First Tier Loans and all accrued and unpaid interest thereon as at the time of the obtaining of such financing, provided that the recourse of such lender shall be limited to the assets of the Companies, and no Shareholder shall

Attachment 1-M

MIFRS Transition Summary Impact

File Number:	EB-2017-0039
Exhibit:	1
Attachment:	1-M
Page:	1 of 1
Date:	August 28th, 2017

Appendix 2-Y
Summary of Impacts to Revenue Requirement from Transition to MIFRS

Revenue Requirement Component	**2018 MIFRS**	**2018 CGAAP [1]**	**Difference**	**Reasons why the revenue requirement component is different under MIFRS**
Closing NBV 2017	$ 51,973,522	$ 48,018,373	$ 3,955,148	Capitalization - decrease in capital under MIFRS
Closing NBV 2018	$ 54,818,923	$ 49,620,419	$ 5,198,504	Capitalization - decrease in capital under MIFRS
Average NBV	$ 53,396,222	$ 48,819,396	$ 4,576,826	
Working Capital	$ 5,705,908	$ 5,655,031	$ 50,877	Capitalization - increase in OM&A under MIFRS
Rate Base	$ 59,102,130	$ 54,474,427	$ 4,627,704	
Return on Rate Base	$ 3,288,915	$ 3,086,303	$ 202,612	
			$ -	
OM&A	$ 7,752,813	$ 7,256,989	$ 495,824	Capitalization - increase in OM&A under MIFRS
Depreciation	$ 1,848,004	$ 3,645,515	-$ 1,797,511	Depreciation - decrease in depreciation expense under MIFRS
PILs or Income Taxes	$ 227,249	$ 654,158	-$ 426,909	Depreciation - increase in Schedule 1 addback under CGAAP; Capitalization
			$ -	
Less: Revenue Offsets	-$ 691,821	-$ 691,821	$ -	
			$ -	
			$ -	
			$ -	
Insert description of additional item(s)			$ -	
Total Base Revenue Requirement	$ 12,425,160	$ 13,951,144	-$ 1,525,984	

1. Applicants must provide a summary of the dollar impacts of MIFRS to each component of the revenue requirement (e.g. rate base, operating costs, etc.), including the

Exhibit 2:

Rate Base

Table of Contents

List of Attachments

2.1 Rate Base

2.1.1 Overview

This Exhibit provides detailed explanations of Essex Powerlines Corporation's ("EPLC") historical and projected Rate Base from 2010 Board Approved ("BAP") amounts to 2017 Bridge Year and 2018 Test Year. Further, detailed variance analysis is provided for any year over year variance over EPLC's materiality threshold. EPLC has prepared this Exhibit in accordance with Chapter 2 of the "Filing Requirements for Electricity Distribution Rate Applications – 2017 Edition for 2018 Rate Applications" issued July 20th, 2017.

EPLC has calculated its 2018 Test Year Rate Base by using the average of the projected opening and closing 2018 Test Year Gross Fixed Assets and Accumulated Depreciation and adding a Working Capital Allowance ("WCA") which is determined by taking the sum of EPLC's cost of power and controllable costs; multiplied by an allowance factor. For the purposes of this Application, EPLC has used the deemed rate of 7.5% for the WCA factor which represents a 7.5% decrease from the 2010 BAP. Further information regarding EPLC's WCA calculation can be found in Section 2.4 of this Exhibit.

For the purpose of this Application, capital assets include Property, Plant and Equipment ("PP&E") and intangible assets that enable EPLC to distribute electricity to its customers. EPLC's proposed 2018 Rate Base does not include any non-distribution assets. EPLC's controllable expenses include operations, maintenance, billing and collecting and administrative expenses.

Figure 1 below outlines EPLC's historical Rate Base calculation from 2010 BAP to the proposed 2018 Test Year. 2017 and 2018 reflect projected amounts whereas 2010 to 2016 reflect actual results. EPLC's proposed 2018 Test Year Rate Base is $59,927,210 which represents a 45.7% increase (or a 5.71% yearly average increase) from the 2010 BAP Rate Base. Detailed explanations for the increases to Rate Base are described in Section 2.2 of this Exhibit.

Figure 1 – Rate Base Continuity Schedule

Description	2010 BAP	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Accounting Standard	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Gross Fixed Assets	$ 50,352,174	$ 49,083,253	$ 51,669,129	$ 57,371,668	$ 60,692,887	$ 65,778,217	$ 72,109,471	$ 76,452,554	$ 81,886,262	$ 86,844,505
Accumulated Depreciation	$ (16,335,848)	$ (16,290,184)	$ (18,356,056)	$ (20,735,930)	$ (22,530,327)	$ (23,960,237)	$ (26,444,102)	$ (27,550,954)	$ (29,220,079)	$ (31,068,083)
Net Book Value	$ 34,016,326	$ 32,793,069	$ 33,313,073	$ 36,635,738	$ 38,162,560	$ 41,817,980	$ 45,665,369	$ 48,901,600	$ 52,666,183	$ 55,776,422
Average Net Book Value	**$ 33,009,250**	**$ 32,138,850**	**$ 33,053,071**	**$ 34,974,405**	**$ 37,399,149**	**$ 39,990,270**	**$ 43,741,674**	**$ 47,283,484**	**$ 50,783,891**	**$ 54,221,302**
Total Working Capital	$ 54,069,758	$ 54,778,916	$ 56,734,399	$ 58,590,963	$ 57,589,775	$ 64,252,177	$ 69,042,180	$ 78,624,142	$ 74,975,367	$ 76,078,771
Allowance Factor	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	7.50%
Working Capital Allowance	**$ 8,110,464**	**$ 8,216,837**	**$ 8,510,160**	**$ 8,788,644**	**$ 8,638,466**	**$ 9,637,827**	**$ 10,356,327**	**$ 11,793,621**	**$ 11,246,305**	**$ 5,705,908**

Figure 2 below summarizes EPLC's historical WCA for years 2010 through 2016 and calculated for years 2017 and 2018. EPLC's proposed 2018 Test Year WCA is $5,705,908 which represents a 29.6% reduction from the 2010 BAP WCA. Further details about EPLC's WCA calculation are provided in Section 2.4 of this Exhibit.

Figure 2 – Historical Working Capital Analysis

Description	2010 BAP	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Accounting Standard	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Operations	$ 1,111,126	$ 767,608	$ 1,003,987	$ 1,190,375	$ 1,207,057	$ 1,545,489	$ 1,332,350	$ 1,337,677	$ 1,221,419	$ 1,518,208
Maintenance	$ 1,517,732	$ 1,496,651	$ 1,614,034	$ 2,013,059	$ 1,515,425	$ 1,448,980	$ 1,808,438	$ 1,833,650	$ 1,572,404	$ 1,548,463
Billing & Collecting	$ 1,480,565	$ 1,305,098	$ 1,131,257	$ 1,174,568	$ 1,329,771	$ 1,158,128	$ 1,229,676	$ 1,348,249	$ 1,499,880	$ 1,550,150
Community Relations	$ 22,500	$ 16,957	$ 11,394	$ 8,539	$ 8,451	$ 10,016	$ 12,013	$ 6,482	$ 23,442	$ 23,396
Admin & General	$ 2,068,443	$ 1,894,041	$ 1,786,257	$ 1,806,757	$ 1,966,590	$ 2,541,606	$ 2,381,742	$ 2,455,564	$ 2,950,224	$ 3,070,058
Property Taxes	$ 85,824	$ 68,136	$ 43,471	$ 43,122	$ 45,301	$ 44,568	$ 41,843	$ 41,042	$ 42,621	$ 42,538
Total Controllable Costs	**$ 6,286,190**	**$ 5,548,490**	**$ 5,590,400**	**$ 6,236,418**	**$ 6,072,596**	**$ 6,748,787**	**$ 6,806,061**	**$ 7,022,665**	**$ 7,309,990**	**$ 7,752,813**
Cost of Power	$ 47,783,568	$ 49,232,444	$ 51,143,998	$ 52,354,545	$ 51,542,202	$ 57,503,389	$ 62,236,119	$ 71,601,477	$ 67,716,983	$ 68,325,958
Total Working Capital	**$ 54,069,758**	**$ 54,780,934**	**$ 56,734,399**	**$ 58,590,963**	**$ 57,614,798**	**$ 64,252,177**	**$ 69,042,180**	**$ 78,624,142**	**$ 75,026,973**	**$ 76,078,771**
Allowance Factor	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	7.50%
Working Capital Allowance	**$ 8,110,464**	**$ 8,217,140**	**$ 8,510,160**	**$ 8,788,644**	**$ 8,642,220**	**$ 9,637,826**	**$ 10,356,327**	**$ 11,793,621**	**$ 11,254,046**	**$ 5,705,908**

EPLC currently owns four separate non-distribution solar photovoltaic assets:

i) 500 kW DC, 12021 McNorton Street, Tecumseh, Ontario;
ii) 10 kW DC, Erie Street North, Leamington, Ontario;
iii) 10 kW DC, William Street, Amhestburg, Ontario;
iv) 10 kW DC, 50 Victoria Avenue North, Leamington, Ontario;

EPLC has not included any of these assets, or any of their associated revenues and expenses, in Rate Base or anywhere in this Application.

EPLC has included Attachment 2-A (Fixed Asset Continuity Schedules), consistent with Board Appendix 2-BA. It should be noted that EPLC will be proposing an adjustment to Net Book Value in 2017 that will reduce Rate Base. For the purpose of this Application, this adjustment has been used to calculate the change in Accounting Standards however all Rate Base calculations within this Exhibit are consistent with EPLC's RRR filings.

For the purpose of capital planning, EPLC considers Conservation & Demand Management initiatives as a means of deferring or avoiding future infrastructure projects as part of its distribution system planning process.

EPLC has also realized operating efficiencies as a result of the deployment and operationalization of smart meters and related technologies, mainly through the deployment of SmartMAP. Further information about SmartMAP and its functionality can be found in EPLC's DSP which is included as Attachment 2-C of this Exhibit.

2.1.2 Rate Base Variance Analysis

EPLC has created Figure 3 below which demonstrates Rate Base variances from 2010 BAP to the 2018 Test Year.

Figure 3 – Historical Rate Base Variance

Description	2010 BAP	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Accounting Standard	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Gross Fixed Assets	$ 50,352,171	$ 49,083,254	$ 51,669,129	$ 57,371,669	$ 60,692,887	$ 65,778,218	$ 72,109,472	$ 76,452,554	$ 81,886,262	$ 86,844,505
Accumulated Depreciation	$ (16,335,848)	$ (16,290,184)	$ (18,356,056)	$ (20,735,930)	$ (22,530,327)	$ (23,960,238)	$ (26,444,103)	$ (27,550,955)	$ (29,220,080)	$ (31,068,084)
Net Book Value	$ 34,016,323	$ 32,793,070	$ 33,313,273	$ 36,635,739	$ 38,162,560	$ 41,817,980	$ 45,665,369	$ 48,901,599	$ 52,666,182	$ 55,776,421
Average Net Book Value	**$ 33,009,250**	**$ 32,138,850**	**$ 33,053,071**	**$ 34,974,405**	**$ 37,399,149**	**$ 39,990,270**	**$ 43,741,674**	**$ 47,283,484**	**$ 50,783,891**	**$ 54,221,302**
Total Working Capital	$ 54,069,758	$ 54,778,916	$ 56,734,399	$ 58,590,963	$ 57,589,775	$ 64,252,177	$ 69,042,180	$ 78,624,142	$ 74,975,367	$ 76,078,771
Allowance Factor	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	7.50%
Working Capital Allowance	**$ 8,110,464**	**$ 8,216,837**	**$ 8,510,160**	**$ 8,788,644**	**$ 8,638,466**	**$ 9,637,827**	**$ 10,356,327**	**$ 11,793,621**	**$ 11,246,305**	**$ 5,705,908**
Rate Base	**$ 41,119,714**	**$ 40,355,687**	**$ 41,563,231**	**$ 43,763,049**	**$ 46,037,615**	**$ 49,628,097**	**$ 54,098,001**	**$ 59,077,105**	**$ 62,030,196**	**$ 59,927,210**
Variances		**2010 BAP vs. 2010 Actual**	**2010 Actual vs. 2011 Actual**	**2011 Actual vs. 2012 Actual**	**2012 Actual vs. 2013 Actual**	**2013 Actual vs. 2014 Actual**	**2014 Actual vs. 2015 Actual**	**2015 Actual vs. 2016 Actual**	**2016 Actual vs. 2017 Bridge**	**2017 Bridge vs. 2018 Test**
Gross Fixed Assets		$ (1,268,917)	$ 2,585,875	$ 5,702,540	$ 3,321,218	$ 5,085,331	$ 6,331,254	$ 4,343,082	$ 5,433,708	$ 4,958,243
Accumulated Depreciation		$ 45,664	$ (2,065,872)	$ (2,379,874)	$ (1,794,397)	$ (1,429,911)	$ (2,483,865)	$ (1,106,852)	$ (1,669,125)	$ (1,848,004)
Net Book Value		$ (1,223,253)	$ 520,203	$ 3,322,466	$ 1,526,821	$ 3,655,420	$ 3,847,389	$ 3,236,230	$ 3,764,583	$ 3,110,239
Average Net Book Value		**$ (870,400)**	**$ 914,221**	**$ 1,921,334**	**$ 2,424,744**	**$ 2,591,121**	**$ 3,751,404**	**$ 3,541,810**	**$ 3,500,407**	**$ 3,437,411**
Total Working Capital		$ 709,158	$ 1,955,483	$ 1,856,564	$ (1,001,188)	$ 6,662,401	$ 4,790,003	$ 9,581,962	$ (3,648,775)	$ 1,103,404
Allowance Factor		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-7.50%
Working Capital Allowance		**$ 106,374**	**$ 293,322**	**$ 278,485**	**$ (150,178)**	**$ 999,360**	**$ 718,500**	**$ 1,437,294**	**$ (547,316)**	**$ (5,540,397)**
Rate Base		**$ (764,026)**	**$ 1,207,543**	**$ 2,199,819**	**$ 2,274,566**	**$ 3,590,481**	**$ 4,469,904**	**$ 4,979,104**	**$ 2,953,091**	**$ (2,102,986)**

Variances are a result of additions to Gross Assets and a decrease to Working Capital Allowance. Sections 2.2 and 2.4 below further detail these variances.

2.2 Gross Assets – Property, Plant & Equipment & Depreciation

2.2.1 Breakdown by Function

EPLC has categorized its gross assets into four primary categories, consistent with the Uniform System of Accounts ("USoA") as described below:

- **Intangible Plant:** Assets include USoA range of accounts 1606 to 1611 and generally include assets such as software;

- **Distribution Plant:** Assets include USoA range of accounts 1805 to 1860 and generally include assets such as poles, wires, meters, transformers, etc.;

- **General Plant:** Assets include USoA range of accounts 1905 to 1990 and generally include assets such as buildings, transportation equipment, computer hardware, tools, etc.;

- **Contribution & Grants:** Includes USoA account 1995 and captures contributions made towards capital either received or forecasted to be received consistent with the Distribution System Code. EPLC does not utilize Account 2440.

Figure 4 below outlines the breakdown described above. Year over year variances are summarized as part of Section 2.2.2 below.

Figure 4 – Historical Gross Plant Breakdown

Description	2010 BAP	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Accounting Standard	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,556,875	$ 1,853,567	$ 2,017,508
Distribution Plant	$ 55,778,952	$ 54,421,747	$ 58,696,440	$ 63,997,158	$ 69,060,163	$ 74,780,571	$ 82,012,540	$ 86,694,126	$ 91,805,950	$ 96,903,200
General Plant	$ 4,973,738	$ 4,724,845	$ 4,975,699	$ 6,247,373	$ 6,697,485	$ 7,184,579	$ 7,732,047	$ 6,767,688	$ 8,017,638	$ 8,939,447
Contribution & Grants	$ (10,400,516)	$ (10,063,338)	$ (12,003,010)	$ (12,872,862)	$ (15,064,761)	$ (16,186,932)	$ (17,635,115)	$ (18,566,136)	$ (19,790,893)	$ (21,015,650)
Total Gross Assets	**$ 50,352,174**	**$ 49,083,254**	**$ 51,669,129**	**$ 57,371,669**	**$ 60,692,887**	**$ 65,778,218**	**$ 72,109,471**	**$ 76,452,553**	**$ 81,886,262**	**$ 86,844,505**

2.2.2 Variance Analysis on Gross Asset Additions

This section was prepared by EPLC in order to explain year over year variance by USoA account. EPLC used a materiality threshold of $65,000 identified by cells highlighted in red in each of the figures within this section.

2010 BAP Vs. 2010 Actual

EPLC experienced a net decrease in Gross Assets of $1,268,920 between the 2010 BAP and 2010 Actual.

Figure 5 – 2010 BAP vs. 2010 Actual – By Account

USoA	Description	2010 BAP	2010 Actual	Variance
	Intangible Plant			
1611	Computer Software	$ -	$ -	$ -
1612	Land Rights	$ -	$ -	$ -
	Subtotal	**$ -**	**$ -**	**$ -**
	Distribution Plant			
1805	Land	$ 47,899	$ 47,899	$ 0
1806	Land Rights	$ 71,972	$ 97,579	$ 25,607
1820	Distribution Station Equipment < 50 kV	$ 95,292	$ 102,722	$ 7,430
1830	Poles, Towers & Fixtures	$ 5,954,727	$ 5,731,639	$ (223,088)
1835	Overhead Conductors & Devices	$ 6,262,137	$ 5,495,913	$ (766,224)
1840	Underground Conduit	$ 8,874,535	$ 8,523,236	$ (351,299)
1845	Underground Conduit & Devices	$ 10,420,429	$ 10,289,850	$ (130,579)
1850	Line Transformers	$ 13,622,935	$ 13,356,674	$ (266,261)
1855	Services	$ 7,264,023	$ 6,818,570	$ (445,453)
1860	Meters	$ 3,165,003	$ 3,957,664	$ 792,661
1860	Meters - Smart Meter Sub-Account	$ -	$ -	$ -
	Subtotal	**$ 55,778,952**	**$ 54,421,747**	**$(1,357,205)**
	General Plant			
1905	Land	$ 191,700	$ 190,119	$ (1,581)
1908	Building & Fixtures	$ 1,649,060	$ 1,607,140	$ (41,920)
1915	Office Furniture & Equipment	$ 142,501	$ 159,415	$ 16,914
1920	Computer Equipment - Hardware	$ 62,049	$ 251,403	$ 189,354
1925	Computer Software	$ 1,331,173	$ 1,037,697	$ (293,476)
1930	Transportation Equipment	$ 1,097,902	$ 982,829	$ (115,073)
1935	Stores Equipment	$ 24,040	$ 29,711	$ 5,671
1940	Tools, Shop & Garage Equipment	$ 200,751	$ 214,968	$ 14,217
1945	Measurement & Testing Equipment	$ 35,403	$ 54,338	$ 18,935
1955	Communication Equipment	$ 239,159	$ 197,224	$ (41,935)
	Subtotal	**$ 4,973,738**	**$ 4,724,845**	**$ (248,893)**
	Contributions & Grants			
1995	Contributions & Grants	$(10,400,516)	$(10,063,338)	$ 337,178
	Subtotal	**$(10,400,516)**	**$(10,063,338)**	**$ 337,178**
	Grand Total	**$ 50,352,174**	**$ 49,083,254**	**$(1,268,920)**

Intangible Plant

No material variance to explain.

Distribution Plant

Account 1830 – Poles, Towers & Fixtures

Typical projects that flow through Account 1830 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized a decrease of $223,088 in Account 1830 from 2010 BAP to 2010 Actual. This variance is largely made up of a one year deferral of the connection a large scale Renewable Energy Standard Offer Program ("RESOP") solar PV generator that occurs in 2011.

Significant projects in 2010 include:

- Malden Road rebuild from Todd Lane to Morton (Municipal request; job 750);
- Sunnyside 4kV Conversion F2 & F3 Phase 1 (Single Voltage Utility conversion; job 760);
- VIF3 Conversion on Elliot Street (Single Voltage Utility conversion; job 339);

Account 1835 – Overhead Conductors & Devices

Typical projects that flow through Account 1835 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized a decrease of $766,224 in Account 1835 from 2010 BAP to 2010 Actual. This variance is largely made up of a one year deferral of the connection of a planned subdivision which actually occurred in 2011.

Significant projects in 2010 include:

- Malden Road rebuild from Todd Lane to Morton (Municipal request; job 750);
- Porcelain Insulator Replacement (Insulator Replacement, job 955);

Account 1840 – Underground Conduit

Typical projects that flow through Account 1840 include:

- General engineering & operational support;
- Customer expansion requests;
- Cable Replacement projects;
- Conversion projects;
- Emergencies;

EPLC realized a decrease of $351,299 in Account 1840 from 2010 BAP to 2010 Actual. This variance is largely the result of lower than expected and budgeted cable replacement work completed in Amherstburg.

Significant projects in 2010 include:

- Lutsch to Orange Mill Conversion (Single Voltage Utility, job 658);
- Laurier Parkway Expansion (Municipal Request, job 773);
- Pacific Cable Replacement relating to Live Front removal (Cable Replacement job 696);

Account 1845 – Underground Conduit & Devices

Typical projects that flow through Account 1845 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Conversion projects;
- PMH Replacement projects;
- Emergencies;

EPLC realized a decrease of $130,579 in Account 1845 from 2010 BAP to 2010 Actual. This variance is largely the result of a delay in PMH replacement work originally planned in 2010.

Significant projects in 2010 include:

- Malden Road rebuild from Todd Lane to Morton (Municipal request; job 750);
- Vollmer Complex Expansion (Municipal Request, job 909);
- Laurier Parkway Expansion (Municipal Request, job 773);

Account 1850 – Line Transformers

Typical projects that flow through Account 1850 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Transformer Replacement program;
- PMH Replacement projects;
- Emergencies/reactive replacements;

EPLC realized a decrease of $266,261 in Account 1850 from 2010 BAP to 2010 Actual. This variance is largely the result of lower than expected transformer related work in 2010.

Significant projects in 2010 include:

- Malden Road rebuild from Todd Lane to Morton (Municipal request; job 750);
- Lutsch to Orange Mill Conversion (Single Voltage Utility, job 658);
- Leamington Pollution Control Plant Upgrade (Municipal Request, job 773);

Account 1855 – Services

Typical projects that flow through Account 1855 include:

- General engineering & operational support;
- Customer expansion requests;
- New service requests;
- Transformer Replacement program;
- Emergencies/reactive replacements;

EPLC realized a decrease of $445,453 in Account 1855 from 2010 BAP to 2010 Actual. This variance is largely the result of lower than expected services related work in 2010.

Significant projects in 2010 include:

- Leamington Pollution Control Plant Upgrade (Municipal Request, job 773);
- Oakridge Subdivision Phase 2 (Subdivision, job 848);
- Malden Road rebuild from Todd Lane to Morton (Municipal request; job 750);
- Tecumseh Road Bell Building Service (New Service Upgrade C&I, job 788);

Account 1860 – Meters

Typical projects that flow through Account 1860 include:

- Retail metering replacements;
- Commercial and industrial investments;
- Smart Metering Initiative;

EPLC realized an increase of $792,661 in Account 1860 from 2010 BAP to 2010 Actual. This variance is largely the result of the finalization of the Smart Metering Initiative installation along with various new C&I services.

General Plant

Account 1920 – Computer Equipment - Hardware

EPLC realized an increase of $189,354 in Account 1920 from 2010 BAP to 2010 Actual. This variance is largely made up of the following items:

- New Server, license and associated hardware $82k
- Two Toshiba Photocopiers $23k;
- Eleven Toughbooks for onsite information and communication for linemen and supervisors – $20k
- Hardware upgrade to facilitate Microsoft Dynamics (GP upgrade related) - $16k

Account 1925 – Computer Software

EPLC realized a decrease of $293,476 in Account 1925 from 2010 BAP to 2010 Actual. EPLC had initially planned to upgrade its financial system to Cayenta in 2010 as detailed in its previous

Cost of Service Application (EB-2009-0143). EPLC decided to move forward with Great Plains ("GP"), a different, more cost effective software platform that also provided additional functionality. GP was fully implemented in 2011 however EPLC realized approximately $341k in costs in 2010. EPLC was initially planning $795k for Cayenta. The resulting decrease in spending on GP in 2010 is the primary driver of the variance.

Account 1930 – Transportation Equipment

EPLC realized a decrease of $115,073 in Account 1930 from 2010 BAP to 2010 Actual. Additions in 2010 include:

- Purchase of trucks #66, #67, #68, #69, #70, #71 - $213k;
- Sale of small trucks #42, #48, #55 and car #57 – ($107k);
- Fleet refurbishment - $62k;
- GPS/Modems/Inverters for fleet – $55k

The primary reason for variance (decrease) from 2010 BAP and 2010 Actual is the sale of small trucks ($107k) listed above along with savings realized upon the completion of the transactions above from figures that were budgeted.

Contributions & Grants

Account 1995 – Contributions & Grants

This variance can be attributed to the following:

i) Variance in 2010 opening balance of $1,054,575;
ii) Variance in 2010 additions of $717,397;

EPLC traditionally receives approximately $1.4M per year in Capital Contributions & Grants. The 2010 Actual balance results in an increase of $267k from the average balance.

2010 Actual Vs. 2011 Actual

Figure 6 – 2010 Actual vs. 2011 Actual – By Account

USoA	Description	2010 Actual	2011 Actual	Variance
	Intangible Plant			
1611	Computer Software	$ -	$ -	$ -
1612	Land Rights	$ -	$ -	$ -
	Subtotal	**$ -**	**$ -**	**$ -**
	Distribution Plant			
1805	Land	$ 47,899	$ 47,899	$ -
1806	Land Rights	$ 97,579	$ 108,990	$ 11,410
1820	Distribution Station Equipment < 50 kV	$ 102,722	$ 103,107	$ 385
1830	Poles, Towers & Fixtures	$ 5,731,639	$ 6,006,615	$ 274,976
1835	Overhead Conductors & Devices	$ 5,495,913	$ 5,684,239	$ 188,326
1840	Underground Conduit	$ 8,523,236	$ 9,701,439	$ 1,178,203
1845	Underground Conduit & Devices	$ 10,289,850	$ 10,917,707	$ 627,858
1850	Line Transformers	$ 13,356,674	$ 14,233,655	$ 876,982
1855	Services	$ 6,818,570	$ 7,692,638	$ 874,068
1860	Meters	$ 3,957,664	$ 4,200,151	$ 242,487
1860	Meters - Smart Meter Sub-Account	$ -		$ -
	Subtotal	**$ 54,421,747**	**$ 58,696,440**	**$ 4,274,693**
	General Plant			
1905	Land	$ 190,119	$ 190,119	$ -
1908	Building & Fixtures	$ 1,607,140	$ 1,633,771	$ 26,631
1915	Office Furniture & Equipment	$ 159,415	$ 159,415	$ -
1920	Computer Equipment - Hardware	$ 251,403	$ 306,043	$ 54,640
1925	Computer Software	$ 1,037,697	$ 946,329	$ (91,368)
1930	Transportation Equipment	$ 982,829	$ 1,172,081	$ 189,253
1935	Stores Equipment	$ 29,711	$ 34,367	$ 4,656
1940	Tools, Shop & Garage Equipment	$ 214,968	$ 242,672	$ 27,703
1945	Measurement & Testing Equipment	$ 54,338	$ 63,987	$ 9,649
1955	Communication Equipment	$ 197,224	$ 226,916	$ 29,691
	Subtotal	**$ 4,724,845**	**$ 4,975,699**	**$ 250,855**
	Contributions & Grants			
1995	Contributions & Grants	$ (10,063,338)	$ (12,003,010)	$ (1,939,672)
	Subtotal	**$ (10,063,338)**	**$ (12,003,010)**	**$ (1,939,672)**
	Grand Total	**$ 49,083,254**	**$ 51,669,129**	**$ 2,585,876**

Intangible Plant

No material variance to explain.

Distribution Plant

Account 1830 – Poles, Towers & Fixtures

Typical projects that flow through Account 1830 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $274,976 in Account 1830 from 2010 Actual to 2011 Actual. This variance is largely made up of a one year deferral of the connection a RESOP solar PV generator that was originally planned in 2010, as described in the section above.

Significant projects in 2011 include:

- Helios RESOP Connection (FIT & Generation connection; job 124);
- Malden Road Conversion (Municipal request; job 750);
- Centennial primary replacement (Cable replacement; job 11-1293);

Account 1835 – Overhead Conductors & Devices

Typical projects that flow through Account 1835 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $188,326 in Account 1835 from 2010 Actual to 2011 Actual. This variance is largely made up of new connection requests that EPLC is required to facilitate.

Significant projects in 2011 include:

- Trillium Subdivision (Subdivision, job 1151);
- Sunnyside F2 Conversion Boismier to Maple (Single Voltage Utility, job 894);
- Victory Subdivision Phase 4 (Subdivision, job 11-1304);

Account 1840 – Underground Conduit

Typical projects that flow through Account 1840 include:

- General engineering & operational support;
- Customer expansion requests;
- Cable Replacement projects;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $1,178,203 in Account 1840 from 2010 Actual to 2011 Actual. This variance is largely a result of lower than expected cable replacement work completed in 2010 which was caught up in 2011.

Significant projects in 2011 include:

- End of Life Cable Replacement – Amherstburg (Cable Replacement program, job 696);

Account 1845 – Underground Conduit & Devices

Typical projects that flow through Account 1845 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Conversion projects;
- PMH Replacement projects;
- Emergencies;

EPLC realized an increase of $627,858 in Account 1845 from 2010 Actual to 2011 Actual. This variance is largely the result of a delay in PMH replacement work originally planned in 2010, moved to 2011 and beyond.

Significant projects in 2011 include:

- General Amherst Three Phase Loop Upgrade (New Service Upgrades C&I, job 883);
- Sandwich Street PMH Replacement (PMH Replacement Program, job 11-1321)
- MVI PMH224 Replacement (PMH Replacement Program, job 11-1255);
- Dillon Reactive Transformer & Line Replacement (Primary Cable Replacement, 1190);

Account 1850 – Line Transformers

Typical projects that flow through Account 1850 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Transformer Replacement program;
- PMH Replacement projects;
- Emergencies/reactive replacements;

EPLC realized an increase of $876,982 in Account 1850 from 2010 Actual to 2011 Actual. This variance is largely the result considerable storm damage that occurred in May and July of 2011.

Significant projects in 2011 include:

- July 2nd Storm Repairs (O/H Reactive Replacements; job 11-1217);
- May 29th Storm Repairs (O/H Reactive Replacements; job 11-1199);
- 6th Concession Transformer Replacement (Transformer Replacement program, job 11-1272);

Account 1855 – Services

Typical projects that flow through Account 1855 include:

- General engineering & operational support;
- Customer expansion requests;
- New service requests;

- Transformer Replacement program;
- Emergencies/reactive replacements;

EPLC realized an increase of $874,068 in Account 1855 from 2010 Actual to 2011 Actual. This variance is mainly the result of new residential secondary connections, ongoing Woodbridge Conversion as well as the installation of a retail point of supply at the Vollmer Complex in LaSalle in order to accommodate temporary switching conditions with Hydro One.

Significant projects in 2011 include:

- New Secondary Services/Connections (Residential Connection/Extension, job 12);
- Woodbridge Conversion (Single Voltage Utility Conversion, job 11-1287);
- Vollmer Complex Retail Supply Point (Municipal request; job 11-1341);

Account 1860 – Meters

Typical projects that flow through Account 1860 include:

- Retail metering replacements;
- Commercial and industrial investments;
- Smart Metering Initiative;

EPLC realized an increase of $242,487 in Account 1860 from 2010 Actual to 2011 Actual. This variance is primarily the result of the addition of new C&I services, Interval metering upgrades from A1R to A3R and the Vollmer Complex Retail Supply Point work required to accommodate temporary switching conditions with Hydro One.

General Plant

Account 1925 – Computer Software

EPLC realized a decrease of $91,368 in Account 1925 from 2010 Actual to 2011 Actual. EPLC spent approximately $36k on various software products including four GP licenses, payroll software customization and GP enhancements. EPLC also reallocated approximately $128k in GP costs to affiliated companies. This reallocation is the primary driver of the 2010 to 2011 variance.

Account 1930 – Transportation Equipment

EPLC realized an increase of $189,253 in Account 1930 from 2010 Actual to 2011 Actual. Additions in 2011 include:

- New cab, chassis & aerial device, Truck #107 - $257k;
- Sale of Single Bucket Truck – ($127k);
- Fleet refurbishment - $47k;
- GPS System for Fleet - $10k;

Contributions & Grants

Account 1995 – Contributions & Grants

While this variance is above EPLC's materiality threshold, EPLC traditionally receives approximately $1.4M per year in Capital Contributions & Grants. This contribution can vary dramatically depending on the type of development that is ongoing at the time. The 2011 Actual balance results in an increase of $539k from the average balance which is above average. This increase is as a result of greater than expected contributions collected for new subdivision and service connections.

2011 Actual Vs. 2012 Actual

Figure 7 – 2011 Actual vs. 2012 Actual – By Account

USoA	Description	2011 Actual	2012 Actual	Variance
	Intangible Plant			
1611	Computer Software	$ -	$ -	$ -
1612	Land Rights	$ -	$ -	$ -
	Subtotal	**$ -**	**$ -**	**$ -**
	Distribution Plant			
1805	Land	$ 47,899	$ 47,899	$ -
1806	Land Rights	$ 108,990	$ 115,165	$ 6,175
1820	Distribution Station Equipment < 50 kV	$ 103,107	$ 114,073	$ 10,966
1830	Poles, Towers & Fixtures	$ 6,006,615	$ 6,463,571	$ 456,957
1835	Overhead Conductors & Devices	$ 5,684,239	$ 6,414,747	$ 730,509
1840	Underground Conduit	$ 9,701,439	$ 10,656,520	$ 955,081
1845	Underground Conduit & Devices	$ 10,917,707	$ 11,570,868	$ 653,161
1850	Line Transformers	$ 14,233,655	$ 15,077,416	$ 843,761
1855	Services	$ 7,692,638	$ 8,376,599	$ 683,961
1860	Meters	$ 4,200,151	$ 5,160,299	$ 960,149
1860	Meters - Smart Meter Sub-Account	$ -	$ -	$ -
	Subtotal	**$ 58,696,440**	**$ 63,997,158**	**$ 5,300,719**
	General Plant			
1905	Land	$ 190,119	$ 190,119	$ -
1908	Building & Fixtures	$ 1,633,771	$ 2,394,956	$ 761,185
1915	Office Furniture & Equipment	$ 159,415	$ 180,243	$ 20,829
1920	Computer Equipment - Hardware	$ 306,043	$ 306,043	$ -
1925	Computer Software	$ 946,329	$ 1,186,475	$ 240,146
1930	Transportation Equipment	$ 1,172,081	$ 1,282,473	$ 110,392
1935	Stores Equipment	$ 34,367	$ 37,075	$ 2,708
1940	Tools, Shop & Garage Equipment	$ 242,672	$ 329,469	$ 86,797
1945	Measurement & Testing Equipment	$ 63,987	$ 63,987	$ -
1955	Communication Equipment	$ 226,916	$ 276,532	$ 49,617
	Subtotal	**$ 4,975,699**	**$ 6,247,373**	**$ 1,271,673**
	Contributions & Grants			
1995	Contributions & Grants	$ (12,003,010)	$ (12,872,862)	$ (869,853)
	Subtotal	**$ (12,003,010)**	**$ (12,872,862)**	**$ (869,853)**
	Grand Total	**$ 51,669,129**	**$ 57,371,669**	**$ 5,702,540**

Intangible Plant

No material variance to explain.

Distribution Plant

Account 1830 – Poles, Towers & Fixtures

Typical projects that flow through Account 1830 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $456,957 in Account 1830 from 2011 Actual to 2012 Actual. This variance is mainly attributed to increased spending on System Renewal projects and an increase in System Access spending for new connections.

Significant projects in 2012 include:

- Direct Buried Cable Replacement in Tecumseh (Direct Buried Cable Replacement program, job 1194)
- Sunnyside F1 SW70007 Conversion (Single Voltage Utility, job 12-1183)
- Underground Conversion – Franklin to Rickway (Conversion; job 12-1014);
- Laurier Parkway Phase 2 (Residential connection/extension; job 12-1191);
- Georgia F1 Conversion - Oak to Marlborough (Conversion; job 1115);

Account 1835 – Overhead Conductors & Devices

Typical projects that flow through Account 1835 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;

- Conversion projects;
- Emergencies;

EPLC realized an increase of $730,509 in Account 1835 from 2011 Actual to 2012 Actual. This variance is largely made up of new connection requests that EPLC is required to facilitate, ongoing system conversion and a large commercial renewal project.

Significant projects in 2012 include:

- HPAC Subdivision Phase 6A (Subdivision, job 12-1277);
- Beachgrove Site Upgrades (Transformer/cable replacement, job 12-1236);
- Malden F1-FS70487 Conversion to station (Conversion, job 12-1152);

Account 1840 – Underground Conduit

Typical projects that flow through Account 1840 include:

- General engineering & operational support;
- Customer expansion requests;
- Cable Replacement projects;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $955,081 in Account 1840 from 2011 Actual to 2012 Actual. This variance is largely a result of greater than expected new connections both residential and commercial.

Significant projects in 2012 include:

- HPAC Subdivision Phase 6A (Subdivision, job 12-1277);
- David/Cada Cable & Transformer Replacement (Cable replacement, job 12-1134);
- Forest Trail Subdivision Phase 1 (Subdivision, job 12-1000);
- Tecumseh Road Medical Centre (New service C&I, job 12-1021);

Account 1845 – Underground Conduit & Devices

Typical projects that flow through Account 1845 include:

- General engineering & operational support;

- Customer expansion requests;
- Livefront Transformer replacements;
- Conversion projects;
- PMH Replacement projects;
- Emergencies;

EPLC realized an increase of $653,161 in Account 1845 from 2011 Actual to 2012 Actual. This variance is the result of ongoing PMH replacement work and cable replacement work in Tecumseh.

Significant projects in 2012 include:

- Switching cubicle replacement on Centennial (PMH Replacement Program, job 12-1144);
- Direct Buried Cable Replacement in Tecumseh (Direct Buried Cable Replacement program, job 1194)

Account 1850 – Line Transformers

Typical projects that flow through Account 1850 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Transformer Replacement program;
- PMH Replacement projects;
- Emergencies/reactive replacements;

EPLC realized an increase of $876,982 in Account 1850 from 2011 Actual to 2012 Actual. This variance is related to considerable C&I related work completed throughout the year as well as a significant industrial reactive transformer replacement.

Significant projects in 2012 include:

- Morton Industrial Transformer Replacement (U/G Reactive Replacements, job 12-1286);
- Sacred Heart School Expansion (New Service Upgrade C&I, job 12-1213);
- Leamington Robson Road Livefront upgrade (Transformer Replacement Program, job 12-1099);
- 3rd Concession New Service (New Service Upgrade C&I, job 12-1220);

Account 1855 – Services

Typical projects that flow through Account 1855 include:

- General engineering & operational support;
- Customer expansion requests;
- New service requests;
- Transformer Replacement program;
- Emergencies/reactive replacements;

EPLC realized an increase of $683,961 in Account 1855 from 2011 Actual to 2012 Actual. This variance is mainly the result of new residential secondary connections, ongoing Woodbridge Conversion as well as the installation of a retail point of supply at the Vollmer Complex in LaSalle in order to accommodate temporary switching conditions with Hydro One.

Significant projects in 2012 include:

- New Secondary Services/Connections (Residential Connection/Extension, job 12-0012);
- Laurier Transformer Conversion (Residential connection/extension; job 12-1285);
- Simcoe Underground Service (Residential connection/extension, job 12-1308);
- Essex Golf Club Transformer Replacement (Transformer Replacement Project; job 12-1202);

Account 1860 – Meters

Typical projects that flow through Account 1860 include:

- Retail metering replacements;
- Commercial and industrial investments;
- Smart Metering Initiative;

EPLC realized an increase of $960,149 in Account 1860 from 2011 Actual to 2012 Actual. This variance is primarily the result of the addition of smart metering initiative capital, new C&I services and Interval metering upgrades from A1R to A3R.

General Plant

Account 1908 – Building & Fixtures

The 2012 increase in 1908 of $761,185 is related to renovations completed at EPLC's 2730 Highway #3 location. EPLC consolidated billing and customer service from its prior location at the Essex Civic Center (360 Fairview Avenue, Essex, Ontario) to the Highway #3 location as EPLC's lease was expiring and future costs were proposed to increase substantially. EPLC's entire operation is now consolidated in one building instead of being split across multiple sites.

Account 1925 – Computer Software

EPLC realized an increase of $240,146 in Account 1925 from 2011 Actual to 2012 Actual. EPLC spent approximately $172k on finalizing its GP upgrade as well as $39k on management scorecards to track year over year performance. The remaining additions include standard software license renewals required for business continuity.

Account 1930 – Transportation Equipment

EPLC realized an increase of $110,392 in Account 1930 from 2011 Actual to 2012 Actual. Additions in 2012 include:

- New Truck #108 and associated hardware - $225k;
- Sale of 3x Small Trucks – ($62k);
- Sale of 1x Large Truck – ($140k);
- CPR Defibrillators - $6k;
- Fleet refurbishment - $2k;
- 2x New Trucks - $79k

Account 1940 – Tools, Shop & Garage Equipment

EPLC realized an increase of $86,797 in Account 1940 from 2011 Actual to 2012 Actual. Additions in 2012 include:

- Meter Testing Equipment - $21k
- VON ARC Reflection System - $30k
- Miscellaneous shop/garage equipment - $35k

EPLC experience a minor increase in equipment as it relates to the implementation of the smart metering initiative.

Contributions & Grants

Account 1995 – Contributions & Grants

While this variance is above EPLC's materiality threshold, EPLC traditionally receives approximately $1.4M per year in Capital Contributions & Grants, on average. This contribution can vary dramatically depending on the type of development that is ongoing at the time. The 2012 Actual balance results in a decrease of $530k from the average balance which is below average. This decrease is as a result of greater than expected contributions collected for new subdivision and service connections in the prior year.

2012 Actual Vs. 2013 Actual

Figure 8 – 2012 Actual vs. 2013 Actual – By Account

USoA	Description	2012 Actual	2013 Actual	Variance
	Intangible Plant			
1611	Computer Software	$ -	$ -	$ -
1612	Land Rights	$ -	$ -	$ -
	Subtotal	**$ -**	**$ -**	**$ -**
	Distribution Plant			
1805	Land	$ 47,899	$ 47,899	$ -
1806	Land Rights	$ 115,165	$ 175,427	$ 60,262
1820	Distribution Station Equipment < 50 kV	$ 114,073	$ 115,505	$ 1,432
1830	Poles, Towers & Fixtures	$ 6,463,571	$ 6,852,565	$ 388,994
1835	Overhead Conductors & Devices	$ 6,414,747	$ 6,909,277	$ 494,530
1840	Underground Conduit	$ 10,656,520	$ 11,489,326	$ 832,806
1845	Underground Conduit & Devices	$ 11,570,868	$ 12,495,775	$ 924,907
1850	Line Transformers	$ 15,077,416	$ 16,432,674	$ 1,355,258
1855	Services	$ 8,376,599	$ 9,221,942	$ 845,343
1860	Meters	$ 5,160,299	$ 5,319,772	$ 159,472
1860	Meters - Smart Meter Sub-Account	$ -	$ -	$ -
	Subtotal	**$ 63,997,158**	**$ 69,060,163**	**$ 5,063,004**
	General Plant			
1905	Land	$ 190,119	$ 190,119	$ -
1908	Building & Fixtures	$ 2,394,956	$ 2,422,357	$ 27,401
1915	Office Furniture & Equipment	$ 180,243	$ 188,609	$ 8,365
1920	Computer Equipment - Hardware	$ 306,043	$ 324,149	$ 18,106
1925	Computer Software	$ 1,186,475	$ 1,252,529	$ 66,055
1930	Transportation Equipment	$ 1,282,473	$ 1,553,552	$ 271,079
1935	Stores Equipment	$ 37,075	$ 37,075	$ -
1940	Tools, Shop & Garage Equipment	$ 329,469	$ 383,628	$ 54,159
1945	Measurement & Testing Equipment	$ 63,987	$ 63,987	$ -
1955	Communication Equipment	$ 276,532	$ 281,480	$ 4,947
	Subtotal	**$ 6,247,373**	**$ 6,697,485**	**$ 450,112**
	Contributions & Grants			
1995	Contributions & Grants	$ (12,872,862)	$ (15,064,761)	$(2,191,898)
	Subtotal	**$ (12,872,862)**	**$ (15,064,761)**	**$(2,191,898)**
	Grand Total	**$ 57,371,669**	**$ 60,692,887**	**$ 3,321,218**

Intangible Plant

No material variance to explain.

Distribution Plant

Account 1830 – Poles, Towers & Fixtures

Typical projects that flow through Account 1830 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $388,994 in Account 1830 from 2012 Actual to 2013 Actual. This variance is mainly attributed to increased spending for the Detroit River International Crossing ("DRIC") project and Herb Gray Parkway.

Significant projects in 2013 include:

- LaSalle DRIC Project (Municipal request, job 13-1032);
- Monopoly Subdivision transformer & cable replacement (Conversion; job 12-1084)
- Cherrylawn livefront replacement (transformer replacement; job 12-1120);

Account 1835 – Overhead Conductors & Devices

Typical projects that flow through Account 1835 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $494,530 in Account 1835 from 2012 Actual to 2013 Actual. This variance is largely made up of new connection requests that EPLC is required to facilitate as well as ongoing system conversion.

Significant projects in 2013 include:

- Northway Subdivision Phase 2 (Subdivision, job 12-1335);
- Legacy Grove Subdivision (Subdivision, job 13-1021);
- Malden F3-Maple Conversion (Conversion, job 12-1368);

Account 1840 – Underground Conduit

Typical projects that flow through Account 1840 include:

- General engineering & operational support;
- Customer expansion requests;
- Cable Replacement projects;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $832,806 in Account 1840 from 2012 Actual to 2013 Actual. This variance is a result of greater than expected new connections both residential and a livefront transformer conversion project.

Significant projects in 2013 include:

- Lithgow livefront transformer conversion (Replacement – Lithgow Livefront Transformers, job 12-1244);
- HPAC Subdivision Phase 7A (Subdivision, job 13-1070);
- HPAC Subdivision Phase 6B (Subdivision, job 13-1424);
- Woodbridge Phase 3 (Subdivision, job 13-1226);

Account 1845 – Underground Conduit & Devices

Typical projects that flow through Account 1845 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;

- Conversion projects;
- PMH Replacement projects;
- Emergencies;

EPLC realized an increase of $924,907 in Account 1845 from 2012 Actual to 2013 Actual. This variance is the result of ongoing PMH replacement work, and the beginning of work required for the DRIC/ Herb Gray Parkway projects.

Significant projects in 2013 include:

- Various PMH Replacements (PMH Replacement Program, job 13-1001);
- DRIC Homestead Supply (Municipal Request, job 13-1033);

Account 1850 – Line Transformers

Typical projects that flow through Account 1850 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Transformer Replacement program;
- PMH Replacement projects;
- Emergencies/reactive replacements;

EPLC realized an increase of $1,355,258 in Account 1850 from 2012 Actual to 2013 Actual. This variance is mainly related to considerable Municipal Request related work in relocation of service as well as new services.

Significant projects in 2013 include:

- Richmond Terrace Service (New Service Upgrade C&I, job 13-1094);
- Service Relocation – Lacasse Park (Municipal Request, job 13-1485);
- Amherstburg Livefront upgrades (Transformer Replacement Program, job 13-1485);
- LaSalle Townhall Relocation (Municipal Request, job 13-1056);

Account 1855 – Services

Typical projects that flow through Account 1855 include:

- General engineering & operational support;
- Customer expansion requests;
- New service requests;
- Transformer Replacement program;
- Emergencies/reactive replacements;

EPLC realized an increase of $845,343 in Account 1855 from 2012 Actual to 2013 Actual. This variance is mainly the result of new commercial and industrial expansions, with the largest projects residing in Leamington and Tecumseh as well as new residential secondary connections.

Significant projects in 2013 include:

- MNSI Insulator Replacements (New Service Upgrades C&I, job 13-1006);
- Sandwich Street C&I Expansion (New Service Upgrades C&I, job 13-1084);
- New Secondary Services/Connections (Residential Connection/Extension, job 13-0012);

Account 1860 – Meters

Typical projects that flow through Account 1860 include:

- Retail metering replacements;
- Commercial and industrial investments;
- Smart Metering Initiative;

EPLC realized an increase of $159,472 in Account 1860 from 2012 Actual to 2013 Actual. This variance is primarily the result of the change out of REX1 meters along with new C&I services.

General Plant

Account 1925 – Computer Software

EPLC realized an increase of $66,055 in Account 1925 from 2012 Actual to 2013 Actual. Additions in 2013 include:

- GP to CIS Integration
- CIS Mcare Upgrade
- Smart Meter Map Program
- Work Request Upgrade

- Unbilled Revenue Program

Account 1930 – Transportation Equipment

EPLC realized an increase of $271,079 in Account 1930 from 2012 Actual to 2013 Actual. Additions in 2013 include:

- 2x New Trucks and associated hardware - $347k;
- Sale of Fleet assets – ($111k);
- Trailer - $4k;
- Fleet refurbishment - $30k;

Contributions & Grants

Account 1995 – Contributions & Grants

While this variance is above EPLC's materiality threshold, EPLC traditionally receives approximately $1.4M per year in Capital Contributions & Grants, on average. This contribution can vary dramatically depending on the type of development that is ongoing at the time. The 2013 Actual balance results in an increase of $792k from the average balance which is above average. This increase is a result of greater than expected contributions collected for new subdivision and service connections.

2013 Actual Vs. 2014 Actual

Figure 9 – 2013 Actual vs. 2014 Actual – By Account

USoA	Description	2013 Actual	2014 Actual	Variance
	Intangible Plant			
1611	Computer Software	$ -	$ -	$ -
1612	Land Rights	$ -	$ -	$ -
	Subtotal	**$ -**	**$ -**	**$ -**
	Distribution Plant			
1805	Land	$ 47,899	$ 47,899	$ -
1806	Land Rights	$ 175,427	$ 190,498	$ 15,071
1820	Distribution Station Equipment < 50 kV	$ 115,505	$ 115,505	$ -
1830	Poles, Towers & Fixtures	$ 6,852,565	$ 7,343,189	$ 490,624
1835	Overhead Conductors & Devices	$ 6,909,277	$ 7,340,765	$ 431,488
1840	Underground Conduit	$ 11,489,326	$ 12,740,042	$ 1,250,716
1845	Underground Conduit & Devices	$ 12,495,775	$ 13,335,773	$ 839,997
1850	Line Transformers	$ 16,432,674	$ 17,747,645	$ 1,314,971
1855	Services	$ 9,221,942	$ 10,266,869	$ 1,044,927
1860	Meters	$ 5,319,772	$ 5,652,387	$ 332,615
1860	Meters - Smart Meter Sub-Account	$ -	$ -	$ -
	Subtotal	**$ 69,060,163**	**$ 74,780,571**	**$ 5,720,408**
	General Plant			
1905	Land	$ 190,119	$ 190,119	$ -
1908	Building & Fixtures	$ 2,422,357	$ 2,422,357	$ -
1915	Office Furniture & Equipment	$ 188,609	$ 190,108	$ 1,499
1920	Computer Equipment - Hardware	$ 324,149	$ 367,497	$ 43,348
1925	Computer Software	$ 1,252,529	$ 1,327,398	$ 74,868
1930	Transportation Equipment	$ 1,553,552	$ 1,842,598	$ 289,046
1935	Stores Equipment	$ 37,075	$ 37,075	$ -
1940	Tools, Shop & Garage Equipment	$ 383,628	$ 461,960	$ 78,333
1945	Measurement & Testing Equipment	$ 63,987	$ 63,987	$ -
1955	Communication Equipment	$ 281,480	$ 281,480	$ -
	Subtotal	**$ 6,697,485**	**$ 7,184,579**	**$ 487,094**
	Contributions & Grants			
1995	Contributions & Grants	$ (15,064,761)	$ (16,186,932)	$ (1,122,171)
	Subtotal	**$ (15,064,761)**	**$ (16,186,932)**	**$ (1,122,171)**
	Grand Total	**$ 60,692,887**	**$ 65,778,218**	**$ 5,085,331**

Intangible Plant

No material variance to explain.

Distribution Plant

Account 1830 – Poles, Towers & Fixtures

Typical projects that flow through Account 1830 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $490,624 in Account 1830 from 2013 Actual to 2014 Actual. This variance is mainly attributed to ongoing and increased spending for the DRIC/ Herb Gray Parkway projects.

Significant projects in 2014 include:

- LaSalle DRIC Project (Municipal request, job 13-1038);
- Monopoly Subdivision Conversion Phase 2 (Conversion; job 14-270)
- Cherrylawn Conversion Phase 2 (Cable replacement; job 14-1267);
- Sunnyside F1/F2 Conversion (Single Voltage Utility, job 13-1471/13-1512);

Account 1835 – Overhead Conductors & Devices

Typical projects that flow through Account 1835 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $431,488 in Account 1835 from 2013 Actual to 2014 Actual. This variance is largely made up of new connection requests that EPLC is required to facilitate as well as refurbishment of PMH50200.

Significant projects in 2014 include:

- PMH50200 Replacement (PMH Replacement Program, job 14-1265);
- Ulster Street Subdivision (Subdivision, job 13-1513);

Account 1840 – Underground Conduit

Typical projects that flow through Account 1840 include:

- General engineering & operational support;
- Customer expansion requests;
- Cable Replacement projects;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $1,250,716 in Account 1840 from 2013 Actual to 2014 Actual. This variance is a result of new connections both residential and mid-sized commercial development.

Significant projects in 2014 include:

- Wyoming Commercial Development (New service upgrades – C&I, job 13-1506);
- Boismier Subdivision Phase 2 (Subdivision, job 14-1406);
- Naccarato Phase 2 (Subdivision, job 14-1255);

Account 1845 – Underground Conduit & Devices

Typical projects that flow through Account 1845 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Conversion projects;
- PMH Replacement projects;
- Emergencies;

EPLC realized an increase of $839,997 in Account 1845 from 2013 Actual to 2014 Actual. This variance is the result of ongoing work required for the DRIC/ Herb Gray Parkway projects, residential connections requests as well as a large municipal pumping station project.

Significant projects in 2014 include:

- Lakewood Pumping Station (Municipal request, job 14-1409);
- Seven Lakes Phase 3A (Subdivisions, job 14-1325);
- Malden Tower Service (Residential Connection/Extension, job 13-1451);
- DRIC Homestead Supply (Municipal Request, job 13-1522);

Account 1850 – Line Transformers

Typical projects that flow through Account 1850 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Transformer Replacement program;
- PMH Replacement projects;
- Emergencies/reactive replacements;

EPLC realized an increase of $1,314,971 in Account 1850 from 2013 Actual to 2014 Actual. This variance is mainly related to ongoing work to replace livefront transformers in Amherstburg as well as servicing a new industrial load.

Significant projects in 2014 include:

- Amherstburg Livefront upgrades (Transformer Replacement Program, job 14-1268);
- Setterington Industrial Service (New Service Upgrade C&I, job 14-1424);
- Blown transformer Donalda Crescent (Transformer Replacement Program, job 14-1430);

Account 1855 – Services

Typical projects that flow through Account 1855 include:

- General engineering & operational support;
- Customer expansion requests;
- New service requests;

- Transformer Replacement program;
- Emergencies/reactive replacements;

EPLC realized an increase of $1,044,927 in Account 1855 from 2013 Actual to 2014 Actual. This variance is mainly the result of new commercial and industrial expansions, with the largest projects residing in Tecumseh as well as new residential secondary connections.

Significant projects in 2014 include:

- New Riverside Drive Service (New Service Upgrades C&I, job 14-1318);
- Sandwich Street FIT Connection (FIT & Generation Connections, job 13-1461);
- New Secondary Services/Connections (Residential Connection/Extension, job 14-0012);

Account 1860 – Meters

Typical projects that flow through Account 1860 include:

- Retail metering replacements;
- Commercial and industrial investments;

EPLC realized an increase of $332,615 in Account 1860 from 2013 Actual to 2014 Actual. This variance is primarily the result of the ongoing change out of REX1 meters from 2013 along with new C&I services.

General Plant

Account 1925 – Computer Software

EPLC realized an increase of $74,868 in Account 1925 from 2013 Actual to 2014 Actual. Additions in 2014 include:

- Northstar (Billing System) Upgrade;
- Work Estimation Update;
- MIS System Software

Account 1930 – Transportation Equipment

EPLC realized an increase of $289,046 in Account 1930 from 2013 Actual to 2014 Actual. Additions in 2014 include:

- Sale of Fleet assets – ($136k);
- Fleet refurbishment - $425k;

2014 saw a sharp increase in refurbishment required to maintain the safety and integrity of EPLC's existing fleet including approximately $202k for significant maintenance and body work on a bucket truck, $85k for new cab & chassis for truck #107 and $68k for refurbishing an F550.

Account 1940 – Tools, Shop & Garage Equipment

EPLC realized an increase of $78,333 in Account 1940 from 2013 Actual to 2014 Actual. Additions in 2014 include:

- Forklift - $55k
- Miscellaneous shop/garage equipment - $24k

EPLC experience a minor increase in equipment as a result of a forklift purchase required to safely load trucks and move distribution related equipment.

Contributions & Grants

Account 1995 – Contributions & Grants

While this variance is above EPLC's materiality threshold, EPLC traditionally receives approximately $1.4M per year in Capital Contributions & Grants, on average. This contribution can vary dramatically depending on the type of development that is ongoing at the time. The 2014 Actual balance results in a decrease of $278k from the average balance which is below average. This decrease is a result of greater than expected contributions collected for new subdivision and service connections in the prior year.

2014 Actual Vs. 2015 Actual

Figure 10 – 2014 Actual vs. 2015 Actual – By Account

USoA	Description	2014 Actual	2015 Actual	Variance
	Intangible Plant			
1611	Computer Software	$ -	$ -	$ -
1612	Land Rights	$ -	$ -	$ -
	Subtotal	**$ -**	**$ -**	**$ -**
	Distribution Plant			
1805	Land	$ 47,899	$ 47,899	$ -
1806	Land Rights	$ 190,498	$ 205,159	$ 14,661
1820	Distribution Station Equipment < 50 kV	$ 115,505	$ -	$ (115,505)
1830	Poles, Towers & Fixtures	$ 7,343,189	$ 8,277,989	$ 934,800
1835	Overhead Conductors & Devices	$ 7,340,765	$ 8,330,924	$ 990,160
1840	Underground Conduit	$ 12,740,042	$ 13,019,342	$ 279,301
1845	Underground Conduit & Devices	$ 13,335,773	$ 13,920,280	$ 584,507
1850	Line Transformers	$ 17,747,645	$ 18,562,128	$ 814,483
1855	Services	$ 10,266,869	$ 11,329,169	$ 1,062,301
1860	Meters	$ 5,652,387	$ 4,484,564	$(1,167,823)
1860	Meters - Smart Meter Sub-Account	$ -	$ 3,835,084	$ 3,835,084
	Subtotal	**$ 74,780,571**	**$ 82,012,540**	**$ 7,231,969**
	General Plant			
1905	Land	$ 190,119	$ 190,119	$ -
1908	Building & Fixtures	$ 2,422,357	$ 2,471,271	$ 48,914
1915	Office Furniture & Equipment	$ 190,108	$ 196,088	$ 5,980
1920	Computer Equipment - Hardware	$ 367,497	$ 371,372	$ 3,875
1925	Computer Software	$ 1,327,398	$ 1,344,441	$ 17,043
1930	Transportation Equipment	$ 1,842,598	$ 2,244,755	$ 402,157
1935	Stores Equipment	$ 37,075	$ 37,092	$ 17
1940	Tools, Shop & Garage Equipment	$ 461,960	$ 518,499	$ 56,539
1945	Measurement & Testing Equipment	$ 63,987	$ 63,987	$ -
1955	Communication Equipment	$ 281,480	$ 294,423	$ 12,943
	Subtotal	**$ 7,184,579**	**$ 7,732,047**	**$ 547,468**
	Contributions & Grants			
1995	Contributions & Grants	$(16,186,932)	$(17,635,115)	$(1,448,183)
	Subtotal	**$(16,186,932)**	**$(17,635,115)**	**$(1,448,183)**
	Grand Total	**$ 65,778,218**	**$ 72,109,471**	**$ 6,331,254**

Intangible Plant

No material variance to explain.

Distribution Plant

Account 1820 – Distribution Station Equipment <50 kV

As part of EPLC's Single Voltage Utility initiative, EPLC successfully retired all distribution substations feeding its customers in 2015. This retirement is the sole cause of the variance in 2015.

Account 1830 – Poles, Towers & Fixtures

Typical projects that flow through Account 1830 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $934,800 in Account 1830 from 2014 Actual to 2015 Actual. This variance is mainly attributed to ongoing and increased spending for the DRIC/ Herb Gray Parkway projects as well as the beginning of the Pole Replacement program in Amherstburg.

Significant projects in 2015 include:

- Howard/Huron Line Conversion related to DRIC (Conversion, job 15-1493)
- LaSalle DRIC Project (Municipal request, job 13-1036);
- Amherstburg Pole Replacement (Pole Replacement program, job 15-1606)
- Sunnyside F2 Conversion (Single Votlage Utility, job 13-1498)
- Golfwood Subdivision (Subdivisions, job 12-1225)

Account 1835 – Overhead Conductors & Devices

Typical projects that flow through Account 1835 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $990,160 in Account 1835 from 2014 Actual to 2015 Actual. This variance is largely made up of new connection requests that EPLC is required to facilitate, significant investment in cable replacement and the removal of porcelain insulators in Tecumseh and Leamington.

Significant projects in 2015 include:

- Porcelain insulator replacement – Tecumseh/Leamington (Insulator Replacement Program, job 15-1600, 13-1337);
- Cherrylawn Phase 2 Cable Replacement (Primary Cable Replacement, job 14-1267);
- New commercial connection Seacliff Drive (New service C&I, job 15-1629);

Account 1840 – Underground Conduit

Typical projects that flow through Account 1840 include:

- General engineering & operational support;
- Customer expansion requests;
- Cable Replacement projects;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $279,301 in Account 1840 from 2014 Actual to 2015 Actual. This variance is a result of new connections residential subdivision connections.

Significant projects in 2015 include:

- Lakewood Subdivision (Subdivision, job 15-1540);

- Seven Lakes Phase 2A (Subdivision, job 15-1638);
- HPAC Subdivision Phase 10A & 7B (Subdivision, job 15-1678);

Account 1845 – Underground Conduit & Devices

Typical projects that flow through Account 1845 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Conversion projects;
- PMH Replacement projects;
- Emergencies;

EPLC realized an increase of $584,507 in Account 1845 from 2014 Actual to 2015 Actual. This variance is mainly the result of EPLC's ongoing PMH replacement program, Transformer Replacement program as well as residential connection requests.

Significant projects in 2015 include:

- PMH32110 Replacement (PMH Replacement Program, job 14-1266);
- Elsworth Subdivision Phase 1 (Subdivisions, job 14-1327);
- Amherstburg Livefront Replacement (Transformer Replacement program, job 15-1668);
- Amherstburg MV50120 Replacement (PMH Replacement Program, job 15-1669);

Account 1850 – Line Transformers

Typical projects that flow through Account 1850 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Transformer Replacement program;
- PMH Replacement projects;
- Emergencies/reactive replacements;

EPLC realized an increase of $814,483 in Account 1850 from 2014 Actual to 2015 Actual. This variance is related to servicing new customer connections as well as EPLC's transformer Replacement program.

Significant projects in 2015 include:

- Seven Lakes Subdivision Phases 3B and 3D (Subdivision, job 15-1505);
- Amberly Crescent Conversion (Transformer Replacement Program, job 15-1698);
- Normandy Apartment Complex (Residential Connection/Extension, job 14-1436);
- Gore Street Service Upgrade (New Service Upgrades C&I, job 15-1546);

Account 1855 – Services

Typical projects that flow through Account 1855 include:

- General engineering & operational support;
- Customer expansion requests;
- New service requests;
- Transformer Replacement program;
- Emergencies/reactive replacements;

EPLC realized an increase of $1,062,301 in Account 1855 from 2014 Actual to 2015 Actual. This variance is mainly the result of new residential secondary connections, transformer replacements and service upgrades.

Significant projects in 2015 include:

- Front Road Transformer Conversion (Transformer Replacement program, job 15-1518);
- Reaume Road New Service (Residential Connection/Extension, job 15-1566);
- New Secondary Services/Connections (Residential Connection/Extension, job 15-0012);

Account 1860 – Meters

Typical projects that flow through Account 1860 include:

- Retail metering replacements;
- Commercial and industrial investments;
- Transactions related to recovery of the Smart Metering Initiative;

EPLC realized a decrease of $1,167,823 in Account 1860 from 2014 Actual to 2015 Actual as well as an increase in 1860 Smart Metering Sub-Account of $3,835,084 over the same time period. This variance is the result of EPLC allocating the actual costs associated with the Smart Metering Initiative to the correct Board approved account in preparation of disposition in 2016.

An offsetting decrease to account 1860 occurred as a result of remaining stranded meter costs and routine metering installations and replacements, where required over the course of regular business.

General Plant

Account 1930 – Transportation Equipment

EPLC realized an increase of $402,157 in Account 1930 from 2014 Actual to 2015 Actual. Additions in 2015 include:

- Purchase of Truck #113, RBD Freightliner - $271k;
- Purchase of Truck #106, Freightliner – $99k;
- Fleet Housing Refurbishment - $21k;
- Truck refurbishment - $10k;

Contributions & Grants

Account 1995 – Contributions & Grants

While this variance is above EPLC's materiality threshold, EPLC traditionally receives approximately $1.4M per year in Capital Contributions & Grants, on average. This contribution can vary dramatically depending on the type of development that is ongoing at the time. The 2015 Actual balance results are in line with the historical average.

1 ## 2015 Actual Vs. 2016 Actual

2 **Figure 11 – 2015 Actual vs. 2016 Actual – By Account**

USoA	Description	2015 Actual	2016 Actual	Variance
	Intangible Plant			
1611	Computer Software	$ -	$ 1,349,073	$ 1,349,073
1612	Land Rights	$ -	$ 207,803	$ 207,803
	Subtotal	**$ -**	**$ 1,556,875**	**$ 1,556,875**
	Distribution Plant			
1805	Land	$ 47,899	$ 35,899	$ (12,000)
1806	Land Rights	$ 205,159	$ -	$ (205,159)
1820	Distribution Station Equipment < 50 kV	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 8,277,989	$ 8,897,418	$ 619,428
1835	Overhead Conductors & Devices	$ 8,330,924	$ 9,205,503	$ 874,579
1840	Underground Conduit	$ 13,019,342	$ 13,230,112	$ 210,770
1845	Underground Conduit & Devices	$ 13,920,280	$ 14,457,773	$ 537,493
1850	Line Transformers	$ 18,562,128	$ 19,300,481	$ 738,353
1855	Services	$ 11,329,169	$ 12,154,283	$ 825,114
1860	Meters	$ 4,484,564	$ 9,412,656	$ 4,928,093
1860	Meters - Smart Meter Sub-Account	$ 3,835,084	$ -	$(3,835,084)
	Subtotal	**$ 82,012,540**	**$ 86,694,126**	**$ 4,681,587**
	General Plant			
1905	Land	$ 190,119	$ 190,119	$ -
1908	Building & Fixtures	$ 2,471,271	$ 2,513,740	$ 42,469
1915	Office Furniture & Equipment	$ 196,088	$ 216,760	$ 20,672
1920	Computer Equipment - Hardware	$ 371,372	$ 488,700	$ 117,329
1925	Computer Software	$ 1,344,441	$ 585	$(1,343,856)
1930	Transportation Equipment	$ 2,244,755	$ 2,381,417	$ 136,662
1935	Stores Equipment	$ 37,092	$ 47,367	$ 10,275
1940	Tools, Shop & Garage Equipment	$ 518,499	$ 564,329	$ 45,830
1945	Measurement & Testing Equipment	$ 63,987	$ 70,248	$ 6,260
1955	Communication Equipment	$ 294,423	$ 294,423	$ -
	Subtotal	**$ 7,732,047**	**$ 6,767,688**	**$ (964,359)**
	Contributions & Grants			
1995	Contributions & Grants	$(17,635,115)	$(18,566,136)	$ (931,021)
	Subtotal	**$(17,635,115)**	**$(18,566,136)**	**$ (931,021)**
	Grand Total	**$ 72,109,471**	**$ 76,452,553**	**$ 4,343,082**

3

4

Intangible Plant

Account 1611 – Computer Software

EPLC realized an increase of $1,349,073 in Account 1611 from 2015 Actual to 2016 Actual. This large increase is a result of a re-allocation of Computer Software from Account 1925 to better align with direction in the APH.

Account 1612 – Land Rights

EPLC realized an increase of $205,803 in Account 1612 from 2015 Actual to 2016 Actual. This increase is a result of a re-allocation of Land Rights from Account 1806 to better align with direction in the APH.

Distribution Plant

Account 1806 – Land Rights

EPLC realized a decrease of $205,159 in Account 1806 from 2015 Actual to 2016 Actual. This decrease is a result of a re-allocation of Land Rights to Account 1612 to better align with direction in the APH.

Account 1830 – Poles, Towers & Fixtures

Typical projects that flow through Account 1830 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $619,428 in Account 1830 from 2015 Actual to 2016 Actual. This variance is attributed to EPLC's pole replacement program as well as the beginning of EPLC's Self-Healing Grid initiative for enhanced system reliability.

Significant projects in 2016 include:

- LaSalle Pole Replacement (Pole Replacement program, job 16-1619);
- Tecumseh Reclosure Installation (Self-Healing Grid, job 16-1598);
- Seven Lakes Phase 2B Subdivision (Subdivision, job 16-1691);

Account 1835 – Overhead Conductors & Devices

Typical projects that flow through Account 1835 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $874,579 in Account 1835 from 2015 Actual to 2016 Actual. This variance is largely made up of new connection requests that EPLC is required to facilitate, a significant commercial service upgrade and the ongoing removal of porcelain insulators in Leamington.

Significant projects in 2016 include:

- Ongoing Porcelain insulator replacement – Leamington (Insulator Replacement Program, job 15-1600);
- Sunnyside F1 Front from Victory to Station (Single Voltage Utility, job 14-1269);
- New commercial upgrade - Ivan (New service upgrade C&I, job 13-1413);

Account 1840 – Underground Conduit

Typical projects that flow through Account 1840 include:

- General engineering & operational support;
- Customer expansion requests;
- Cable Replacement projects;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $210,770 in Account 1840 from 2015 Actual to 2016 Actual. This variance is a result of new connections residential subdivision connections.

Significant projects in 2016 include:

- Monopoly Subdivision Phase 3 (Subdivision, job 15-1492);
- Santos Phase 2 (Subdivision, job 15-1488);
- Daytona Phase 1 (Subdivision, job 16-1731);
- Forest Trails Phase 2B (Subdivision, job 16-1682);

Account 1845 – Underground Conduit & Devices

Typical projects that flow through Account 1845 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Conversion projects;
- PMH Replacement projects;
- Emergencies;

EPLC realized an increase of $537,493 in Account 1845 from 2015 Actual to 2016 Actual. This variance is mainly the result of EPLC's ongoing PMH replacement program with the addition of some 8kV conversion work and a commercial expansion on Seacliff Drive.

Significant projects in 2016 include:

- Simcoe to Fryer 8kV Conversion (Single Voltage Utility Conversion, job 15-1693);
- Amherstburg PMH Replacements (PMH Replacement Program, job 16-1700);
- Seacliff Drive Expansion (New service upgrades C&I, job 16-1715);

Account 1850 – Line Transformers

Typical projects that flow through Account 1850 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Transformer Replacement program;
- PMH Replacement projects;
- Emergencies/reactive replacements;

EPLC realized an increase of $738,353 in Account 1850 from 2015 Actual to 2016 Actual. This variance is related to servicing new customer connections as well as EPLC's transformer Replacement program.

Significant projects in 2016 include:

- Seacliff Drive Expansion (New service upgrades C&I, job 16-1704);
- Hamilton Drive Transformer Replacement (Transformer Replacement Program, job 16-1781);
- Manning Road Condo (Residential Connection/Extension, job 15-1637);

Account 1855 – Services

Typical projects that flow through Account 1855 include:

- General engineering & operational support;
- Customer expansion requests;
- New service requests;
- Transformer Replacement program;
- Emergencies/reactive replacements;

EPLC realized an increase of $825,114 in Account 1855 from 2015 Actual to 2016 Actual. This variance is mainly the result of new residential secondary connections and service upgrades.

Significant projects in 2016 include:

- Erie Street South Service Upgrade (New Service Upgrades C&I, job 16-1592);
- Setterington service relocation (Residential Connection/Extension, job 16-1638);
- New Secondary Services/Connections (Residential Connection/Extension, job 16-0012);

Account 1860 – Meters

Typical projects that flow through Account 1860 include:

- Retail metering replacements;
- Commercial and industrial investments;
- Transactions related to recovery of the Smart Metering Initiative;

EPLC realized an increase of $4,928,093 in Account 1860 from 2015 Actual to 2016 Actual as well as a corresponding decrease in 1860 Smart Metering Sub-Account of $3,835,084 over the same time period. This variance is the result of EPLC receiving approval to recover the costs of the Smart Metering Initiative as part of its 2015 IRM (EB-2014-0072). As a result, EPLC moved the approved balance in Smart Meter Sub-Account to the main Meter account 1860. The incremental 2016 increase in account 1860 of $1,093,009 is a result of remaining stranded meter costs and routine metering installations and replacements, where required over the course of regular business.

General Plant

Account 1920 – Computer Equipment - Hardware

EPLC realized an increase of $117,329 in Account 1920 from 2015 Actual to 2016 Actual. Additions in 2016 include:

- Miscellaneous computer hardware (laptops, desktops, etc.) - $25k;
- IT Infrastructure & Security Upgrades - $103k
- Paper Folder Machine - $11k

Account 1925 – Computer Software

EPLC realized a decrease of $1,343,856 in Account 1925 from 2015 Actual to 2016 Actual. This large decrease is a result of a re-allocation of Computer Software to Account 1611 to better align with direction in the APH.

Account 1930 – Transportation Equipment

EPLC realized an increase of $136,662 in Account 1930 from 2015 Actual to 2016 Actual. Additions in 2016 include:

- Purchase of 3x small pickup Trucks - $135k;

Contributions & Grants

Account 1995 – Contributions & Grants

While this variance is above EPLC's materiality threshold, EPLC traditionally receives approximately $1.4M per year in Capital Contributions & Grants, on average. This contribution can vary dramatically depending on the type of development that is ongoing at the time. The

2016 Actual balance results in a decrease of $469k from the average balance which is below average.

1 ## 2016 Actual Vs. 2017 Bridge

2 **Figure 12 – 2016 Actual vs. 2017 Bridge – By Account**

USoA	Description	2016 Actual	2017 Bridge	Variance
	Intangible Plant			
1611	Computer Software	$ 1,349,073	$ 1,603,573	$ 254,500
1612	Land Rights	$ 207,803	$ 249,995	$ 42,192
	Subtotal	**$ 1,556,875**	**$ 1,853,568**	**$ 296,692**
	Distribution Plant			
1805	Land	$ 35,899	$ 35,899	$ -
1806	Land Rights	$ -	$ -	$ -
1820	Distribution Station Equipment < 50 kV	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 8,897,418	$ 9,829,756	$ 932,338
1835	Overhead Conductors & Devices	$ 9,205,503	$ 9,747,151	$ 541,648
1840	Underground Conduit	$ 13,230,112	$ 13,964,522	$ 734,410
1845	Underground Conduit & Devices	$ 14,457,773	$ 15,245,984	$ 788,211
1850	Line Transformers	$ 19,300,481	$ 20,326,051	$ 1,025,570
1855	Services	$ 12,154,283	$ 12,976,997	$ 822,714
1860	Meters	$ 9,412,656	$ 9,679,588	$ 266,932
1860	Meters - Smart Meter Sub-Account	$ -	$ -	$ -
	Subtotal	**$ 86,694,126**	**$ 91,805,949**	**$ 5,111,823**
	General Plant			
1905	Land	$ 190,119	$ 190,119	$ -
1908	Building & Fixtures	$ 2,513,740	$ 2,800,544	$ 286,804
1915	Office Furniture & Equipment	$ 216,760	$ 226,760	$ 10,000
1920	Computer Equipment - Hardware	$ 488,700	$ 844,851	$ 356,150
1925	Computer Software	$ 585	$ 585	$ -
1930	Transportation Equipment	$ 2,381,417	$ 2,868,417	$ 487,000
1935	Stores Equipment	$ 47,367	$ 97,367	$ 50,000
1940	Tools, Shop & Garage Equipment	$ 564,329	$ 624,329	$ 60,000
1945	Measurement & Testing Equipment	$ 70,248	$ 70,247	$ (0)
1955	Communication Equipment	$ 294,423	$ 294,423	$ -
	Subtotal	**$ 6,767,688**	**$ 8,017,642**	**$ 1,249,954**
	Contributions & Grants			
1995	Contributions & Grants	$ (18,566,136)	$ (19,790,893)	$(1,224,757)
	Subtotal	**$ (18,566,136)**	**$ (19,790,893)**	**$(1,224,757)**
	Grand Total	**$ 76,452,553**	**$ 81,886,267**	**$ 5,433,713**

3

4

Intangible Plant

Account 1611 – Computer Software

EPLC is planning an increase of $254,500 in Account 1925 from 2016 Actual to 2017 Bridge Year. Additions in 2017 include:

- Harris Reporting Tool - $10k;
- Silver Blaze – Capricorn (CIS/Customer Service upgrade) – $40k;
- GP Upgrade - $90k;
- CIS Upgrade - $50k;
- Website Update - $65k;

The GP and CIS upgrades are required in order to allow ongoing product support into the future and to ensure the integrity of the systems that have not been upgraded for several years.

Distribution Plant

EPLC plans to invest $5,154,015 in Distribution Plant assets in the 2017 Bridge Year. Between 2010 and 2016, EPLC invested, on average, approximately $5,378,730 per year. EPLC submits that its expected investments in Distribution Plant are in line with historical spending (slightly less) and therefore reasonable. Figure 13 below provides a summary of EPLC planned Distribution Plant investments.

Figure 13 – 2017 Bridge Year Distribution Plant

Description	2017 Bridge
Residential Connections	$ 761,636
C&I Connections	$ 349,960
Conversions	$ 1,847,151
Municipal Requests & Asset Purchases	$ 770,360
FIT & Generation Connections	$ 188,892
Smart Grid/Self Healing Grid	$ 264,843
Replacements	$ 826,699
Emergencies	$ 144,474
Distribution Plant Total	**$ 5,154,015**

The following is a breakdown of Distribution Plant by category. Since values for 2017 are forecast only, they are not presented by account.

Residential Connections

Residential connections relate to the planned/forecast work required to facilitate connection of new residential customers to the distribution system as well as expand existing services, where required. In 2017, EPLC plans to invest $761,636 in residential connections where $375,000 relates to new connections and $386,636 relates to residential expansions. These values are based on historical spending and trending.

C&I Connections

C&I connections relate to the planned/forecasted work required to facilitate connection of new C&I customers to the distribution system as well as expand existing services, where required. In 2017, EPLC plans to invest $349,960 in C&I connections. These values are based on historical spending and trending.

Conversions

Conversion projects generally relate to upgrading existing 4kV/8kV distribution assets to 27.6kV. In 2017, EPLC plans to invest $1,847,151 in conversion projects. The following is a brief summary of planned conversion projects for 2017 which relate to the finalization of EPLC's Single Voltage Utility Initiative and the continuation of EPLC's Direct Buried Cable Replacement program:

- 8kV conversion from Gore to Dalhousie in Amherstburg. Removal of SD50002. Estimated cost of $425,000. This is a Single Voltage Utility Initiative;

- 4kV conversion of Main Street North in Amherstburg. Estimated cost $160,000. This is a Single Voltage Utility Initiative;

- Front road conversion in LaSalle. Estimated cost of $80,000. This is a Single Voltage Utility Initiative;

- Conversion of near end of life Direct Buried Cable, mainly located in residential backyards, allowed through easements, to front yard right of way. Estimated cost of $1,229,416. This is a Direct Buried Cable Replacement initiative;

Municipal Requests & Asset Purchases

Municipal Requests & Asset Purchases relate to planned/forecasted asset relocation work as well as asset purchases from HONI, where required. Types of asset relocations include road widening projects, right of way improvements, etc. EPLC typically sees one or two major municipal request per year.

EPLC also anticipates that HONI asset purchase will be required to facilitate long term load transfer removal as well to accommodate significant HONI work currently ongoing in the Leamington and Amherstburg service territories.

In 2017, EPLC plans to invest $770,360 in Municipal Requests & Asset Purchases where $600,000 relates to Municipal Requests and $170,360 relates to HONI asset purchase. These values are based on historical spending and trending.

FIT & Generation Connections

FIT & Generation connections relate to the planned/forecasted work required to facilitate connection of new FIT and other generation customers (ie. microFIT, net metering, merchant generation, etc.) to the distribution system. In 2017, EPLC plans to invest $188,892 in FIT & Generation connections. These values are based on historical spending and trending as well as known upcoming projects.

Smart Grid / Self-Healing Grid

Smart Grid / Self-Healing Grid refers to EPLC's planned investments to build a Self-Healing grid to reduce interruptions related to distribution/transmission plant owned by Hydro One. In 2017, EPLC plans to continue investing $264,843 in this initiative which largely relates to the installation and commissioning of reclosures at strategic points throughout its distribution system. More information can be found in EPLC's GEA Plan and DSP, included as Attachments in Exhibit 1 of this Application and as Attachment 2-C respectively.

Replacements

Replacement project generally relate to upgrading and/or replacing existing equipment that is either at end of life, not functioning as intended, damaged or deteriorated. In 2017, EPLC plans to invest $826,699 in replacement projects. The following is a brief summary of planned replacement projects for 2017:

- *Pole Replacement Program:* EPLC plans to replace approximately 119 poles in 2017 as part of its Pole Replacement Program. These poles were identified for replacement through EPLC's preventative maintenance program where core sampling was completed via pole drilling. EPLC's estimated cost in 2017 is $460,478;

- *Load Break Replacements:* EPLC has been slowly replacing approximately two load break switches per year to improve reliability, enhance distribution system operability and replace ageing assets. EPLC's estimated cost in 2017 is $58,752;

- PMH Replacement Program: Similarly to the Load Break Replacement program above, EPLC has been slowly replacing approximately two PMHs per year to improve reliability, enhance distribution system operability and replace ageing assets. EPLC's estimated cost in 2017 is $144,432;

- *Metering Upgrade & Replacement Program:* This program includes upgrading interval metering installations as a result of seal expiry, upgrades from A1R to A3R meters and GPRS upgrades for enhanced reliability and improved functionality, replacing smart meters, where required and replacing gatekeepers and modems for ongoing smart meter communication. EPLC's estimated cost in 2017 is $163,037;

Emergencies

Emergencies relate to the planned/forecasted work related to overhead and underground reactive replacements. In 2017, EPLC plans to invest $144,474 in Emergencies where $80,784 relates to forecasted overhead reactive replacements and $63,690 relates to forecasted underground reactive replacements. These values are based on historical spending and trending.

General Plant

Account 1908 – Building & Fixtures

EPLC is planning an increase of $286,804 in Account 1908 from 2016 Actual to the 2017 Bridge Year. Planned additions in 2017 include:

- Replace backup generator at operations center - $75k;
- Planned Rooftop HVAC maintenance - $36k;
- Operations Mapping Room Enhancements - $25k;
- Fleet garage drainage repair - $75k;
- New fencing at Leamington Pole Yard - $30k;
- A/C unit refurbishment in IT room - $19k;
- Miscellaneous Ops Center repairs/maintenance - $27k;

Account 1920 – Computer Equipment - Hardware

EPLC realized an increase of $356,150 in Account 1920 from 2016 Actual to 2017 Bridge Year. This variance is largely made up of the following items:

- Desktops/Laptops/Tablets/Toughbooks – $26k;
- Network/Security Appliances - $37k;
- Cybersecurity & GP Related Upgrade - $283k

In 2017, EPLC is investing in its Information Technology ("IT") infrastructure in order to be compliant with the Board's proposed Cybersecurity Framework (EB-2016-0032). For additional information about the capital requirements of the Cybersecurity Framework, please refer to EPLC's DSP which is included as Attachment 2-C of this Exhibit. The additional customer benefits of Cybersecurity Framework compliance include:

- Managed detection and response services;
- Network Interceptor Capabilities;
- Continuous Vulnerability Scanning;
- Threat Intelligence;
- Security Portal & Reporting;
- 24/7 Security Operations Centre;

Account 1930 – Transportation Equipment

EPLC is planning an increase of $487,000 in Account 1930 from 2016 Actual to the 2017 Bridge Year. Planned additions in 2017 include:

- Back RBD Truck - $250k;
- Purchase of UG Truck – $95k;
- Replacement of Truck #65 - 50k;
- Reel/Tensioner Trailer replacement - $80k;
- Yard ATV - $12k

Contributions & Grants

Account 1995 – Contributions & Grants

While this variance is above EPLC's materiality threshold, EPLC traditionally receives approximately $1.4M per year in Capital Contributions & Grants, on average. EPLC has budgeted conservative values of $1.22M for the Bridge and Test Years which are typical for years without large one time projects.

2017 Bridge Vs. 2018 Test

Figure 14 – 2017 Bridge vs. 2018 Test – By Account

USoA	Description	2017 Bridge	2018 Test	Variance
	Intangible Plant			
1611	Computer Software	$ 1,603,573	$ 1,718,573	$ 115,000
1612	Land Rights	$ 249,995	$ 298,936	$ 48,941
	Subtotal	**$ 1,853,568**	**$ 2,017,508**	**$ 163,941**
	Distribution Plant			
1805	Land	$ 35,899	$ 35,899	$ -
1806	Land Rights	$ -	$ -	$ -
1820	Distribution Station Equipment < 50 kV	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 9,829,756	$ 10,262,670	$ 432,914
1835	Overhead Conductors & Devices	$ 9,747,151	$ 10,586,627	$ 839,476
1840	Underground Conduit	$ 13,964,522	$ 14,829,081	$ 864,559
1845	Underground Conduit & Devices	$ 15,245,984	$ 16,099,450	$ 853,466
1850	Line Transformers	$ 20,326,051	$ 21,366,845	$ 1,040,794
1855	Services	$ 12,976,997	$ 13,777,367	$ 800,370
1860	Meters	$ 9,679,588	$ 9,945,259	$ 265,671
1860	Meters - Smart Meter Sub-Account	$ -	$ -	$ -
	Subtotal	**$ 91,805,949**	**$ 96,903,199**	**$ 5,097,250**
	General Plant			
1905	Land	$ 190,119	$ 190,119	$ -
1908	Building & Fixtures	$ 2,800,544	$ 3,170,540	$ 369,996
1915	Office Furniture & Equipment	$ 226,760	$ 236,760	$ 10,000
1920	Computer Equipment - Hardware	$ 844,851	$ 1,006,660	$ 161,809
1925	Computer Software	$ 585	$ 585	$ -
1930	Transportation Equipment	$ 2,868,417	$ 3,138,417	$ 270,000
1935	Stores Equipment	$ 97,367	$ 147,367	$ 50,000
1940	Tools, Shop & Garage Equipment	$ 624,329	$ 684,329	$ 60,000
1945	Measurement & Testing Equipment	$ 70,247	$ 70,247	$ -
1955	Communication Equipment	$ 294,423	$ 294,423	$ -
	Subtotal	**$ 8,017,642**	**$ 8,939,447**	**$ 921,805**
	Contributions & Grants			
1995	Contributions & Grants	$ (19,790,893)	$ (21,015,650)	$ (1,224,757)
	Subtotal	**$ (19,790,893)**	**$ (21,015,650)**	**$ (1,224,757)**
	Grand Total	**$ 81,886,267**	**$ 86,844,505**	**$ 4,958,239**

Intangible Plant

Account 1611 – Computer Software

EPLC is planning an increase of $115,000 in Account 1925 from 2017 Bridge Year to the 2018 Test Year. Planned additions in 2018 include:

- Utility Dashboard - $40k;
- ESRI ArcView/Arc Editor (GIS) Upgrade - $25k;
- New Work Estimator $30k;

Distribution Plant

EPLC plans to invest $5,146,191 in Distribution Plant assets in the 2018 Test Year. Between 2010 and 2016, EPLC invested, on average, approximately $5,378,730 per year. EPLC submits that its expected investments in Distribution Plant are in line with historical spending (slightly less) and therefore reasonable. Figure 15 below provides a summary of EPLC planned Distribution Plant investments.

Figure 15 – 2018 Test Year Distribution Plant

Description	2018 Test
Residential Connections	$ 776,869
C&I Connections	$ 356,959
Conversions	$ 2,224,410
Municipal Requests & Asset Purchases	$ 701,474
FIT & Generation Connections	$ 181,370
Smart Grid/Self Healing Grid	$ 270,140
Replacements	$ 487,606
Emergencies	$ 147,363
Distribution Plant Total	**$ 5,146,191**

The following is a breakdown of Distribution Plant by category. Since values for 2018 are forecasted only, they are not presented by account.

Residential Connections

Residential connections relate to the planned/forecasted work required to facilitate connection of new residential customers to the distribution system as well as expand existing services, where required. In 2018, EPLC plans to invest $776,869 in residential connections where $382,500 relates to new connections and $394,369 relates to residential expansions. These values are based on historical spending and trending.

C&I Connections

C&I connections relate to the planned/forecasted work required to facilitate connection of new C&I customers to the distribution system as well as expand existing services, where required. In 2018, EPLC plans to invest $356,959 in C&I connections. These values are based on historical spending and trending.

Conversions

Conversion projects generally relate to upgrading existing 4kV/8kV distribution assets to 27.6kV. In 2018, EPLC plans to invest $2,224,410 in conversion projects which related to the e continuation of EPLC's Direct Buried Cable Replacement program. The Direct Buried Cable Replacement program converts near end of life Direct Buried Cable, mainly located in residential backyards, allowed through easements, to front yard right of way.

Municipal Requests & Asset Purchases

Municipal Requests & Asset Purchases relate to planned/forecasted asset relocation work as well as asset purchases from HONI, where required. Types of asset relocations include road widening projects, right of way improvements, etc. EPLC typically sees one or two major municipal request per year.

EPLC also anticipates that HONI asset purchase will be required to facilitate long term load transfer removal as well to accommodate significant HONI work currently ongoing in the Leamington area.

In 2018, EPLC plans to invest $701,474 in Municipal Requests & Asset Purchases where $612,000 relates to Municipal Requests and $89,474 relates to HONI asset purchase. These values are based on historical spending and trending.

FIT & Generation Connections

FIT & Generation connections relate to the planned/forecasted work required to facilitate connection of new FIT and other generation customers (ie. microFIT, net metering, merchant generation, etc.) to the distribution system. In 2018, EPLC plans to invest $181,370 in FIT & Generation connections. These values are based on historical spending and trending as well as known upcoming projects.

Smart Grid / Self-Healing Grid

Smart Grid / Self-Healing Grid refers to EPLC's planned investments to build a Self-Healing grid to reduce interruptions related to distribution/transmission plant owned by Hydro One. In 2018, EPLC plans to continue investing $270,140 in this initiative which largely relates to the installation and commissioning of reclosures at strategic points throughout its distribution system. More information can be found in EPLC's GEA Plan and DSP, included as Attachments in Exhibit 1 of this Application and as Attachment 2-C respectively.

Replacements

Replacement project generally relate to upgrading and/or replacing existing equipment that is either at end of life, not functioning as intended, damaged or deteriorated. In 2018, EPLC plans to invest $487,606 in replacement projects. The following is a brief summary of planned replacement projects for 2018:

- *Pole Replacement Program:* EPLC plans to replace approximately 29 poles in 2018 as part of its Pole Replacement Program. These poles were identified for replacement through EPLC's preventative maintenance program where core sampling was completed via pole drilling. EPLC's estimated cost in 2018 is $114,062;

- *Load Break Replacements:* EPLC has been slowly replacing approximately two load break switches per year to improve reliability, enhance distribution system operability and replace ageing assets. EPLC's estimated cost in 2018 is $59,927;

- PMH Replacement Program: Similarly to the Load Break Replacement program above, EPLC has been slowly replacing approximately two PMHs per year to improve reliability, enhance distribution system operability and replace ageing assets. EPLC's estimated cost in 2018 is $147,321;

- *Metering Upgrade & Replacement Program:* This program includes upgrading interval metering installations as a result of seal expiry, upgrades from A1R to A3R meters and GPRS upgrades for enhanced reliability and improved functionality, replacing smart meters, where required and replacing gatekeepers and modems for ongoing smart meter communication. EPLC's estimated cost in 2018 is $166,297;

Emergencies

Emergencies relate to the planned/forecasted work related to overhead and underground reactive replacements. In 2018, EPLC plans to invest $147,363 in Emergencies where $82,400 relates to forecasted overhead reactive replacements and $64,964 relates to forecasted underground reactive replacements. These values are based on historical spending and trending.

General Plant

Account 1908 – Building & Fixtures

EPLC is planning an increase of $369,996 in Account 1908 from the 2017 Bridge Year to the 2018 Test Year. Planned additions in 2018 include:

- Storage Pole Barn for fleet - $300k;
- Miscellaneous Ops Center repairs/maintenance - $70k;

Additional information about EPLC's planned spending for account 1908 for the 2018 Test Year can be found in EPLC's DSP as Attachment 2-C.

Account 1920 – Computer Equipment - Hardware

EPLC realized an increase of $161,809 in Account 1920 from 2017 Bridge Year to 2018 Test Year. This variance is made up of the following items:

- Desktops/Laptops/Tablets/Toughbooks – $21k;
- Network/Security Appliances - $10k;
- Cybersecurity & GP Related Upgrade - $130k

In 2018, EPLC is planning on finalizing its initial investment in its IT infrastructure in order to be compliant with the Board's proposed Cybersecurity Framework (EB-2016-0032). For additional information about the capital requirements of the Cybersecurity Framework, please refer to EPLC's DSP which is included as Attachment 2-C of this Exhibit. The additional customer benefits of Cybersecurity Framework compliance include:

- Managed detection and response services;
- Network Interceptor Capabilities;
- Continuous Vulnerability Scanning;
- Threat Intelligence;
- Security Portal & Reporting;
- 24/7 Security Operations Centre;

Account 1930 – Transportation Equipment

EPLC is planning an increase of $270,000 in Account 1930 from the 2017 Bridge Year to the 2018 Test Year. Planned additions in 2018 include:

- Replacement of Truck #66 – $50k;
- Replacement of Truck #68 – $95k
- Replacement of Truck #69 - $95k
- Replacement of Chipper - $30k

Additional information about EPLC's fleet management and 2018 Test Year spending can be found in EPLC's DSP as Attachment 2-C.

Contributions & Grants

Account 1995 – Contributions & Grants

While this variance is above EPLC's materiality threshold, EPLC traditionally receives approximately $1.4M per year in Capital Contributions & Grants, on average. EPLC has budgeted conservative values of $1.22M for the Bridge and Test Years which are typical for years without large one time projects.

2.3 Incremental Capital Module Adjustments

EPLC confirms that it has not received any Incremental Capital Module ("ICM") adjustments as part of any previous IRM application.

EPLC is in consultation with HONI as it relates to the construction of Leamington TS. Once costs and allocations are known and better defined, EPLC plans on submitting an ICM as part of that year's IRM application.

2.4 Allowance for Working Capital

2.4.1 Overview

On June 3rd, 2015, the Board issued an update to Electricity Distributors with the following direction related to the calculation of Working Capital Allowance:

"Effective immediately, the OEB is adopting a new default value of 7.5% of the sum of the cost of power and operating, maintenance and administration costs. As in the past, distributors who not wish to use the default value can request approval for a distributor-specific working capital allowance supported by the appropriate evidence from a lead-lag study or equivalent analysis."

In accordance with the Board's direction, EPLC is using the default value of 7.5% of the sum of the cost of power and operating, maintenance and administration costs. EPLC proposes a Working Capital Allowance of $5,705,908 outlined further below as Figure 16.

Figure 16 – EPLC Working Capital Summary

Description	2010 BAP	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Accounting Standard	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Operations	$ 1,111,126	$ 740,910	$ 886,624	$ 1,029,174	$ 989,797	$ 1,328,451	$ 1,174,581	$ 1,050,289	$ 923,551	$ 1,180,903
Maintenance	$ 1,517,732	$ 1,444,596	$ 1,425,359	$ 1,740,450	$ 1,274,077	$ 1,245,495	$ 1,594,293	$ 1,439,707	$ 1,188,941	$ 1,204,436
Billing & Collecting	$ 1,459,419	$ 1,285,533	$ 1,107,563	$ 1,157,794	$ 1,322,080	$ 1,158,128	$ 1,221,816	$ 1,348,249	$ 1,499,880	$ 1,550,150
Community Relations	$ 43,646	$ 36,522	$ 35,088	$ 25,312	$ 16,142	$ 10,016	$ 19,873	$ 6,482	$ 23,442	$ 23,396
Admin & General	$ 2,068,443	$ 1,970,775	$ 2,092,295	$ 2,240,566	$ 2,400,175	$ 2,948,703	$ 2,740,229	$ 3,123,469	$ 3,563,129	$ 3,751,390
Property Taxes	$ 85,824	$ 68,136	$ 43,471	$ 43,122	$ 45,301	$ 44,568	$ 41,843	$ 41,042	$ 42,621	$ 42,538
Total Controllable Costs	**$ 6,286,190**	**$ 5,546,471**	**$ 5,590,400**	**$ 6,236,418**	**$ 6,047,573**	**$ 6,748,787**	**$ 6,806,061**	**$ 7,022,665**	**$ 7,254,991**	**$ 7,752,813**
Cost of Power	$ 47,783,568	$ 49,232,444	$ 51,143,998	$ 52,354,545	$ 51,542,202	$ 57,503,389	$ 62,236,119	$ 71,601,477	$ 67,716,983	$ 68,325,958
Total Working Capital	**$54,069,758**	**$54,778,916**	**$56,734,399**	**$58,590,963**	**$57,589,775**	**$64,252,177**	**$69,042,180**	**$78,624,142**	**$74,971,974**	**$76,078,771**
Allowance Factor	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	7.50%
Working Capital Allowance	**$ 8,110,464**	**$ 8,216,837**	**$ 8,510,160**	**$ 8,788,644**	**$ 8,638,466**	**$ 9,637,826**	**$10,356,327**	**$11,793,621**	**$11,245,796**	**$ 5,705,908**

2.4.2 Controllable Costs

In order to calculate EPLC's proposed WCA, EPLC has utilized its expected Operations, Maintenance, Billing & Collecting, Community Relations, Admin & General, property taxes and annual LEAP contributions. For additional information about EPLC's OM&A expenses, please refer to Exhibit 4 of this Application.

EPLC has included forecasted LEAP contributions by multiplying its projected 2018 Test Year Service Revenue Requirement of $13,162,895 by 0.12%. Further details about the calculation of LEAP contributions can also be found in Exhibit 4 of this Application.

2.4.3 Cost of Power

Overview

EPLC has calculated its Cost of Power ("COP") for the 2018 Test Year based on its load forecast outlined in Exhibit 3 of this Application. EPLC's load forecast has been adjusted to account for savings related to Conservation & Demand Management initiatives. Figure 17 below outlines EPLC's 2010 BAP amounts, historical balances from 2010 through 2016 and projections for the 2017 Bridge and 2018 Test Years.

Figure 17 – Cost of Power Summary

Account	Description	2010 BAP	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
4705	Power Purchased	$ 37,397,381	$ 39,264,299	$ 40,910,118	$ 41,969,005	$ 34,467,556	$ 36,636,537	$ 36,289,026	$ 40,684,266	$ 14,422,756	$ 14,148,136
4707	Global Adjustment	$ -	$ -	$ -	$ -	$ 8,069,903	$ 12,453,890	$ 17,969,068	$ 22,465,594	$ 47,475,132	$ 46,571,172
4708	WMS & RRRP	$ 4,029,222	$ 3,869,446	$ 3,686,258	$ 3,771,378	$ 2,288,747	$ 2,261,797	$ 2,120,790	$ 2,969,459	$ 2,136,299	$ 2,095,622
4714	RTSR - Network	$ 3,061,960	$ 2,943,206	$ 3,367,535	$ 3,606,709	$ 3,821,304	$ 3,498,236	$ 3,473,406	$ 3,085,440	$ 2,480,774	$ 2,170,307
4716	RTSR - Connection	$ 2,764,186	$ 2,615,703	$ 2,675,457	$ 2,500,551	$ 2,401,567	$ 2,159,619	$ 1,887,852	$ 1,848,460	$ 1,651,540	$ 1,537,179
4750	Low Voltage	$ 530,819	$ 539,791	$ 504,630	$ 506,902	$ 493,126	$ 493,310	$ 495,977	$ 548,257	$ 507,088	$ 1,524,252
4751	Smart Metering Entity					$ 46,735	$ 40,253	$ (9,827)	$ (39,364)	$ 277,527	$ 279,290
	Total	**$ 47,783,568**	**$ 49,232,444**	**$ 51,143,998**	**$ 52,354,545**	**$ 51,588,937**	**$ 57,543,642**	**$ 62,226,291**	**$ 71,562,114**	**$ 68,951,117**	**$ 68,325,958**

Power Purchased

EPLC used the "Regulated Price Plan Report – May 1 2017 to April 30 2018" (dated April 20th, 2017), published by the Board, to calculate the commodity price used for this Application. Figure 18 below outlines the information that EPLC used, more specifically from Table ES-1 on page 4 of the Board's report.

Figure 18 – Commodity Price

RPP Supply Cost Summary for the period from May 1, 2017 through April 30, 2018		
Forecast Wholesale Electricity Price		$ 22.81
Load-Weighted Price for RPP Consumers ($/MWh)		$ 24.83
Impact of the Global Adjustment ($/MWh)	+	$ 87.67
Adjustment to Address Bias Towards Unfavourable Variance ($/MWh)	+	$ 1.00
Adjustment to Clear Existing Variance ($/MWh)	+	$ 1.40
Average Supply Cost for RPP Consumers ($/MWh)	=	**$ 114.90**

EPLC used its 2016 actual consumption for both RPP and non-RPP to calculate the weighted average rate ($0.1130/kWh) summarized below in Figure 19.

Figure 19 – Commodity Price

Rate Class	RPP kWh	Non-RPP kWh	Total kWh
Residential	243,846,775	11,543,647	255,390,422
General Service < 50 kW	48,730,479	18,078,514	66,808,993
General Service > 50 to 4999 kW	21,566,532	198,051,917	219,618,449
Unmetered Scattered Load	1,086,503	467,865	1,554,368
Sentinel Lighting	306,413	29,345	335,758
Street Lighting	-	4,268,688	4,268,688
Embedded Distributor	-	-	-
Total	**315,536,702**	**232,439,976**	**547,976,678**
Allocation %	57.58%	42.42%	100.00%
Commodity Rate ($/kWh)	$ 0.1149	$ 0.1105	
Weighted Average Rate ($/kWh)	**$ 0.0662**	**$ 0.0469**	**$ 0.1130**

EPLC understands that these values can be updated to reflect more current projections prior to the approval of this Application.

Regulatory Charges

For both the 2017 Bridge Year and 2018 Test Year and as per the Decision and Order resulting from EB-2016-0362 (December 15th, 2016), EPLC used $0.0036 for Wholesale Market Service Charge ("WMS").

For both the 2017 Bridge Year and 2018 Test Year and as per the Decision and Order resulting from EB-2017-0234 (June 22nd, 2017), EPLC used $0.0003 for Rural or Remote Rate Protection ("RRRP").

Smart Metering Entity

EPLC's Smart Metering Entity ("SME") costs are calculated based on the Board approved rate of $0.79 per customer per month for all Residential and General Service < 50 kW customers as per EB-2012-0100/EB-2012-0211 (March 28th, 2013). This charge is in effect until October 31st, 2018 or as further directed by the Board.

Low Voltage

In order to calculate the 2017 Bridge Year Low Voltage charges, EPLC utilized its 2017 IRM Board approved rates (EB-2016-0069) and the results of the 2017 load forecast. The resulting charges are summarized below in Figure 20.

Figure 20 – 2017 LV Charges

Rate Class	2017 BAP LV Charges	
	kWh	kW
Residential	$ 0.0010	
General Service < 50 kW	$ 0.0010	
General Service > 50 to 4999 kW		$ 0.3506
Unmetered Scattered Load	$ 0.0010	
Sentinel Lighting		$ 0.2816
Street Lighting		$ 0.2798
Embedded Distributor		$ 0.3506

In order to calculate the proposed 2018 Test Year Low Voltage charges, EPLC utilized the processes outlined in Exhibit 8, Section 8.3. The resulting charges are summarized below in Figure 21.

Figure 21 – 2018 Proposed Low Voltage Charges

Rate Class	2018 Proposed Low Voltage	
	kWh	kW
Residential	$ 0.0031	
General Service < 50 kW	$ 0.0030	
General Service > 50 to 4999 kW		$ 1.2718
Unmetered Scattered Load	$ 0.0030	
Sentinel Lighting		$ 0.8743
Street Lighting		$ 0.8686
Embedded Distributor		$ -

RTSR Charges

In order to calculate the 2017 Bridge Year RTSR charges, EPLC utilized its 2017 IRM Board approved rates (EB-2016-0069) and the results of the 2017 load forecast. For the 2018 Test Year, EPLC utilized the RTSR rates calculated in Exhibit 8, section 8.4. The resulting calculations are summarized below as Figure 22.

Figure 22 – 2018 Proposed RTSR Charges

Rate Class	Unit	Proposed Network	Proposed Line & Connection
Residential	kWh	$ 0.0046	$ 0.0030
General Service Less Than 50 kW	kWh	$ 0.0039	$ 0.0029
General Service 50 to 4,999 kW	kW	$ 1.6326	$ 1.1567
General Service 50 to 4,999 kW – Interval Metered	kW	$ 2.0111	$ 1.2826
Unmetered Scattered Load	kWh	$ 0.0039	$ 0.0029
Sentinel Lighting	kW	$ 1.2569	$ 0.8817
Street Lighting	kW	$ 1.2393	$ 0.8760
Embedded Distributor	N/A	N/A	N/A

Cost of Power Calculations

Figure 23 below summarizes EPLC's calculation of its proposed 2017 Bridge Year and 2018 Test Year Cost of Power used for its WCA.

Figure 23 – Proposed Cost of Power - 2017/2018

Rate Class	2017 Bridge					2018 Test				
	Load Forecast	Loss Factor	Billing Determinant	Rate	Amount	Load Forecast	Loss Factor	Billing Determinant	Rate	Amount
Commodity										
Residential	247,700,344	1.0355	256,493,706	$ 0.1130	$ 28,983,789	245,374,118	1.0355	254,084,899	$ 0.1130	$ 28,711,594
General Service Less Than 50 kW	65,087,892	1.0355	67,398,512	$ 0.1130	$ 7,616,032	62,707,450	1.0355	64,933,564	$ 0.1130	$ 7,337,493
General Service 50 to 4,999 kW	179,829,958	1.0355	186,213,922	$ 0.1130	$ 21,042,173	176,280,306	1.0355	182,538,257	$ 0.1130	$ 20,626,823
Unmetered Scattered Load	1,554,368	1.0355	1,609,548	$ 0.1130	$ 181,879	1,554,368	1.0355	1,609,548	$ 0.1130	$ 181,879
Sentinel Lighting	335,758	1.0355	347,677	$ 0.1130	$ 39,288	335,758	1.0355	347,677	$ 0.1130	$ 39,288
Street Lighting	2,799,882	1.0355	2,899,278	$ 0.1130	$ 327,618	2,799,882	1.0355	2,899,278	$ 0.1130	$ 327,618
Embedded Distributor	31,681,583	1.0355	32,806,279	$ 0.1130	$ 3,707,110	29,865,554	1.0355	30,925,781	$ 0.1130	$ 3,494,613
Total					**$ 61,897,888**					**$ 60,719,308**
Regulatory Charges										
Residential	247,700,344	1.0355	256,493,706	$ 0.0039	$ 1,000,325	245,374,118	1.0355	254,084,899	$ 0.0039	$ 990,931
General Service Less Than 50 kW	65,087,892	1.0355	67,398,512	$ 0.0039	$ 262,854	62,707,450	1.0355	64,933,564	$ 0.0039	$ 253,241
General Service 50 to 4,999 kW	179,829,958	1.0355	186,213,922	$ 0.0039	$ 726,234	176,280,306	1.0355	182,538,257	$ 0.0039	$ 711,899
Unmetered Scattered Load	1,554,368	1.0355	1,609,548	$ 0.0039	$ 6,277	1,554,368	1.0355	1,609,548	$ 0.0039	$ 6,277
Sentinel Lighting	335,758	1.0355	347,677	$ 0.0039	$ 1,356	335,758	1.0355	347,677	$ 0.0039	$ 1,356
Street Lighting	2,799,882	1.0355	2,899,278	$ 0.0039	$ 11,307	2,799,882	1.0355	2,899,278	$ 0.0039	$ 11,307
Embedded Distributor	31,681,583	1.0355	32,806,279	$ 0.0039	$ 127,944	29,865,554	1.0355	30,925,781	$ 0.0039	$ 120,611
Total					**$ 2,136,299**					**$ 2,095,622**
Smart Metering Entity										
Residential	27,310		27,310	$ 0.7900	$ 258,899	27,484		27,484	$ 0.7900	$ 260,548
General Service Less Than 50 kW	1,965		1,965	$ 0.7900	$ 18,628	1,977		1,977	$ 0.7900	$ 18,742
General Service 50 to 4,999 kW	-		-	$ -	$ -	-		-	$ -	$ -
Unmetered Scattered Load	-		-	$ -	$ -	-		-	$ -	$ -
Sentinel Lighting	-		-	$ -	$ -	-		-	$ -	$ -
Street Lighting	-		-	$ -	$ -	-		-	$ -	$ -
Embedded Distributor	-		-	$ -	$ -	-		-	$ -	$ -
Total					**$ 277,527**					**$ 279,290**
Low Voltage Charges										
Residential	247,700,344	1.0000	247,700,344	$ 0.0010	$ 247,700	245,374,118	1.0000	245,374,118	$ 0.0031	$ 755,844
General Service Less Than 50 kW	65,087,892	1.0000	65,087,892	$ 0.0010	$ 65,088	62,707,450	1.0000	62,707,450	$ 0.0030	$ 186,724
General Service 50 to 4,999 kW	455,239	1.0000	455,239	$ 0.3506	$ 159,607	446,253	1.0000	446,253	$ 1.2718	$ 567,551
Unmetered Scattered Load	1,554,368	1.0000	1,554,368	$ 0.0010	$ 1,554	1,554,368	1.0000	1,554,368	$ 0.0030	$ 4,628
Sentinel Lighting	2,080	1.0000	2,080	$ 0.2816	$ 586	2,080	1.0000	2,080	$ 0.8743	$ 1,819
Street Lighting	8,848	1.0000	8,848	$ 0.2798	$ 2,476	8,848	1.0000	8,848	$ 0.8686	$ 7,686
Embedded Distributor	85,786	1.0000	85,786	$ 0.3506	$ 30,077	80,869	1.0000	80,869	$ -	$ -
Total					**$ 507,088**					**$ 1,524,252**
RTSR - Network										
Residential	247,700,344	1.0355	256,493,706	$ 0.0048	$ 1,231,170	245,374,118	1.0355	254,084,899	$ 0.0046	$ 1,168,791
General Service Less Than 50 kW	65,087,892	1.0355	67,398,512	$ 0.0041	$ 276,334	62,707,450	1.0355	64,933,564	$ 0.0039	$ 253,241
General Service 50 to 4,999 kW	455,239	1.0000	455,239	$ 2.0924	$ 952,543	446,253	1.0000	446,253	$ 1.9912	$ 888,580
Unmetered Scattered Load	1,554,368	1.0355	1,609,548	$ 0.0041	$ 6,599	1,554,368	1.0355	1,609,548	$ 0.0039	$ 6,277
Sentinel Lighting	2,080	1.0000	2,080	$ 1.3077	$ 2,720	2,080	1.0000	2,080	$ 1.2444	$ 2,588
Street Lighting	8,848	1.0000	8,848	$ 1.2894	$ 11,409	8,848	1.0000	8,848	$ 1.2270	$ 10,856
Embedded Distributor	85,786	1.0000	85,786	$ -	$ -	80,869	1.0000	80,869	$ -	$ -
Total					**$ 2,480,775**					**$ 2,330,333**
RTSR - Connection										
Residential	247,700,344	1.0355	256,493,706	$ 0.0032	$ 820,780	245,374,118	1.0355	254,084,899	$ 0.0030	$ 762,255
General Service Less Than 50 kW	65,087,892	1.0355	67,398,512	$ 0.0030	$ 202,196	62,707,450	1.0355	64,933,564	$ 0.0029	$ 188,307
General Service 50 to 4,999 kW	455,239	1.0000	455,239	$ 1.3480	$ 613,663	446,253	1.0000	446,253	$ 1.2826	$ 572,365
Unmetered Scattered Load	1,554,368	1.0355	1,609,548	$ 0.0030	$ 4,829	1,554,368	1.0355	1,609,548	$ 0.0029	$ 4,668
Sentinel Lighting	2,080	1.0000	2,080	$ 0.9267	$ 1,928	2,080	1.0000	2,080	$ 0.8817	$ 1,834
Street Lighting	8,848	1.0000	8,848	$ 0.9207	$ 8,147	8,848	1.0000	8,848	$ 0.8760	$ 7,751
Embedded Distributor	85,786	1.0000	85,786	$ -	$ -	80,869	1.0000	80,869	$ -	$ -
Total					**$ 1,651,541**					**$ 1,537,179**
Grand Total					**$ 68,951,118**					**$ 68,485,984**

2.4.4 Variance Analysis on Working Capital Allowance

EPLC has calculated year over year variances for its WCA. Figure 24 below details EPLC's calculation. This section will discuss variances in excess of EPLC's calculated materiality threshold which is discussed in Exhibit 1 of this Application.

Figure 24 – Working Capital Variance Analysis

Description	2010 BAP	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Accounting Standard	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Total Controllable Expenses	$ 6,286,190	$ 5,546,471	$ 5,590,400	$ 6,236,418	$ 6,047,573	$ 6,735,361	$ 6,792,635	$ 7,009,238	$ 7,241,564	$ 7,752,813
Total Cost of Power	$ 47,783,568	$ 49,232,444	$ 51,143,998	$ 52,354,545	$ 51,542,202	$ 57,503,389	$ 62,236,119	$ 71,601,477	$ 67,716,983	$ 68,325,958
Total Working Capital	**$ 54,069,758**	**$ 54,778,916**	**$ 56,734,399**	**$ 58,590,963**	**$ 57,589,775**	**$ 64,238,750**	**$ 69,028,753**	**$ 78,610,715**	**$ 74,958,547**	**$ 76,078,771**
Allowance Factor	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	7.50%
Working Capital Allowance	**$ 8,110,464**	**$ 8,216,837**	**$ 8,510,160**	**$ 8,788,644**	**$ 8,638,466**	**$ 9,635,812**	**$ 10,354,313**	**$ 11,791,607**	**$ 11,243,782**	**$ 5,705,908**
Variances		**2010 BAP vs. 2010 Actual**	**2010 Actual vs. 2011 Actual**	**2011 Actual vs. 2012 Actual**	**2012 Actual vs. 2013 Actual**	**2013 Actual vs. 2014 Actual**	**2014 Actual vs. 2015 Actual**	**2015 Actual vs. 2016 Actual**	**2016 Actual vs. 2017 Bridge**	**2017 Bridge vs. 2018 Test**
Total Controllable Expenses		$ (739,719)	$ 43,929	$ 646,018	$ (188,845)	$ 687,788	$ 57,274	$ 216,603	$ 232,326	$ 511,249
Total Cost of Power		$ 1,448,876	$ 1,911,554	$ 1,210,546	$ (812,342)	$ 5,961,187	$ 4,732,729	$ 9,365,359	$ (3,884,494)	$ 608,975
Total Working Capital		**$ 709,158**	**$ 1,955,483**	**$ 1,856,564**	**$ (1,001,188)**	**$ 6,648,975**	**$ 4,790,003**	**$ 9,581,962**	**$ (3,652,168)**	**$ 1,120,224**
Allowance Factor		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-7.50%
Working Capital Allowance		**$ 106,374**	**$ 293,322**	**$ 278,485**	**$ (150,178)**	**$ 997,346**	**$ 718,501**	**$ 1,437,294**	**$ (547,825)**	**$ (5,537,874)**

2010 BAP Vs. 2010 Actual

EPLC has calculated a net increase in WCA of $106,374 between the 2010 BAP and 2010 Actual results. This increase is a result of a significant increase to the Cost of Power, driven almost entirely by increases to the commodity cost of electricity (increase of $0.0060/kWh increase). The Cost of Power increase is offset by reductions to Controllable Expenses, driven mainly by efficiencies realized in the Operations department. EPLC's purchased kWh also decreased by 23,336,596 kWh.

2010 Actual Vs. 2011 Actual

EPLC has calculated a net increase in WCA of $293,322 between the 2010 Actual and 2011 Actual results. This increase is a result of a significant increase to the Cost of Power, driven almost entirely by increases to the commodity cost of electricity (increase of $0.0061/kWh). Increases to Controllable Expenses are not material. EPLC's purchased kWh also decreased by 16,048,761 kWh.

2011 Actual Vs. 2012 Actual

EPLC has calculated a net increase in WCA of $278,485 between the 2011 Actual and 2012 Actual results. This increase is a result of an increase to the Cost of Power, driven primarily by increases to the commodity cost of electricity (increase of $0.0054/kWh). EPLC's Controllable Costs increased by approximately $646k as a result of an increase in maintenance expense related to EPLC's voltage conversion initiative. EPLC's purchased kWh also decreased by 17,775,640 kWh.

2012 Actual Vs. 2013 Actual

EPLC has calculated a net decrease in WCA of $150,178 between the 2012 Actual and 2013 Actual results. This decrease is a result of a decrease to EPLC's average Cost of Power, driven primarily by a decrease in the commodity cost of electricity (decrease of $0.0013/kWh). EPLC's Controllable Costs also decreased largely as a result of a reduction/normalization of maintenance work related to EPLC's voltage conversion initiative. EPLC's purchased kWh also decreased marginally by 1,467,829 kWh.

2013 Actual Vs. 2014 Actual

EPLC has calculated a net increase in WCA of $999,360 between the 2013 Actual and 2014 Actual results. This increase is a result of an increase to the Cost of Power, driven primarily by increases to the commodity cost of electricity (increase of $0.0119/kWh). EPLC's Controllable Costs increased by approximately $701k as a result of an increase to Employee Pensions and Benefit allocations and the new bargaining unit contract terms coming into effect. EPLC's purchased kWh also decreased by 2,907,398 kWh.

2014 Actual Vs. 2015 Actual

EPLC has calculated a net increase in WCA of $718,501 between the 2014 Actual and 2015 Actual results. This increase is a result of an increase to the Cost of Power, driven primarily by increases to the commodity cost of electricity (increase of $0.0078/kWh Increases to Controllable Expenses are not material. EPLC's purchased kWh also increased by 5,596,628 kWh.

2015 Actual Vs. 2016 Actual

EPLC has calculated a net increase in WCA of $1,437,294 between the 2015 Actual and 2016 Actual results. This increase is a result of an increase to the Cost of Power, driven primarily by increases to the commodity cost of electricity (increase of $0.0130/kWh). Increases to Controllable Expenses are as a result of increases to Admin & General which are largely related to restructuring of EPLC management staff. Further information can be found in Exhibit 4 of this Application. EPLC's purchased kWh also increased by 19,233,823 kWh.

2016 Actual Vs. 2017 Bridge Year

EPLC has calculated a net decrease in WCA of $547,825 between the 2016 Actual results and 2017 Bridge Year forecast. This decrease is in small part a result of a decrease to the commodity portion of the cost of electricity (decrease of $0.0027/kWh). The WCA decrease is primarily driven by an expected decrease to EPLC's purchased kWh by 18,986,893. Increases to Controllable Expenses are mainly the result of incremental third party work required in IT to accommodate the Board's Cyber Security Framework. Further information can be found in Exhibit 4 of this Application.

2017 Actual Vs. 2018 Test Year

EPLC has calculated a net decrease in WCA of $5,537,874 between the 2017 Bridge Year and 2018 Test Year forecasts. This decrease is primarily driven by a decrease in the Working Capital Allowance factor from 15% to 7.5% as prescribed by the Board. Increases to Controllable Expenses are mainly the result of incremental third party work required in IT to accommodate the Board's Cyber Security Framework. Further information can be found in Exhibit 4 of this Application.

2.5 Treatment of Stranded Meter Assets

2.5.1 Overview

As part of the 2015 IRM (EB-2014-0072), EPLC applied for final disposition of Smart Metering Costs. Also in its 2015 IRM, EPLC stated that stranded meters would be brought forward at its next Cost of Service Application.

In this Application, EPLC is seeking disposition of $1,095,650 which represents the Net Book Value of stranded metering assets as at April 30th, 2018.

EPLC has prepared this section in accordance with the Board's *Guideline G-2011-0001, Smart Meter Funding and Cost Recovery – Final Disposition (December 15th, 2011)*.

As per Appendix A-1 of Board Guideline G-2011-0001, EPLC left stranded meters in Account 1860 and in Rate Base. The amount used in the calculation of stranded meters is based on balances accumulated in Account 1860 including labour, labour overhead, materials and expenses and vehicle related expenses, all allocated at standard EPLC rates. EPLC has been diligent in the deployment of smart meters as indicated by its installed cost below the provincial average.

Accumulated amortization of stranded metering assets was derived by estimating the year of installation, factoring the actual year of removal and using a 25 year useful life up to April 30th, 2018.

No carrying charges have been recorded for stranded metering assets, in accordance with the Accounting Procedures Handbook.

2.5.2 Stranded Meter Treatment

In accordance with Board Appendix 2-S, EPLC's proposed treatment of stranded meters is summarized below as Figure 25. The actual Board Appendix 2-S is also included as Attachment 2-B of this Exhibit.

Figure 25 –Treatment of Stranded Meters

Year	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
	(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2008	$ 65,437	$ 34,414		$ 31,023		$ 31,023
2009	$1,224,257	$ 359,336		$ 864,921		$ 864,921
2010	$2,328,222	$ 695,859		$ 1,632,363		$ 1,632,363
2011	$2,617,818	$ 858,988		$ 1,758,830		$ 1,758,830
2012	$2,617,818	$ 963,700		$ 1,654,118		$ 1,654,118
2013	$2,617,818	$ 1,068,413		$ 1,549,405		$ 1,549,405
2014	$2,617,818	$ 1,173,126		$ 1,444,692		$ 1,444,692
2015	$2,617,818	$ 1,277,838		$ 1,339,980		$ 1,339,980
2016	$2,617,818	$ 1,382,551		$ 1,235,267		$ 1,235,267
2017	$2,617,818	$ 1,487,264		$ 1,130,554		$ 1,130,554
2018	$2,617,818	$ 1,522,168		$ 1,095,650		$ 1,095,650

EPLC has included a proposed Rate Rider for the recovery of the $1,095,650 outlined in Figure 23 above. Further details are included in Exhibit 9 of this Application.

2.6 Capital Expenditures

2.6.1 Overview

In this section, EPLC has organized its capital expenditures in accordance with the work program categories in the Board's *"Filing Requirements for Electricity Distribution and Transmission Applications, Consolidated Distribution System Plan Filing Requirements"* (March 28th, 2013). Those categories are:

- System Access;
- System Renewal;
- System Service;
- General Plant;

Consistent with its DSP (Attachment 2-C), EPLC has, to the best of its ability, organized its planned spending by category as well as included an analysis of historical spending from 2010 through to the 2018 Test Year below.

EPLC actively participates in a variety of asset management and planning related initiatives within its communities and as a regional distributor. EPLC participates in Group 1 (Windsor/Essex) of the IESO's regional planning groups and also regularly meets with other entities such HONI, Union Gas, Bell, Cogeco Cable, IESO, various Provincial Ministries as well as the four municipal communities that it services. Also included in EPLC's DSP is coordinated infrastructure planning with third parties such as HONI.

EPLC is not planning any renewable energy generation capacity upgrades for the 2018 Test Year.

It should be noted that values in this section represent capital additions and does not consider Work In Progress, unless explicitly referenced.

2.6.2 Analysis of Capital Expenditures

Figure 26 below provides an overview of EPLC's historical capital expenditures by prescribed category for the years 2010 through 2017.

Figure 26 – Historical Capital Expenditure Summary

Category	2010		2011		2012		2013		2014		2015		2016		2017	
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Budget
	$ '000		$ '000		$ '000		$ '000		$ '000		$ '000		$ '000		$ '000	
System Access	Note 1	$ 1,928	Note 1	$ 1,502	Note 1	$ 1,717	Note 1	$ 1,766	Note 1	$ 2,532	Note 1	$ 2,341	Note 1	$ 1,759	Note 1	$ 1,712
System Renewal	Note 1	$ 1,675	Note 1	$ 1,833	Note 1	$ 2,698	Note 1	$ 3,113	Note 1	$ 3,012	Note 1	$ 2,695	Note 1	$ 2,125	Note 1	$ 2,655
System Service	Note 1	$ 693	Note 1	$ 940	Note 1	$ 885	Note 1	$ 185	Note 1	$ 177	Note 1	$ 2,196	Note 1	$ 1,005	Note 1	$ 787
General Plant	Note 1	$ 960	Note 1	$ 251	Note 1	$ 1,272	Note 1	$ 450	Note 1	$ 487	Note 1	$ 547	Note 1	$ 384	Note 1	$ 1,504
Total Expenditure	**$ -**	**$ 5,255**	**$-**	**$ 4,526**	**$-**	**$ 6,572**	**$-**	**$ 5,513**	**$-**	**$ 6,208**	**$-**	**$ 7,779**	**$-**	**$ 5,274**	**$ -**	**$ 6,658**
System OM&A	Note 1	$ 5,480	Note 1	$ 5,547	Note 1	$ 6,193	Note 1	$ 6,027	Note 1	$ 6,704	Note 1	$ 6,764	Note 1	$ 6,982	Note 1	$ 7,267

Figure 27 below provides an overview of ECPL's forecasted capital expenditures by prescribed category for the years 2018 through 2022.

Figure 27 – Forecasted Capital Expenditure Summary

Forecast Periods				
2018	2019	2020	2021	2022
$ '000				
$ 1,746	$ 1,781	$ 1,816	$ 1,853	$ 1,835
$ 2,693	$ 1,362	$ 2,304	$ 2,248	$ 2,195
$ 707	$ 2,186	$ 1,126	$ 1,243	$ 1,342
$ 1,037	$ 856	$ 976	$ 927	$ 968
$ 6,183	**$ 6,185**	**$ 6,222**	**$ 6,270**	**$ 6,339**
$ 7,710	$ 7,797	$ 7,834	$ 8,319	$ 8,444

Figures 26 and 27 above are consistent with Board Appendix 2-AB which is also included as Attachment 2-D of this Exhibit.

2.6.3 Variance Analysis by Spending Category

The following variance analysis is done in accordance with the materiality threshold calculated in Exhibit 1 of this Application. The materiality threshold calculated by EPLC is $65,000.

2010 Actual Vs. 2011 Actual

EPLC realized a net decrease in capital expenditures of $729,239 in 2011, relative to 2010. Figure 28 below summarizes these variances by category.

Figure 28 – 2010 Actual Vs. 2011 Actual Capital Expenditures

Category	2010 Actual	2011 Actual	Variance
System Access	$ 1,927.76	$ 1,502.38	$ (425.38)
System Renewal	$ 1,674.86	$ 1,832.55	$ 157.69
System Service	$ 692.63	$ 939.77	$ 247.14
General Plant	$ 959.55	$ 250.85	$ (708.69)
Total Expenditure	**$ 5,254.79**	**$ 4,525.55**	**$ (729.24)**

System Access

In 2011, EPLC realized a decrease in System Access of $425,380. This variance can be mainly attributed to a decrease in Municipal Request related work for the Herb Gray parkway compared to 2010, a reduction in Commercial/Industrial work related to the Leamington Pollution Control plant in Leamington and expansion of Laurier Parkway (both completed in 2010).

System Renewal

In 2011, EPLC realized an increase in System Renewal of $157,690. This variance can be mainly attributed to an increase to EPLC's Primary Cable Replacement program.

System Service

In 2011, EPLC realized an increase in System Service of $247,142. This variance can be mainly attributed significant resources being allocated to FIT & Generation connections as well as HONI asset purchases in the LaSalle area.

General Plant

In 2011, EPLC realized a decrease in General Plant of $708,691. This variance is related to limited refurbishment and investment required on EPLC buildings, computer software and hardware, fleet and tools & equipment.

2011 Actual Vs. 2012 Actual

EPLC realized a net increase in capital expenditures of $2,046,844 in 2012, relative to 2011. Figure 29 below summarizes these variances by category.

Figure 29 – 2011 Actual Vs. 2012 Actual Capital Expenditures

Category	2011 Actual	2012 Actual	Variance
System Access	$ 1,502.38	$ 1,717.27	$ 214.89
System Renewal	$ 1,832.55	$ 2,698.02	$ 865.47
System Service	$ 939.77	$ 885.44	$ (54.34)
General Plant	$ 250.85	$ 1,271.67	$ 1,020.82
Total Expenditure	**$ 4,525.55**	**$ 6,572.39**	**$ 2,046.84**

System Access

In 2012, EPLC realized an increase in System Access of $214,893. This variance can be mainly attributed to an increase in residential expansion and subdivision related work which is slightly offset in a reduction in Municipal related requests.

System Renewal

In 2012, EPLC realized an increase in System Renewal of $865,470. This variance can be mainly attributed to an increase to EPLC's Pole Replacement ($78,916), Direct Buried Cable Replacement ($667,752) and Voltage conversion ($506,294) programs with an offsetting decrease to its Primary Cable Replacement initiative ($498,387).

System Service

In 2012, EPLC realized a reduction in System Service of $54,340. This amount is deemed immaterial based on EPLC's calculated materiality threshold.

General Plant

In 2012, EPLC realized an increase in General Plant of $1,020,818. This variance is related to renovations completed at its 2730 Highway #3 location. EPLC consolidated billing and customer service from its prior location at the Essex Civic Center (360 Fairview Avenue, Essex, Ontario) to the Highway #3 location as EPLC's lease was expiring and future costs were proposed to increase substantially.

2012 Actual Vs. 2013 Actual

EPLC realized a net decrease in capital expenditures of $1,059,276 in 2013, relative to 2012. Figure 30 below summarizes these variances by category.

Figure 30 – 2012 Actual Vs. 2013 Actual Capital Expenditures

Category	2012 Actual	2013 Actual	Variance
System Access	$ 1,717.27	$ 1,765.51	$ 48.24
System Renewal	$ 2,698.02	$ 3,112.73	$ 414.71
System Service	$ 885.44	$ 184.77	$ (700.67)
General Plant	$ 1,271.67	$ 450.11	$ (821.56)
Total Expenditure	**$ 6,572.39**	**$ 5,513.12**	**$ (1,059.28)**

System Access

In 2013, EPLC realized an increase in System Access of $48,238. This amount is deemed immaterial based on EPLC's calculated materiality threshold.

System Renewal

In 2013, EPLC realized an increase in System Renewal of $414,714. This variance can be mainly attributed to an increase to EPLC's Pole Replacement program ($283,942) and addition of the Lithgow Livefront transformer replacement project ($389,704). The two aforementioned additions were slightly offset with a corresponding decrease to the Direct Buried Cable Replacement program ($196,702).

System Service

In 2013, EPLC realized a decrease in System Service of $700,666. This variance can be mainly attributed to a year over year reduction relating to the Smart Metering Initiative ($515,559) and a significant decrease relating to significant HONI asset purchases in 2012 ($218,901).

General Plant

In 2013, EPLC realized a decrease in General Plant of $821,561. This variance is largely related to the completion of renovations completed at its 2730 Highway #3 location described in 2012 above.

2013 Actual Vs. 2014 Actual

EPLC realized a net increase in capital expenditures of $694,385 in 2014, relative to 2013. Figure 31 below summarizes these variances by category.

Figure 31 – 2013 Actual Vs. 2014 Actual Capital Expenditures

Category	2013 Actual	2014 Actual	Variance
System Access	$ 1,765.51	$ 2,531.93	$ 766.43
System Renewal	$ 3,112.73	$ 3,011.97	$ (100.76)
System Service	$ 184.77	$ 176.50	$ (8.27)
General Plant	$ 450.11	$ 487.09	$ 36.98
Total Expenditure	**$ 5,513.12**	**$ 6,207.50**	**$ 694.39**

System Access

In 2014, EPLC had an increase in System Access of $766,426. This variance can be mainly attributed to an increase in Municipal Requests related to the Herb Gray Parkway project.

System Renewal

In 2014, EPLC had a decrease in System Renewal of $100,755. This variance can be mainly attributed to a decrease to EPLC's Pole Replacement ($283,942), Direct Buried Cable Replacement ($524,394) programs, completion of the Lithgow Livefront replacement ($389,704). The three aforementioned reductions were slightly offset with a corresponding increase to the Primary Cable replacement program ($713,295) and the beginning of the Monopoly subdivision conversion ($675,210).

System Service

In 2014, EPLC had a decrease in System Service of $8,267. This amount is deemed immaterial based on EPLC's calculated materiality threshold.

General Plant

In 2014, EPLC had an increase in General Plant of $36,981. This amount is deemed immaterial based on EPLC's calculated materiality threshold.

2014 Actual Vs. 2015 Actual

EPLC had a net increase in capital expenditures of $1,571,935 in 2015, relative to 2014. Figure 32 below summarizes these variances by category

Figure 32 – 2014 Actual Vs. 2015 Actual Capital Expenditures

Category	2014 Actual	2015 Actual	Variance
System Access	$ 2,531.93	$ 2,340.96	$ (190.97)
System Renewal	$ 3,011.97	$ 2,695.18	$ (316.79)
System Service	$ 176.50	$ 2,195.82	$ 2,019.32
General Plant	$ 487.09	$ 547.47	$ 60.37
Total Expenditure	**$ 6,207.50**	**$ 7,779.44**	**$ 1,571.93**

System Access

In 2015, EPLC realized a decrease in System Access of $190,972. This variance can be mainly attributed to an increase in residential expansion and subdivision related work which is offset by a significant reduction in Municipal related requests which relates to substantial completion of work for the Herb Gray Parkway project.

System Renewal

In 2015, EPLC realized a decrease in System Renewal of $316,790. This variance can be mainly attributed to a decrease to EPLC's Direct Buried Cable Replacement ($201,400), Voltage Conversion ($305,008) and Primary Cable Replacement ($599,677) programs and a reduction for the Monopoly subdivision conversion project ($415,373). The four aforementioned reductions were slightly offset with a corresponding increase to the Pole Replacement program ($142,617) and the beginning of the Insulator Replacement project ($132,486) and Howard/6th Concession conversion project ($744,587).

System Service

In 2015, EPLC realized an increase in System Service of $2,019,323. This variance is a result of the Smart Metering Initiative ($2,051,075).

General Plant

In 2015, EPLC realized an increase in General Plant of $60,375. This amount is deemed immaterial based on EPLC's calculated materiality threshold.

2015 Actual Vs. 2016 Actual

EPLC realized a net decrease in capital expenditures of $2,505,333 in 2016, relative to 2015. Figure 33 below summarizes these variances by category.

Figure 33 – 2015 Actual Vs. 2016 Actual Capital Expenditures

Category	2015 Actual	2016 Actual	Variance
System Access	$ 2,340.96	$ 1,759.27	$ (581.69)
System Renewal	$ 2,695.18	$ 2,125.34	$ (569.84)
System Service	$ 2,195.82	$ 1,005.36	$ (1,190.46)
General Plant	$ 547.47	$ 384.13	$ (163.34)
Total Expenditure	**$ 7,779.44**	**$ 5,274.10**	**$ (2,505.33)**

System Access

In 2016, EPLC realized a decrease in System Access of $581,691. This variance can be mainly attributed to a decrease in residential expansion and subdivision related work as well as completion of work for the Herb Gray Parkway project.

System Renewal

In 2016, EPLC realized a decrease in System Renewal of $569,841. This variance can be mainly attributed to the completion of the Howard/6th Concession project ($744,587) and decrease to EPLC's Voltage Conversion project ($461,232) offset by corresponding increases to the Transformer Replacement ($246,642) and Pole Replacement ($178,075) programs.

System Service

In 2016, EPLC realized a decrease in System Service of $1,190,461. This variance is a result of substantial completion of the Smart Metering Initiative ($1,963,154) project described above in 2015 offset by the commencement of EPLC's Self-Healing Grid initiative ($633,057).

General Plant

In 2016, EPLC realized a decrease in General Plant of $163,340. This variance is largely related to a substantial decrease in transportation equipment required offset by an increase in computer hardware. EPLC's fleet management required limited capital in 2016.

2016 Actual Vs. 2017 Bridge Year

EPLC is planning a net increase in capital expenditures of $1,384,361 in 2017, relative to 2016. Figure 34 below summarizes these variances by category.

Figure 34 – 2016 Actual Vs. 2017 Bridge Year Capital Expenditures

Category	2016 Actual	2017 Bridge	Variance
System Access	$ 1,759.27	$ 1,711.60	$ (47.67)
System Renewal	$ 2,125.34	$ 2,655.29	$ 529.94
System Service	$ 1,005.36	$ 787.13	$ (218.23)
General Plant	$ 384.13	$ 1,504.45	$ 1,120.32
Total Expenditure	**$ 5,274.10**	**$ 6,658.47**	**$ 1,384.36**

System Access

In 2017, EPLC is planning a decrease in System Access of $47,673. This amount is deemed immaterial based on EPLC's calculated materiality threshold.

System Renewal

In 2017, EPLC is planning an increase in System Renewal of $529,944. This variance can be mainly attributed to the planned increases to EPLC's Voltage Conversion ($531,793) and Direct Buried Cable Replacement ($856,380) programs as well as the beginning of the Overhead Rebuild program ($329,454). These increases are slightly offset by the completion of the Monopoly subdivision project ($312,264), Insulator Replacement program ($145,399) and Transformer Replacement program ($424,720).

System Service

In 2017, EPLC is planning a decrease in System Service of $218,231. This variance is a result of a reduction to EPLC's Self-Healing Grid initiative ($368,214) offset by HONI Asset Purchases in the LaSalle and Leamington areas ($170,360) and planned Feed-In-Tariff ("FIT") projects ($108,807).

General Plant

In 2017, EPLC is planning an increase in General Plant of $1,120,321. This increase is a result of three primary drivers. Approximately $244,331 of the variance relates to upgrades and required maintenance at EPLC's Highway #3 location. Approximately $238,821 of the variance relates to increase in computer hardware required for cyber security and financial system (Great Plains) upgrade. Approximately $350,338 of the variances relates to an increase in transportation equipment which is driven mainly by new backyard RBD truck.

2017 Bridge Year Vs. 2018 Test Year

EPLC is planning a net decrease in capital expenditures of $475,465 in 2018, relative to 2017. Figure 35 below summarizes these variances by category.

Figure 35 – 2017 Bridge Year Vs. 2018 Test Year Capital Expenditures

Category	2017 Bridge	2018 Test	Variance
System Access	$ 1,711.60	$ 1,745.83	$ 34.23
System Renewal	$ 2,655.29	$ 2,693.08	$ 37.80
System Service	$ 787.13	$ 707.28	$ (79.85)
General Plant	$ 1,504.45	$ 1,036.81	$ (467.64)
Total Expenditure	**$ 6,658.47**	**$ 6,183.00**	**$ (475.46)**

System Access

In 2018, EPLC is planning an increase in System Access of $34,232. This amount is deemed immaterial based on EPLC's calculated materiality threshold.

System Renewal

In 2018, EPLC is planning a decrease in System Renewal of $37,795. This amount is deemed immaterial based on EPLC's calculated materiality threshold.

System Service

In 2018, EPLC is planning a decrease in System Service of $79,851. This variance is primarily the result of a reduction in HONI Asset Purchases in the LaSalle and Leamington areas described above in 2017 ($80,886).

General Plant

In 201, EPLC is planning a decrease in General Plant of $467,641. This decrease is a result of the reduction of one-time spending related to computer hardware, transportation and building upgrades outlined in 2017 above. Further details about capital expenditures for the 2018 Test Year can be found in EPLC's DSP included as Attachment 2-C.

2019 to 2021 Forecast & Trend

EPLC is planning relatively flat net increases in capital expenditures over the course of 2019 through to 2021. Figure 36 below summarizes these variances by category along with the associated year over year variances in dollars and by percentage.

Figure 36 – 2019 to 2021 Forecast & Trend

Category	2019 Forecast	2020 Forecast	2021 Forecast
System Access	$ 1,780.74	$ 1,816.36	$ 1,852.69
System Renewal	$ 1,362.25	$ 2,303.72	$ 2,247.82
System Service	$ 2,186.07	$ 1,125.55	$ 1,243.06
General Plant	$ 855.60	$ 976.21	$ 926.84
Total Expenditure	**$ 6,184.66**	**$ 6,221.84**	**$ 6,270.40**
Year Over Year ($)		$ 37.18	$ 48.56
Year Over Year (%)		0.60%	0.78%

System Access

EPLC plans very flat and consistent System Access related capital expenditures from 2019-2021. Year over year increases are within EPLC's materiality threshold.

System Renewal

Planned System Renewal related capital expenditures are relatively flat in 2020 and 2021 however are significantly lower in 2019 as a result of planned System Service expenditures (see below). EPLC deferred portions of its Direct Buried Cable Replacement program into future years to smooth out planned investments.

System Service

Planned System Service related capital expenditures are flat in 2020 and 2021 however are significantly higher in 2019 to accommodate the planned purchase of two new breaker positions from Malden Transformer Station (estimated cost of $1,500,000). EPLC deferred other planned asset purchases and its Direct Buried Cable Replacement program (see System Renewal above) to future years in order to accommodate this purchase and also smooth capital expenditures.

General Plant

EPLC's fleet management plan is the primary cause of any year over year General Plant variance over the course of the 2019 through 2021 time periods. Planned spending in Transportation Equipment is $275,000 in 2019, $395,000 in 2020 and $445,000 in 2021.

2.6.4 Capital Projects

Figure 37 below outlines EPLC's historical capital expenditures by project, for years 2010 through 2016 and forecasted spending for the 2017 Bridge Year and 2018 Test Year. EPLC has completed Figure 37 consistent with Board Appendix 2-AA and is also included as Attachment 2-E of this Exhibit.

EPLC has provided a breakdown of all significant projects that approach its material threshold. Additionally, EPLC has also included detailed capital project summaries as part of its DSP (see Attachment 2-C).

Figure 37 – Capital Expenditures – By Project & Year

Projects	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
System Access								
Subdivisions	$ 540,677	$ 728,506	$ 240,014	$ 150,424	$ 1,020,249	$ 446,196	$ 375,000	$ 382,500
Residential Connection/Extension	$ 188,901	$ 471,954	$ 429,496	$ 677,866	$ 872,062	$ 1,050,696	$ 386,636	$ 394,369
Municipal Requests	$ 721,963	$ 140,953	$ 1,048,671	$ 1,577,009	$ 311,344	$ 12,336	$ 600,000	$ 612,000
New Service Upgrades - C&I	$ 120,392	$ 226,150	$ 100,871	$ 21,124	$ 3,767	$ 99,080	$ 349,960	$ 356,959
Miscellaneous	$ (69,558)	$ 149,705	$ (53,546)	$ 105,509	$ 133,539	$ 150,961	$ -	$ -
Subtotal - System Access	**$ 1,502,375**	**$ 1,717,268**	**$ 1,765,507**	**$ 2,531,933**	**$ 2,340,960**	**$ 1,759,269**	**$ 1,711,596**	**$ 1,745,828**
System Renewal								
Pole Replacement Program	$ 115,417	$ 194,333	$ 478,275	$ 193,281	$ 335,898	$ 513,973	$ 460,478	$ 114,062
O/H Reactive Replacements	$ 110,554	$ 6,908	$ -	$ 6,145	$ -	$ 104,563	$ 80,784	$ 82,400
U/G Reactive Replacements	$ 8,785	$ 53,159	$ 10,765	$ -	$ 6,890	$ -	$ 63,690	$ 64,964
Install/Replace Load Breaks	$ 34,236	$ 3,612	$ -	$ -	$ -	$ 64,119	$ 58,752	$ 59,927
Direct Buried Cable Replacement Program	$ 346,712	$ 1,100,768	$ 851,290	$ 299,670	$ 88,733	$ 43,582	$ 1,229,416	$ 2,224,410
PMH Replacement Program	$ 162,024	$ 27,180	$ 122,012	$ 63,630	$ 55,209	$ 135,236	$ 144,432	$ 147,321
Single Voltage Utility - Conversion	$ 423,196	$ 929,490	$ 935,091	$ 852,182	$ 547,174	$ 85,942	$ 617,735	$ -
Replacement - Lithgow Livefront Transformers	$ -	$ -	$ 389,704	$ -	$ -	$ -	$ -	$ -
Conversion - Monopoly Subdivisions	$ -	$ -	$ -	$ 675,210	$ 259,837	$ 312,264	$ -	$ -
Insulator Replacement	$ -	$ -	$ -	$ -	$ 132,486	$ 145,399	$ -	$ -
Conversion - Howard/6th Concession	$ -	$ -	$ -	$ -	$ 744,587	$ -	$ -	$ -
Primary Cable Replacement	$ 522,882	$ 24,495	$ -	$ 713,295	$ 113,618	$ 93,316	$ -	$ -
Transformer Replacement Program	$ 57,308	$ 47,978	$ 108,721	$ 143,405	$ 178,078	$ 424,720	$ -	$ -
Miscellaneous	$ 51,431	$ 310,092	$ 216,870	$ 65,157	$ 232,675	$ 202,228	$ -	$ -
Subtotal - System Renewal	**$ 1,832,545**	**$ 2,698,015**	**$ 3,112,729**	**$ 3,011,974**	**$ 2,695,184**	**$ 2,125,343**	**$ 2,655,287**	**$ 2,693,082**
System Service								
FIT & Generation Connections	$ 463,599	$ 30,227	$ 91,689	$ 25,824	$ 67,577	$ 80,085	$ 188,892	$ 181,370
HONI Asset Purchases	$ 468,859	$ 232,123	$ 13,222	$ 89,077	$ 21,142	$ -	$ 170,360	$ 89,474
Metering Upgrade & Replacement Program	$ -	$ 56,878	$ 100,139	$ 7,712	$ 8,460	$ 156,282	$ 163,037	$ 166,297
Smart Metering Initiative	$ -	$ 515,559	$ -	$ -	$ 2,051,075	$ 87,921	$ -	$ -
Self Healing Grid Reclosers	$ -	$ -	$ -	$ 61,005	$ -	$ 633,057	$ 264,843	$ 270,140
Miscellaneous	$ 7,314	$ 50,649	$ (20,282)	$ (7,117)	$ 47,571	$ 48,019	$ -	$ -
Subtotal - System Service	**$ 939,772**	**$ 885,435**	**$ 184,769**	**$ 176,502**	**$ 2,195,825**	**$ 1,005,363**	**$ 787,132**	**$ 707,281**
General Plant								
Bldgs & Fixtures	$ 13,214	$ 844,622	$ 21,981	$ -	$ 48,914	$ 42,469	$ 286,800	$ 370,000
Office Furniture/Equip	$ -	$ 29,967	$ 6,711	$ 876	$ 5,980	$ 20,672	$ 10,000	$ 10,000
Computer Equipment HW	$ 27,112	$ -	$ 13,501	$ 25,333	$ 5,837	$ 117,329	$ 356,150	$ 161,809
Computer Software	$ 17,981	$ 34,572	$ 52,989	$ 166,960	$ 17,043	$ 4,632	$ 254,500	$ 115,000
Transportation Equip	$ 156,970	$ 198,529	$ 307,516	$ 248,438	$ 401,244	$ 136,662	$ 487,000	$ 270,000
Tools & Equipment	$ 35,577	$ 163,983	$ 47,415	$ 45,486	$ 68,451	$ 62,365	$ 110,000	$ 110,000
Miscellaneous	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - General Plant	**$ 250,855**	**$ 1,271,673**	**$ 450,112**	**$ 487,094**	**$ 547,468**	**$ 384,129**	**$ 1,504,450**	**$ 1,036,809**
Total	**$ 4,525,547**	**$ 6,572,392**	**$ 5,513,117**	**$ 6,207,502**	**$ 7,779,437**	**$ 5,274,104**	**$ 6,658,465**	**$ 6,183,000**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*								
Total	**$ 4,525,547**	**$ 6,572,392**	**$ 5,513,117**	**$ 6,207,502**	**$ 7,779,437**	**$ 5,274,104**	**$ 6,658,465**	**$ 6,183,000**

2.6.5 Capitalization Policy

EPLC has included its approved Capitalization and Amortization policies as Attachment 2-F of this Exhibit.

2.6.6 Capitalization of Overhead

EPLC performed an analysis to determine whether overhead costs were eligible for capitalization under IFRS. The results of EPLC's analysis are detailed below in Figure 38. Figure 38 is consistent with Board Appendix 2-D which is included as Attachment 2-G of this Exhibit.

Figure 38 – Overhead Expense

Description	2011	2012	2013	2014	2015	2016	2017	2018
OM&A Before Capitalization	**Historical Year**	**Historical Year**	**Historical Year**	**Historical Year**	**Historical Year**	**Historical Year**	**Bridge Year**	**Test Year**
Distribution	$ 2,311,983	$ 2,769,624	$ 2,288,897	$ 2,573,946	$ 2,768,874	$ 2,489,996	$ 2,112,492	$ 2,200,339
Billing & Collecting	$ 1,131,257	$ 1,174,568	$ 1,329,771	$ 1,158,128	$ 1,229,676	$ 1,348,249	$ 1,499,880	$ 1,550,150
Community Relations	$ 11,394	$ 8,539	$ 8,451	$ 10,016	$ 12,013	$ 6,482	$ 23,442	$ 23,396
Administrative & General	$ 2,092,295	$ 2,240,566	$ 2,400,175	$ 2,962,130	$ 2,753,655	$ 3,136,895	$ 3,579,949	$ 3,796,390
Labour Burden	$ 229,006	$ 293,809	$ 370,247	$ 375,867	$ 420,809	$ 426,466	$ 486,528	$ 496,528
Material Burden	$ 415,547	$ 451,614	$ 117,111	$ 94,162	$ 92,905	$ 79,266	$ 88,476	$ 90,246
Vehicle Burden	$ 153,393	$ 234,821	$ 251,570	$ 216,004	$ 263,029	$ 228,808	$ 240,000	$ 250,000
Total OM&A Before Capitalization (B)	**$ 6,344,875**	**$ 7,173,540**	**$ 6,766,223**	**$ 7,390,252**	**$ 7,540,961**	**$ 7,716,163**	**$ 8,030,767**	**$ 8,407,049**
Capitalized OM&A								
Labour Burden	$ 229,006	$ 293,809	$ 370,247	$ 375,867	$ 420,809	$ 426,466	$ 486,528	$ 496,528
Material Burden	$ 415,547	$ 451,614	$ 117,111	$ 94,162	$ 92,905	$ 79,266	$ 88,476	$ 90,246
Vehicle Burden	$ 153,393	$ 234,821	$ 251,570	$ 216,004	$ 263,029	$ 228,808	$ 240,000	$ 250,000
Total Capitalized OM&A (A)	**$ 797,946**	**$ 980,244**	**$ 738,928**	**$ 686,033**	**$ 776,743**	**$ 734,540**	**$ 815,004**	**$ 836,774**
% of Capitalized OM&A (=A/B)	**12.6%**	**13.7%**	**10.9%**	**9.3%**	**10.3%**	**9.5%**	**10.1%**	**10.0%**

2.6.7 Costs of Eligible Investments for the Connection of Qualifying Generation Facilities

EPLC has included the total costs of $70,601.63, which includes carrying costs, for Renewable Expansion Investments incurred in 2014 and 2015. EPLC enabled the connection of two solar photovoltaic projects in its service territory that required distribution expansion above and beyond normal conditions.

The Burden Reduction Act, 2017 Schedule 10, Section (5) amended section 79.1 (1) which required the OEB to provide rate protection for costs incurred to make an eligible investment in order to connect a qualifying generation facility.

As a result, EPLC has not included Board Appendices 2-FA and 2-FC since the Renewable Expansion Investment costs are below materiality in each respective year. Further details about how EPLC intends to recover these costs are further described in Exhibit 9 of this Application.

2.6.8 Policy Options for the Funding of Capital

The Board released the *"Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module"* in September, 2014. In this report, the Board established the following mechanism to allow distributors like EPLC to better align capital spending and prioritization with enhanced rate predictability and smoothing:

> *"The review and approval of business cases for incremental capital requests that are subject to the criteria of materiality, need and prudence are advanced to coincide with the distributor's cost of service application. To distinguish this from Incremental Capital Module ("ICM"), this new mechanism will be named the Advanced Capital Module ("ACM").*
>
> *Advancing the reviews of eligible discrete capital projects, included as part of a distributor's Distribution System Plan ("DSP") and scheduled to go into service during the IR term, is expected to facilitate enhanced pacing and smoothing of rate impacts, as the distributor, the Board and other stakeholders will be examining the capital projects over the five-year horizon of the DSP."*

As per section 2.3 above, EPLC is in consultation with HONI as it relates to the construction of Leamington TS. Once costs and allocations are known and better defined, EPLC plans on submitting an ICM as part of that year's IRM application.

Should the project expand beyond an ICM and where an ACM would be required, EPLC will review and notify the Board accordingly.

2.6.9 Addition of ICM Assets to Rate Base

EPLC confirms that it has not received any Incremental Capital Module ("ICM") adjustments as part of any previous IRM application. As a result, no ICM related assets have been added to Rate Base.

2.6.10 Service Quality & Reliability Performance

The Board's Reporting and Record Keeping Requirements ("RRR") Guideline requires distributors such as EPLC to file Service Quality Indicators ("SQIs") annually. Figure 39 below outlines EPLC's last 5 historical years from 2012 through 2016.

EPLC has consistently performed at or above the Board's prescribed targets and no corrective action is currently required. EPLC plans to maintain and/or improve on the performance metrics noted. EPLC has also included Board Appendix 2-G as Attachment 2-I of this Exhibit.

Figure 39 – Service Quality Indicators

Indicator	5 Year Historical Average	2012	2013	2014	2015	2016
Including outages caused by loss of supply						
SAIDI	3.698	4.530	5.370	3.820	2.230	2.540
SAIFI	2.982	3.830	3.580	2.460	1.840	3.200
Excluding outages caused by loss of supply						
SAIDI	1.252	0.890	2.240	1.160	1.340	0.630
SAIFI	0.744	0.610	1.120	0.660	0.830	0.500
Excluding major event days						
SAIDI	1.252	0.890	2.240	1.160	1.340	0.630
SAIFI	0.744	0.610	1.120	0.660	0.830	0.500
Indicator	**OEB Minimum Standard**	**2012**	**2013**	**2014**	**2015**	**2016**
Low Voltage Connections	90%	93.2%	92.7%	93.0%	92.3%	90.5%
High Voltage Connections	90%	N/A	N/A	N/A	N/A	N/A
Telephone Accessibility	65%	68.5%	66.4%	78.0%	79.2%	73.6%
Appointments Met	90%	95.7%	94.3%	94.7%	94.8%	90.8%
Written Response to Enquires	80%	93.9%	91.2%	91.7%	84.7%	96.3%
Emergency Urban Response	80%	91.2%	92.9%	96.3%	100.0%	97.7%
Emergency Rural Response	80%	N/A	N/A	N/A	N/A	N/A
Telephone Call Abandon Rate	10%	7.0%	1.7%	1.2%	1.4%	0.8%
Appointment Scheduling	90%	96.8%	96.5%	95.5%	98.5%	98.8%
Rescheduling a Missed Appointment	100%	100.0%	100.0%	100.0%	100.0%	100.0%
Reconnection Performance Standard	85%	96.7%	93.3%	95.3%	93.7%	97.5%

Attachment 2-A

Fixed Asset Continuity Schedules

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard CGAAP
Year **2010**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 588,578	$ 449,119		$ 1,037,697	-$ 334,169	-$ 150,110		-$ 484,278	$ 553,419
CEC	1612	Land Rights (Formally known as Account 1906)	$ 62,519	$ 35,061		$ 97,579	-$ 3,399	-$ 1,601		-$ 5,000	$ 92,579
N/A	1805	Land	$ 47,899	$ -		$ 47,899				$ -	$ 47,899
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV				$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 102,722	$ -		$ 102,722	-$ 18,379	-$ 4,773		-$ 23,152	$ 79,570
47	1825	Storage Battery Equipment				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 5,278,538	$ 453,101		$ 5,731,639	-$ 528,986	-$ 114,467		-$ 643,453	$ 5,088,186
47	1835	Overhead Conductors & Devices	$ 5,161,417	$ 334,496		$ 5,495,913	-$ 2,263,290	-$ 312,857		-$ 2,576,148	$ 2,919,765
47	1840	Underground Conduit	$ 8,233,531	$ 289,706		$ 8,523,236	-$ 1,575,660	-$ 210,276		-$ 1,785,936	$ 6,737,300
47	1845	Underground Conductors & Devices	$ 9,568,801	$ 721,049		$ 10,289,850	-$ 3,172,818	-$ 450,575		-$ 3,623,393	$ 6,666,457
47	1850	Line Transformers	$ 12,047,175	$ 1,309,499		$ 13,356,674	-$ 3,280,457	-$ 528,295		-$ 3,808,752	$ 9,547,921
47	1855	Services (Overhead & Underground)	$ 6,285,635	$ 532,935		$ 6,818,570	-$ 1,686,526	-$ 277,135		-$ 1,963,661	$ 4,854,909
47	1860	Meters	$ 3,432,272	$ 525,392		$ 3,957,663	-$ 805,475	-$ 148,395		-$ 953,871	$ 3,003,793
47	1860	Meters (Smart Meters)				$ -				$ -	$ -
N/A	1905	Land	$ 191,700	$ -	-$ 1,581	$ 190,119				$ -	$ 190,119
47	1908	Buildings & Fixtures	$ 1,606,060	$ 1,080		$ 1,607,140	-$ 156,568	-$ 78,512		-$ 235,080	$ 1,372,060
13	1910	Leasehold Improvements				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 128,881	$ 30,534		$ 159,415	-$ 57,171	-$ 22,200		-$ 79,371	$ 80,044
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 61,474	$ 189,930		$ 251,403	-$ 35,039	-$ 33,616		-$ 68,655	$ 182,748
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 759,026	$ 330,900	-$ 107,097	$ 982,829	-$ 205,602	-$ 92,823	$ 107,097	-$ 191,328	$ 791,500
8	1935	Stores Equipment	$ 29,711			$ 29,711	-$ 8,435	-$ 4,448		-$ 12,883	$ 16,829
8	1940	Tools, Shop & Garage Equipment	$ 174,134	$ 40,834		$ 214,968	-$ 48,885	-$ 25,181		-$ 74,066	$ 140,902
8	1945	Measurement & Testing Equipment	$ 43,186	$ 11,152		$ 54,338	-$ 6,458	-$ 5,443		-$ 11,901	$ 42,438
8	1950	Power Operated Equipment				$ -				$ -	$ -
8	1955	Communications Equipment	$ 197,224			$ 197,224	-$ 89,671	-$ 36,741		-$ 126,412	$ 70,812
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment				$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises				$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	1980	System Supervisor Equipment				$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants	-$ 8,396,091	-$ 1,667,247		-$ 10,063,338	$ 157,227	$ 219,928		$ 377,155	-$ 9,686,183
47	2440	Deferred Revenue[5]									
						$ -				$ -	$ -
		Sub-Total	**$ 45,604,391**	**$ 3,587,540**	**-$ 108,678**	**$ 49,083,253**	**-$ 14,119,761**	**-$ 2,277,521**	**$ 107,097**	**-$ 16,290,184**	**$ 32,793,068**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 45,604,391**	**$ 3,587,540**	**-$ 108,678**	**$ 49,083,253**	**-$ 14,119,761**	**-$ 2,277,521**	**$ 107,097**	**-$ 16,290,184**	**$ 32,793,068**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,277,521**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 89,667
Stores Equipment	
Net Depreciation	-$ 2,187,853

Notes:

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

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

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

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

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

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

Accounting Standard CGAAP
Year **2011**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 1,037,697	-$ 91,368		$ 946,329	-$ 484,278	-$ 120,676		-$ 604,954	$ 341,375
CEC	1612	Land Rights (Formally known as Account 1906)	$ 97,579	$ 11,410		$ 108,990	-$ 5,000	-$ 2,066		-$ 7,066	$ 101,924
N/A	1805	Land	$ 47,899	$ -		$ 47,899	$ -			$ -	$ 47,899
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 102,722	$ 385		$ 103,107	-$ 23,152	-$ 4,117		-$ 27,269	$ 75,838
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 5,731,639	$ 274,976		$ 6,006,615	-$ 643,453	-$ 193,867		-$ 837,320	$ 5,169,295
47	1835	Overhead Conductors & Devices	$ 5,495,913	$ 488,326	-$ 300,000	$ 5,684,239	-$ 2,576,148	-$ 228,956	$ 114,000	-$ 2,691,103	$ 2,993,135
47	1840	Underground Conduit	$ 8,523,236	$ 1,178,203		$ 9,701,439	-$ 1,785,936	-$ 274,681		-$ 2,060,617	$ 7,640,822
47	1845	Underground Conductors & Devices	$ 10,289,850	$ 627,858		$ 10,917,707	-$ 3,623,393	-$ 423,812		-$ 4,047,205	$ 6,870,502
47	1850	Line Transformers	$ 13,356,674	$ 876,982		$ 14,233,655	-$ 3,808,752	-$ 559,269		-$ 4,368,021	$ 9,865,634
47	1855	Services (Overhead & Underground)	$ 6,818,570	$ 874,068		$ 7,692,638	-$ 1,963,661	-$ 289,810		-$ 2,253,471	$ 5,439,167
47	1860	Meters	$ 3,957,663	$ 195,760	$ 22,310	$ 4,175,733	-$ 953,871	-$ 155,401		-$ 1,109,271	$ 3,066,462
47	1860	Meters (Smart Meters)	$ -	$ 24,417		$ 24,417	$ -	-$ 488		-$ 488	$ 23,928
N/A	1905	Land	$ 190,119			$ 190,119	$ -			$ -	$ 190,119
47	1908	Buildings & Fixtures	$ 1,607,140	$ 26,631		$ 1,633,771	-$ 235,080	-$ 64,818		-$ 299,898	$ 1,333,873
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 159,415			$ 159,415	-$ 79,371	-$ 15,061		-$ 94,431	$ 64,983
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 251,403	$ 54,640		$ 306,043	-$ 68,655	-$ 51,907		-$ 120,562	$ 185,481
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 982,829	$ 316,345	-$ 127,092	$ 1,172,081	-$ 191,328	-$ 161,612	$ 127,092	-$ 225,848	$ 946,233
8	1935	Stores Equipment	$ 29,711	$ 4,656		$ 34,367	-$ 12,883	-$ 3,204		-$ 16,087	$ 18,281
8	1940	Tools, Shop & Garage Equipment	$ 214,968	$ 27,703		$ 242,672	-$ 74,066	-$ 22,882		-$ 96,948	$ 145,724
8	1945	Measurement & Testing Equipment	$ 54,338	$ 9,649		$ 63,987	-$ 11,901	-$ 5,916		-$ 17,817	$ 46,170
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 197,224	$ 29,691		$ 226,916	-$ 126,412	-$ 16,874		-$ 143,286	$ 83,630
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 10,063,338	-$ 1,939,672		-$ 12,003,010	$ 377,155	$ 288,452		$ 665,607	-$ 11,337,403
47	2440	Deferred Revenue[5]	$ -				$ -				
						$ -				$ -	$ -
		Sub-Total	**$ 49,083,253**	**$ 2,990,657**	**-$ 404,782**	**$ 51,669,128**	**-$ 16,290,184**	**-$ 2,306,964**	**$ 241,092**	**-$ 18,356,056**	**$ 33,313,072**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 49,083,253**	**$ 2,990,657**	**-$ 404,782**	**$ 51,669,128**	**-$ 16,290,184**	**-$ 2,306,964**	**$ 241,092**	**-$ 18,356,056**	**$ 33,313,072**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,306,964**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 184,823
Stores Equipment	
Net Depreciation	-$ 2,122,141

File Number:	EB-2017-0039
Exhibit:	2
Tab:	2-A
Page:	3 of 10
Date:	August 28th, 2017

Accounting Standard	CGAAP
Year	**2012**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 946,329	$ 29,330	$ 210,816	$ 1,186,475	-$ 604,954	-$ 76,486	-$ 89,939	-$ 771,379	$ 415,096
CEC	1612	Land Rights (Formally known as Account 1906)	$ 108,990	$ 6,175		$ 115,165	-$ 7,066	-$ 2,407		-$ 9,473	$ 105,692
N/A	1805	Land	$ 47,899	$ -		$ 47,899	$ -			$ -	$ 47,899
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 103,107	$ 10,966		$ 114,073	-$ 27,269	-$ 4,344		-$ 31,612	$ 82,461
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 6,006,615	$ 456,957		$ 6,463,571	-$ 837,320	-$ 205,289		-$ 1,042,609	$ 5,420,962
47	1835	Overhead Conductors & Devices	$ 5,684,239	$ 730,509		$ 6,414,747	-$ 2,691,103	-$ 252,579		-$ 2,943,682	$ 3,471,065
47	1840	Underground Conduit	$ 9,701,439	$ 955,081		$ 10,656,520	-$ 2,060,617	-$ 313,087		-$ 2,373,704	$ 8,282,816
47	1845	Underground Conductors & Devices	$ 10,917,707	$ 653,161		$ 11,570,868	-$ 4,047,205	-$ 448,094		-$ 4,495,300	$ 7,075,569
47	1850	Line Transformers	$ 14,233,655	$ 843,761		$ 15,077,416	-$ 4,368,021	-$ 592,640		-$ 4,960,661	$ 10,116,755
47	1855	Services (Overhead & Underground)	$ 7,692,638	$ 683,961		$ 8,376,599	-$ 2,253,471	-$ 322,721		-$ 2,576,192	$ 5,800,407
47	1860	Meters	$ 4,175,733	$ 210,492	$ 186,180	$ 4,572,405	-$ 1,109,271	-$ 169,377		-$ 1,278,648	$ 3,293,757
47	1860	Meters (Smart Meters)	$ 24,417	$ 570,008	-$ 6,531	$ 587,894	-$ 488	-$ 33,219		-$ 33,707	$ 554,186
N/A	1905	Land	$ 190,119			$ 190,119	$ -			$ -	$ 190,119
47	1908	Buildings & Fixtures	$ 1,633,771	$ 761,185		$ 2,394,956	-$ 299,898	-$ 79,682		-$ 379,580	$ 2,015,376
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 159,415	$ 25,424	-$ 4,595	$ 180,243	-$ 94,431	-$ 16,141	$ 4,595	-$ 105,977	$ 74,266
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 306,043			$ 306,043	-$ 120,562	-$ 50,831		-$ 171,393	$ 134,650
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 1,172,081	$ 312,049	-$ 201,657	$ 1,282,473	-$ 225,848	-$ 185,945	$ 172,491	-$ 239,302	$ 1,043,171
8	1935	Stores Equipment	$ 34,367	$ 2,708		$ 37,075	-$ 16,087	-$ 3,572		-$ 19,659	$ 17,416
8	1940	Tools, Shop & Garage Equipment	$ 242,672	$ 86,797		$ 329,469	-$ 96,948	-$ 28,086		-$ 125,034	$ 204,435
8	1945	Measurement & Testing Equipment	$ 63,987			$ 63,987	-$ 17,817	-$ 6,399		-$ 24,216	$ 39,772
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 226,916	$ 49,617		$ 276,532	-$ 143,286	-$ 20,766		-$ 164,051	$ 112,481
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 12,003,010	-$ 869,853		-$ 12,872,863	$ 665,607	$ 344,643		$ 1,010,250	-$ 11,862,613
47	2440	Deferred Revenue[5]	$ -				$ -				
						$ -				$ -	$ -
		Sub-Total	**$ 51,669,128**	**$ 5,518,327**	**$ 184,213**	**$ 57,371,668**	**-$ 18,356,056**	**-$ 2,467,021**	**$ 87,147**	**-$ 20,735,930**	**$ 36,635,738**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 51,669,128**	**$ 5,518,327**	**$ 184,213**	**$ 57,371,668**	**-$ 18,356,056**	**-$ 2,467,021**	**$ 87,147**	**-$ 20,735,930**	**$ 36,635,738**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,467,021**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 179,623
Stores Equipment	
Net Depreciation	-$ 2,287,398

Accounting Standard CGAAP
Year **2013**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 1,186,475	$ 66,055		$ 1,252,529	-$ 771,379	-$ 84,022		-$ 855,400	$ 397,129
CEC	1612	Land Rights (Formally known as Account 1906)	$ 115,165	$ 60,262		$ 175,427	-$ 9,473	-$ 2,902		-$ 12,375	$ 163,052
N/A	1805	Land	$ 47,899			$ 47,899	$ -			$ -	$ 47,899
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 114,073	$ 1,572		$ 115,645	-$ 31,612	-$ 4,594		-$ 36,207	$ 79,438
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 6,463,571	$ 427,090		$ 6,890,662	-$ 1,042,609	-$ 219,433		-$ 1,262,042	$ 5,628,619
47	1835	Overhead Conductors & Devices	$ 6,414,747	$ 542,962		$ 6,957,709	-$ 2,943,682	-$ 276,494		-$ 3,220,176	$ 3,737,534
47	1840	Underground Conduit	$ 10,656,520	$ 914,367		$ 11,570,888	-$ 2,373,704	-$ 346,792		-$ 2,720,496	$ 8,850,392
47	1845	Underground Conductors & Devices	$ 11,570,868	$ 1,015,489		$ 12,586,357	-$ 4,495,300	-$ 480,111		-$ 4,975,411	$ 7,610,947
47	1850	Line Transformers	$ 15,077,416	$ 1,487,986		$ 16,565,402	-$ 4,960,661	-$ 635,746		-$ 5,596,407	$ 10,968,996
47	1855	Services (Overhead & Underground)	$ 8,376,599	$ 928,132		$ 9,304,732	-$ 2,576,192	-$ 352,153		-$ 2,928,344	$ 6,376,387
47	1860	Meters	$ 4,572,405	$ 171,490	-$ 14,935	$ 4,728,961	-$ 1,278,648	-$ 274,103		-$ 1,552,751	$ 3,176,210
47	1860	Meters (Smart Meters)	$ 587,894	$ 37,316		$ 625,210	-$ 33,707	-$ 31,148		-$ 64,856	$ 560,354
N/A	1905	Land	$ 190,119			$ 190,119	$ -			$ -	$ 190,119
47	1908	Buildings & Fixtures	$ 2,394,956	$ 27,401		$ 2,422,357	-$ 379,580	-$ 94,562		-$ 474,141	$ 1,948,216
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 180,243	$ 8,365		$ 188,609	-$ 105,977	-$ 17,562		-$ 123,539	$ 65,070
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 306,043	$ 18,106		$ 324,149	-$ 171,393	-$ 50,350		-$ 221,744	$ 102,406
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 1,282,473	$ 382,064	-$ 110,985	$ 1,553,552	-$ 239,302	-$ 273,213	$ 110,986	-$ 401,529	$ 1,152,023
8	1935	Stores Equipment	$ 37,075			$ 37,075	-$ 19,659	-$ 3,708		-$ 23,366	$ 13,709
8	1940	Tools, Shop & Garage Equipment	$ 329,469	$ 54,159		$ 383,628	-$ 125,034	-$ 33,574		-$ 158,608	$ 225,020
8	1945	Measurement & Testing Equipment	$ 63,987			$ 63,987	-$ 24,216	-$ 6,399		-$ 30,614	$ 33,373
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 276,532	$ 4,947		$ 281,480	-$ 164,051	-$ 21,372		-$ 185,423	$ 96,057
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 12,872,863	-$ 2,191,898		-$ 15,064,761	$ 1,010,250	$ 360,377		$ 1,370,627	-$ 13,694,134
47	2440	Deferred Revenue[5]	$ -				$ -				
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 57,371,668**	**$ 3,955,868**	**-$ 125,920**	**$ 61,201,616**	**-$ 20,735,930**	**-$ 2,847,858**	**$ 110,986**	**-$ 23,472,802**	**$ 37,728,814**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 57,371,668**	**$ 3,955,868**	**-$ 125,920**	**$ 61,201,616**	**-$ 20,735,930**	**-$ 2,847,858**	**$ 110,986**	**-$ 23,472,802**	**$ 37,728,814**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,847,858**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 263,924
Stores Equipment	
Net Depreciation	-$ 2,583,934

File Number:	EB-2017-0039
Exhibit:	2
Tab:	2-A
Page:	5 of 10
Date:	August 28th, 2017

Accounting Standard CGAAP Shown below is RCGAAP. The model did not have that
Year **2013** accounting standard as an available option in the list

			Cost				**Accumulated Depreciation**				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 1,186,475	$ 66,055		$ 1,252,529	-$ 771,379	-$ 342,040		-$ 1,113,418	$ 139,111
CEC	1612	Land Rights (Formally known as Account 1906)	$ 115,165	$ 60,262		$ 175,427	-$ 9,473	-$ 2,930		-$ 12,403	$ 163,024
N/A	1805	Land	$ 47,899			$ 47,899	$ -			$ -	$ 47,899
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 114,073	$ 1,432		$ 115,505	-$ 31,612	-$ 4,002		-$ 35,614	$ 79,890
47	1825	Storage Battery Equipment	$ -			$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 6,463,571	$ 388,994		$ 6,852,565	-$ 1,042,609	-$ 148,490		-$ 1,191,099	$ 5,661,466
47	1835	Overhead Conductors & Devices	$ 6,414,747	$ 494,530		$ 6,909,277	-$ 2,943,682	-$ 95,859		-$ 3,039,541	$ 3,869,736
47	1840	Underground Conduit	$ 10,656,520	$ 832,806		$ 11,489,326	-$ 2,373,704	-$ 199,739		-$ 2,573,444	$ 8,915,882
47	1845	Underground Conductors & Devices	$ 11,570,868	$ 924,907		$ 12,495,775	-$ 4,495,300	-$ 229,618		-$ 4,724,918	$ 7,770,857
47	1850	Line Transformers	$ 15,077,416	$ 1,355,258		$ 16,432,674	-$ 4,960,661	-$ 326,072		-$ 5,286,733	$ 11,145,941
47	1855	Services (Overhead & Underground)	$ 8,376,599	$ 845,343		$ 9,221,942	-$ 2,576,192	-$ 144,526		-$ 2,720,718	$ 6,501,224
47	1860	Meters	$ 4,572,405	$ 150,060	-$ 14,935	$ 4,707,530	-$ 1,278,648	-$ 167,575		-$ 1,446,223	$ 3,261,307
47	1860	Meters (Smart Meters)	$ 587,894	$ 24,347		$ 612,241	-$ 33,707	-$ 31,148		-$ 64,855	$ 547,385
N/A	1905	Land	$ 190,119			$ 190,119	$ -			$ -	$ 190,119
47	1908	Buildings & Fixtures	$ 2,394,956	$ 27,401		$ 2,422,357	-$ 379,580	-$ 42,858		-$ 422,438	$ 1,999,919
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 180,243	$ 8,365		$ 188,609	-$ 105,977	-$ 16,755		-$ 122,732	$ 65,876
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 306,043	$ 18,106		$ 324,149	-$ 171,393	-$ 141,384		-$ 312,778	$ 11,372
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 1,282,473	$ 382,064	-$ 110,985	$ 1,553,552	-$ 239,302	-$ 157,920	$ 110,986	-$ 286,236	$ 1,267,316
8	1935	Stores Equipment	$ 37,075			$ 37,075	-$ 19,659	-$ 3,670		-$ 23,329	$ 13,746
8	1940	Tools, Shop & Garage Equipment	$ 329,469	$ 54,159		$ 383,628	-$ 125,034	-$ 58,184		-$ 183,218	$ 200,410
8	1945	Measurement & Testing Equipment	$ 63,987			$ 63,987	-$ 24,216	-$ 11,669		-$ 35,885	$ 28,102
8	1950	Power Operated Equipment	$ -			$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	$ 276,532	$ 4,947		$ 281,480	-$ 164,051	-$ 59,435		-$ 223,486	$ 57,994
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 12,872,863	-$ 2,191,898		-$ 15,064,761	$ 1,010,250	$ 278,492		$ 1,288,742	-$ 13,776,019
47	2440	Deferred Revenue[5]	$ -				$ -				
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 57,371,668**	**$ 3,447,138**	**-$ 125,920**	**$ 60,692,886**	**-$ 20,735,930**	**-$ 1,905,383**	**$ 110,986**	**-$ 22,530,327**	**$ 38,162,559**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 57,371,668**	**$ 3,447,138**	**-$ 125,920**	**$ 60,692,886**	**-$ 20,735,930**	**-$ 1,905,383**	**$ 110,986**	**-$ 22,530,327**	**$ 38,162,559**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,905,383**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 152,550
Stores Equipment	
Net Depreciation	-$ 1,752,832

Accounting Standard CGAAP Shown below is RCGAAP. The model did not have that
Year **2014** accounting standard as an available option in the list

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 1,252,529	$ 74,868		$ 1,327,398	-$ 1,113,418	-$ 75,831		-$ 1,189,249	$ 138,148
CEC	1612	Land Rights (Formally known as Account 1906)	$ 175,427	$ 15,071		$ 190,498	-$ 12,403	-$ 3,679		-$ 16,082	$ 174,416
N/A	1805	Land	$ 47,899			$ 47,899	$ -			$ -	$ 47,899
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 115,505			$ 115,505	-$ 35,614	-$ 3,599		-$ 39,214	$ 76,291
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 6,852,565	$ 490,624		$ 7,343,189	-$ 1,191,099	-$ 129,121		-$ 1,320,220	$ 6,022,969
47	1835	Overhead Conductors & Devices	$ 6,909,277	$ 431,488		$ 7,340,765	-$ 3,039,541	-$ 73,359		-$ 3,112,900	$ 4,227,864
47	1840	Underground Conduit	$ 11,489,326	$ 1,250,716		$ 12,740,042	-$ 2,573,444	-$ 122,833		-$ 2,696,277	$ 10,043,765
47	1845	Underground Conductors & Devices	$ 12,495,775	$ 839,997		$ 13,335,773	-$ 4,724,918	-$ 365,105		-$ 5,090,023	$ 8,245,750
47	1850	Line Transformers	$ 16,432,674	$ 1,287,293	$ 27,678	$ 17,747,645	-$ 5,286,733	-$ 353,494		-$ 5,640,227	$ 12,107,418
47	1855	Services (Overhead & Underground)	$ 9,221,942	$ 1,044,927	-$ 0	$ 10,266,869	-$ 2,720,718	-$ 166,800		-$ 2,887,518	$ 7,379,351
47	1860	Meters	$ 4,707,530	$ 68,368	$ 237,709	$ 5,013,607	-$ 1,446,223	-$ 178,821		-$ 1,625,044	$ 3,388,563
47	1860	Meters (Smart Meters)	$ 612,241	$ 26,539		$ 638,780	-$ 64,855	-$ 23,884		-$ 88,739	$ 550,040
N/A	1905	Land	$ 190,119			$ 190,119	$ -			$ -	$ 190,119
47	1908	Buildings & Fixtures	$ 2,422,357			$ 2,422,357	-$ 422,438	-$ 27,100		-$ 449,538	$ 1,972,819
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 188,609	$ 1,499		$ 190,108	-$ 122,732	-$ 17,979		-$ 140,712	$ 49,396
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 324,149	$ 43,348		$ 367,497	-$ 312,778	-$ 4,346		-$ 317,124	$ 50,373
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 1,553,552	$ 425,100	-$ 136,054	$ 1,842,598	-$ 286,236	-$ 146,305	$ 136,054	-$ 296,487	$ 1,546,111
8	1935	Stores Equipment	$ 37,075		$ -	$ 37,075	-$ 23,329	-$ 2,673		-$ 26,002	$ 11,073
8	1940	Tools, Shop & Garage Equipment	$ 383,628	$ 78,333	$ -	$ 461,960	-$ 183,218	-$ 63,233		-$ 246,451	$ 215,509
8	1945	Measurement & Testing Equipment	$ 63,987			$ 63,987	-$ 35,885	-$ 11,235		-$ 47,120	$ 16,868
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 281,480			$ 281,480	-$ 223,486	-$ 43,937		-$ 267,423	$ 14,056
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 15,064,761	-$ 1,122,171		-$ 16,186,932	$ 1,288,742	$ 247,371		$ 1,536,113	-$ 14,650,819
47	2440	Deferred Revenue[5]	$ -				$ -				
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 60,692,886**	**$ 4,955,998**	**$ 129,333**	**$ 65,778,217**	**-$ 22,530,327**	**-$ 1,565,965**	**$ 136,054**	**-$ 23,960,237**	**$ 41,817,980**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 60,692,886**	**$ 4,955,998**	**$ 129,333**	**$ 65,778,217**	**-$ 22,530,327**	**-$ 1,565,965**	**$ 136,054**	**-$ 23,960,237**	**$ 41,817,980**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,565,965**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 141,330
Stores Equipment	
Net Depreciation	-$ 1,424,634

File Number:	EB-2017-0039
Exhibit:	2
Tab:	2-A
Page:	7 of 10
Date:	August 28th, 2017

Accounting Standard MIFRS
Year **2015**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 1,327,398	$ 17,043		$ 1,344,441	-$ 1,189,249	-$ 75,579		-$ 1,264,828	$ 79,612
CEC	1612	Land Rights (Formally known as Account 1906)	$ 190,498	$ 14,661		$ 205,159	-$ 16,082	-$ 3,983		-$ 20,065	$ 185,094
N/A	1805	Land	$ 47,899			$ 47,899	$ -			$ -	$ 47,899
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 115,505		-$ 115,505	$ -	-$ 39,214	$ -	$ 39,214	$ 0	$ 0
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 7,343,189	$ 934,800		$ 8,277,989	-$ 1,320,220	-$ 133,666		-$ 1,453,886	$ 6,824,103
47	1835	Overhead Conductors & Devices	$ 7,340,765	$ 990,160		$ 8,330,925	-$ 3,112,900	-$ 73,557		-$ 3,186,457	$ 5,144,467
47	1840	Underground Conduit	$ 12,740,042	$ 279,301		$ 13,019,343	-$ 2,696,277	-$ 226,513		-$ 2,922,790	$ 10,096,553
47	1845	Underground Conductors & Devices	$ 13,335,773	$ 584,507		$ 13,920,280	-$ 5,090,023	-$ 287,646	$ 14,190	-$ 5,363,479	$ 8,556,801
47	1850	Line Transformers	$ 17,747,645	$ 923,100	-$ 108,617	$ 18,562,128	-$ 5,640,227	-$ 287,574	$ 47	-$ 5,927,754	$ 12,634,374
47	1855	Services (Overhead & Underground)	$ 10,266,869	$ 1,062,301	-$ 0	$ 11,329,169	-$ 2,887,518	-$ 158,272		-$ 3,045,790	$ 8,283,379
47	1860	Meters	$ 5,013,607	$ 241,104	-$ 770,147	$ 4,484,564	-$ 1,625,044	-$ 139,296		-$ 1,764,340	$ 2,720,224
47	1860	Meters (Smart Meters)	$ 638,780	$ 3,196,304		$ 3,835,084	-$ 88,739	-$ 244,350	-$ 1,104,875	-$ 1,437,964	$ 2,397,119
N/A	1905	Land	$ 190,119			$ 190,119	$ -			$ -	$ 190,119
47	1908	Buildings & Fixtures	$ 2,422,357	$ 48,914		$ 2,471,271	-$ 449,538	-$ 41,157		-$ 490,695	$ 1,980,576
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 190,108	$ 5,980		$ 196,088	-$ 140,712	-$ 8,342		-$ 149,054	$ 47,034
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 367,497	$ 3,875		$ 371,372	-$ 317,124	-$ 35,385		-$ 352,509	$ 18,863
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 1,842,598	$ 402,157		$ 2,244,755	-$ 296,487	-$ 189,589		-$ 486,076	$ 1,758,679
8	1935	Stores Equipment	$ 37,075	$ 17		$ 37,092	-$ 26,002	-$ 2,198		-$ 28,200	$ 8,892
8	1940	Tools, Shop & Garage Equipment	$ 461,960	$ 56,539		$ 518,499	-$ 246,451	-$ 42,042		-$ 288,493	$ 230,006
8	1945	Measurement & Testing Equipment	$ 63,987			$ 63,987	-$ 47,120	-$ 6,269		-$ 53,389	$ 10,599
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 281,480	$ 12,943		$ 294,423	-$ 267,423	-$ 29,553		-$ 296,976	-$ 2,554
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]	-$ 16,186,932	-$ 1,448,183		-$ 17,635,115	$ 1,536,113	$ 552,530		$ 2,088,643	-$ 15,546,472
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 65,778,217**	**$ 7,325,523**	**-$ 994,269**	**$ 72,109,471**	**-$ 23,960,237**	**-$ 1,432,441**	**-$ 1,051,424**	**-$ 26,444,102**	**$ 45,665,369**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 65,778,217**	**$ 7,325,523**	**-$ 994,269**	**$ 72,109,471**	**-$ 23,960,237**	**-$ 1,432,441**	**-$ 1,051,424**	**-$ 26,444,102**	**$ 45,665,369**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,432,441**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 183,143
Stores Equipment	
Net Depreciation	-$ 1,249,298

Accounting Standard MIFRS
Year **2016**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 1,344,441	$ 5,217		$ 1,349,658	-$ 1,264,828	-$ 63,196	$ 207,551	-$ 1,120,473	$ 229,184
CEC	1612	Land Rights (Formally known as Account 1906)	$ 205,159	$ 2,644		$ 207,803	-$ 20,065	-$ 4,114		-$ 24,179	$ 183,624
N/A	1805	Land	$ 47,899		-$ 12,000	$ 35,899	$ -			$ -	$ 35,899
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ -			$ -	$ 0			$ 0	$ 0
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,277,989	$ 598,652	$ 20,776	$ 8,897,417	-$ 1,453,886	-$ 148,824	$ 82,818	-$ 1,519,892	$ 7,377,525
47	1835	Overhead Conductors & Devices	$ 8,330,925	$ 956,400	-$ 81,821	$ 9,205,504	-$ 3,186,457	-$ 89,922	-$ 8,048	-$ 3,284,427	$ 5,921,076
47	1840	Underground Conduit	$ 13,019,343	$ 213,140	-$ 2,370	$ 13,230,112	-$ 2,922,790	-$ 232,711	$ 53,219	-$ 3,102,282	$ 10,127,831
47	1845	Underground Conductors & Devices	$ 13,920,280	$ 577,705	-$ 40,212	$ 14,457,773	-$ 5,363,479	-$ 293,497	-$ 20,759	-$ 5,677,735	$ 8,780,038
47	1850	Line Transformers	$ 18,562,128	$ 774,929	-$ 36,576	$ 19,300,481	-$ 5,927,754	-$ 334,035	$ 21,050	-$ 6,240,739	$ 13,059,743
47	1855	Services (Overhead & Underground)	$ 11,329,169	$ 893,280	-$ 68,166	$ 12,154,283	-$ 3,045,790	-$ 178,610	-$ 20,809	-$ 3,245,209	$ 8,909,074
47	1860	Meters	$ 4,484,564	$ 411,948	$ 664,128	$ 5,560,640	-$ 1,764,340	-$ 96,476	-$ 85,895	-$ 1,946,711	$ 3,613,929
47	1860	Meters (Smart Meters)	$ 3,835,084	$ 66,961	-$ 50,029	$ 3,852,015	-$ 1,437,964	-$ 278,118		-$ 1,716,082	$ 2,135,933
N/A	1905	Land	$ 190,119			$ 190,119	$ -			$ -	$ 190,119
47	1908	Buildings & Fixtures	$ 2,471,271	$ 42,469		$ 2,513,740	-$ 490,695	-$ 42,169	$ 12,486	-$ 520,378	$ 1,993,362
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 196,088	$ 20,672		$ 216,760	-$ 149,054	-$ 9,697	-$ 4,553	-$ 163,304	$ 53,456
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 371,372	$ 117,329		$ 488,701	-$ 352,509	-$ 11,815	$ 49,702	-$ 314,622	$ 174,079
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 2,244,755	$ 136,662		$ 2,381,417	-$ 486,076	-$ 213,884	-$ 27,154	-$ 727,114	$ 1,654,303
8	1935	Stores Equipment	$ 37,092	$ 10,275		$ 47,367	-$ 28,200	-$ 2,701	$ 10,121	-$ 20,780	$ 26,587
8	1940	Tools, Shop & Garage Equipment	$ 518,499	$ 45,830		$ 564,329	-$ 288,493	-$ 46,828	$ 53,783	-$ 281,538	$ 282,791
8	1945	Measurement & Testing Equipment	$ 63,987	$ 6,260		$ 70,247	-$ 53,389	-$ 6,599	$ 11,341	-$ 48,647	$ 21,601
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 294,423			$ 294,423	-$ 296,976	-$ 29,874	$ 51,594	-$ 275,256	$ 19,166
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 17,635,115	-$ 931,021		-$ 18,566,136	$ 2,088,643	$ 589,771		$ 2,678,414	-$ 15,887,722
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 72,109,471**	**$ 3,949,352**	**$ 393,730**	**$ 76,452,553**	**-$ 26,444,102**	**-$ 1,493,299**	**$ 386,447**	**-$ 27,550,954**	**$ 48,901,599**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 72,109,471**	**$ 3,949,352**	**$ 393,730**	**$ 76,452,553**	**-$ 26,444,102**	**-$ 1,493,299**	**$ 386,447**	**-$ 27,550,954**	**$ 48,901,599**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,493,299**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 206,612
Stores Equipment	
Net Depreciation	-$ 1,286,687

File Number:	EB-2017-0039
Exhibit:	2
Tab:	2-A
Page:	9 of 10
Date:	August 28th, 2017

Accounting Standard MIFRS
Year 2017

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals [6]	Closing Balance	Opening Balance	Additions	Disposals [6]	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 1,349,658	$ 254,500		$ 1,604,158	-$ 1,120,473	-$ 81,624		-$ 1,202,097	$ 402,060
CEC	1612	Land Rights (Formally known as Account 1906)	$ 207,803	$ 42,192		$ 249,995	-$ 24,179	-$ 4,604		-$ 28,783	$ 221,212
N/A	1805	Land	$ 35,899			$ 35,899	$ -			$ -	$ 35,899
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ -			$ -	$ 0			$ 0	$ 0
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,897,417	$ 932,338		$ 9,829,755	-$ 1,519,892	-$ 163,794		-$ 1,683,686	$ 8,146,069
47	1835	Overhead Conductors & Devices	$ 9,205,504	$ 541,648		$ 9,747,152	-$ 3,284,427	-$ 104,679		-$ 3,389,106	$ 6,358,045
47	1840	Underground Conduit	$ 13,230,112	$ 734,410		$ 13,964,522	-$ 3,102,282	-$ 243,945		-$ 3,346,227	$ 10,618,296
47	1845	Underground Conductors & Devices	$ 14,457,773	$ 788,211		$ 15,245,984	-$ 5,677,735	-$ 314,089		-$ 5,991,824	$ 9,254,160
47	1850	Line Transformers	$ 19,300,481	$ 1,025,570		$ 20,326,051	-$ 6,240,739	-$ 322,980		-$ 6,563,719	$ 13,762,333
47	1855	Services (Overhead & Underground)	$ 12,154,283	$ 822,714		$ 12,976,997	-$ 3,245,209	-$ 197,036		-$ 3,442,245	$ 9,534,752
47	1860	Meters	$ 5,560,640	$ 266,932		$ 5,827,572	-$ 1,946,711	-$ 106,260		-$ 2,052,971	$ 3,774,601
47	1860	Meters (Smart Meters)	$ 3,852,015			$ 3,852,015	-$ 1,716,082	-$ 278,118		-$ 1,994,200	$ 1,857,815
N/A	1905	Land	$ 190,119			$ 190,119	$ -			$ -	$ 190,119
47	1908	Buildings & Fixtures	$ 2,513,740	$ 286,800		$ 2,800,540	-$ 520,378	-$ 45,350		-$ 565,728	$ 2,234,812
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 216,760	$ 10,000		$ 226,760	-$ 163,304	-$ 11,209		-$ 174,513	$ 52,247
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 488,701	$ 356,150		$ 844,851	-$ 314,622	-$ 73,917		-$ 388,539	$ 456,312
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 2,381,417	$ 487,000		$ 2,868,417	-$ 727,114	-$ 211,990		-$ 939,104	$ 1,929,313
8	1935	Stores Equipment	$ 47,367	$ 50,000		$ 97,367	-$ 20,780	-$ 5,708		-$ 26,488	$ 70,879
8	1940	Tools, Shop & Garage Equipment	$ 564,329	$ 60,000		$ 624,329	-$ 281,538	-$ 52,011		-$ 333,549	$ 290,780
8	1945	Measurement & Testing Equipment	$ 70,247			$ 70,247	-$ 48,647	-$ 6,895		-$ 55,542	$ 14,706
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 294,423			$ 294,423	-$ 275,256	-$ 15,040		-$ 290,296	$ 4,126
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 18,566,136	-$ 1,224,757		-$ 19,790,893	$ 2,678,414	$ 367,800	-$ 490,336	$ 2,555,878	-$ 17,235,015
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 76,452,553**	**$ 5,433,708**	**$ -**	**$ 81,886,261**	**-$ 27,550,954**	**-$ 1,871,449**	**-$ 490,336**	**-$ 29,912,740**	**$ 51,973,522**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 76,452,553**	**$ 5,433,708**	**$ -**	**$ 81,886,261**	**-$ 27,550,954**	**-$ 1,871,449**	**-$ 490,336**	**-$ 29,912,740**	**$ 51,973,522**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,871,449**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 204,782
Stores Equipment	
Net Depreciation	-$ 1,666,667

File Number:	EB-2017-0039
Exhibit:	2
Tab:	2-A
Page:	10 fo 10
Date:	August 28th, 2017

Accounting Standard MIFRS
Year **2018**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 1,604,158	$ 115,000		$ 1,719,158	-$ 1,202,097	-$ 103,175		-$ 1,305,272	$ 413,885
CEC	1612	Land Rights (Formally known as Account 1906)	$ 249,995	$ 48,941		$ 298,936	-$ 28,783	-$ 5,515		-$ 34,298	$ 264,638
N/A	1805	Land	$ 35,899			$ 35,899	$ -			$ -	$ 35,899
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ -			$ -	$ 0			$ 0	$ 0
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 9,829,755	$ 432,914		$ 10,262,669	-$ 1,683,686	-$ 177,447		-$ 1,861,133	$ 8,401,536
47	1835	Overhead Conductors & Devices	$ 9,747,152	$ 839,476		$ 10,586,628	-$ 3,389,106	-$ 118,491		-$ 3,507,597	$ 7,079,030
47	1840	Underground Conduit	$ 13,964,522	$ 864,559		$ 14,829,081	-$ 3,346,227	-$ 263,932		-$ 3,610,159	$ 11,218,923
47	1845	Underground Conductors & Devices	$ 15,245,984	$ 853,466		$ 16,099,450	-$ 5,991,824	-$ 341,450		-$ 6,333,274	$ 9,766,176
47	1850	Line Transformers	$ 20,326,051	$ 1,040,794		$ 21,366,845	-$ 6,563,719	-$ 348,809		-$ 6,912,528	$ 14,454,318
47	1855	Services (Overhead & Underground)	$ 12,976,997	$ 800,370		$ 13,777,367	-$ 3,442,245	-$ 213,267		-$ 3,655,512	$ 10,121,855
47	1860	Meters	$ 5,827,572	$ 265,671		$ 6,093,243	-$ 2,052,971	-$ 124,013		-$ 2,176,984	$ 3,916,259
47	1860	Meters (Smart Meters)	$ 3,852,015			$ 3,852,015	-$ 1,994,200	-$ 278,118		-$ 2,272,318	$ 1,579,697
N/A	1905	Land	$ 190,119			$ 190,119	$ -			$ -	$ 190,119
47	1908	Buildings & Fixtures	$ 2,800,540	$ 370,000		$ 3,170,540	-$ 565,728	-$ 51,918		-$ 617,646	$ 2,552,894
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 226,760	$ 10,000		$ 236,760	-$ 174,513	-$ 11,445		-$ 185,958	$ 50,802
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 844,851	$ 161,809		$ 1,006,660	-$ 388,539	-$ 121,790		-$ 510,329	$ 496,331
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 2,868,417	$ 270,000		$ 3,138,417	-$ 939,104	-$ 273,932		-$ 1,213,036	$ 1,925,381
8	1935	Stores Equipment	$ 97,367	$ 50,000		$ 147,367	-$ 26,488	-$ 10,101		-$ 36,589	$ 110,778
8	1940	Tools, Shop & Garage Equipment	$ 624,329	$ 60,000		$ 684,329	-$ 333,549	-$ 49,066		-$ 382,615	$ 301,714
8	1945	Measurement & Testing Equipment	$ 70,247			$ 70,247	-$ 55,542	-$ 5,458		-$ 61,000	$ 9,248
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 294,423			$ 294,423	-$ 290,296	-$ 13,332		-$ 303,628	-$ 9,206
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 19,790,893	-$ 1,224,757		-$ 21,015,650	$ 2,555,878	$ 398,418		$ 2,954,295	-$ 18,061,355
						$ -	$ -			$ -	$ -
		Sub-Total	**$ 81,886,261**	**$ 4,958,243**	**$ -**	**$ 86,844,504**	**-$ 29,912,740**	**-$ 2,112,841**	**$ -**	**-$ 32,025,581**	**$ 54,818,923**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 81,886,261**	**$ 4,958,243**	**$ -**	**$ 86,844,504**	**-$ 29,912,740**	**-$ 2,112,841**	**$ -**	**-$ 32,025,581**	**$ 54,818,923**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,112,841**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 264,837
Stores Equipment	
Net Depreciation	-$ 1,848,004

Attachment 2-B

Stranded Meter Treatment

File Number:	EB-2017-0039
Exhibit:	2
Attachment	2-B
Page:	1 of 1
Date:	August 28th, 2017

Appendix 2-S
Stranded Meter Treatment

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2008		$ 65,437	$ 34,414	$ -	$ 31,023	$ -	$ 31,023
2009		$ 1,224,257	$ 359,336	$ -	$ 864,921	$ -	$ 864,921
2010		$ 2,328,222	$ 695,859	$ -	$ 1,632,363	$ -	$ 1,632,363
2011		$ 2,617,818	$ 858,988	$ -	$ 1,758,830	$ -	$ 1,758,830
2012		$ 2,617,818	$ 963,700	$ -	$ 1,654,118	$ -	$ 1,654,118
2013		$ 2,617,818	$ 1,068,413	$ -	$ 1,549,405	$ -	$ 1,549,405
2014		$ 2,617,818	$ 1,173,126	$ -	$ 1,444,692	$ -	$ 1,444,692
2015		$ 2,617,818	$ 1,277,838	$ -	$ 1,339,980	$ -	$ 1,339,980
2016		$ 2,617,818	$ 1,382,551	$ -	$ 1,235,267	$ -	$ 1,235,267
2017	(1)	$ 2,617,818	$ 1,487,264	$ -	$ 1,130,554	$ -	$ 1,130,554
2018		$ 2,617,818	$ 1,522,168	$ -	$ 1,095,650	$ -	$ 1,095,650

Notes:

(1) *For 2017, please indicate whether the amounts provided are on a forecast or actual basis.*

Some distributors have transferred the cost of stranded meters from Account 1860 - Meters to "Sub-account Stranded Meter Costs of Account 1555", while in some cases distributors have left these costs in Account 1860. Depending on which treatment the applicant has chosen. please provide the information under either of the two scenarios (A and B below), as applicable.

Scenario A: *If the stranded meter costs were transferred to "Sub-account Stranded Meter Costs" of Account 1555, the above table should be completed and the following information should be provided in Exhibit 9.*

1 A description of the accounting treatment followed by the applicant on stranded meter costs for financial accounting and reporting purposes.

2 The amount of the pooled residual net book value of the removed from service stranded meters, less any contributed capital (net of accumulated amortization), and less any net proceeds from sales, which were transferred to this sub-account as of December 31, 2010.

3 A statement as to whether or not, since transferring the removed stranded meter costs to the sub-account, the recording of depreciation expenses was continued in order to reduce the net book value through accumulated depreciation. If so, the total depreciation expense amount for the period from the time the costs for the stranded meters were transferred to the sub-account to December 31, 2010 should be provided.

If no depreciation expenses were recorded to reduce the net book value of stranded meter costs through accumulated depreciation, the total depreciation expense amount that would have been applicable from the time that the stranded meter costs were transferred to the sub-account of Account 1555 to December 31, 2010 should be provided. In addition, the following information should be provided:

a) Whether or not carrying charges were recorded for the stranded meter cost balances in the sub-account, and if so, the total carrying charges recorded to December 31, 2010.

b) The estimated amount of the pooled residual net book value of the removed from service meters, less any net proceeds from sales and contributed capital, at the time when the smart meters will have been fully deployed (e.g., as of December 31, 2010). If the smart meters have been fully deployed, the actual amount should be provided.

c) A description as to how the applicant intends to recover in rates the remaining costs for stranded meters, including the proposed accounting treatment, the proposed disposition period, and the associated bill impacts.

Scenario B: *If the stranded meter costs remained recorded in Account 1860, the above table should be completed and the following information should be provided in Exhibit 9:*

1 A description of the accounting treatment followed by the applicant on stranded meter costs for financial accounting and reporting purposes.

2 The amount of the pooled residual net book value of the removed from service stranded meters, less any contributed capital (net of accumulated amortization), and less any net proceeds from sales, as of December 31, 2010.

3 A statement as to whether or not the recording of depreciation expenses continued in order to reduce the net book value through accumulated depreciation. If so, provision of the total (cumulative) depreciation expense for the period from the time that the meters became stranded to December 31, 2010.

4 If no depreciation expenses were recorded to reduce the net book value of stranded meters through accumulated depreciation, the total (cumulative) depreciation expense amount that would have been applicable for the period from the time that the meters became stranded to December 31, 2010.

5 The estimated amount of the pooled residual net book value of the removed from service meters, less any net proceeds from sales and contributed capital, at the time when smart meters will have been fully deployed. If the smart meters have been fully deployed, please provide the actual amount.

6 A description as to how the applicant intends to recover in rates the costs for stranded meters, including the proposed accounting treatment, the proposed disposition period and the associated bill impacts.

Distributors should also provide the Net Book Value per class of meter as of December 31, 2010 as well as the number of meters that were removed / stranded. In preparing this information, distributors should review the Board's letter of January 16, 2007 *Stranded Meter Costs Related to the Installation of Smart Meters* which stated that records were to be kept of the type and number of each meter to support the stranded meter costs.

Attachment 2-C

EPLC Distribution System Plan

Essex Powerlines Corporation
Distribution System Plan

2018 Cost of Service Application

Historical Period: 2013 to 2017

Forecast Period: 2018 to 2022

11 August 2017

Table of Contents

List of Appendices

List of Figures

List of Tables

1 Introduction

Essex Powerlines Corporation ("**EPL**") has prepared this Distribution System Plan ("**DSP**") in accordance with the Ontario Energy Board's ("**OEB**'s") *Chapter 5 Consolidated Distribution System Plan Filing Requirements* dated 28 March 2013 (the "**Filing Requirements**") as part of its 4th Generation IR Application based on a 2018 forward test year cost of service review ("**the Application**").

1.1 Objectives & Scope of Work

EPL's DSP has been prepared to support the four (4) key objectives from the OEB's *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* ("**RRFE**"):

1. Customer Focus: services are provided in a manner that responds to identified customer preferences;
2. Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;
3. Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
4. Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.

In alignment with these four outcomes, EPL's overarching objective of its five (5)-year plan is to provide a modern, smart grid fit for the 21st century at inflation-aligned costs. In order to achieve the goals EPL has set for itself, EPL continually strives to:

- Provide detailed outage communication to all customers.
- Continually look to drive costs down with the implementation of modern management techniques and other process improvements.
- Incorporate full system control room functions by distributing the responsibility throughout the Operations department as opposed to centralizing the function into a twenty-four (24) hour control room.
- Invest in software systems to streamline and automate daily work tasks including: the tracking and recording of asset condition data, the inputting of time entry information, job cost tracking, inventory management, job kitting, the design and accurate estimation of planned work, and the recording of all asset information in the Geospatial Information System ("**GIS**"), among others.
- Develop and integrate into daily use an advanced distribution system monitoring mapping system, called "SmartMAP", that continuously monitors all measurable system events (e.g. meter outages, distribution fault indicators, transformer loading, etc.) and automatically notifies the appropriate personnel of any system condition that requires further investigation and inspection.

EPL chose to respond and manage its unique challenges by implementing changes and new processes that are responsive to the Values it has adopted. These Values and those adopted by the electrical industry in Ontario, such as the RRFE, are integral to how EPL prioritizes its capital investments and guide its future direction.

1.2 Outline of Report

This DSP has been organized using the same headings as the Filing Requirements, with the corresponding section number from the Filing Requirements included in brackets for each heading.

The report contains four sections including this introductory section as Section 1. Section 2 provides a high-level overview of the DSP, including coordinated planning with third parties and performance measurement for continuous improvement. Section 3 provides an overview of EPL's asset management process, including an overview of the assets managed and asset lifecycle optimization policies and practices. Section 4 provides a summary of EPL's capital expenditure plan, including an overview of the capital expenditure planning process, an assessment of the system capability for REG, and justification of material projects.

1.3 Background & Drivers

EPL's capital investments over the planning period have been aligned to the four (4) categories of system access, system renewal, system service, and general plant. Investments within these categories have been paced and prioritized to meet the objectives of the RRFE.

System access investments are modifications to EPL's distribution system (including asset relocations) that EPL is obligated to perform to provide customers with access to electricity services via the distribution system. Drivers for this investment category are customer service requests, other third-party infrastructure development requests, and mandated service obligations (e.g. as per the Distribution System Code).

System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of EPL's distribution system to provide customers with electricity services. Assets and asset systems may be at the end of their service life due to failure, failure risk, substandard performance, high performance risk, or functional obsolescence.

System service investments are modifications to EPL's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements. Drivers for this investment category include expected changes in load that will constrain the ability of the system to provide consistent service delivery and meeting system operational objectives in safety, reliability, power quality, and system efficiency.

General plant investments are modifications, replacements or additions to EPL's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities. Drivers for this investment category include system capital investment support, system maintenance support, business operations efficiency, and non-system physical plant.

Table 1-1 summarizes the drivers for the capital projects/programs planned over the forecast period.

Table 1-1: Capital investment drivers over the forecast period

Investment Category	Driver	Projects/Programs
System access	Customer service requests	Residential connections/extensions
		New service upgrades – commercial and industrial
		Subdivisions
	Third-party infrastructure development requirements	Municipal requests
	Mandated service obligations	Metering upgrade and replacement program
System renewal	Asset failure	Overhead reactive replacements
		Underground reactive replacements
	Assets at the end of their service life due to failure risk	Pole replacement program
		PMH replacement program
		Load break switch replacement
		Infrastructure rebuild program
System service	System operability	Purchase/sell HONI Leamington assets
		Purchase/sell HONI LaSalle assets
	System reliability	Self-healing grid reclosers
	System capacity	Malden TS new feeders and reconfiguration
	Customer-driven generation connection requests	FIT and generation connections
		MicroFIT connections
General plant	Non-system physical plant	Buildings and fixtures
	Business operations efficiency	Computer software
	Non-system equipment at the end of its service life	Tools and equipment
		Transportation equipment
		Office furniture and equipment
		Computer hardware
		Stores equipment

1.4 Description of the Utility Company

Restructuring of the utility industry presented many challenges and opportunities when the *Investing in Ontario Act, 2008* (Bill 35) was passed. Existing public utility commissions had to evolve and become standard Ontario business corporations, owned by local municipalities that they served. The new corporations answered to the OEB and were responsible for regulatory, rate setting, and licensing matters in the electricity market.

At that time, the four (4) municipalities of Amherstburg, LaSalle, Leamington, and Tecumseh made a strategic decision to pool the resources of their utilities together to avoid various costs of deregulation and to maximize efficiencies of scale.

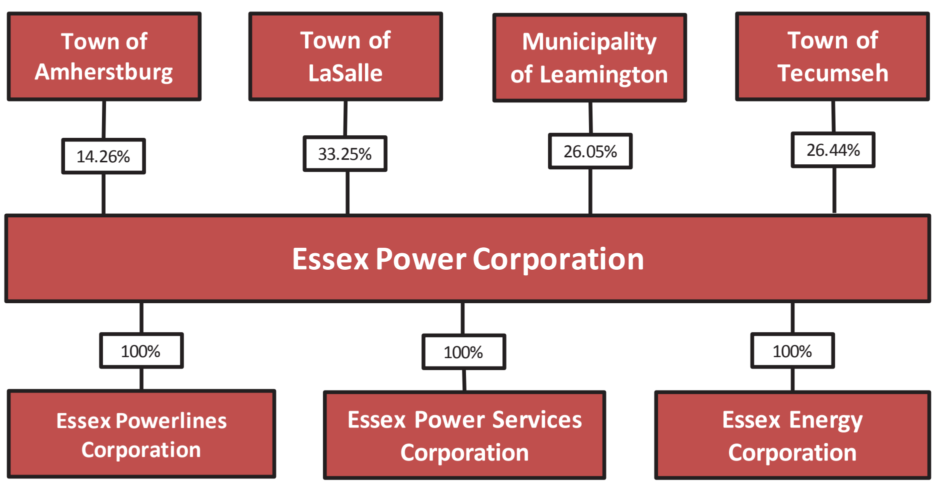
On June 1, 2000, the Towns of Amherstburg, LaSalle, and Tecumseh and the Municipality of Leamington amalgamated their small utilities to form what is currently known as the Essex Power Group of Companies. The assets, such as the wires were transferred to EPL. Essex Power Services Corporation received the employees such as lineman and the billing clerks and Essex Power Corporation received the finance, analyst, and management positions required to oversee the subsidiaries and provide administrative financial support.

All administration from the four (4) utilities was consolidated. Operations such as billing, collecting, finance, payroll, and accounts payable were centralized in November 2000; administrative staff were located at the Essex County Civic Centre in Essex, Ontario. Outside staff were moved to the Oldcastle service station in the spring of 2003. All staff were consolidated into the Oldcastle service station in 2012.

Today, EPL strives to provide value to its now approximately 30,000 customers by minimizing outages and providing best-in-class customer service with minimal increases to electricity distribution rates. The Application will outline the various ways that EPL is achieving these goals.

Figure 1-1 illustrates Essex Power Corporation's corporate structure and its relationship with its four (4) respective shareholders.

Figure 1-1: Essex Power Corporation's corporate structure



Essex Power Corporation is owned by four (4) municipally-owned shareholders: the Town of Amherstburg (14.26%), the Town of LaSalle (33.25%), the Municipality of Leamington (26.05%), and the Town of Tecumseh (26.44%). While equity percentages differ for each shareholder, they each hold equal voting rights. Essex Power Corporation serves as the holding company for its subsidiary group of companies.

EPL is a wholly-owned subsidiary of Essex Power Corporation. EPL is a licensed local distribution company (“**LDC**”), with Distribution License ED-2002-0499, which distributes electricity to approximately 30,000 customers across its four (4) shareholder communities.

Essex Power Services Corporation is a wholly-owned, unregulated subsidiary of Essex Power Corporation and aims to provide best-in-class municipal and LDC services such as streetlight maintenance and subdivision work. Essex Power Services Corporation is also a Meter Service Provider – MSP1034 – registered with the Independent Electricity System Operator (“**IESO**”).

Essex Energy Corporation is a wholly-owned, unregulated subsidiary of Essex Power Corporation. Essex Energy Corporation is a dynamic energy technology company providing various services and technology-related solutions to electrical utilities, generators, transmitters, and consumers across North America.

1.4.1 Service Area including Map

EPL’s service area consists of four non-contiguous regions in Essex County located in south-western Ontario: the Town of Amherstburg, the Town of LaSalle, the Municipality of Leamington, and the Town of Tecumseh. Figure 1-2 depicts the County of Essex with EPL’s service areas highlighted. The individual towns are geographically dispersed over a large area, increasing travel time and increasing response time without thorough planning and the availability of advanced sensing and distribution automation equipment. EPL is bordered by Hydro One Networks Inc. (“**HONI**”) south and east of Tecumseh and LaSalle, and the Leamington and Amherstburg service areas are completely encompassed by HONI. EPL is also bordered by EnWin Utilities west of Tecumseh and north of LaSalle. ELK Energy does not directly border EPL’s service areas, but also distributes electricity in the County of Essex.

EPL does not own any substations and instead receives power from four (4) transformer stations (“**TS**”) owned by HONI. Each service area is embedded in a densely-populated area of Ontario and the resultant distribution system is heavily tied to and dependent upon HONI-owned distribution assets. This dependence and influence results in a high percentage of outages originating on the HONI system and beyond the control of EPL to manage with traditional distribution assets such as manually-operated switches and without advanced distribution system sensing devices.

Figure 1-2: Map depicting EPL's four non-contiguous service areas

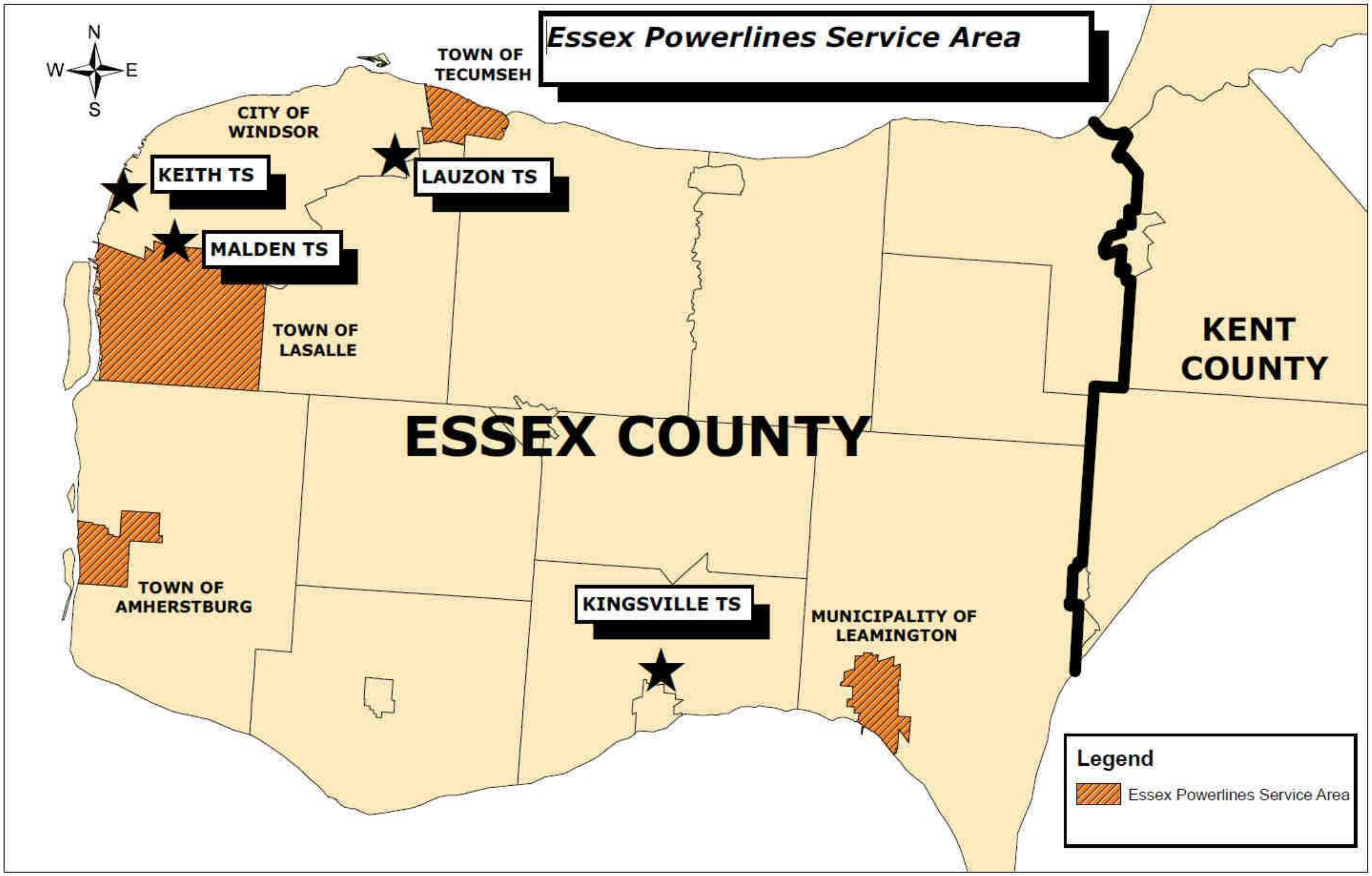
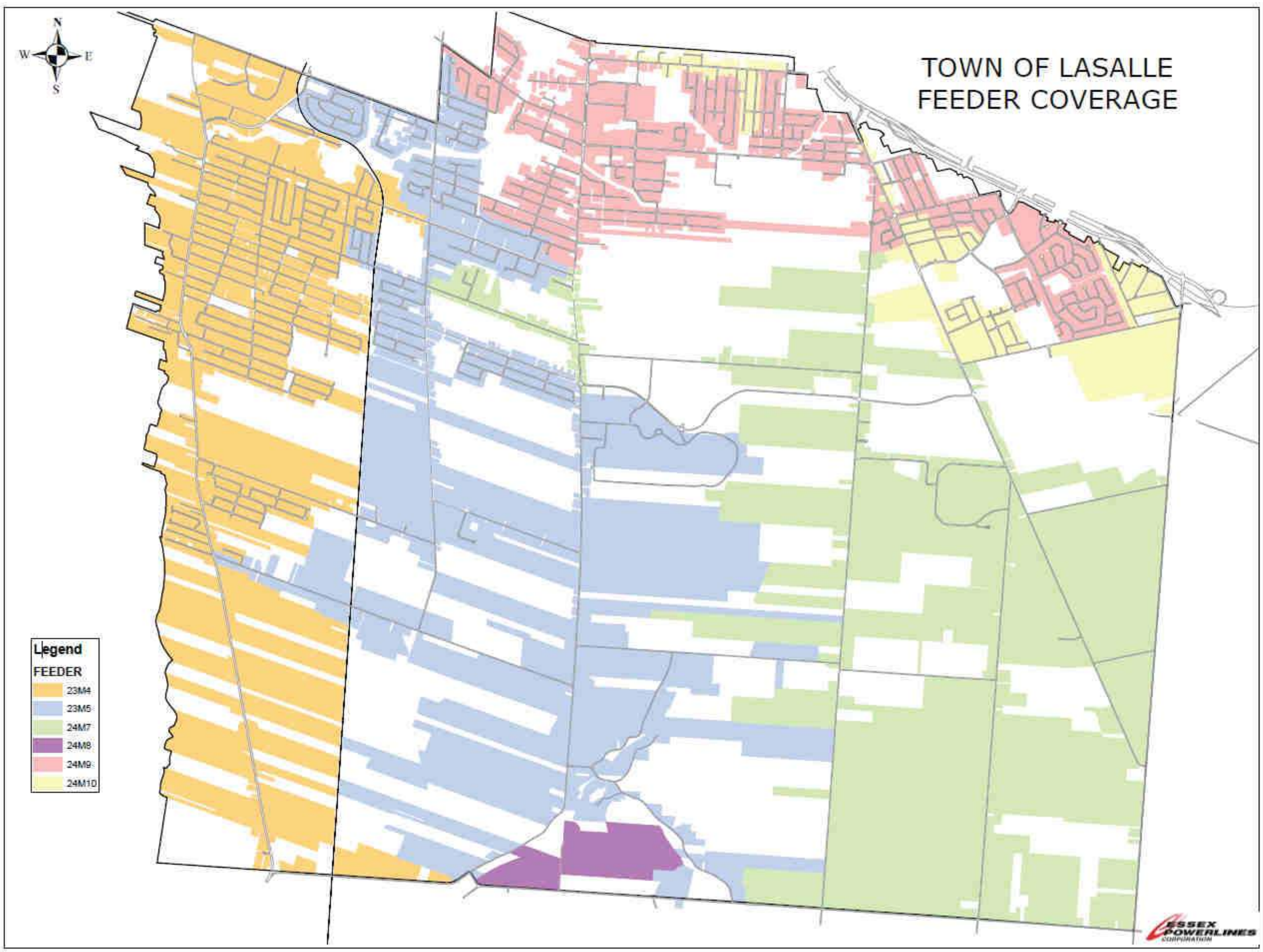
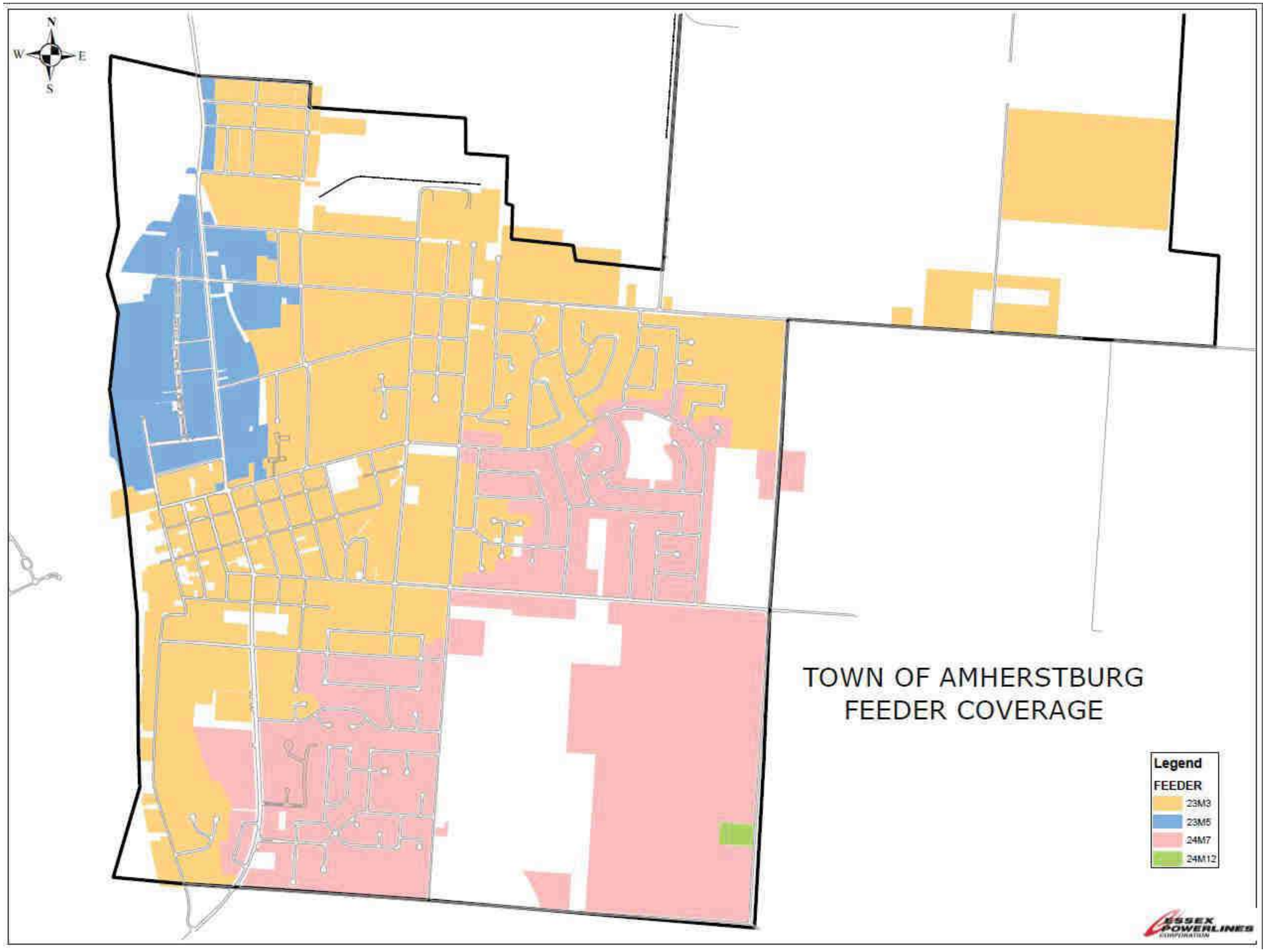


Figure 1-3: EPL's distribution system in LaSalle

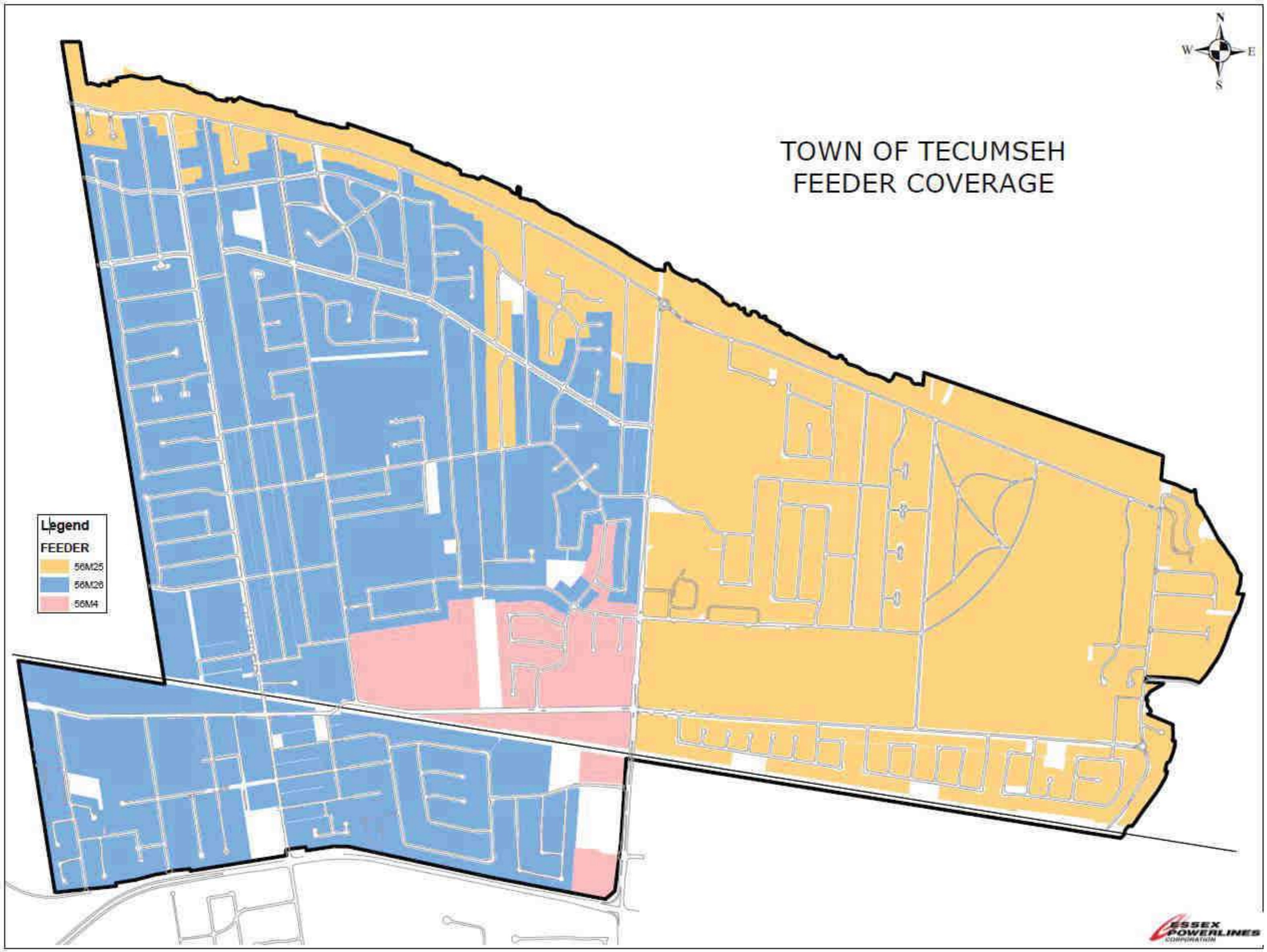


1 Figure 1-4: EPL's distribution system in Amherstburg



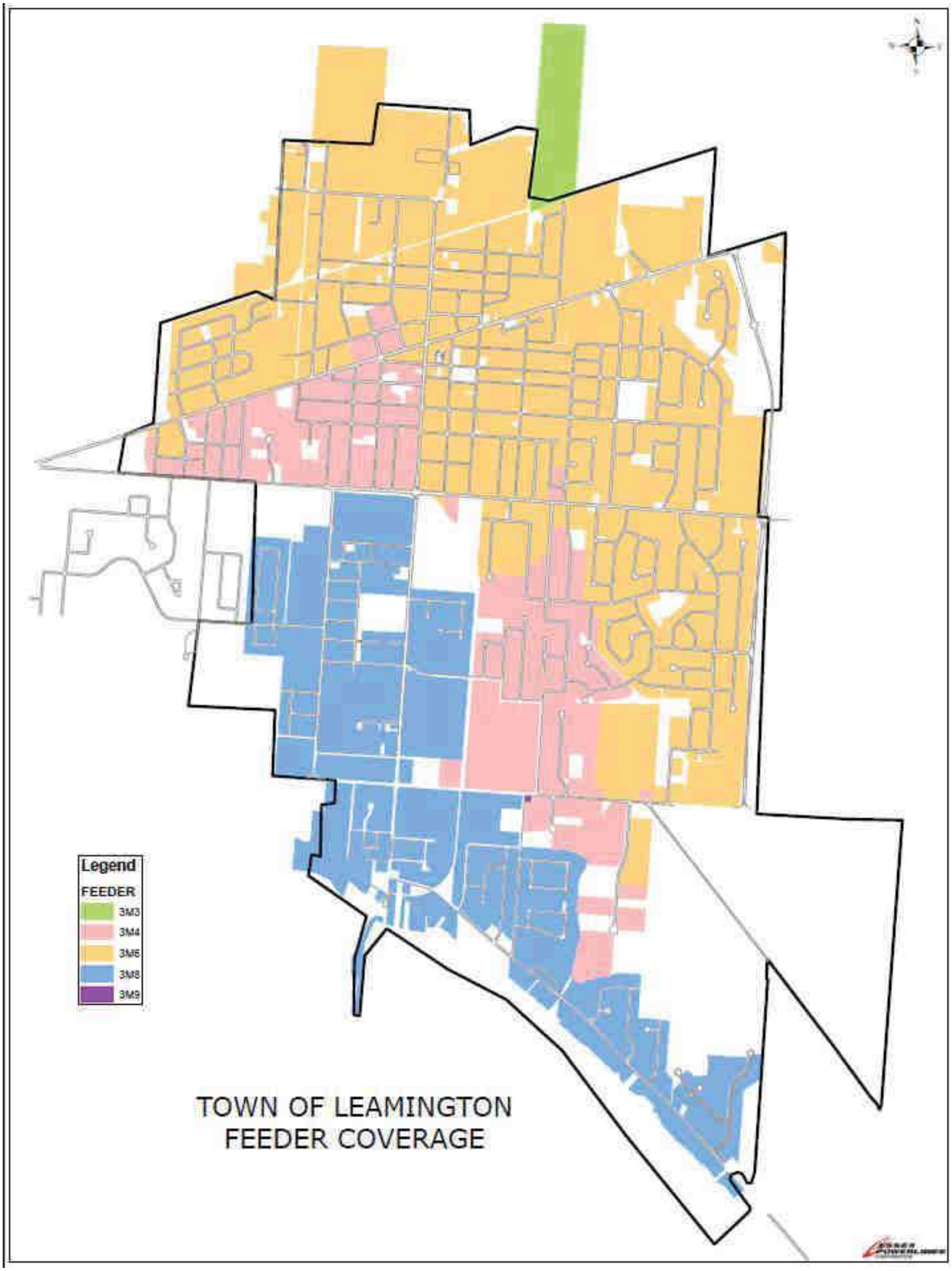
2

1 Figure 1-5: EPL's distribution system in Tecumseh



2

1 Figure 1-6: EPL's distribution system in Leamington



2

1.4.2 Mission & Vision Statement

EPL's mission and vision statements are presented below:

Mission Statement:

Essex Power Corporation is a dynamic energy company that provides safe, reliable, and economical energy supply and services to our customers. Our commitment to innovation, performance management, and leading by example has built the foundation at Essex Power and our affiliates to establish a diverse set of energy products and services that are valued by our customers. At Essex Power, *"Your Power Is Our Priority"*.

Vision Statement:

Essex Power Corporation's vision is to be an Energy Provider that utilizes "best in class" people, processes, and technology to lead the market place in sustainable energy solutions. Our customers will receive the greatest value by integrating an economic and environmental balance to the products and services we will deliver to them. As an Energy Provider, we will be a community leader in ensuring that environmental stewardship is a vital component of our services to increase customer awareness of proper energy utilization and management.

1.4.3 Corporate Values

EPL's capital investment strategy is driven by its corporate values. These corporate values, formulated for EPL's parent company, Essex Power Corporation, have been adopted without change by all affiliated companies in the Essex Power Corporation group of companies.

EPL's business plan and objectives are currently centered around four (4) primary themes:

- Tying EPL's key values with the RRFE;
- Deploying "Best-In-Class" solutions and technologies on common platforms with various channel partners;
- Standardizing to a common primary voltage class & assets; and
- Developing and implementing a "Self-Healing Grid".

EPL's mandate is to implement the items above, which will have material benefits for customers, all while maintaining reasonable distribution rates.

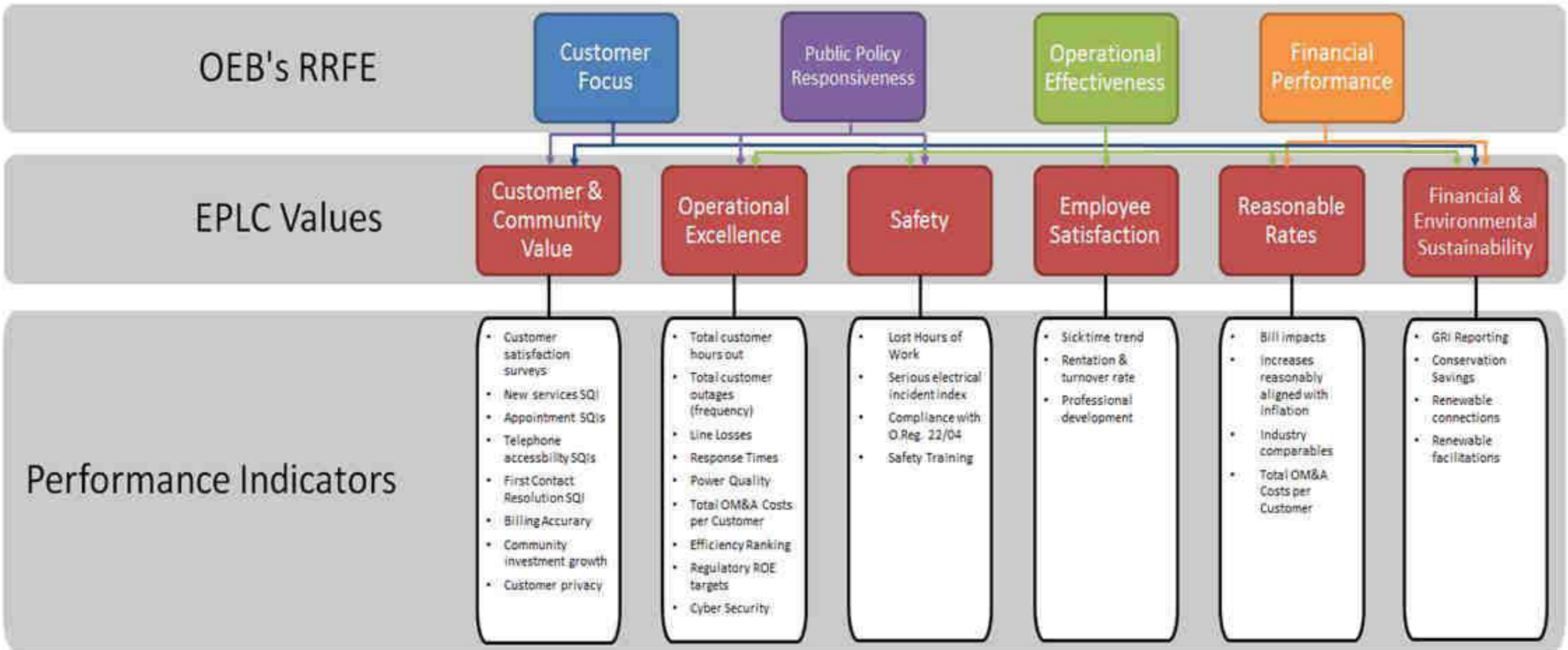
1.4.3.1 Tying EPL's Key Values with the RRFE

EPL has identified six (6) core corporate values:

1. Customer & Community Value;
2. Operational Excellence;
3. Safety;
4. Employee Satisfaction;
5. Reasonable Rates; and
6. Financial & Environmental Sustainability.

Figure 1-7 relates EPL's corporate values to the four (4) objectives of the RRFE.

Figure 1-7: EPL’s corporate values



1.4.3.1.1 Customer & Community Value

<u>Description of Value & Ties to RRFE:</u>

EPL's core value of driving Customer & Community Value is defined as follows:

"EPL is dedicated to meeting and exceeding customer & community needs by providing services that are cost effective and put the needs of its customers first."

This value can be tied to the OEB's RRFE outcomes of Customer Focus and Public Policy Responsiveness.

Examples of EPL's commitment to this value can be demonstrated as follows:

- Customer Satisfaction Surveys;
- Energy conservation and demand management ("**CDM**") program participation;
- Investing back in each of the four (4) shareholder communities through various charitable organizations; and
- Maintaining just and reasonable rates in line with inflation.

1.4.3.1.2 Operational Excellence

<u>Description of Value & Ties to RRFE:</u>

EPL's core value of delivering Operational Excellence is defined as follows:

"EPL strives for Operational Excellence through all services that it provides by advocating continuous improvement and implementing Best-In-Class and cost-effective solutions that deliver customer value."

This value can be tied to the OEB's RRFE outcomes of Operational Effectiveness and Public Policy Responsiveness.

Examples of EPL's commitment to this value can be demonstrated as follows:

- Development of EPL's DSP;
- Implementing best-in-class solutions and shared services;
- Facilitating the self-healing grid;
- Progressing towards a single distribution voltage;
- Successful and cost-effective implementation of public policy initiatives such as smart meters, Time of Use ("**TOU**") billing, renewable energy generation ("**REG**") connections and facilitation, CDM programs, etc.; and
- Maintaining just and reasonable rates in line with inflation.

1.4.3.1.3 Safety

<u>Description of Value & Ties to RRFE:</u>

EPL's core value of advocating the importance of Safety across its entire operation can be defined as follows:

"EPL is committed to a Safety-First mentality across its entire operation."

This value can be tied to the OEB's RRFE outcomes of Operational Effectiveness and Public Policy Responsiveness.

Examples of EPL's commitment to this value can be demonstrated as follows:

- Joint Health & Safety Committee;
- First Aid, CPR, and defibrillator training;
- Specialized Safety Training; and
- School Electrical Safety Awareness.

1.4.3.1.4 Employee Satisfaction

Description of Value & Ties to RRFE:

EPL's core value of driving Employee Satisfaction is defined as follows:

"EPL is committed to encouraging and developing engaged and empowered employees."

This value can be tied to the OEB's RRFE outcome of Operational Effectiveness.

Examples of EPL's commitment to this value can be demonstrated as follows:

- Wellness Committee;
- Employee Assistance Program;
- Corporate Charity Events;
- Employee Recognition; and
- Corporate Team-Building Events.

1.4.3.1.5 Reasonable Rates

Description of Value & Ties to RRFE:

EPL's core value of maintaining Reasonable Rates is defined as follows:

"EPL will implement Best-In-Class technologies and solutions to provide our employees with the necessary information to make prudent decisions, control costs and minimize interruptions while providing reasonable rates for our electricity customers."

This value can be tied to the OEB's RRFE outcomes of Operational Effectiveness and Financial Performance.

Examples of EPL's commitment to this value can be demonstrated as follows:

- Maintaining just and reasonable rates, in line with inflation;
- Prudent Investments in Smart Grid; and
- Controllable Costs per Customer in line with leaders in Ontario.

1.4.3.1.6 Financial & Environmental Sustainability

Description of Value & Ties to RRFE:

EPL's core value of championing Financial & Environmental Sustainability is defined as follows:

"EPL strives to achieve balanced economic, social and environmental returns that ensure the future viability of our company for the benefit and well-being of our shareholders and the communities we serve."

This value can be tied to the OEB's RRFE outcomes of Operational Effectiveness, Customer Focus, and Financial Performance.

Examples of EPL's commitment to this value can be demonstrated as follows:

- Yearly Global Reporting Initiative sustainability reporting;
- CDM program participation;
- Facilitating REG connections; and
- Maintaining just and reasonable rates in line with inflation.

1.4.3.2 Best-In-Class Solutions & Shared Services

EPL has worked closely with a variety of service providers to maximize the scope and quality of services rendered to customers. One such example of a Best-In-Class technology deployment was in 2012. EPL, in partnership with its sister company Essex Energy Corporation, was successfully awarded an Ontario Smart Grid Fund grant to demonstrate the capabilities and functionality of a new software product called SmartMAP.

The SmartMAP product uses smart meter data as its primary source of information, which provides many cost-effective advantages for small- and medium-sized LDCs. SmartMAP aims to enhance the Operations, Engineering, and Customer Service departments in the effective management of REG integration, outage identification and restoration, and an overall faster, more efficient, and cost-effective decision-making tool.

The implementation of SmartMAP has enabled:

- Integration of existing smart meters with the Outage Management System to transmit "last gasp" data in real time, allowing the analysis component to pinpoint exact outage locations, predict causes, and suggest switching changes to restore power faster;
- Transformer loading profile (kWh vs. time of day, kVA vs. time of day) aiding in identification of under- or over-loaded assets;
- Reporting of line losses from wholesale meters, transformers, and residential meters;
- Identification and location of low voltage conditions which signal failing equipment or wrong transformer tap settings;
- Reconciliation of loads connected to each transformer to assist in identifying non-technical losses;
- Web application available to Operations personnel such that reporting and problem-solving is made quicker and easier;

- Ability to communicate critical network alarms and messages to a cellular phone through the use of email or SMS;
- Visual monitoring of real-time operational data from field devices (fault/line monitors, automated reclosers or switches, and any other field device capable of providing real time feedback) on a graphic display; and
- A common platform for data and analysis that can be used by different LDCs across any geography.

EPL, along with its partner Collus PowerStream, was recently awarded the Innovation Excellence Award by the Electricity Distributors Association for the joint "Digital Grid 2.0" project which featured the SmartMAP product.

1.4.3.3 Essex Powerlines – An Efficient Single-Voltage Utility

For more than a decade now, EPL has prioritized the completion of necessary conversion work to simplify its distribution system, reduce inventory, shrink maintenance costs, and reduce its distribution losses for the benefit of EPL's customers. While EPL generally only controls approximately 20% of the total electricity (i.e. distribution charges), reducing losses has been a mandate for at EPL since distribution losses affect a broader portion of the electricity bill.

EPL has eliminated eight (8) substations (with the last one coming out of service in 2016) and converted significant lengths of line to become as close to a single-voltage utility as technically possible. EPL still has a small number of step down transformers in remote areas; however, EPL plans to convert them when most technically and financially feasible.

As a result of this work, EPL has been able to significantly reduce distribution losses throughout its distribution system resulting in significant savings for its customers.

Table 1-2: EPL Voltage Conversion Results

Line Loss Category	2017 (Actual)	2018 (Proposed)	Variance
Secondary Metered Customer	1.0602	1.0355	-0.0247
Primary Metered Customer	1.0496	1.0251	-0.0245

1.4.3.4 The Self-Healing Grid

In 2014, EPL completed its first iteration of its Green Energy Act Plan and, subsequently, a Smart Grid Development Plan. Along with SmartMAP, EPL outlined its plan to shift to a smarter grid that was capable of reducing the impact of Loss of Supply incidents on customers. By installing upgrades in three (3) key areas, EPL is evolving its grid into a "Self-Healing Grid":

1. Line monitors;
2. Reclosers; and
3. Wholesale meters.

Line Monitors:

The installation of line monitors provides EPL with a significant improvement to the information that it currently collects relating to the day-to-day operation of its system. This improved information allows EPL to make better operational, engineering, and planning decisions. Integrating this data into the SmartMAP toolset has also provided EPL near real-time data at a fraction of the cost of SCADA implementation.

Reclosers:

Historically, EPL's service territory consisted solely of manual load-break switches which required manual operation and provided no fault protection. Fault protection was provided by a station breaker or an upstream recloser outside of EPL's service territory. With the implementation of remotely-controlled reclosers ("**smart reclosers**"), EPL is facilitating the capabilities of remote operation, real-time outage detection, as well as the ability to isolate the system from an upstream distributor/transmitter. Furthermore, incremental data about EPL's distribution system is gathered and fed into the SmartMAP toolset.

Wholesale Meters:

EPL has upgraded its wholesale metering installation to ION TCP/IP installations in order to enhance meter data transfer, add outage detection and facilitate real-time data acquisition. These upgrades to EPL's wholesale meter data have been implemented directly into the SmartMAP toolset.

As Loss of Supply incidents continue to cause over 75% of EPL's total customer interruption hours, EPL continues to make prudent investments to minimize customer outage impacts and enhance overall customer value.

1.4.4 Customers Served

EPL services approximately 30,000 customers in its four non-contiguous service areas, but does not service all customers within the respective municipalities' borders except for the Town of LaSalle. In the other towns, the rural areas are serviced by HONI. EPL's customer base is primarily residential and small commercial customers and there are very few large industrial customers.

Most of EPL's customers fall into one of the following classes: Residential, General Service ("**GS**") less than 50 kW, GS greater than 50 kW (up to 2,999 kW), and GS 3,000 to 4,999 kW. EPL also serves streetlight customers (municipalities), sentinel lights, and unmetered loads. The year-end customer counts for the years 2013 to 2016 of the historical period are shown in Table 1-3. The total number of customers increased by an average rate of 5% per annum over this period.

Table 1-3: Year-end customer counts over the historical period

Customer Class	2013	2014	2015	2016
GS 3,000 to 4,999 kW	1	1	0	0
GS less than 50 kW	1,904	1,910	1,936	1,953
GS greater than 50 kW	214	216	217	223
Residential	26,466	26,590	26,815	27,137
Streetlights	2,621	2,713	2,701	2,720
Sentinel Lights	175	172	174	173
Unmetered	140	140	141	140
Total	**31,521**	**31,742**	**31,985**	**32,346**

1.4.5 Energy Conservation and Demand Management

EPL is an active participant in CDM programs administered by the IESO. Under the previous CDM framework spanning from 2011 to 2014, EPL was assigned a net annual peak demand savings target of 7.19 MW and a net cumulative energy savings target of 21.54 GWh.

As shown in Figure 1-8, Essex did not meet its target for net annual peak demand savings, finishing at 3.2 MW or forty-four percent (44.4%) of the target. The loss of a demand response contract with Heinz Corporation was the biggest detriment to EPL's performance. EPL's service territory is primarily residential with only small-scale industrial customers, making demand management programs difficult to implement.

Figure 1-8 also depicts the net cumulative energy savings performance, which exceeded EPL's target, totalling 23.3 GWh or 108.0% of the target. The two most effective programs for EPL were the Retrofit and HVAC Incentive programs. EPL's customers realized 9,806,366 kWh and 3,470,981 kWh in savings, respectively, through these programs.

Figure 1-8: CDM achievements under the previous framework

Final 2014 Achievement Against Targets	2014 Incremental	2011-2014 Achievement Against Target	% of Target Achieved
Net Annual Peak Demand Savings (MW)	1.7	3.2	44.4%
Net Energy Savings (GWh)	3.8	23.3	108.0%

Unless otherwise noted, results are presented using scenario 1which assumes that demand response resources have a persistence of 1year.

Achievement by Sector

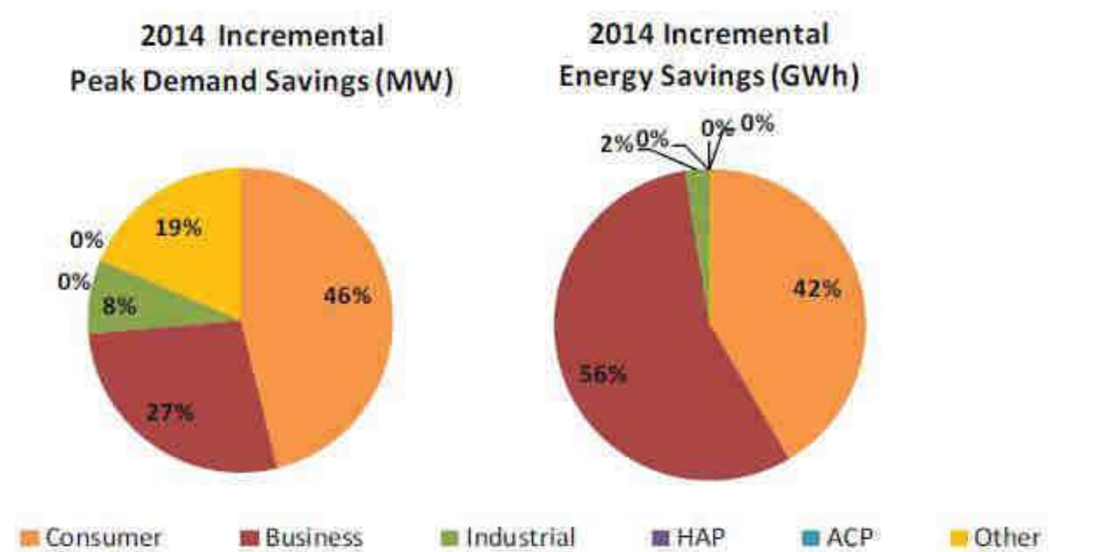


Figure 1-9: CDM performance under the previous framework relative to other LDCs

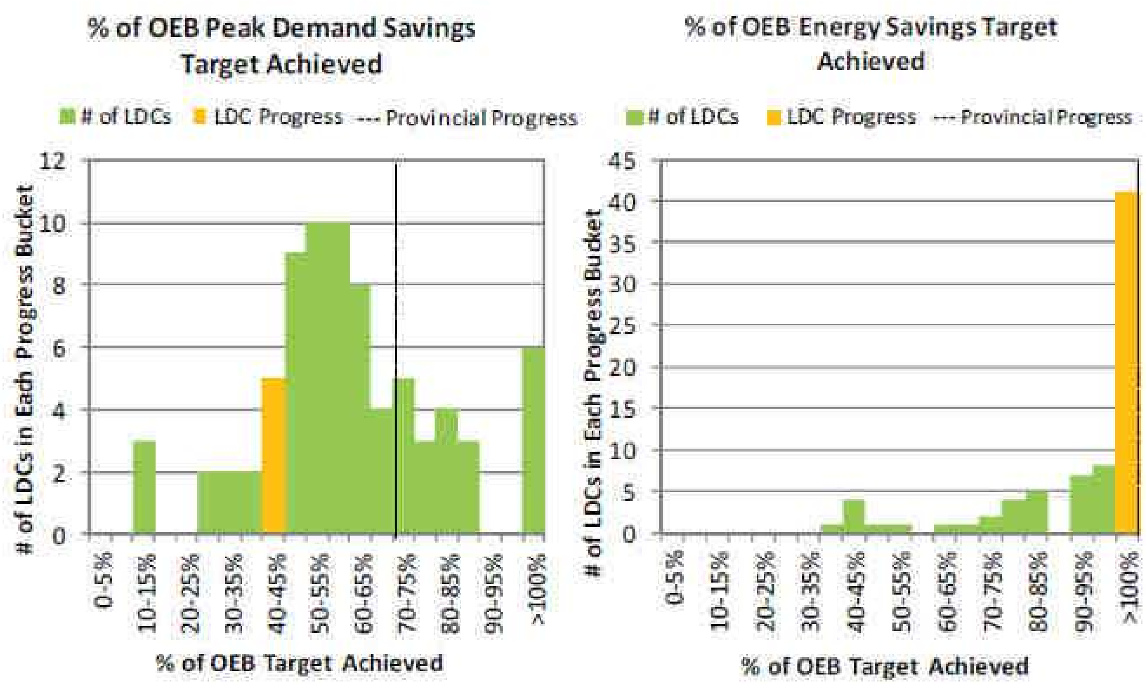


Figure 1-9 depicts EPL's performance under the previous CDM framework relative to other LDCs in the province of Ontario. EPL finished in the bottom quartile for net annual peak demand savings and at the top of the scale for net cumulative energy savings.

The IESO's latest Conservation First Framework spans from 2015 to 2020 and focuses solely on energy conservation. This approach is suited to EPL since its customer base mostly consists of residential customers. EPL was assigned a target of 31.43 GWh in net cumulative energy savings over the six (6)-year period. EPL's annual energy savings targets for the years 2015 through 2020 are presented in Table 1-4.

Table 1-4: EPL's CDM achievement plan under the Conservation First Framework

Year	2015	2016	2017	2018	2019	2020
Annual Energy Savings Target (MWh)	2,660	7,256	10,200	3,837	3,805	3,866

EPL plans to target residential and low-income customers through province-wide Coupon, Heating and Cooling, Home Assistance, and New Construction programs. Small business, customers will be targeted through province-wide Retrofit, Small Business Lighting, High Performance New Construction, and Audit Funding programs. EPL has also planned three unique programs: the Residential Solar PV program for residential customers, the Social Benchmarking program for residential and low-income customers, and the Smart Thermostat program for residential, low-income, and small business customers. Commercial, agricultural, institutional, and industrial customers will be targeted through a number of initiatives such as the Retrofit, High Performance New Construction, Audit Funding, Process and System Upgrades, and Energy Manager programs. These programs are all funded through the 2015-2020 CDM Framework.

In addition, there are several programs from the 2011-2014 CDM Framework that were extended into 2015 through the 2011-2014 Master CDM Agreement. These programs contributed to the 2015 energy savings achievements, but were not funded through the 2015-2020 CDM Framework. Key programs include Residential New Construction, the Bi-Annual Retailer Event, and Heating and Cooling Initiatives.

In 2015 EPL achieved twelve percent (12%) of its six (6)-year target, which is greater than the annual target shown in Table 1-4, while only spending two percent (2%) of its allocated budget. This first-year performance under the Conservation First Framework positions EPL suitably for achieving even greater energy savings in future program years, as significant conservation projects were identified in 2015 for implementation in 2016.

2 Distribution System Plan (5.2)

The section provides a high-level overview of the information filed in the DSP, coordinated infrastructure planning with third parties, and the measures used to monitor distribution system planning performance.

2.1 Distribution System Plan Overview (5.2.1)

As stated in the objective of this DSP, it is EPL's intention to provide a modern, smart grid fit for the 21st century at inflation-aligned costs. To achieve this, EPL is planning to spend less on reactive replacements since planned capital projects and programs are more cost effective. EPL is investing more of its system renewal budget towards underground cable replacements than overhead rebuilds, partly in response to the changing demographics of its system (less overhead kilometres of line) and partly in response to an increased impact of direct-buried cable failures. New reclosers, automated switches, and other smart grid devices are planned to be installed each year of the forecast period to improve the efficiency and functionality of the self-healing grid.

EPL is proposing to purchase and sell assets from and to HONI in LaSalle, Leamington and Amherstburg. This rationalization of asset ownership will accomplish several operational goals simultaneously:

- Create clearer demarcation of asset ownership between HONI and EPL. This will simplifier day-to-day operation of the distribution system.
- Increase the effectiveness of both parties to isolate parts of the system for maintenance and restore power to their respective customers more quickly.
- Significantly simplify the installation and development of a smart grid, a key focus of EPL's DSP throughout the forecast period.

In general, this will allow EPL to ensure that assets are managed more effectively.

In addition, as a result of the asset transfers and a planned HONI upgrade of Malden TS, a feeder reconfiguration planned over the forecast period will ensure sufficient capacity is available to serve EPL's customers. The overall impact of these changes is to focus and address loss of supply issues to improve system reliability.

Other key investments over the forecast period include: system access projects initiated by customers and municipalities, capital contributions to HONI related to Malden TS, and general plant investments required to replace key Automated Metering Infrastructure ("**AMI**") components such as gatekeepers and modems, at end of life.

2.1.1 Key Elements of the DSP (5.2.1a)

Table 2-1 presents the net capital expenditures by investment category, including the system operations and maintenance ("**O&M**") costs for both the historical and forecast period.

Table 2-1: Historical and forecast net capital expenditures and system O&M

Category	Historical ($ '000)					Forecast ($ '000)				
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
System Access	1,766	2,532	2,341	1,759	1,712	1,746	1,781	1,816	1,853	1,835
System Renewal	3,113	3,012	2,695	2,125	2,655	2,693	1,362	2,304	2,248	2,195
System Service	185	177	2,196	1,005	787	707	2,186	1,126	1,243	1,342
General Plant	450	487	547	384	1,504	1,037	856	976	927	968
Net Capital Expenses	5,513	6,208	7,779	5,274	6,658	6,183	6,185	6,222	6,270	6,339
System O&M	2,722	2,994	3,141	3,171	2,794	3,067	3,116	3,162	3,213	3,264

2.1.1.1 System Access

System access investments over the forecast period are driven by customer service requests, municipal infrastructure development requirements, and mandated service obligations such as metering. Customer service requests include residential expansions, individual secondary services, and commercial/industrial services, all of which are partially funded by the customer. Other services such as Feed-in-Tariff ("**FIT**") connections, MicroFIT connections, individual secondary commercial services, and additional commercial meters are 100% funded by the customer. EPL is obligated to relocate its assets, which occupy the public Right-of-Way ("**ROW**"), if requested by municipal entities. These types of jobs are subject to a partial cost-sharing agreement with the municipal entity involved. Mandated service obligations include metering costs over the forecast period, driven by failed and/or obsolete components.

2.1.1.2 System Renewal

System renewal investments over the forecast period are broadly driven by the capital requirements to replace assets at the end of their service life. This includes the planned replacements of poles, switches, and pad-mounted switchgear. Larger projects to rebuild sections the distribution system are planned over the forecast period. Unplanned, reactive replacement of failed underground and overhead assets are also included as part of this investment category.

Over the historical period, EPL's system renewal initiatives focused on voltage conversion – completed in 2017 – and other initiatives such as live-front switchgear replacements.

2.1.1.3 System Service

System service investments over the forecast period are driven by system expansions due to asset acquisitions, system expansions to enable REG investments, and investments into reclosers as part of a self-healing grid to improve system reliability and decrease outage restoration costs. Capital investment in LaSalle from 2019 to 2021 will be made as part of the Malden TS upgrade and will reconfigure the feeders egressing from Malden TS. EPL has budgeted capital funds from 2018 through 2022 as the net expenditures from purchasing and selling assets to/from HONI: in Leamington during the years 2018 and 2019 and LaSalle for the years 2020 through 2022. Investments are required each year of the plan to enable new REG installations to be connected to EPL's system. Finally, new recloser and other smart grid device installations have been planned each year of the forecast period as part of the self-healing grid rollout. These devices will reduce: outage restoration times, the number of customers affected by outages, and EPL resources required to restore power.

2.1.1.4 General Plant

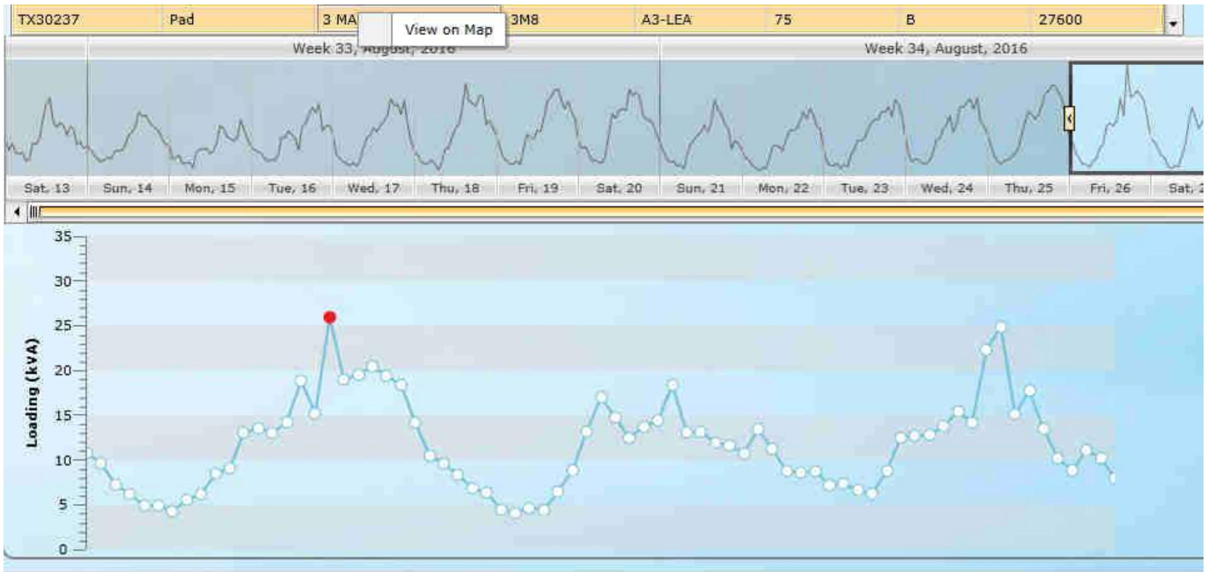
General plant investments over the forecast period are driven by business operations efficiency improvements and non-system physical plant and equipment at the end of its service life. Material programs in this category pertain to buildings and fixtures, transportation equipment, computer software, computer hardware, and tools and equipment.

2.1.2 Anticipated Sources of Cost Savings (5.2.1b)

EPL's investment plan has been optimized using the asset management tools and analyses described in Section 3.1.2. Inputs into EPL's risk-based decision-making model include cost savings and spending, which are optimized along with the other planning objectives (see Section 3.1.1) when developing the five-year investment plan. Therefore, EPL's holistic plan considers cost savings and spending for each proposed project. These impacts can most readily be quantified by annual system O&M spending. Over the historical period the average annual system O&M spending was $2.43M compared to an average of $2.11M over the forecast period. Meanwhile the annual inflation rate over this period is assumed to be 2% and, therefore, the cost savings impacts are greater in real terms.

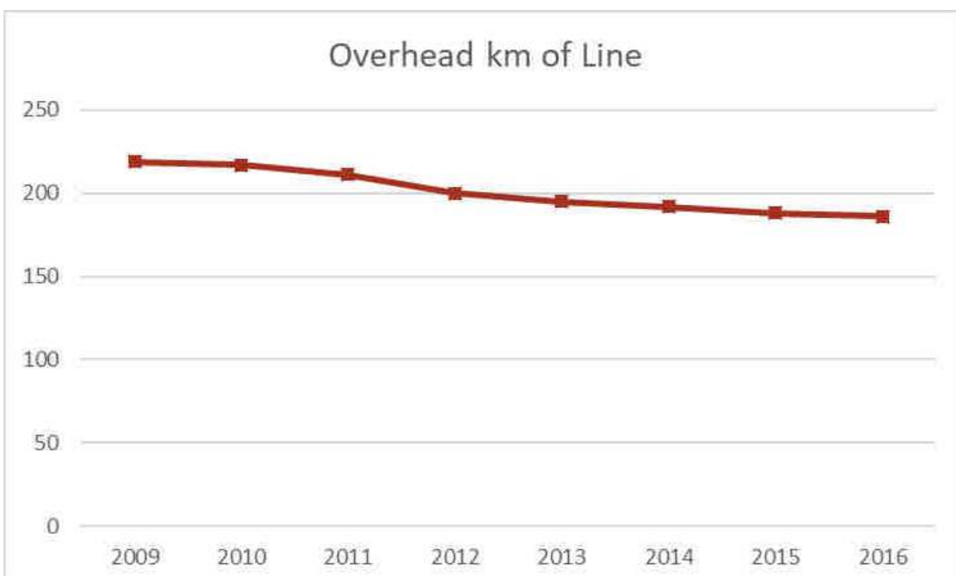
EPL considers lifecycle cost optimization as part of its planning process to fully utilize assets and improve their operating performance. Software models are used to determine the optimal size and number of transformers, as well as the optimal size and length of wires. Transformer peak and historical load data are used to determine how much load or how many customers can be added to the secondary system. In the example shown in Figure 2-1, EPL was able to verify the load history of a distribution transformer to allow additional customer connections without replacing the transformer. Alerts for overloading of a transformer can pre-emptively predict its overloading and can be used to calculate the loss of life due to overloading.

Figure 2-1: EPL is able to monitor transformer load



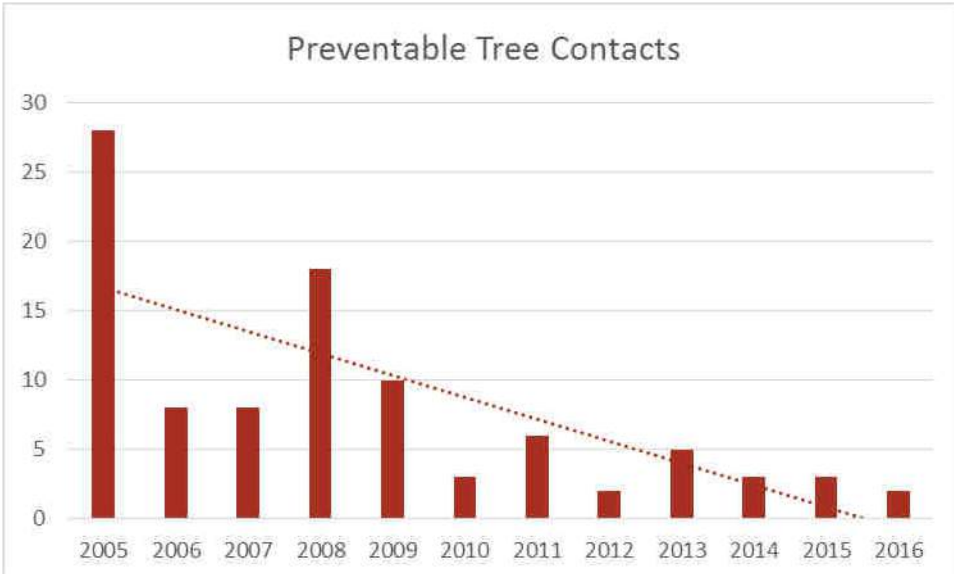
Recently, EPL completed a significant portion of its voltage conversion program, harmonizing its service area to 27.6/16 kV. In addition to eliminating the need to own and maintain a distribution substation, the voltage conversion investments have allowed EPL to reduce its stock, inventory, and kilometres of line under management while the number of customers has continued to increase. Figure 2-2 depicts a decrease in the overhead kilometres of line owned by EPL. Furthermore, EPL was able to reduce its inventory of transformers by analyzing failure rates to determine the number of each size required.

Figure 2-2: Kilometres of overhead line owned by EPL



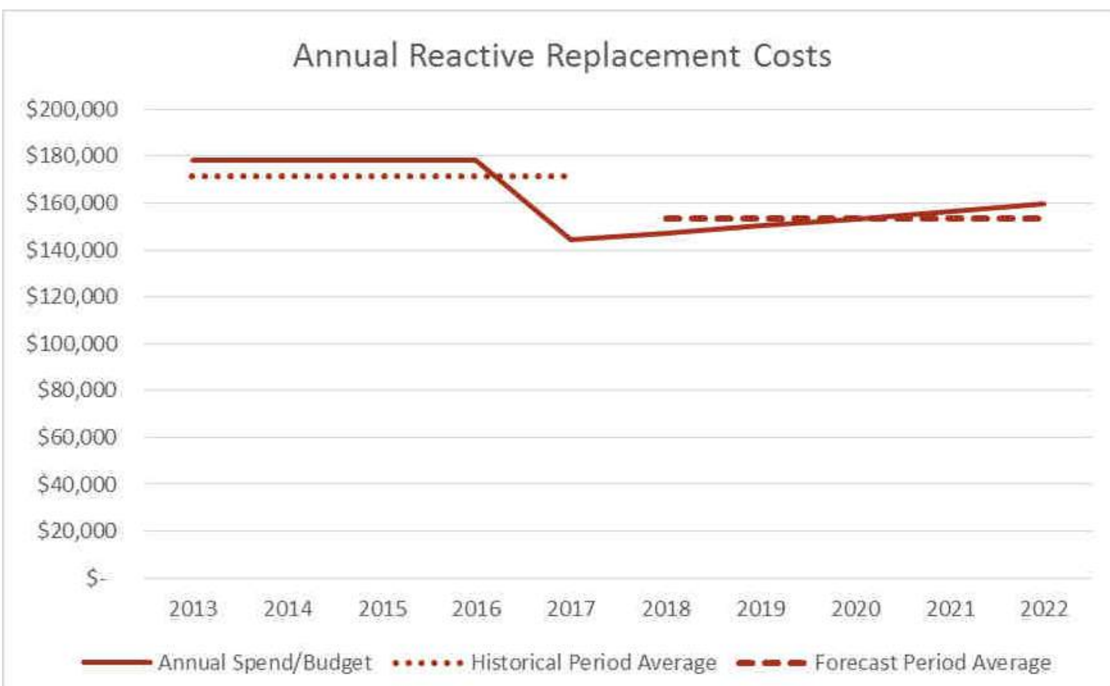
EPL's robust tree-trimming program has reduced the number of preventable tree contacts (i.e. branch contacts) causing an outage. Along with improving the reliability experienced by EPL's customers, the reduction in tree contact outages decreases cost requirements to restore the line. Figure 2-3 depicts this trend.

Figure 2-3: Preventable tree contacts have been trending downwards



EPL has increased the amount of planned capital work over the forecast period and has consequently budgeted less capital spending on reactive replacements over the forecast period compared to the historical period average. This is a more cost-effective investment strategy since planned replacements generally cost less than reactive replacements, which may require emergency or overtime work.

Figure 2-4: Annual reactive replacement costs



EPL has also planned investments in the system service category that will help to achieve cost efficiencies over the forecast period. New distribution recloser installations as part of a self-healing grid are primarily installed to improve the reliability of EPL's system by reducing the duration and number of customers affected by an outage. The installation of new distribution reclosers and other smart grid devices, such as remote notification fault indicators, has the added benefit of localizing the source of an outage. This reduces the number of truck-rolls for locating the outage source, thereby reducing O&M costs associated with each outage restoration.

2.1.3 Period Covered by DSP (5.2.1c)

The proposed DSP has been prepared for the following period:

Table 2-2: Period covered by the DSP

Historical Period					Forecast Period				
				Bridge Year	Test Year				
2013	2014	2015	2016	2017	2018	2019	2020	2021	2022

2.1.4 Vintage of the Information (5.2.1d)

The information contained within this DSP should be considered current as of July 2017.

2.1.5 Important Changes to Asset Management Processes (5.2.1e)

This is EPL's first DSP filing; however, since its previous Cost of Service Application in 2010, EPL has invested in improved data quality and improved asset management analytic tools. Specifically, EPL has improved the data quality of its Geo-Spatial Information System ("**GIS**") and partnered with a technology firm, UtiliSmart Corporation, to overlay EPL's proven Distribution Engineering Simulation Software ("**DESS**") onto the GIS. The resultant SmartMAP software solution received funding through the Ontario Ministry of Energy's Smart Grid Fund. The initiative started in 2012 and continues to be developed and enhanced. EPL's asset management software was also enhanced with Asset Condition Assessment ("**ACA**") capabilities overlaid onto the GIS, called "HealthMAP". Additional information pertaining to EPL's asset management planning process can be found in Section 3.1.2.

The HealthMAP provides valuable inputs to the ACA report used to quantify the condition of EPL's assets. Deficiencies noted during inspections, the priority of the issues, and test results can be directly exported from the HealthMAP tool. EPL's ACA report is attached as Appendix J to the DSP.

2.1.6 DSP Contingencies (5.2.1f)

The majority of system access investments planned over the forecast period must be initiated by parties external to EPL. Customer service projects such as residential expansions, individual secondary services, and commercial/industrial services are requested by the customer. Municipal requirements to relocate EPL's assets occupying the ROW are initiated at the request of the municipality involved. Therefore, the level of capital investment in these categories depends on the amount of work requested by customers and municipalities.

Reactive spending in the system renewal category is largely outside of EPL's control. Dependent on factors such as storms and unclaimed damage to EPL's plant, spending in this category can fluctuate between years.

Some system service investments pertaining to system expansion are contingent on construction activities by HONI. The need to invest in transmission capacity in these areas was identified through the Regional Planning Process (see Section 2.2.2). There are existing agreements related to the construction of Leamington TS to purchase assets from and sell assets to HONI. There is also an existing agreement to purchase assets from HONI in LaSalle that is contingent on the completion of the Malden TS upgrade project. A project to reconfigure EPL's feeders egressing from Malden TS is also contingent on the successful completion of the upgrade by HONI.

2.2 Coordinated Planning with Third Parties (5.2.2)

2.2.1 Summary of Consultations (5.2.2a)

2.2.1.1 Customer Surveys

EPL commissioned Innovative Research Group ("**INNOVATIVE**") to design and carry out a Customer Satisfaction Survey of EPL's residential and GS<50 customers on its behalf in 2014. Two years later, EPL commissioned Convergys to perform a Top Down Survey to measure and help improve customer satisfaction. The latest Ratepayer Telephone Survey was completed by INNOVATIVE in 2017.

<u>Purpose of the Consultations</u>

The purpose of the customer surveys is to measure customer satisfaction, determine customer needs and preferences, and identify opportunities to improve customer experience. The INNOVATIVE Customer Satisfaction Survey also educated participants about Ontario's distribution system, EPL's role in delivering power to households and businesses, the interpretation of their electricity bill, and the availability of e-billing. The Convergys survey focused on the key drivers to customer satisfaction to identify opportunities for improvement. The most recent INNOVATIVE Ratepayer Telephone Survey asked customers whether they accept EPL's current five-year plan (this DSP) and distinguished between customers' willingness to pay for reliability improvements versus maintaining system reliability and

<u>Whether EPL Initiated the Consultation</u>

EPL commissioned INNOVATIVE and Convergys to initiate the customer consultations on its behalf.

<u>Other Participants in the Consultation</u>

Customers participated in telephone surveys conducted by the research firms. The INNOVATIVE Customer Satisfaction Survey included 210 residential and 98 GS<50 customers. The Convergys survey interviewed 400 residential and 100 GS<50 customers. The INNOVATIVE Ratepayer Telephone Survey interviewed 524 residential customers, 51 GS<50 customers, and 9 GS>50 customers.

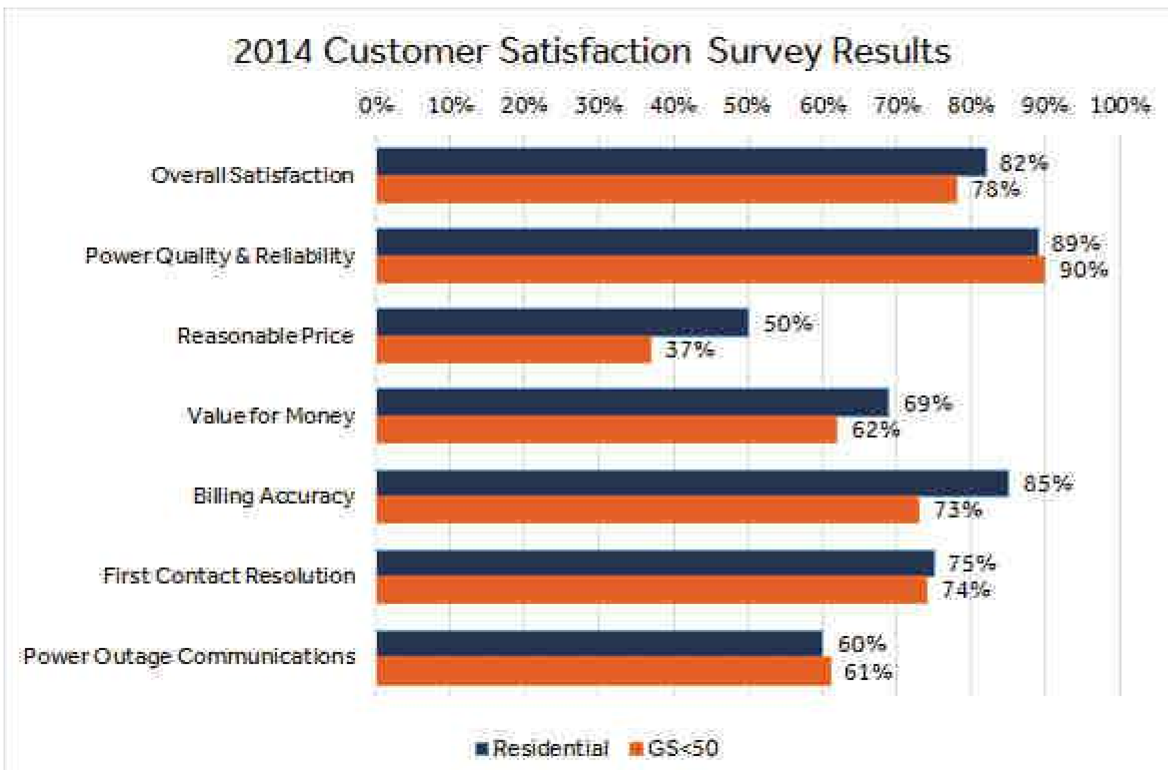
<u>Nature and Prospective Timing of the Final Deliverables</u>

Both INNOVATIVE reports are attached as Appendix D.

INNOVATIVE submitted the final report for its Customer Satisfaction Survey findings in November 2014. Overall, eighty-two percent (82%) of residential customers and seventy-eight percent (78%) of GS<50 customers indicated they were satisfied with EPL. Figure 2-5 depicts customer satisfaction measured in terms of:

- Power quality and reliability
- Reasonable price
- Billing accuracy
- First contact resolution
- Power outage communications
- Value for money

Figure 2-5: Percentage of satisfied customers for surveyed customer classes in 2014



The Ratepayer Telephone Survey was finalized in July 2017. Residential and GS customers agree that EPL should spend what is needed to maintain the current length of unexpected outages. While residential customers tend to think EPL should spend what is needed to maintain the current level of unexpected outages, GS customers lean towards spending what is needed to reduce the number of unexpected power outages. The majority of residential and GS customers agree that EPL should:

- Invest what it takes to replace aging infrastructure to maintain system reliability, even if that requires an increase to their bill;
- Replace equipment proactively before it breaks down;
- Modernize the distribution system; and
- Ensure staff have access to proper tools and equipment as long as EPL spends its funds wisely.

At the end of the survey, eighty-two percent (82%) of residential customers gave social permission for a rate increase of approximately $0.30 per month based on EPL's proposed DSP, with forty-five percent (45%) opining that the rate increase is reasonable and they support it, while thirty-seven percent (37%) don't like the proposed rate increase but feel it is necessary. Meanwhile, only sixteen percent (16%) of surveyed residential customers oppose the rate increase and feel it is unreasonable. Out of the sixty (60) surveyed GS customers, twenty-five (25) find the proposed rate increase reasonable and support it, twenty-two (22 don't like the proposed rate increase but feel it is necessary, and twelve (12) oppose the rate increase and find it unreasonable.

Convergys submitted the final report of its findings in November 2016. The customer satisfaction measured by Convergys in 2016 is summarized in Figure 2-6. Overall satisfaction and the quality of power service (reliability) is consistent with 2014 measurements. Residential customers prioritize customer service as a key driver to overall satisfaction, while business customers prioritize reliability and power quality. Quality of customer service increased, while first contact resolution decreased. The 2014 INNOVATIVE survey indicated that first contact resolution tends to be low when customers call regarding power outages. Affordability of service is still a key issue for EPL's customers.

Figure 2-6: Customer satisfaction measured in 2016

The complete report is attached as Appendix E.

Effect on the DSP

The customer feedback received from the surveys indicates that the cost of electricity is important to EPL's customers, especially residential households. The majority of residential and General Service customers are satisfied with the reliability, power quality, and customer service offered by EPL. To address the preferences of its customers, EPL has not planned any substantial rate increases for its customers. Instead EPL has developed a five-year DSP that identifies key investments to operate a modern smart grid fit for the 21st century, while keeping rate proposed rate increases in line with inflation. Specifically, a consumer bill impact metric has been identified in Section 2.3.1.2 to measure the success of the DSP.

EPL's customers support investing what it takes to replace aging infrastructure to maintain system reliability, even if that requires an increase to their bill. EPL has identified a number of programs in the system renewal program that meet these expectations including replacement of poles, replacement of load-break switches, replacement of live-front switchgear, and circuit rebuilds. These are all proactive replacement programs supported by EPL's customers.

EPL's customers see the importance of modernizing the grid. EPL has adopted a Smart Grid Development Plan – as introduced in Section 1.4.3.4 – to facilitate a self-healing grid. System service investments to install reclosers over the forecast period fit into this framework.

EPL's customers believe that it is important for EPL's staff to have the equipment and tools they need to manage the system efficiently, safely and reliably. Planned investments into computer hardware, computer software, transportation equipment, stores equipment, buildings and fixtures, and tools and equipment align with this customer preference.

Overall, customers surveyed in 2017 provided social permission for the DSP.

2.2.1.2 Municipal Consultations

Purpose of the Consultations

Consultations with municipalities, who are also EPL's shareholders, are critical components of EPL's project planning and daily operations. EPL is engaged in weekly Adjustment Committee meetings on property zoning variances. Weekly Development Support Committee meetings provide details regarding planned and ongoing construction activities for private businesses and residences. Quarterly utility meetings allow the municipalities and various utility participants to coordinate their planned and ongoing construction activities. In addition, meetings related to alley closing or land transfers take place as needed, Planning Act meetings take place as applicable, and meetings for specific projects take place as needed.

EPL also participates in meetings with the County of Essex and the Ontario Ministry of Transportation ("**MTO**") as required to obtain information pertaining to the capital work planned.

Whether EPL Initiated the Consultation

The meetings are initiated by EPL or the municipalities. County and MTO meetings are typically initiated by the County and MTO, respectively.

Other Participants in the Consultation

The meetings are attended by representatives of different municipal divisions (e.g. municipal projects, water) and other utilities (e.g. Bell, Cogeco, HONI, Union Gas, MNSi).

Nature and Prospective Timing of the Final Deliverables

The meeting minutes of items discusses are the main deliverables for most municipal consultations. Following the utility meetings, EPL receives an updated project list from the various municipal divisions and from the other utility participants. EPL provides its own list of capital projects and pertinent operations activities (e.g. tree trimming) to participants in the meetings.

Effect on the DSP

Municipal consultations are critical to allocating budget and resources for system access investments including residential expansions, individual secondary services, new commercial/industrial services, and third-party infrastructure development requests. Planned projects in the near-term are used to forecast the capital requirements of the five-year DSP.

2.2.1.3 Consultations with HONI

Purpose of the Consultations

EPL often communicates and meets with HONI with the overarching objective of providing reliable and cost-effective service to EPL's customers. In addition to the IESO's Regional Planning Process, HONI and EPL hold quarterly planning meetings to discuss operating issues, billing issues, customer complaints, work coordination, joint-use of poles, and generation connection. Other communications and meetings take place to discuss specific projects such as Leamington TS and the Malden TS upgrade, as well as projects to separate shared assets by LDC, asset, customer, etc.

Whether EPL Initiated the Consultation

Consultations may be initiated by either EPL or HONI.

Other Participants in the Consultation

The only participants are EPL and HONI.

Nature and Prospective Timing of the Final Deliverables

Meeting minutes from these consultations typically summarize the deliverables and timeline commitments agreed to by each party in the meeting. Deliverables include updated construction schedules, updated project cost estimates, an updated list of generation projects, agreements pertaining to asset transfers, and any requisite studies.

Effect on the DSP

A significant portion of the system service investments over the five-year planning period of the DSP are a result of coordinated planning activities with HONI. In 2018 and 2019, EPL will purchase and sell assets related to Leamington TS in transactions with HONI. From 2019 to 2021, EPL will reconfigure its feeders egressing from Malden TS in conjunction with two new feeders as a result of planning activities with HONI. Finally, the system service budget from 2020 to 2022 includes the purchase and sale of assets in LaSalle in transactions with HONI. The planned asset transfers are anticipated to be required to facilitate long-term load transfer removal as well to accommodate significant HONI work currently ongoing in the respective areas.

2.2.1.4 Consultations with IESO

Purpose of the Consultations

Outside of the Regional Planning Process, EPL consults with the IESO to discuss the connection of new generation and energy storage projects to EPL's distribution system and the administration of CDM programs.

Whether EPL Initiated the Consultation

Consultations may be initiated by either EPL or the IESO.

Other Participants in the Consultation

The only participants are EPL and the IESO.

Nature and Prospective Timing of the Final Deliverables

The IESO provides updates to generator applications within EPL's service area. EPL worked closely with the IESO on a 1.25 MW energy storage facility planned in Leamington. This energy storage facility is scheduled to be connected in 2018. EPL previously submitted its CDM plan to the IESO and reports annual updates regarding budget spent and savings achieved.

Specifically for this DSP, EPL submitted its REG Investments Plan to the IESO and the IESO provided its Comment Letter in response. For more information, see Section 2.2.3.

Effect on the DSP

The cost of the assets required to connect the energy storage facility is included in EPL's 2018 budget. EPL has planned investments until 2018 to accommodate REG connections, which fall under the system service category and have been coordinated with the IESO. Consultations with the IESO are also used to forecast system access projects for FIT and MicroFIT connections (which are 100% contributed by the customer) and renewable expansions.

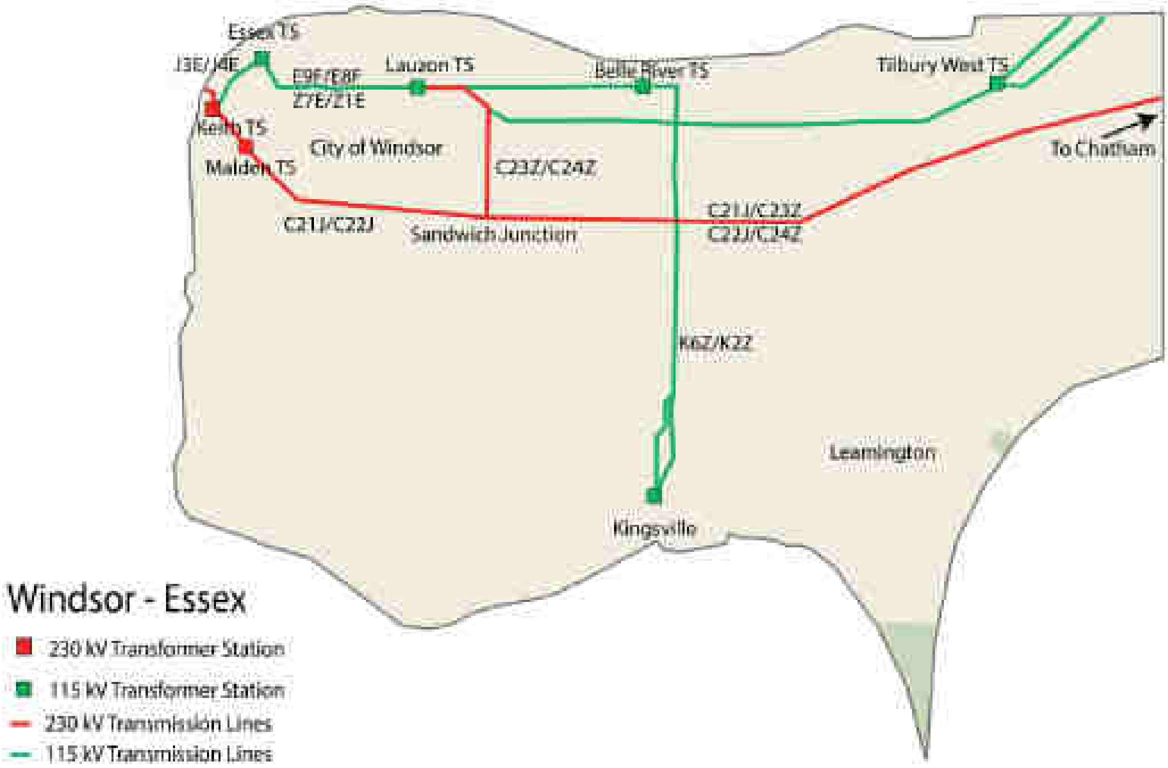
2.2.2 Regional Planning Process (5.2.2b)

EPL is part of the Windsor-Essex region in the most southerly part of Ontario that includes the City of Windsor, the Municipality of Leamington, the Towns of Amherstburg, Essex, Kingsville, Lakeshore, LaSalle, Tecumseh, and the Township of Pelee, as well as the western portion of the Municipality of Chatham-Kent.

EPL participated in the Regional Planning Process by providing the information required to complete the Regional Infrastructure Plan including impact assessments of regional supply plans and a review of potential distribution system options to meet regional needs. EPL attended the working group meetings for the Windsor-Essex region, which also involved the following entities:

- the IESO
- E.L.K. Energy Inc.
- Entegrus Inc.
- HONI

Figure 2-7: The transmission system in the Windsor-Essex region



The Regional Planning Process identified that the demand in the Kingsville-Leamington area had recently reached the supply capacity and that the supply in the broader region does not comply with the IESO's Ontario Resource and Transmission Assessment Criteria ("**ORTAC**") load restoration criteria. An Integrated Regional Resource Plan ("**IRRP**") was prepared on 28 April 2015, addressing the region's electricity needs from 2014 to 2033. The IRRP – attached as Appendix B – recommended an integrated solution with a mix of energy conservation, REG resources, and transmission reinforcements. A new 230-kV TS and transmission line will be constructed near Leamington providing an additional 150 MW of capacity. After the partial refurbishment of Kingsville TS, the combined supply in the Kingsville-Leamington area will be 210 MW, enough to meet the forecast demand accounting for energy conservation and REG resources.

2.2.3 IESO Comment Letter (5.2.2c)

On February 27, 2015 EPL submitted its REG Investments Plan to the IESO as part of its DSP. EPL's REG Investments Plan indicates that, as of the end of 2016, it has connected one hundred fifty (150) MicroFIT projects, twelve (12) FIT projects, and two (2) Renewable Energy Standard Offer Program ("**RESOP**") projects totalling 1.2536 MW, 2.838 MW, and 15 MW respectively. EPL has forecast connections for an additional 1.28 MW from four (4)

FIT projects in 2017, 0.9 MW from three (3) FIT projects in 2018, 0.384 MW from two (2) FIT projects in 2019, and 0.1 MW from ten (10) MicroFIT projects. The IESO commented that the information provided by EPL was "substantially consistent with that of the IESO". The Letter of Comment from the IESO is attached as Appendix C.

EPL's correspondence with the IESO also listed the investments planned to accommodate REG for the years 2017 through 2020. Table 2-3 summarizes the REG investments projected for the 2018 Test Year.

Table 2-3: REG investments projected in the 2018 Test Year

Type	Nameplate Capacity (kW)	Renewable Expansion Cost
Solar Rooftop	200	$25,000
Solar Rooftop	200	$0
Solar Rooftop	200	$25,000
Solar Rooftop	500	$30,000
Solar Rooftop	1250	$30,000
2018 (estimated)	**2350**	**$110,000**

The IESO also confirmed EPL's involvement in the Regional Planning Process and acknowledged that the REG investments identified in EPL's plan are consistent with the IESO's records.

2.3 Performance Measurement for Continuous Improvement (5.2.3)

Good distributor planning is an essential element of the OEB's performance-based rate-setting approach. Table 2-4 summarizes the metrics EPL will use to assess its DSP performance measured against customer-oriented performance, cost efficiency and effectiveness, and asset/system operations performance. The motivation for each measure and the desired outcome of each metric is listed.

Table 2-4: List of metrics and their desired outcomes

Performance Outcome	Measure	Motivation	Metric	Desired Outcome
Customer-oriented performance	System reliability	Regulatory/ consumer	SAIDI	0.91 or less
			SAIFI	1.77 or less
			CAIDI	1.77 or less
			Root cause of power interruptions	Identify root cause of outages
	Consumer bill impacts	Regulatory/ consumer	Percentage bill increase	2% or inflation annually
	Power quality	Regulatory/ consumer	Voltage at customer meter	0 unresolved power quality concerns
	Customer satisfaction	Regulatory/ consumer	Customer satisfaction survey results	80% or greater
	Service quality	Regulatory/ consumer	Telephone accessibility	Greater than 65%
			Telephone call abandon rate	Less than 10%
			Connection of new services	Greater than 90%
			Appointments scheduling	Greater than 90%
			Appointments met	Greater than 90%
			Missed appointments rescheduling	100%
			Written response to enquiries	Greater than 80%
			Emergency response	Greater than 80%
			Reconnection performance	Greater than 85%
			Billing accuracy	Greater than 98%
Cost efficiency and effectiveness	DSP implementation progress	Regulatory/ consumer	Percentage of projects completed in the budget year	Greater than 80%
			Project spending (planned vs. actual)	+/- 10%
			Annual capital spending (planned vs. actual)	+/- 10%
	Efficiency assessment	Regulatory/ consumer	Results of efficiency assessment	Group 2
	Total cost	Regulatory/ consumer	Total cost per customer	Monitor performance relative to peers
			Total cost per km of line	
Asset/system operations performance	Safety	Regulatory/ corporate	Serious electrical incident index	0
	System performance	Corporate	Distribution losses	4% or less
	Asset performance	Corporate	Primary Cable failures	3 per year or less
		Corporate	Switchgear failures	2 per year or less

2.3.1 Customer-oriented Performance

Customer-oriented performance is assessed using the following measures:

1. System reliability
2. Consumer bill impacts
3. Power quality
4. Customer satisfaction
5. Service quality

2.3.1.1 System Reliability

A reliable supply of electricity is important to consumers and businesses alike; therefore, system reliability indices are key metrics for measuring the success of a DSP.

2.3.1.1.1 Definition of Measures (5.2.3a)

In order to measure the reliability of electricity delivered to its customers, EPL tracks System Average Interruption Frequency Index ("**SAIFI**"), System Average Interruption Duration Index ("**SAIDI**"), and Customer Average Interruption Duration Index ("**CAIDI**"). SAIFI is the average frequency of sustained power interruptions and is calculated by dividing the total number of customer interruptions over a given year by the total number of customers served. SAIDI is the average outage duration and is calculated by dividing the total number of customer-hours of sustained interruptions over a given year by the number of customers served. CAIDI reflects the average time for electricity service to be restored following an outage and is calculated by dividing the total customer-hours of sustained interruptions over a given year by the total number of sustained interruptions for that year.

EPL's system reliability targets are to operate its system better than the previous five-year historical average measured in SAIFI, SAIDI, and CAIDI. Loss of supply outages are excluded in the calculation of the targets and performance since these outages are beyond EPL's control; however, EPL works closely with its supply transmitter (HONI) to reduce incidents of loss of supply. Based on the historical five-year average from 2012 to 2016, EPL's system reliability targets are 0.71 for SAIFI, 1.20 for SAIDI, and 1.77 for CAIDI (all excluding loss of supply).

2.3.1.1.2 Historical Performance (5.2.3b)

Since reliability performance targets are based on the previous five-year historical average, then naturally half of the years will be below target and half of the years will be above target. EPL's historical SAIFI performance, including and excluding loss of supply, is presented in Figure 2-8. SAIFI excluding loss of supply was better than the five-year average in 2014 and 2015 and worse than the average in 2013. EPL's historical SAIDI performance, including and excluding loss of supply, is presented in Figure 2-9. SAIDI excluding loss of supply was better than the five-year average in 2014 and 2015 and worse than the average in 2013. Finally, EPL's historical CAIDI performance, including and excluding loss of supply, is presented in Figure 2-10. CAIDI excluding loss of supply was better than the five-year average in 2015 and worse than the average in 2013 and 2014.

Figure 2-8: Historical SAIFI performance including and excluding loss of supply

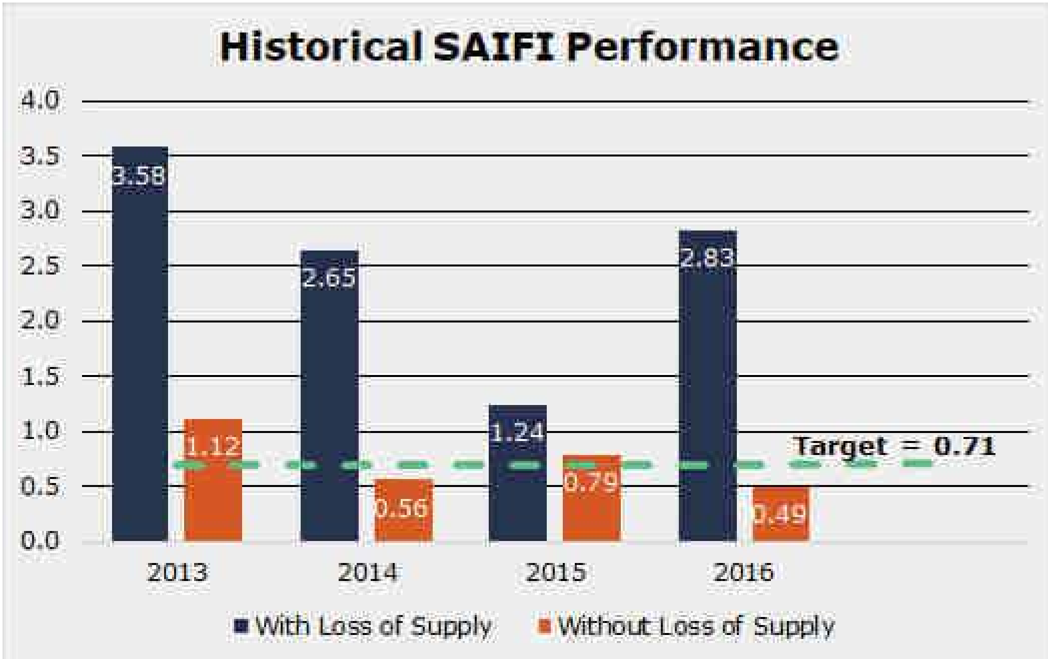


Figure 2-9: Historical SAIDI performance including and excluding loss of supply

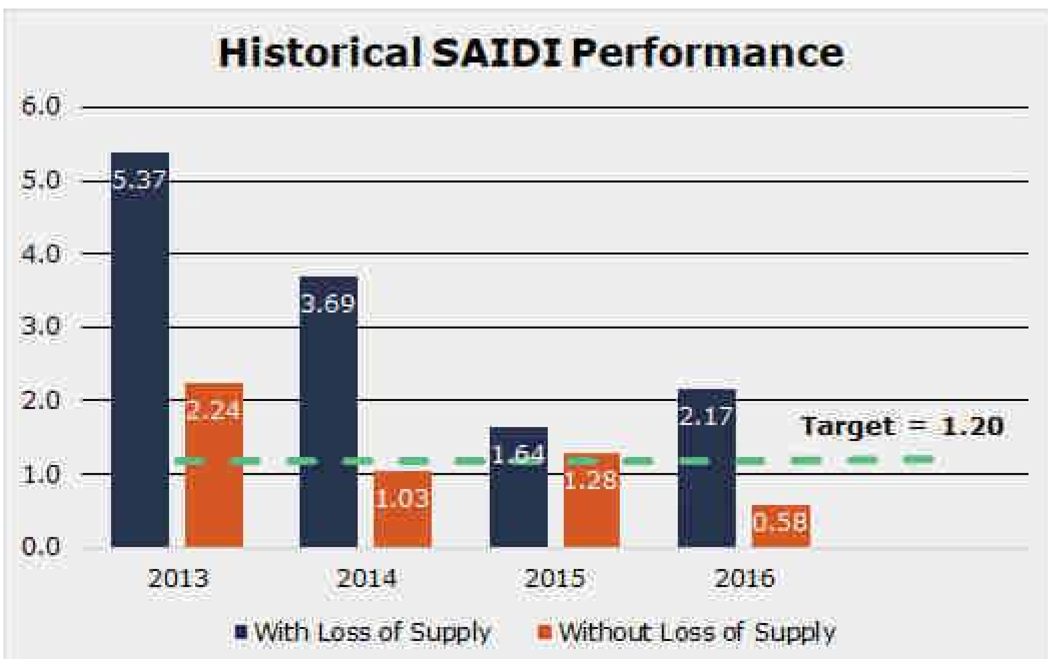
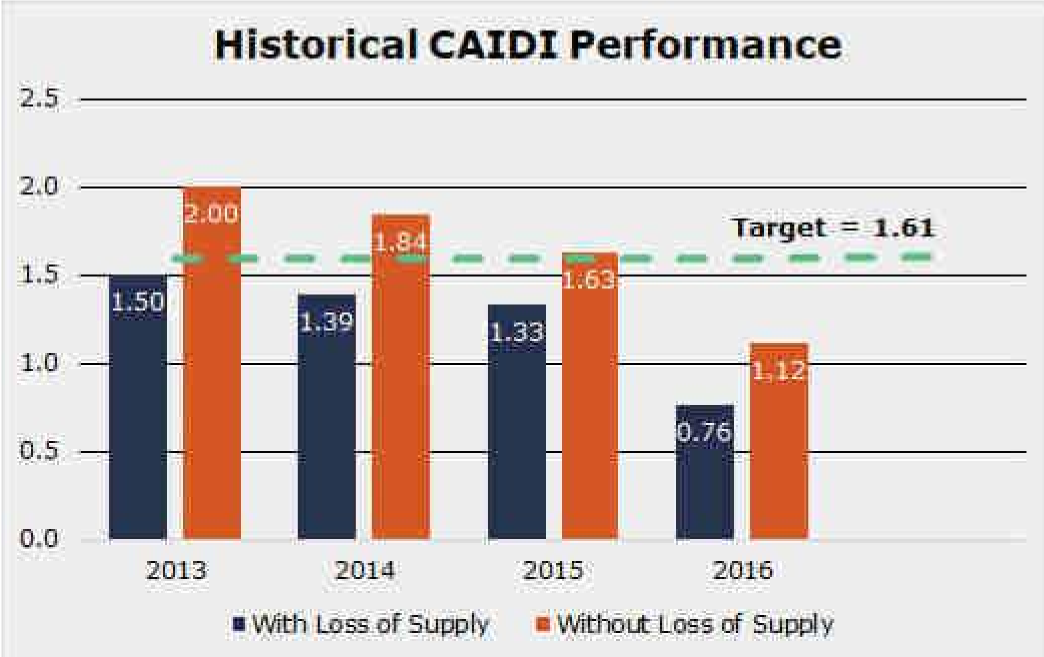


Figure 2-10: Historical CAIDI performance including and excluding loss of supply



For further analysis of the root cause of power interruption, Figure 2-11 presents the customer interruption hours by cause code and Figure 2-12 presents the number of customer interruptions by cause code for the years 2013 to 2016. As shown, loss of supply has by far the greatest reliability impact on EPL's customers. The next two biggest impacts are defective equipment outages and scheduled outages.

Figure 2-11: Customer interruption hours by cause code (2013 to 2016)

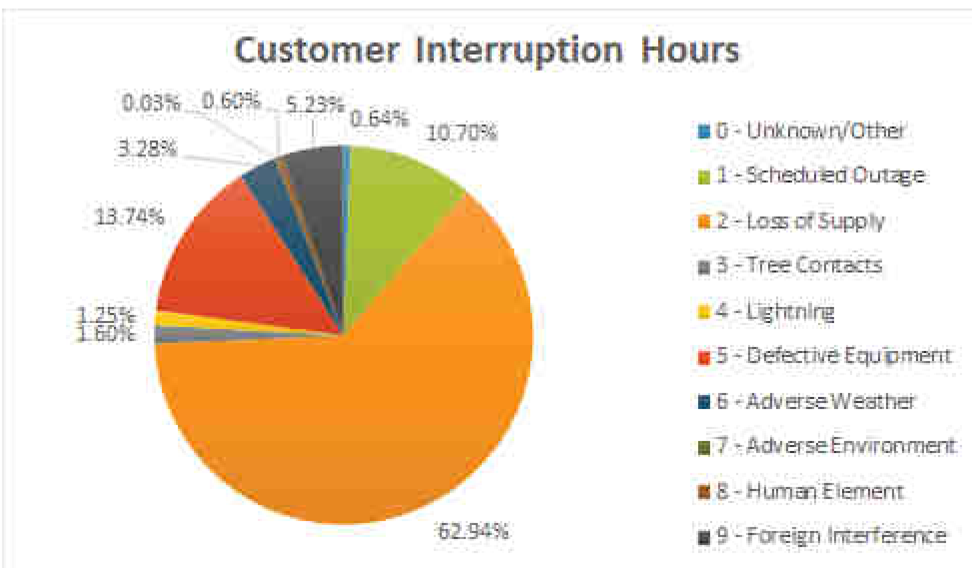
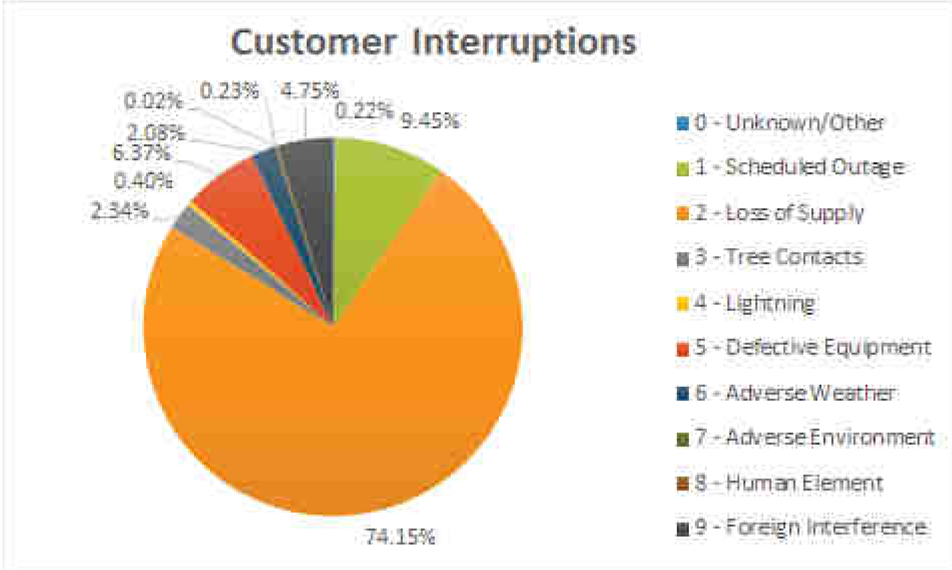


Figure 2-12: Customer interruptions by cause code (2013 to 2016)



2.3.1.1.3 Effect on the DSP (5.2.3c)

Loss of supply outages continue to be the foremost concern for power interruptions experienced by customers. As noted in Section 2.2.1.3, EPL meets regular with HONI in part to address concerns of EPL's customers including loss of supply outages. EPL has budgeted capital expenditures in the system service category to purchase assets owned by HONI that already supply EPL's customers. By effectively managing these assets, EPL is proactively addressing the loss of supply issues to provide better system reliability for its customers.

Planned outages are the next biggest contributor. The number of planned outages has increased as EPL has shifted its work from reactive replacements to planned capital programs. Although the number of planned outages has increased, the impact of outages caused by defective equipment has been trending downwards as shown in Figure 2-13. EPL mitigates the impact of planned outages by providing customers with advance notice so they can plan accordingly.

A more thorough analysis of the impact of defective equipment outages is provided in Figure 2-14 for overhead equipment and Figure 2-15 for underground equipment. The impacts of defective overhead equipment are trending downwards, while defective underground equipment impacts are trending upwards, indicating the need to invest relatively more in underground equipment compared to overhead. Over the forecast period, EPL plans to invest more in direct-buried cable replacements than overhead rebuilds under the system renewal investment category.

Figure 2-13: Severity - Impacts of outages caused by defective equipment

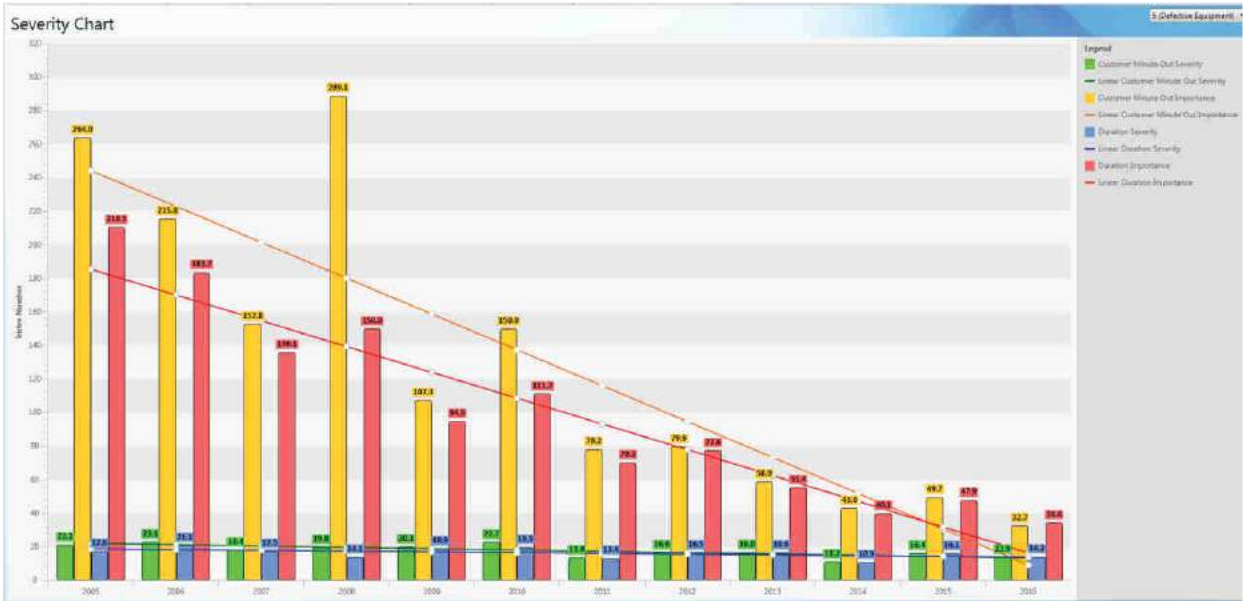


Figure 2-14: Severity - Impacts of outages caused by defective overhead equipment

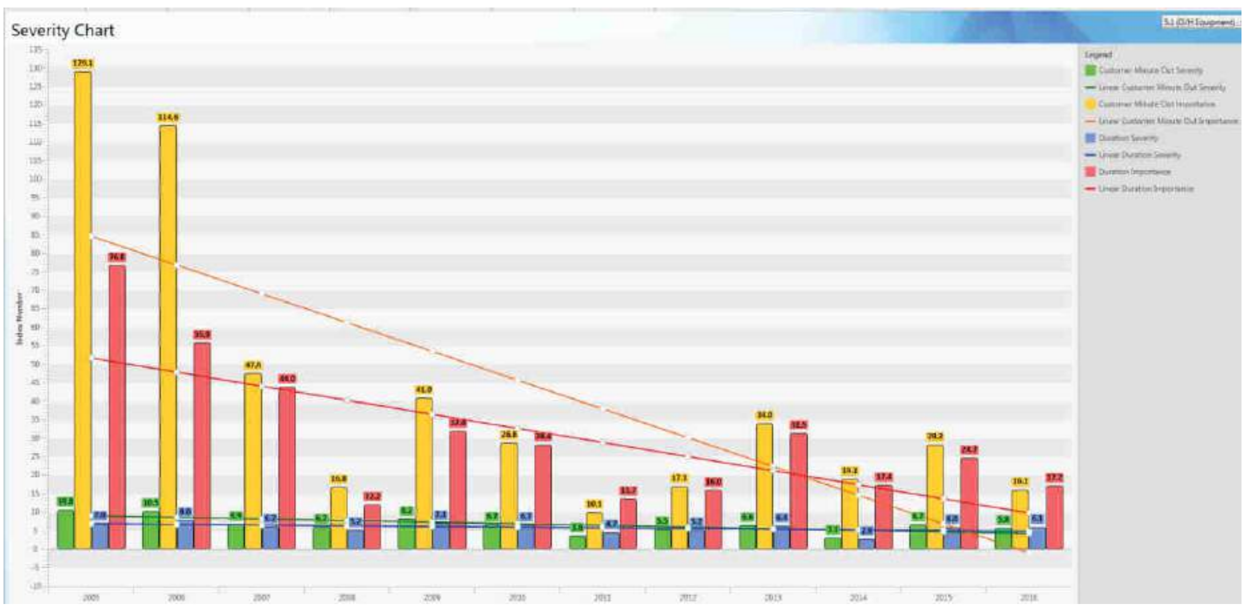
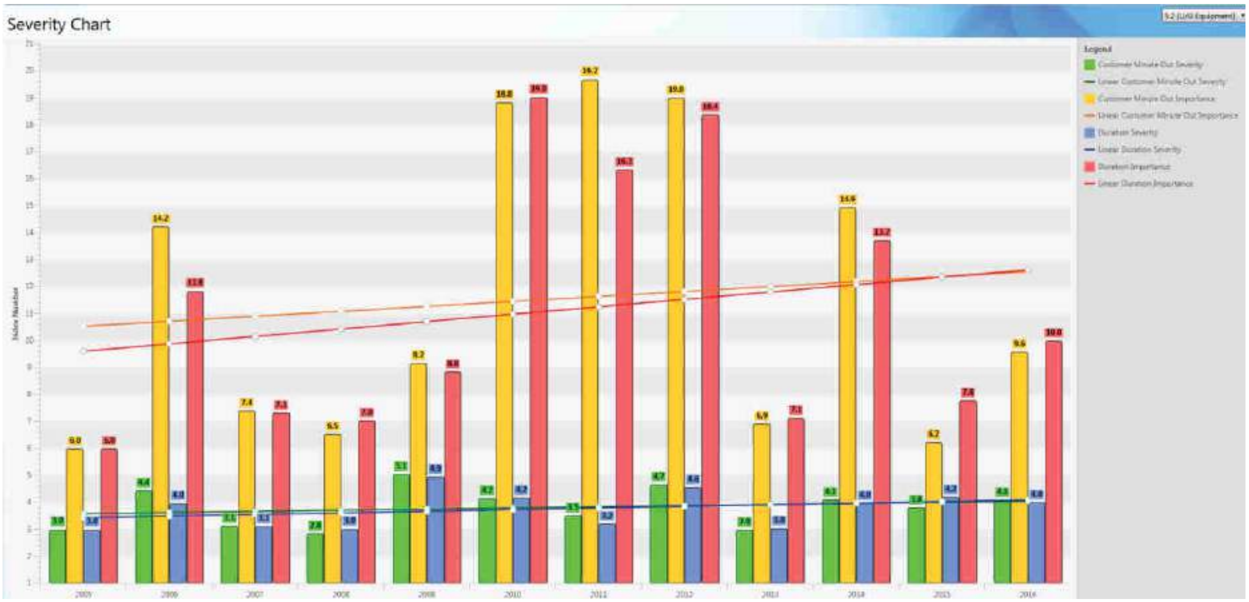


Figure 2-15: Severity - Impacts of outages caused by defective underground equipment



2.3.1.2 Consumer Bill Impacts

EPL's customers have stated that the cost of electricity is important to them and, furthermore, EPL's primary objective is to provide a modern distribution system at inflation-aligned rates. Therefore, the consumer bill impact metric is a key measure of the success of EPL's planning and DSP execution.

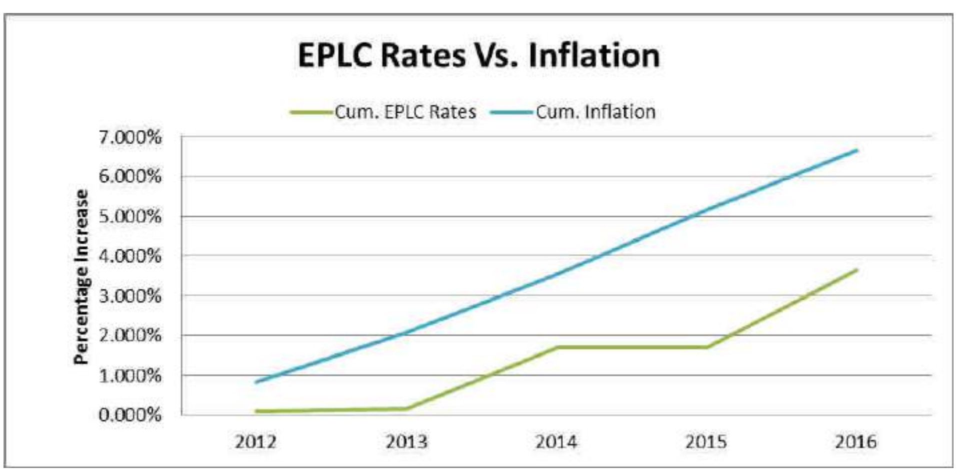
2.3.1.2.1 Definition of Measure (5.2.3a)

Consumer bill impacts are measured as the percentage annual increase of the distribution costs for a typical residential consumer. EPL's target for this metric is to align annual rate increases with inflation, which is close to two percent (2%) per year.

2.3.1.2.2 Historical Performance (5.2.3b)

Historically, EPL's annual distribution cost increases have been less than inflation.

Figure 2-16: Consumer rate increases compared to inflation



2.3.1.2.3 Effect on the DSP (5.2.3c)

EPL's total spending over the forecast period is limited by rigorously applying this metric. In EPL's project prioritization process, projected consumer bill impacts act as budget constraint. The projects and programs listed in this DSP have been selected based on this constraint.

2.3.1.3 Power Quality

EPL tracks power quality by monitoring the voltage at various customer meters.

2.3.1.3.1 Definition of Measure (5.2.3a)

A power quality concern exists when, under normal operating conditions, the voltage measured at the customer meter is outside of the CAN3-C235-83 voltage variation limits. To monitor power quality over the forecast period, EPL will begin to track the number of outstanding substantiated power quality concerns reported at year-end as a metric.

2.3.1.3.2 Historical Performance (5.2.3b)

EPL will begin tracking this metric in response to the Filing Requirements so there is no historical data to report on. Presently, EPL is monitoring voltage at various customer meters and there are no outstanding power quality concerns.

2.3.1.3.3 Effect on the DSP (5.2.3c)

Typically, a voltage excursion at the meter may indicate a problem with the meter itself. EPL has programs planned over the forecast period to upgrade interval meters and replace end-of-life smart meters. Otherwise there are no outstanding power quality concerns on EPL's system.

2.3.1.4 Customer Satisfaction

Customer satisfaction is measured by a third party which surveys EPL's customers.

2.3.1.4.1 Definition of Measure (5.2.3a)

The customer satisfaction measure is defined as the percentage of customers who are satisfied with the service they receive from EPL. EPL's target for this metric is to achieve a customer satisfaction score of 80% or greater

2.3.1.4.2 Historical Performance (5.2.3b)

EPL began formally tracking customer satisfaction using a metric in 2014. In each year, customer satisfaction has been above target.

Figure 2-17: Customer satisfaction measured in 2014, 2015, and 2016

2.3.1.4.3 Effect on the DSP (5.2.3c)

Each and every contact EPL has with its customers affects the level of satisfaction perceived by customers. Customer satisfaction impacts virtually every aspect of the DSP. Consultations and customer surveys are conducted to understand the needs and preferences of customers. EPL's customers are satisfied with the reliability and quality of power supplied by EPL, but are concerned with the cost of electricity. Therefore, EPL will continue to make investments into its distribution system as required without burdening its customers with large rate increases. In fact, EPL's planned budget aligns its annual rate increases with inflation while providing a modern and reliable distribution system.

2.3.1.5 Service Quality

Service quality metrics are defined in the *Distribution System Code* and provide a detailed overview of the quality of customer service provided by EPL.

2.3.1.5.1 Definition of Measure (5.2.3a)

The *Distribution System Code* sets the minimum service quality requirements that a distributor must meet in carrying out its obligations to distribute electricity under its license and the *Energy Competition Act, 1998*. As required by the OEB, EPL records and submits all performance measures, which are compared with the OEB's established levels to evaluate EPL's customer service quality. The performance measures are described below, as defined in the *Distribution System Code*.

Connection of New Services

The OEB sets out the following requirements for the connection of new services:

- A connection for a new service request for a low voltage ("**LV**") (less than 750 V) service must be completed within five business days from the day on which all applicable service conditions are satisfied, or at such a later date as agreed by the customer and distributor.

- A connection for a new service request for a high voltage ("**HV**") (greater than 750 V) service must be completed within ten business days from the day on which all applicable service conditions are satisfied, or at such a later date as agreed to by the customer and distributor.

The target for this metric is ninety percent or greater (≥90%).

Telephone Accessibility

The OEB requires that qualified incoming calls to the distributor's customer care telephone number must be answered within the thirty (30)-second time period as established below:

- For qualified incoming calls that are transferred to the distributor's interactive voice response system, the thirty (30) seconds shall be counted from the time the customer selects to speak to a customer service representative.
- In all other cases, the thirty (30) seconds shall be counted from the first ring.

The target for this metric is sixty-five percent or greater (≥65%).

Telephone Call Abandon Rate

As required by the OEB, the number of qualified incoming calls to a distributor's customer care telephone number that are abandoned before they are answered shall be ten percent or less (≤10%) on a yearly basis. A qualified incoming call will only be considered abandoned if the call is abandoned after the thirty (30)-second time period has elapsed.

Appointments Scheduled

When a customer or a representative of a customer requests an appointment with a distributor, the distributor shall schedule the appointment to take place within five business days of the day on which all applicable service conditions are satisfied, or on such a later date as may be agreed upon by the customer and the distributor. This includes Underground Locate Requests. The target for this metric is ninety percent or greater (≥90%).

Appointments Met

When an appointment is either:

- requested by a customer or a representative of a customer; or
- required by a distributor with a customer or a representative of a customer,

the distributor must offer to schedule the appointment during the distributor's regular hours of operation within a window that is no greater than four hours. The distributor must then arrive for the appointment within the scheduled timeframe. This includes Underground Locate Requests. The target for this metric is ninety percent or greater (≥90%).

Appointments Rescheduled

When an appointment with a customer or a representative of a customer is going to be missed, a distributor must:

- attempt to contact the customer before the scheduled appointment to inform the customer that the appointment will be missed; and
- attempt to contact the customer within one business day to reschedule the appointment.

The target for this metric is one hundred percent (100%).

Written Responses to Enquiries

A written response to a qualified enquiry shall be sent by a distributor within ten business days. The target for this metric is eighty percent or greater (≥80%).

Emergency Response

Emergency calls (i.e. assistance by the distributor has been requested by fire, police, or ambulance services) must be responded to within two (2) hours in rural areas and within one (1) hour in urban areas. The target for this metric is eighty percent or greater (≥80%).

Reconnection Performance Standard

Where a distributor has disconnected the property of a customer for non-payment, the distributor shall reconnect the property within two (2) business days of the date on which the customer:

- makes payment in full of the amount overdue for payment as specified in the disconnection notice; or
- enters into an arrears payment agreement with the distributor.

The target for this metric is eighty-five percent or greater (≥85%).

Billing Accuracy

The billing accuracy metric was established by the OEB in 2014. The percentage of bills accurately issued is calculated by subtracting the number of inaccurate bills issued for the year from the total number of bills issued for the year and dividing that number by the total number of bills issued for the year (the total number of bills issued for the year includes original and reissued bills). Accurate bills that need to be cancelled in order to correct another bill shall not be included in the calculation of billing accuracy measure. A distributor should not include customer accounts that are unmetered accounts (e.g. street lighting and unmetered scattered loads) or power generation accounts when calculating the percentage of accurate bills.

A bill is considered inaccurate if:

- the bill contains incorrect customer information, meter readings, or rates; or
- the bill has been issued to the customer and subsequently cancelled due to a billing error; or
- there has been a billing adjustment in a subsequent bill as a result of a previous billing error.

The target for this metric is ninety-eight percent or greater (≥98%).

2.3.1.5.2 Historical Performance (5.2.3b)

EPL's service quality measure performance over the historical period is depicted in Table 2-5. There were not high voltage new service connections and no emergency calls for EPL's rural areas over this time period. Billing accuracy was added to the OEB's *Electricity Reporting & Record Keeping Requirements* for 2014 and was not tracked in prior years.

Table 2-5: Historical performance for service quality measures

Metric	Target	2013	2014	2015	2016
New Services - Low Voltage	≥90%	92.7%	93.0%	92.3%	90.5%
New Services - High Voltage	N/A	N/A	N/A	N/A	N/A
Telephone Accessibility	≥65%	66.4%	78.0%	79.2%	73.6%
Telephone Call Abandon Rate	≤10%	1.7%	1.2%	1.4%	0.8%
Appointments Scheduled	≥90%	96.5%	95.5%	98.52	98.8%
Appointments Met	≥90%	94.3%	94.7%	94.8%	90.8%
Appointments Rescheduled	100%	100.0%	100.0%	100.0%	100.0%
Written Responses to Enquiries	≥80%	91.2%	91.7%	84.7%	96.3%
Emergency Response - Urban	≥80%	92.9%	96.3%	100.0%	97.7%
Emergency Response - Rural	≥80%	N/A	N/A	N/A	N/A
Reconnection Performance Standard	≥85%	93.3%	95.3%	93.7%	97.5%
Billing Accuracy	≥98%	N/A	99.8%	98.1%	99.9%

2.3.1.5.3 Effect on the DSP (5.2.3c)

EPL has met all of its service quality targets and, therefore, has not planned any investments over the forecast period to specifically address these requirements.

2.3.2 Cost Efficiency and Effectiveness

Cost efficiency and effectiveness is measured in terms of:

1. DSP implementation progress
2. Pacific Economics Group ("**PEG**") Efficiency Assessment
3. Total cost

2.3.2.1 DSP Implementation Progress

DSP implementation progress measures the annual success of EPL's project execution and planning quality.

2.3.2.1.1 Definition of Measure (5.2.3a)

DSP implementation progress is measured as the percentage of projects completed in the budget year, the individual variance of project spending, and the total annual variance for capital spending compared to the budgeted amount. Table 2-6 summarizes the targets for each of these metrics. EPL understands that not all projects budgeted within a year will be completed that year, as other critical capital work may be required; therefore, this target allows that twenty percent (20%) of projects may be deferred if necessary. The project and total capital budget variances targets are tighter, targeting spending within ten percent (10%) of the budget.

Table 2-6: DSP implementation metrics and targets

Metric	Target
Percentage of projects completed in the budget year	Greater than 80%
Project spending (planned vs. actual)	+/- 10%
Annual capital spending (planned vs. actual)	+/- 10%

2.3.2.1.2 Historical Performance (5.2.3b)

Since this is EPL's first DSP, there is no historical performance to report.

2.3.2.1.3 Effect on the DSP (5.2.3c)

From a work plan perspective, EPL is confident that it can capably execute its planned projects in their budget year. From a financial planning perspective, EPL has applied the utmost care in its budgeting process, considering both past replacement costs and expected future labour costs in its cost determination. The main risks in achieving these metrics are due to external factors. A significant portion of the system service budget over the forecast period will go towards the purchase and sale of assets to and from HONI. EPL has worked closely with HONI in drafting the agreements that will dictate the terms of these asset transfers to mitigate these risks and enable a successful DSP implementation.

2.3.2.2 Efficiency Assessment

The PEG Efficiency Assessment compares a distributor's expected costs to its actual costs based on models developed by PEG for the OEB.

2.3.2.2.1 Definition of Measure (5.2.3a)

The PEG Efficiency Assessment places distributors into five (5) groups as summarized in Table 2-7. EPL's target for this metric is to maintain its performance in Group 2.

Table 2-7: Definition of PEG Efficiency Assessment results

Group	Definition
Group 1	Actual costs are less than 25% of predicted costs
Group 2	Actual costs are between 10% and 25% less than predicted costs
Group 3	Actual costs are within 10% of predicted costs
Group 4	Actual costs are between 10% and 25% greater than predicted costs
Group 5	Actual costs are greater than 25% of predicted costs

2.3.2.2.2 Historical Performance (5.2.3b)

EPL was assessed to be in Group 2 during each year of the historical period for which an assessment was completed (2013 to 2015).

2.3.2.2.3 Effect on the DSP (5.2.3c)

EPL's holistic asset management process is built around improving cost effectiveness as described in Section 2.1.2. Inputs into EPL's risk-based decision-making model include cost savings and spending, which are optimized along with the other planning objectives to ensure the cost effectiveness of each project listed in this DSP. EPL has budgeted less reactive replacements over the forecast period than historical investment levels and this shift to more planned replacements will enable work to be completed more cost effectively. Other investments such as new recloser installations will improve operational efficiency by reducing the number of truck-rolls required to restore power during an outage.

2.3.2.3 Total Cost

The total cost measure on the OEB scorecards considers the sum of EPL's operating and capital costs.

2.3.2.3.1 Definition of Measure (5.2.3a)

The total cost measure is normalized per customer and per km of line. EPL monitors its performance with respect to these metrics relative to its peers, especially E.L.K. Energy Inc., Entegrus Powerlines Inc., and EnWin Utilities Ltd.

2.3.2.3.2 Historical Performance (5.2.3b)

Figure 2-18 depicts the total cost per customer over the historical period. In addition to usual wage and benefit costs for EPL's employees, EPL made in investments into new information, financial and operating systems technology, and renewal growth of the distribution system. There were also significant investments made during the years 2013 through 2015 related to a provincial construction project: the Herb Gray Parkway, an expressway route leading to the US. EPL's customer base grew by an average of 0.7% per year over the historical period.

Figure 2-18: Total cost per customer over the historical period

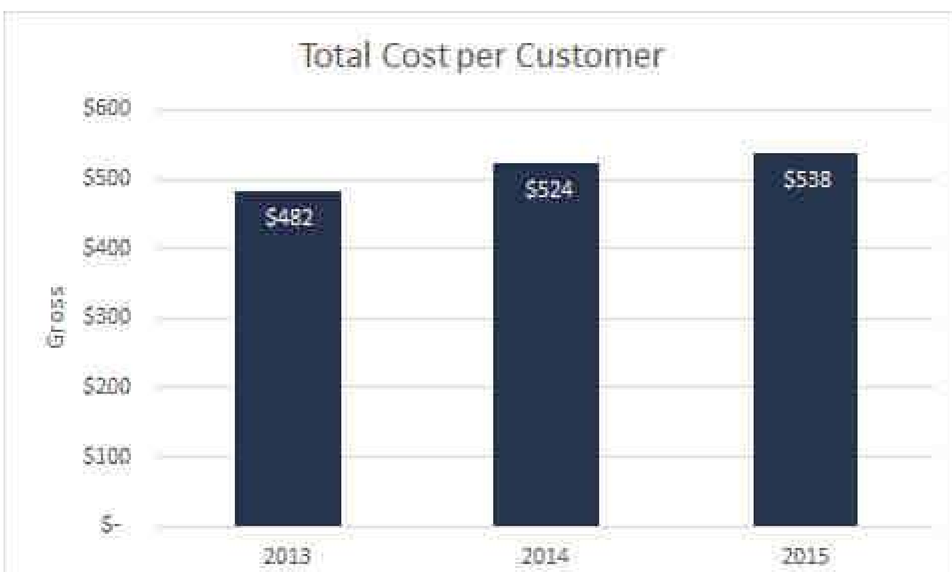
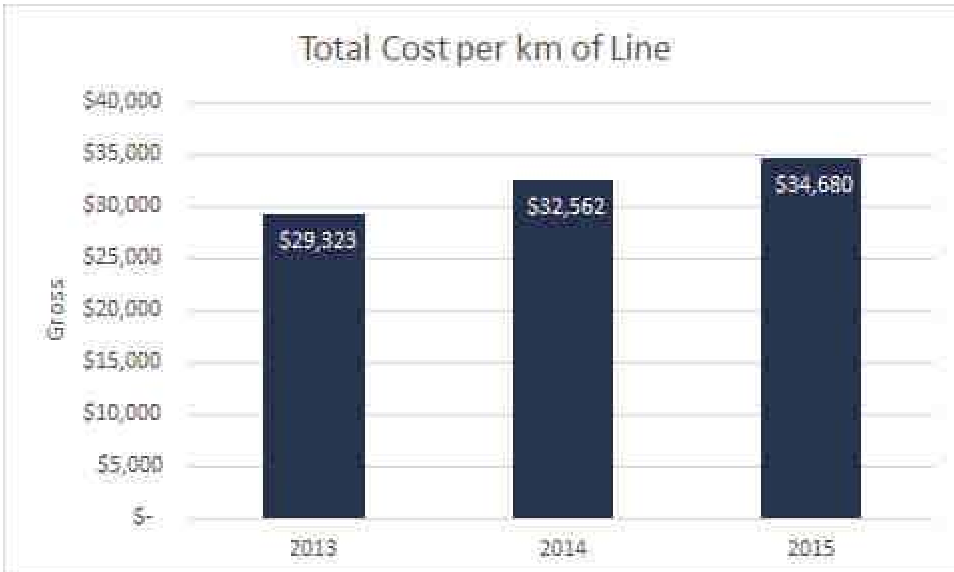


Figure 2-19 depicts the total cost per kilometre of line over the historical period. The total cost increased over the historical period for the same reasons listed above. In addition, EPL has decreased the length of line it manages due to voltage conversions.

Figure 2-19: Total cost per km of line over the historical period



EPL monitors its total cost performance relative to its peers, especially E.L.K. Energy Inc., Entegrus Powerlines Inc., and EnWin Utilities Ltd. Figure 2-20 compares EPL's total cost per customer to its peers based on a three (3)-year average from 2013 to 2015, while Figure 2-21 compares total cost per kilometre of line. In both comparisons, EPL is performing well compared to its peers. The results show that EPL is investing the right amount in its system and assets, while balancing external priorities, such as provincial construction projects.

Figure 2-20: Total cost per customer compared to peers

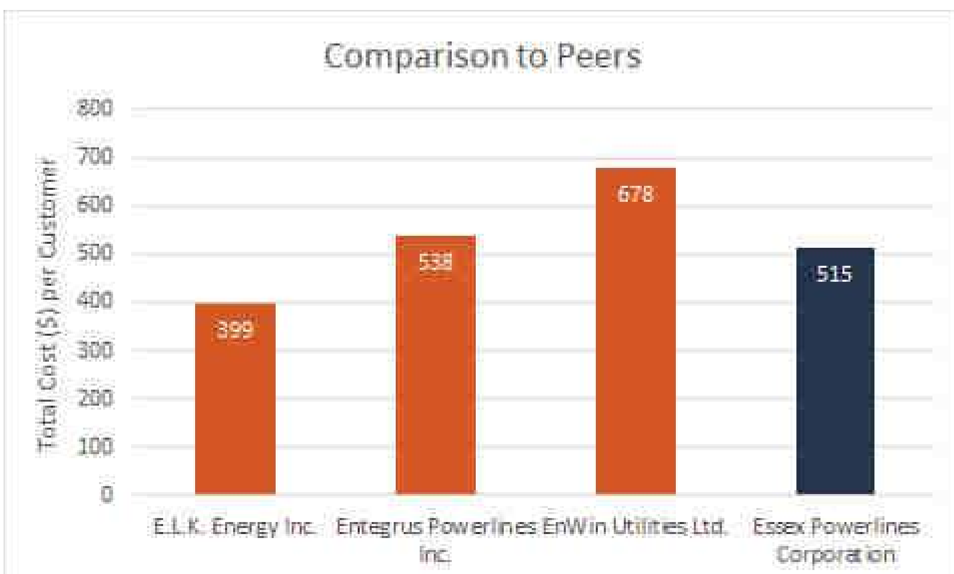
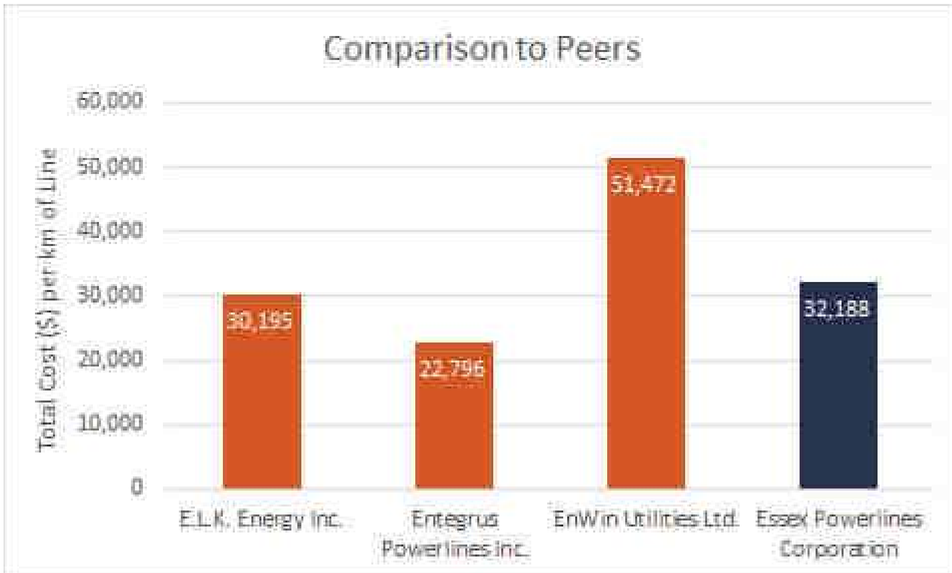


Figure 2-21: Total cost per km of line compared to peers



2.3.2.3.3 Effect on the DSP (5.2.3c)

Similar to the effects described in Section 2.3.2.2.3, EPL has developed a robust capital expenditure plan that will allow EPL to develop a modern distribution grid without the need for extraneous increases in cost. Furthermore, EPL plans to limit total cost increases to 2% per year in order to align consumer rate increases with inflation.

EPL's customer base is expected to continue to grow at a slow pace over the forecast period. Previous voltage conversions have reduced the kilometres of line owned by EPL. Although this has increased the total cost per kilometre of line, in the near- and long-term total cost increases are reduced since the elimination of substations and the reduction in line length under management equate to less O&M costs. As noted in Section 2.1.2, EPL's average system O&M spending over the forecast period is projected to $2.11M compared to $2.43M over the historical period. Investments in the system service category involving the sale and purchase of assets to and from HONI will also alter the length of line under management by EPL.

2.3.3 Asset/System Operations Performance

2.3.3.1 Safety

As noted in Section 3.1.1, EPL's top asset management objective is to ensure the safety of the public and its employees. Therefore, the success of EPL's DSP can be measured in terms of its safety performance.

2.3.3.1.1 Definition of Measure (5.2.3a)

Safety is measured using the OEB scorecard metric for Serious Electrical Incident Index. EPL's target for this metric is zero (0) serious electrical incidents.

2.3.3.1.2 Historical Performance (5.2.3b)

EPL has had zero (0) serious electrical incidents over the historical period.

2.3.3.1.3 Effect on the DSP (5.2.3c)

Safety is a key component in EPL's asset management practices. In a risk-based approach to asset management, safety must be balanced with other objectives such as environmental, regulatory, and service quality. Based on EPL's strategic business objectives, public and employee safety are weighted as the most significant asset management objective used to identify asset candidates for replacements, justify investments, and prioritize projects within the budget constraints. Therefore, projects identified in this DSP consider safety as part of a balanced, risk-based asset management approach. For example, EPL's pole replacement program has a safety component since poles are tested to identify those with the greatest risk of failure. Likewise, other system renewal investments consider safety impacts using the same methodology. System service investments pertaining to asset transfers do not have a significant safety component, but EPL will ensure compliance with Ontario Regulation 22/04 of the assets as a requirement. Investments into self-healing grid reclosers have many safety features including hot-line tagging and automated hold-offs. At a minimum, other investments in the system access and general plant categories will not add additional safety risks.

2.3.3.2 System Performance – Distribution Losses

System reliability was already discussed under customer-oriented performance (Section 2.3.1.1). EPL also measures system performance in terms of annual distribution losses.

2.3.3.2.1 Definition of Measure (5.2.3a)

Distribution losses are defined as the annual percentage line loss. Since EPL does not own any substations losses primarily occur along the distribution feeders, but distribution transformers and secondary lines also contribute to losses. Distribution losses depend on numerous factors including load, ambient temperature, conductor size, and imperfections in the assets. EPL would like its distribution losses to be as low as possible and considers four percent or less (≤4%) as a target for the historical period.

2.3.3.2.2 Historical Performance (5.2.3b)

Figure 2-22 depicts EPL's annual percentage line loss over the historical period, which shows significant variations due to external factors. Distribution losses are expected to be less than the four percent (4%) target over the forecast period since the voltage conversion program has been completed.

Figure 2-22: Annual percentage line loss over the historical period

2.3.3.2.3 Effect on the DSP (5.2.3c)

EPL recently completed its voltage conversion program, which has contributed to keeping distribution losses close to four percent (4%). As part of its asset management process, EPL calculates the optimal wire size for its system in order to reduce costs while considering line losses. Therefore, the replacement of underground direct-buried cables and overhead rebuilds are both expected to reduce distribution losses using the optimal wire size. The replacement of distribution transformers with new models that meet the latest energy efficiency standards will also reduce distribution losses.

2.3.3.3 Asset Performance

EPL tracks its asset-specific performance for the purpose of measuring the effectiveness of its planning and DSP implementation.

2.3.3.3.1 Definition of Measure (5.2.3a)

Asset performance is measured by the annual number of cable failures and annual number of switchgear failures. These assets were selected because they are major assets which cause defect equipment outages and which are also replaced proactively compared to run-to-failure assets. EPL's goal is for the failure rates for these assets over the forecast period to be better than the historical trends. EPL has defective equipment information going back to 2005 and observed an average of 4.3 cable failures and 2.6 switchgear failures per year until to 2016. Therefore, EPL is targeting to reduce this to three or less (≤3) cable failures and two or less (≤2) switchgear failures per year over the forecast period.

2.3.3.3.2 Historical Performance (5.2.3b)

The annual number of cable failures over the historical period is depicted in Figure 2-23 and the annual number of switchgear failures over the forecast period is depicted in Figure 2-24. Since the forecast period targets were chosen to show improvements over the historical average, then naturally the number of failures was above target in some years: in 2013, there were four (4) cable failures and in 2016 there were three (3) switchgear failures.

Figure 2-23: Annual number of cable failures over the historical period

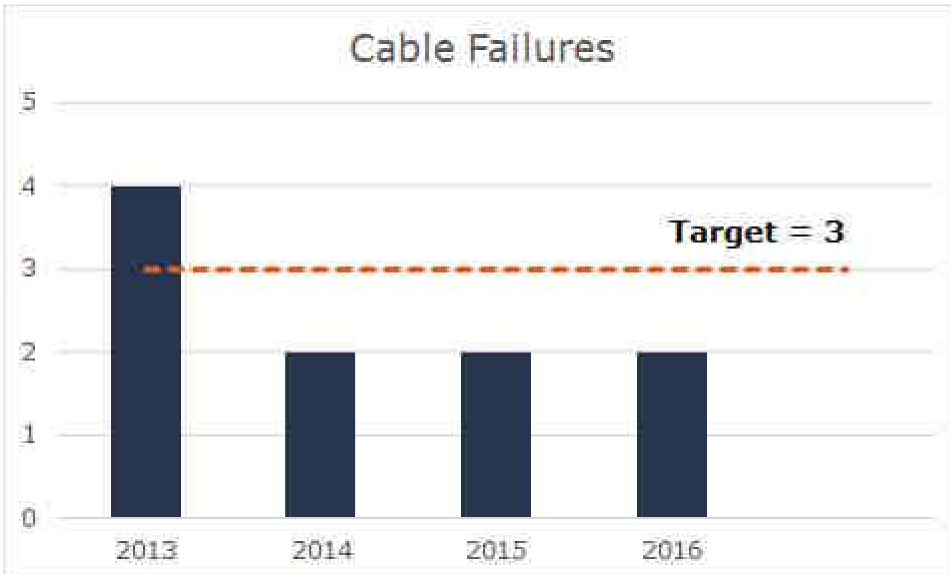
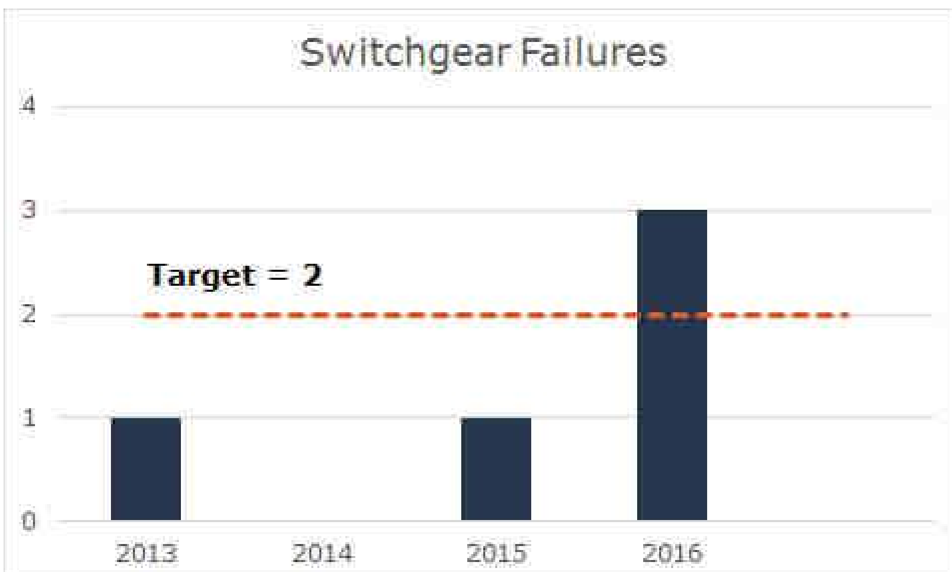


Figure 2-24: Annual number of switchgear failures over the historical period



2.3.3.3.3 Effect on the DSP (5.2.3c)

As previously mentioned, EPL has budgeted less reactive replacements over the forecast period and is moving towards a more proactive asset management approach. System renewal programs to replace direct-buried cable and pad-mounted switchgear will address these asset performance metrics.

3 Asset Management Process (5.3)

The purpose of EPL's asset management process is to develop projects for the future planning horizon using leading-edge Asset Investment Strategy ("**AIS**") tools. The Institute of Asset Management defines AIS as "the set of disciplines, methods, procedures, and tools to optimize the whole life business impact of costs, performance and risk exposures (associated with the availability, efficiency, quality, longevity and regulatory / safety / environmental compliance) of the company's physical assets".

The traditional approach to utility planning involved development of budgets using a "silo" approach where capital and O&M expenditures were planned for specific needs and then rolled up into an annual budget with no common linkage across the planning process. This approach is sub-optimal because little or no consideration is given to the trade-off opportunities, the value overlap, or the risk mitigation capability between capital investments and O&M programs. By determining its desired asset performance and risk tolerance, EPL is able to develop an optimal resource investment plan, as detailed in this section.

3.1 Asset Management Process Overview (5.3.1)

3.1.1 Asset Management Objectives (5.3.1a)

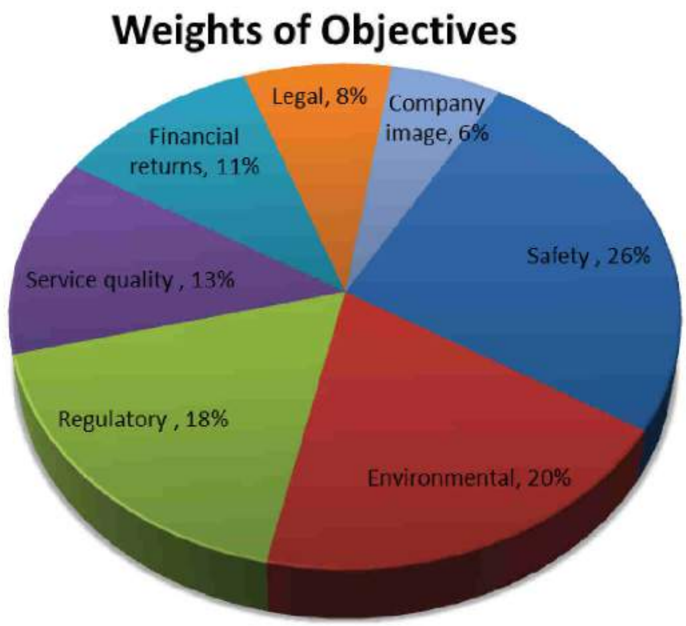
A robust AIS relies on a clear understanding and the precise definitions of the organization's strategic business objectives. EPL has established seven strategic business objectives that are applied to its asset management process. EPL assesses the risk that an asset poses to its performance in these seven objectives using quantified data whenever possible. In cases where EPL does not currently possess the capability to assess an asset's impact on a strategic business objective using quantitative data, then qualitative scores, which consider both the probability and consequence for each objective, are used. Table 3-1 lists the seven strategic business objectives and describes how EPL's risk exposure is accounted for through its asset management process for each objective.

Table 3-1: EPL's asset management objectives and related corporate goals

No.	Strategic Business Objective	Relation to Asset Management Processes
1	Public/Employee Safety	Qualitative scores (probability and consequence) for employee and public safety
2	Environmental	Qualitative scores (probability and consequence) for environmental implications
3	Regulatory	Qualitative scores (probability and consequence) for regulatory compliance
4	Service quality	Quantitative scores for SAIDI and SAIFI
5	Financial returns	Calculated Net Present Value ("**NPV**")
6	Legal	Qualitative scores (probability & consequence) for legal exposure
7	Company Image	Quantitative data for customer complaints

For the purpose of prioritizing investments, these seven business objectives are assigned relative weights, which are described in Figure 3-1.

Figure 3-1: Numerical weights assigned to EPL's asset management objectives



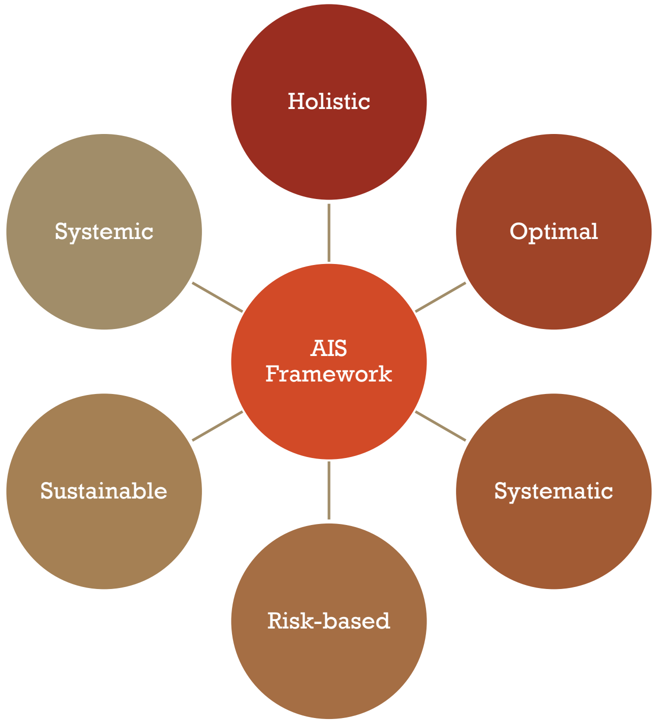
Since qualitative scoring is applied to the safety, environmental, and regulatory business objectives, all of which have high numerical weights, there is a risk of a high sensitivity in the asset management process results. To mitigate this risk, EPL applies a consistent methodology in its risk assessments, as described in Section 3.3.2 covering EPL's asset lifecycle risk management policies and practices. EPL is working towards developing a performance management framework that can quantify the risk exposure in these categories to ensure a more objective assessment in the future.

3.1.2 Components of the Asset Management Process (5.3.1b)

EPL's AIS is a risk-disciplined value-creation approach to strategic investment decisions that improves operational efficiency and system performance. In the past, utility companies built robust, redundant systems with underutilized capacity because regulatory environments encouraged such behaviour. By understanding the risk versus value trade-off associated with investing in asset replacement and system reticulation needs, the inherent value built into these systems can be reduced, released, or re-deployed for other capital resource requirements.

The capability to develop an effective value-added risk-disciplined approach to investment decisions, consistent data reporting, good data repositories, and good analysis tools are necessary. EPL uses an Asset Optimization Tool, which was developed by Texas Utilities and is currently owned by UMS Group Inc. The tool is used for making justified, risk-based decisions into asset investments on EPL's system. The AIS is based on the best-in-class asset management framework described by the PAS-55 and ISO 55000 series asset management standards. The key characteristics of the AIS framework applied by the Asset Optimization Tool are shown in Figure 3-2.

Figure 3-2: Key characteristics of EPL's AIS framework

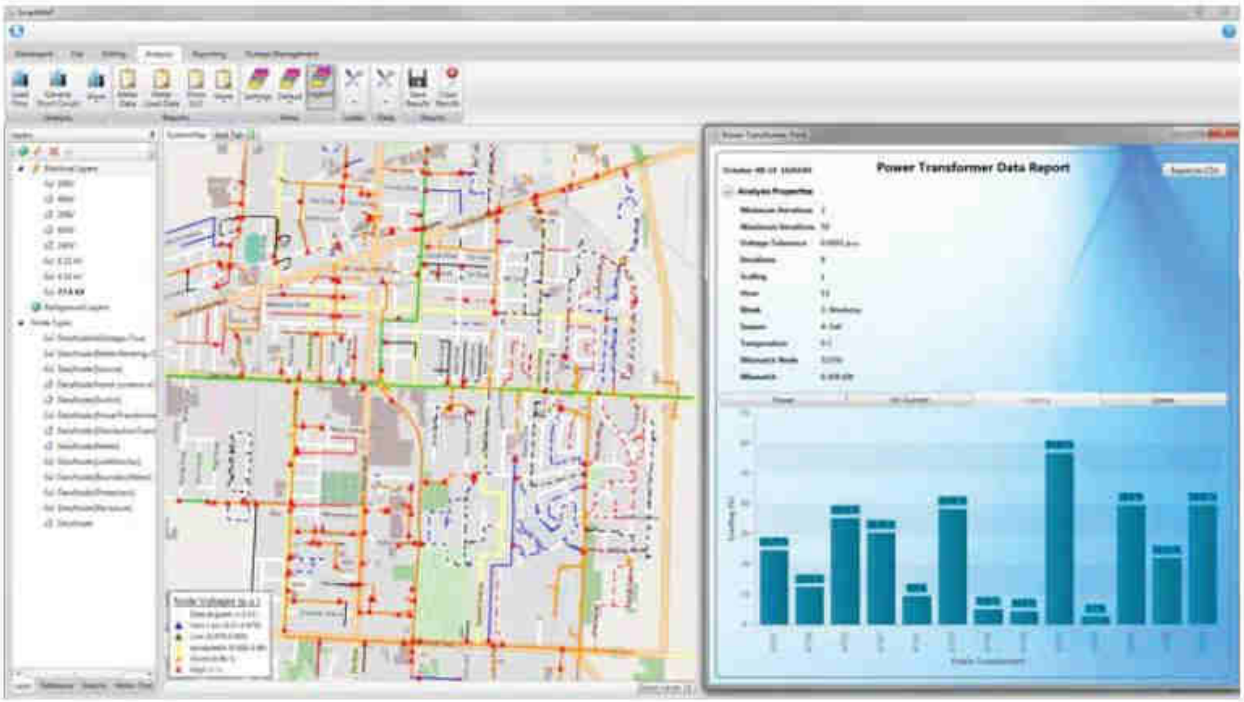


This AIS methodology employs a portfolio approach to investment decisions that embraces the performance linkage between capital and O&M expenditures. This approach helps facilitate development of an optimal Asset Investment Plan ("**AIP**") that includes a mixture of projects and programs that deliver the most value for the resource allocation. Spending is optimized based on the achievement of the seven strategic business objectives described in Section 3.1.1.

Quantification of the operational risk exposure mitigated by a project or program in the AIP is very important. Without this capability, management cannot make risk-informed financial decisions associated with a given resource allocation plan. Furthermore, better strategic and tactical decisions regarding asset replacement and maintenance investment decisions can only be made if the data is credible. Thus, the systems necessary for data reporting, storing, and analysis are crucial. EPL partnered with UtiliSmart Corporation to create SmartMAP: an integrated distribution monitoring and control system.

SmartMAP was developed based on EPL's proven DESS and overlaid on a GIS with full connectivity and asset information. SmartMAP integrates voltage and load profiles, line temperature monitoring, ambient temperature, and line loss measurement. With this information, EPL can accurately assess asset capacity utilization and identify constraints on the system. This streamlines EPL's ability to meet customer/developer requests and to identify potential capacity upgrade projects. SmartMAP also includes fault current measurement and outage detection, which are used to identify damage to distribution assets and improve outage restoration time.

Figure 3-3: SmartMAP integrates the asset register, DESS, and GIS

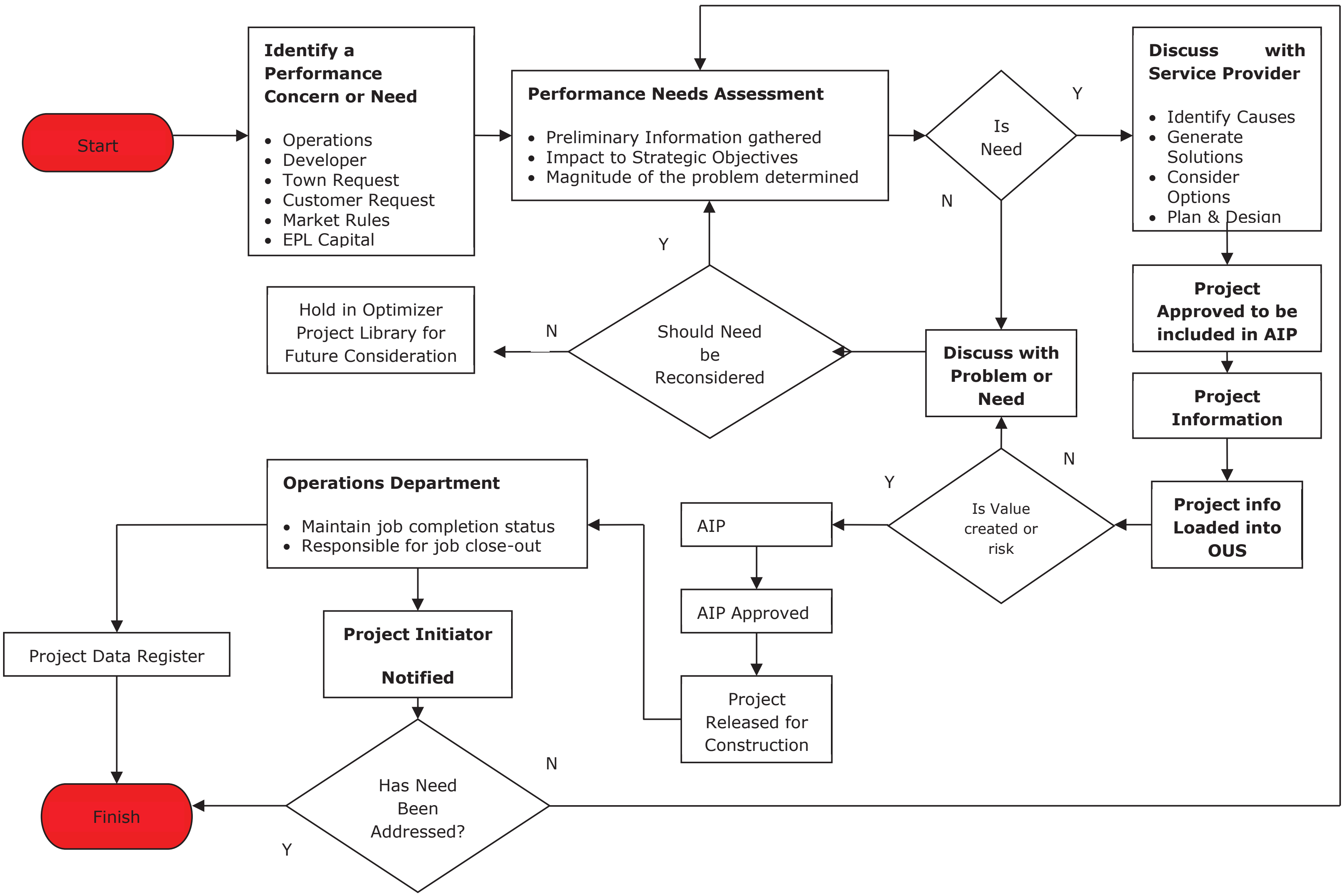


The software suite also includes HealthMAP, which integrates the asset health index with the GIS and provides alerts for out-of-range distribution system data. The health index is used in the asset condition assessment to determine the probability of an asset failure. The probability combined with the consequence of an asset failure constitutes a complete risk analysis. This includes quantification of SAIDI and SAIFI to determine the reliability risk as part of the consequence of failure analysis. The value creation is defined in terms of performance delivery and the risk mitigation capability is defined in terms of the Operational Beta described in Section 3.3.2. EPL's customers directly benefit from the reduction in lifecycle costs of asset ownership, a reduction in the number of assets on the system, and inventory reduction.

Usage of these software tools allows EPL to manage its AIP as a live model and make modifications to the plan as necessary. Resource planning is also incorporated in the tools to ensure adequate resource availability to carry out the plan. EPL directs cyclical planned inspections and preventative maintenance activities to correct identified problems. Therefore, Reliability Centred Maintenance statistics are kept within acceptable severity/importance indices.

EPL also relies on analysis of outage statistics for each service area and historical period data on customer interruptions caused by equipment failure, as described in Section 2.3.1.1, to aid in its decision-making process. The complete AIS process is summarized in Figure 3-4. The integration of this consistent framework ensures that right-sized investments are made at the right time.

1 Figure 3-4: EPL's decision-making process based on the AIS



2

3.2 Overview of Assets Managed (5.3.2)

3.2.1 Description of the Service Area (5.3.2a)

EPL's service area is thirty-seven percent (37%) rural and sixty-three percent (63%) urban, consisting of four (4) non-contiguous service areas encompassing the Towns of Tecumseh, LaSalle, and Amherstburg and the Municipality of Leamington.

Situated in some of the most southern parts of Ontario, EPL's service areas are subject to periodic heavy snowfalls, ice accumulation, and strong winds typical of the region. In 2015, the region experienced 3013 heating degree days and 355 cooling degree days with a maximum recorded wind gust of 91 km/h.

Lengths of cables and conductors are measured in measured in kilometres of circuit, where a 1-km run of three-phase cable is measured as 1 km rather than 3 km. EPL owns 189.7 km of overhead lines and 262.6 km of underground cables.

The areas served by EPL have experienced slow economic growth over the past several years that have resulted in some load loss, while the recent completion of the Herb Gray Parkway in the Towns of LaSalle and Tecumseh has improved the economic conditions. The expansion of the greenhouse industry in the Municipality of Leamington has added additional load as well as spin-off customers within EPL's service territory.

3.2.2 Summary of System Configuration (5.3.2b)

EPL does not own any transformer stations and instead receives power directly from HONI feeders demarcated with primary metering units. EPL operates its distribution system at a single voltage: three phase lines are 27.6/16 kV and single-phase lines are 16 kV. Table 3-2 summarizes the system configuration.

Table 3-2: Summary of system configuration

Conductor Type	Three Phase (km)	Single Phase (km)	Total (km)*
Overhead	109.4	80.2	189.7
Underground	35.3	227.3	262.6

**totals may not add up due to rounding*

3.2.3 Summary of Asset Condition Assessment (5.3.2c)

The complete ACA report is attached as Appendix J. EPL's ACA is based on data compiled in June 2017 and covers the following classes of fixed assets owned:

- Wood poles;
- Concrete poles;
- Steel poles;
- Pad-mounted distribution transformers;
- Pole-mounted distribution transformers;
- Pad-mounted switchgear;
- Dip poles (primary risers); and

- Primary underground cables.

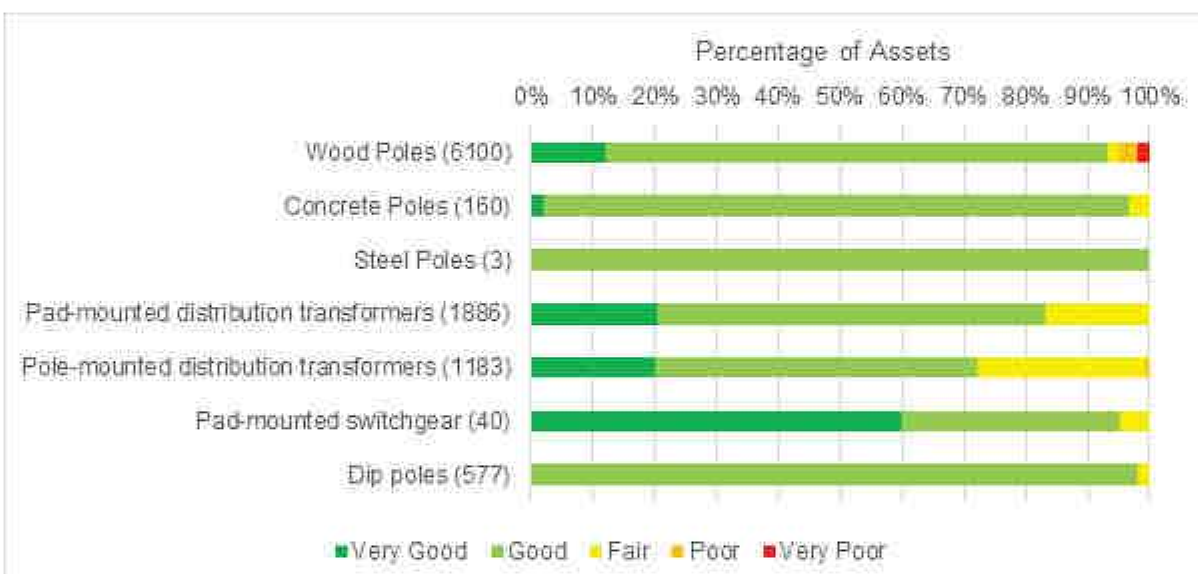
Table 3-3 summarizes the assessment criteria and Typical Useful Life ("**TUL**") for each asset class. Age demographics are not tracked for dip poles. The condition was determined for all asset classes except primary underground cables, for which only age demographics are known. Statistics for primary underground cable failures were used to support an age-based replacement plan.

Table 3-3: Asset count, assessment criteria, and TUL for each asset class

Asset Class	Count	Assessment Criteria	TUL (years)
Wood poles	6100	Test results (Resistograph), visual inspection results, service age	50
Concrete poles	160	Visual inspection results, service age	50
Steel poles	3	Visual inspection results, service age	60
Pad-mounted distribution transformers	1886	Visual inspection results, service age	40
Pole-mounted distribution transformers	1183	Visual inspection results, service age	40
Pad-mounted switchgear	40	Visual inspection results, service age	30
Dip poles (primary risers)	577	Visual inspection results	N/A
Direct-buried primary underground cables	45.8 km	Service age, reliability statistics	30
Primary underground cables in conduit	216.8 km	Service age, reliability statistics	40

The assets are assessed to be in one of five (5) conditions: Very Good, Good, Fair, Poor, or Very Poor. The results of the ACA are summarized in Figure 3-5, whereas underground cables are assessed separately (see Section 3.2.3.8). Overhead conductors generally do not drive investment decisions so are not assessed as part of the ACA.

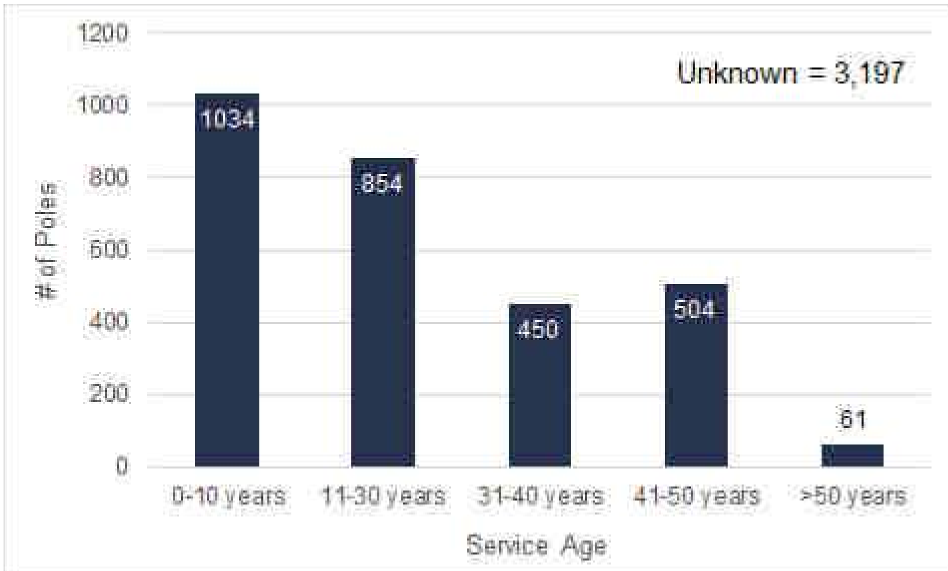
Figure 3-5: Summary of ACA



3.2.3.1 Wood Poles

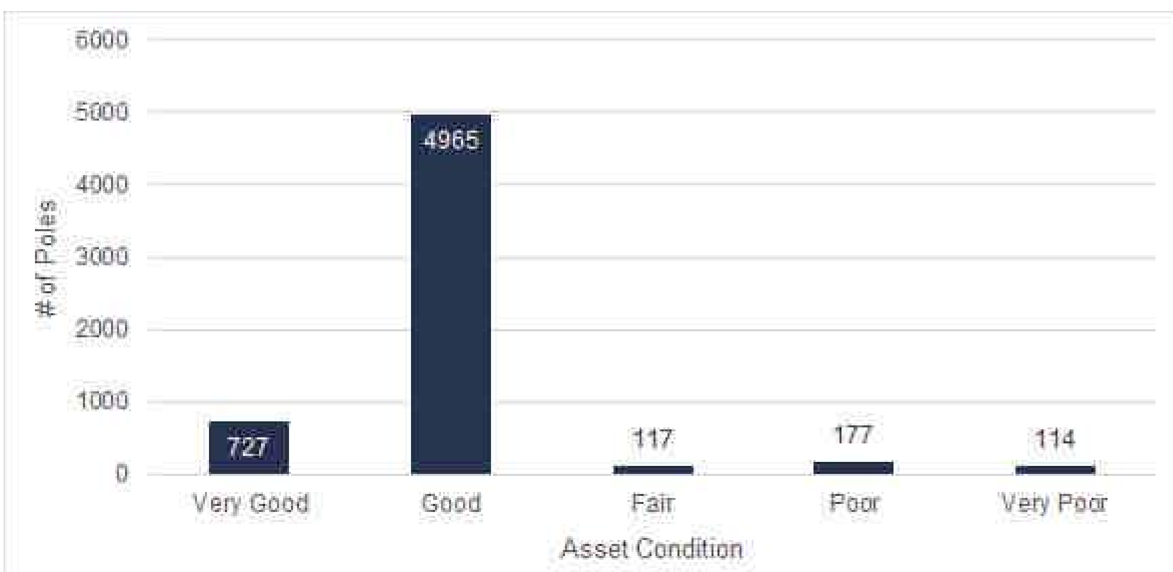
EPL owns 6100 wood poles across its four (4) service territories. The service age is known for 2903 – or 48% – of EPL's wood poles. Figure 3-6 presents the age distribution of the known set. The distribution is skewed towards newer poles since modern data collection processes are more accurate.

Figure 3-6: Age demographics of wood poles



The overall distribution consolidated between the four (4) service areas is presented in Figure 3-6. The results suggest a pole replacement rate of 1.5-2% per year, depending on the final results of the risk analysis, which is reflective of a fifty-year TUL.

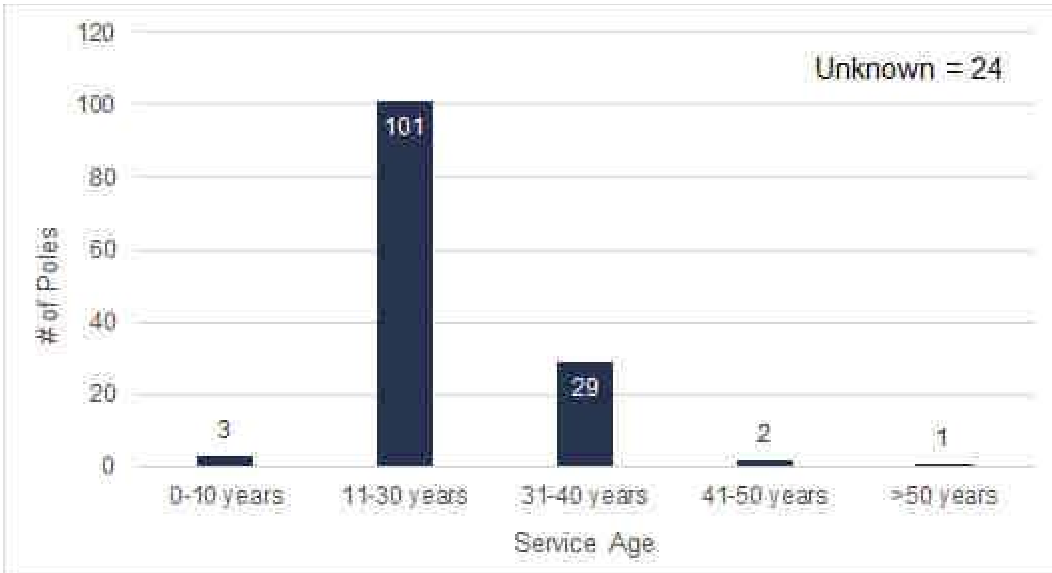
Figure 3-7: Condition assessment results for wood poles



3.2.3.2 Concrete Poles

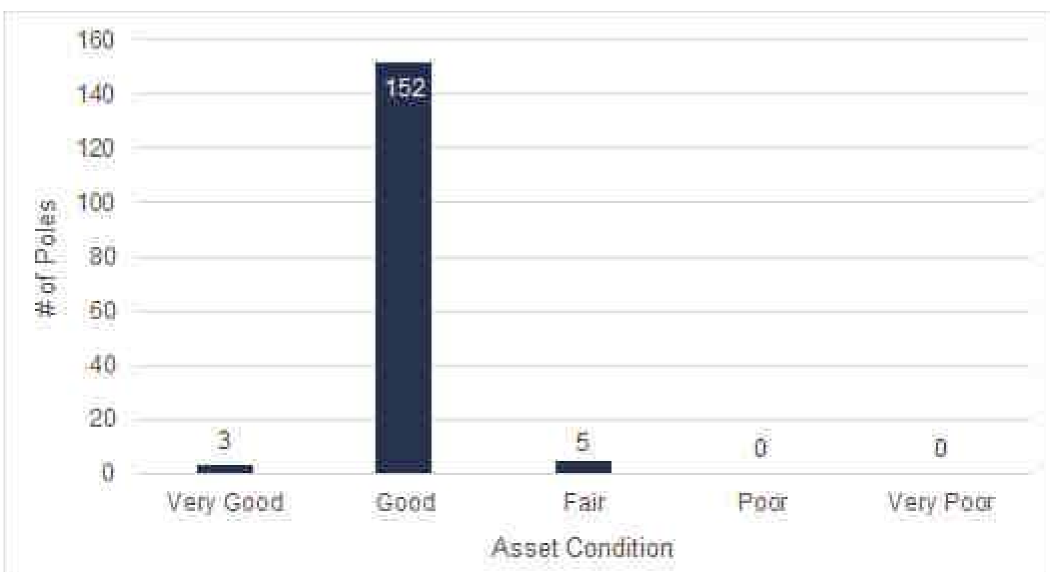
EPL owns 160 concrete poles across its four (4) service territories. The service age is known for 136 – or 85% – of the concrete poles. Figure 3-8 presents the age distribution of the known set of concrete poles. There have been very few concrete pole installations in the past ten (10) years.

Figure 3-8: Age demographics of concrete poles



The overall distribution of concrete pole condition consolidated between the four (4) service areas is depicted in Figure 3-9. The results suggest that there are no immediate replacement needs for concrete poles.

Figure 3-9: Condition assessment results for concrete poles



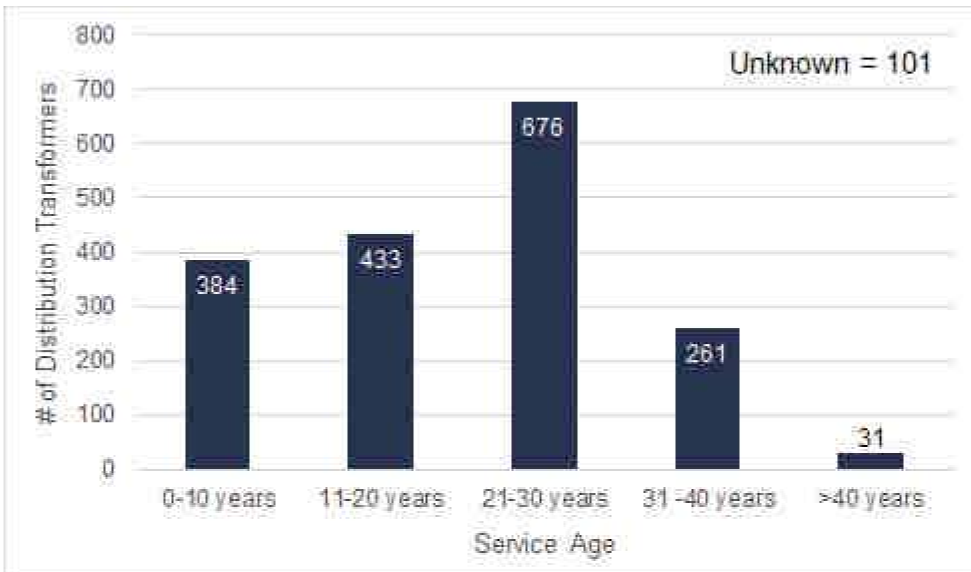
3.2.3.3 Steel Poles

EPL owns three (3) steel poles: two (2) in LaSalle and one (1) in Leamington. The service age is known for just one (1) of the poles, which is thirty-seven (37) years old and situated in LaSalle. The three (3) steel poles were all assessed to be in Good condition. The results suggest that there are also no immediate replacement needs for steel poles.

3.2.3.4 Pad-mounted Distribution Transformers

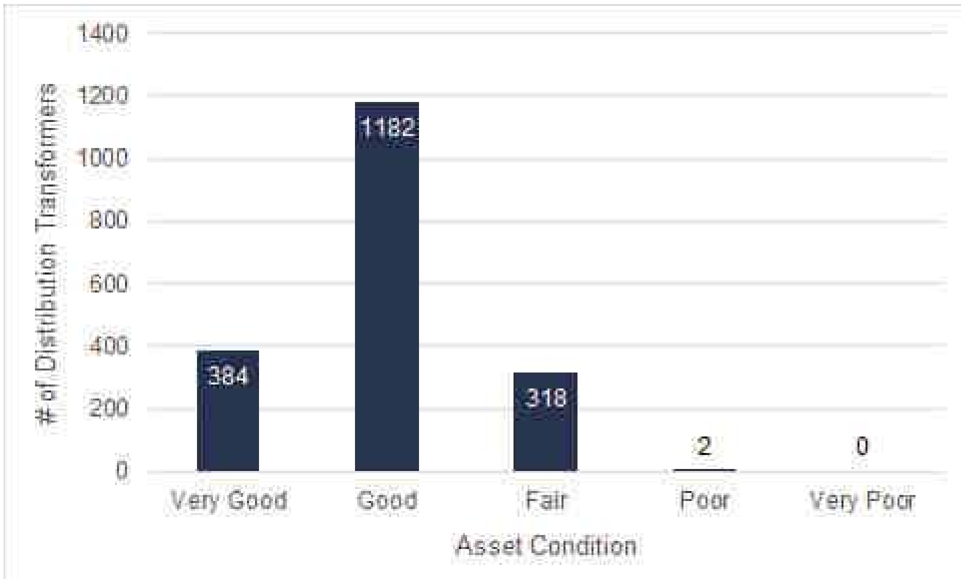
EPL owns 1886 pad-mounted distribution transformers across its four (4) service territories. The service age is known for 1785 – or 95% – of the pad-mounted transformers. Figure 3-10 presents the age distribution of the known set of pad-mounted transformers.

Figure 3-10: Age demographics of pad-mounted transformers



The overall distribution of pad-mounted transformer condition consolidated between the four (4) service areas is depicted in Figure 3-11. The majority of the pad-mounted distribution transformers are in Good condition, while just two (2) are in Poor condition.

Figure 3-11: Condition assessment results for pad-mounted transformers



3.2.3.5 Pole-mounted Distribution Transformers

EPL owns 1183 pole-mounted distribution transformers across its four (4) service territories. The service age is known for 991 – or 84% – of the pole-mounted transformers. Figure 3-12 presents the age distribution of the known set of pole-mounted transformers.

Figure 3-12: Age demographics of pole-mounted transformers

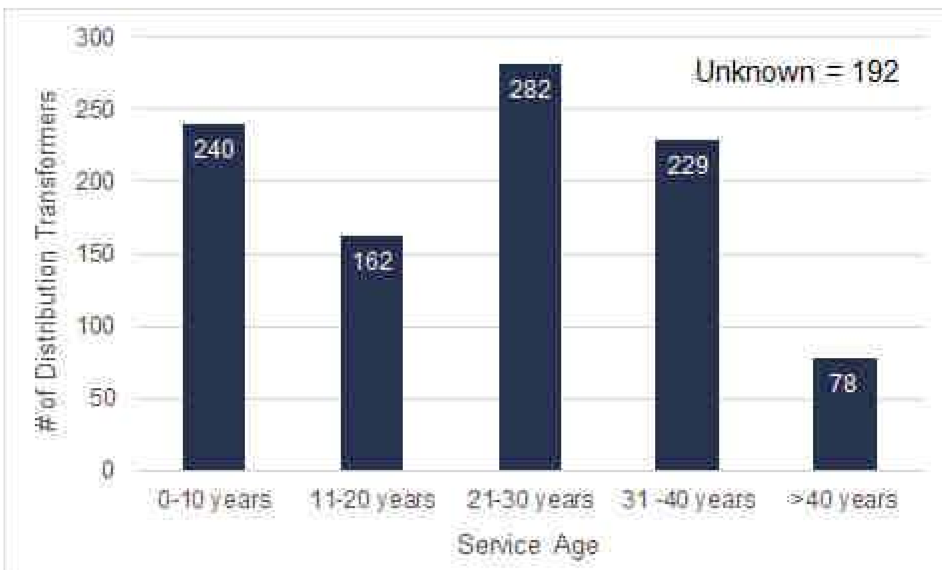


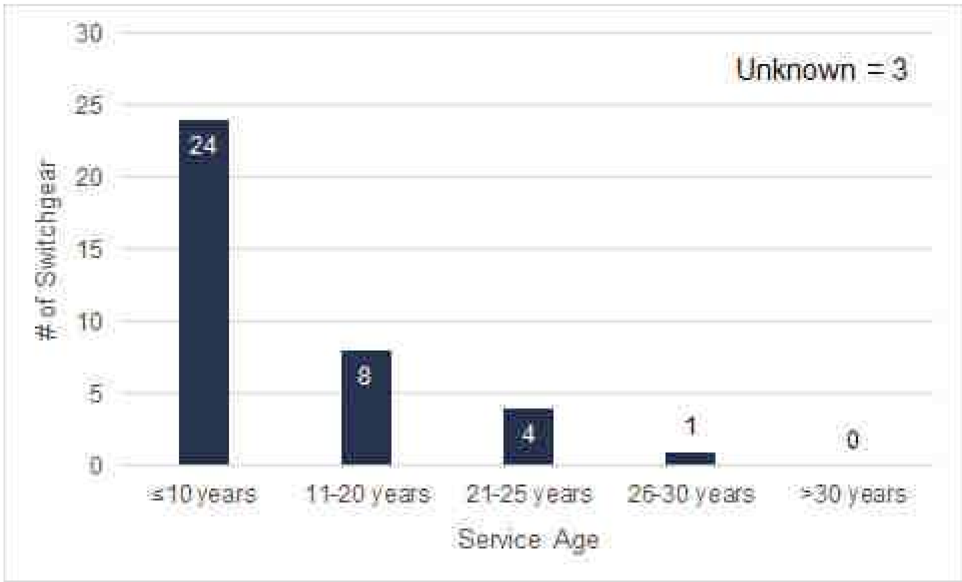
Figure 3-13 depicts the overall distribution of pole-mounted transformer condition consolidated between the four (4) service areas. Five (5) pole-mounted distribution transformers are in Poor condition and one (1) is in Very Poor condition. The majority of the pole-mounted distribution transformers are in Good condition.

Figure 3-13: Condition assessment results for pole-mounted transformers

3.2.3.6 Pad-mounted Distribution Switchgear

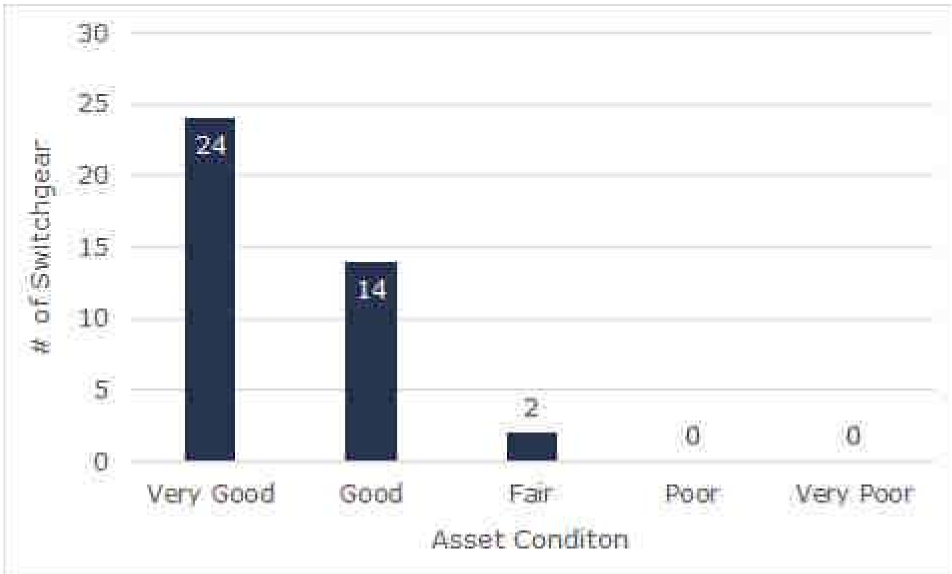
EPL owns forty (40) pad-mounted switchgear and the service age is known for thirty-seven (37) of them. Figure 3-14 presents the age distribution of the known set of pad-mounted switchgear.

Figure 3-14: Age demographics of pad-mounted switchgear



The condition assessment results for pad-mounted switchgear are presented in Figure 3-15. Two (2) of the switchgear are in Fair condition, while the rest are in Good or Very Good condition.

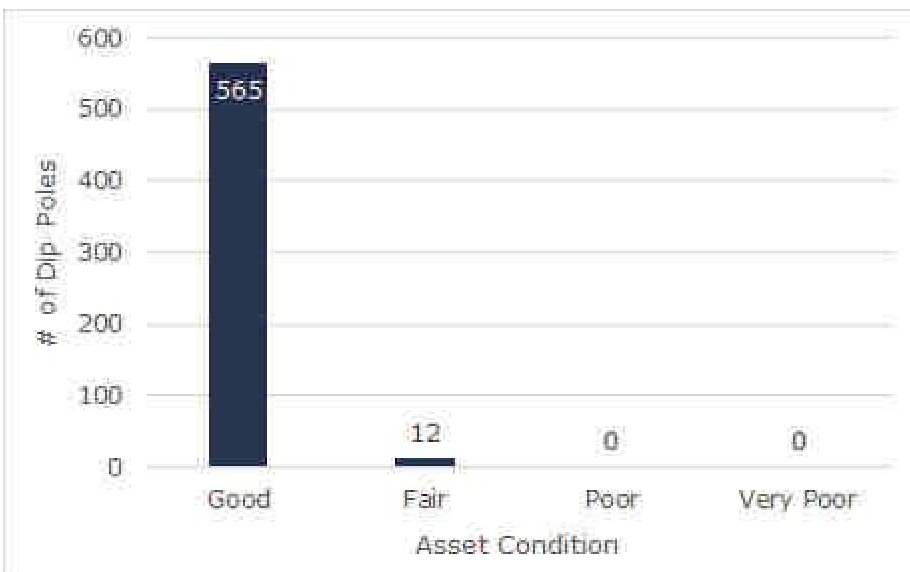
Figure 3-15: Condition assessment results for pad-mounted switchgear



3.2.3.7 Dip Poles (Primary Riser)

EPL has dip poles at 577 locations. Figure 3-16 presents the results of the condition assessment. Twelve poles are in Fair condition, while the rest are in Good condition.

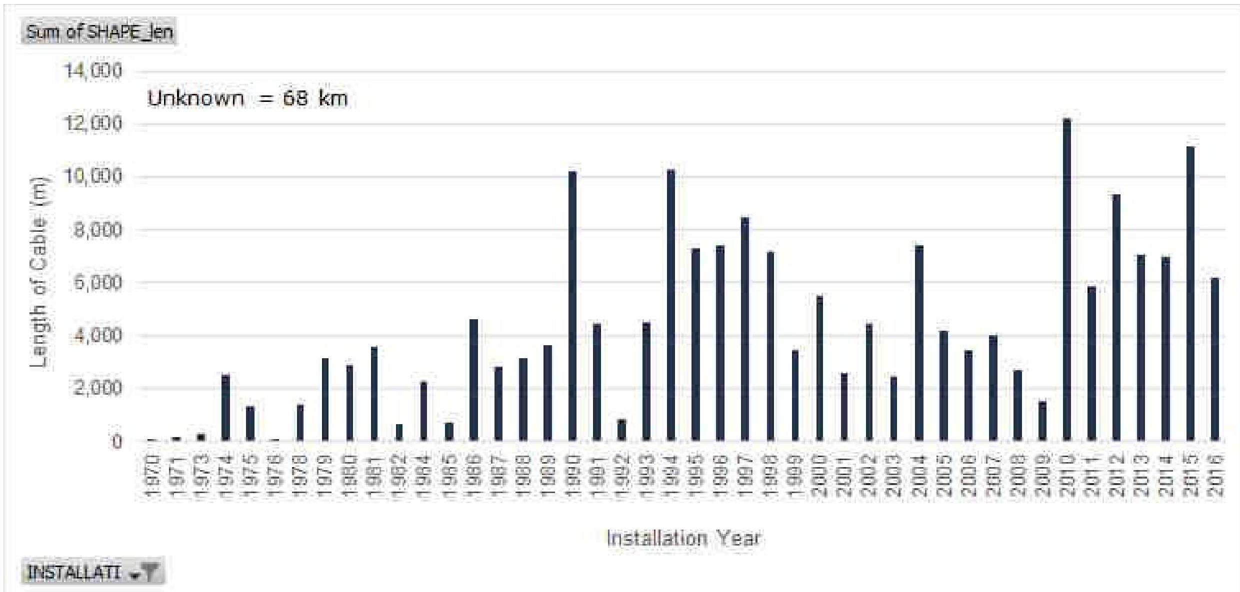
Figure 3-16: Condition Assessment Results for Dip Poles



3.2.3.8 Primary Underground Cables

The installation year is known for 194.9 km of the cables – or 74%. Figure 3-17 presents the cable length by installation year. EPL uses a TUL of thirty (30) years for direct-buried cables and forty (40) years for cables in conduits. Since 1986, all primary cables were installed in conduits; therefore, the significant amount of cable installed in 1990 and from 1994 to 1997 will reach their TUL beginning in 2030.

Figure 3-17: Installation Year of Primary Underground Cable



Out of the 67.7 km for which the installation date is unknown, 25.8 km was installed in conduit and is most likely less than thirty (30) years old. The remaining 41.9 km direct-buried cable was presumably installed prior to 1986 and has exceeded TUL. Based on this analysis, 48.9 km – or 19% – of EPL's underground cable have exceeded TUL. Table 3-4 summarizes the service age of EPL's primary underground cable relative to TUL.

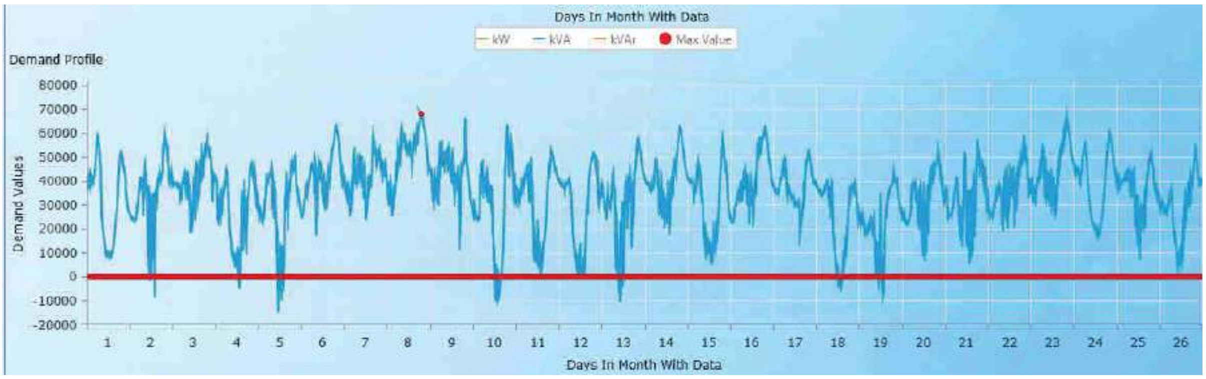
Table 3-4: Primary underground cable service age relative to TUL

Service Age	Cable Length (km)
Past TUL	48.9
Will reach TUL by 2026	16.9
Will reach TUL by 2036	54.7
Will reach TUL by 2046	49.2
Will reach TUL by 2056	67.1
Unknown but will reach TUL after 2026	25.8
Total	**262.6**

3.2.4 System Utilization (5.3.2d)

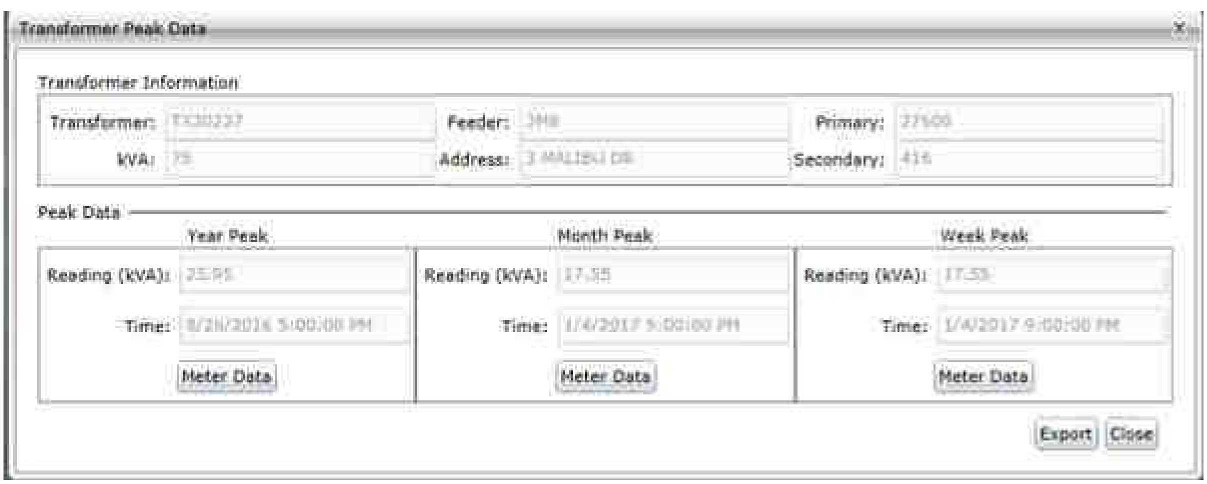
System modeling is an important aspect of good distributor planning in order to meet customer needs. For example, fault levels must be calculated and provided to customers who request this information as per the *Distribution System Code*. The system model that EPL uses is called DESS, which is updated twice per year with current assets and customer information. SmartMAP is used on a yearly basis in conjunction with HONI to complete load and phase balancing. This process ensures distribution feeders are balanced correctly per *Distribution System Code Section 6.4* requirements and verifies whether line loading, voltages, and equipment sizing are within acceptable the limits. DESS is integrated with SmartMAP to utilize actual distribution system data for its load flow simulations. Currently and over the past two years, EPL's total load has been in reverse flow at times because of the large amount of REG connected within and downstream of EPL's system. The load profile shown in *Figure 3-18* demonstrates that on days with large solar production along *with wind farm generation, the generation exceeds EPL's demand.*

Figure 3-18: EPL's net demand is negative at times due to the high penetration of REG



Transformer loading is an import part of the decision-making process when considering utilization of assets for system access and system renewal investments. HealthMAP and SmartMAP have full connectivity of all customers to transformers. The actual loading profiles are used by EPL's engineering department to determine if new customers can be added to existing transformers. Figure 3-19 depicts the dashboard of information available. Alert messages are set up to alert EPL staff of an overloaded transformer situation. Transformers are designed to operate above rated capacity for a limited period of time, but sustained overloading accelerates transformer degradation.

Figure 3-19: EPL considers the load of individual transformers



3.3 Asset Lifecycle Optimization Policies and Practices (5.3.3)

3.3.1 Asset Lifecycle Optimization Policies and Practices (5.3.3a)

Providing a reliable source of electricity to customers within a limited budget are the key pressures faced by LDCs in Ontario. The frequency and timing of distribution system equipment maintenance is an important factor in this balance. EPL relies on a combination of Reliability-Centred Maintenance ("**RCM**"), predictive maintenance, and cyclical inspections to manage its distribution assets.

RCM focuses on preventing failures with the most serious consequences, while predictive maintenance uses diagnostic methods to schedule maintenance in a timely manner. Integrating the two streams of information along with the asset risk assessment used for capital planning produces an optimal strategy for spending that considers both capital and system O&M costs. As assets are replaced through system renewal investments, the risk exposure on the system is reduced, thus reducing the need for RCM and preventative maintenance. At the same time, other assets on the system continue to age, thus increasing their failure probability and increasing the need for RCM and preventative maintenance. These two competing factors define the complex interactions between system renewal investments and system O&M costs, which EPL has yet to quantitatively define.

3.3.1.1 Reliability-Centred Maintenance

RCM considers the risk of customer outages, asset failure probabilities, methods to reduce the risk failure (probability or consequence), costs, the asset's role in the system, and other measures when selecting a specific maintenance program for an asset. RCM offers the following benefits:

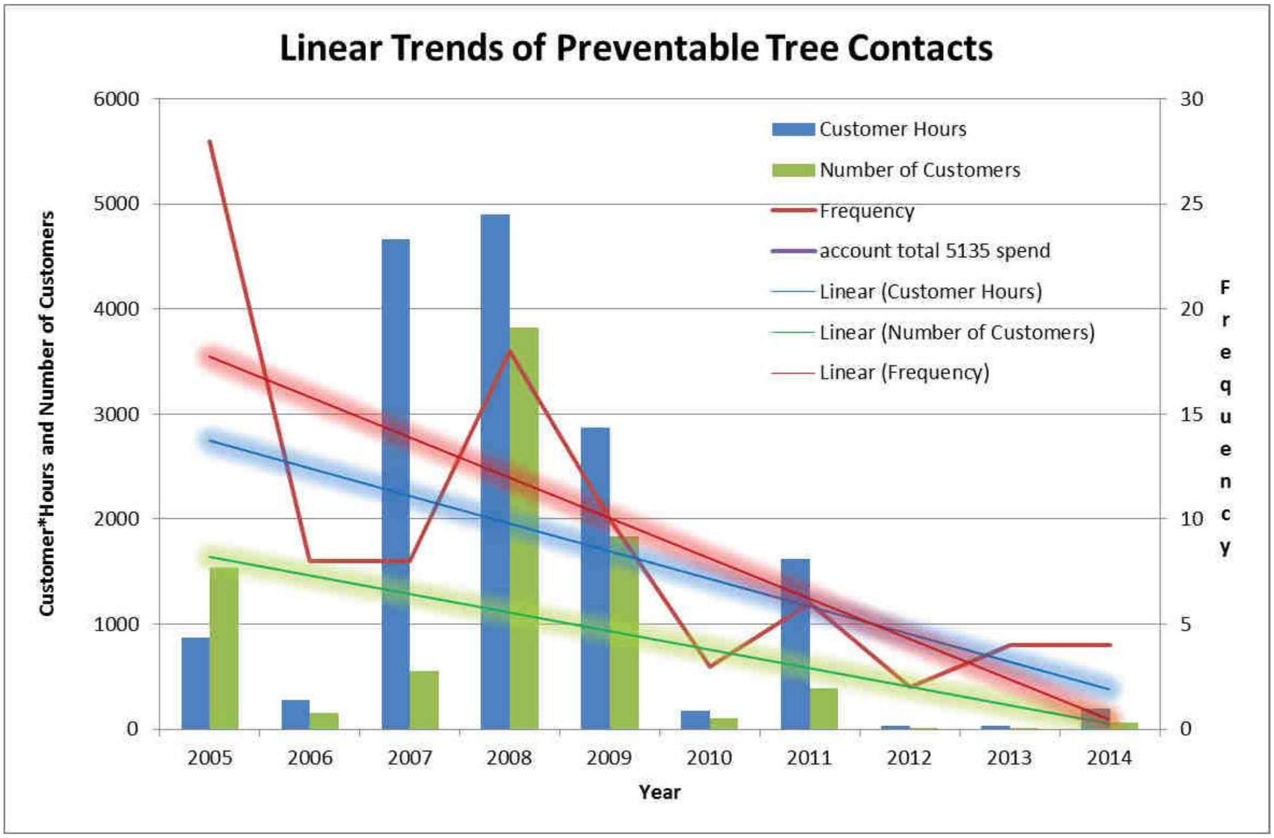
- The consequences of a single event on the distribution system are determined.
- The severity and importance of each component are assessed.
- Failures with the greatest consequences are prevented.
- Unnecessary maintenance is avoided.

The cost associated with each failure is used to predict future costs using failure trends. EPL has used RCM for the past ten years to assess and monitor the health of the distribution system assets. RCM is divided into 45 categories for reporting purposes and each outage is entered under the correct category.

Vegetation management is a key consideration of RCM. Using RCM trends EPL can monitor are preventable and unpreventable tree contacts resulting in an outage. A tree contact is defined as preventable when tree branches within the limits of the line cause a power outage – these could have been removed before the outage occurred. A tree contact is defined as unpreventable when the whole tree or long branches not within the limits of a line come in contact with the line. EPL also reviews road designs and customer plans submitted in order to ensure that new vegetation is planted be away from existing and future lines. During municipal and customer planning, EPL works with these groups to ensure vegetation clearance standards are conformed to.

EPL increased its spending on vegetation management since 2010, when Ontario Regulation 22/04 was modified to require vegetation management surrounding secondary lines as well as primary. Prior to 2011 secondary lines were not maintained just when power outages occurred on an unplanned basis. Preventable tree contact impacts to customers have trended sharply downward since this change was implemented, as shown in Figure 3-20. Therefore, in addition to meeting regulatory requirements EPL's vegetation management programs provide value in unplanned tree trimming cost reductions and improved reliability.

Figure 3-20: Preventable tree contact trends



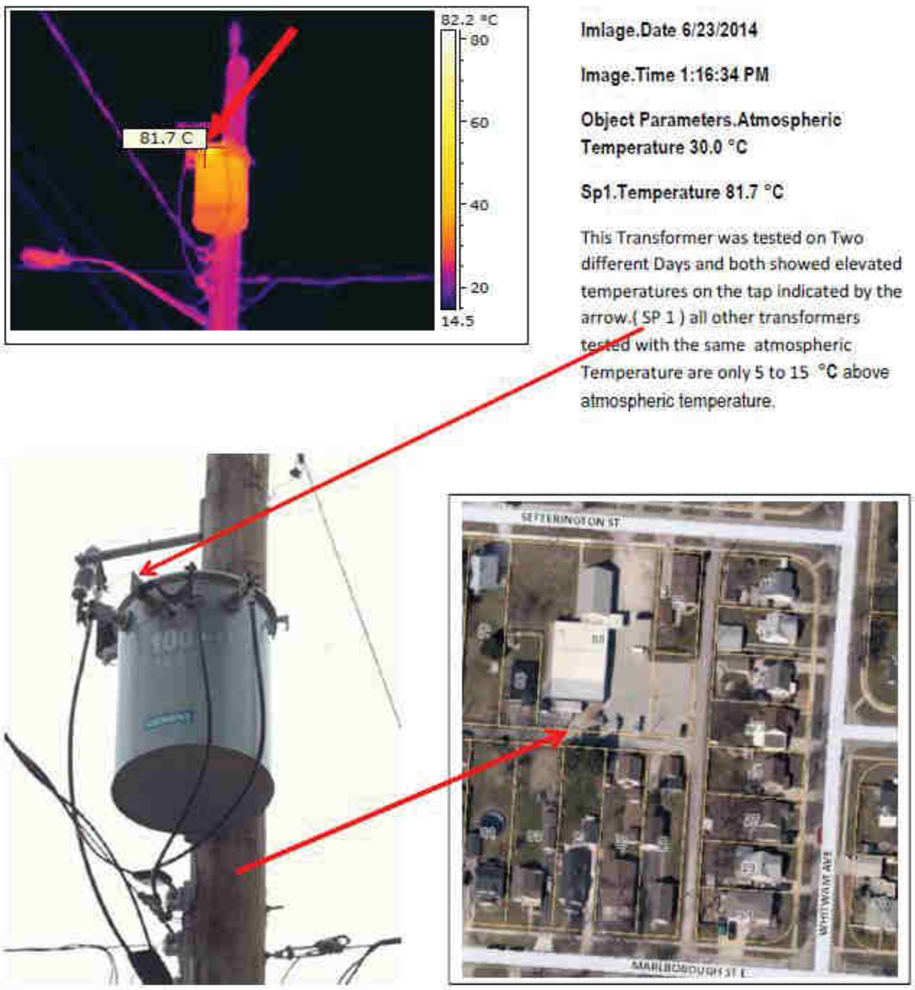
3.3.1.2 Predictive Maintenance

Predictive maintenance uses innovative technology, software, programs, and practices to identify components that are close to failure or are operating outside of normal ranges. EPL's predictive maintenance activities include infrared inspections and line monitors.

Infrared and ultrasonic inspections are both non-destructive test methods used to assess the performance of overhead components and major underground components of EPL's distribution system. These inspections identify distribution equipment which are close to failure or which are exhibiting signs of deterioration but still operating normally. Equipment which are close to failure are replaced on a high priority basis. Equipment which are starting to show signs of deterioration are monitored and programs are planned to repair or replace the equipment in the future.

Figure 3-21 depicts an example of an overhead transformer with an overheating connection. The mitigation strategy for this transformer would be to increase the inspection frequency of the transformer to check for signs of damage or wear and clean the connections.

Figure 3-21: Infrared inspection identifying hotspots on an overhead transformer



3.3.1.3 Preventative Maintenance

Regular preventative maintenance is performed on distribution assets to assess their condition and ensure proper operation. The preventative maintenance procedure follows standard industry practices and manufacturer recommendations. The assets are tracked in EPL's database and the results of the preventative maintenance are used to assess the condition of the equipment. Conditions are evaluated by linemen into three (3) severity categories: low, medium, and high. The database is reviewed for trends and problems requiring immediate actions.

3.3.1.4 Inspections

EPL's inspection programs are based on the minimum inspection requirements listed in Appendix C of the *Distribution System Code*. Line patrols are performed on a three (3)-year cycle. Overhead transformers are inspected for signs of rust or oil leaks and transformer bushings are checked for cracks or contamination. Ground lead attachments and ground wire on arrestors are checked to ensure proper ground connection. In addition, transformers are checked for bird/animal nests and tree trimming requirements.

Wood poles are inspected for insect infestation or woodpecker damage; crossarms, pole tops, and pole shells are assessed for deterioration; leaning poles are noted; and a sound test determines the hollowness. Insulators on the poles are checked for chips, cracks, and contamination. Poles positioned in hazardous locations are also noted.

Load break switches are inspected for corrosion or mechanical deterioration and are maintained regularly. Overhead lines are checked for signs of corrosion, broken strands, abrasions, annealing, and elongation. Line connections to the switches are inspected. Line patrol inspection results are not formally documented. Instead, line staff note any deficiencies during line patrols or trouble calls for immediate or scheduled replacement depending on the severity of the damage or deterioration.

EPL's underground inspection program covers pad-mounted equipment and underground cable terminations. Underground transformers require very little maintenance and are inspected for paint condition, signs of corrosion, and oil leaks. Transformer bushings are checked for cracks or contamination. Switchgear are inspected for paint, corrosion, and mechanical deterioration and are maintained regularly. Underground cable terminations, which are exposed in pad-mounted equipment and riser poles, are inspected for signs of moisture ingress.

Table 3-5: EPL's inspection and maintenance programs

Asset	Inspection Programs	Maintenance Programs	Other
Overhead transformers	Inspected every three (3) years	None	Infrared scans
Underground transformers	Inspected every three (3) years	Some maintenance as required (vegetation control, paint condition, connection cleaning and tightening)	Infrared scans
Poles	Inspected every three (3) years	None	Pole testing
Load break switches	Inspected every three (3) years	Regular maintenance (adjustments as required)	Infrared scans
Switchgear	Inspected every three (3) years	Regular maintenance (cleaning and adjusting)	Infrared scans
Underground cables	Terminations inspected every three (3) years (at pad-mounted equipment and riser poles)	None	None
Overhead conductors	Inspected every three (3) years	None	None

EPL's assets are recorded in a database to manage inspection requirements based on standard industry practices and manufacturer recommendations. This database is reviewed for trends and problems requiring immediate action, and planned actions. Immediate actions may be taken if there is a concern for security, public access, or an outage.

Inspections are entered on a tablet and can be viewable through secure web portals. A map of inspection results is used by engineering staff to analyze and monitor asset condition. EPL staff can use this information to measure deterioration as assets age. Inspections also find items like theft of copper from poles as a covered ground wire runs down the outside of some poles to ground equipment. These items are repaired following the inspection.

Figure 3-22: Map of inspection results

3.3.2 Asset Lifecycle Risk Management Policies and Practices (5.3.3b)

EPL's distribution system maintenance and inspection programs are aimed in part to protect the public from physical, electrical and environmental hazards by maintaining a schedule of regular asset inspections and maintenance activities. *Ontario Regulation 22/04 – Electrical Distribution Safety* is a key regulation which requires all LDCs including EPL to maintain distribution standards, material standards, and construction verification programs to safeguard the public from hazards associated with the distribution system. EPL follows all regulatory requirements and guidelines to ensure the distribution system has a low risk impact on the environment.

A significant component of EPL's risk management policies and practices are the RCM and predictive maintenance activities described in Section 3.3.1. In addition, EPL's risk-based asset management process considers risk at each stage in the asset's lifecycle when making decision on the optimal timing of asset repair or replacement. Risk is evaluated by considering both the probability of an event occurring and its consequence. All seven strategic business objectives listed in Section 3.1.1 are considered in this analysis.

On the overhead distribution side, a pole failure can be a significant safety risk as the result could injure the public and/or cause a lengthy interruption. Poles which are closer to the supply have a greater reliability impact in case of a failure, since they serve a greater number of downstream customers. Overhead transformers have a low risk of failure; their outage impact is limited to a small number of customers for a short duration. The risk of failure of load break switches and overhead conductors are low; although these assets may have a high failure impact, their failure probability is low.

On the underground system, switchgear failures also pose a significant failure risk, as a customer outage would likely occur and the safety of the public and staff would be impacted. As with overhead transformers, underground transformers have a low risk of failure; their outage impact is limited to a small number of customers for a short duration. The impact of an underground cable failure is low and public safety is not likely to be impacted as cables are buried and not exposed.

Conclusions of risk analyses use a scoring system to select and prioritize capital expenditures. Each potential project is scored in the risk matrix shown in Figure 3-23 by considering all seven strategic business objectives and using the following formulation.

$$R_e = R_f + \beta(R_m - R_f)$$

- R_e is the expected rate of return.
- R_f is the risk-free rate of return
- R_m is the average market rate of return

By definition:

- Operational β less than 1 is low risk.
- Operational β equal to 1 is average risk
- Operational β greater than 1 is higher risk

Figure 3-23: Risk matrix to select and prioritize capital expenditures

Risk Map

Probability

5	Common/ Almost Certain	1.0	1.4	2.1	2.8	4.0
4	Most likely	0.9	1.3	1.8	2.5	3.5
3	Moderate	0.7	1.0	1.4	1.9	2.7
2	Likely	0.6	0.8	1.2	1.7	2.4
1	Rare	0.5	0.7	1.0	1.4	2.0
		Insignificant	Minor	Moderate	Major	Catastrophic
		1	2	3	4	5

Consequence

As part of the asset risk assessment, the asset's age and estimated remaining life are recorded and any concerns are identified. The risk assessment has three components:

- Public safety risk assessment
- Worker safety risk assessment
- Major equipment failure risk assessment

Crew members and the operations manager directly perform risk assessments of assets in the field. Any additional risks identified are populated in risk assessment forms. The inputs come from the operating personnel, shareholders, customer calls, emergency personnel (police, fire), health and safety meetings, other LDCs, and joint-use partners.

Based on the inspection during risk assessment process, every possible area of concern is noted and prioritized. Various criteria are evaluated such as concerns with unauthorized entry by public, proximity, clearance for workers, multiple sources of voltage, condition of the assets, presence of PCBs, etc. An overall asset risk ranking is produced as shown in Table 3-6. The rankings portray the severity of the risk with each asset by providing the timeframe within which capital work should be done to improve the condition.

Table 3-6: Overall asset risk rating

Priority	Low	Medium	High
Intervention timing	Four (4) to seven (7) years	Two (2) to three (3) years	One (1) year

4 Capital Expenditure Plan (5.4)

This section focuses on the capital investments planned by EPL over the forecast period. EPL's materiality threshold for this Application is $65,000.

4.1 Summary (5.4.1)

A summary of EPL's capital expenditure plan is outlined below and demonstrates key information explaining the significant aspects of the plan in order to meet EPL strategic corporate and asset management objectives. The capital expenditure plan was developed by leveraging key outputs of the asset management process. Projects have been divided into four (4) categories as outlined in the Filing Requirements.

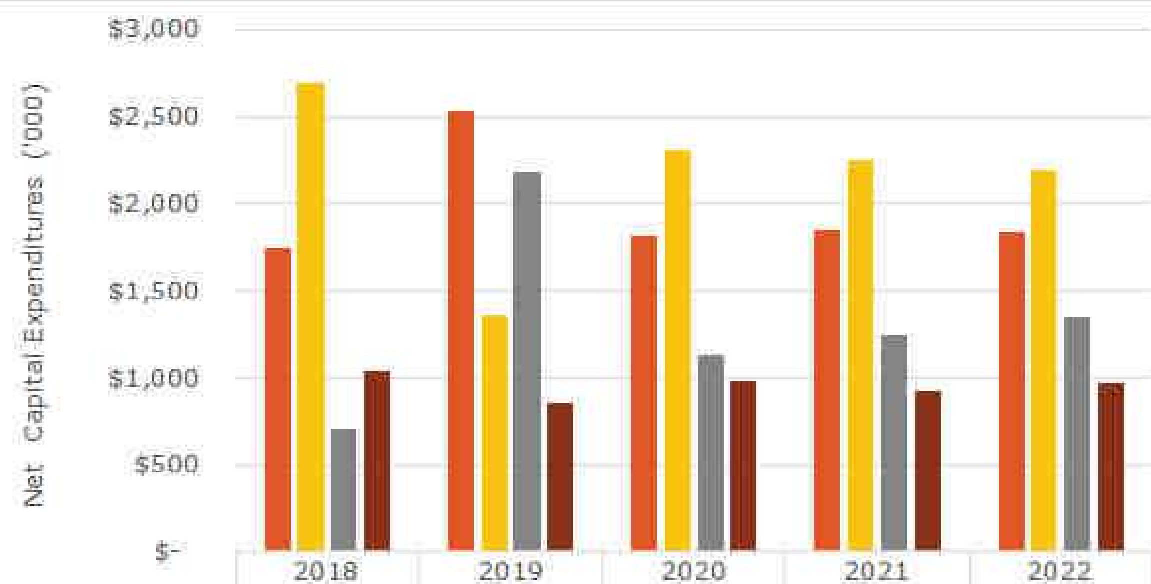
4.1.1 Ability to Connect New Load (5.4.1a)

With the exception of planned expansion-related spending in LaSalle, the remaining three (3) communities can accommodate planned load growth for the foreseeable future. Customer growth in LaSalle has necessitated the purchase of a new feeder and breaker position from HONI to continue to serve customers.

4.1.2 Capital Expenditures over the Forecast Period (5.4.1b)

Figure 4-1 presents the total annual capital expenditures by investment category over the forecast period.

Figure 4-1: Total annual capital expenditures over the forecast period



	2018	2019	2020	2021	2022
System Access	$1,746	$2,532	$1,816	$1,853	$1,835
System Renewal	$2,693	$1,362	$2,304	$2,248	$2,195
System Service	$707	$2,186	$1,126	$1,243	$1,342
General Plant	$1,037	$856	$976	$927	$968

4.1.3 Description of Investments (5.4.1c)

4.1.3.1 System Access

System access investments account for, on average, 31% of EPL's net capital expenditures over the forecast period. Investments in this category are driven by external requests and mandated obligations to accurately meter customers. For all programs, the forecast costs are driven by historical trends and increased by inflation.

Subdivisions

Investments are made to facilitate the connection of new residential subdivisions and the associated customers to EPL's distribution system. EPL coordinates its planning and construction activities directly with developers.

Residential Connections/Expansions

Residential requests for connection or expansion are costs associated with activities relating to plant relocation or plant upgrades to accommodate customer-related changes. EPL coordinates its planning and construction activities directly with customers and developers.

Municipal Requests

Municipal requests are costs associated with activities relating to plant relocation or plant upgrades to accommodate municipally-requested changes. Examples of municipal requests include, but are not limited to, road widenings, right of way improvements, and utility relocation projects. EPL coordinates its planning and construction activities directly with the municipalities and their contractors.

New Commercial/Industrial Service Upgrades

New service upgrades for commercial and industrial customers are budgeted annually. The investment costs are associated with activities relating to plant relocation or plant upgrades to accommodate customer-related changes. EPL coordinates its planning and construction activities directly with customers and their contractors.

Meter Upgrade and Replacement Program

The purpose of this program is to replace meters due to failure, technology limitations requiring upgrades, or seal expiry. The program also includes gatekeeper and modem replacements to enhance connection and reliability of data. In addition to considering historical spending trends and inflation, budgeting is reviewed annually based on communication and data needs of new technologies.

4.1.3.2 System Renewal

System renewal investments account for, on average, 34% of EPL's net capital expenditures over the forecast period. Investments in this category are driven by assets at the end of their service life due to failure or failure risk.

Pole Replacement Program

The purpose of this program is to replace poles that have either failed or are at the end of their service life due to failure risk. Through its thorough preventative maintenance program, EPL reviews the condition of its poles continuously to limit failure and maximize safety via non-destructive testing methods such as drilling. Poles which have been tested to have a remaining strength of below sixty percent (60%) are prioritized for replacement. Budgeting is reviewed annually based on preventative maintenance program findings and availability of resources.

Reactive Replacement Programs

The purpose of these programs (overhead reactive replacements and underground reactive replacements) is to replace overhead and underground equipment that has failed as a result of damage incurred in the field. Budgeting is reviewed annually and is based on historical spending trends adjusted for expected inflation.

Install/Replace Load-Break Switches

The purpose of this program is to replace load-break switches that have either failed or are at the end of their service life due to failure risk. As part of the self-healing grid initiative, load-break switches are upgraded during their planned replacement for reliability and automation purposes.

Infrastructure Rebuild Program

The purpose of this program is to replace overhead and underground services and circuits that are located in alleys, right of ways, etc. in customer backyards. Budgeting is reviewed annually based on urgency of work required and potential safety hazards. EPL intends to increase accessibility of all of its plant while limiting inconveniences to its customers.

Switchgear Replacement Program

The purpose of this program is to replace live-front switchgear units that have failed or are at the end of their service life due to failure risk. Through its thorough preventative maintenance program, EPL reviews the condition of live-front switchgear units continuously to limit failure and maximize safety via infrared and physical inspection. Budgeting is reviewed annually based on preventative maintenance program findings and availability of resources.

4.1.3.3 System Service

System service investments account for, on average, 21% of EPL's net capital expenditures over the forecast period. Investments into this category are driven by customer requests for generation connection, system capacity constraints, and other system operational objectives: reliability and operability.

Purchase/Sell HONI Assets

The HONI Asset Purchase projects in Leamington (2018 and 2019) and LaSalle (2020 to 2022) are initiatives to transfer assets between EPL and HONI so that each distributor controls assets within its geographical distribution service territory boundary. Loss of supply outages have been a problem for EPL's customers; therefore, the asset transfers have been planned to improve operability and reliability. The budgeted expenditures are based on the estimated purchase and sale prices.

Malden TS – New Feeders and Reconfiguration

Capital expenditures pertaining to the upgrades at Malden TS, two (2) new feeders, and feeder reconfigurations in LaSalle are driven by system capacity constraints. Customer growth in LaSalle has necessitated the purchase of a new feeder and breaker position from HONI to continue to serve customers.

FIT and Generation Connections

This program accommodates the connection of REG to EPL's distribution system, including FIT connections (greater than 10 kW up to 500 kW) and generation connections (greater than 500 kW). Investments are driven by customer requests for FIT and generation connections. The expenditure forecast is made based on applications being processed and the projected nameplate capacity of applications to be received.

MicroFIT Connections

This program accommodates the connection of REG to EPL's distribution system under the MicroFIT program (10 kW or less). Investments are driven by customer requests and the expenditures are forecast based on the applications being processed and the projected number of applications to be received. This program falls below the materiality threshold.

Self-healing Grid Reclosers

The installation of new reclosers has been planned as part of EPL's broader Smart Grid Development Plan (see Section 1.4.3.4). EPL has identified that loss of supply outages are major concerns for the reliability of electricity experienced by its customers. The main benefit of installing reclosers as part of a self-healing grid is to reduce the impact of loss of supply incidents to customers. The new reclosers will allow remote operation, real-time outage detection, and the ability to isolate the distribution system from the upstream distributor/transmitter.

4.1.3.4 General Plant

General plant investments account for, on average, fifteen percent (15%) of EPL's net capital expenditures over the forecast period. General plant investments are modifications, replacements, or additions to assets that are not part of the distribution system; including land and buildings, tools and equipment, rolling stock (fleet), and computer hardware and software used to support day to day business and operations activities.

Tools and Equipment

Costs for tools correspond to all purchases of large or major tools with a value of $500 or more. The budget for this cost item is forecast based on scheduled replacement equipment for one of several reasons:

- If the equipment fails a required test for electrical integrity or continuity.
- If the equipment is at end-of-life.
- If the equipment is damaged beyond repair.

Office Furniture

Office furniture costs include desks, tables, chairs, and partitions. This forecast is based on a simple projection based on historical purchases. The budget is generally below the materiality threshold.

Transportation Equipment

EPL has identified fleet purchasing requirements using the criteria identified in its fleet management policy (see Appendix I: Fleet Purchasing Policy). The fleet assessment identifies large and small vehicles that will reach end-of-life in the forecast period and the associated replacement cost. EPL's capital expenditures related to fleet are designed to maintain the current compliment and functional capability.

The budget is forecast based on the fleet management policy, which uses a combination of mileage, maintenance costs, and age as determining factors. In all cases, a physical inspection is performed by the Facility Operations and Risk Mitigation Supervisor before a final determination is made. The Facility Operations and Risk Mitigation Supervisor's assessment includes a determination of whether or not the vehicle is safe to operate, is well maintained, and, in their estimation, can be reliably and economically maintained for an additional year. Vehicles are reviewed annually until retired from use.

Computer Hardware

Computer costs are for all purchases of all planned and unplanned computer related equipment, which includes: laptops, printers, and network equipment. Budgeting for this cost item is based on assessing forward looking requirements such as system upgrades, evaluating existing hardware obsolescence and assessing for regulatory changes (i.e. Cyber Security framework in 2017). Typically, EPL phases in its planned system upgrades gradually and consistently to keep expenditures relatively smooth.

Computer Software

Software costs are for all purchases of new software and upgrades to existing software. Throughout the forecast period, EPL plans to upgrade its website, work management systems, service order processes, and GIS, as well as implement utility dashboards for greater management visibility throughout its core business. Typically, EPL phases in its planned software upgrades gradually and consistently to keep expenditures relatively smooth.

Buildings and Fixtures

Building costs include all work, equipment, and services over $500 that are related to EPL-owned properties and buildings. The budget is forecast based on planned work and purchases required for the repair or replacement of old equipment.

EPL conducted a building assessment (see Appendix H: Building Condition Review) via a qualified third party, which factored into the determination of this forecast. This building assessment was completed by an external consulting firm specializing in building assessments of this nature and incudes reviews and analysis by civil and mechanical engineers.

Stores Equipment

Stores equipment costs can vary depending on the nature of the expenditure. EPL's budget for Stores Equipment is generally based on historical spending. Where specific items are known in advance of the budgeting process, EPL budgets accordingly but consistently tries to spend within a historical range of approximately $50,000.

4.1.4 List of Material Capital Expenditures (5.4.1d)

The material capital expenditure projects/programs are sorted by category and listed below.

4.1.4.1 System Access

Table 4-1 lists the material capital expenditures in the system access category planned over the forecast period.

Table 4-1: List of material capital expenditures – system access

Project/Program	Budget				
	2018	2019	2020	2021	2022
Subdivisions	$382,500	$390,150	$397,953	$405,912	$414,030
Residential Connections/Expansions	$394,369	$402,256	$410,301	$418,507	$426,877
Municipal Requests	$612,000	$624,240	$636,725	$649,459	$662,448
New Service Upgrades - C&I	$356,959	$364,098	$371,380	$378,808	$386,384
Metering Upgrade & Replacement Program	$166,297	$169,623	$173,016	$176,476	$180,006

4.1.4.2 System Renewal

Table 4-2 lists the material capital expenditures in the system renewal category planned over the forecast period.

Table 4-2: List of material capital expenditures – system renewal

Project/Program	Budget				
	2018	2019	2020	2021	2022
Pole Replacement Program	$114,062	$558,674	$488,663	$121,043	$592,870
Overhead Reactive Replacements	$82,400	$84,048	$85,729	$87,443	$89,192
Underground Reactive Replacements	$64,964	$66,263	$67,588	$68,940	$70,319
Install/Replace Load Breaks	$59,927	$61,126	$62,348	$63,595	$64,867
Infrastructure Rebuild Program	$2,229,416	$229,416	$1,229,416	$1,529,416	$1,329,416
Switchgear Replacement Program	$147,321	$150,267	$153,272	$156,338	$79,732

4.1.4.3 System Service

Table 4-3 lists the material capital expenditures in the system service category planned over the forecast period. MicroFIT connections are also categorized as system service investments but fall below the materiality threshold.

Table 4-3: List of material capital expenditures – system service

Project/Program	Budget				
	2018	2019	2020	2021	2022
Purchase/Sell HONI Leamington Assets	$89,474	$283,873	$-	$-	$-
Malden TS 2x New Feeder & Reconfiguration	$-	$1,500,000	$250,000	$350,000	$-
FIT & Generation Connections	$181,370	$112,200	$114,444	$116,733	$119,068
Purchase/Sell HONI LaSalle Assets	$-	$-	$465,311	$474,617	$584,109
Self-healing Grid Reclosers	$270,140	$275,543	$281,054	$286,675	$292,408

4.1.4.4 General Plant

Table 4-4 lists the material capital expenditures in the general plant category planned over the forecast period. Expenditures pertaining to office furniture and stores equipment are also planned over the forecast period, but fall below the materiality threshold.

Table 4-4: List of material capital expenditures – general plant

Project/Program	Budget				
	2018	2019	2020	2021	2022
Buildings & Fixtures	$370,000	$350,000	$350,000	$250,000	$250,000
Computer Software	$115,000	$80,000	$80,000	$80,000	$80,000
Fleet	$270,000	$275,000	$395,000	$445,000	$560,000
Tools & Equipment	$60,000	$60,000	$60,000	$60,000	$60,000
Computer Hardware	$161,809	$95,000	$80,000	$85,000	$80,000

4.1.5 Expenditures related to a Regional Planning Process (5.4.1e)

EPL has fulfilled its obligations with respect to the Regional Planning Process but no Regional Investment Plan has been completed for the Winsor-Essex region at this time. An IRRP has been completed for the Windsor-Essex region (see Appendix B: Windsor-Essex Region Integrated Regional Resource Plan). HONI is currently seeking Section 92 approval from the OEB.

Since there are currently neither details nor expectations with respect to line work that may be included in a Regional Investment Plan, the DSP does not include any related capital plans. There is, however, an upcoming capital contribution to HONI for the construction of the new Leamington TS, that will be required in 2018. The timing and the exact amount of EPL's expected capital contribution is not yet finalized.

EPL is committed to the Regional Planning Process and will continue to participate as the process evolves. Future DSP's will incorporate any capital expenditures that result out of such studies. The current DSP does not include any direct accommodation for such costs.

4.1.6 Customer Engagement Activities (5.4.1f)

EPL is committed to continuous customer engagement. The major initiatives to highlight include the INNOVATIVE Customer Satisfaction Surveys, the Convergys Top Down Survey, and the Customer Engagement Handbooks. The purpose of these surveys is to measure customer satisfaction, determine customer needs and preferences, and identify opportunities to improve customer experience.

4.1.6.1 INNOVATIVE Customer Surveys

Two (2) reports by INNOVATIVE are attached to this DSP as Appendix D. The Ratepayer Telephone Survey was completed in 2017 and the Customer Satisfaction Survey was completed in 2014.

4.1.6.1.1 INNOVATIVE Ratepayer Telephone Survey (2017)

The Ratepayer Telephone Survey interviewed 524 residential customers, 51 GS<50 customers, and 9 GS>50 customers. Both residential and GS customers agree that their top priorities are (in order):

1. Delivering reasonable electricity distribution prices;
2. Ensuring reliable electricity service; and
3. Preventing or reducing the length of power outages caused by extreme weather.

System Reliability Preferences

Residential customers prefer EPL spend what is needed to maintain the current number and duration of outages, while GS customers lean towards reducing the number of outages and maintaining the length of outages.

Figure 4-2: Residential customer system reliability preferences

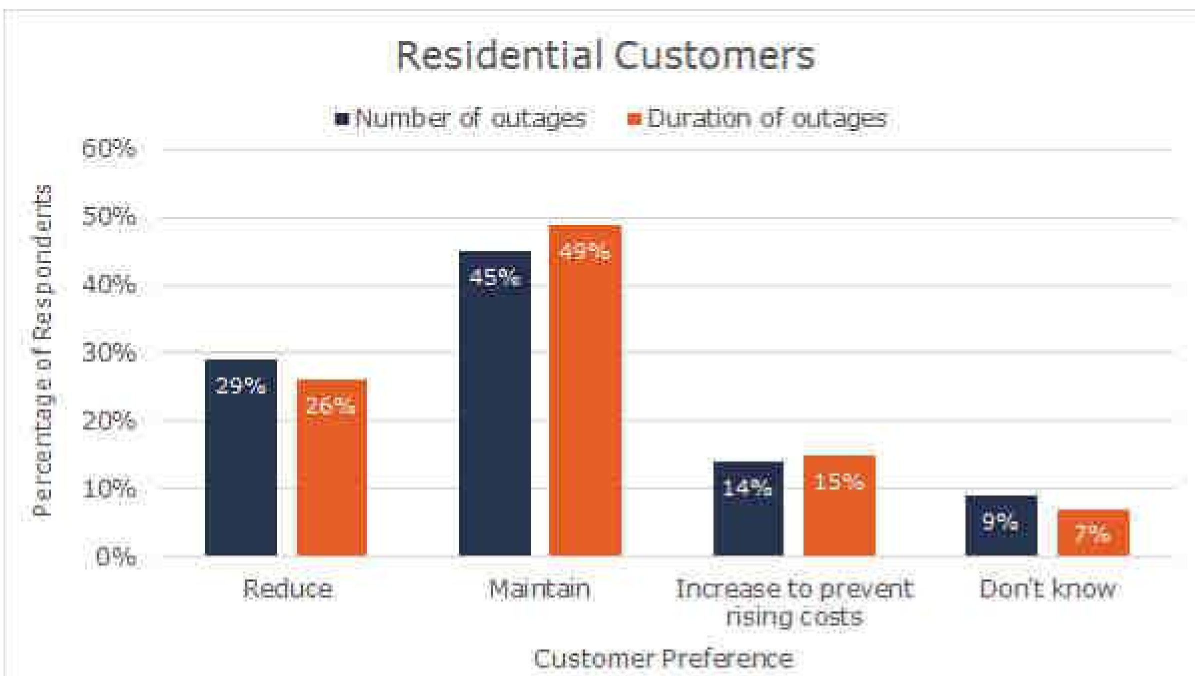
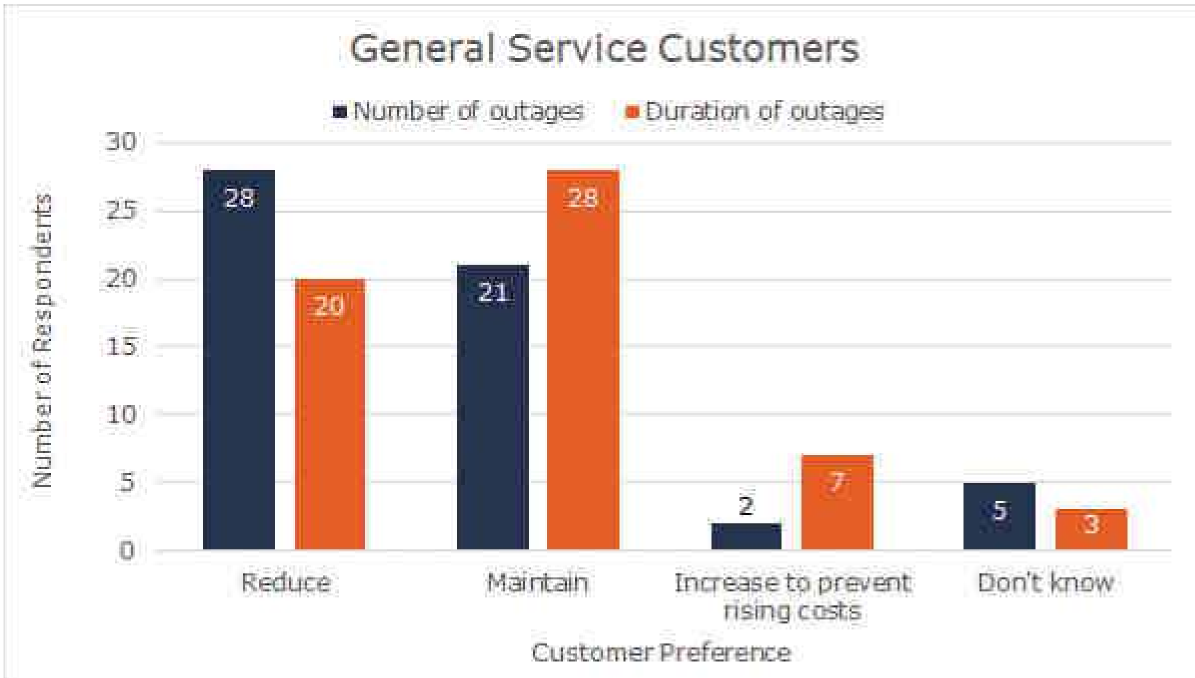


Figure 4-3: General Service customer system reliability preferences



Category-Specific Investment Preferences

Seventy-one percent (71%) of residential customers believe that EPL should invest what it takes to replace the system's aging infrastructure to maintain system reliability, while nineteen percent (19%) believe that EPL should lower its estimated investment in renewing the system's aging infrastructure to lessen possible bill increases. Similarly, eighty percent (80%) of GS customers are in favour of replacing aging infrastructure and fifteen percent (15%) believe system renewal spending should be reduced to lessen bill impacts.

Seventy-five percent (75%) of residential customers feel the best approach is to replace equipment before it breaks down, while nineteen percent (19%) feel a run-to-failure strategy is best. Similarly, 67% of GS customers support a proactive equipment replacement strategy, while 23% support a run-to-failure strategy.

Eighty-five percent (85%) of residential customers think grid modernization is "very" or "somewhat" important, while just twelve percent (12%) feel it is "not very important" or "not important at all". Similarly, 83% of GS customers think grid modernization is "very" or "somewhat" important, while 10% feel that it is "not very important".

Seventy-one percent (71%) of residential customers believe that, while EPL should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably. On the contrary, 25% of residential customers believe that EPL should find ways to make do with the buildings, equipment, and IT systems it already has. Similarly, seventy-two percent (72%) of GS customers believe that while EPL should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably. Twenty-three (23%) of GS customers believe EPL should find ways to make do with the buildings, equipment, and IT systems it already has.

Customer Opinions

Survey participants were asked to describe their level of agreement with various statements related to the timing of investments, their trust in experts, reducing electricty consumption and costs, the obligation to maintain the existing electricity network for future genreations, grid modernization, and the impact of power outages on vulnerable people.

Table 4-5 summarizes the responses of residential customers, while Table 4-6 summarizes the responses of GS customers.

Table 4-5: Residential customer opinions on very topics

Statement	Percentage of Respondents					
	Strongly agree	Somewhat agree	Neither agree nor disagree	Somewhat disagree	Strongly disagree	Don't know
We should invest in our electricity system infrastructure now or we will end up paying more the longer we delay our system renewal.	39%	40%	1%	9%	5%	4%
The electricity sector is so complicated and confusing; we just have to trust that the experts will find the right balance in keeping cost down while making the right investments and spending decisions.	27%	38%	2%	11%	18%	2%
I think Essex Powerlines should do more to help customers find ways to reduce their electricity consumption and costs.	49%	31%	1%	9%	7%	2%
Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations.	43%	43%	2%	5%	4%	2%
We need to modernize the local electricity system so consumers can have greater control over their electricity usage.	37%	44%	2%	7%	5%	3%
A few power outages are fine for me personally, but I worry about the impact this has on more vulnerable people, such as the elderly.	52%	34%	1%	7%	4%	1%

Table 4-6: GS customer opinions on very topics

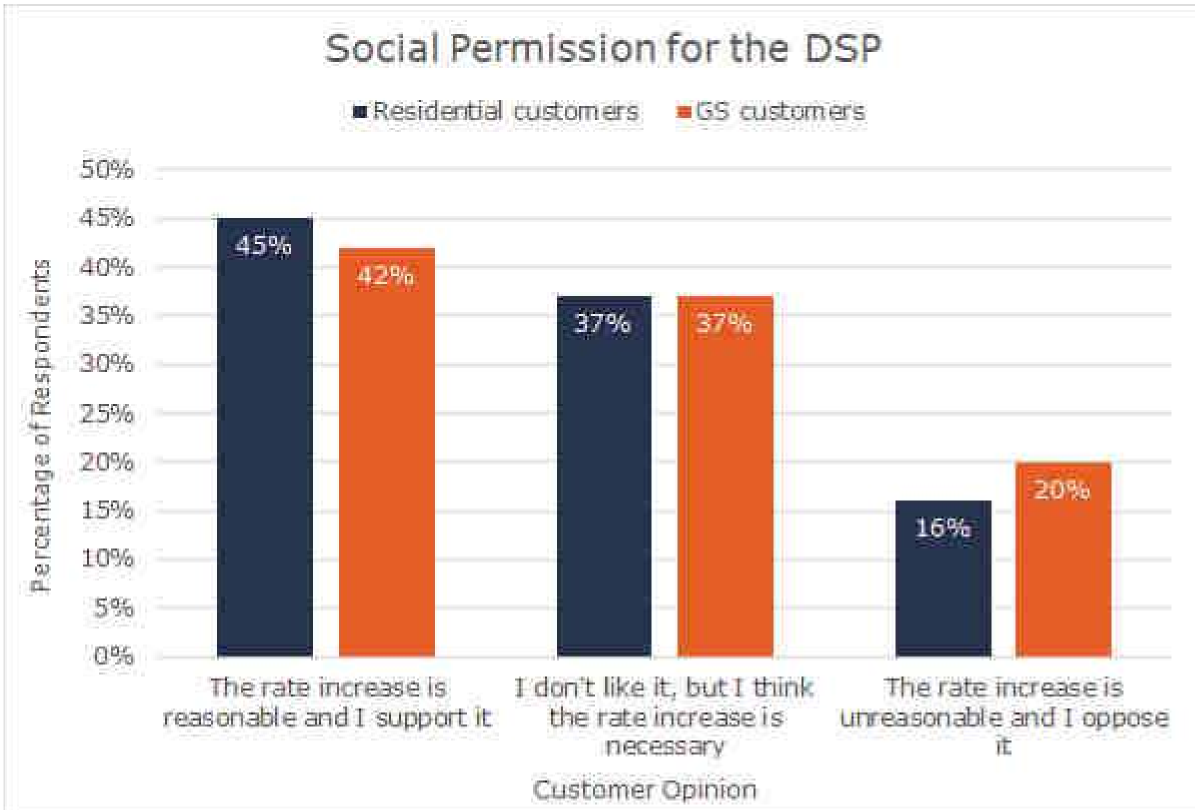
Statement	Number of Respondents					
	Strongly agree	**Somewhat agree**	**Neither agree nor disagree**	**Somewhat disagree**	**Strongly disagree**	**Don't know**
We should invest in our electricity system infrastructure now or we will end up paying more the longer we delay our system renewal.	25	22	0	5	2	5
The electricity sector is so complicated and confusing; we just have to trust that the experts will find the right balance in keeping cost down while making the right investments and spending decisions.	20	19	0	8	12	1
I think Essex Powerlines should do more to help customers find ways to reduce their electricity consumption and costs.	36	14	1	5	3	1
Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations.	32	20	0	6	1	0
We need to modernize the local electricity system so consumers can have greater control over their electricity usage.	20	32	0	4	3	0
A few power outages are fine for me personally, but I worry about the impact this has on more vulnerable people, such as the elderly.	17	20	2	8	12	1

In summation, both groups of customers believe that EPL should not defer infrastructure investment, experts in the industry should be trusted, EPL should help customers lower electricity consumption and costs, the electricity grid should be maintained for futrue future generations, there is a need to modernize the grid, and that the impact that power outages have on vulnerable people should be considered.

Assessment of the DSP

The majority of surveyd residential and GS customers provided social permission for the DSP, either by stating that the rate increase is reasonable and they support it, or that they don't like the rate increase but think it is necessary.

Figure 4-4: Customer assessment of the DSP



4.1.6.1.2 INNOVATIVE Customer Satisfaction Survey (2014)

The Customer Satisfaction Survey interviewed 210 residential and 98 GS<50 customers via telephone in 2014. Customers who participated were educated about Ontario's distribution system, EPL's role in delivering power to households and businesses, the interpretation of their electricity bill, and the availability of e-billing.

EPL's customers understand that some outages are unavoidable and the vast majority of EPL's customers are satisfied with reliability and power quality of electricity services provided by EPL. The cost of electricity is more of a concern to EPL's customers, particularly because over half of EPL's customers believe the cost of electricity has grown faster than other household (or business) expenses. About two-thirds of customers feel EPL offers good value for money.

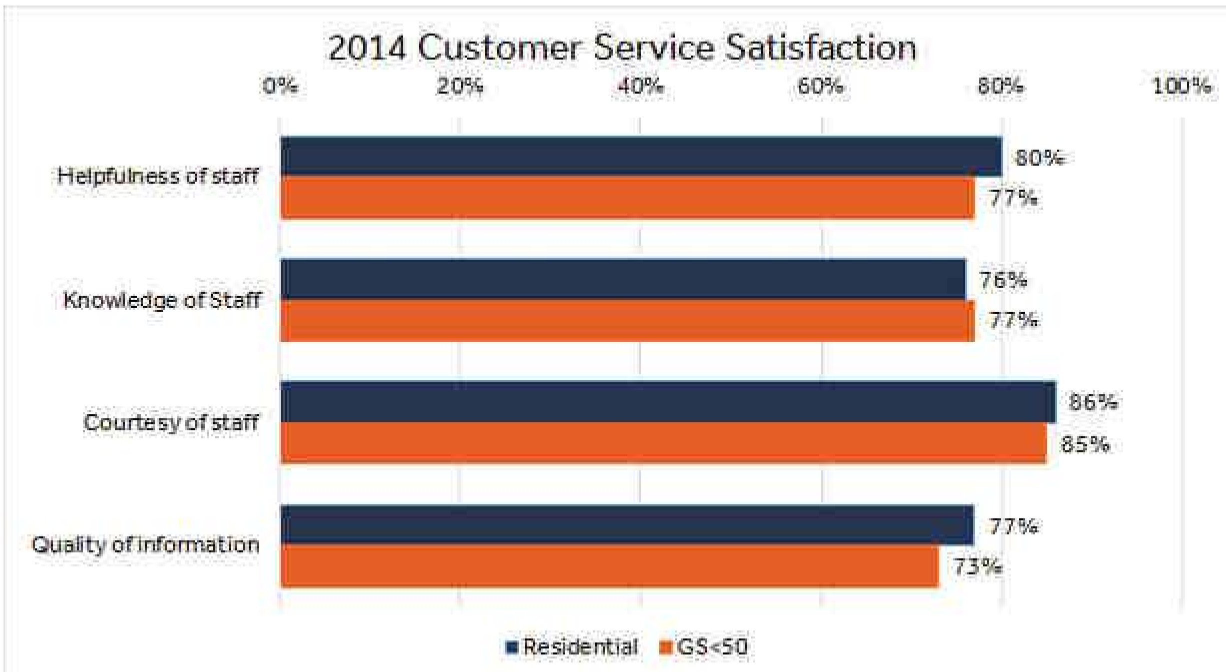
Perceived issues with smart meters was the most commonly cited reason for lacking confidence in billing accuracy. Residential customers reporting an outage were less likely to find an immediate resolution, while GS<50 customers were less satisfied with making payment arrangements or other issues. Customers experiencing more outages were less satisfied with power outage communications.

The Customer Satisfaction Survey measured four (4) facets of customer service satisfaction for residential and GS<50 customers:

1. The helpfulness of staff;
2. The knowledge of staff;
3. The level of courtesy of staff; and
4. The quality of information provided by staff.

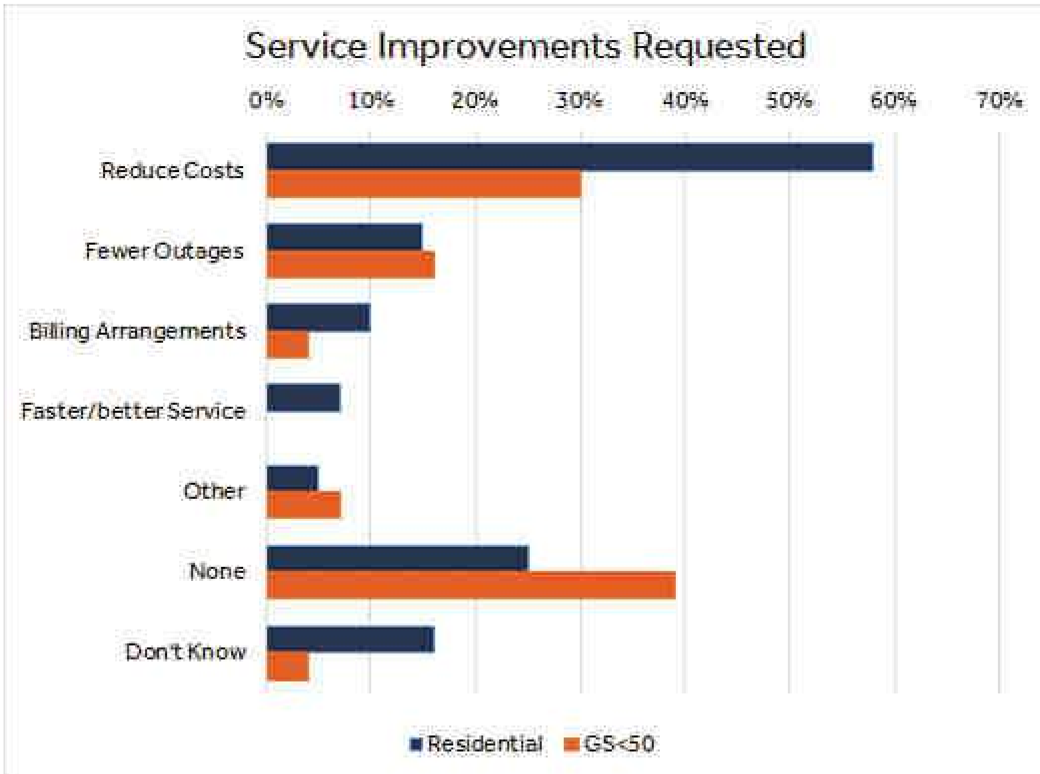
EPL scored between seventy-three percent (73%) and eighty-six percent (86%) in each of these categories.

Figure 4-5: 2014 customer service satisfaction survey results



As indicated in Figure 4-6, residential customers who indicated they would like reduced costs also asked for other improvements including fewer outages, improved billing arrangements, faster/better service, and other improvements. Customers haven't asked for online outage maps or a smart phone app; telephone communication is the preferred method to be informed of outages. The survey also indicated that the majority of EPL's customers are not users of social media.

Figure 4-6: Percentage of customers requesting service improvements (2014 survey)



4.1.6.2 Convergys Top Down Survey

The Convergys Top Down Survey culminates the results of four hundred (400) residential and one hundred (100) GS<50 customers interviewed in 2016. The survey measured customer satisfaction in terms of overall satisfaction, service/brand performance, communication, billing, and contact handling.

Figure 4-7 depicts customer satisfaction measured against key drivers. EPL scored highest when measured against the top drivers for business and residential customers. Ninety percent (90%) of customers are satisfied with power quality, eight-nine percent (89%) are satisfied with the customer service they receive, and eighty-eight percent (88%) are satisfied with the reliability of their electrical service. EPL scored eight percent (80%) when measured against value of service, seventy-seven percent (77%) for being a leader in the community, seventy-four percent (74%) for providing tools to manage energy consumption, and seventy-two percent (72%) for the promotion of energy conservation programs. The biggest opportunity to improve customer satisfaction is with respect to affordability of service, about which only forty-two percent (42%) of EPL's customers are satisfied. This was the lowest scoring attribute for both business and residential customers.

Figure 4-7: Drivers for customer satisfaction (2016 survey)

EPL's customers prefer to contact EPL via telephone, but the Convergys survey identified an opportunity to improve self-service options for billing and payment through EPL's website to reduce the number of related calls. Twenty-three percent (23%) of residential customers that had contacted EPL within the past six (6) months did not have their problems resolved, indicating an opportunity to follow through with services promised to avoid repeat contacts.

The Convergys report recommended investing in service reliability and customer service, which are the key drivers of customer satisfaction. The report also recommended better communication regarding billing to educate customers on rates and fees charged.

The complete report by Convergys is included as Appendix E.

4.1.6.3 Customer Engagement Handbooks

Customer Engagement Handbooks will be posted onto EPL's website. The purpose of this consultation is to collect customer feedback on EPL's DSP over the five-year period from 2018 to 2022. The Customer Engagement Handbooks are attached as Appendix F to the DSP.

4.1.6.4 Effects on the DSP

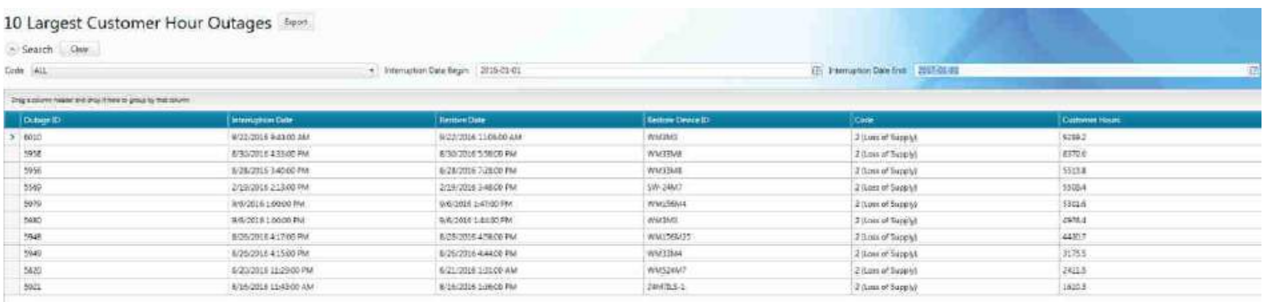
The customer feedback received from the surveys indicates that the cost of electricity is important to EPL's customers, especially residential households. The majority of residential and General Service customers are satisfied with the reliability, power quality, and customer service offered by EPL. To address the preferences of its customers, EPL has not planned any substantial rate increases for its customers. Instead EPL has developed a five (5)-year DSP that identifies key investments to operate a modern smart grid fit for the 21st century, while limiting annual rate increases to two percent (2%) or in line with inflation.

Investments into computer software and self-healing grid reclosers will improve operational efficiency and help to achieve this objective.

In general, EPL considers cost savings and investment optimization in all of its planned projects and programs. EPL uses a risk-based decision-making model to optimize spending relative to the targeted rate of expenditures. System O&M spending has been reduced compared to historical values through initiatives such as eliminating substations and voltage conversion. For a complete description of cost-saving measures implemented by EPL, see Section 2.1.2.

Reliability continues to be a top driver for customer satisfaction and EPL's customers have experienced a significant number of loss of supply outages. In 2016, the ten (10) largest outages experienced by customers were all loss of supply events. New recloser installations will help isolate EPL's customers from loss of supply events. Asset transfers with HONI planned in Leamington and LaSalle will ensure each LDC is responsible for the assets in its service area to improve operability and reliability for customers.

Figure 4-8: The ten largest outages in 2016 were all loss of supply events


10 Largest Customer Hour Outages

Outage ID	Interruption Date	Restore Date	Restore Device ID	Code	Customer Hours
6010	9/22/2016 9:43:00 AM	9/22/2016 11:06:00 AM	WM3M3	2 (Loss of Supply)	9289.2
5958	8/30/2016 4:33:00 PM	8/30/2016 5:58:00 PM	WM33M8	2 (Loss of Supply)	6370.0
5956	6/28/2016 3:40:00 PM	6/28/2016 7:28:00 PM	WM33M8	2 (Loss of Supply)	5513.8
5549	2/19/2016 2:13:00 PM	2/19/2016 3:48:00 PM	SW-24M7	2 (Loss of Supply)	5508.4
5979	9/6/2016 1:00:00 PM	9/6/2016 1:47:00 PM	WM156M4	2 (Loss of Supply)	5302.6
5980	9/6/2016 1:00:00 PM	9/6/2016 1:48:00 PM	WM3M3	2 (Loss of Supply)	4978.4
5948	8/26/2016 4:17:00 PM	8/26/2016 4:58:00 PM	WM156M35	2 (Loss of Supply)	4430.7
5949	8/26/2016 4:15:00 PM	8/26/2016 4:44:00 PM	WM33M4	2 (Loss of Supply)	3175.5
5820	6/20/2016 11:29:00 PM	6/21/2016 1:31:00 AM	WM524M7	2 (Loss of Supply)	2411.5
5921	8/16/2016 11:43:00 AM	8/16/2016 1:06:00 PM	24M7LS-1	2 (Loss of Supply)	1620.3

EPL's customers believe it is important to invest in renewing the electricity system in order to maintain reliability and upkeep the infrastructure for future generations. EPL has identified a number of programs in the system renewal program that meet these expectations including replacement of poles, replacement of load-break switches, replacement of live-front switchgear, and circuit rebuilds. These are all proactive replacement programs supported by EPL's customers.

EPL's customers see the importance of modernizing the grid. EPL has adopted a Smart Grid Development Plan – as introduced in Section 1.4.3.4 – to facilitate a self-healing grid. System service investments to install reclosers over the forecast period fit into this framework.

EPL's customers believe that it is important for EPL's staff to have the equipment and tools they need to mange the system efficiently and reliably. Planned investments into computer hardware, computer software, transportation equipment, stores equipment, buildings and fixtures, and tools and equipment align with this customer preference.

Overall, customers surveyed in 2017 provided social permission for the DSP.

4.1.7 System Development over the Forecast Period (5.4.1g)

This section describes how EPL expects its system to develop over the forecast period with respect to load and customer growth, Smart Grid development, and the accommodation of REG projects.

4.1.7.1 Load and Customer Growth

Table 4-7 and Table 4-8 present the kWh and CDM-adjusted kWh forecasts, respectively. Table 4-9 and Table 4-10 present the kW and CDM-adjusted kW forecasts, respectively.

Table 4-7: Forecast of energy delivered (kWh)

Normal Forecast

kWh	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2016 Normalized	2017 Forecast	2018 Forecast
Residential	256,003,979	250,406,105	245,551,953	244,757,239	255,390,422	249,168,165	247,700,344	246,544,006
GS < 50	67,056,278	65,663,990	65,242,011	65,329,579	66,808,993	64,675,919	65,087,892	65,487,649
GS > 50	160,883,812	164,887,609	166,100,613	171,874,066	187,031,606	175,310,400	179,829,958	183,374,335
Embedded Distributor	35,429,534	36,931,636	38,058,828	38,655,620	32,586,843	32,586,843	31,681,583	29,865,554
Street Light	6,205,705	6,271,491	6,286,758	6,227,063	4,268,688	4,268,688	2,799,882	2,799,882
Sentinel Light	383,994	342,834	350,518	341,136	335,758	335,758	335,758	335,758
USL	1,558,152	1,549,960	1,555,546	1,558,152	1,554,368	1,554,368	1,554,368	1,554,368
Total	527,521,454	526,053,625	523,146,226	528,742,855	547,976,676	527,900,141	528,989,785	529,961,552

Table 4-8: CDM-adjusted forecast for energy delivered (kWh)

kWh	2018 Weather Normal Forecast	CDM Adjustment	2018 CDM Adjusted Forecast
Residential	246,544,006	1,169,888	245,374,118
GS < 50	65,487,649	2,780,199	62,707,450
GS > 50	183,374,335	7,094,029	176,280,306
Embedded Distributor	29,865,554	0	29,865,554
Street Light	2,799,882	0	2,799,882
Sentinel Light	335,758	0	335,758
USL	1,554,368	0	1,554,368
Total	529,961,552	11,044,116	518,917,436

Table 4-9: Load forecast (kW)

Normal Forecast

kW	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2016 Normalized	2017 Forecast	2018 Forecast
GS > 50	416,357	399,217	394,614	459,153	476,121	443,798	455,239	464,212
Embedded Distributor	109,304	96,078	84,453	106,798	87,828	88,238	85,786	80,869
Street Light	18,742	19,025	15,872	18,023	13,490	13,490	8,848	8,848
Sentinel Light	2,100	2,100	2,068	2,088	2,080	2,080	2,080	2,080
Total	546,503	516,420	497,007	586,062	579,519	547,606	551,954	556,009

Table 4-10: CDM-adjusted load forecast (kW)

kW	2018 Weather Normal Forecast	CDM Adjustment	2018 CDM Adjusted Forecast
GS > 50	464,212	17,959	446,253

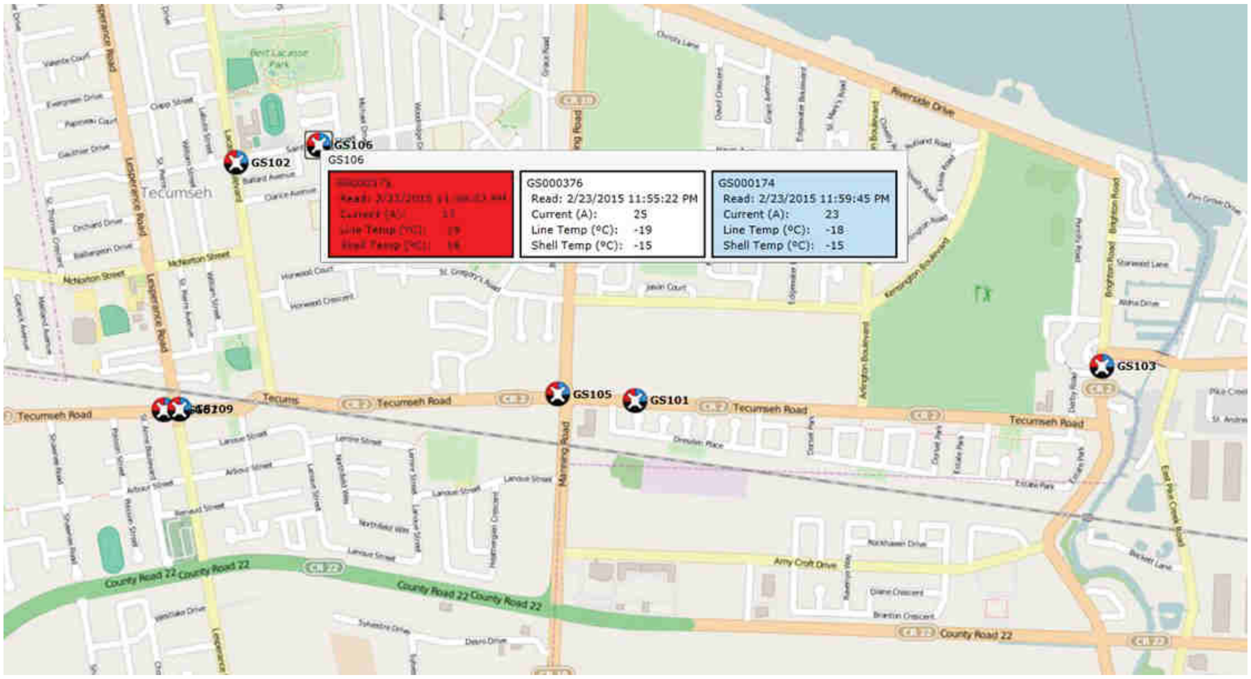
Embedded Distributor	80,869	0	80,869
Street Light	8,848	0	8,848
Sentinel Light	2,080	0	2,080
Total	556,009	17,959	538,051

4.1.7.2 Smart Grid Development

In 2014, EPL completed its first iteration of its Green Energy Act Plan and subsequently a Smart Grid Development Plan. In this plan, EPL outlined its plan to shift to a smarter grid that is capable of reducing the impact of loss of supply incidents to customers by investing in reclosers as part of a self-healing grid. Historically, EPL's service territory consisted solely of manual load break switches which required manual operation and provided no fault protection. Fault protection was provided by a station breaker or an upstream recloser outside of EPL service territory. With the implementation of smart reclosers, EPL is facilitating the capabilities of remote operation, real-time outage detection as well as the ability to isolate itself from an upstream distributor/transmitter. Further, incremental data about EPL's distribution system is gathered and fed into the SmartMAP toolset.

EPL has also been deploying line monitors to replace older Faulted Circuit Indicators. The line monitors can provide more information on real-time system status and historical events compared to the older technology. The deployment of these devices notifies operators that a fault has occurred in the distribution system, the date and time of the fault, and the specifics of that fault (fault current, location, phase, if it cleared or was momentary). A notification is also provided if a device is out of power and no power exists on the line. SmartMAP uses the fault data in its outage detection algorithm, which searches for customers that are out of power via the AMI and other power-monitoring devices. The approximate location of the fault is identified based on a calculation of the fault current in comparison to the measured value. This improves the outage response time. The line sensors themselves can be monitored through the SmartMAP tool.

Figure 4-9: Screenshot from SmartMAP depicting line sensor locations and statuses



The line monitors can measure and record air temperature and line temperature. Figure 4-10 depicts example measurements during winter, while Figure 4-11 depicts example measurements during summer, near-peak conditions. The profiles in both examples show that the line is not being heated due to loading. This type of information is used to identify the actual operating conditions for switching and load optimization.

Figure 4-10: Example air (top) and line (bottom) temperature measurements in winter

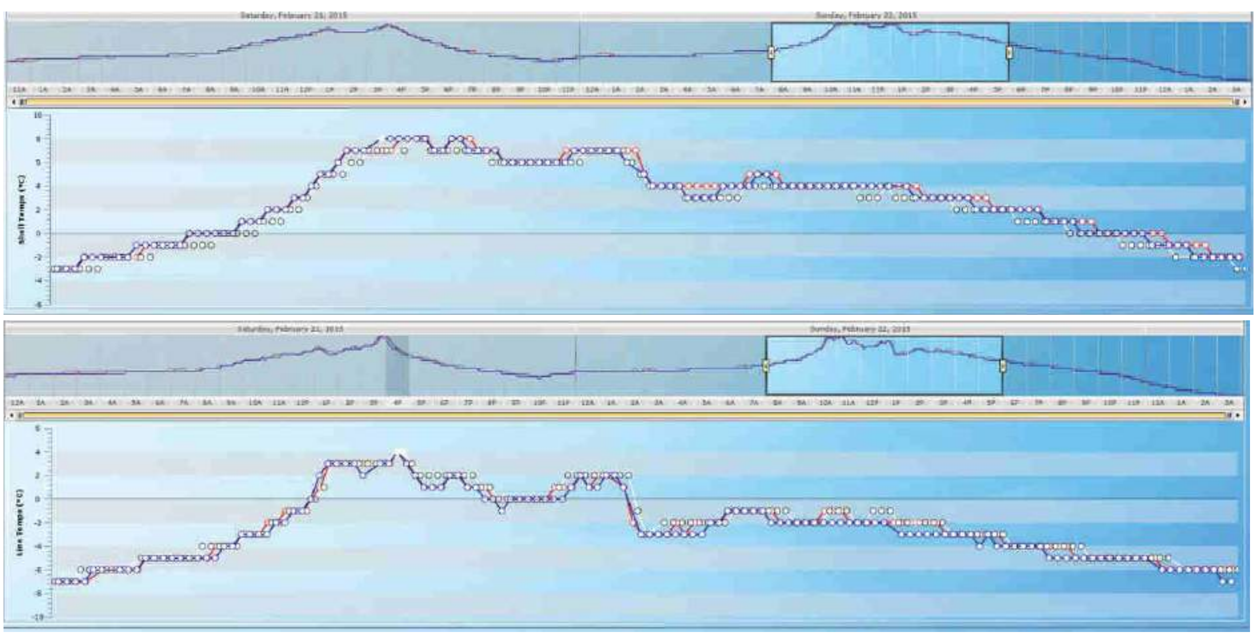
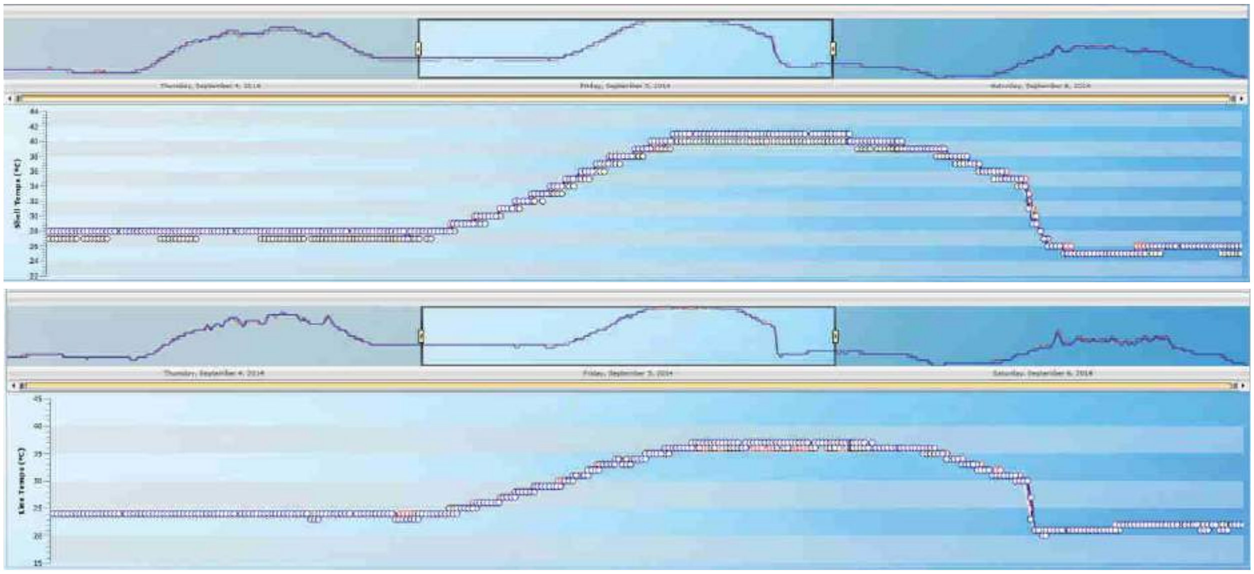
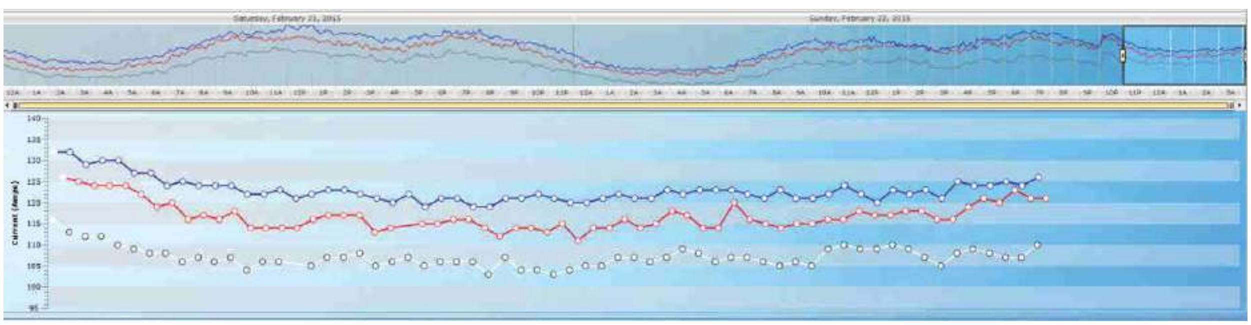


Figure 4-11: Example air (top) and line (bottom) temperature measurements in summer



Aggregation of line monitor data for each phase is used to determine the phase balance over time at the locations. Keeping the system in balance is an important part of the distribution system management. Figure 4-12 depicts an example where the current measurements differ for each phase

Figure 4-12: Example phase balance measurements



4.1.7.3 REG Accommodation

EPL has forecast the number and capacity of REG connections expected over the forecast period and has planned investments in the system service category, namely "FIT & Generation Connections" and "MicroFIT Connections", in order to continue to accommodate REG. In each case, additional transformation is planned and the need to expand the existing system is assessed. For more information, see Section 4.3.

4.1.8 Customer Preferences, Technology Opportunities, Innovation (5.4.1h)

Several projects/programs in the 2018 Test Year have been planned in response to customer preferences; to take advantage of technology-based opportunities to improve operational efficiency, asset management, and the integration of distributed generation and complex loads; and to study or demonstrate innovative processes, services, business models, or technologies.

Table 4-11 lists the capital projects/programs planned for the Test Year along with an identifier indicating the planning driver, as determined by EPL: 1 = Customer preference, 2 = Technology, 3 = Innovation.

1 Table 4-11: Capital projects/programs by planning driver

	Project/Program	Alignment with EPL Core Values	(1) - Customer Preferences (2) – Technology (3) - Innovation	2018 Test Year Expenditure (Forecast)
System Access	Subdivisions	Customer & Community Value	1	$382,500
System Access	Residential Connection/Expansion	Customer & Community Value	1	$394,369
System Access	Municipal Requests	Customer & Community Value	1	$612,000
System Access	New Service Upgrades - C&I	Customer & Community Value	1	$356,959
System Access	Metering Upgrade & Replacement Program	Customer & Community Value, Operational Excellence	1,2	$166,297
System Service	Purchase/Sell HONI Leamington Assets	Customer & Community Value, Operational Excellence	1	$89,474
System Service	FIT & Generation Connections	Customer & Community Value, Financial & Environmental Sustainability	1,2	$181,370
System Service	MicroFIT Connections	Customer & Community Value, Financial & Environmental Sustainability	1,2	$14,166*
System Service	Self-healing Grid Reclosers	Customer & Community Value, Operational Excellence	1,2,3	$270,140
System Renewal	Pole Replacement Program	Operational Excellence	1	$114,062
System Renewal	Overhead Reactive Replacements	Operational Excellence	1	$82,400
System Renewal	Underground Reactive Replacements	Operational Excellence	1	$64,964
System Renewal	Install/Replace Load Breaks	Operational Excellence	1	$59,927
System Renewal	Infrastructure Rebuild Program	Operational Excellence	1	$2,229,416
System Renewal	Switchgear Replacement Program	Operational Excellence	1	$147,321
General Plant	Tools & Equipment	Operational Excellence, Safety	2	$60,000
General Plant	Office Furniture	Operational Excellence, Employee Satisfaction	2	$10,000*
General Plant	Transportation Equipment	Operational Excellence, Safety	2	$270,000
General Plant	Computer Hardware	Operational Excellence	2	$161,809
General Plant	Computer Software	Operational Excellence	1,2,3	$115,000
General Plant	Buildings & Fixtures	Operational Excellence	2	$370,000
General Plant	Stores Equipment	Operational Excellence	2	$50,000*

2 *Values below the materiality threshold of approximately $60,000

3

4.1.8.1 Customer Preferences

System access investments are all driven by customer preferences. Subdivisions, residential connections/expansions and new commercial and industrial service upgrades are initiated by customer requests to connect to EPL's distribution system. Capital expenditures related to municipal requests are in response to development in the communities EPL serves. Metering upgrades and replacements are driven by a mandated service obligation to accurately meter customers.

Investments related to FIT and generation connections (greater than 10 kW) and MicroFIT connections (10 kW or less) are driven by customer requests to connect REG to the distribution system.

System reliability is a key driver of customer satisfaction. EPL's customers have spent a significant amount of time without power due to loss of supply events. Investments into self-healing grid reclosers, computer software, and the purchase/sale of assets to/from HONI will address loss of supply issues. Investments in the system renewal category also address system reliability by replacing assets at the end of their service life due to failure or failure risk.

4.1.8.2 Technology-based Opportunities

Technology has always played an important role in the electricity industry. EPL has recently completed its voltage conversion program to improve operational efficiency and asset management, providing power at a single voltage without the need to own and operate distribution substations. Investments into smart meters will continue to be made as existing meters are replaced and upgraded; all new meters are equipped with two-way communication over the AMI.

MicroFIT, FIT, and generation connections take advantage of technology-based opportunities to integrate distributed generation. EPL already has a high penetration level of distributed generation and, at times, its net demand profile is negative.

EPL has been installing reclosers and line sensors in the field since 2011. These technologies are used to develop a self-healing grid able to locate and isolate faults to restore service to unfaulted sections of the line. The field hardware is supported by an integrated GIS, SCADA, and OMS combined with the analytical engineering toolset of the SmartMAP platform.

Other investments into tools and equipment, fleet, buildings and fixtures, office furniture, stores equipment, and computer hardware always take advantage of technology-based opportunities to improve operational efficiency.

EPL intends to continue to invest in field automation technologies in order to push technological tools to those employees who can take greatest advantage. Examples such as: mobile wireless laptops and tablets, smart phones, device aware enterprise services, smart grid device notifications, enhanced outage communication, distribution analysis result notifications to field staff, field work flow automation, etc. are all projects and technologies that EPL has implemented or intends to enhance throughout the forecast period.

Each of these technologies and enhanced services serve to increase worker productivity, situational awareness and customer communication. The desired result is to decrease operating costs while increasing EPL's ability to effectively manage its assets to the benefit of its customers.

4.1.8.3 Innovative Processes, Services, Business Models, or Technologies

EPL's overall goal of its innovative practices is to keep costs down while increasing the quality of service provided to EPL's customers. EPL's customers have indicated that the cost of electricity is an important driver to their satisfaction (see Appendix D and Appendix E). Investing in innovation will help EPL achieve its targets in system reliability, power quality, and consumer bill impacts.

The development of the SmartMAP and HealthMAP toolsets (under the computer software budget) and the implementation of reclosers as part of a self-healing grid demonstrate innovative processes and technologies. The SmartMAP toolset was developed by EPL in partnership with UtiliSmart Corporation. The toolset overlays EPL's proven DESS onto a GIS for improved data analytics and mapping capabilities. This was one of the projects in Ontario which received funding through the Ministry of Energy's Smart Grid Fund.

EPL is also able to demonstrate innovative processes, service, and business models by extending its control functionality to front line staff through field technologies such as laptops and the SmartMAP toolset. In this way, EPL does not operate a centralized control room. This reduces costs and increases the capability of front line staff to manage system issues.

4.2 Capital Expenditure Planning Process Overview (5.4.2)

4.2.1 Planning Objectives, Assumptions, and Criteria (5.4.2a)

EPL's capital expenditure planning objective is to find the optimal selection of projects with the maximum benefit-cost ratio. The capital expenditures are planned by taking into account of risk mitigation and value creation project benefits.

1. **Risk mitigation**: ensuring that all projects above the risk tolerance threshold are identified as part of the Business Plan and if the project(s) is/are deferred, due consideration is given to communicating the consequences associated with the deferral(s).
2. **Value creation**: optimal resource deployment to address well defined business objectives and track resulting performance value creation against desired performance value expectations.

In order to better understand underlying sensitivities and trade-offs between capital and operating expense, EPL has prepared project rankings and analysis for three (3) distinct scenarios:

1. **Scenario A: All Projects**. This is the unconstrained budget case where all projects are completed. This scenario is used as a base case assuming all resource needs are met.

2. **Scenario B: Minimum.** Only projects that mitigate risks beyond EPL's acceptable risk-level will be included in the business plan. This scenario includes all medium-to-high risk projects. This case is not recommended as a final plan because a risk hold posture is never cost effective. Mitigating risk or risk hold causes an organization to spend higher levels over time because risk mitigation is no longer planned and proactive as it becomes more an exercise in unplanned reactive encounters. These situations generate funding needs at higher premiums (by as much as twice the cost of proactive measures) because the materials generally have to be expedited and labor paid at overtime rates to ensure timely completion. This scenario is used as the least resource planning requirement and used as the low end of the range for optimal resource planning.
3. **Scenario C: Optimum.** This scenario comprises projects that optimize the value creation (benefits) and risk mitigation against cash-outlays.

Multiple scenarios were run to determine best case options for business planning. The final business plan was developed between Options "A" and "B". All high risk will be addressed and those projects creating real value for the investment will be included in the business plan.

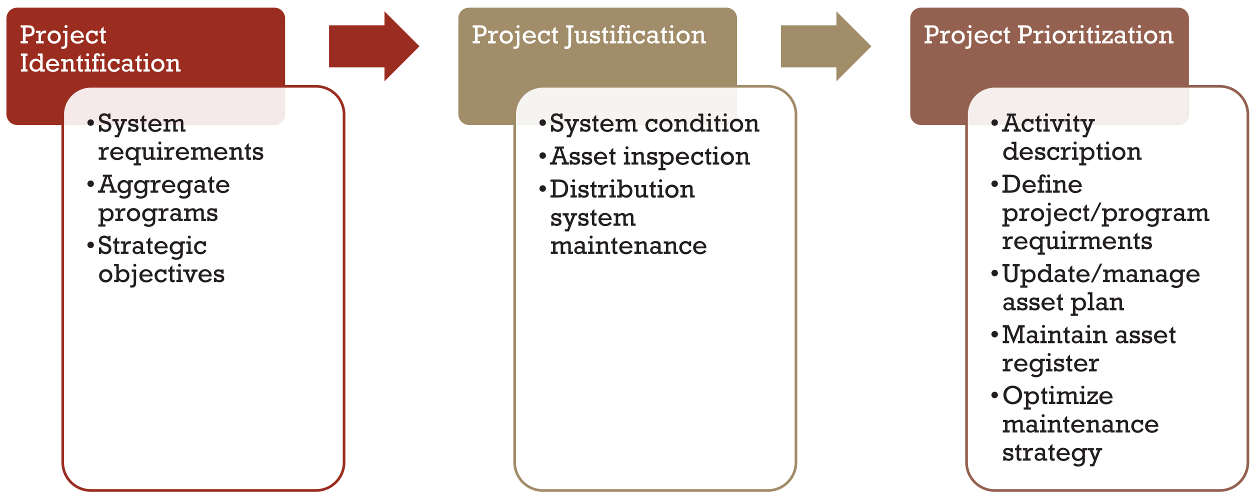
4.2.2 Non-Wires Alternatives to Relieving System Capacity (5.4.2b)

EPL does not have any policy nor procedure whereby non-distribution system alternatives to relieving system capacity or operational constraints are considered. For information pertaining to the Regional Planning Process, see Section 2.2.2.

4.2.3 Processes, Tools, and Methods (5.4.2c)

EPL uses a three (3)-step process to identify, select, prioritize, and pace the execution of its projects/programs in each investment category.

Figure 4-13: An overview of EPL's capital expenditure planning process



4.2.3.1 Project Identification

The EPL's AIS process begins by determining system requirements. The specific inputs include, but are not limited to, load additions, maintenance programs (outage restoration, Conditions of Service requirements, theft of assets, human intervention, etc.), conversions, system performance and new standards. Service orders, minor field maintenance (non-program work where no system reconfiguration is required), and any minor load additions are also included in these programs. However, these items are analyzed and monitored as aggregate programs (collection of like projects for the year). In addition, determining the system enhancement requirements as a function of asset deterioration, load growth, customer needs, and new product availability is performed.

Potential projects to be input in Project Information Plan are gathered and assessed. Input and analysis is done using tools, statistics, databases, customer/developer input, assessments, and non-destructive examination.

Maximizing the use of online systems allows recording and monitoring the distribution line operation through faults, operational counts, age, and load using IT-based solutions.

A component database stores, records, and monitors the condition of the distribution assets. This information is valuable in determining the value of individual equipment failures on the seven (7) strategic objectives used in the AIS. These integrated databases containing EPL's entire asset information allows recording of equipment failures and the specifics associated with each event. System inspection and condition data are used to plan proactive replacements as opposed to reactive replacements.

4.2.3.2 Project Justification

System condition using non-destructive techniques correlate the onset of failure allowing planned replacements as opposed to reactive replacements. Infrared and ultrasonic analysis of the system along with asset inspection can identify the onset of failure. For example, arrestors contain a pressure sensitive material that begins to break down with age. The onset of failure shows arrestors that have lost part of the pressure holding capacity. Similarly, failing connections, tracking insulators/equipment, and reduced oil levels can be identified using these non-destructive techniques and planned repairs or replacement can be scheduled before failure.

The frequency and timing of distribution system maintenance is an important factor in balancing the costs and unplanned outages. In-service failures can be prevented and the lifetime of equipment can be extended using non-destructive techniques, oil analysis, and statistical analysis of service lifetimes. Equipment inventory is kept to a minimum using this approach.

4.2.3.3 Project Prioritization

Once the potential investments have been identified, the projects are divided into phases that can be completed in any one (1) year. Each project or project phase (if applicable) requires the inputs to the project to be collected. The inputs into the Project Information Plan are costs (savings and spend), risks, and strategic value. All projects are run through the Optimizer Tool to determine the project mix that reduces the most amount of risk while providing the most strategic value.

The strategic value of a project is measured against the seven (7) asset management objectives described in Figure 3-1:

- Public and employee safety;
- Regulatory (OEB) direction;
- Service quality: SAIFI and SAIDI;
- Financial returns: NPV;
- Legal claims;
- Community image: customer complaints; and
- Environmental.

The risk of project deferral is assessed using the numeric scores for consequence and probability defined in Table 4-12 and Table 4-13. Risk is calculated as the product of the probability and consequence scores.

Table 4-12: Definitions of numeric scores describing the consequence of project deferral

Numeric Score	Definition of Financial Risk	Definition of Service Quality Risk	Company Image Risk	Legal Risk	Regulatory Risk	Safety Risk (Both staff and public risk)	Environmental Risk
Consequence = 5	>$50,000 in lost revenue or avoided cost	>1.0% overall reduction to SAIFI, SAIDI	>10 written or 50 verbal complaints, general public outcry	Litigation cost <$1,000	Non-reportable compliance issues	Minor WSIB injury	Minor disturbance, no documentation required
Consequence = 4	<$50,000 in lost revenue or avoided cost	<1.0% overall reduction to SAIFI, SAIDI	<10 written or 50 verbal complaints, concerns raised to regulator, coverage by local media	Litigation cost <$10,000	Regulator reportable issues - minor	WSIB reportable injury	Disturbance requiring internal environmental documentation and/or company environmental assistance
Consequence = 3	<$10,000 in lost revenue or avoided cost	<0.5% overall reduction to SAIFI, SAIDI	<8 written or 40 verbal complaints, concerns raised to local government, board of directors	Litigation cost <$50,000	Significant regulatory compliance issues. Notification required.	Medical injury, WSIB reportable, EUSA reportable, Ministry of Labour reportable	Disturbance involving private property and/or potential claims and company environmental assistance
Consequence = 2	<$5,000 in lost revenue or avoided cost	<0.1% overall reduction to SAIFI, SAIDI	<6 written or 30 verbal complaints, multiple concerns made to company	Litigation cost <$500,000	Serious regulatory compliance issues. Fines, direction or oversight required.	Lost time injury, WSIB reportable, EUSA investigation, Ministry of Labour investigation	Disturbance requiring Ministry of Environment documentation, company environmental assistance and regulatory assistance on site.
Consequence = 1	<$1,000 in lost revenue or avoided cost	<0.05% overall reduction to SAIFI, SAIDI	<4 written or 20 verbal complaints, individual concerns to company	Litigation cost >$500,000	Damaging regulatory compliance issues. Loss of license	Multiple lost time injuries, WSIB reportable, EUSA investigation, Ministry of Labour fine/directive	Disturbance requiring MOE assistance onsite and public evacuation and company environmental assistance.

Table 4-13: Definition of numeric scores describing the probability of each consequence

Numeric Score	Definition of Financial Risk	Definition of Service Quality Risk	Company Image Risk	Legal Risk	Regulatory Risk	Safety Risk (Both staff and public risk)	Environmental Risk
Probability = 5	More than 4 events per year	More than 4 events per year	More than 4 events per year	More than 4 events per year	More than 4 events per year	More than 4 events per year	More than 4 events per year
Probability = 4	Quarterly, 2-4 events per year	Quarterly, 2-4 events per year	Quarterly, 2-4 events per year	Quarterly, 2-4 events per year	Quarterly, 2-4 events per year	Quarterly, 2-4 events per year	Quarterly, 2-4 events per year
Probability = 3	One event per year	One event per year	One event per year	One event per year	One event per year	One event per year	One event per year
Probability = 2	1 event every 3 years	1 event every 3 years	1 event every 3 years	1 event every 3 years	1 event every 3 years	1 event every 3 years	1 event every 3 years
Probability = 1	1 event every 10 years	1 event every 10 years	1 event every 10 years	1 event every 10 years	1 event every 10 years	1 event every 10 years	1 event every 10 years

The AIS is used to gather the inputs needed for each Project Information Plan. The following items are used in each evaluate and optimize the investment portfolio.

Activity Description

- Identify potential risks.
- Estimate probability of occurrence.
- Define consequences.
- Calculate risk score.
- Compare to project risk threshold.
- Determine alignment of risk exposure with owner's requirements.
- Define risk mitigation strategy if required.
- Select solution.

Define Project/Program Requirements

- Approve selected option(s).
- Determine project/program impact.
- Conduct impact study or change standards, if required.
- Document objective and consequences.
- Identify unique requirements.
- Identify major material requirements.
- Identify appropriate standards.
- Identify resource requirements.
- Identify project milestones and program cycles.
- Assign priority score.

Update/Manage Asset Plan

- Incorporate project/program into asset plan.
- Determine impacts on plan.
- Determine need to reanalyze projects.
- Identify potential portfolio risks.
- Determine probability of occurrence.
- Calculate consequence.
- Calculate risk score of portfolio.

- Compare risk with threshold.
- Determine if impacts are acceptable
- Adjust plan if required.
- Analyze finances.
- Analyze completion status.
- Analyze performance results.
- Assess variance from plan.
- Identify potential solution to address variances if required.
- Issue/re-issue asset plan.

Maintain Asset Register

- Document individual asset information.
- Describe asset's role and mission in system.
- Define system configuration.
- Validate information.
- Determine validity of data.
- Input data into asset register.

Optimize Maintenance Strategy

- Review asset(s) condition/facts.
- Review asset(s) role/mission.
- Review asset performance history.
- Determine failure modes.
- Determine consequences of failure.
- Assess preventability of failure mode.
- Identify condition-based maintenance activities.
- Identify time-based maintenance activities.
- Identify redesign solutions.
- Determine run-to-failure options where appropriate.

The outputs are analyzed and listed for each year from 2018 to 2022. As new projects are identified or inputs change the optimized results are rerun to identify new project lists. Table 4-14 summarizes the output of the project prioritization tool for material projects planned in the 2018 Test Year. The sum of the risk and strategic objective scores are displayed in the rightmost column and used to rank the projects.

Table 4-14: 2018 Test Year project prioritization

Project Name	Project Classification	Project Type	Net Capital Expenditures	Risk/Strategic Objective Score
Residential Connection/Expansion	Serve New Customers - Residential	Residential Connections	$394,369	28.57
New Service Upgrades – C&I	Serve New Customers - C & I	Commercial Connections	$356,959	28.57
New Residential Subdivisions	Serve New Customers - Residential	Residential Connections	$382,500	28.43
Overhead Reactive Replacements	None	Reactive	$82,400	21.36
Underground Reactive Replacements	None	Reactive	$64,964	21.29
Municipal Requests	Increase System Capacity - Improvements	Expansions	$612,000	14.71
FIT & Generation Connections	Increase System Capacity - Improvements	Expansions	$181,370	14.00
Install/Replace Load Breaks	Increase System Capacity - Improvements	Preventative	$59,927	13.57
Switchgear Replacement Program	Increase System Capacity - Improvements	Preventative	$147,321	13.55
Metering Upgrade & Replacement Program	None	Metering	$166,297	13.43
Self-healing Grid Reclosers	Increase System Capacity - Improvements	Preventative	$270,140	11.03
Infrastructure Rebuild Program	Increase System Capacity - Improvements	Enhancements	$2,224,410	10.57
Computer Hardware	None	General Plant	$161,809	10.49
Computer Software	None	General Plant	$115,000	10.36
Purchase/Sell HONI Leamington Assets	None	Expansions	$89,474	9.86
Pole Replacement Program	None	Reactive	$114,062	9.43
Transportation Equipment	None	General Plant	$270,000	7.43
Tools & Equipment	None	General Plant	$60,000	7.13
Buildings & Fixtures	None	General Plant	$370,000	5.48

4.2.4 Customer Engagement (5.4.2d)

EPL employs a multi-faceted approach to customer engagement, as previously discussed in Section 2.2.1.1 and Section 4.1.6. Customer feedback is incorporated into every stage of the planning process, from project/program design, to budget allocation, to project execution. The methods used to engage customers for the purpose of identifying their needs, priorities, and preferences include:

- Engaged Innovative Research Group in 2017 to perform telephone surveys and solicit feedback (a copy of the report is attached as Appendix D).
- Engaged Convergys to perform a telephone-based customer survey in 2016 (see Appendix E).
- Hosted four (4) open house sessions – one (1) in each community – that were advertised through multiple channels where customers could attend and provide feedback.
- Posted customer class specific handbooks on its website which highlighted and summarized this document and provided a timeframe where customers could submit feedback online (copies of the various handbooks are attached as Appendix F).

4.2.5 REG Investment Prioritization (5.4.2e)

REG investments are prioritized alongside other capital projects using the processes, tools, and methods described in Section 4.2.3.

4.3 System Capability Assessment for REG (5.4.3)

4.3.1 Applications for Renewable Generators over 10 kW (5.4.3a)

Table 4-15 lists the applications from renewable generators over 10 kW for connection to EPL's service area.

Table 4-15: REG applications over 10 kW being processed

Feeder	Address	Type	Nameplate Capacity (kW)	Estimated Connection Year
23M3	400 Sandwich St. South, Amherstburg	Solar Rooftop	200	2018
3M4	55 Talbot St. West, Leamington	Solar Rooftop	500	2017
3M4	24 Oak Street East, Leamington	Solar Rooftop	190	2017
3M6	25 Ivan Street, Leamington	Solar Rooftop	500	2017
3M4	129 Erie Street South, Leamington	Solar Rooftop	90	2017
23M5	111 St. Arnaud, Amherstburg	Solar Rooftop	200	2018
24M9	5840 Malden Road, LaSalle	Solar Rooftop	250	2019
3M8	1 Henry Cres., Leamington	Solar Rooftop	134	2019
23M3	310 Thomas Road, Amherstburg	Solar Rooftop	500	2018
Total Nameplate Capacity (kW)			**2564**	

4.3.2 Forecast REG Connections (5.4.3b)

EPL has forecast the number and capacity of REG connections for the years 2017 through 2020 based on the applications being processed and those expected to be received.

Table 4-16: Forecast REG connections (2017 to 2020)

REG	Number	Nameplate Capacity (MW)
FIT applications being processed	9	2.564
MicroFIT applications being processed	10	0.1
Projected (2018)	5	1.25
Projected (2019)	5	1.25
Projected (2020)	5	1.25
Total	**34**	**6.414**

4.3.3 Capacity to Connect REG (5.4.3c)

EPL estimates that the following capacity is currently available across its distribution feeders for the following stations. Note that capacity is subject to change at any time. Values are calculated using HONI's Capacity Calculator:

- 15MW Malden;
- 13MW Keith;
- 10MW Lauzon; and
- 5MW Kingsville.

4.3.4 REG Connection Constraints (5.4.3d)

The following feeders are not currently accepting applications for connection based on guidance from HONI:

- Malden M7;
- Lauzon M25;
- Lauzon M26; and
- Keith M4.

4.3.5 Embedded Distributor Constraints (5.4.3e)

EPL does not have any current embedded distributor constraints.

4.4 Capital Expenditure Summary (5.4.4)

Table 4-17 presents the historical and forecast capital expenditures and system O&M. Since this is EPL's first DSP, the "previous plan" and variance are only reported for the total annual capital expenditures.

Table 4-17: Historical and forecast capital expenditures and system O&M

Category	Historical															Forecast				
	2013			2014			2015			2016			2017			2018	2019	2020	2021	2022
	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.*	Var.					
	$ `000		%	$ `000		%	$ `000		%	$ `000		%	$ `000		%	$ `000	$ `000	$ `000	$ `000	$ `000
System Access	-	1,766	-	-	2,532	-	-	2,341	-	-	1,759	-	-	1,712	-	1,746	1,781	1,816	1,853	1,835
System Renewal	-	3,113	-	-	3,012	-	-	2,695	-	-	2,125	-	-	2,655	-	2,693	1,362	2,304	2,248	2,195
System Service	-	185	-	-	177	-	-	2,196	-	-	1,005	-	-	787	-	707	2,186	1,126	1,243	1,342
General Plant	-	450	-	-	487	-	-	547	-	-	384	-	-	1,504	-	1,037	856	976	927	968
Total	6,872	5,513	-20%	5,085	6,208	22%	5,571	7,779	40%	4,464	5,274	18%	6,658	6,658	0%	6,183	6,185	6,222	6,270	6,339
System O&M	-	2,289	-	-	2,574	-	-	2,769	-	-	2,490	-	-	2,112	-	2,200	2,275	2,413	2,247	2,342

**0 months of actual data included in 2017.*

4.4.1 Variances in Capital Expenditures

4.4.1.1 Intangible Plant

Account 1611 – Computer Software

EPL is planning an increase of $115,000 in Account 1925 from 2017 Bridge Year to the 2018 Test Year. Planned additions in 2018 include:

- Utility Dashboard - $40k;
- ESRI ArcView/Arc Editor (GIS) Upgrade - $25k; and
- New Work Estimator $30k.

4.4.1.2 Distribution Plant

EPL plans to invest $5,146,191 in Distribution Plant assets in the 2018 Test Year. Between 2010 and 2016, EPL invested, on average, approximately $5,378,730 per year. EPL submits that its expected investments in Distribution Plant are in line with historical spending (slightly less) and, therefore, reasonable. Table 4-18 provides a summary of EPL planned Distribution Plant investments.

Table 4-18: Summary of Distribution Plant investments

Description	2018 Test
Residential Connections	$ 776,868.72
C&I Connections	$ 356,959.20
Conversions	$ 2,224,409.82
Municipal Requests & Asset Purchases	$ 701,474.00
FIT & Generation Connections	$ 181,369.76
Smart Grid/Self Healing Grid	$ 270,139.86
Replacements	$ 487,606.35
Emergencies	$ 147,363.30
Distribution Plant Total	**$ 5,146,191.00**

The following is a breakdown of Distribution Plant by category. Since values for 2018 are forecasted only, they are not presented by account.

Residential Connections

Residential connections relate to the planned/forecast work required to facilitate connection of new residential customers to the distribution system as well as expand existing services, where required. In 2018, EPL plans to invest $776,869 in residential connections where $382,500 relates to new connections and $394,369 relates to residential expansions. These values are based on historical spending and trending.

C&I Connections

C&I connections relate to the planned/forecasted work required to facilitate connection of new C&I customers to the distribution system as well as expand existing services, where required. In 2018, EPL plans to invest $356,959 in C&I connections. These values are based on historical spending and trending.

Conversions

Conversion projects generally relate to upgrading existing 4kV/8kV distribution assets to 27.6kV. In 2018, EPL plans to invest $2,224,410 in conversion projects which relates to the continuation of EPL's Infrastructure Replacement program and primarily focuses on replacement of end-of-life direct-buried cables, mainly located in residential backyards, allowed through easements, to front yard ROW.

Municipal Requests & Asset Purchases

Municipal Requests & Asset Purchases relate to planned/forecast asset relocation work as well as asset purchases from HONI, where required. Types of asset relocations include road widening projects, ROW improvements, etc. EPL typically sees one (1) or two (2) major municipal request per year.

EPL also anticipates that HONI asset purchase will be required to facilitate long-term load transfer removal as well to accommodate significant HONI work currently ongoing in the Leamington area.

In 2018, EPL plans to invest $701,474 in Municipal Requests & Asset Purchases where $612,000 relates to Municipal Requests and $89,474 relates to HONI asset purchase. These values are based on historical spending and trending.

FIT & Generation Connections

FIT & Generation connections relate to the planned/forecast work required to facilitate connection of new FIT and other generation customers (i.e. MicroFIT, net metering, merchant generation, etc.) to the distribution system. In 2018, EPL plans to invest $181,370 in FIT & Generation connections. These values are based on historical spending and trending as well as known upcoming projects.

Smart Grid / Self-Healing Grid

Smart Grid / Self-Healing Grid refers to EPL's planned investments to build a self-healing grid to reduce interruptions related to distribution/transmission plant owned by HONI. In 2018, EPL plans to continue investing $270,140 in this initiative which largely relates to the installation and commissioning of reclosers at strategic points throughout its distribution system. More information can be found in EPL's GEA Plan and DSP, included as Attachments 2-C and 2-D respectively.

Replacements

Replacement projects generally relate to upgrading and/or replacing existing equipment that is either at end of life, not functioning as intended, damaged, or deteriorated. In 2018, EPL plans to invest $487,606 in replacement projects. The following is a brief summary of planned replacement projects for 2018:

- *Pole Replacement Program:* EPL plans to replace approximately twenty-nine (29) poles in 2018 as part of its Pole Replacement Program. These poles were identified for replacement through EPL's preventative maintenance program where core sampling was completed via pole drilling. EPL's estimated cost in 2018 is $114,062.

- *Load-Break Replacements:* EPL has been slowly replacing approximately two (2) load-break switches per year to improve reliability, enhance distribution system operability, and replace aging assets. EPL's estimated cost in 2018 is $59,927.
- *Switchgear Replacement Program*: Similar to the Load-Break Replacement program, EPL has been slowly replacing approximately two (2) live-front switchgear units per year to improve reliability, enhance distribution system operability, and replace aging assets. EPL's estimated cost in 2018 is $147,321.
- *Metering Upgrade & Replacement Program:* This program includes upgrading interval metering installations as a result of seal expiry, upgrades from A1R to A3R meters and GPRS upgrades for enhanced reliability and improved functionality, replacing smart meters where required, and replacing gatekeepers and modems for ongoing smart meter communication. EPL's estimated cost in 2018 is $166,297.

Emergencies

Emergencies relate to the planned/forecast work for overhead and underground reactive replacements. In 2018, EPL plans to invest $147,363 in Emergencies where $82,400 relates to forecast overhead reactive replacements and $64,964 relates to forecast underground reactive replacements. These values are based on historical spending and trending.

4.4.1.3 General Plant

Account 1908 – Building & Fixtures

EPL is planning an increase of $369,996 in Account 1908 from the 2017 Bridge Year to the 2018 Test Year. Planned additions in 2018 include:

- Storage Pole Barn for fleet - $300k; and
- Miscellaneous Ops Center repairs/maintenance - $70k.

Additional information about EPL's planned spending for account 1908 for the 2018 Test Year can be found in EPL's DSP as Attachment 2-C.

Account 1920 – Computer Equipment - Hardware

EPL realized an increase of $161,809 in Account 1920 from 2017 Bridge Year to 2018 Test Year. This variance is made up of the following items:

- Desktops/Laptops/Tablets/Toughbooks – $21k;
- Network/Security Appliances - $10k; and
- Cybersecurity & GP Related Upgrade - $130k.

Account 1930 – Transportation Equipment

EPL is planning an increase of $270,000 in Account 1930 from the 2017 Bridge Year to the 2018 Test Year. Planned additions in 2018 include:

- Replacement of Truck #66 – $50k;
- Replacement of Truck #68 – $95k;

- Replacement of Truck #69 - $95k; and
- Replacement of Chipper - $30k,

Additional information about EPL's fleet management and 2018 Test Year spending can be found in EPL's DSP as Attachment 2-C.

4.4.1.4 Contributions & Grants

Account 1995 – Contributions & Grants

While this variance is above EPL's materiality threshold, EPL traditionally receives approximately $1.4M per year in Capital Contributions & Grants, on average. EPL has budgeted conservative values of $1.22M for the Bridge and Test Years which are slightly below average but typical for years without large one-time projects.

4.4.2 Trends in Capital Expenditures

EPL generally projects its capital expenditures at least five (5) years into the future and prioritizes projects based on the methodology outlined in Section 4.2.3.3. Through this project prioritization process, EPL also considers historical spending and optimizing projects to smooth out spending, where possible. As a result, EPL is currently forecasting relatively flat capital spending into the future. This allows EPL to continuously re-invest in its asset base, but also modernize the grid as previously evidenced by the Single-Voltage Utility initiative and forthcoming with the Self-Healing Grid initiative planned to be implemented over the course of the next five (5) years.

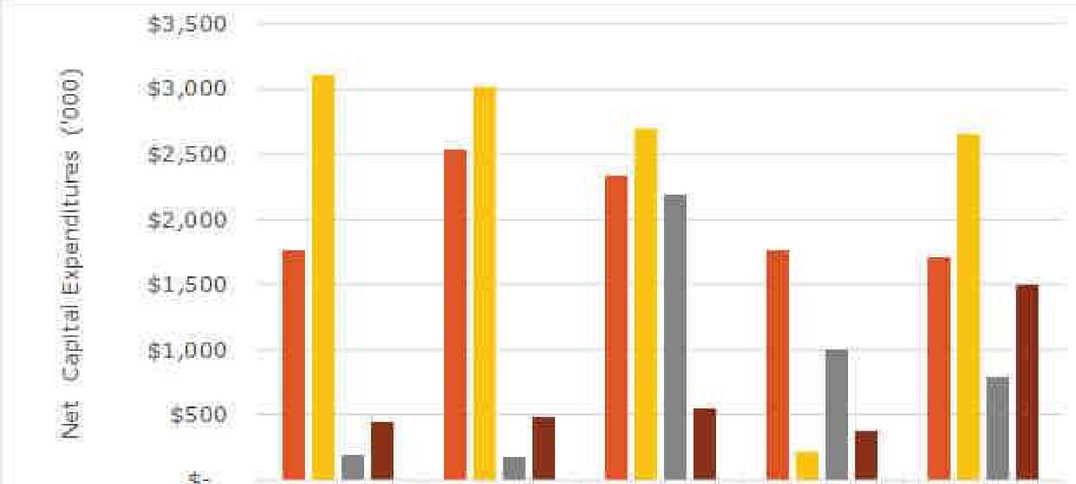
4.5 Justifying Capital Expenditures (5.4.5)

4.5.1 Overall Plan (5.4.5.1)

4.5.1.1 Comparative Expenditures by Category over the Historical Period

Figure 4-14 presents the net capital expenditures for each investment category – system access, system renewal, system service, and general plant – for the year 2013 through 2017

Figure 4-14: Comparative expenditures by category over the historical period

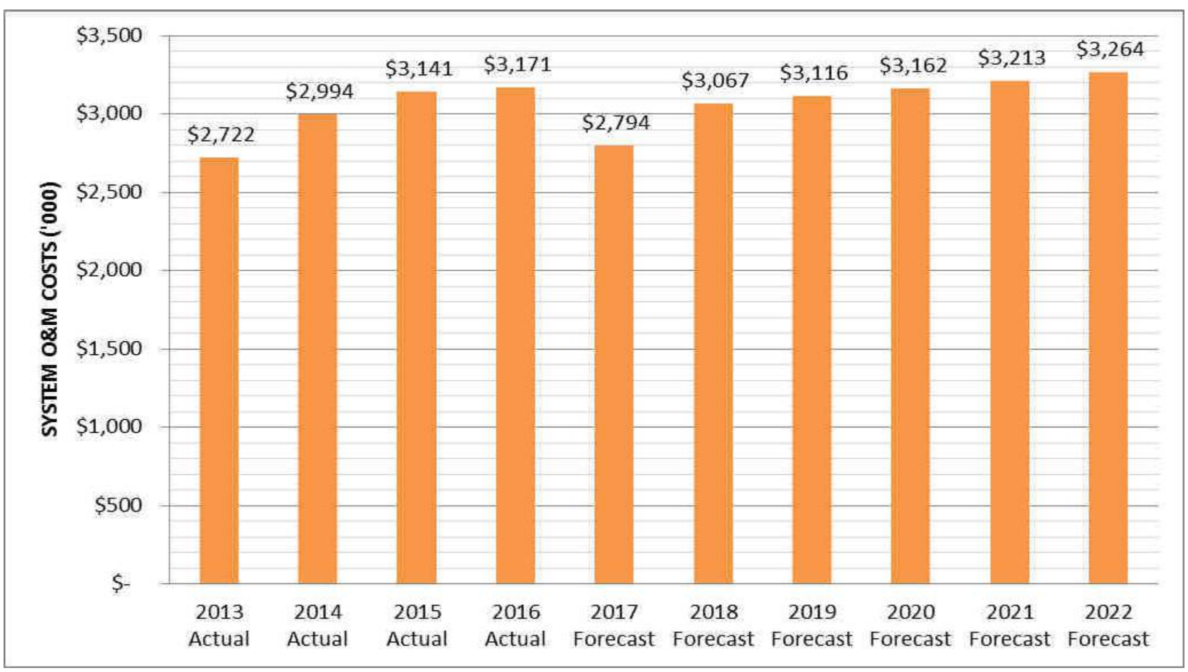


	2013	2014	2015	2016	2017
System access	$1,766	$2,532	$2,341	$1,759	$1,712
System renewal	$3,113	$3,012	$2,695	$215	$2,655
System service	$185	$177	$2,196	$1,005	$787
General plant	$450	$487	$547	$384	$1,504

4.5.1.2 Forecast Impact of System Investment on System O&M Costs

Based on EPL's proposed investment plan and other cost-saving initiatives, system O&M costs have been forecast to increase below the rate of inflation to an average of $3.1M per year for the years 2017 through 2022 compared to an average of $3.0M per year 2013 through 2016. Figure 4-15 depicts the system O&M costs, actual and forecast, for the years 2013 through 2022.

Figure 4-15: Actual and forecast system O&M costs



4.5.1.3 Investment Drivers by Category

Table 4-19 lists the drivers of investment by category.

Table 4-19: Investment drivers by category

Investment Category	Driver	Projects/Programs
System access	Customer service requests	Residential connections/extensions
		New service upgrades – commercial and industrial
		Subdivisions
	Third-party infrastructure development requirements	Municipal requests
	Mandated service obligations	Metering upgrade and replacement program
System renewal	Asset failure	Overhead reactive replacements
		Underground reactive replacements
	Assets at the end of their service life due to failure risk	Pole replacement program
		PMH replacement program
		Load break switch replacement
		Infrastructure rebuild program
System service	System operability	Purchase/sell HONI Leamington assets
		Purchase/sell HONI LaSalle assets
	System reliability	Self-healing grid reclosers
	System capacity	Malden TS new feeders and reconfiguration
	Customer-driven generation connection requests	FIT and generation connections
		MicroFIT connections
General plant	Non-system physical plant	Buildings and fixtures
	Business operations efficiency	Computer software
	Non-system equipment at the end of its service life	Tools and equipment
		Transportation equipment
		Office furniture and equipment
		Computer hardware
		Stores equipment

4.5.1.3.1 System Access

Historically, customer service requests for residential connections/extensions, new commercial and industrial service upgrades, and subdivisions have fluctuated between years. EPL has forecast its required investments based on the expected number of customer service requests in each of these categories.

Third-party infrastructure development requirements are also prone to large fluctuation driven by external factors. The combined spending due to this driver was $2.6M in 2013 and 2014 due to a large provincial project, but was only $12k in 2016. The forecast budget is based on the expected requests to be received.

EPL is mandated to meter customers to ensure accurate billing. Meter replacements are made due to failure, technology limitations requiring upgrades, or seal expiry. There is a downward spending trend for metering investments as a result of the implementation of smart meters.

4.5.1.3.2 System Renewal

Reactive replacements of underground and overhead equipment are driven by asset failures. Reactive replacement requirements have been unusually low over the historical period and are expected to statistically correct towards the mean.

Several programs replace assets at the end of their service life due to failure risk. Over the historical period, EPL was focussing its efforts on its voltage conversion programs to complete the transition to a single-voltage system without substations. With the completion of its voltage conversion program in 2017, EPL will instead focus on its Overhead Line Rebuild Program, its Direct-buried Cable Replacement Program, and installing/replacing load break switches. Expenditure rates for pole and switchgear replacements align with historical spending.

4.5.1.3.3 System Service

EPL has gradually been improving the operability of its system and the ability to manage the distribution system equipment that serves its customers through asset purchases from HONI. EPL has planned additional asset transfers as part of a broader strategy for both LDCs to manage and control the assets serving their respective customers.

EPL installed its first recloser in 2011 and will continue to install reclosers over the forecast period. The primary driver is system reliability. Sixty-three percent (63%) of the customer-interruption hours and seventy-three percent (73%) of the customer interruption over the historical period were loss of supply events. Reclosers will be used as part of a self-healing grid for automatic source-transfer to quickly restore power using an alternate source in case of a loss of supply event.

Investments at Malden TS, along with new feeders and feeder reconfiguration address system capacity constraints in LaSalle. The investments will add approximately 10 MVA of new capacity for the LaSalle area, which will sufficiently meet its needs for a long period of time.

Projects to facilitate REG connections are driven by customer requests to connect to the system. Historically, this has included RESOP connections and more recently has included MicroFIT and FIT connections. The number and capacity of REG connection requests over the forecast period has been forecast based on the applications being processed and the applications expected to be received. The FIT program continues to be popular and the most recent FIT 5 offering resulted in many applications to the IESO. This investment category may also include connections of REG greater than 500 kW outside of the FIT program.

4.5.1.3.4 General Plant

EPL's IT strategy will continue to focus on business operational efficiency improvements in order to meet its goal of delivering a modern, smart grid at inflation-aligned prices. EPL has been developing a SmartMAP toolset used for operations and planning. The SmartMAP's control functionality is used by front-line staff to perform switching operations rather than relying on a centralized control room. The outage detection algorithms are able to automatically locate and isolate a fault before restoring power to customers on an unfaulted section of the line.

Investment into non-system physical plant (i.e. buildings and fixtures) was low for the years 2013 through 2016 and additional investments have been planned based on EPL's Building Condition Review (see Appendix H).

Other investments into non-system physical equipment at the end of their service life include tools, fleet, office furniture, computer hardware, and stores equipment. EPL invests in vehicles according to its Fleet Purchasing Policy (see Appendix I). Fleet investments can be lumpy when heavy vehicles require replacement compared to personnel vehicles. The forecast spending on tools and equipment aligns with the historical spending and is based on the expected rate of equipment reaching end-of-life. Office furniture expenditures are budgeted as $10k per year over the forecast period based on the expected rate of replacement. Computer hardware investments align with the lifecycles of the various equipment, such as servers, and EPL's overall IT strategy. Other investments such as stores equipment are adjusted for inflation.

4.5.1.4 REG Requirements

For information related to EPL's system capability assessment, see Section 4.3.

4.5.2 Material Investments (5.4.5.2)

The focus on this section is on projects/activities that meet the materiality threshold set out in Chapter 2 of the Filing Requirements. For EPL this threshold is $60,000.

This section provides information regarding material projects for the capital expenditure in 2018. Project narratives have been prepared for these projects and are assembled in Appendix A.

Appendix A: Project Narratives

Table of Contents

New Residential Subdivisions

A. General Information on the Project/Activity

The purpose of the New Residential Subdivisions program is to facilitate the connection of new Residential Subdivisions and associated customers to EPL's distribution system. New subdivision plans for the 2018 Test Year are not known at this time. Forecast costs are driven by historical trends and increased by inflation. The final cost is determined based on the economic evaluation, which is completed once project specifics are known.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$240.0	$150.4	$1,020.2	$446.2	$375.0	$382.5	$390.2	$398.0	$405.9	$414.0
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
150 residential (estimated)

Load
300 kVA (estimated)

2018 Test Year Expenditure Timing

	Q1	**Q2**	**Q3**	**Q4**
Capital	$95,625	$95,625	$95,625	$95,625
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

The biggest risk to completion of this program as planned relates to the cost and timing of the investment. Projects within this program are initiated by customers and the actual spending can vary between years. This is an OEB-mandated activity. EPL has highly-trained staff that work with project developers to the best of their ability to manage timelines and to best accommodate the customer. Meetings with customers take place frequently and at their request to best manage customer expectations.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Customer service requests.*

ii. Secondary Drivers: *Mandated service obligations.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, and Financial & Environmental Sustainability.*

iv. Information Used to Justify the Investment: *New residential subdivisions and connections are driven by customer/developer request and are to be connected within OEB-mandated timelines.*

b) Priority: *New Residential Subdivision investments are made based on customer/developer request. This program is non-discretionary. The process is managed by EPL staff through various systems to ensure proper visibility and timeliness. New Residential Subdivisions are a high priority for EPL since they are linked directly with the customers that EPL serves.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked third (3rd) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *These investments are mandated by the OEB.*

i. Cost Effectiveness: *Whenever possible, new subdivisions use standardized designs to maximize cost effectiveness for the affected customer and minimize rate impact for EPL's customers in general.*

ii. Net Customer Benefits: *Customers benefit from a connection to the electricity grid.*

iii. Impact on Reliability: *New subdivisions are constructed using best utility practices that consider reliability by design.*

iv. Cost-Benefit Analysis: *Not applicable.*

2. Safety

New construction meets the latest distribution standards for safety.

3. Cyber-Security, Privacy

The investment does not raise any cyber-security or privacy concerns.

4. Co-ordination, Interoperability

EPL coordinates directly with customers, contractors, developers, and other agencies such as ESA.

5. Economic Development

The connection of customers to the electricity grid supports economic development in the communities that EPL serves.

6. Environmental Benefits

New transformers installed in the subdivisions meet the latest standards for energy efficiency and line losses are considered in the design of the subdivision service.

C. Category-Specific Requirements

Timing/Priority

New Residential Subdivision investments are made based on customer/developer request. This process is managed by EPL staff through various systems to ensure proper visibility and timeliness. New Residential Subdivisions are a high priority for EPL since they are linked directly with the customers that EPL serves.

Customer Preferences

EPL consistently meets with developers and customers to ensure that their needs are met in accordance with EPL's Conditions of Service.

Cost Factors

Costs are generally driven by the specific requests of the customer/developer and can vary from project to project. EPL employs good utility practice and engineering practices to ensure that costs are controlled and minimized for the customer.

Planning Objectives

Other planning objectives such as reliability and operability are incorporated into the design of the subdivision service.

Project Design/Implementation Options

Project design and implementation options for this program are not known until the customer service request is received. In general, designs can vary from project to project and must be made in accordance with EPL's Conditions of Service. Final design and implementation decisions are made by EPL's engineering department.

Results of the Final Economic Evaluation

The results of the final economic evaluation will not be available until the subdivision plans have been finalized by developers. The number of new connections and 2018 Test Year spending has been estimated based on historical values.

REG Investment System Impacts

Not applicable.

Residential Connections/Expansions

A. General Information on the Project/Activity

Residential Connection/Expansion requests are costs associated with activities relating to plant relocation or plant upgrades to accommodate customer-related changes. EPL consistently deals with a variety of requests that are not known at the time of budgeting. Forecast costs are driven by historical trends and increased by inflation.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$429.5	$677.9	$872.1	$1,050.7	$386.6	$394.4	$402.3	$410.3	$418.5	$426.9
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not Applicable

Load
Not Applicable

2018 Test Year Expenditure Timing

	Q1	**Q2**	**Q3**	**Q4**
Capital	$98,592	$98,592	$98,592	$98,592
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

The biggest risk to completion of this program as planned relates to the cost and timing of the investment. Projects within this program are initiated by customers and the actual spending can vary between years. This is an OEB-mandated activity. EPL has highly-trained staff that work with project developers to the best of their ability to manage timelines and to best accommodate the customer. Meetings with customers take place frequently and at their request to best manage customer expectations.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information. Note that actual costs can vary dramatically from year to year depending on the number of customer requests.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Customer service requests.*

ii. Secondary Drivers: *Mandated service obligations.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, and Financial & Environmental Sustainability.*

iv. Information Used to Justify the Investment: *New residential connections/expansions are driven by customer/developer request and are mandated by the OEB to be completed.*

b) Priority: *New Residential Connections/Expansions are made based on customer/developer request. This program is non-discretionary. The process is managed by EPL staff through various systems to ensure proper visibility and timeliness. Projects within this program are executed with a high priority, as they are linked directly with the customers that EPL serves and connections must be made within timelines specified in the Distribution System Code.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked first (1st) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *These investments are mandated by the OEB.*

i. Cost Effectiveness: *Whenever possible, residential connections/expansions use standardized designs to maximize cost effectiveness for the affected customer and minimize rate impact for EPL's customers in general.*

ii. Net Customer Benefits: *Customers benefit from a connection to the electricity grid.*

iii. Impact on Reliability: *Improvements to the secondary bus are considered as part of the projects in this program; however, reliability is not a significant driver.*

iv. Cost-Benefit Analysis: *Not applicable.*

2. Safety

New construction meets the latest distribution standards for safety.

3. Cyber-Security, Privacy

Not applicable.

4. Co-ordination, Interoperability

EPL coordinates directly with customers, contractors, developers and other agencies such as ESA.

5. Economic Development

The connection of customers to the electricity grid supports economic development in the communities that EPL serves.

6. Environmental Benefits

There are no applicable environmental benefits as a result of these investments.

C. Category-Specific Requirements

Timing/Priority

New Residential Connections/Expansion investments are made based on customer/developer request. This process is managed by EPL staff through various systems to ensure proper visibility and timeliness. New Residential Connections/Expansions are a high priority for EPL since they are linked directly with the customers that EPL serves.

Customer Preferences

EPL consistently meets with developers and customers to ensure that their needs are met in accordance with EPL's Conditions of Service.

Cost Factors

Costs are generally driven by the specific requests of the customer/developer and can vary from project to project. EPL employs good utility practice and engineering practices to ensure that costs are controlled and minimized for the customer.

Planning Objectives

Other objectives such as reliability of the secondary bus and transformer loading are always considered; however, investments under this program are driven primarily by customer requests.

Project Design/Implementation Options

Project design and implementation options for this program are not known until the customer service request is received. In general, designs can vary from project to project and must be made in accordance with EPL's Conditions of Service. Whenever possible, EPL uses standardized designs. Final design and implementation decisions are made by EPL's engineering department.

Results of the Final Economic Evaluation

Not applicable.

REG Investment System Impacts

Not applicable.

Municipal Requests

A. General Information on the Project/Activity

Municipal Requests are costs associated with activities relating to plant relocation or plant upgrades to accommodate municipally-requested changes. Examples of Municipal Requests include, but are not limited to, road widenings, right of way improvements, and utility relocation projects. EPL consistently deals with a variety of yearly requests that are not known at the time of budgeting. Forecast costs are driven by historical trends and increased by inflation.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$1,048	$1,577	$311.3	$12.3	$600.0	$612.0	$624.2	$636.7	$649.5	$662.4
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not Applicable

Load
Not Applicable

2018 Test Year Expenditure Timing

	Q1	**Q2**	**Q3**	**Q4**
Capital	$153,000	$153,000	$153,000	$153,000
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

The biggest risk to the completion of the program is the initiation of the work by the municipalities. The historical spending above shows that the actual spending can vary greatly between years depending on the amount of work requested by municipalities. To mitigate this risk, EPL has highly-trained staff that work with project developers to manage timelines and to best accommodate municipal requests. Meetings with municipalities take place frequently and at their request to best manage expectations.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information. Note that actual costs can vary dramatically from year to year.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Third-party infrastructure development requirements.*

ii. Secondary Drivers: *Not applicable.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, and Financial & Environmental Sustainability.*

iv. Information Used to Justify the Investment: *Municipal Requests are driven by municipal/shareholder request and are to be mandated by the OEB to be completed.*

b) Priority: *Since EPL's assets occupy the public right of way, this work is mandatory; therefore, this program is non-discretionary. The municipal request process is managed by EPL staff through various systems to ensure proper visibility and timeliness. The scope of work can vary wildly therefore timing and resourcing are closely managed and monitored by EPL staff.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked sixth (6^{th}) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *These investments are mandated by the OEB however certain types of projects are fully or partially recoverable from the municipality.*

i. Cost Effectiveness: *Whenever possible, new construction uses standardized designs to maximize cost effectiveness.*

ii. Net Customer Benefits: *Customers benefit from the work performed by the municipalities, which supports development and quality of life improvements in various communities.*

iii. Impact on Reliability: *Reliability objectives are always considered; however, investments under this program are driven by municipal infrastructure development requirements.*

iv. Cost-Benefit Analysis: *Not applicable.*

2. Safety

New construction meets the latest distribution standards for safety.

3. Cyber-Security, Privacy

Not applicable.

4. Co-ordination, Interoperability

EPL coordinates directly with customers, Municipalities, contractors, developers, and other agencies such as ESA. Quarterly utility meetings allow the municipalities and various utility participants to coordinate their planned and ongoing construction activities.

5. Economic Development

Some of these projects include community improvement projects; therefore, some areas can become more accessible, reliable, and aesthetically pleasing.

6. Environmental Benefits

There are no applicable environmental benefits as a result of these investments.

C. Category-Specific Requirements

Timing/Priority

The timing and priority of projects within this program are based on specific municipal requests. This process is managed by EPL staff through various systems to ensure proper visibility and timeliness. Municipal Requests are a high priority for EPL since they are linked directly with the communities that EPL serves.

Customer Preferences

EPL consistently meets with developers, Municipalities and customers to ensure that their needs are met in accordance with EPL's Conditions of Service.

Cost Factors

Costs are generally driven by the specific requests of the municipality or developer and can vary from project to project. EPL employs good utility practice and engineering practices to ensure that costs are controlled and minimized.

Planning Objectives

Other objectives such as reliability and capacity are always considered; however, investments under this program are driven by municipal infrastructure development requirements.

Project Design/Implementation Options

Project design and implementation options for this program are not known until the municipal request is received. In general, designs can vary for projects under this program and must be made in accordance with EPL's Conditions of Service. Whenever possible, EPL uses standardized designs. Final design and implementation decisions are made by EPL's engineering department.

Results of the Final Economic Evaluation

Not applicable.

REG Investment System Impacts

Not applicable.

New Service Upgrades – C&I

A. General Information on the Project/Activity

*New Service Upgrades for commercial and industrial ("**C&I**") customers are budgeted annually. The investment costs are associated with activities relating to plant relocation or plant upgrades to accommodate customer-related changes. EPL consistently deals with a variety of requests that are not known at the time of budgeting. Forecast costs are driven by historical trends and increased by inflation. EPL received fewer requests for C&I service upgrades over the historical period compared to previous years. Historically, spending in this category has been aligned to the forecast costs.*

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$100.9	$21.1	$3.8	$99.1	$350.0	$357.0	$364.1	$371.4	$378.8	$386.4
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not Applicable

Load
Not Applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$89,240	$89,240	$89,240	$89,240
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

The biggest risk to completion of this program as planned relates to the cost and timing of the investment. Projects within this program are initiated by customers and the actual spending can vary between years. This is an OEB-mandated activity. EPL has highly-trained staff that work with project developers to the best of their ability to manage timelines and to best accommodate the customer. Meetings with customers take place frequently and at their request to best manage customer expectations.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information. Note that actual costs can vary dramatically from year to year and EPL saw a significant reduction from 2013 through 2016 as a result of less development in the region. More development is expected beginning in 2017 and EPL must ensure it has enough capital allocated to serve new connections.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Customer service requests.*

ii. Secondary Drivers: *Mandated service obligations.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, and Financial & Environmental Sustainability.*

iv. Information Used to Justify the Investment: *New Service Upgrades – C&I are driven by customer/developer request and are mandated by the OEB to be completed.*

b) Priority: *New Service Upgrades – C&I are made based on customer/developer request. This program is non-discretionary. The process is managed by EPL staff through various systems to ensure proper visibility and timeliness. Projects within this program are executed with a high priority, as they are linked directly with the customers that EPL serves and connections must be made within timelines specified in the Distribution System Code.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked second (2nd) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *These investments are mandated by the OEB.*

i. Cost Effectiveness: *Whenever possible, new service upgrades use standardized designs to maximize cost effectiveness for the affected customer and minimize rate impact for EPL's customers in general.*

ii. Net Customer Benefits: *Customers benefit from a connection to the electricity grid.*

iii. Impact on Reliability: *Improvements to the secondary bus are considered as part of the projects in this program; however, reliability is not a significant driver.*

iv. Cost-Benefit Analysis: *Not applicable.*

2. Safety

New construction meets the latest distribution standards for safety.

3. Cyber-Security, Privacy

Not applicable.

4. Co-ordination, Interoperability

EPL coordinates directly with customers, contractors, developers, and other agencies such as ESA.

5. Economic Development

The connection of C&I customers directly supports job creation in the communities that EPL serves.

6. Environmental Benefits

There are no applicable environmental benefits as a result of these investments.

C. Category-Specific Requirements

Timing/Priority

New Service Upgrades – C&I investments are made based on customer/developer request. This process is managed by EPL staff through various systems to ensure proper visibility and timeliness. New Service Upgrades – C&I are a high priority for EPL since they are linked directly with the customers that EPL serve.

Customer Preferences

EPL consistently meets with developers and customers to ensure that their needs are met in accordance with EPL's Conditions of Service.

Cost Factors

Costs are generally driven by the specific requests of the customer/developer and can vary from project to project. EPL employs good utility practice and engineering practices to ensure that costs are controlled and minimized for the customer.

Planning Objectives

Other objectives such as reliability of the secondary bus and transformer loading are always considered; however, investments under this program are driven primarily by customer requests.

Project Design/Implementation Options

Project design and implementation options for this program are not known until the customer service request is received. In general, designs can vary from project to project and must be made in accordance with EPL's Conditions of Service. Whenever possible, EPL uses standardized designs. Final design and implementation decisions are made by EPL's engineering department.

Results of the Final Economic Evaluation

Not applicable.

REG Investment System Impacts

Not applicable.

Metering Upgrade & Replacement Program

A. General Information on the Project/Activity

The purpose of this program is to replace meters due to communication failure, technology limitations requiring upgrades due to regulation changes, or seal expiry. The program also includes gatekeeper and modem replacements to enhance connection and reliability of data. Budgeting is reviewed annually based on communication and data needs of new technologies as well as historical spending trends adjusted for inflation. EPL received fewer requests for metering upgrades over the historical period compared to previous years. Historically, spending in this category has been aligned to the forecast costs. The 2018 Test Year expenditure forecast includes 351 interval meters, 672 smart meters, and 4 gatekeepers.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Capital	$100.1	$7.7	$8.5	$54.2	$163.0	$166.3	$169.6	$173.0	$176.5	$180.0
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not applicable

Load
Not applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$41,574	$41,574	$41,574	$41,574
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

Risks are minimal for these projects as they represent standard industry practices. There is risk in loss of data and equipment lead times; however, EPL is in regular communication with vendors to ensure customer value and is upgrading meters, where required, to avoid data related problems in the future.

Comparative Expenditure Information

Comparative expenditures over the historical period are shown in the table above.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Mandated service obligations.*

ii. Secondary Drivers: *Assets at the end of their service life due to failure or functional obsolescence.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, and Financial & Environmental Sustainability.*

iv. Information Used to Justify the Investment: *EPL uses Measurement Canada seal expiry and recent failures as the metrics to justify these projects.*

b) Priority: *Metering is a mandated service obligation; therefore, this program is non-discretionary. EPL prioritizes replacements based on recent failures and direction from the OEB and Measurement Canada.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked tenth (10th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *There are no alternatives to these metering upgrades and replacements as reliable and accurate metering information is mandated by the OEB and Measurement Canada.*

i. Cost Effectiveness: *All new meters include network connections to Advanced Metering Infrastructure ("**AMI**").*

ii. Net Customer Benefits: *Enhanced customer confidence.*

iii. Impact on Reliability: *These investments can improve the reliability of data provided to the provincial Meter Data Management Repository and billing system. New meters communicate a "last gasp" to EPL's self-healing grid in case of a loss of power. This information facilitates accurate assessment of the grid condition to restore the maximum number of customers as soon as possible.*

iv. Cost-Benefit Analysis: *Not applicable.*

2. Safety

New meters conform to the latest safety standards.

3. Cyber-Security, Privacy

The investment will be made in conjunction with major cyber-security upgrades underway in 2017. Smart meter data is collected and transferred over a secure network. In accordance with best practices for data security, access to the data is restricted to EPL staff who require access via secure log-in.

4. Co-ordination, Interoperability

Customer coordination is required in order to minimize customer impact and outage times. Appointments are made to attempt to best accommodate the customer.

5. Economic Development

*Metering is mandatory in order to supply a customer with electrical service, which supports economic development. Smart meters enable time-of-use ("**TOU**") rates and allow residential and business customers alike to manage their consumption.*

6. Environmental Benefits

Smart meters enable TOU billing, which incentivizes customers to shift consumption from peak hours (when gas-fired peaking plants are needed) to off-peak hours (more dependent on emission-free sources such as hydroelectric and nuclear).

C. Category-Specific Requirements

Timing/Priority

The Metering Upgrade & Replacement Program timing is dependent on the urgency of the replacement as well as availability of resources. Data/reliability centered replacements are dealt with as quickly as possible whereas scheduled replacements are accommodated when timing is optimal for EPL crews and customers.

Customer Preferences

The project is driven by mandated service obligations. Appointments are made to attempt to best accommodate the customer.

Cost Factors

The project is driven by mandated service obligations. EPL employs good utility practices and engineering practices to ensure that costs are controlled and minimized for the customer.

Planning Objectives

This program supports EPL's objective of a providing a modern, smart grid fit for the 21st century at inflation-aligned costs.

Project Design/Implementation Options

Standardized designs and installation procedures are used to maximize cost effectiveness of each job.

Results of the Final Economic Evaluation

Not applicable.

REG Investment System Impacts

Not applicable.

Pole Replacement Program

A. General Information on the Project/Activity

The purpose of this program is to replace poles that have either failed or are at the end of their service life due to failure risk. Through its thorough preventative maintenance program, EPL reviews the condition of its poles continuously to limit failure and maximize safety via non-destructive testing methods such as drilling. Budgeting is reviewed annually based on preventative maintenance program findings and availability of resources.

EPL plans to replace approximately twenty-nine (29) poles in 2018 as part of its Pole Replacement Program. These poles were identified for replacement through EPL's preventative maintenance program where core sampling was completed via pole drilling.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Capital	$478.3	$193.3	$335.9	$514.0	$460.5	$114.1	$558.7	$488.7	$121.0	$592.9
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not applicable

Load
Not applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$28,516	$28,516	$28,516	$28,516
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

Pole replacements are well understood and, therefore, risks are minimal for these projects as they represent standard industry practices. There is incremental risk in dealing with auguring holes during the winter months where sub-zero temperatures can persist. However, this can be mitigated by scheduling around predictable adverse weather conditions. Many replacements take place near customer premises or businesses; therefore, EPL will ensure that the necessary signage and safety precautions are utilized. Any/all inconvenienced customers will be notified.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information. Note that actual costs can vary dramatically from year to year based on the expected number of replacements planned/required. EPL's poles are inspected and tested on a three (3)-year cycle. Replacement of poles *also follows this cycle, which ensures that the poles prioritized for replacement were recently assessed to be at the end of their service life and pose an unacceptable risk without intervention.*

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Assets at the end of their service life as a result of failure risk.*

ii. Secondary Drivers: *The secondary drivers are poles at the end of their service life due to failure, safety, and reliability. Allowing old and deteriorating poles in the field can result in significant safety concerns to EPL staff and customers.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, Safety, and Financial & Environmental Sustainability.*

iv. Information Used to Justify the Investment: *EPL's preventative maintenance program and recent failures are the metrics that EPL uses to justify these projects.*

b) Priority: *All capital projects have been prioritized and optimized based on Financial, Service Quality, Community Image, Legal, Regulatory, Safety and Environmental metrics. EPL prioritizes replacements based on recent failures and its preventative maintenance program.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked sixteenth (16th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *Alternatives to pole replacements include a complete overhead rebuild, undergrounding the span, and the "do nothing". Poles included in this program are not part of an overhead rebuild since the adjacent poles are typically not at the end of their service life. Undergrounding a single span is not feasible. In the case of the "do nothing" option, old and deteriorating poles would remain in the field without intervention, which can result in significant safety concerns, lengthy customer outages, and increases to system O&M costs.*

i. Cost Effectiveness: *EPL uses inspection and age data to determine pole replacements cost effectively. For poles identified for replacement under this program, spot pole replacements – rather than planned overhead rebuilds – are the most cost-effective alternative.*

ii. Net Customer Benefits: *Customers will benefit from fewer outages.*

iii. Impact on Reliability: *This program will replace poles in poor condition before they fail and cause extended outages; hence, improving reliability.*

iv. Cost-Benefit Analysis: *The Pole Replacement Program replaces poles that are at end of service life due to failure or failure risk as identified during the pole inspection process. This will improve reliability by reducing unplanned outages and hence reducing outage costs. Also, this program avoids future system O&M costs since replacements can be scheduled during regular hours rather than relying on trouble calls, which take longer and can require overtime hours.*

Other alternatives, such as undergrounding the line section, are not feasible and are, therefore, not recommended. In the case of a failed pole, doing nothing is not an option as a pole is required to support the overhead conductors and provide proper clearances. In the case of a pole at risk of failure, doing nothing would not achieve the project benefits of eliminating risks to public and employee safety, maintaining system reliability, and avoiding future O&M (trouble call) costs.

This project will result in greater reliability for EPL customers, lower system O&M costs over time, lessen EPL's legal liability and exposure, and lead to enhanced safety for crews and the general population. The project as scoped is the optimal approach and the preferred trade-off between costs and benefits.

<u>2. Safety</u>

Proper asset management of old and deteriorating equipment in the field mitigates safety concerns for EPL staff and customers. All new construction meets the latest distribution standards for safety.

<u>3. Cyber-Security, Privacy</u>

This program does not raise any cyber-security or privacy concerns.

<u>4. Co-ordination, Interoperability</u>

Coordination with entities such as HONI is critical to ensure consistency with joint-use agreements, ensure safety, and co-ordinate planned outages.

<u>5. Economic Development</u>

One of the drivers for this program is reliability and a reliable electricity supply supports economic development.

<u>6. Environmental Benefits</u>

There are no significant environmental benefits as a result of these investments.

C. Category-Specific Requirements

<u>Asset Performance-Related Targets</u>

The replacement of aged and deteriorating overhead plant will maintain EPL's reliability performance, specifically with respect to the number of outages (SAIFI). For the years 2013 through 2016, defective equipment outages accounted for the most customer-hours of interruption excluding loss of supply events; therefore, the investment will contribute to reducing defective equipment outages. A reliable supply of electricity supports customer satisfaction.

*EPL relies on a combination of Reliability-Centred Maintenance ("**RCM**"), predictive maintenance, preventative maintenance, and cyclical inspections to manage its distribution assets. Plant that is scheduled for replacement is generally at the end of its service life due to failure or failure risk or otherwise requires replacement due to reliability and/or safety concerns.*

Condition of Assets

Poles are inspected on a three (3)-year cycle. EPL also has a pole testing program to assess the condition of its poles. EPL owns 6228 poles, of which 6062 are made of wood, 163 are made of concrete, and 3 are made of steel. The Pole Replacement Program focuses on wood poles.

1 presents the age profile for wood poles; the age demographics are unknown for the remaining 3291 wood poles. Figure 2 presents the results of the condition assessment.

Figure 1: System-wide age profile for wood poles

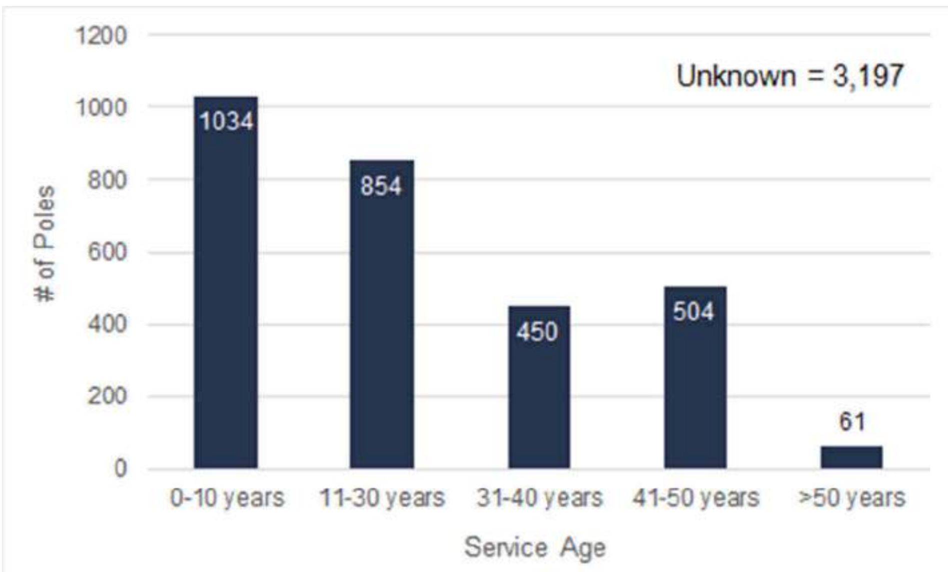
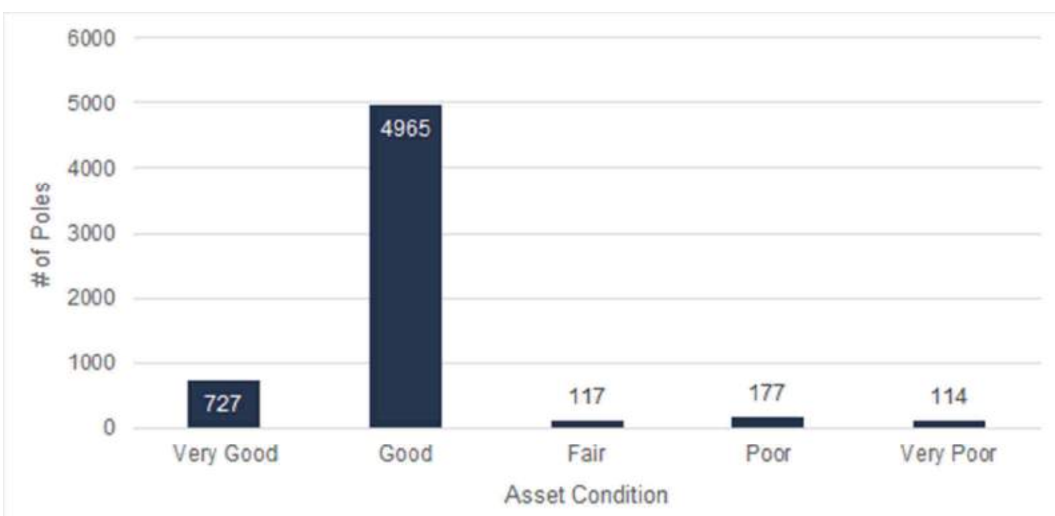


Figure 2: Condition assessment results for wood poles



Project Impacts

i. Number of Customers Affected: *Specific yearly values are not currently known; however, the number of customers can vary significantly from year to year.*

ii. Quantitative Customer Impacts: *Specific yearly values are not currently known; however, the length of outages can vary significantly from year to year.*

iii. Qualitative Customer Impacts: *Customers will receive value through reduced unplanned outages and enhanced reliability.*

iv. Value of Customer Impact: *Customers will receive value through reduced unplanned outages and enhanced reliability.*

Project Timing Factors

Pole replacement timing is dependent on the urgency of the replacement as well as availability of resources. Safety or reliability-centered replacements are dealt with as quickly as possible, whereas scheduled replacements are accommodated when timing is optimal for EPL crews.

Consequences for System O&M Cost

The Pole Replacement Program will help reduce O&M costs over time through reductions in reactive maintenance spending.

The failure of a pole increases system O&M costs. Unplanned pole change-outs usually take longer to replace, as the downed pole must first be located and the work may need to be done at night. A failed pole may also break the conductors, which are not usually replaced as part of the pole replacement program.

Reliability / Safety Factors

Proper asset management of old and deteriorating equipment in the field mitigates safety and reliability concerns.

Comparison of Project Timing Alternatives

There are limited alternatives to the Pole Replacement program and the consequences of delaying replacements can result in significant reliability and safety concerns.

Analysis of Project Enhancements

All new construction meets the latest distribution standards. Possible project enhancements are assessed when planning the pole replacement job. This can include selecting a higher pole class for corner poles or other key locations such as road or river crossings.

Overhead Reactive Replacements

A. General Information on the Project/Activity

The purpose of this program is to replace overhead equipment that has failed as a result of damage incurred in the field. Budgeting is reviewed annually and is based on historical spending trends adjusted for expected inflation. Reactive spending over the historical period was less than the long-term average, which is expected to statistically correct towards the mean.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Capital	$0	$6.1	$0	$0	$80.8	$82.4	$84.0	$85.7	$87.4	$89.2
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Varies

Load
Varies

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$20,600	$20,600	$20,600	$20,600
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

Since this is a reactive program, the actual spending can vary compared to the budget depending on the quantity of assets that fail during the year. Overhead lines are exposed to external factors such as wind, snow, ice, lightning, and unclaimed damage to EPL's plant from vehicles. The primary risk to the completion of this program is ensuring that sufficient capital is available to mitigate a variety of different restoration/repair scenarios. EPL's preventative maintenance program has allowed EPL to better control these costs over time.

Comparative Expenditure Information

Note that actual costs can vary dramatically from year to year based on the actual number of events incurred. Reactive spending over the historical period was less than the long-term average, which is expected to statistically correct towards the mean.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Assets at the end of their service life due to failure.*

ii. Secondary Drivers: *The secondary drivers are safety and reliability. Storm conditions can present safety-related risks to both EPL staff and customers. Failed assets need immediate repair or replacement for quick restoration. Other major cost drivers include third-party tree trimming, on-call premiums, etc.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, and Safety.*

iv. Information Used to Justify the Investment: *Customer restoration is an OEB-mandated activity. Public/employee safety is one of the top objectives of EPL's asset management. Failed assets, if not replaced/repaired immediately, pose safety hazards; therefore, this is investment is highly required.*

b) Priority: *This is a non-discretionary program. Customer restoration is an OEB-mandated activity and, therefore, this activity is required.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked fourth (4th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *The alternative to this program is a "do nothing" approach; however, doing nothing is not an option with failed assets as they need to be repaired/replaced for customer restoration. Design alternatives, where applicable, are evaluated for each case to ensure that restoration is completed quickly and cost effectively.*

i. Cost Effectiveness: *In each case, service is restored by the most cost effective means.*

ii. Net Customer Benefits: *Customers will benefit from quick restoration as a result of this activity.*

iii. Impact on Reliability: *Ensuring sufficient investment in case of a failure will lower or maintain SAIDI within the target by allowing quick customer restoration.*

iv. Cost-Benefit Analysis: *Overhead assets that generally fail as a result of storm or adverse conditions beyond the control of EPL need to be repaired /replaced to ensure customer restoration and deliver reliable service. Benefits of this activity are quick customer restoration and improved reliability and safety.*

2. Safety

Safety is a critical driver for this project since storm conditions can present safety-related risks to both EPL staff and customers. All new construction meets the latest distribution standards for safety.

3. Cyber-Security, Privacy

This program does not raise any cyber-security or privacy concerns.

4. Co-ordination, Interoperability

Coordination with entities such as HONI is critical to ensure timely and effective restoration.

5. Economic Development

Restoration of electrical service supports economic development in the areas that EPL serves.

6. Environmental Benefits

There are no significant environmental benefits as a result of these investments.

C. Category-Specific Requirements

Asset Performance-Related Targets

Replaced overhead assets have generally failed as a result of storm or adverse conditions beyond the control of EPL. Ensuring sufficient investment in case of a failure will lower or maintain SAIDI within the target by allowing quick customer restoration and will improve customer satisfaction.

*EPL relies on a combination of proactive replacements, Reliability-Centred Maintenance ("**RCM**"), predictive maintenance, preventative maintenance, and cyclical inspections to manage its distribution assets and reduce the amount of reactive work required.*

Condition of Assets

This program is not driven by asset condition; replaced overhead assets have generally failed as a result of storm or adverse conditions beyond the control of EPL.

Project Impacts

i. Number of Customers Affected: *Specific yearly values are not currently known; however, the number of customers can vary significantly from year to year.*

ii. Quantitative Customer Impacts: *Specific yearly values are not currently known; however, the length of outages can vary significantly from year to year.*

iii. Qualitative Customer Impacts: *Customers will receive value through quick customer restoration.*

iv. Value of Customer Impact: *Ensuring sufficient funding for this project ensures that EPL has the resources it requires to fund reactive overhead replacements in a timely and safe manner for its customers.*

Project Timing Factors

Restoration timing can vary dramatically depending on the nature of the asset failure(s), EPL's assessment of the damage, and coordination with other utilities including Hydro One.

Consequences for System O&M Cost

When there is a storm or otherwise adverse conditions, the initial response is treated as O&M, while new equipment installed in the field is capitalized.

Reliability / Safety Factors

Failed overhead equipment, if not responded to by EPL crews, pose safety and reliability concerns.

Comparison of Project Timing Alternatives

There are limited alternatives for this project and the consequences of delaying replacements can result in significant reliability and safety concerns.

Analysis of Project Enhancements

All new plant meets the latest distribution system standards.

Underground Reactive Replacements

A. General Information on the Project/Activity

The purpose of this program is to replace underground equipment that has failed as a result of damage incurred in the field. Budgeting is reviewed annually and is based on historical spending trends adjusted for expected inflation. Reactive spending over the historical period was less than the long-term average, which is expected to statistically correct towards the mean.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Capital	$10.7	$0	6.9	$0	$63.7	$65.0	$66.3	$67.6	$68.9	$70.3
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not applicable

Load
Not applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$16,241	$16,241	$16,241	$16,241
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

Since this is a reactive program, the actual spending can vary compared to the budget depending on the quantity of assets that fail during the year. Underground cables can exhibit insulation failure (e.g. treeing, pinhole) or fail due to a dig-in. The primary risk to the completion of this program is ensuring that sufficient capital is available to mitigate a variety of different restoration/repair scenarios. EPL's preventative maintenance program has allowed EPL to better control these costs over time.

Comparative Expenditure Information

Note that actual costs can vary dramatically from year to year based on the actual number of events incurred. Reactive spending over the historical period was less than the long-term average, which is expected to statistically correct towards the mean.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Assets at the end of their service life due to failure.*

ii. Secondary Drivers: *The secondary drivers are safety and reliability. Failed assets need immediate repair or replacement for quick restoration. Major cost drivers include third-party trenching, on-call premiums, etc.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, and Safety.*

iv. Information Used to Justify the Investment: *This program is required to replace failed assets and for fast restoration. Customer restoration is an OEB-mandated activity. Public/employee safety is one of the top objectives of EPL's asset management. Failed assets, if not replaced/repaired immediately, pose safety hazards; therefore, this is investment is highly required.*

b) Priority: *This is a non-discretionary program. Customer restoration is an OEB-mandated activity and, therefore, this activity is required.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked fifth (5th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *The alternative to this program is a "do nothing" approach. In case of failed assets doing nothing is not an option and hence not recommended. Other alternatives, where applicable, are evaluated based on each failure case to ensure that restoration is completed quickly and cost effectively.*

i. Cost Effectiveness: *In each case, service is restored by the most cost effective means.*

ii. Net Customer Benefits: *Customers will benefit from fast restoration.*

iii. Impact on Reliability: *Reserving sufficient budget for reactive replacement ensures fast restoration and hence maintaining reliability target.*

iv. Cost-Benefit Analysis: *Not applicable.*

2. Safety

Safety is a critical driver for this project since failed underground plant, if not corrected, can present potential safety-related risk to EPL staff and customers. All new construction meets the latest distribution standards for safety.

3. Cyber-Security, Privacy

This program does not raise any cyber-security or privacy concerns.

4. Co-ordination, Interoperability

Coordination with entities such as HONI is critical to ensure timely and effective restoration.

5. Economic Development

Restoration of electrical service supports economic development in the areas that EPL serves.

6. Environmental Benefits

There are no significant environmental benefits as a result of these investments.

C. Category-Specific Requirements

Asset Performance-Related Targets

*Ensuring sufficient investment in case of a failure will lower or maintain SAIDI within the target by allowing quick customer restoration and will improve customer satisfaction. EPL relies on a combination of proactive replacements, Reliability-Centred Maintenance ("**RCM**"), predictive maintenance, preventative maintenance, and cyclical inspections to manage its distribution assets and reduce the amount of reactive work required.*

Condition of Assets

This program is not driven by asset condition; replaced underground assets have generally failed as a result of storm or adverse conditions beyond the control of EPL.

Project Impacts

i. Number of Customers Affected: *Specific yearly values are not currently known; however, the number of customers can vary significantly from year to year.*

ii. Quantitative Customer Impacts: *Specific yearly values are not currently known; however, the length of outages can vary significantly from year to year.*

iii. Qualitative Customer Impacts: *The investment will maintain reliability performance associated with underground assets.*

iv. Value of Customer Impact: *Ensuring sufficient funding for this project ensures that EPL has the resources it requires to fund reactive underground replacements in a timely and safe manner for its customers.*

Project Timing Factors

Restoration timing can vary dramatically depending on the nature of the asset failure(s), EPL's assessment of the damage, and coordination with other utilities including HONI.

Consequences for System O&M Cost

When there is a storm or otherwise adverse conditions, the initial response is treated as O&M, while new equipment installed in the field is capitalized.

Reliability / Safety Factors

Allowing damaged assets in the field can result in significant safety concerns to EPL staff and customers.

Comparison of Project Timing Alternatives

Failed underground equipment, if not responded to by EPL crews, pose reliability and safety concerns.

1 Analysis of Project Enhancements

2 *All new plant meets the latest distribution system standards.*

Install/Replace Load Breaks

A. General Information on the Project/Activity

The purpose of this program is to replace load-break switches that have either failed or are at the end of their service life due to failure risk. As part of EPL's self-healing grid initiative, load-break switches identified for replacements are upgraded for reliability and automation purposes. EPL is planning to replace two (2) load-break switches per year.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$0	$0	$0	$0	$58.8	$59.9	$61.1	$62.3	$63.6	$64.9
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not applicable

Load
Not applicable

2018 Test Year Expenditure Timing

	Q1	**Q2**	**Q3**	**Q4**
Capital	$14,982	$14,982	$14,982	$14,982
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

Risks are minimal for these projects as they represent standard industry practices. There is incremental risk in procurement; however, EPL is in regular communication with vendors to ensure customer value.

Comparative Expenditure Information

There were no expenditures under third program for the years 2013 through 2016. The planned investment beginning in 2017 coincides with the self-healing grid initiative.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Assets at the end of their service life as a result of failure risk.*

ii. Secondary Drivers: *The secondary drivers are asset failure, reliability, and safety. Switch failures can result in customer outages and reduce the operability of the system.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, Safety, and Financial & Environmental Sustainability.*

iv. Information Used to Justify the Investment: *EPL's preventative maintenance program and recent failures are the metrics that EPL uses to justify these projects.*

b) Priority: *All capital projects have been prioritized and optimized based on Financial, Service Quality, Community Image, Legal, Regulatory, Safety and Environmental metrics. EPL prioritizes replacements based on recent failures and its preventative maintenance program.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked eighth (8^{th}) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *Possible alternatives to the replacement of a load-break switch include the "do nothing" option. If a switch is identified as a failure risk or has failed, then it will reduce the operability of the system. Replacement is the optimal approach to enable grid operation during feeder work and when restoring power.*

i. Cost Effectiveness: *Planned replacements are more cost effective than reactive replacements, which may require emergency restoration or overtime hours.*

ii. Net Customer Benefits: *Customers will benefit from improved operability of the system, allowing EPL's crews to perform work on the system and power to be more restored more effectively during an outage.*

iii. Impact on Reliability: *Reliability impacts are mitigated through proactive switch replacement. The upkeep of load break switches allows EPL to flexibly transfer load under outage scenarios.*

iv. Cost-Benefit Analysis: *The proactive replacement of load break switches is the most cost-effective option and provides the greatest benefits for EPL's customers. This is the optimal approach.*

2. Safety

All new construction meets the latest distribution standards for safety.

3. Cyber-Security, Privacy

This program does not raise any cyber-security or privacy concerns. The communication capabilities of the new switches are secured on EPL's network.

4. Co-ordination, Interoperability

Coordination with entities such as HONI is critical to ensure consistency with joint-use agreements, ensure safety, and co-ordinate planned outages.

5. Economic Development

One of the drivers for this program is reliability and a reliable electricity supply supports economic development.

6. Environmental Benefits

There are no significant environmental benefits as a result of these investments.

C. Category-Specific Requirements

Asset Performance-Related Targets

The replacement of aged and deteriorating overhead plant will maintain EPL's reliability performance, specifically with respect to the number of outages (SAIFI). The proactive replacement of load-break switches also supports operability of the system, allowing EPL to quickly restore power under contingency scenarios and reducing the duration of outages (SAIDI). A reliable supply of electricity supports customer satisfaction.

*EPL relies on a combination of Reliability-Centred Maintenance ("**RCM**"), predictive maintenance, preventative maintenance, and cyclical inspections to manage its distribution assets. Plant that is scheduled for replacement is generally at the end of its service life due to failure or failure risk or otherwise requires replacement due to reliability and/or operability concerns.*

Condition of Assets

Load break switches are inspected on a three (3)-year cycle. Load break switches also undergo regular maintenance – with adjustments as required – and infrared inspection. Assets replaced under this program are assessed to be at the end of their service life based on the results of the maintenance and inspections.

Project Impacts

i. Number of Customers Affected: *Specific yearly values are not currently known; however, the number of customers can vary significantly from year to year.*

ii. Quantitative Customer Impacts: *Specific yearly values are not currently known; however, the length of outages can vary significantly from year to year.*

iii. Qualitative Customer Impacts: *Customers will receive value through reduced unplanned outages and enhanced reliability.*

iv. Value of Customer Impact: *Customers will receive value through reduced unplanned outages and enhanced reliability.*

Project Timing Factors

Load break switch replacement timing is dependent on the urgency of the replacement as well as availability of resources. Reliability-centered replacements are dealt with as quickly as possible, whereas scheduled replacements are accommodated when timing is optimal for EPL crews.

Consequences for System O&M Cost

This program will contribute to a reduction in reactive maintenance spending, which will reduce overall system O&M costs. The failure of a pole increases system O&M costs. Unplanned replacements usually take longer to perform and may require overtime hours.

Reliability / Safety Factors

Proper asset management of old and deteriorating equipment in the field mitigates safety and reliability concerns.

Comparison of Project Timing Alternatives

EPL has paced two (2) load-break switches per year to avoid replacing switches before they reach end-of-life. The timing also corresponds with EPL's self-healing grid initiative described in its Green Energy Act Plan and Smart Grid Development Plan.

Analysis of Project Enhancements

New load-break switches installed in the field are enhanced with communication capabilities to facilitate a self-healing grid.

Infrastructure Rebuild Program

A. General Information on the Project/Activity

The purpose of this program is to replace overhead and underground circuits that are located in alleys, right of ways, etc. in customer backyards. In particular, this program focuses on replacement of direct-buried cables. Budgeting is reviewed annually based on the urgency of work required and potential safety hazards. EPL intends to increase accessibility of all of its plant while limiting inconveniences to its customers.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Capital	$814.5	$290.1	$88.7	$43.6	$900.0	$2,229.4	$229.4	$1,229.4	$1,529.4	$1,329.4
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not applicable

Load
Not applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$557,354	$557,354	$557,354	$557,354
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

Program timing and cost can be impacted since work must be performed on customer premises. Customers are provided notice of the work well in advance to reduce the inconvenience and EPL will ensure that the necessary signage and safety precautions are utilized. The work will be done by dedicated crews who are familiar with this type of work.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information. Note that actual costs can vary dramatically from year to year based on the expected number of replacements planned/required.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Assets at the end of their service life due to failure risk.*

ii. Secondary Drivers: *The secondary drivers are safety and reliability. In response to customer requests, this project will increase accessibility of all of its plant while limiting inconveniences to its customers.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, and Safety.*

iv. Information Used to Justify the Investment: *EPL's preventative maintenance program, as well as customer requests, are used to justify these investments.*

b) Priority: *EPL prioritizes conversions based on recent failures, age of plant, customer requests, and other planned work in the area of the conversion. All capital projects have been prioritized and optimized based on Financial, Service Quality, Community Image, Legal, Regulatory, Safety, and Environmental metrics. Public/ employee safety is the highest priority objective for EPL.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked twelfth (12th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *For direct-buried cable replacements, there are four (4) alternatives: do nothing, replace with direct-buried cable, replace with cable runs in ducts, and replace with overhead service. Alternatives to overhead rebuilds include the "do nothing" option, like-for-like rear lot rebuild, spot pole replacements, undergrounding the circuits, or rebuilding the service in the front.*

i. Cost Effectiveness: *This program replaces rear lot infrastructure, which would otherwise require expensive emergency repairs since specialized equipment is oftentimes required in order to minimize customer inconvenience. The proactive replacement of assets and conversion of rear-lot to front service is the most cost-effective approach. Since the assets are in proximity to one another, the overhead rebuild option is more cost effective than reactive replacements or spot pole replacements.*

ii. Net Customer Benefits: *Customers benefit in terms of future reliability of their electricity supply and future convenience for inspection and repair work no longer required in customer backyards. This program lessens inconvenience for the customer in circumstances where EPL needs to access its equipment and results in faster restoration times.*

iii. Impact on Reliability: *This program mitigates the risk of an unplanned asset failure – particularly direct-buried cables – and also reduces outage restoration time since duct-embedded cables can be repaired much quicker than direct-buried cables. Overhead lines and poles in the field are aged and deteriorating which can result in unplanned outages. This will particularly impact outages due to adverse weather and tree contacts on customer premises. Moreover, with ease of access to equipment, fast restoration can be achieved.*

iv. Cost-Benefit Analysis: *In the case of the "do nothing" option, customer requests to increase accessibility will not be met and accessing plant in backyards can also prove to be difficult, unsafe, and cost-ineffective since specialized equipment is oftentimes required in order to minimize customer inconvenience. Replacing with direct-buried cables would require the right of way to be dug up again in case of a future cable failure, which is sub-optimal. Converting specific sections of the underground feeders would not be feasible and would reduce the satisfaction of the affected customers.*

Rebuilding in backyard does not solve the clearance issue which is one of the motives of this project. In most cases, a spot pole replacement is equivalent to a like-for-like replacement and does not solve the accessibility issue for assets on customer premises. Undergrounding an existing overhead circuit is much more expensive and, therefore, not recommended.

Replacing the direct-buried cable with duct-embedded cable runs is the optimal trade-off between benefits and costs, providing the most benefits to EPL's customers. Rebuilding overhead lines in the right of way at the front of a property eases access for EPL staff resulting in safer work and creates less inconvenience for the customer in circumstances where EPL needs to access its equipment and results in faster restoration times.

2. Safety

Proper asset management of old and deteriorating equipment in the field mitigates safety concerns for EPL staff and customers. Accessing plant in backyards can also prove to be difficult and unsafe. All new construction meets the latest distribution standards for safety. Furthermore, the risk of a dig-in in the customer's backyard is mitigated.

3. Cyber-Security, Privacy

This program does not raise any cyber-security or privacy concerns.

4. Co-ordination, Interoperability

Coordination with entities such as HONI is critical to ensure consistency with joint-use agreements, ensure safety, and co-ordinate planned outages.

5. Economic Development

This program proactively addresses system reliability, which is conducive to economic development.

6. Environmental Benefits

There are no applicable environmental benefits as a result of these investments.

C. Category-Specific Requirements

Asset Performance-Related Targets

To monitor asset performance, EPL tracks the number of cable failures each year. This investment will help EPL reduce the number of cable failures each year. The replacement of direct-buried cables will maintain EPL's reliability performance, specifically with respect to the number of outages (SAIFI) and the time required to restore power (SAIDI). The conversion from rear lot to front service will also reduce the time required to restore power (SAIDI). For the years 2013 through 2016, defective equipment *outages accounted for the most customer-hours of interruption excluding loss of supply events; therefore, the investment will contribute to reducing defective equipment outages. EPL is specifically targeting to limit the number of primary cable failures cable failures to three or less (≤3) per year. A reliable supply of electricity supports customer satisfaction.*

*EPL relies on a combination of Reliability-Centred Maintenance (“**RCM**”), predictive maintenance, preventative maintenance, and cyclical inspections to manage its distribution assets. Plant that is scheduled for replacement is generally at the end of its service life due to failure risk or requires replacement due to reliability and/or safety concerns.*

<u>Condition of the Assets</u>

Underground cable terminations (at pad-mounted equipment and riser poles) are inspected every three (3) years. Figure 3 presents the cable length by installation year. EPL uses a TUL of thirty (30) years for direct-buried cables and forty (40) years for cables in conduits, which is consistent with common industry practices for primary TR XLPE cables. Since 1986, all primary cables were installed in conduits; therefore, the significant amount of cable installed in 1990 and from 1994 to 1997 will reach their TUL beginning in 2030.

Figure 3: Installation year of primary underground cables

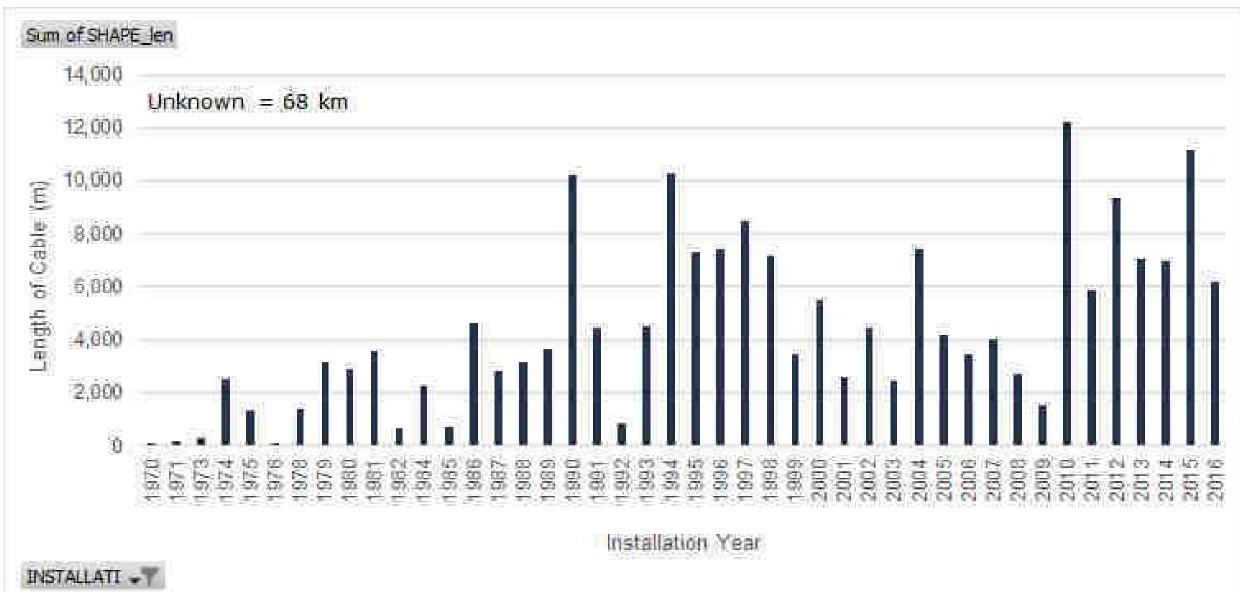
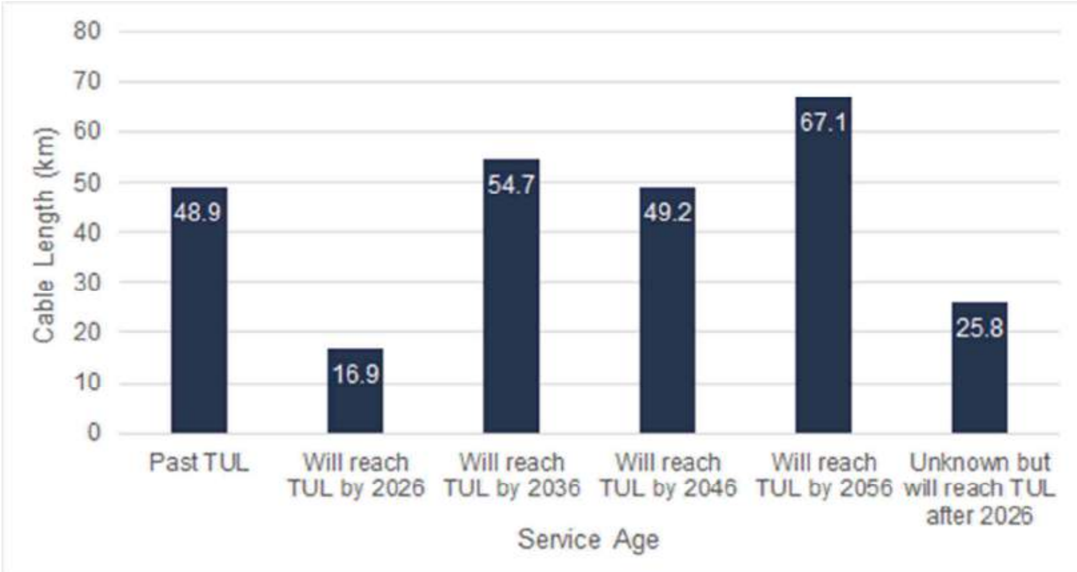


*Figure 4 depicts the age distribution of EPL’s underground cables relative to TUL. A total of 48.9 km of cables are past their typical useful life (“**TUL**”) and an additional 16.9 km will reach TUL by 2026. EPL will target the oldest direct-buried cables that have surpassed TUL.*

Figure 4: Age of cables relative to TUL



Overhead conductors and poles are inspected every three (3) years. Poles are also tested to assess their condition. 1 depicts the known age demographics for EPL's wood poles. The age demographics are unknown for the remaining 3197 wood poles. Figure 6 presents the results of the condition assessment for wood poles. EPL will target the worst condition poles.

Figure 5: System-wide age profile for wood poles

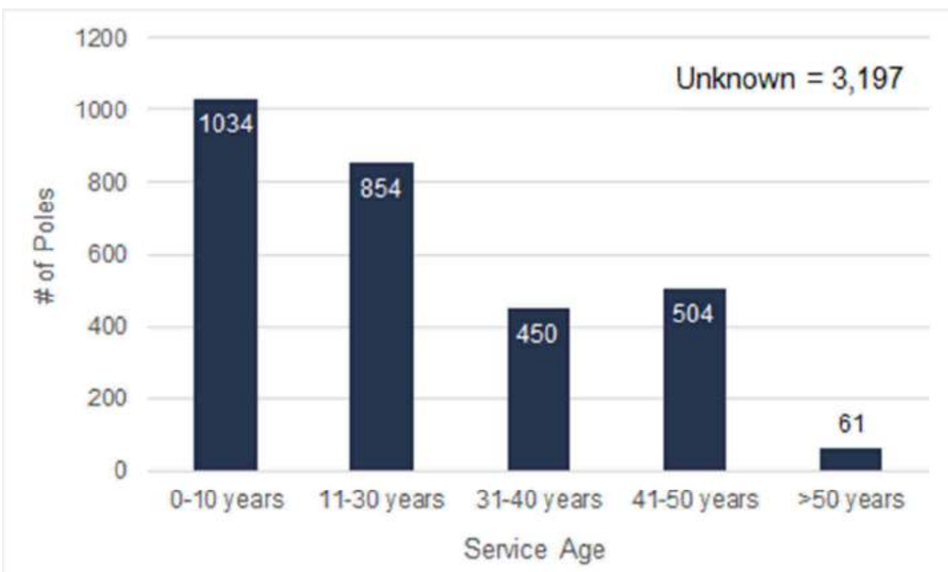
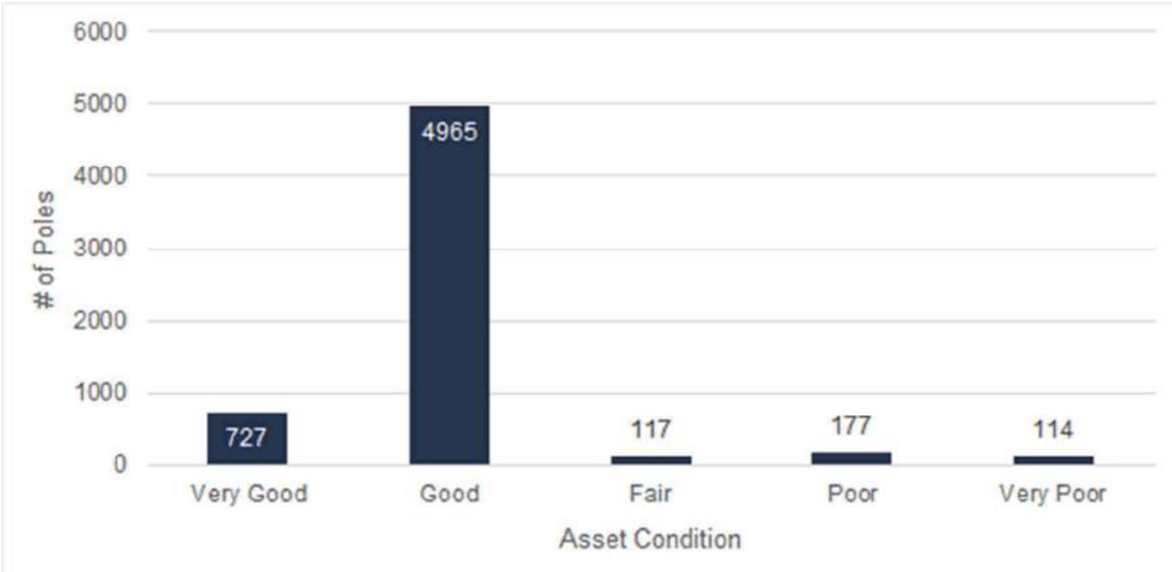


Figure 6: Condition assessment results for wood poles



Project Impacts

i. Number of Customers Affected: *Specific yearly values are not currently known; however, the number of customers is generally low.*

ii. Quantitative Customer Impacts: *Specific yearly values are not currently known; however, the length of outages can vary significantly from year to year.*

iii. Qualitative Customer Impacts: *Customers will receive value through faster response and restoration times.*

iv. Value of Customer Impact: *Customers will receive value through reduced unplanned outages, faster response times, less potential damage to customer property, and enhanced reliability.*

Project Timing Factors

The Infrastructure Rebuild Program timing is dependent on the urgency of the replacement as well as availability of resources. Safety or reliability-centered replacements are dealt with as quickly as possible, whereas scheduled replacements are accommodated when timing is optimal for EPL crews.

The timing of the investment is coordinated with other programs planned by EPL; therefore, the planned investment is less in 2019 compared to the other years due to the system service investments planned in that year. The timing of the investment is, therefore, also tied to external factors which may change the planned timing of system service investments and would also affect the timing of other investments planned by EPL.

Consequences for System O&M Cost

The Infrastructure Rebuild Program will help reduce customer outages and improve response times. There will be negligible impacts to system O&M costs.

Reliability / Safety Factors

Proper asset management of old and deteriorating equipment in the field mitigates safety concerns for EPL staff and customers. This program helps maintain system reliability.

Comparison of Project Timing Alternatives

There are limited alternatives to the Infrastructure Rebuild Program and the consequences of delaying replacements can result in significant reliability and safety concerns.

Analysis of Project Enhancements

A like-for-like replacement would restore rear lot service to customers, whereas the planned project installs duct-embedded or overhead front service. For a like-for-like replacement, customer requests to increase accessibility will not be met and accessing plant in backyards can also prove to be difficult, unsafe, and cost-ineffective since specialized equipment is oftentimes required in order to minimize customer inconvenience. This project will result in greater reliability for EPL's customers, lessen EPL's legal liability and exposure, and lead to enhanced safety for workers and the general population.

Switchgear Replacement Program

A. General Information on the Project/Activity

The purpose of this program is to replace live-front switchgear units that have failed or are at the end of their service life due failure risk. Through its thorough preventative maintenance program, EPL reviews the condition of all switchgear units continuously to limit failure and maximize safety via infrared and physical inspection. Budgeting is reviewed annually based on preventative maintenance program findings and availability of resources. EPL is planning to replace two (2) live-front switchgear per year.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$122.0	$63.6	$55.2	$135.2	$144.4	$147.3	$150.3	$153.3	$156.3	$79.7
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not applicable

Load
Not applicable

2018 Test Year Expenditure Timing

	Q1	**Q2**	**Q3**	**Q4**
Capital	$36,830	$36,830	$36,830	$36,830
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

Risks are minimal for these projects as they represent standard industry practices. There is incremental risk in procurement however EPL is in regular communication with vendors to ensure customer value.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information. To date, EPL has been fairly consistent in spending and relating to planned investment.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Assets at the end of their service life due to failure risk.*

ii. Secondary Drivers: *The secondary drivers to this program include asset failure, safety, and reliability. Allowing old and deteriorating equipment in the field can result in significant safety and reliability concerns to EPL staff and customers.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, Safety, and Financial & Environmental Sustainability.*

iv. Information Used to Justify the Investment: *EPL's preventative maintenance program and recent failures are the metrics that EPL uses to justify these projects.*

b) Priority: *EPL prioritizes replacements based on recent failures and its preventative maintenance program. All capital projects have been prioritized and optimized based on Financial, Service Quality, Community Image, Legal, Regulatory, Safety and Environmental metrics.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked ninth (9th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *The alternative to replacing live-front switchgear units is to do nothing. In the case of a switchgear failure, this alternative is not feasible. Allowing old and deteriorating equipment in the field can result in significant safety concerns, lengthy customer outages, and resulting increases to O&M. Therefore, planned replacements are the preferred alternative.*

i. Cost Effectiveness: *EPL uses inspection and age data to cost-effectively plan live-front replacements. In general, it is more cost effective to proactively replace a switchgear unit rather than reactively, which may require emergency or overtime hours.*

ii. Net Customer Benefits: *Customers will benefit from reduced outages.*

iii. Impact on Reliability: *This program will replace live-front switchgear at the end of their service life before they fail and cause extended outages; hence, improving the reliability.*

iv. Cost-Benefit Analysis: *The Switchgear Replacement Program replaces assets that are at end of service life due to failure or failure risk as identified during the inspection process. This will improve reliability by reducing unplanned outages and will also reduce outage costs. Also, this program avoids future O&M costs as replacements can be scheduled during regular hours rather than relying on trouble calls, which take longer and can be overtime hours.*

In the case of the "do nothing" option, project benefits of eliminating risks to public and employee safety, maintaining system reliability, and avoiding future O&M (trouble calls) costs will not be achieved.

2. Safety

Proper asset management of old and deteriorating equipment in the field mitigates safety concerns to EPL staff and customers. All new construction meets the latest distribution standards for safety.

3. Cyber-Security, Privacy

Switchgear units can be controlled remotely and access to the units over SCADA is restricted to operators in EPL's office with log-in credentials.

4. Co-ordination, Interoperability

Co-ordination with entities such as HONI is critical to ensure consistency with joint-use agreements, manage switching, ensure safety, and when co-ordinate planned outages.

5. Economic Development

This program proactively addresses system reliability, which supports economic development.

6. Environmental Benefits

There are no significant environmental benefits as a result of these investments.

C. Category-Specific Requirements

Asset Performance-Related Targets

To monitor asset performance, EPL tracks the number of switchgear failures each year. This investment will help EPL reduce the number of switchgear failures each year and will maintain EPL's reliability performance, specifically with respect to the number of outages (SAIFI) and the time required to restore power (SAIDI) through availability of switching. For the years 2013 through 2016, defective equipment outages accounted for the most customer-hours of interruption excluding loss of supply events; therefore, the investment will contribute to reducing defective equipment outages. EPL specifically tracks the annual number of switchgear failures, with the goals of limiting them to two or less (≤2) per year. A reliable supply of electricity supports customer satisfaction.

*EPL relies on a combination of Reliability-Centred Maintenance ("**RCM**"), predictive maintenance, preventative maintenance, and cyclical inspections to manage its distribution assets. Plant that is scheduled for replacement is generally at the end of its service life due to failure risk or requires replacement due to reliability and/or safety concerns.*

Condition of Assets

EPL inspects its switchgear units on a three (3)-year cycle, including visual and infrared. Switchgear units are regularly maintained through adjustments and cleaning. Figure 7 depicts the age demographics of EPL's switchgear units and Figure 8 summarizes the results of the condition assessment.

Figure 7: System-wide age profile for PMH switchgear units

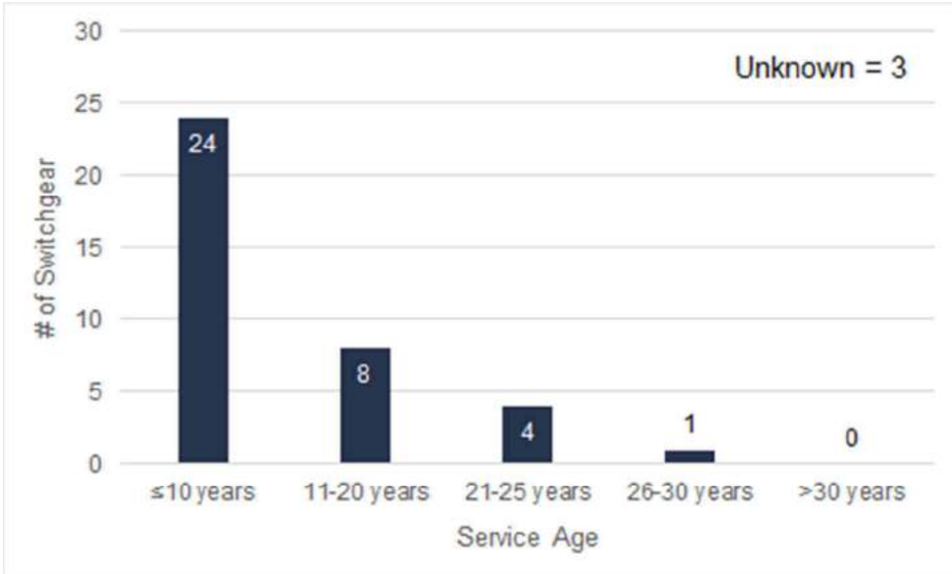


Figure 8: Condition assessment results for switchgear

<u>Project Impacts</u>

i. Number of Customers Affected: *Specific yearly values are not currently known; however, the number of customers can vary significantly from year to year.*

ii. Quantitative Customer Impacts: *Specific yearly values are not currently known; however, the length of outages can vary significantly from year to year.*

iii. Qualitative Customer Impacts: *Customers will receive value through reduced unplanned outages and enhanced reliability.*

iv. Value of Customer Impact: *Customers will receive value through reduced unplanned outages and enhanced reliability*.

Project Timing Factors

Switchgear replacement timing is dependent on the urgency of the replacement as well as availability of resources. Safety or reliability-centered replacements are dealt with as quickly as possible, whereas scheduled replacements are accommodated when timing is optimal for EPL crews.

Consequences for System O&M Cost

The PMH Replacement Program will help reduce system O&M costs over time through reductions in reactive maintenance spending.

Reliability / Safety Factors

Proper asset management of old and deteriorating equipment in the field mitigates safety and reliability concerns.

Comparison of Project Timing Alternatives

There are limited alternatives to the Switchgear Replacement Program and the consequences of delaying replacements can result in significant reliability and safety concerns.

Analysis of Project Enhancements

All new plant meets the latest distribution system standards. Remote access and control are both enabled on new switchgear units installed in the field.

HONI Asset Purchase - Leamington

A. General Information on the Project/Activity

The HONI Asset Purchase – Leamington project is an initiative to transfer assets between EPL and HONI so that each distributor controls assets within in geographical distribution service territory boundary. The estimated spend in 2018 is $278,307 and revenue from sale of assets to Hydro One is $188,833 for a net capital spend of $89,474. This constitutes:

1. *Purchase 5.9 km of poles, conductors, and insulators in locations where Hydro One does not have another feeder (i.e. 3M6 and 3M4) within EPL's service territory.*
2. *Sell 1.1 km of conductors and insulators (3M9 circuit).*
3. *Sell poles along the east side of an arterial road, on which EPL has no assets.*

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Capital	$0	$0	$0	$0	$0	$89.5	$283.9	$0	$0	$0
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
No incremental customer attachments

Load
No incremental load

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$22,369	$22,369	$22,369	$22,369
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

The primary risk with this project is the ongoing negotiation with HONI. There are transactions that go both ways and the fair market value of all assets considered will need to be agreed on by both parties.

Comparative Expenditure Information

This is a new project in 2018 and historical spending analysis is, therefore, not available.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *System operational objectives – operability.*

ii. Secondary Drivers: *System operational objectives – reliability.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, and Operational Excellence.*

iv. Information Used to Justify the Investment: *EPL used subject matter experts, good utility practice, and regulation as metrics to justify the investment.*

b) Priority: *EPL prioritizes asset transfers based on resource availability and in accordance with good utility practice and engineering. This is a mid/low priority project.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this project was ranked fifteenth (15^{th}) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *The alternative to this initiative would be to continue working closely with Hydro One to coordinate operation of the system for both preventative and reactive situations. Loss of Supply events has continued to become a larger portion of EPL's total customer outages.*

i. Cost Effectiveness: *Not applicable.*

ii. Net Customer Benefits: *EPLC customers will see an improvement to outage length and severity as Loss of Supply events are reduced through the implementation of this project. Ongoing implementation of this project will also see minor reduced OM&A costs over time as overtime and overall crew hours are reduced.*

iii. Impact on Reliability: *This project will lead to improved reliability as EPL strives to limit its exposure to Loss of Supply events. By gaining control of the assets serving its customers, EPL will have the ability to move loads between the feeders to quickly restore power to the customers.*

iv. Cost-Benefit Analysis: *Not applicable. Assets are selected based on location and proximity to EPL's service territory.*

2. Safety

EPL employees will see safety-related improvements as EPL staff will control the assets that serve its customers.

3. Cyber-Security, Privacy

This project does not raise any cyber-security or privacy concerns.

4. Co-ordination, Interoperability

EPL will continue discussing and negotiating the transaction with Hydro One. Following a successful transaction, EPL will have improved control of its own system. There are limited concerns with regards to interoperability.

5. Economic Development

One of the drivers of this project is reliability and a reliable supply of electricity is conducive to economic development.

6. Environmental Benefits

There are no significant environmental benefits achieved based on this project.

C. Category-Specific Requirements

Assessment of Benefits for Customers

EPL's customers will see an improvement to outage length and severity as Loss of Supply events are reduced through the implementation of this project.

Regional Electricity Infrastructure Requirements

This project did not result from a Regional Planning Process.

Incorporation of Advanced Technology

Since the investment entails a transfer of in-service assets, there will not be advanced technology incorporated.

Reliability, Safety, Efficiency and Coordination Benefits

EPL's employees will see safety-related improvements as EPL staff control the assets that serve its respective customers. This project will lead to improved reliability as EPL strives to limit its exposure to Loss of Supply events.

Timing/Priority Factors

Formal timelines are not yet established however it is believed that the transactions will take place over the course of 2018 and 2019.

Cost-Benefit Analysis

Not applicable.

FIT & Generation Connections

A. General Information on the Project/Activity

This project is to accommodate the connection of renewable energy generation to EPL's distribution system. This program includes FIT connections (10 kW up to 500 kW) and generation connections (greater than 500 kW), but does not include microFIT connections (less than 10 kW).

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$68.2	$13.6	$55.5	$63.1	$175.0	$167.2	$112.2	$114.4	$116.7	$119.0
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not applicable

Load
Not applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$41,801	$41,801	$41,801	$41,801
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

The primary risk with this project is whether or not the various generation projects planned by third parties proceed.

Comparative Expenditure Information

Historical spending is listed above. EPL is planning for two larger FIT connections in 2017/2018 which explain the increases in those respective years.

REG Investment Criteria

REG investments are planned and made in accordance with EPL's Green Energy Act Plan. The anticipated connections and expansion costs in 2018 are listed below.

Type	Nameplate Capacity (kW)	Renewable Expansion Cost
Solar Rooftop	200	$25,000
Solar Rooftop	200	$0
Solar Rooftop	200	$25,000
Solar Rooftop	500	$30,000
Solar Rooftop 5X250	1250	$30,000

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Customer-driven generation connection requests.*

ii. Secondary Drivers: *Not applicable.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, and Financial & Environmental Sustainability.*

iv. Information Used to Justify the Investment: *FIT & generation connections are driven by customer/developer request and are to be connected within OEB mandated timelines.*

b) Priority: *FIT & Generation connections are made based on customer/developer request. This process is managed by EPL staff through various systems to ensure proper visibility and timeliness. New FIT & Generation Connections are a high priority for EPL as they are linked directly with the customers that we serve.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked seventh (7^{th}) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *These investments are mandated by the OEB. Expansion options are evaluated to determine the least-cost solution while ensuring that a connection does not materially and/or negatively impact existing customers. Options which may exist to improve the system are also evaluated, where applicable.*

i. Cost Effectiveness: *EPL evaluates renewable expansion options to determine the least-cost option.*

ii. Net Customer Benefits: *Customers benefit from the ability to connect renewable energy generators to the grid to provide power.*

iii. Impact on Reliability: *Expansion options are evaluated to ensure that the connection does not materially and/or negatively impact existing customers.*

iv. Cost-Benefit Analysis: *EPL evaluates renewable expansion options to determine the least-cost option.*

2. Safety

These investments do not impact safety or raise safety-related awareness. EPL is, however, continuing to update its protocols and procedures as its distribution system evolves into a smarter grid.

3. Cyber-Security, Privacy

This program does not raise any cyber-security or privacy concerns.

4. Co-ordination, Interoperability

EPL coordinates directly with customers, contractors, developers, and other agencies such as ESA. EPL also coordinates with HONI on a regular basis to discuss connection constraint on specific feeders and possible solutions.

5. Economic Development

The connection of REG supports economic development in Ontario through the installation and commissioning work required at the facilities.

6. Environmental Benefits

REG is a provincially-mandated program intended to offset emissions from natural gas burning energy sources in Ontario.

C. Category-Specific Requirements

Assessment of Benefits for Customers

These investments are mandated by the OEB. Developers, who may also be customers, benefit from the connection facilitating the ability to sell power to the grid. EPL's customers benefit from distribution-connected REG facilities relieving capacity on its feeders. EPL's customers and, in general, Ontario residents benefit from energy generated from emission-free renewable sources.

Regional Electricity Infrastructure Requirements

This program is not a result of a Regional Planning Process. Information related to this planned investment was provided to the IESO.

Incorporation of Advanced Technology

Not applicable.

Reliability, Safety, Efficiency, and Coordination Benefits

These investments are mandated by the OEB and are intended to support a provincial objective to reduce greenhouse gases and ensure a sustainable energy future.

Timing/Priority Factors

The timing of projects within these programs depend on initiation by REG developers. EPL has forecast the number of anticipated connections in its GEA Plan based on the interconnection status of each applications being processed and projected applications to be received. Formal timelines for each connection are prescribed by the OEB.

Cost-Benefit Analysis

Expansion options are evaluated to determine the least-cost solution while ensuring that a connection does not materially and/or negatively impact existing customers. Options which may exist to improve the system are also evaluated, where applicable. Alternatives include not connecting the generator (which is non-compliant from a regulatory perspective), or other less cost-effective measures.

Self-Healing Grid - Reclosers

A. General Information on the Project/Activity

In 2014, EPL completed its first iteration of its Green Energy Act Plan and subsequently a Smart Grid Development Plan. In this plan, EPL outlined its plan to shift to a smarter grid that is capable of reducing the impact of Loss of Supply incidents to customers by investing in three primary categories. Reclosers represent one of these three categories. The reclosers will be installed as tie switches in multiple locations to facilitate automatic switching and service restoration in case of a Loss of Supply event.

Historically, EPL's service territory consisted solely of manual load break switches which required manual operation and provided no fault protection. Fault protection was provided by a station breaker or an upstream recloser outside of EPL service territory. With the implementation of smart reclosers, EPL is facilitating the capabilities of remote operation, real-time outage detection as well as the ability to isolate itself from an upstream distributor/transmitter. Further, incremental data about EPL's distribution system is gathered and fed into the SmartMAP toolset.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$0	$0	$0	$0	$264.8	$270.1	$275.5	$281.1	$286.7	$292.4
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
No incremental customer attachments

Load
No incremental load

2018 Test Year Expenditure Timing

	Q1	**Q2**	**Q3**	**Q4**
Capital	$67,535	$67,535	$67,535	$67,535
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

As EPL works towards implementing a variety of smart grid related initiatives, it is continuously updating its operating procedures and protocols to ensure staff safety. The automation of switches and reclosers throughout its distribution system introduces new and complex issues to be resolved by EPL and the industry in general.

Since this program is beginning in 2017, there are risks to its cost and execution, which are not well-known. To mitigate these risks, EPL works closely with third-party vendors and subject matter experts to ensure project within this program are completed on time and on budget.

Comparative Expenditure Information

This is a new project in 2017 and historical spending analysis is, therefore, not available.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *System operational objectives – reliability*

ii. Secondary Drivers: *Safety and cost effectiveness.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value and Operational Excellence.*

iv. Information Used to Justify the Investment: *EPL used subject matter experts, third-party vendors, good utility practice and regulation as metrics to justify the investment.*

b) Priority: *Reclosers are installed to isolate EPL from upstream Loss of Supply events and improve system reliability, which is a priority for EPL. These projects are medium/high in terms of priority and they fall behind only mandated regulated capital activities. Individual installations would occur as timing allows, prioritized based on resource availability and in accordance with the proper safety protocols.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked eleventh (11th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *The alternative to this initiative would be to continue working closely with Hydro One to coordinate outages to limit and minimize response times, outage frequency, outage severity and outage length. Loss of Supply events has continued to become a larger portion of EPL total customer outages.*

EPL's current distribution system contains manual load break switches which do not provide any fault protection; therefore, fault protection is provided by a station breaker or upstream recloser. Reclosers are able to automatically trip open on fault, isolating the faulted section and keeping customers upstream from the recloser unaffected. On momentary faults (lightning, animals, etc.), the recloser will trip on a fault and automatically reclose after a few seconds minimizing outage time and eliminating truck rolls.

The reclosers are also able to provide system information to SmartMAP. A recloser action can trigger outage determination in SmartMAP to quickly identify an outage. Momentary outages caused by the reclosers can also be tracked in SmartMAP, contributing to the accuracy of CELDI and CEMI outage statistics. The data will also increase knowledge about power flow within the system, aiding in *operations and engineering decisions because voltage and current data will be stored and historical trends can be evaluated. In the event of an outage, SmartMAP has the ability to look at historical data supplied by all of its data sources and determine whether or not it is possible to do a short-term load transfer to restore power. This will greatly aid in moving towards a self-healing grid, because having switches which can be triggered remotely and knowledge about whether or not the switches can be operated safely is crucial to making the decision to operate the switch to restore power.*

i. Cost Effectiveness: *Ongoing implementation of this project will reduce O&M costs as overtime and overall crew hours are reduced. Auto-reclosing after a temporary fault will restore power without sending a crew.*

ii. Net Customer Benefits: *EPL customers will see a significant improvement to outage length and severity as Loss of Supply events are reduced through the implementation of this project. The improved cost effectiveness will improve customer value by reducing O&M costs and allowing EPL to deliver a modern smart grid at inflation-aligned prices.*

iii. Impact on Reliability: *This project will have a significant impact on reliability as EPL strives to limit its exposure to Loss of Supply events. The project is expected to improve SAIDI and SAIFI performance.*

iv. Cost-Benefit Analysis: *No detailed analysis of benefits and costs was performed.*

<u>2. Safety</u>

As EPL works towards implementing a variety of smart grid related initiatives, it is continuously updating its operating procedures and protocols to ensure staff safety. The automation of switches and reclosers throughout its distribution system introduces new and complex issues to be resolved by EPL and the industry in general. The timing curves of the reclosers will reduce the exposure to fault energy in the event of a contact. Reclosers will be installed as per up to date installation standards, and on poles that meet current standards ensuring that the highest levels of worker and public safety are met. The reclosers include safety features such as hold-off tags that prevent remote/automatic operation when manual work is being performed. Where installations require the placement of new poles or hardware, the new assets will also be up to current safety standards.

<u>3. Cyber-Security, Privacy</u>

EPL will ensure that all equipment and software deployed using best industry related practice. The improvements will be made in conjunction with major cyber-security upgrades underway in 2017.

<u>4. Co-ordination, Interoperability</u>

Discussions with Hydro One are ongoing as smart grid initiatives are implemented that affect equipment from both distributors. The automation of these devices will require constant communication with Hydro One and it is expected that improved reliability will result. Several meetings have already taken place and, as additional switches are integrated and commissioned, several more will be required. There is substantial work on HONI's end to update their systems, processes, and protocols to accommodate the request.

<u>5. Economic Development</u>

The main driver of this project is reliability and a reliable supply of electricity is conducive to economic development.

6. Environmental Benefits

The recloser installations – as part of a self-healing grid – will reduce the number of truck-rolls required to respond to trouble calls; firstly, by automatically isolating the fault and restoring service and, secondly, by auto-reclosing to clear temporary faults. The net environmental benefit is less emissions.

C. Category-Specific Requirements

Assessment of Benefits for Customers

EPL's customers will see a significant improvement to outage length and severity as Loss of Supply events are reduced through the implementation of this project. Ongoing implementation of this project will reduce O&M costs time as overtime and overall crew hours are reduced.

Regional Electricity Infrastructure Requirements

This program was not a result of a Regional Planning Process.

Incorporation of Advanced Technology

Historically, EPL's service territory consisted solely of manual load break switches which required manual operation and provided no fault protection. Fault protection was provided by a station breaker or an upstream recloser outside of EPL service territory. With the implementation of smart reclosers, EPL is facilitating the capabilities of remote operation, real-time outage detection as well as the ability to isolate itself from an upstream distributor/transmitter.

Reliability, Safety, Efficiency and Coordination Benefits

This project will have a significant impact on reliability as EPL strives to limit its exposure to Loss of Supply events.

Timing/Priority Factors

Reclosers are planned to be installed throughout 2017-2022 in each of the four distinct service territories.

Detailed Analysis by Feeder

Single line diagrams depicting the proposed locations of the reclosers are attached to accompany the analysis provided below for each feeder.

Tecumseh

56M26: This feeder is located in the Tecumseh service area and has an interconnected distribution network with normally-open interconnection points. The 56M26 has had a consistently-high SAIDI. EPL owns all of the distribution lines on this feeder within the territory allowing the addition of distribution automation equipment to be placed where it is most effective without ownership restrictions. The approximate locations of three (3) recommended reclosers, five (5) normally-open smart switches, and five (5) line monitors have been marked on the single line of Tecumseh (attached).

56M4: This feeder is located in the Tecumseh service area and has an interconnected distribution network with normally-open interconnection points. The 56M4 feeder has low SAIDI and the recommended switching adding a recloser, a normally-open smart switch, and one (1) line monitor.

56M25: This feeder is located in the Tecumseh service area and has an interconnected distribution network with normally-open interconnection points. The 56M25 feeder has had an average SAIDI. EPL owns all of the distribution lines on this feeder within the territory allowing the addition of distribution automation equipment to be placed where it is most effective without ownership restrictions. The approximate locations of four (4) recommended reclosers, three (3) normally-open smart switches, and two (2) line monitors have been marked on the single line of Tecumseh (attached).

Leamington

3M6: This feeder is located in the Leamington service area with a radial distribution network and normally-open interconnection points. The 3M6 feeder has had the highest SAIDI with most customer outage hours and a drastic increase over the last two (2) years. HONI owns most of the main feeder running through the service area with EPL owning the lines branching off. This makes it more difficult to add automated switching/reclosers to sectionalize areas. If possible, it would be most beneficial if EPL could install equipment on HONI-owned lines in EPL's service territory, but this would first have to be arranged with HONI. With this challenge, there are not a lot of recommended additions on this feeder even though it has had a high SAIDI index. The approximate location of three (3) recommended reclosers, two (2) normally-open smart switches, and four (4) line monitors have been marked on the single line of Leamington (attached).

3M4: This feeder is located in the Leamington service area with a radial distribution network and normally-open interconnection points. The 3M4 feeder has a low SAIDI and the only switching added would be five (5) normally-open smart switches proposed in the other feeders, and two (2) line monitors.

3M8: This feeder is located in the Leamington service area with a radial distribution network and normally-open interconnection points. The 3M8 feeder has a SAIDI that is a little high but the highest year, 2010, was due in large part to a tornado. The approximate locations of two (2) recommended reclosers, three (3) normally open smart switches, and two (2) line monitors have been marked on the single line of Leamington (attached).

LaSalle and Amherstburg

23M3: This feeder is located in the Amherstburg service area with a radial distribution network and normally-open interconnection points. The 23M3 feeder has had a SAIDI higher than desired. EPL owns all of the distribution lines on this feeder within the territory making the addition of distribution automation equipment to be placed where it is most effective without restrictions. The recommended additions of two (2) reclosers, four (4) normally open smart switches, and four (4) line monitors are located on the single line of LaSalle and Amherstburg (attached).

23M4: This feeder is located in the LaSalle service area with a radial distribution network and normally-open interconnection points. The 23M4 feeder has a low SAIDI index, but EPL would like to allow for sectionalizing faulted sections by adding switching to the start of the service territory and after the area with the most outages. One (1) recloser, three (3) normally-open smart switches, and two (2) line monitors will be placed as shown in the single line for LaSalle and Amherstburg (attached).

23M5: This feeder is located in the LaSalle and Amherstburg service areas with a radial distribution network and normally-open interconnection points. The 23M5 feeder has a low SAIDI, so two (2) reclosers will be installed, three (3) normally-open smart switches, and three (3) line monitors will be added as indicated in the single line for LaSalle and Amherstburg (attached).

24M7: This feeder is located in the LaSalle and Amherstburg service areas with a radial distribution network and normally open interconnection points. The 24M7 feeder has had a decreasing SAIDI over the last few years and most of the outage time came from the Amherstburg service area. HONI owns most of the main feeder running through the Amherstburg with EPL owning the lines branching off. Two (2) reclosers, two (2) normally-open smart switches, and four (4) line monitors are located on the single line for LaSalle and Amherstburg (attached).

24M9: This feeder is located in the LaSalle service area with a radial distribution network and normally-open interconnection points. The 24M9 feeder has had an increasing SAIDI over the past few years. HONI owns a portion of the main feeder running through the service area with EPL owning the lines branching off. This makes it more difficult to add automated switching/reclosers to sectionalize areas. The addition of one (1) recloser, one (1) normally-open smart switch, and two (2) line monitors are located on the single line for LaSalle and Amherstburg (attached).

24M10: This feeder is located in the LaSalle service area with a radial distribution network and normally-open interconnection points. The 24M10 feeder has a low SAIDI and the only recommended switching is one (1) recloser.

Figure 9: Single line diagram of Tecumseh depicting proposed recloser locations

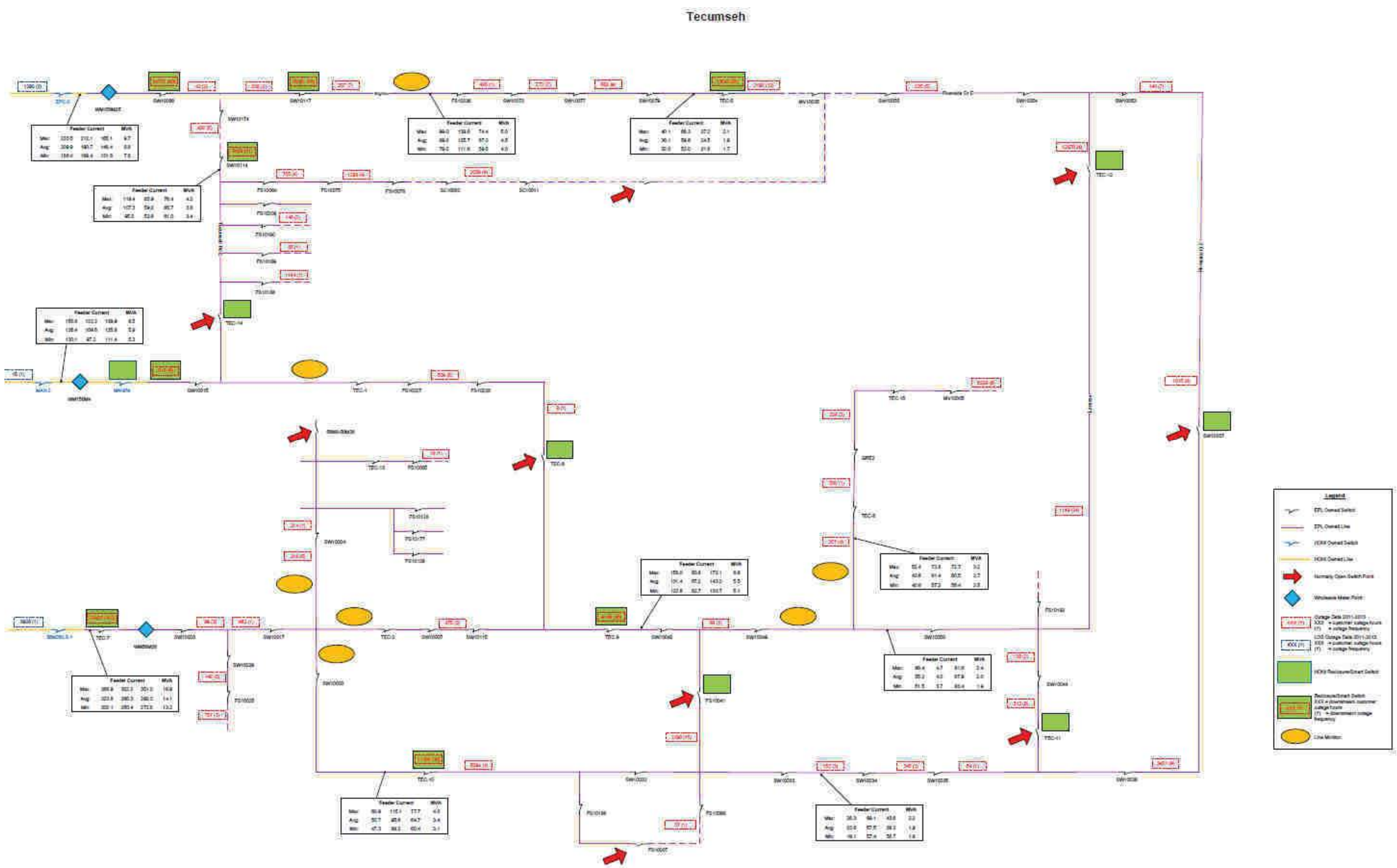
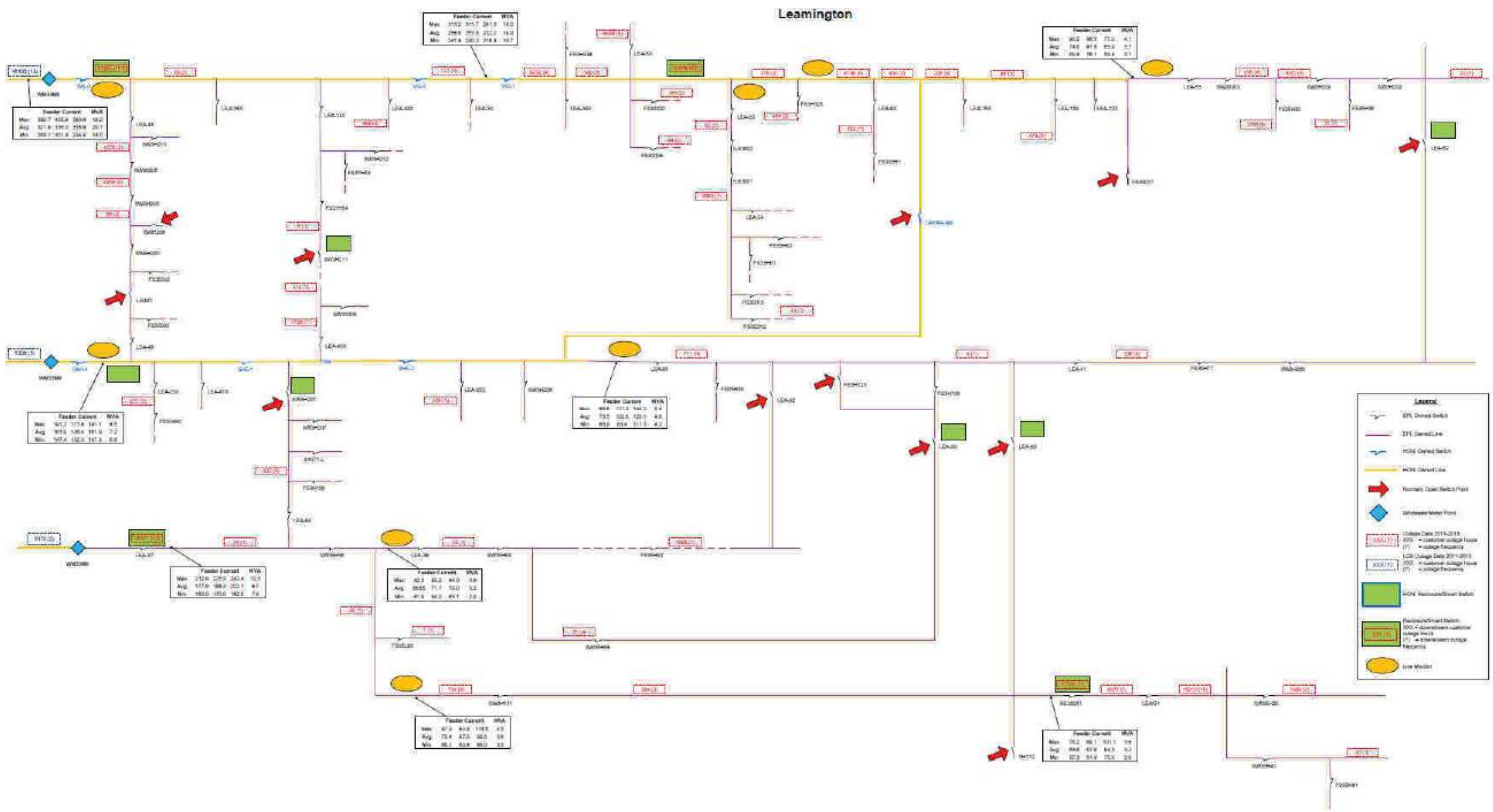
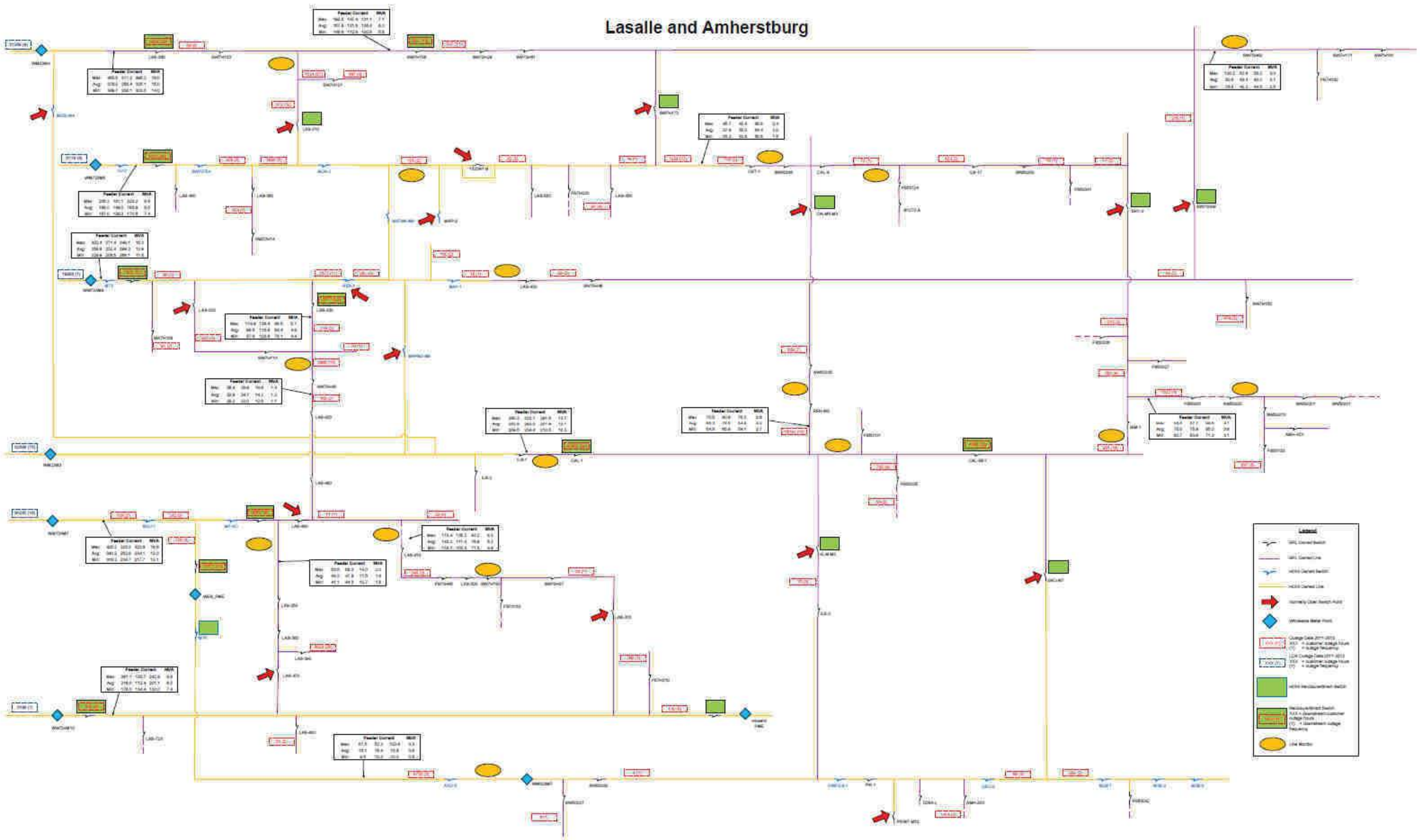


Figure 10: Single line diagram of Leamington depicting proposed recloser locations



1 **Figure 11: Single line diagram of LaSalle and Amherstburg depicting proposed recloser locations**



2

Building & Fixtures

A. General Information on the Project/Activity

The Building Condition Review, completed in 2016 and attached as Appendix H of the DSP, outlined and recommended several major projects to be completed over the next several years. EPL has spread the investment over multiple years to reduce the rate impact.

The planned work in 2018 includes the construction of a new storage facility for fleet and some supplies. The existing facility is not designed for the number of vehicles currently accommodated and backing vehicles in and out is problematic and an identified safety issue. A smaller, non-heated garage is proposed to store some larger vehicles, while the existing garage will continue to be used for the remainder of the vehicles.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$22.0	$0.0	$48.9	$42.5	$286.8	$370.0	$350.0	$350.0	$250.0	$250.0
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not applicable

Load
Not applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$92,500	$92,500	$92,500	$92,500
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

There is limited risk/exposure for this project.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information. Historical spending relates to minor improvements to the existing improvements. Planned work in 2018 and 2019 includes re-paving the parking lot; phased over two (2) years. Planned work in 2021 includes replacement of end-of-life HVAC units.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Non-system physical plant.*

ii. Secondary Drivers: *Not applicable.*

iii. Related Objectives: *This project supports EPL's Core Values of Operational Excellence and Employee Satisfaction.*

iv. Information Used to Justify the Investment: *EPL used subject matter experts, third-party vendors, good utility practice, and regulation as metrics to justify the investment.*

b) Priority: *This project represents a lower priority project however EPL requires additional garage space in the near future or risks the integrity of its existing fleet and inventory. This project is lower priority than distribution system projects (system access, system renewal, and system service) planned in the 2018 Test Year.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked nineteenth (19th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *Failure to properly house and maintain EPL's fleet and miscellaneous equipment/inventory will result in increased maintenance costs and OM&A, as well as faster asset degradation. An alternative would include housing EPL fleet and inventory at a third-party offsite garage; however, this alternative introduces a variety of other risks and liabilities.*

i. Cost Effectiveness: *Not applicable.*

ii. Net Customer Benefits: *This project supplies space to house and maintain EPL's fleet of vehicles. Properly-stored vehicles are protected from the elements and last longer; therefore, customers benefit from the rate impact.*

iii. Impact on Reliability: *Better maintained fleet and equipment can result in longer asset lives as well as enhanced performance resulting in improved reliability.*

2. Safety

Backing vehicles in and out of existing garage is currently creating safety concerns as a result of site limitations. The proposed new garage will eliminate this safety concern.

3. Cyber-Security, Privacy

Not applicable.

4. Co-ordination, Interoperability

Not applicable.

5. Economic Development

Not applicable.

6. Environmental Benefits

Not applicable.

C. Category-specific Requirements

Results of Quantitative and Qualitative Analyses

The existing garage is too small to properly house fleet and perform required maintenance. There is very limited risk associated with not doing this project. See Appendix H of the DSP – Building Condition Review – for detailed analysis.

Business Case Justification

See Appendix H of the DSP – Building Condition Review – for detailed analysis.

Computer Software

A. General Information on the Project/Activity

*EPL strives to continuously improve its interactions with customers and overall customer service. Throughout 2018, EPL plans to upgrade its website, Work Management Systems, service order processes, upgrade its Geo-Spatial Information System (“**GIS**”), and implement utility dashboards for greater management visibility throughout its core business.*

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ ‘000)					Future Costs ($ ‘000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$53.0	$167.0	$17.0	$4.6	$254.5	$115.0	$80.0	$80.0	$80.0	$80.0
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not applicable

Load
Not applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$28,750	$28,750	$28,750	$28,750
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

EPL’s primary computer software risk revolves around service interruption. EPL plans to mitigate potential service related outages by implementing contingency plans and parallel systems, where possible, as well as cost-effective solutions.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information. Note that actual costs can vary dramatically from year to year based on the expected number of system upgrades or new systems purchased. Historical spending was allocated to SmartMAP, GIS upgrades, and the Work Management System.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Business operations efficiency.*

ii. Secondary Drivers: *Not applicable.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, and Financial & Environmental Sustainability.*

iv. Information Used to Justify the Investment: *EPL utilized subject matter experts, third-party vendors, good utility practice, and regulation as metrics to justify the investment.*

b) Priority: *Having up-to-date software and technologies promotes efficiency and reliability of information across EPL's various departments. Failure to make these investments over time will result in EPL failure to meet its various regulatory and customer satisfaction levels. This is a medium-priority project, as it is partly customer-driven.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked fourteenth (14th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *Failure to maintain, upgrade and embrace new technologies can ultimately lead to potential system failures, productivity decreases, poor customer service and lost data. EPL evaluates alternative products and vendors on a regular basis to ensure the best and most cost-effective solution is selected based on prescribed needs.*

i. Cost Effectiveness: *Enhanced work management, service order, and GIS will improve workflow and enhance decision-making by increasing available information and thereby helping EPL optimize available resources.*

ii. Net Customer Benefits: *Upgrades to the GIS will provide more accurate information being available to EPL staff, which can help with decision-making and can lead to reduced outage times as well as faster response times. Customer service will be improved.*

iii. Impact on Reliability: *The accuracy of field data recorded in SmartMAP and the GIS directly affects the ability of field crews to safely and quickly perform work on the distribution system. Upgrades to the Work Management Systems will improve tracking Service Quality Indicators, thus improving the quality of data reported. Improved data quality will allow EPL to design projects that address specific types of outages identified.*

2. Safety

Safety is not a major driver for this project.

3. Cyber-Security, Privacy

EPL will ensure that all equipment and software deployed using best industry related practice. This project will be completed in conjunction with ongoing cyber-security upgrades underway in 2017.

4. Co-ordination, Interoperability

There is no material impact to the program as it results to coordination/interoperability.

5. Economic Development

Not applicable.

6. Environmental Benefits

Not applicable.

C. Category-Specific Requirements

Results of Quantitative and Qualitative Analyses

EPL's goal is to maintain the most up to date or most cost-effective software necessary to meet its obligations to customers and relevant regulation and ensure maximized employee efficiency.

Business Case Justification

Alternative options to the planned project include "do nothing", which will cause many of systems to become unsupported by the vendor/supplier and, thus, posing intolerable risk to customer service, and purchasing difference software, which is cost prohibitive.

Transportation Equipment

A. General Information on the Project/Activity

EPL plans to replace three (3) on-call trucks and a wood chipper. Two (2) trucks (i.e. Ford F350 or equivalent) are budgeted at $95,000 each and a third truck at $50,000 (i.e. Ford F150 or equivalent). The wood chipper replacement is budgeted at $30,000. Existing trucks are nearing end-of-life and require substantial maintenance in accordance with EPL's Fleet Purchasing Policy. Details are provided in EPL's Fleet Purchasing Policy, attached as Appendix I of the DSP.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$307.5	$248.4	$401.2	$136.7	$487.0	$270.0	$275.0	$395.0	$445.0	$560.0
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not applicable

Load
Not applicable

2018 Test Year Expenditure Timing

	Q1	**Q2**	**Q3**	**Q4**
Capital	$67,500	$67,500	$67,500	$67,500
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

There is limited risk/exposure for this project.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information. Note that actual costs can vary dramatically from year to year based on fleet investment requirements.

*Investments in 2013 included replacement of a radial boom derrick ("**RBD**") (unit 710 in the Fleet Purchasing Policy replaced with unit 110), the purchase of a landscape trailer, and the purchase of unit 73 (metering van for sub-foreperson).*

Investments in 2014 included replacement of a medium-duty dump truck (unit 711 with unit 112), replacement of a bucket unit with a material handler (unit 75 with unit 111), replacement of a forklift with a larger forklift, and replacement of a front-loader with a case tractor equipped with a bucket and scraper.

Expenditures were made in 2015 to replace an RBD (unit 358 with unit 113).

Investments in 2016 included replacement of unit 62 with unit 76 (Supervisor unit) and replacement of units 63 and 64 with units 74 and 75 (metering vans).

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Non-system equipment at the end of its service due to failure, failure risk, or substandard performance.*

ii. Secondary Drivers: *Not applicable.*

iii. Related Objectives: *This project supports EPL's Core Values of Operational Excellence, Safety, and Employee Satisfaction.*

iv. Information Used to Justify the Investment: *The investment is justified based on EPL's Fleet Management Policy, which considers the age and mileage for all gas-power vehicles (less than 4500 kg).*

b) Priority: *Delay of this project will result in increased OM&A costs and could moderately affect operational effectiveness. This project is a low-mid range priority relative to other material projets/programs planned in the 2018 Test Year.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked seventeenth (17th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *Project alternatives include continuous maintenance; however, this option will drive OM&A costs up over time as well as put EPL staff and customers at risk of mechanical breakdown due to aging equipment which could have impacts on reliability, employee safety, and overall customer satisfaction.*

i. Cost Effectiveness: *This investment will ensure that EPL staff are able to effectively perform their duties in the field and perform routine and reactive maintenance and system-related expansions.*

ii. Net Customer Benefits: *Customers will receive enhanced operational effectiveness as EPL staff will have access to better equipment.*

iii. Impact on Reliability: *The availability of vehicles to ensure the necessary reactive and proactive work is completed supports reliability on the system.*

2. Safety

Newer vehicles include enhanced safety features (i.e. backup camera) as well as less risk associated with older vehicles that have general wear and tear incurred over time and substantial usage.

3. Cyber-Security, Privacy

Not applicable.

4. Co-ordination, Interoperability

Not applicable.

5. Economic Development

The purchasing of vehicles supports economic development in other sectors of the economy.

6. Environmental Benefits

This program replaces older vehicles, which have substandard performance with respect to efficiency and emissions, with new vehicles, which meet the latest emissions and energy efficiency standards.

C. Category-Specific Requirements

Results of Quantitative and Qualitative Analyses

The three (3) trucks to be replaced are all 2006 pickups.

Business Case Justification

Investments in this program are made relative to EPL's Fleet Purchasing Policy, which is attached as Appendix I to the DSP.

Tools & Equipment

A. General Information on the Project/Activity

The purpose of this yearly project is to replace major tools and equipment that has reached end-of-life due to substandard performance and functional obsolescence. Equipment purchased includes, but is not limited to, equipment for troubleshooting, rubber goods, radio equipment, etc. Equipment is purchased on an as-needed basis depending on the type of work required.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Capital	$43.4	$45.5	$55.5	$45.8	$60.0	$60.0	$60.0	$60.0	$60.0	$60.0
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not applicable

Load
Not applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$15,000	$15,000	$15,000	$15,000
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

Tools and equipment purchases are prioritized based on an as-needed basis as determined by the Manager of Operations with input from the Line Supervisor and other EPL staff.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information. Historical spending for this project is fairly consistent over time and no major changes are planned in the near future.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Non-system equipment at the end of its service life due to substandard performance or functional obsolescence.*

ii. Secondary Drivers: *Not applicable.*

iii. Related Objectives: *This project supports EPL's Core Values of Operational Excellence and Safety*.

iv. Information Used to Justify the Investment: *EPC used subject matter experts, third-party vendors, good utility practice, and regulation as metrics to justify the investment.*

b) Priority: *Purchases for Tools and Equipment are completed on an as needed basis. Continual investment is required to ensure compliance and that EPL staff is adequately equipped to maintain its distribution system. Tools and equipment are required to perform routine maintenance on the distribution system.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked eighteenth (18th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *EPL management evaluates, on a case-by-case basis, three (3) primary alternative scenarios when it pertains to Tools and Equipment: Do Not Replace, Like for Like Replacement, or Upgrade. EPL management evaluates each of these scenarios for each Tools and Equipment investment based on information from subject matter experts, third-party vendors, good utility practice, and regulation.*

i. Cost Effectiveness: *Access to the appropriate Tools and Equipment allows EPL staff to maximize workmanship and task completion resulting in shorter task completion timelines.*

ii. Net Customer Benefits: *Access to the appropriate Tools and Equipment allows EPL staff to maximize workmanship and task completion in a timely manner*.

iii. Impact on Reliability: *Access to the appropriate Tools and Equipment allows EPL staff to maximize workmanship and task completion in a timely manner which can have minor impacts on reliability.*

2. Safety

Failure to provide safe, up-to-date, and reliable Tools and Equipment can have substantial safety-related impacts for EPL staff.

3. Cyber-Security, Privacy

Not applicable.

4. Co-ordination, Interoperability

Not applicable.

5. Economic Development

Not applicable.

6. Environmental Benefits

Not applicable.

C. Category-Specific Requirements

Results of Quantitative and Qualitative Analyses

EPL management evaluates, on a case-by-case basis, three (3) primary alternative scenarios when it pertains to Tools and Equipment: Do Not Replace, Like for Like Replacement, or Upgrade. EPL management evaluates each of these scenarios for each Tools and Equipment investment based on information from subject matter experts, third-party vendors, good utility practice, and regulation. Since investments under this program are determined during the year of implementation, these analyses cannot be presented ahead of time.

Business Case Justification

This program's cost is exactly equal to the materiality threshold and investments under this program are determined during the year of implementation on an as-needed basis; therefore, a thorough business case documentation was not completed.

Computer Hardware

A. General Information on the Project/Activity

EPL strives to continuously improve its interactions with customers and overall customer service. Throughout 2017 and 2018, EPL plans to upgrade its IT infrastructure to be more resilient to cyber security threats. Investments include implementation of new IT hardware, standards, processes, and independent review. EPL also expects ongoing capital requirements in order to maintain the appropriate hardware and keep up with cyber security updates.

This category also includes minor Computer Hardware purchases such as computers, monitors, and other computer equipment in line with historical spending.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$13.5	$25.3	$5.8	$117.3	$356.2	$161.8	$80.0	$80.0	$80.0	$80.0
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date

January 1st, 2017

In-Service Date

December 31st, 2018

Customer Attachments

Not applicable

Load

Not applicable

2018 Test Year Expenditure Timing

	Q1	**Q2**	**Q3**	**Q4**
Capital	$40,452	$40,452	$40,452	$40,452
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

EPL's primary computer hardware risk revolves around service interruption and cyber security. EPL plans to mitigate potential service-related outages and/or cyber-attacks and threats by implementing contingency plans, third-party expert review, and parallel systems, where possible. EPL is working to ensure that it implements compliant measures as cost-effectively as possible.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information. Note that historical costs have not been significant however we have begun work in relation to compliance with the Cyber Security Framework starting at the end of 2016 with the vast majority of work being completed in 2018.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Compliance with the Cyber Security Framework and reduce/eliminate risk associated with cyber threats and attacks.*

ii. Secondary Drivers: *Enhance workflow and customer service. Equipment at the end of its service life.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence and Financial & Environmental Sustainability.*

iv. Information Used to Justify the Investment: *EPL utilized subject matter experts, third-party vendors, good utility practice and regulation as metrics to justify the investment.*

b) Priority: *Having up to date software and technologies promotes efficiency and reliability of information across EPL's various departments. Failure to make these investments over time will result in EPLC failure to meet its various regulatory and customer satisfaction levels.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked thirteenth (13th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *Failure to maintain, upgrade and embrace new technologies can ultimately lead to potential system failures, productivity decreases, poor customer service and lost data. EPL evaluates alternative products and vendors on a regular basis to ensure the best and most cost-effective solution is selected based on prescribed needs.*

i. Cost Effectiveness: *Reducing the number of cyber threats and attacks against EPL will allow for avoided costs of resolving cyber security related gaps and customer information breaches.*

ii. Net Customer Benefits: *Implementing cybersecurity upgrades will allow EPL to be in a better position to defend against cyber threats and protect its customers' data and information.*

iii. Impact on Reliability: *This project does not have an effect on system reliability.*

2. Safety

Safety is not a major driver for this project.

3. Cyber-Security, Privacy

Cyber-Security and privacy are the primary drivers of expenditures in the Computer Hardware category. EPL will ensure that all equipment and software deployed using best industry related practice.

4. Co-ordination, Interoperability

EPL will need to coordinate across multiple departments and across different third-party vendors as it relates to the various system upgrades planned.

5. Economic Development

Not applicable.

6. Environmental Benefits

Not applicable

C. Category-Specific Requirements

Results of Quantitative and Qualitative Analyses

EPL's goal is to maintain the most up to date or most cost-effective computer hardware necessary to meet its obligations to customers and relevant regulation (cyber-security framework) and ensure maximized employee efficiency.

Business Case Justification

Failure to maintain, upgrade and embrace new technologies can ultimately lead to potential system failures, productivity decreases, poor customer service and lost data. EPL evaluates alternative products and vendors on a regular basis to ensure the best and most cost-effective solution is selected based on prescribed needs.

Appendix B: Windsor-Essex Region Integrated Regional Resource Plan

WINDSOR-ESSEX REGION
INTEGRATED REGIONAL RESOURCE PLAN

April 28, 2015

ieso
Independent Electricity System Operator

Integrated Regional Resource Plan

Windsor-Essex Region

This Integrated Regional Resource Plan ("IRRP") was prepared by the IESO pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

This IRRP was prepared on behalf of the Windsor-Essex Region Working Group, which included the following members:

- Independent Electricity System Operator
- Essex Powerlines Corporation
- E.L.K Energy Inc.
- Entegrus Inc.
- Hydro One Networks Inc. (Distribution) and
- Hydro One Networks Inc. (Transmission)

The Windsor-Essex Region Working Group assessed the adequacy of electricity supply to customers in the Windsor-Essex Region over a 20-year period; developed a flexible, comprehensive, integrated plan that considers opportunities for coordination in anticipation of potential demand growth scenarios and varying supply conditions in the Windsor-Essex Region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key assumptions over time.

Windsor-Essex Region Working Group members agree with the IRRP's recommendations and support implementation of the plan through the recommended actions. Windsor-Essex Region Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

Table of Contents

List of Figures

List of Tables

List of Appendices

List of Abbreviations

Abbreviation	Description
C&S	Codes and standards ("C&S")
CDM	Conservation Demand Management
CEP	Community Energy Plan
CHP	Combined Heat and Power
CHPSOP	Combined Heat and Power Standard Offer Program
DE	District Energy
DG	Distributed Generation
DR	Demand Response
EA	Environmental Assessment
EM&V	Evaluation, Measurement and Verification
EMS	Energy Management Systems
DESN	Dual Element Spot Network
FIT	Feed-in Tariff
GEA	Green Energy Act, 2009
GHG	Greenhouse Gas
IAP	Industrial Accelerator Program
IESO	Independent Electricity System Operator
IPSP	(2007) Integrated Power System Plan
IRRP	Integrated Regional Resource Planning
L/R	Load Rejection
LAC	Local Advisory Committee
LDC	Local Distribution Company
LTEP	(2013) Long-Term Energy Plan
LTR	Limited Time Rating
MEP	Municipal Energy Plan
MEP/CEP	Municipal or Community Energy Planning
MTS	Municipal Transformer Station
OEB or Board	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPS	(Ontario's) Provincial Policy Statement
PPWG	Planning Process Working Group
PV	Photovoltaic
Region	Windsor-Essex Region
RIP	Regional Infrastructure Plan
SCADA	Supervisory Control And Data Acquisition
SCGT	Simple-Cycle Gas Turbine
SECTR	Supply to Essex County Transmission Reinforcement
SPS	Special Protection System
TOU	Time-of-Use
TS	Transformer Station
Working Group	Technical Working Group for the Windsor-Essex Region

1. Introduction

This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs of the Windsor-Essex Region ("Region") over the next 20 years. This report was prepared by the Independent Electricity System Operator ("IESO") on behalf of a Technical Working Group[1] composed of the IESO, EnWin Utilities Ltd. ("EnWin"), Essex Powerlines Corporation, E.L.K. Energy Inc., Entegrus Inc., and Hydro One Distribution and Hydro One Transmission ("Working Group").[2]

The Region encompasses the City of Windsor, Town of Amherstburg, Town of Essex, Town of Kingsville, Town of Lakeshore, Town of LaSalle, Municipality of Leamington, Town of Tecumseh, the western portion of the Municipality of Chatham-Kent and the Township of Pelee Island. With roughly 400,000 people presently living in the Region, population has remained flat over recent years[3] despite the impacts of the 2008 and 2009 global recession and the decline of automotive manufacturing facilities in the City of Windsor. While the manufacturing sector continues to face recovery challenges in the Region, economic diversification is changing the Region's growth and electricity use. The 2011 Windsor-Essex Regional Economic Roadmap identifies nine industry groups that hold potential for the Region, including advanced manufacturing, tourism, and agri-business.[4] The Region presently has a peak electricity demand of about 800 MW, and this demand is expected to increase at an average of nearly 1% per year.

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is done through regional electricity planning, a process that was formalized by the Ontario Energy Board ("OEB" or "Board") in 2013. In accordance with the OEB regional planning process, transmitters, distributers and the IESO are required to carry out regional planning activities for the 21 electricity planning regions at least once every five years.

---

[1] Information on the working group is available at: www.ieso.ca/Windsor-Essex

[2] See Appendix B for a description of some of the LDCs serving the Region.

[3] *Population counts, for Canada, provinces and territories, census divisions, population centre size groups and rural areas, 2011 Census*, Statistics Canada. At https://www12.statcan.gc.ca/census-recensement/2011/dp-pd/hlt-fst/pd-pl/Table-Tableau.cfm?LANG=Eng&T=703&SR=1&S=80&O=A&RPP=99&CMA=0&PR=35

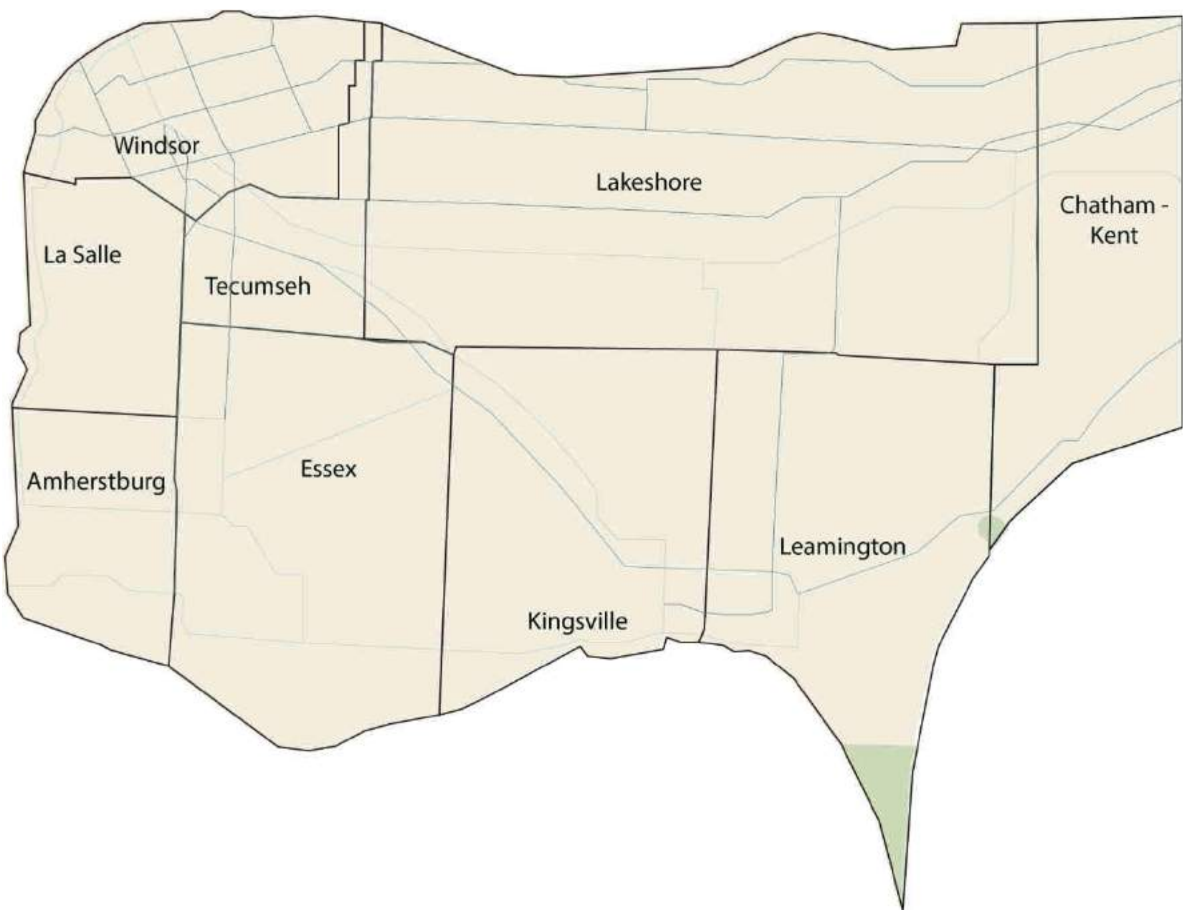
[4] Windsor--Essex Regional Economic Roadmap, Windsor-Essex Economic Development Corporation, February 2011.

Figure 1-1: Ontario's 21 Regional Planning Zones

The area covered by the Windsor-Essex IRRP constitutes one of the 21 electricity planning regions established through the OEB's regional planning process which is shown in Figure 1-1. This IRRP fulfills the requirements for the region as mandated by the OEB.

This IRRP for Windsor-Essex identifies investments for immediate implementation to meet near- and medium-term needs in the Region, and considers whether there are any long-term needs that necessitate options to be developed. No needs were identified for the Township of Pelee Island. Since economic, demographic, and technological conditions will inevitably change, IRRPs will be reviewed on a 5-year cycle so that plans can be updated to reflect the changing electricity outlook. The Windsor-Essex IRRP will be revisited in 2020 or sooner, if significant changes occur relative to the current forecast. The Region, shown in Figure 1-2 below, is defined electrically based on the connectivity of supply stations to Ontario's electricity grid. It is comprised of the City of Windsor, Town of Amherstburg, Town of Essex, Town of Kingsville, Town of Lakeshore, Town of LaSalle, Municipality of Leamington, Town of Tecumseh, and the western portion of the Municipality of Chatham-Kent. The Region has a peak electricity demand of about 800 MW and is served by five local distribution companies ("LDCs"): EnWin Utilities Ltd. ("EnWin"), Essex Powerlines Corporation, E.L.K. Energy Inc., Entegrus Inc., and Hydro One. EnWin and Hydro One are directly connected to the transmission system, while the three other LDCs have low voltage connections to Hydro One distribution feeders.

Figure 1-2: The Windsor-Essex Region



This report is organized as follows:

- A summary of the recommended plan for the Region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the Region and the study scope are discussed in Section 4;
- Demand forecast scenarios, conservation and distributed generation assumptions, are described in Section 5;
- The near- and medium-term plan is presented in Section 6;
- The long-term plan is presented in Section 7;
- A summary of community, aboriginal and stakeholder engagement to date in developing this IRRP and moving forward is provided in Section 8;
- A conclusion is provided in Section 9.

2. The Integrated Regional Resource Plan

The Windsor-Essex IRRP addresses the Region's electricity needs over the next 20 years, from 2014 to 2033, based on application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"). The IRRP identifies needs that are forecast to arise in the near term (0-5 years), medium term (5-10 years) and long term (10-20 years). These planning horizons are distinguished in the IRRP to reflect the different level of commitment required over these time horizons. The plans to address these timeframes are coordinated to ensure consistency. The IRRP was developed based on consideration of planning criteria, including reliability, cost and feasibility; and, in the near term, it seeks to maximize the use of the existing electricity system, where it is economic to do so.

For the near and medium term, the IRRP identifies specific investments that are already being implemented. This is necessary to ensure that they are in service in time to address the Region's more urgent needs, which have been forecast with relative certainty based on current demand trends, conservation targets and other local developments.

For the long term, the IRRP identifies a number of alternatives to meet needs. However, as these needs are forecast to arise further in the future, it is not necessary (nor would it be prudent given forecast uncertainty and the potential for technological change) to commit to specific projects at this time. Instead the IRRP for the long term focuses on developing and maintaining the viability of long-term electricity supply options, engaging with the community, and gathering information to lay the groundwork for future options. A particular emphasis of the long term is identifying the potential for integrating conservation, distributed generation ("DG"), or other localized solutions into the Region and gathering input on community preferences for long-term options.

The needs and recommended actions are summarized below.

2.1 Plan to Address the Near- and Medium-Term Needs

The first component of the near- and medium-term plan is the implementation of targeted conservation. While this planned CDM is expected to make a significant contribution to addressing growth in the

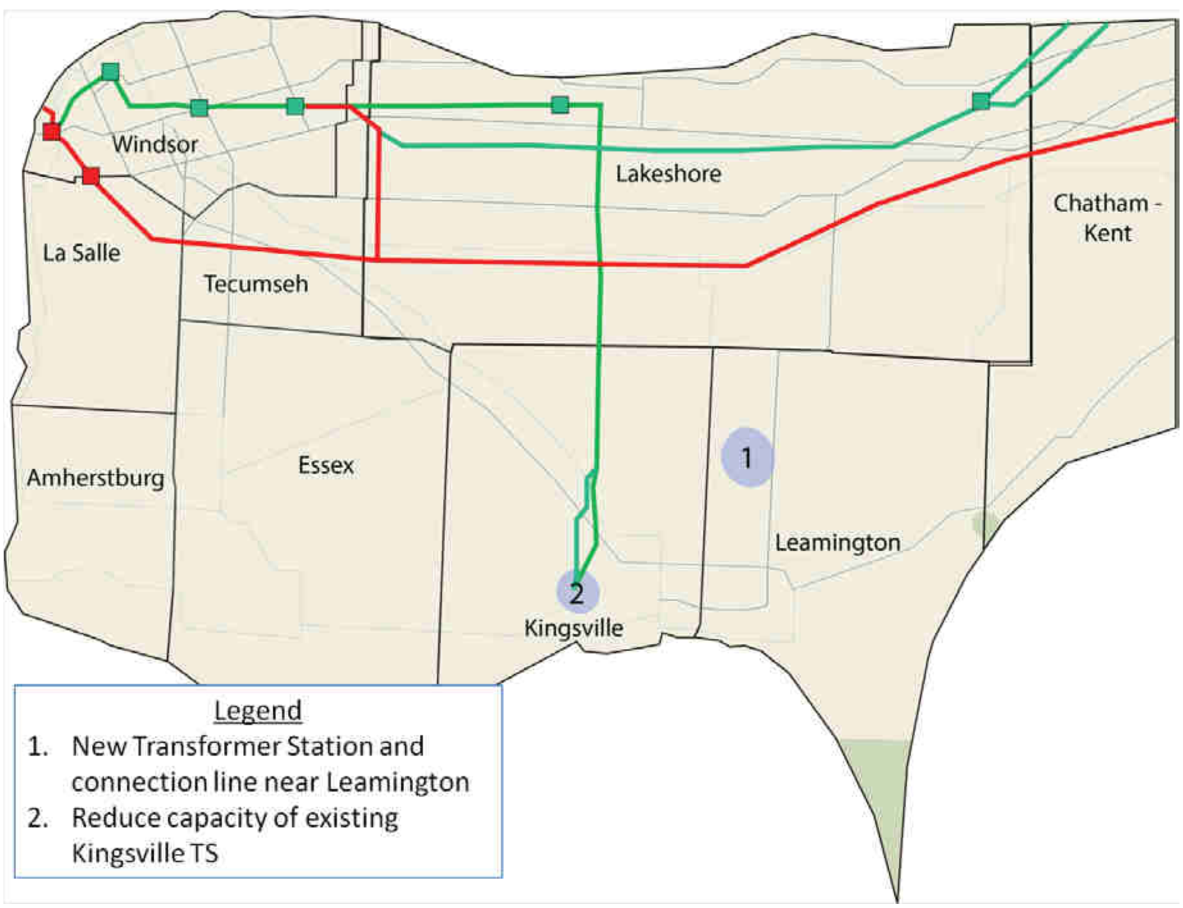
Near- and Medium-Term Needs

- Additional supply capacity in the Kingsville-Leamington area
- Additional restoration capability in the broader Region

Region, residual demand growth, as well as other reliability needs which are not growth related give rise to near-term supply capacity and restoration needs in the Region (see sidebar). Demand in the Kingsville-Leamington portion of the Region has exceeded the supply capacity in recent years and this is expected to continue over the 20-year forecast period. In addition, supply to a large portion of the Region does not comply with the prescribed ORTAC restoration criteria.

An integrated solution composed of conservation, DG resources, and transmission reinforcements in the Region is recommended to address these supply capacity and restoration needs. These components are described in further detail below and the location of transmission investments are indicated in Figure 2-1.

Figure 2-1: Transmission Projects Included in the Windsor-Essex Near-Term Plan



Recommended Actions:

1. Implement conservation and distributed generation

The implementation of provincial conservation targets established in the 2013 Long-Term Energy Plan ("LTEP") is a key component of the near- and medium-term plan for the Region. In developing the demand forecast, peak-demand impacts associated with the provincial targets established in the LTEP were assumed before identifying any residual need; this is consistent with the Conservation First policy. The achievement of these demand reductions will partially depend on the extent to which LDC conservation programs provide peak-demand reductions. Monitoring of conservation success, including measurement of peak demand savings, will be an important element of the near- and medium-term plan, and will also provide input for long-term planning by gauging the actual performance of specific conservation measures, and assessing the potential for future conservation initiatives in the Region.

Provincial programs that encourage the development of DG, such as the Feed-in Tariff ("FIT"), microFIT, and the Combined Heat and Power Standard Offer Program ("CHPSOP"), can also contribute to reducing peak demands on the transmission system in the Region, these will be influenced by local interest and opportunities for development. The LDCs and the IESO will continue supporting these initiatives and will monitor their impacts. Together, conservation and DG resources are expected to offset more than 90% of the growth in the area between 2014 and 2033.

2. Develop new transformer station in Leamington

The balance of the Region's supply capacity and restoration needs can be addressed by the new Supply to Essex County Transmission Reinforcement ("SECTR") project, plus planned sustainment work in the Region.[5] The transmitter that serves the Region, Hydro One, filed the regulatory application for approval of the SECTR project with the OEB in June, 2014. The project consists of the installation of a new 230 kV-supplied transformer station ("TS") near Leamington connected to the existing 230 kV circuits in the Region via a new 13 km double-circuit 230 kV connection line. The estimated completion date for the SECTR project is 2018 and

---

[5] Evidence on the SECTR project is available at the Ontario Energy Board's website at EB-2013-0421:
http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=eb-2013-0421&sortd1=rs_dateregistered&rows=200
Evidence on the needs and alternatives is available in Exhibit B-1-5. Evidence on cost responsibility is available in Exhibit B-4-4.

the total cost is approximately $77 million. On completion, some of the load currently supplied by Kingsville TS will be transferred to the new Leamington TS.

3. Downsize the existing Kingsville transformer station

In conjunction with transferring the majority of the load from the existing Kingsville TS to the new Leamington TS, the Kingsville TS will be downsized through the retirement of aging assets. This will increase the cost-effectiveness of the overall solution.

Together with targeted conservation, these planned transmission facilities will meet the supply capacity and restoration needs of the Kingsville-Leamington area over the forecast period. The addition of a new supply point will also substantially meet the transmission restoration needs for the broader Region. This integrated solution benefits both local customers and broader transmission ratepayers.

2.2 Plan to Address the Long-Term Needs

No long-term needs have been identified in the Region. The Region's demand growth, conservation achievements and generation development will be monitored until the Region's needs are reassessed in the next regional planning cycle. If significant changes occur relative to the current forecast, the next planning cycle may be initiated in advance of the 5-year minimum review timeline.

3. Development of the IRRP

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is done through regional planning. Regional planning assesses the interrelated needs of a region - defined by common electricity supply infrastructure over the near, medium and long term, and develops a plan to ensure cost-effective, reliable, electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as needed basis in Ontario for many years. Most recently, the Ontario Power Authority ("OPA") carried out regional planning activities to address regional electricity supply needs. The OPA conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In 2012, the Ontario Energy Board convened the Planning Process Working Group ("PPWG") to develop a more structured, transparent, and systematic regional planning process. This group was composed of industry stakeholders including electricity agencies, utilities, and stakeholders. In May 2013, the PPWG released the Working Group Report to the Board, setting out the new regional planning process. Twenty-one electricity planning regions in the province were identified in the Working Group Report and a phased schedule for completion was outlined. The Board endorsed the Working Group Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, as well as through changes to the OPA's licence in October 2013. The OPA license changes required it to lead a number of aspects of regional planning, including the completion of comprehensive IRRPs. Following the merger of the IESO and the OPA on January 1, 2015, the regional planning responsibilities identified in the OPA's licence were transferred to the IESO.

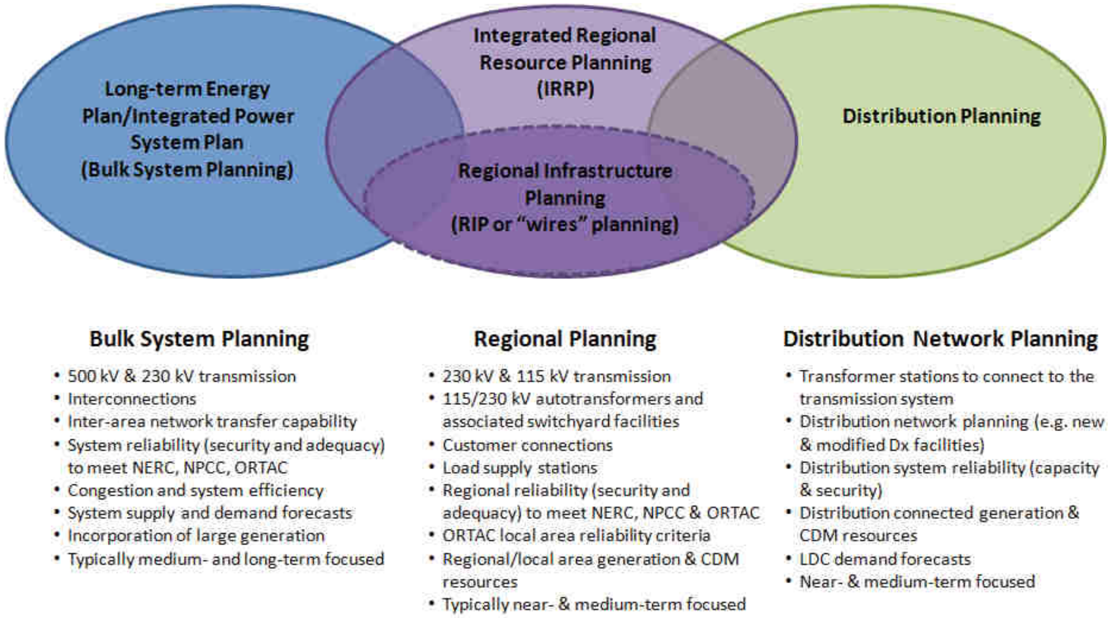
The regional planning process begins with a Needs Screening process performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO then conducts a Scoping Assessment to determine whether a comprehensive IRRP is required, which considers conservation, generation, transmission, and distribution solutions, or whether a straightforward "wires" solution is the only option. If the latter applies, then a transmission and distribution focused Regional Infrastructure Plan ("RIP") is required. The Scoping Assessment process also identifies any sub-regions that require assessment. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter, outside of the regional planning process. At the conclusion of the Scoping Assessment, the IESO produces a report that includes the results of the Needs Screening process – identifying whether an IRRP, RIP or no regional coordination is required - and a preliminary terms of reference. If an IRRP is the identified outcome, then the IESO is required to complete the IRRP within 18 months. If a RIP is required, the transmitter takes the lead and has six months to complete it. Both RIPs and IRRPs are to be updated at least every five years.

The final IRRPs and RIPs are to be posted on the IESO and relevant transmitter websites, and can be used as supporting evidence in a rate hearing or leave to construct application for specific infrastructure investments. These documents may also be used by municipalities and communities for planning purposes and by other parties to better understand local electricity growth and infrastructure requirements.

Regional planning, as shown in Figure 3-1, is just one form of electricity planning that is undertaken in Ontario. There are three types of electricity planning in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

Figure 3-1: Levels of Electricity System Planning



Planning at the bulk system level typically considers the 230 kV and 500 kV network. Bulk system planning considers the major transmission facilities and assesses the resources needed to adequately supply the province. Bulk system planning is typically carried out by the IESO. Distribution planning, which is carried out by LDCs, looks at specific investments on the low voltage, distribution system.

Regional planning can overlap with bulk system planning. For example, overlap can occur at interface points where regional resource options may also address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. An example of this is when a distribution solution addresses the needs of the broader local area or region. Therefore, to ensure efficiency and cost-effectiveness, it is important for regional planning to be coordinated with both bulk and distribution system planning.

By recognizing the linkages with bulk and distribution system planning, and coordinating multiple needs identified within a given region over the long term, the regional planning process provides an integrated assessment of needs. Regional planning aligns near- and long-term solutions and allows specific investments recommended in the plan to be understood as part of a larger context. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication, and allows Ontario ratepayers' interests to be represented along with the interests of LDC ratepayers. Where IRRPs are undertaken, they allow an evaluation of the multiple options available to meet needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

3.2 The IESO's Approach to Regional Planning

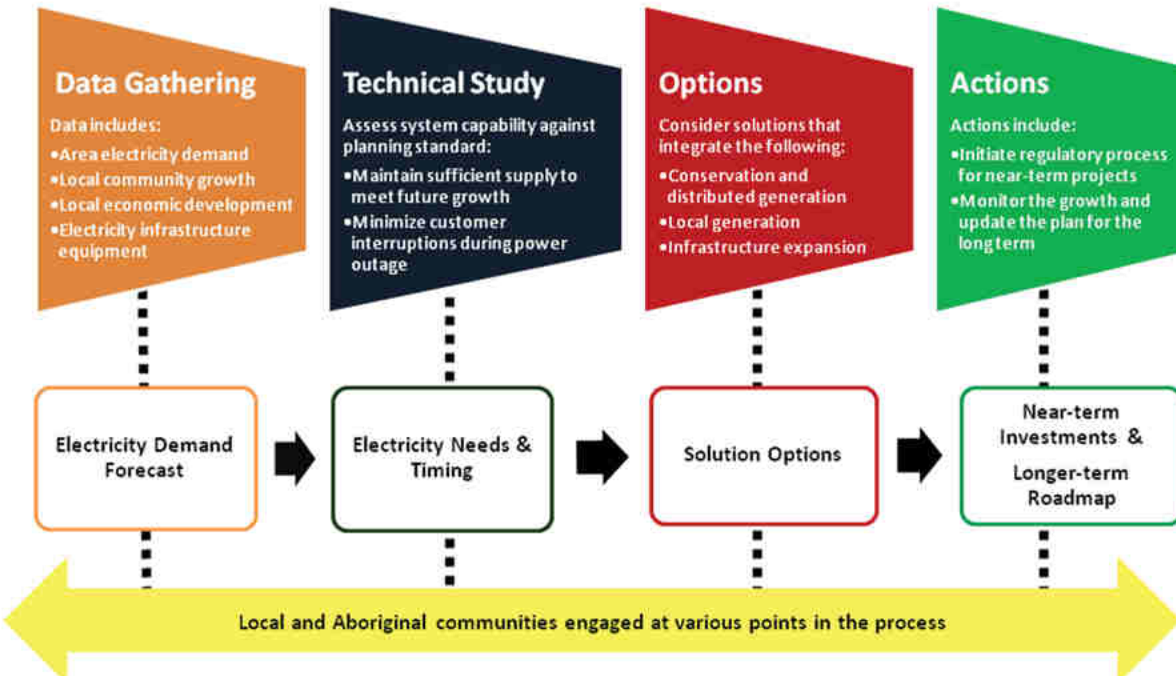
IRRPs assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends so that near-term actions are developed within the context of a longer-term view. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

In developing an IRRP, a different approach is taken to developing the plan for the first 10 years of the plan—the near- and medium-term—than for the longer-term period of 10-20 years. The plan for the first 10 years is developed based on best available information on demand, conservation, and other local developments. Given the long lead time to develop electricity infrastructure, near-term electricity needs require prompt action to enable the specified solutions in a timely manner. By contrast, the long-term plan is characterized by greater forecast uncertainty and longer development lead time; as such solutions do not need to be committed to immediately. Given the potential for changing conditions and technological development, the IRRP for the long term is more directional, focusing on developing and maintaining the viability of options for the future, and continuing to monitor demand forecast scenarios.

In developing an IRRP, the IESO and regional working group (see Figure 3-2 below) carry out a number of steps. These steps include electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and, a recommended plan including actions for the near and long term. Throughout this process, engagement is carried out with First Nation and Métis communities, stakeholders and communities who may have an interest in the regional planning area. The steps of an IRRP are illustrated in Figure 3-2 below.

The IRRP report documents the inputs, findings and recommendations developed through the process described above, and provides recommended actions for the various entities responsible for plan implementation. Where "wires" solutions are included in the plan recommendations, the completion of the IRRP report is the trigger for the transmitter to initiate an RIP process to develop those options. Other actions may involve: development of conservation, local generation, or other solutions; community engagement; or information gathering to support future iterations of the regional planning process in the region.

Figure 3-2: Steps in the IRRP Process



3.3 Windsor-Essex Working Group and IRRP Development

Regional planning was underway in the Windsor-Essex Region prior to the OEB's formalization of the regional planning process. The first phase of regional planning began with the regional plan developed by the former-OPA[6] as part of the 2007 Integrated Power System Plan ("IPSP"), which identified a need for conservation as well as transmission reinforcement in the Region. In 2010, Hydro One received environmental approval for the staged reinforcement identified in the IPSP. The planning work carried out for the IPSP has formed the basis for subsequent regional planning in the Region.

Beginning in 2008, the global economic downturn had a significant impact on electricity demand in the Region, especially the urban portion in and around Windsor. In 2010, a Regional working group consisting of members from the former OPA, the transmitter, the five LDCs, and

[6] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

the IESO, was formed. A study carried out by the former OPA and presented to the working group in 2011 recommended that development activities associated with the proposed Leamington TS temporarily be put on hold as a result of the reduced regional electricity demand.

In 2013 the former-OPA revisited the 2011 study based on an updated load forecast provided by the Region's LDCs. Based on the near-term needs identified, especially in the rural portion in and around Kingsville-Leamington, a transmission solution - the SECTR project - was recommended. In June 2014 Hydro One submitted a Leave to Construct application for this project with the OEB. This was the first of the two stages of transmission expansion described in Hydro One's environmental assessment. The second stage is not contemplated at this time.

As a continuation of this planning work for the Region the former-OPA in 2013 initiated an IRRP for the Region. The Working Group, first established in 2010 and consisting of staff from the former-OPA, the IESO, Hydro One, and the five LDCs serving the Region, was reconvened to support this work.

This Windsor-Essex IRRP is therefore a "transitional" IRRP in that it began prior to development of the OEB's regional planning process and much of the work was completed before the new process and its requirements were known.

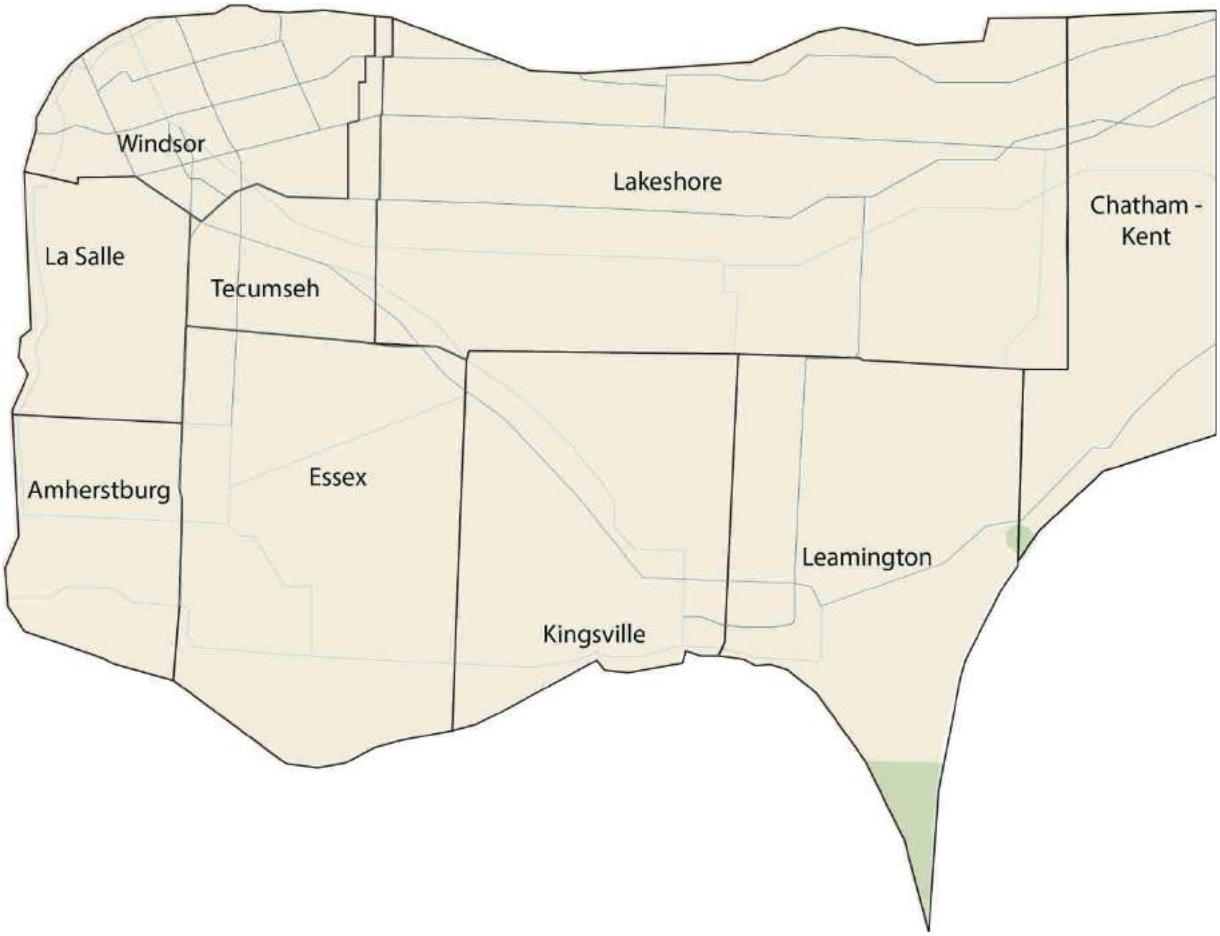
4. Background and Study Scope

This report presents an integrated regional electricity plan for the Windsor-Essex Region for the 20-year period from 2014 to 2033. To set the context for this IRRP, the scope of this IRRP and a description of the Region are described in Section 4.1. Section 4.2 details the transmission-connected generation that plays an important role in providing supply to this Region. Section 4.3 describes the transmission configuration in the Region, and defines the regional planning sub-systems which are used later in this report.

4.1 Study Scope

The Region is comprised of the City of Windsor, Town of Amherstburg, Town of Essex, Town of Kingsville, Town of Lakeshore, Town of LaSalle, Municipality of Leamington, Town of Tecumseh, and the western portion of the Municipality of Chatham-Kent and the Township of Pelee Island. This Region, shown in Figure 4-1 below is comprised of and is served by five LDCs: EnWin Utilities Ltd. ("EnWin"), Essex Powerlines Corporation, E.L.K. Energy Inc., Entegrus Inc., and Hydro One. EnWin and Hydro One are directly connected to the transmission system, while the three other LDCs have low voltage connections to Hydro One distribution feeders.

Figure 4-1: The Windsor-Essex Region



The urban portion of the Region in and around Windsor has a long history of advanced manufacturing, especially in the automotive sector. In light of this the transmitter and distributors over the decades have made investments in electricity infrastructure to enable a very high standard of reliability, which is of strategic importance to the regional and provincial economies. Entertainment tourism is particularly strong in the downtown core, the most significant individual component of which is a provincially owned resort casino.

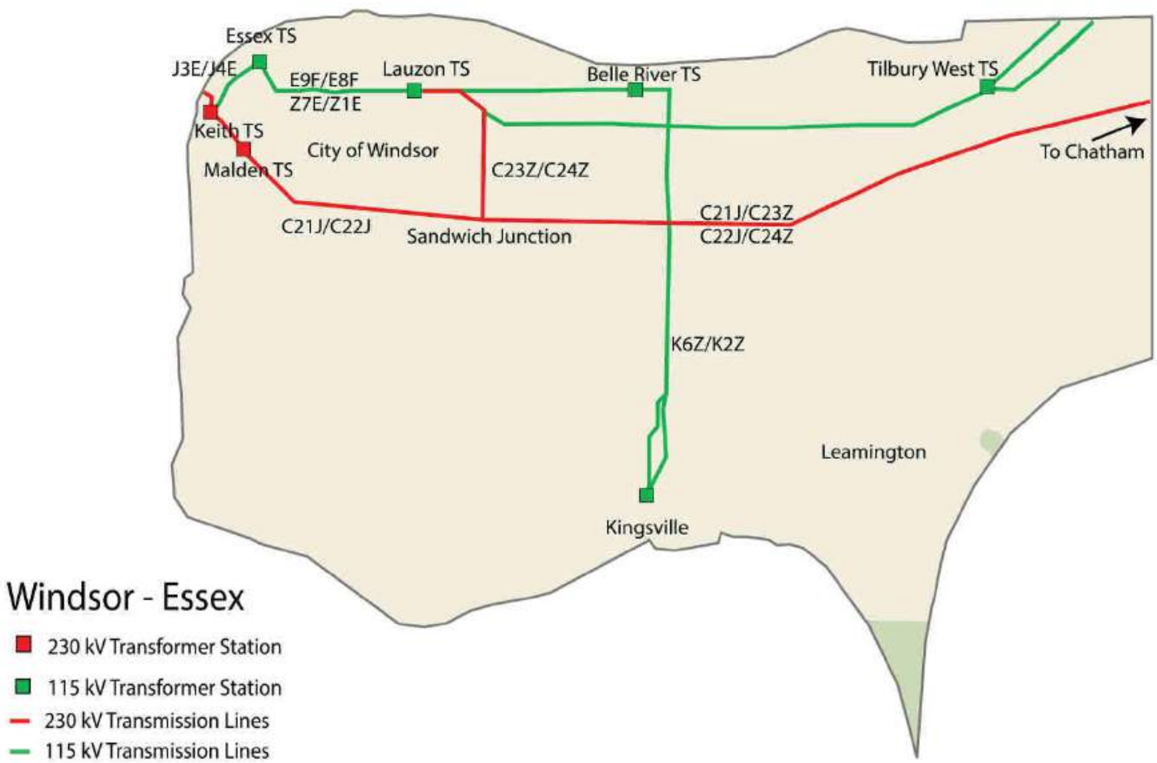
The rural portion of the Region in Essex County supports a combination of manufacturing and agri-business. Essex County contains the largest concentration of greenhouse vegetable production in North America.[7] This sector is expected to experience major growth in the future, with much of the activity taking place in the Kingsville-Leamington area, increasing electricity

[7] County of Essex website:
http://www.countyofessex.on.ca/wps/wcm/connect/COE/COE/ABOUT+ESSEX+COUNTY/

supply requirements in that part of the Region. The County is also home to several large food processing operations, and a growing winery sector.

The Region is supplied from a combination of local generation and from connection to the Ontario grid via a network of 230 kV and 115 kV transmission lines and stations shown in Figure 4-2 below. Electricity distribution and conservation initiatives are carried out by the five LDCs serving the Region.

Figure 4-2: Transmission System in the Windsor-Essex Region



4.2 Transmission Connected Generation

Transmission connected generation comes from a mix of large natural gas generators, load-offsetting behind-the-meter embedded generators, and renewable generation that is shown in Table 4-1 below.

The impact of DG on the demand forecast for the Region will be discussed in more detail later in this report.

Table 4-1: Transmission Connected Generation Facilities in the Region

Technology	Station Name	Contract Expiry Date	Connection Point	Contract Capacity (MW)	Summer Effective Capacity (MW)
Combined Cycle Generating Facility	Brighton Beach Power Station	December 31, 2024	Keith TS	541	526
Combined Heat and Power ("CHP")	West Windsor Power	May 31, 2016	J2N (Keith TS)	128	107
	TransAlta Windsor	December 1, 2016	Z1E	74	74
	East Windsor Cogeneration Centre	November 5, 2029	E8F/E9F	84	80
Renewables	Gosfield Wind Project	January 12, 2029	K2Z	51	8
	Point Aux Roches Wind Farm	December 5, 2031	K6Z	49	8

Electricity transmission connects the Region to the rest of the province through two 230 kV double circuits and two 115 kV single circuits. The principal connection points are Keith TS and Lauzon TS, both of which are transmission assets owned by Hydro One and are located in Windsor. Hydro One also owns Malden TS, Crawford TS, Essex TS, and Walker 1 TS in Windsor. Hydro One owns Belle River TS and Tilbury TS in the northern part of Essex county and Kingsville TS in the southern part of the county. Hydro One is currently seeking OEB approval to build Leamington TS (as part of the SECTR project), also located in the southern part of the county. EnWin owns five transformer stations. One of these serves a broad base of customers (Walker 2 TS); three others are dedicated to individual large users; and one is in the process of being repurposed to serve a broad base of customers as a result of the closure of the large user it previously served. There is also a customer-owned TS serving that customer's facility in Windsor.

The main transmission corridor in the Region connects with the rest of the province at Chatham SS in the Municipality of Chatham-Kent. Two 230 kV double-circuit lines, C21J/C23Z and C22J/C24Z, run east-west in this corridor, located south of Highway 401, from Chatham SS to Sandwich Junction in the Town of Lakeshore. The circuits are reconfigured at this location and double-circuit line C21J/C22J continues west to Keith TS in Windsor, while double-circuit line C23Z/C24Z runs northwest on another corridor to Lauzon TS in Windsor. Keith TS provides an interconnection with the Michigan system via 230 kV circuit J5D and an in-line phase shifter.

Keith TS and Lauzon TS, connect the Region's 115 kV network to the 230 kV transmission system via two auto-transformers in each station. As can be seen in Figure 4-2, above, the main 115 kV transmission corridor runs through the City of Windsor from Keith TS through Essex TS to Lauzon TS. Double-circuit line J3E/J4E located in this corridor connects Keith TS with Essex TS, and double-circuit line Z1E/Z7E connects Essex TS with Lauzon TS. Other 115 kV transmission corridors provide for circuits K2Z and K6Z. 115 kV circuits E8F and E9F are underground cables and provide supply to four EnWin-owned stations. Approximately 65% of the Region's load is supplied by the 115 kV system, with the remainder supplied by transformer stations connected directly to the 230 kV system. Given the large proportion of load which is supplied by the 115 kV system, the reliability of supply via the two connection points at Keith TS and Lauzon TS is especially important.

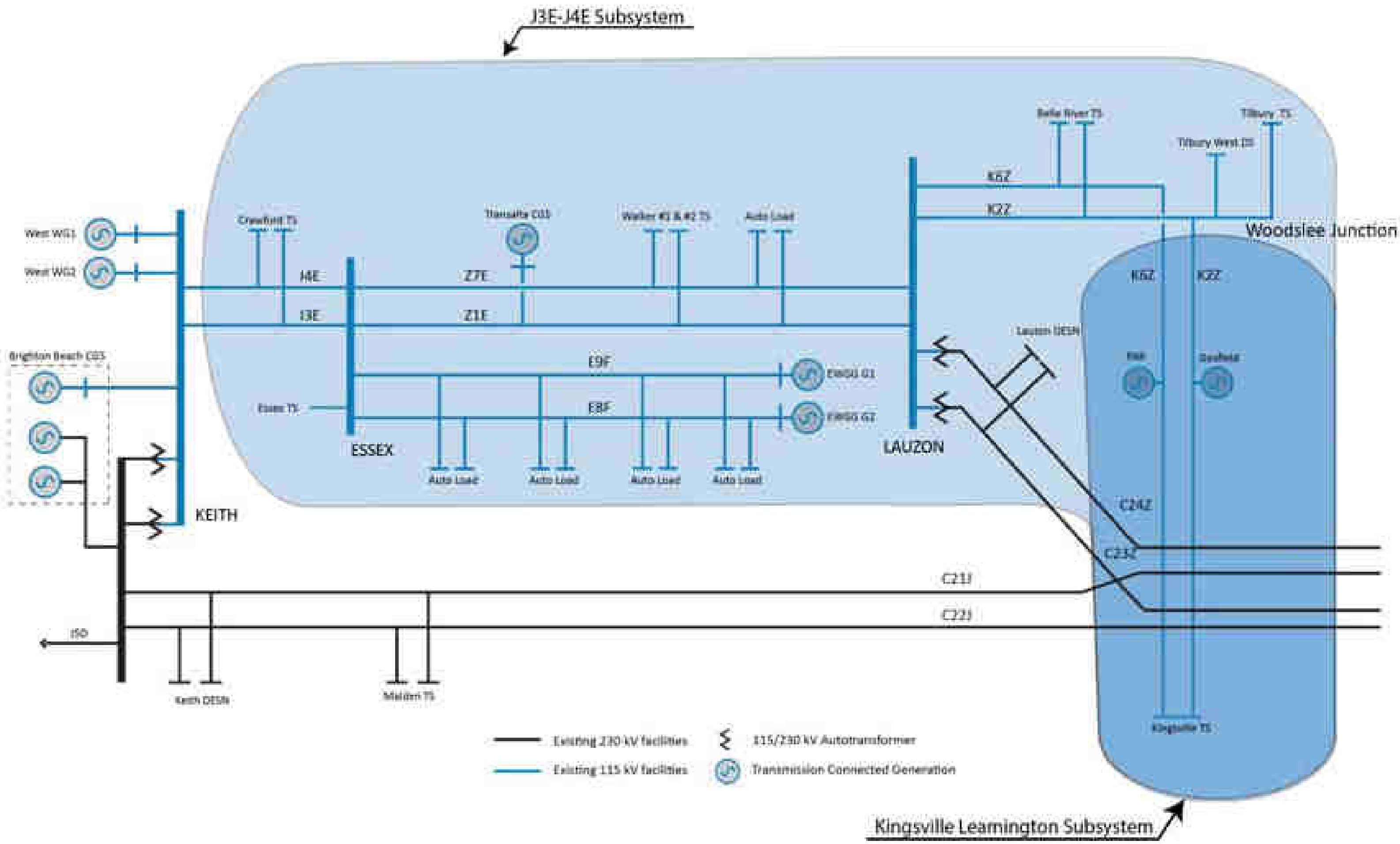
4.2.1 Regional Planning Sub-systems

For the purposes of this IRRP, the transmission system in the Region is divided into the two "nested" sub-systems described below and shown in Figure 4-3:

1. The Kingsville-Leamington sub-system: customers currently supplied from Kingsville TS; and
2. The J3E-J4E sub-system: customers supplied from the 230/115 kV auto-transformers at Keith TS and Lauzon TS via the 115k kV system, as well as customers supplied from the 230 kV Lauzon Dual Element Spot Network ("DESN").

It is important to note that the two sub-systems are overlapping, with the Kingsville-Leamington sub-system nested within the other. Therefore, where the demand for the J3E-J4E sub-system is referred to in this plan it is inclusive of demand in the Kingsville-Leamington sub-system. Similarly, increasing supply to the Kingsville-Leamington sub-system will impact the supply and demand balance in the J3E-J4E sub-system.

Figure 4-3: Windsor-Essex Region Sub-systems



5. Demand Forecast

This section describes the development of the regional demand forecast. Section 5.1 begins by describing electricity demand trends in the Region from 2004 to 2014. Section 5.2 describes the demand forecast used in this study and the methodology used to develop it.

5.1 Historical Demand

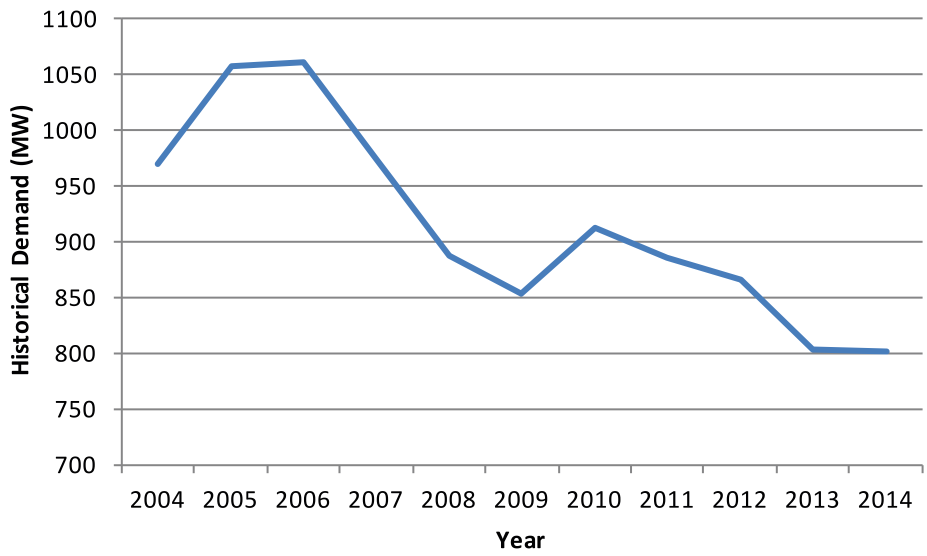
The peak demand in the Region has declined from a high of 1,060 MW in the summer of 2006 to approximately 800 MW in both 2013 and 2014. Figure 5-1 shows the historical summer peak demand observed in the Region from 2004 to 2014. A noticeable peak in 2006 is coincident with the all-time peak in Ontario power demand, while a dip in 2008 and 2009 shows the area's response to the global recession. There is a large concentration of automotive manufacturing facilities in the City of Windsor. The sector is a major economic driver and electricity user within the Region. The decline in Ontario's manufacturing sector and the 2008/09 economic downturn have both caused a decline in electricity use in the Region.

While the manufacturing sector continues to face challenges in recovering, economic diversification is changing the Region's growth and electricity use. The 5-year Windsor-Essex Regional Economic Roadmap, released in 2011, identifies nine industry groups that hold growth potential for the Region, including advanced manufacturing, tourism, and agri-business.[8]

It is important to note some other trends that are reflected in this data. First, this measured demand includes the impact of summer weather conditions, which were unusually cool across the province in 2014. Second, demand on the distribution system that was being met by DG resources operating at the time of the annual peak is not reflected in the measured demand that is supplied from the transmission system. Finally, the data also reflects the achievements of provincial conservation and peak-shifting initiatives, including the Industrial Conservation Initiative for large customers.

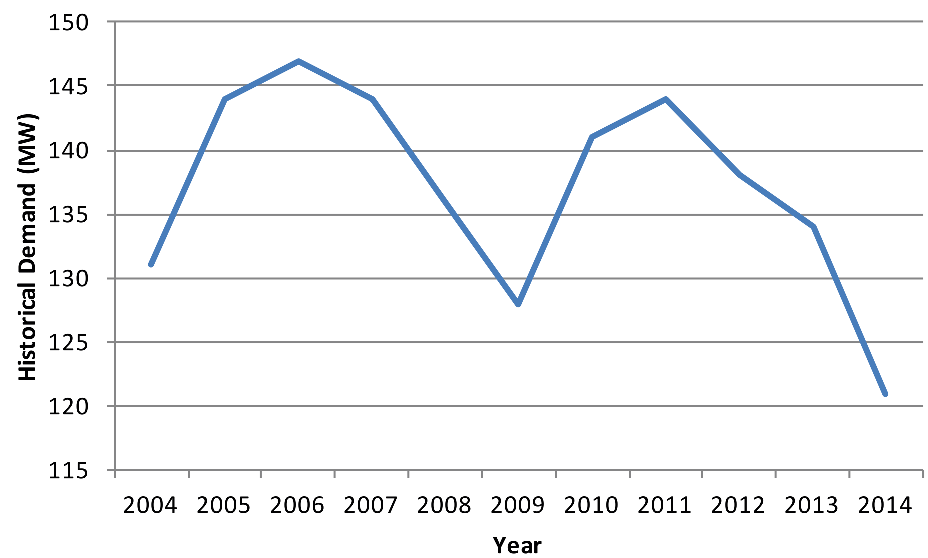
[8] Regional Economic Roadmap, Windsor-Essex Economic Development Corporation, February 2011

Figure 5-1: Historical Electricity Demand in the Region



Peak demand in the Kingsville-Leamington area has experienced fluctuations comparable to the Region since 2004, which is shown in Figure 5-2 below. In addition to the trends described above, this figure shows the impact of approximately 16 MW of effective capacity of DG connected at Kingsville TS by 2015, none of which was connected in 2004.

Figure 5-2: Kingsville-Leamington Historical Electricity Demand[9]



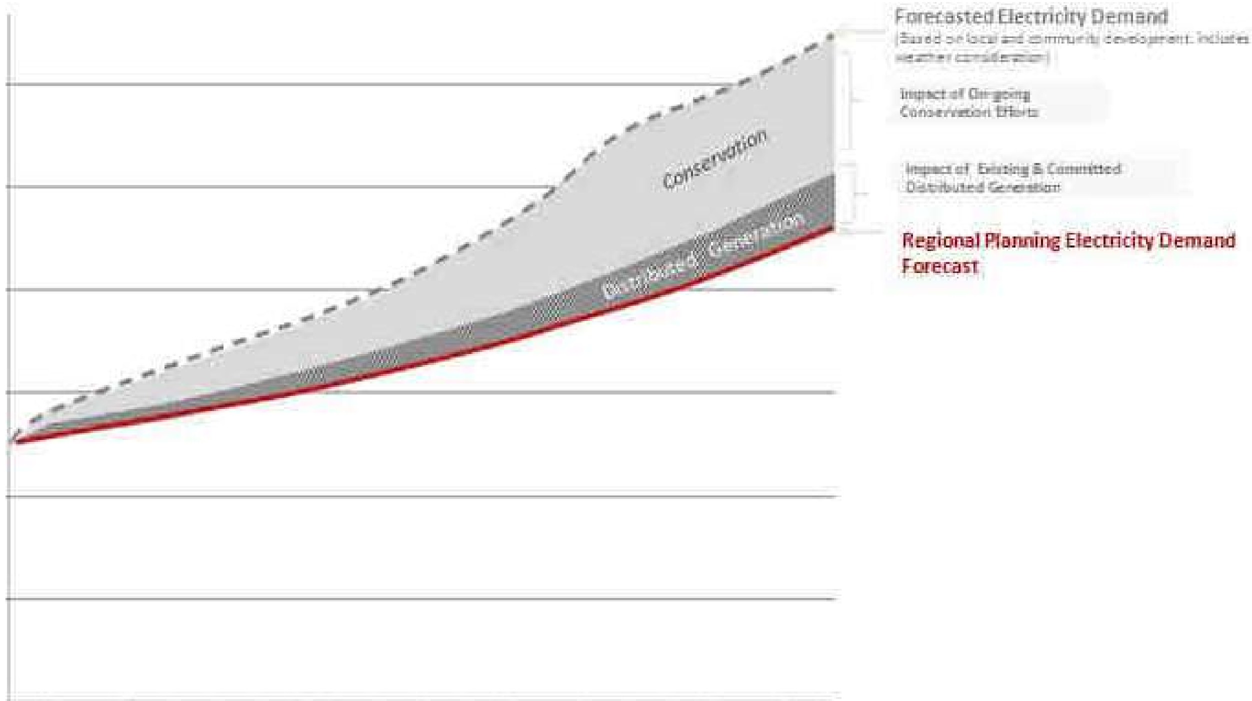
[9] Historical electricity demand reflects the weather experienced at the time of system peak.

5.2 Demand Forecast Methodology

Regional electricity needs are driven by the limits of the infrastructure supplying an area, which is sized to meet peak demand requirements. Therefore, regional planning typically focuses on growth in coincident peak demand, which is the electricity demand of individual stations that coincides in time with the annual peak demand of the region. This represents the electricity demand when the assets in the area are most stressed and resources are most constrained. Energy adequacy is usually not a concern in regional planning, as the Region can generally draw upon energy available from the provincial electricity grid and energy adequacy for the province is planned through a separate process.

A regional peak demand forecast was developed for the forecast period. The steps taken to develop the planning forecast are depicted in Figure 5-3. Gross demand forecasts assuming extreme weather conditions were provided by EnWin and Hydro One, which are directly connected to the transmission system. These forecasts were then modified to reflect the peak demand impacts of provincial conservation targets and DG contracted through provincial programs such as FIT and microFIT to produce a reference planning forecast. The reference planning forecast was then used to assess electricity supply needs in the Region.

Figure 5-3: Development of Demand Forecasts



Using a planning forecast that is net of provincial conservation targets ensures consistency with the province's Conservation First policy by reducing demand requirements before assessing any growth-related needs. However, it should be noted that this inherently assumes that the targets will be met, and that the targets, which are energy-based, will produce the expected local peak demand impacts. An important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by the local LDCs.

For the long-term outlook, from 2024 to 2033, a second demand forecast scenario, consistent with the growth assumptions embodied in the government's 2013 LTEP was added. This low-demand scenario represents a future with lower electricity demand growth, due to higher electricity prices, increased electricity conservation, and lower energy intensity of the economy.

5.3 Reference Forecast

5.3.1 Gross Demand Forecast

Summer peak gross demand forecasts for the 20-year planning horizon were provided by EnWin and Hydro One, the two LDCs which are directly connected to the transmission system, for each of the transformer stations and transmission connected customers in the area. These forecasts reflect the expected demand at each station at the time of the Region's coincident peak under extreme weather conditions, based on factors such as population, household and economic growth, consistent with municipal planning assumptions. It is expected that each station will reach its individual peak demand at a different point in time. From the perspective of ensuring sufficient transmission supply to the Region, it is important to consider the coincident peak, the point in time when the total demand from the stations in the Region peaks. Aggregating the station forecasts identifies the peak electricity demand that must be served by the Region's transmission system.

Based on the LDC's gross demand forecasts, the Region's peak electricity demand is expected to grow by about 175 MW over the next 20 years, with an average annual growth rate of just under 1%, not including the impacts of conservation or DG. The Kingsville-Leamington area is expected to experience over 50 MW of demand growth, or average annual growth of about 1.6%. The reference gross demand forecasts provided by the LDCs are shown in Appendix A.

5.3.2 Conservation Assumed in the Forecast

Conservation plays a key role in maximizing the useful life of existing infrastructure and maintaining reliable supply. Conservation is achieved through a mix of program-related activities including behavioral changes by customers and mandated efficiencies from building codes and equipment standards ("C&S"). These approaches complement each other to maximize conservation results. The conservation savings forecast for the Region are applied to the gross peak demand forecast, along with contracted DG resources, to determine the net peak demand for the Region.

In December 2013 the Ministry of Energy released a revised LTEP, which outlined a provincial conservation target of 30 TWh of energy savings by 2032. In order to represent the effect of these targets within regional planning, the IESO developed an annual forecast for peak demand savings resulting from the provincial energy savings target, which was then expressed as a percentage of demand in each year. These percentages were applied to the LDCs' demand forecasts to develop an estimate of the peak demand impacts from the provincial targets in the Region. The resulting conservation assumed in the reference forecast is shown in Table 5-1. This contribution from conservation is expected to offset most of the growth in electricity demand in the Region to 2033. The above conservation forecast methodology was not applied in developing the low-demand forecast scenario used for the long-term because the scenario already accounts for the anticipated impact of the 2032 conservation targets in its overall growth rate assumptions.

Table 5-1: Peak Demand Savings from 2013 LTEP Conservation Targets in the Windsor-Essex Region

Year	2015	2017	2019	2021	2023	2025	2027	2029	2031	2033
Savings (MW)	12	20	40	58	72	89	105	122	139	149

It is assumed that demand response ("DR") resources already existing in the base year will continue. Savings from potential future DR resources are not included in the forecast and are instead considered as possible solutions to identified needs.

The 2013 LTEP also committed to establishing a new 6-year Conservation First Framework beginning in January 2015 to enable the achievement of all cost-effective conservation. In the near term, Ontario's LDCs have an energy reduction target of 7 TWh to be achieved between 2015 and the end of 2020 through LDC conservation programs enabled by the new Framework. For the program targets, each LDC is required to prepare a conservation plan describing how the target will be achieved. The first conservation plans are due to be completed by LDCs by May, 2015. The LDC conservation plans will link closely with regional plans, providing more detail about how a portion of the conservation targets that have been incorporated into regional planning will be realized.

5.3.3 Distributed Generation Assumed in the Forecast

In addition to conservation resources, DG connected alongside load on the distribution system reduces the amount of demand needed to be supplied via the transmission system. The introduction of the Green Energy and Green Economy Act, and the associated development of Ontario's FIT program, has increased the development of DG in Ontario from renewable fuel sources including wind, solar and biomass. There are also thermal DG resources in the Region, such as combined heat and power generation ("CHP") associated with industrial customers.

With respect to renewable generation, the full installed capacity of these facilities cannot be relied upon to meet the Region's electricity needs due the intermittent nature of the generation. The installed capacity of these facilities is adjusted to reflect the expected, or effective, power output at time of coincident peak. In other words, the effective capacity is the portion of installed renewable generation capacity that contributes to meeting peak demand. Distributed thermal generation is expected to fully contribute to meeting peak demand.

After netting-off the conservation savings, as described above, the forecast is further reduced by the effective capacity of existing and committed DG in the Region. It is estimated that DG in the Region will contribute approximately 65 MW of effective capacity to meeting area peak demand in 2014.

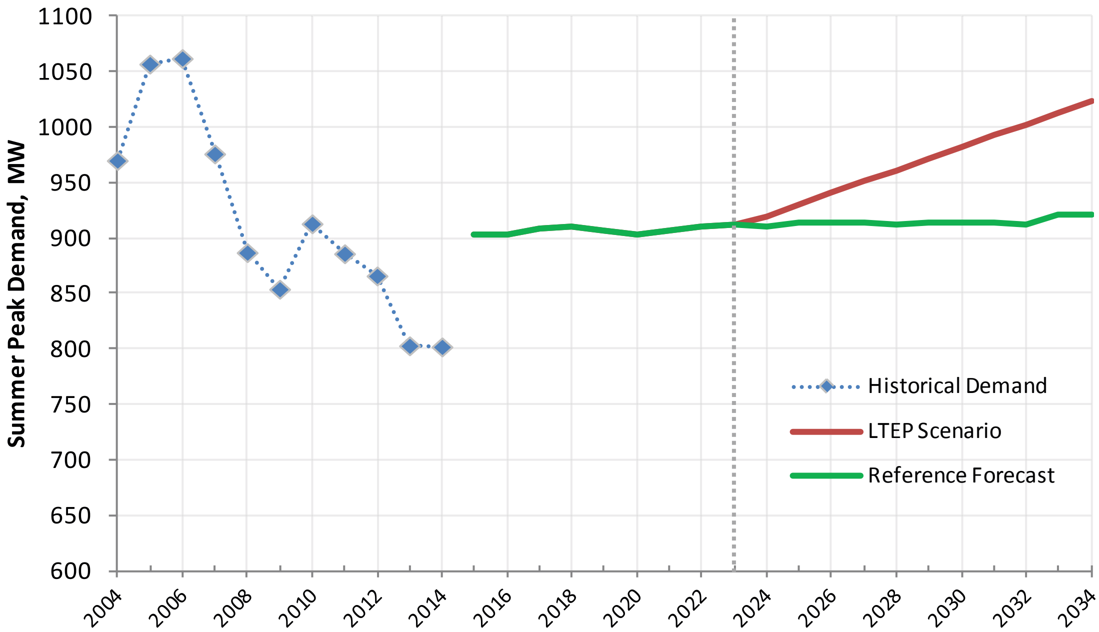
5.4 Windsor-Essex Low Growth Scenario

As noted in Section 5.2, beyond the first 10-years of the planning horizon (ie. beginning in 2024) the IESO developed a second forecast scenario based on the 2013 LTEP. Similar to the reference forecast, this scenario reflects the impact of the conservation targets described in the LTEP. This scenario projects growth over a region, rather than on a station-by-station basis. It was developed by applying the average annual growth rate assumed for southwestern Ontario in the low-demand forecast, about 1.0% per year, to the Region, starting from 2024.

5.5 Planning Forecasts

Figure 5-4 shows the reference forecast and the 2013 low-demand scenario, along with historic demand in the Region.

Figure 5-4: Reference Forecast, 2013 Low-Demand Scenario and Historic Demand in the Region



6. Near- and Medium-Term Plan

Regional planning requires comparing future electricity demand (based on planning forecast) with the capability of the existing system (based on provincial planning criteria). This section includes discussion of the near-term needs and the options to address those needs. No medium-term needs have been identified in the Region. As noted in the previous section, these near-term needs are based on the reference planning forecast provided by the Region's LDCs, reflecting known developments in the area as well as the impact of planned conservation initiatives and DG. These conservation and DG resources are already making a significant contribution toward managing the growth across the Region. For needs related to meeting ORTAC load restoration and load security criteria, which are described in 6.1 Planning Criteria, conservation is not considered a feasible alternative, as these needs are driven by the configuration of the transmission and distribution systems, and are not related to demand growth. Therefore, the Working Group did not consider additional conservation as an alternative to address load restoration times in the Region, and therefore, the near-term plan focuses on improvements to the transmission system.

6.1 Planning Criteria

ORTAC[10] is the provincial standard for assessing the reliability of the transmission system and was applied to assess supply capacity and reliability needs in the Region.

ORTAC includes criteria related to assessment of the bulk transmission system, as well as the assessment of local or regional reliability requirements. The latter criteria are of relevance to regional planning. They can be broadly categorized as addressing two distinct aspects of reliability: (1) providing supply capacity, and (2) limiting the impact of supply interruptions.

With respect to supply capability ORTAC specifies that the transmission system must be able to provide continuous supply to a local area, under specific transmission and generation outage scenarios. The performance of the system in meeting these conditions is used to determine the load meeting capability ("LMC") of an area for the purpose of regional planning. The LMC is the maximum load that can be supplied in the local area with no interruptions in supply or, under certain permissible conditions, with limited controlled interruptions as specified by the ORTAC.

---

[10] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

With respect to supply interruptions ORTAC requires that the transmission system be designed to minimize the impact to customers of major outages, such as a contingency on a double-circuit tower line resulting in the loss of both circuits, in two ways: by limiting the amount of customer load affected; and by restoring power to those affected within a reasonable timeframe. Specifically, ORTAC requires that no more than 600 MW of load be interrupted in the event of a major outage involving two elements. Further, load lost during a major outage must be restored within the following timeframes:

- All load lost in excess of 250 MW must be restored within 30 minutes;
- All load lost in excess of 150 MW must be restored within four hours; and
- All load lost must be restored within eight hours.

6.2 Near-Term Needs

Based on an application of ORTAC two near-term transmission system reliability needs, shown in Table 6-1 below, have been identified. These needs affect different groups of customers in the Region (i.e., different sub-systems), however they can be addressed through the same transmission reinforcement project consisting of a new TS located in Leamington.

Table 6-1: Summary of Windsor-Essex Region Reliability Needs

Sub-system	Need Type	Need Description	Need Date
Kingsville-Leamington Sub-system	Capacity to Meet Demand	Forecast loading on K6Z exceeds the thermal load meeting capability	Today
J3E-J4E Sub-system	Minimize the Impact of Interruption	J3E-J4E does not comply with ORTAC service interruption criteria — i.e., restoration of all load within 8 hours	Today

6.2.1 Kingsville-Leamington: Plan to Address the Need for Additional Supply Capacity and End-of-Life Replacement

Within the Region, the strongest growth in electricity demand is expected to occur in the Kingsville-Leamington area. This growth is predominantly attributable to growth in the greenhouse sector as indicated by customer connection requests received by the applicable LDC, the current outlook for expansion of existing greenhouse operations, and anticipated growth from new operations. Such growth expectations are based on approved and proposed development plans provided by the municipalities of Leamington and Kingsville, and a survey completed by the Ontario Greenhouse Vegetable Growers on behalf of local greenhouse growers.

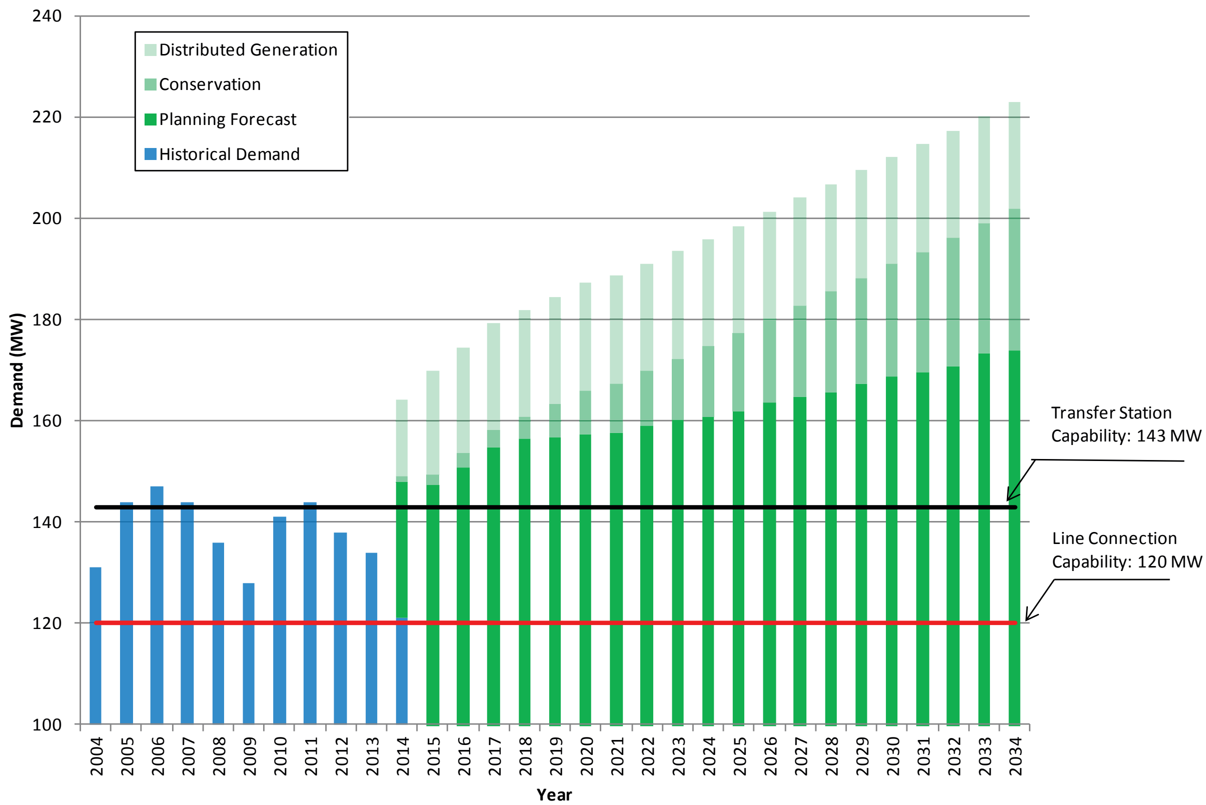
Similarly, the population of Kingsville is expected to increase by 0.5% per year over the next decade, which is higher than the slight population decline expected in the Region overall during the 2014 to 2033 planning horizon.[11]

The planning forecast for the Kingsville-Leamington area is shown in Figure 6-1 below, along with the LMC for the existing Kingsville TS. The approximate planned peak demand reduction between 2014 and 2033 for the Kingsville-Leamington sub-system is 25 MW from conservation, and 6 MW from DG. The peak demand reduction from conservation and DG is expected to offset about 57% of the forecast gross demand growth in the Region between 2014 and 2033. The LMC is based on the 120 MW thermal capability of the 115 kV connection line between Lauzon TS and Kingsville TS, which is the most limiting element of supply to the station. The Kingsville TS capability is higher, at 143 MW.

As shown in Figure 6-1, during the summer months the peak demand has exceeded the 120 MW limit, requiring the use of operating measures. The figure shows that based on the planning forecast, the Kingsville-Leamington area is expected to continue to exceed the capability of the existing Kingsville TS for the forecast period. Additional capacity is therefore required to meet current and future electricity demand in the Kingsville-Leamington sub-system. Until additional capacity is provided, operating measures such as an existing load rejection scheme (which is in violation of ORTAC) will be required. The existing system does not meet ORTAC criteria for supply capacity.

[11] Windsor-Essex Economic Development Corporation website. At www.choosewindsoressex.com.

Figure 6-1: Historical and Forecast Demand and Supply Capabilities in the Kingsville-Leamington Sub-system[12]



After considering "non-wires" and "wires" alternatives, the former-OPA, with the support of working group members, recommended a new station in Leamington to address the need.

In 2014 Hydro One filed a Leave to Construct application with the OEB for transmission expansion in the Leamington area, the SECTR project. The application is currently proceeding through the regulatory process and has a planned in-service date of 2018.

As part of the SECTR planning process, Hydro One identified a near-term need for transformer refurbishment due to end-of-life assets at Kingsville TS. There are currently four transformers at Kingsville TS. One of these units was recently replaced, but the other three units are reaching their end-of-life in the near future. In conjunction with the Leamington area transmission expansion, the option of partially refurbishing Kingsville TS by replacing one of the three transformers that are near end-of-life was recommended. This plan reduces the capacity at

---

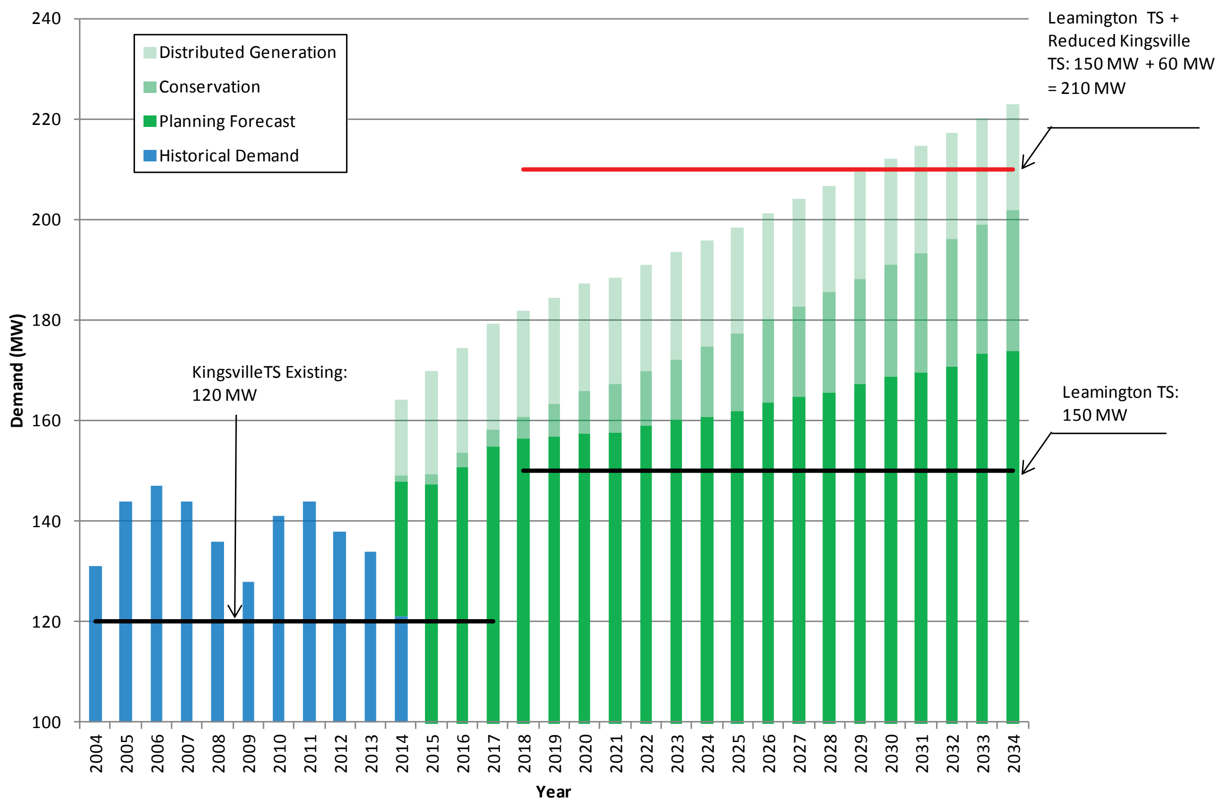
[12] Historic demand values reflect actual electricity demand and weather.

Kingsville TS by reducing the number of the station's transformers from four to two and reduces the LMC of the station from 120 MW to 60 MW, depending on the ability to transfer sufficient existing demand to the new Leamington TS. The result is a net increase in station capacity in the Kingsville-Leamington area, but with a different geographic distribution. This plan results in reduced flexibility for LDCs supplying customers in the Kingsville area. It will, however, be possible to return Kingsville TS to its current capacity in the future, should the forecast indicate the need for additional capacity.

The former-OPA prepared evidence to support Hydro One's regulatory application to the OEB for SECTR. This evidence details the needs in the Region; evaluates "non-wires" and "wires" alternatives; and recommends an integrated solution, comprised of planned conservation and DG resources, the new TS at Leamington, and partial refurbishment at Kingsville TS.

When the SECTR project is completed, and Kingsville TS refurbished with a reduced capacity, the combined supply capability in the Kingsville-Leamington area will be 210 MW. Figure 6-2 shows the supply capability in the Kingsville-Leamington area.

Figure 6-2: Kingsville-Leamington Sub-system Capability after Leamington TS is In-Service



6.2.2 Plan to Minimize the Impact of Supply Interruptions in the Windsor-Essex Region

A large portion of the transmission system in the Region, referred to as the "J3E-J4E sub-system", does not currently comply with ORTAC restoration criteria. In addition to addressing the supply capacity need in the Kingsville-Leamington area, the plan to build a new TS at Leamington will address the restoration need. This need is described in Figure 6-3.

<u>Sub-system Configuration and the Limiting Outage</u>

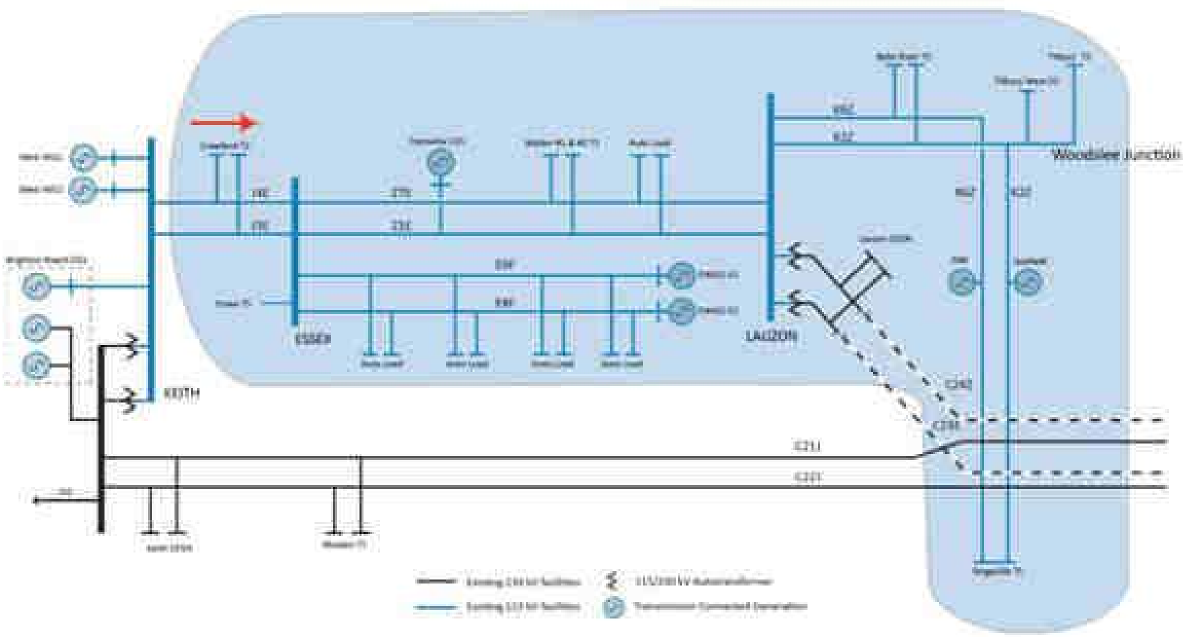
The J3E-J4E sub-system is supplied by two double-circuit 230 kV transmission lines between Chatham SS and Lauzon TS and Keith TS, respectively. The loss of one of these lines (C23Z/C24Z between Chatham and Lauzon) is the most limiting outage for this sub-system. In the event of the loss of the C23Z/C24Z transmission line, the Lauzon DESN station, which is directly connected to this line, is lost immediately. Subsequent to the outage, the 115 kV system supplying most of the City of Windsor, as well as Kingsville, Belle River and Tilbury, must be supplied entirely through the path consisting of the transformers at Keith TS and the 115 kV transmission line between Keith TS and Essex TS (J3E/J4E). The thermal capacity of the two

230/115 kV transformers at Keith TS limits the supply to the 115 kV system to approximately 300 MW. The C23Z/C24Z outage, and the J3E-J4E sub-system which is affected by this outage, are shown in Figure 6-3 below.

One of the Brighton Beach GS gas-fired generators is connected to the 115 kV bus at Keith TS between the Keith transformers and the J3E/J4E transmission line. The capability of the J3E/J4E line, which is higher than the capability of the Keith transformers, can be fully utilized by a combination of supply from the transmission system and generation at Brighton Beach GS. Due to this arrangement, the thermal capacity of the J3E/J4E transmission line limits the supply to the 115 kV system after the C23Z/C24Z double-circuit outage to approximately 440 MW. Because this would not be enough to meet the peak demand on the 115 kV system, the existing load rejection scheme would reject sufficient load immediately following the outage to respect the ratings of J3E/J4E.

The amount of load rejection required will depend on whether or not all local generation is in operation. For example, based on the planning forecast for 2017, following the loss of the C23Z/C24Z double-circuit transmission line, a total of 245 MW of load is interrupted, consisting of about 175 MW at Lauzon DESN and about 70 MW which is interrupted through load rejection, assuming local gas and renewable generation sources are running. This represents approximately 28% of the Windsor-Essex Region electricity demand, and is a substantial amount of demand to be interrupted following an outage. Following the contingency this load must be restored within the period of time prescribed by the ORTAC.

Figure 6-3: Windsor-Essex Region Transmission System Following an Outage to the C23Z/C24Z Transmission Line



Restoration Capability

The existing system lacks the capability to restore power to customers in the J3E-J4E sub-system in accordance with the ORTAC criteria which specifies that load greater than 250 MW must be restored within half an hour, load greater than 150 MW must be restored within 4 hours, and all load interrupted must be restored within 8 hours.

There are three sources of restoration capability which have been identified in the J3E-J4E sub-system: 1) gas-fired generation at Brighton Beach GS and in the J3E-J4E sub-system, 2) transferring load out of the J3E-J4E sub-system, and 3) transmission connected renewable generation within the J3E-J4E sub-system. These three contributors are discussed further below.

As noted previously, one of the gas-fired generating units at Brighton Beach GS is connected to the 115 kV bus at Keith TS. This generation capacity allows the capability of the J3E/J4E transmission line to be fully utilized after the C23Z/C24Z outage.

In addition, there is currently 154 MW of gas-fired generation within the J3E-J4E sub-system, consisting of East Windsor Cogeneration and TransAlta Windsor. The contract for one of these generators, TransAlta Windsor (74 MW), expires in December, 2016. Beyond this date, the amount of gas-fired generation within the sub-system will be reduced to 80 MW. This 80 MW of effective generation will help supply demand in the J3E-J4E sub-system following a major transmission outage until the expiry of the East Windsor Cogeneration contract in November, 2029.

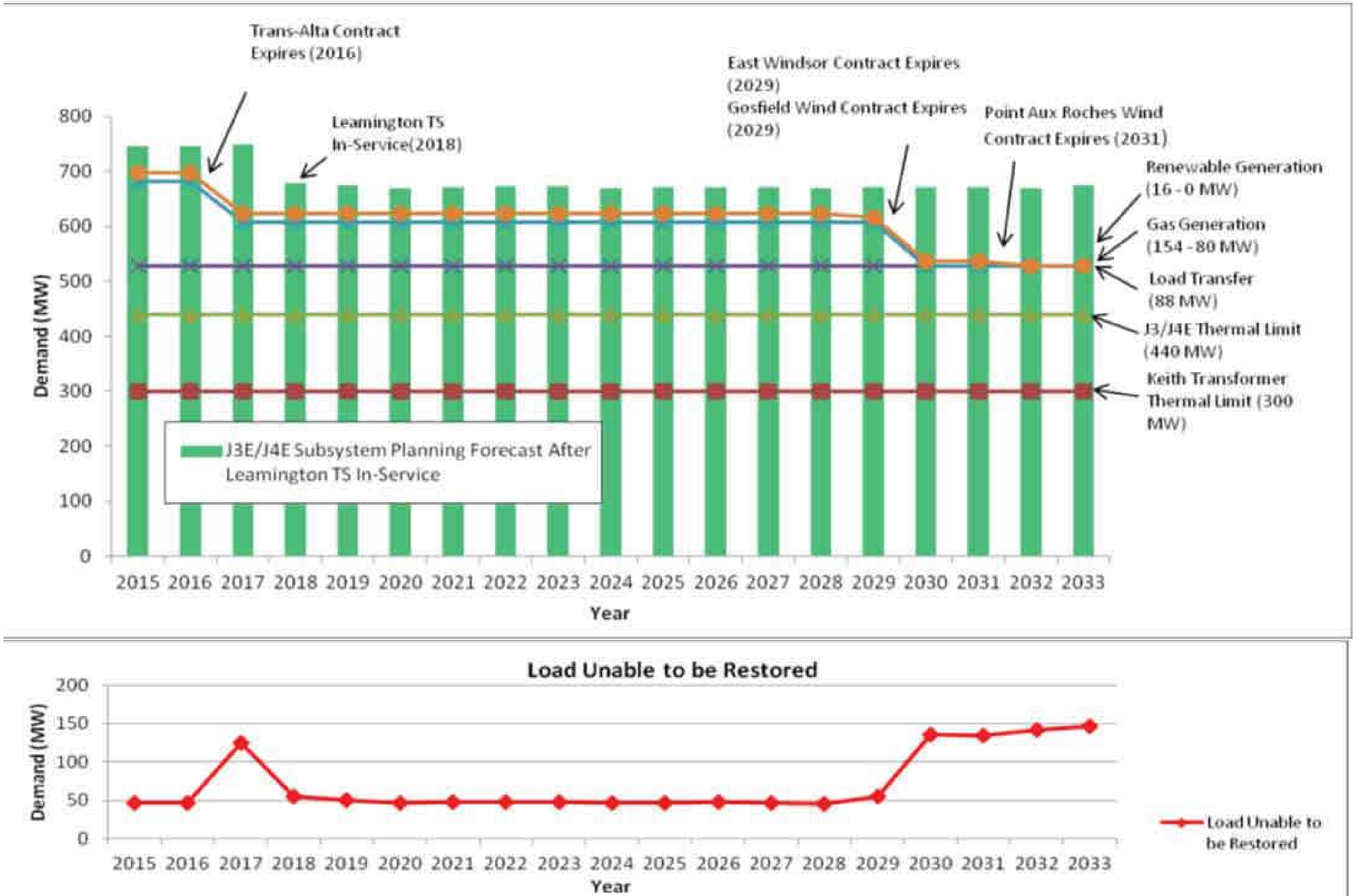
Hydro One has identified that there is a total of 88 MW of capability to transfer load supplied by the 115 kV system to stations supplied by the 230 kV system. This consists of 18 MW of transfer capability to Keith TS, 50 MW to Malden TS, and up to 20 MW of load at Tilbury West DS which can be supplied by the N5K circuit (outside the Region, near Chatham). These transfer capabilities are based on the station capability of Keith TS and Malden TS, and the capability of the N5K circuit.

In addition, as noted in Section 4.2 there is 100 MW of transmission connected renewable generation within the Kingsville-Leamington sub-system. It is reasonable to count on the effective capacity of 16 MW from these facilities for the purpose of providing restoration capability until the two contracts expire in 2029 and 2031 respectively.

The new Leamington TS which has a planned in-service date of 2017 would improve the restoration situation by moving some of the load out of the J3E-J4E sub-system to a new 230 kV supply point. Leamington TS will be supplied by C21J and C22J and will therefore not be affected by the C23Z/C24Z contingency.

Figure 6-4 summarizes the above analysis. After 2016 there is a need for approximately 125 MW of additional restoration capability in order to fully restore the J3E-J4E sub-system following the C23Z/C24Z double-circuit contingency. With the planned Leamington TS in-service in 2018 this requirement will decrease to about 50 MW.

Figure 6-4: J3E – J4E Sub-system Restoration



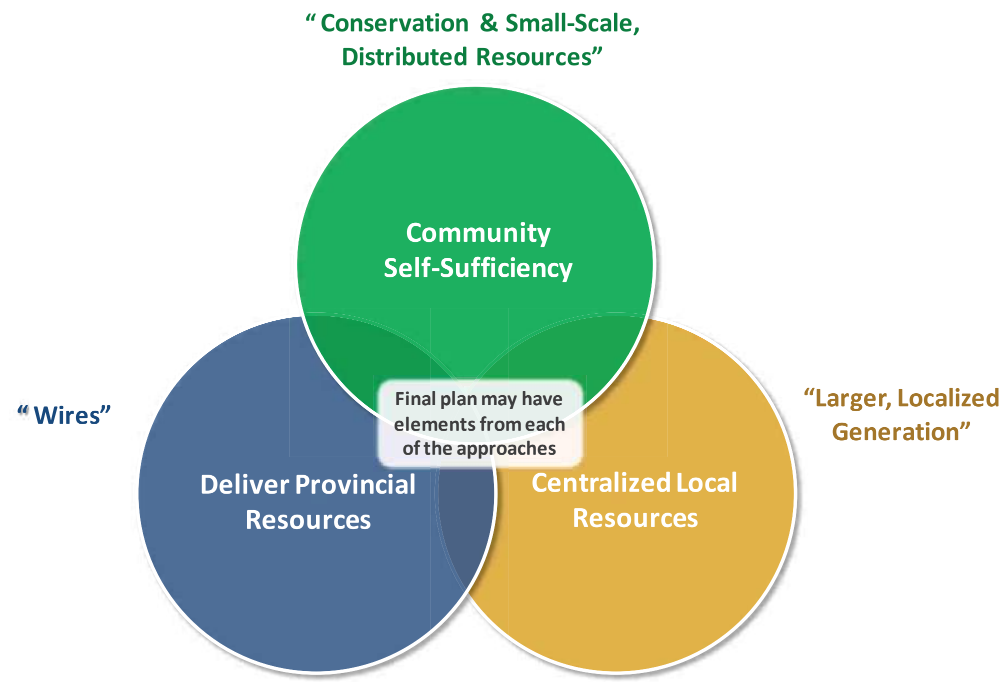
7. Long-Term Plan

No long-term supply capacity needs have been identified in the Region at this time. Therefore, instead of considering specific needs and planning options, long-term planning activities for the Region will include engaging with stakeholders and communities; monitoring demand, conservation, and DG trends in the area; coordinating with municipal or community energy planning activities; and generally laying the foundation for informed planning in the future. The OEB's regional planning process suggests a minimum 5-year cycle, however if significant changes are noted in the region over the coming years the process may be initiated earlier.

In recent years, a number of trends, including technology advances, policy changes supporting DG, greater emphasis on conservation as part of electricity system planning, and increased community interest and desire for involvement in electricity planning and infrastructure siting, are changing the landscape for regional electricity planning. Traditional, "wires" based approaches to electricity planning may not be the best fit for all communities. New approaches that acknowledge and take advantage of these trends, in addition to more traditional "wires-based", should also be considered.

To facilitate discussions about how a community might plan its future electricity supply, three conceptual approaches for meeting a region's long-term electricity needs provide a useful framework (see Figure 7-1). Based on regional planning experience across the province over the last 10 years, it is clear that different approaches are preferred in different regions, depending on local electricity needs and opportunities, and the desired level of involvement by the community in planning and developing its electricity infrastructure.

Figure 7-1: Approaches to Meeting Long-Term Needs



The three approaches are as follows:

- **Delivering provincial resources**, or "wires" planning, is the traditional regional electricity planning approach associated with the development of centralized electric power systems over many decades. This approach involves using transmission and distribution infrastructure to supply a region's electricity needs, taking power from the provincial electricity system. This model takes advantage of generation that is planned at the provincial level, with generation sources typically located remotely from the region. In this approach, utilities (transmitters and distributors) play a lead role in development.
- The **Centralized local resources** approach involves developing one or a few large, local generation resources to supply a community. While this approach shares the goal of providing supply locally with the community self-sufficiency approach below, the emphasis is on large central-plant facilities rather than smaller, distributed resources.
- The **Community self-sufficiency** approach entails an emphasis on meeting community needs largely with local, distributed resources, which can include: aggressive conservation beyond provincial targets; DR; DG and storage; smart grid technologies for managing distributed resources; integrated heat/power/process systems; and electric vehicles. While many of these applications are not currently in widespread use, for regions with long-term needs (i.e., 10-20 years in the future) there is an opportunity to develop and test out these options before commitment of specific projects is required.

> The success of this approach depends on early action to explore potential and develop options, and on the local community taking a lead role. This could be through a municipal energy planning or community energy planning process, or an LDC or other local entity taking initiative to pursue and develop options.

Given that no long-term supply capacity needs have been identified in the Region, it is not necessary to consider the application of these options to Windsor-Essex at this time. These concepts, which are being referenced in other planning regions around the province, are provided as background information for community members and stakeholders who are interested in the long-term considerations for regional electricity supply in Windsor-Essex.

8. Community, Aboriginal and Stakeholder Engagement

Community engagement is an important aspect of the regional planning process. Providing opportunities for input in the regional planning process enables the views and preferences of the community to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken to date for the Windsor-Essex Region IRRP and those that will take place to discuss the Regional planning process and electricity supply needs in the area.

A phased community engagement approach has been developed for the Windsor-Essex IRRP based on the core principles of creating transparency, engaging early and often, and bringing communities to the table. These principles were articulated as a result of the IESO's outreach with Ontarians to determine how to improve the regional planning process, and they are now guiding the IRRP outreach with communities.

Figure 8-1: Summary of Windsor-Essex IRRP Community Engagement Process

Creating Transparency:

Creation of Windsor-Essex IRRP Information Resources

- Dedicated Windsor-Essex IRRP web page created on IESO (former OPA) website providing background information, the IRRP Terms of Reference and listing of the Working Group members
- Dedicated web page added to Hydro One website, and information posted on LDC websites
- Self-subscription service established for Windsor-Essex IRRP for subscribers to receive regional specific updates
- Status: complete

Engaging Early and Often:

Municipal, First Nation & Métis Outreach

- Presentation and discussion at three group meetings with municipal planners from across the planning region
- Information on the plan provided to First Nation communities who may have an interest in the planning area with an invitation to meet
- Information provided to the Métis Nation of Ontario
- Status: initial outreach complete; dialogue to continue

Bringing Communities to the Table:

Broader Community Outreach

- Presentation at Municipal Councils, First Nation communities and Métis Nation of Ontario as requested
- Webinar to discuss regional planning process and electricity needs in the area
- Broader community outreach to be undertaken on education about regional planning in the Windsor-Essex area; feedback from this phase on community values and preferences will inform the decisions to be made in the next planning cycle
- Status: beginning in May 2015; no time limit

Creating Transparency

To start the dialogue on the Windsor-Essex IRRP and build transparency in the planning process, a number of information resources were created for the plan. A dedicated web page was created on the IESO (former-OPA) website to provide a map of the regional planning area, information on why the plan was being developed, the terms of reference for the IRRP and a listing of the organizations involved was posted on the websites of the Working Group members. A dedicated email subscription service was also established for the Windsor-Essex IRRP where communities and stakeholders could subscribe to receive email updates about the IRRP.

Engaging Early and Often

The first step in the engagement of the Windsor-Essex IRRP was providing information to representatives from the municipalities and First Nation communities in the Region. For the municipal meetings, presentations were made to the Windsor-Essex Region municipal planners and Chief Administrative Officers at three group meetings held in Windsor and Chatham during October and November, 2014. Key topics discussed during the meetings included confirmation that the demand forecast reflects municipal planning expectations, system restoration needs, and the strong interest shown by the local greenhouse industry in CHPSOP offered by the former-OPA.

Bringing Communities to the Table

This engagement will begin with a webinar hosted by the Working Group to discuss the plan and approaches for near-term options. Presentations on the Windsor-Essex IRRP will also be made to Municipal Councils, First Nation communities and the Métis Nation of Ontario on request.

To strengthen the discussion, an informational meeting will be held with local representatives from Municipalities including Mayors and economic development groups, Aboriginal communities, local industry and community groups. Following this meeting, a public open house will be held to further expand the discussion and awareness at a community level.

Strengthening processes for early and sustained engagement with communities and the public were introduced following an engagement held in 2013 with 1,250 Ontarians on how to enhance regional electricity planning. This feedback resulted in the development of a series of recommendations that were presented to, and subsequently adopted by the Minister of Energy. Further information can be found in the report entitled "Engaging Local Communities in Ontario's Electricity Planning Continuum"[13] available on the IESO website.

Information on outreach activities for the Windsor-Essex Region IRRP can be found on the IESO website and updates will be sent to all subscribers who have requested updates on the Windsor-Essex IRRP.

---

[13] http://www.powerauthority.on.ca/stakeholder-engagement/stakeholder-consultation/ontario-regional-energy-planning-review

9. Conclusion

This report documents the IRRP that has been carried out for the Windsor-Essex Region and it largely fulfils the OEB requirement to conduct regional planning for this Region. The IRRP identifies electricity needs in the Region over the 20-year period from 2014 to 2033, recommends a plan to address near-term needs, and identifies a monitoring and engagement plan for the next few years, to inform the next regional planning cycle.

Implementation of the near-term plan is already underway, with the LDCs developing conservation plans consistent with the Conservation First policy and with infrastructure projects being developed by Hydro One.

The planning process does not end with the publishing of this IRRP. The Windsor-Essex Working Group will continue to meet at least annually to monitor progress and developments in the Region.

Appendix C: IESO Comment Letter

IESO Letter of Comment

Essex Powerlines Corporation

Renewable Energy Generation Investments Plan

April 28, 2017

ieso
Independent Electricity System Operator

Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the [Independent Electricity System Operator][1] ("[IESO]") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the [IESO], or participated in planning meetings with the [IESO];
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the Renewable Energy Generation ("REG") investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

Essex Powerlines Corporation – Distribution System Plan

On April 10, 2017, the IESO received a REG Information consisting of FIT and microFIT connections, expansion investments, and in-progress applications ("Plan") from Essex Powerlines Corporation ("Essex"). The IESO has reviewed the Plan and provides the following comments.

IESO FIT/microFIT Applications Received

As of December 31, 2016, the Plan indicates that Essex has connected 150 microFIT projects, representing 1.2536 MW of capacity, along with 12 FIT projects and 2 RESOP projects representing 2.838 MW and 15 MW respectively. Essex has forecast connections of an additional 1.28 MW from 4 additional FIT projects in 2017, 0.9 MW from 3 FIT projects in 2018, 0.384 MW from 2 FIT projects in 2019, and an additional 0.1 MW from 10 additional microFIT projects.

According to the IESO's information as of March 31, 2017, the IESO has offered contracts to 152 microFIT projects totalling 1.2628 MW of capacity, 16 FIT projects totaling 4.114 MW, and 2 RESOP projects totalling 15 MW. The additional 4 FIT projects the IESO has record of are assumed to be the 4 additional projects in Essex' forecast for 2017 for which the IESO has issued contracts.

The REG connections information in Essex' Plan is therefore substantially consistent with that of the IESO.

[1] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

Independent Electricity System Operator
1600 – 120 Adelaide Street West, Toronto, ON M5H 1T1
t 416 967-7474 f 416 967-1947 toll free 1-800-797-9604 customer.relations@ieso.ca www.ieso.ca

Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

Essex is one of the five local distribution companies in the Windsor-Essex Region identified through the OEB regional planning process. As member of the Technical Working Group for the Windsor-Essex Region, Essex has been involved in the development of the Windsor-Essex Region Integrated Regional Resource Plan ("IRRP"), which was published in April 2015.[2] On December 22, 2015, Hydro One Networks Inc. published a Regional Infrastructure Plan ("RIP") for this region in which Essex participated as a member of the Working Group.[3]

The regional planning process for this region is now complete and will be undertaken again when the next 5-year planning cycle commences, unless there is sufficient load growth, or an event that triggers the requirement to initiate the regional planning process earlier.

Essex' Plan identifies investments throughout the 2017-2020 period for "transformation and expansions" which will support REG connections. While these investments are not identified in the Hydro One RIP or the IRRP, the IESO's perspective is that they do not require further regional coordination as they are driven by individual connections.

The IESO appreciates the opportunity to comment on the REG Investments Plan provided by Essex, as part of its Distribution System Plan at this time.

[2] http://www.ieso.ca/get-involved/regional-planning/southwest-ontario/windsor-essex
[3] http://www.hydroone.com/RegionalPlanning/Windsor-Essex/Documents/RIP%20Report%20Windsor-Essex.pdf

Independent Electricity System Operator
1600 – 120 Adelaide Street West, Toronto, ON M5H 1T1
t 416 967-7474 f 416 967-1947 toll free 1-800-797-9604 customer.relations@ieso.ca www.ieso.ca

Appendix D: INNOVATIVE Customer Satisfaction Surveys

INNOVATIVE
RESEARCH GROUP

Essex Powerlines Corp.

Ratepayer Telephone Survey

Report

JULY 2017

STRICTLY PRIVILEGED AND CONFIDENTIAL

Summary of Findings:
Residential Customers

- Residential customers are price-sensitive, but they may be willing to pay more if it means improved reliability. While they are confident that they are well protected when it comes to the quality and reliability of electricity in the province, they cannot say the same about price. Further, most report that they are having to do without some other priorities in order to pay their electricity bills.

- Familiarity with the local electricity distribution system is moderate (51% are at least somewhat familiar), but satisfaction with the service they are receiving from Essex Powerlines is high (85%). In response to an open-ended question designed to elicit unmet needs, customers ask for lower rates (32%), or a reduction in outages (19%). However, 31% had no suggestions, and an additional 6% reported that their service is good.

- Respondents were provided with a list of six potential customer priorities and asked to indicate which were most important to them. When it comes to establishing priorities, price outweighs reliability: 57% say delivering reasonable electricity distribution prices is the *most important* priority, compared to 21% who opt for ensuring reliable electrical service. Customers are least interested in storage and solar panels. In response to an open-ended question, 78% reported that there were no important priorities missing from the list that was presented to them.

- Only a third (34%) of customers are at least somewhat familiar with the amount of their electricity bill that is allocated to Essex Powerlines. Almost half (45%) said they were not familiar.

- Almost half (48%) of Essex Powerlines' residential customers have experienced between one and three outages in the past 12 months, but a plurality (40%) report their most recent outage lasted less than 15 minutes and most (55%) said it was a minor inconvenience.

- Asked if Essex Powerlines should aim to maintain or reduce the current number of unplanned outages, 45% would like them to spend what is needed to maintain the current number. Similarly, 49% would prefer the utility spends what is needed to maintain the current duration of unplanned outages.

- However, customers are not averse to spending on improving reliability: most (71%) would like Essex Powerlines to invest what it takes to replace aging infrastructure to maintain system reliability, even if there is an increase to their bill. Further, 75% would like the utility to replace equipment before failure, and 85% feel it is important to invest now in modernizing the local distribution system. And, finally, 71% feel prudence is important, but that utility staff need to have the proper tools and equipment.

- At the end of the survey, 82% of residential customers give social permission to a rate increase of approximately $0.30 per month based on Essex Powerlines' proposed five year plan. Almost half (45%) say the increase is reasonable and they support it, while a further 37% don't like it, but feel it is necessary. By comparison, only 16% find the proposed increase unreasonable and oppose it.

Summary of Findings:
General Service Customers

- Like residential customers, general service customers feel more protected when it comes to the reliability and quality of electricity than the price of electricity. They too report having to put off other spending priorities in order to pay their electricity bills, but they are less likely than residential customers to be willing to pay more for increased reliability.
- About half (n=29) of the general service customers interviewed are familiar with the local electricity distribution system, but most (n=46) are satisfied with the service Essex Powerlines is providing their organization. In response to an open-ended question designed to elicit any unmet needs, the two predominant themes were lower rates, and improved reliability. Many are fine with their current service as is and do not have suggestions for improvement.
- From a list of six customer priorities, the general service customers interviewed ranked delivering reasonably electricity distribution prices most important, followed by ensuring reliable electrical service. The two least important priorities were electrical storage and solar panel installation, and minimizing impact on the environment. Sixteen general service respondents suggested additional priorities, ranging from new infrastructure to reducing (utility) management pay.
- Fewer than half (n=21) of general service respondents are familiar with how much of their monthly bill is allocated to Essex Powerlines.
- While some (n=11) reported no outages in the past 12 months, 22 general service respondents reported experiencing between one and three outages. Some (n=10) said their last outage lasted less than 15 minutes, but 18 said theirs lasted between an hour and six hours. Further, more than half (n=34) said their most recent power outage was a major inconvenience.
- Unlike residential customers, most (n=28) general service respondents would prefer that Essex Powerlines spend what is needed to reduce the number of unexpected power outages. The same number (n=28) would like a more moderate approach when it comes to reducing the duration of unplanned outages, with the goal being to maintain the current length.
- General service respondents feel Essex Powerlines should invest what it takes to replace aging infrastructure to maintain reliability – even if that mean a slight increase in their monthly bill (n=48). And, most (n=40) do not want to wait until breakdown before replacing equipment. Fifty of the sixty general service customers interviewed feel it is important to invest now in modernizing the distribution system, and 43 say the utility should be wise with its spending, but that staff need the proper tools and equipment.
- At the end of the survey, 21 of the 34 general service respondents asked either find the proposed rate increase reasonable and they support it (n=10), or they don’t like it but think it is necessary (n=11). Only 13 oppose the rate increase and find it unreasonable.

Survey Methodology

Field and Design

Essex Powerlines commissioned Innovative Research Group (INNOVATIVE) to conduct a customer engagement telephone survey among their residential, general service under 50 kWh and general service over 50 kWh rate classes in preparation for their upcoming rate application filing with the Ontario Energy Board. INNOVATIVE, on behalf of Essex Powerlines, invited customers from these three rate classes to participate in a 12 minute telephone survey.

- The **residential** survey fielded from June 19th to 27th, 2017
- The **general service** surveys fielded from June 22nd to 29th, 2017

The residential telephone survey used a stratified random sampling approach based on known characteristics, in this case, consumption and community. Overall, 524 residential customers, completed the survey. Slight statistical weights were applied to the final data to ensure the sample was representative of Essex Powerlines customers by community and annual consumption level. The margin of error for the final weighted residential sample of n=500 is ±4.4%, 19 times out of 20.

A total of 51 general service under 50 kWh customers and 9 general service over 50 kWh customers completed the survey. Numerous attempts were made to recruit customers in these rate classes to complete the survey, and these figures represent the final sample once the contact list had been exhausted. The data was combined for reporting purposes, and a qualitative assessment is provided in this report. Due to the qualitative nature of the analysis, no margin error is applied.

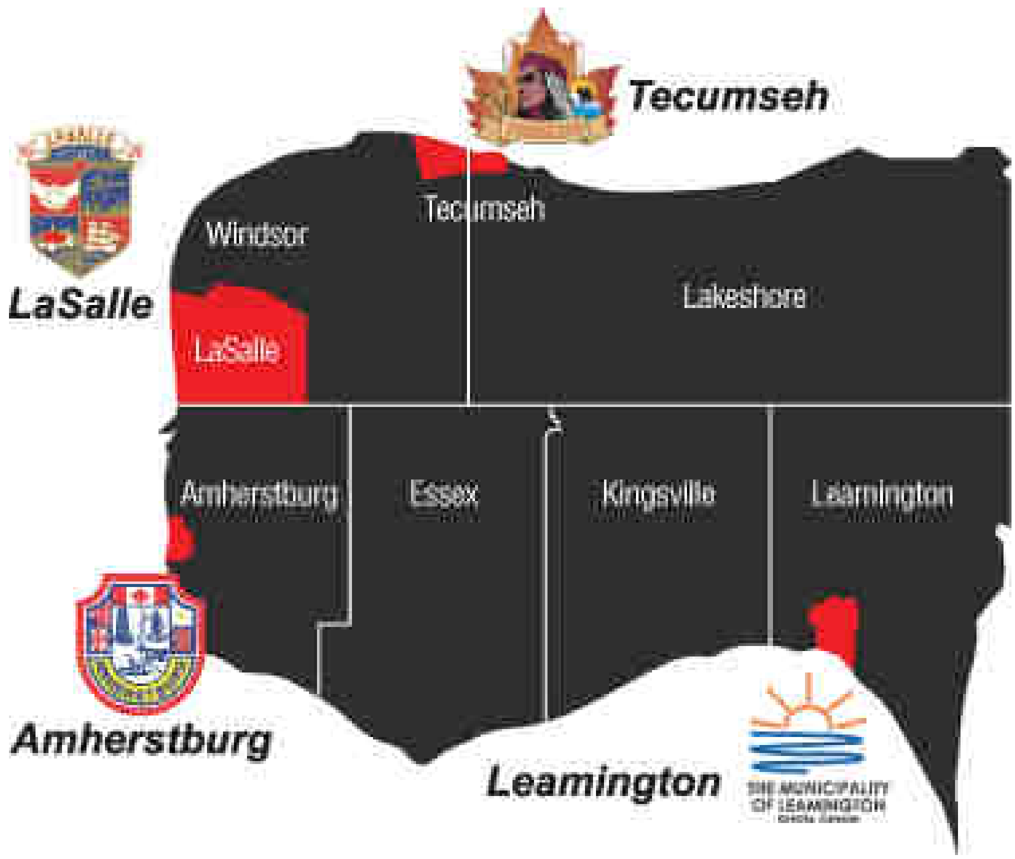
Sample lists were provided by Essex Powerlines. Screening questions were designed to ensure only customers who received an electricity bill from Essex Powerlines were included. In addition, residential customers needed to have primary or shared responsibility over their household’s electricity bill and only the organizations’ decision makers on electricity use were included in the business interviews. Business customers could also be household customers of Essex Powerlines, but were reminded to respond as their organization’s decision-maker.

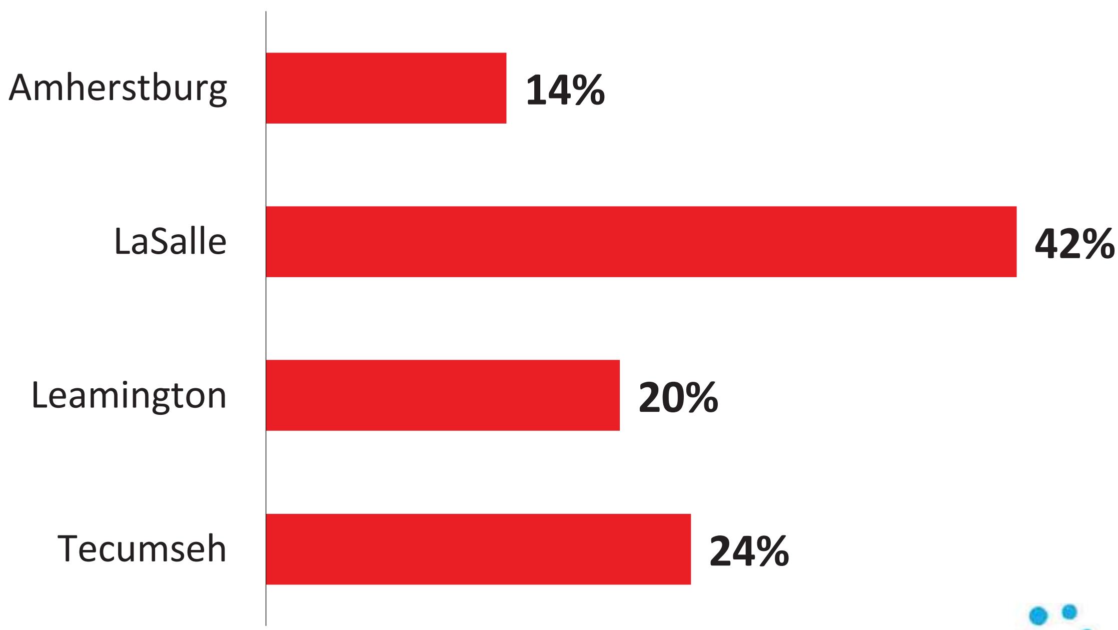
Residential Rate Class

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Residential

Regional Segmentation

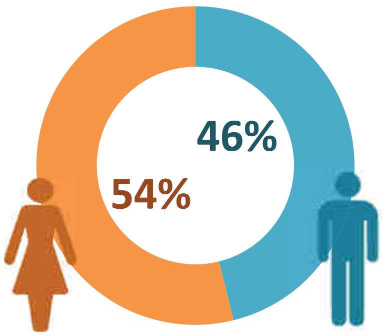




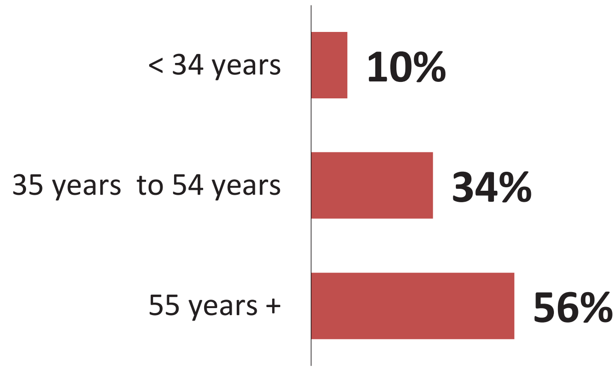
INNOVATIVE RESEARCH GROUP

Segmentation & Demographics

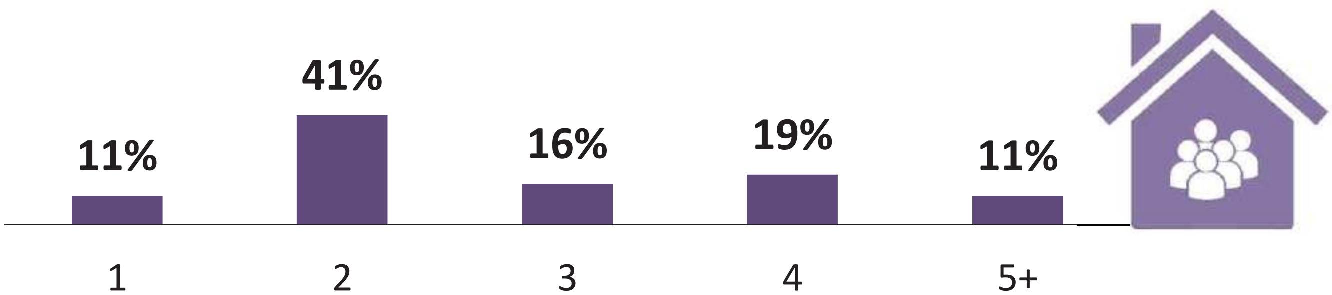
Gender



Age

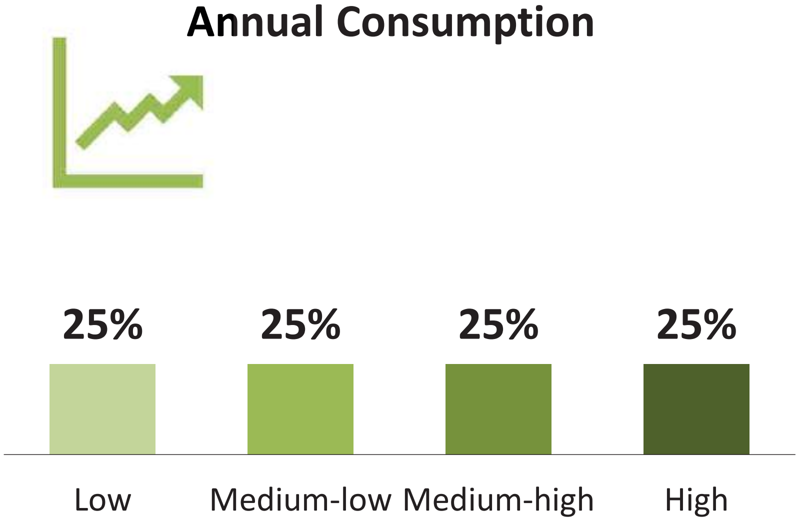


Household Size

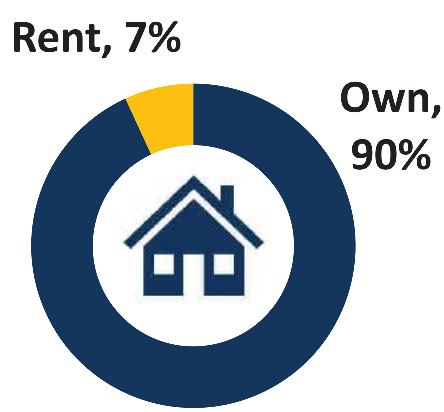


Note: 'Refused' (3%) not shown.

Annual Consumption



Home Ownership



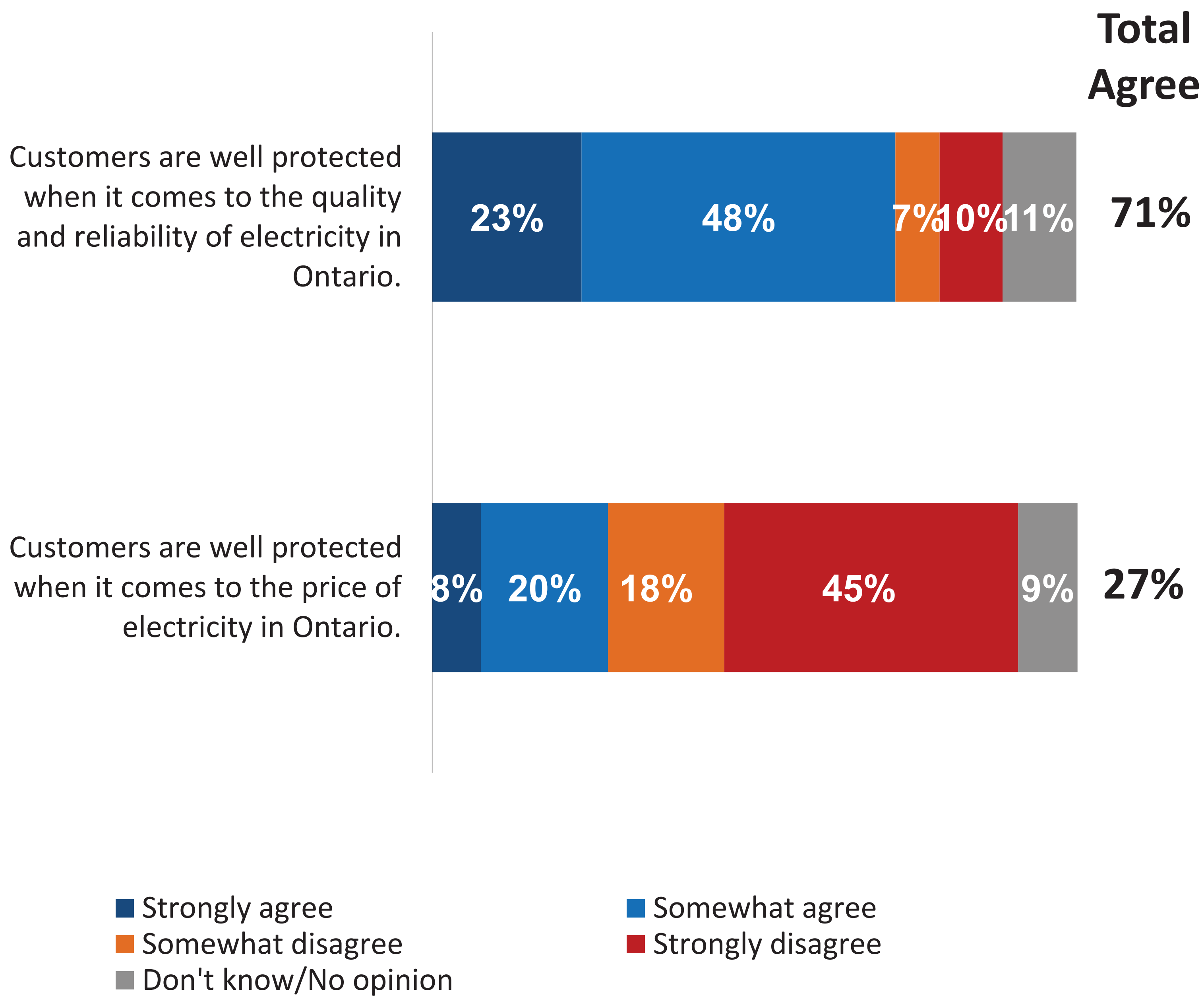
Note: 'Refused' (4%) not shown.

Attitudes Toward Electricity in Ontario:

Residential customers feel protected on quality and reliability, but not on price

Residential

Q Lastly, I'd like to ask you some general questions about the electricity system in Ontario.
For each statement please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree. If you don't know enough to say or don't have an opinion just let me know.
[asked all respondents, n=500]



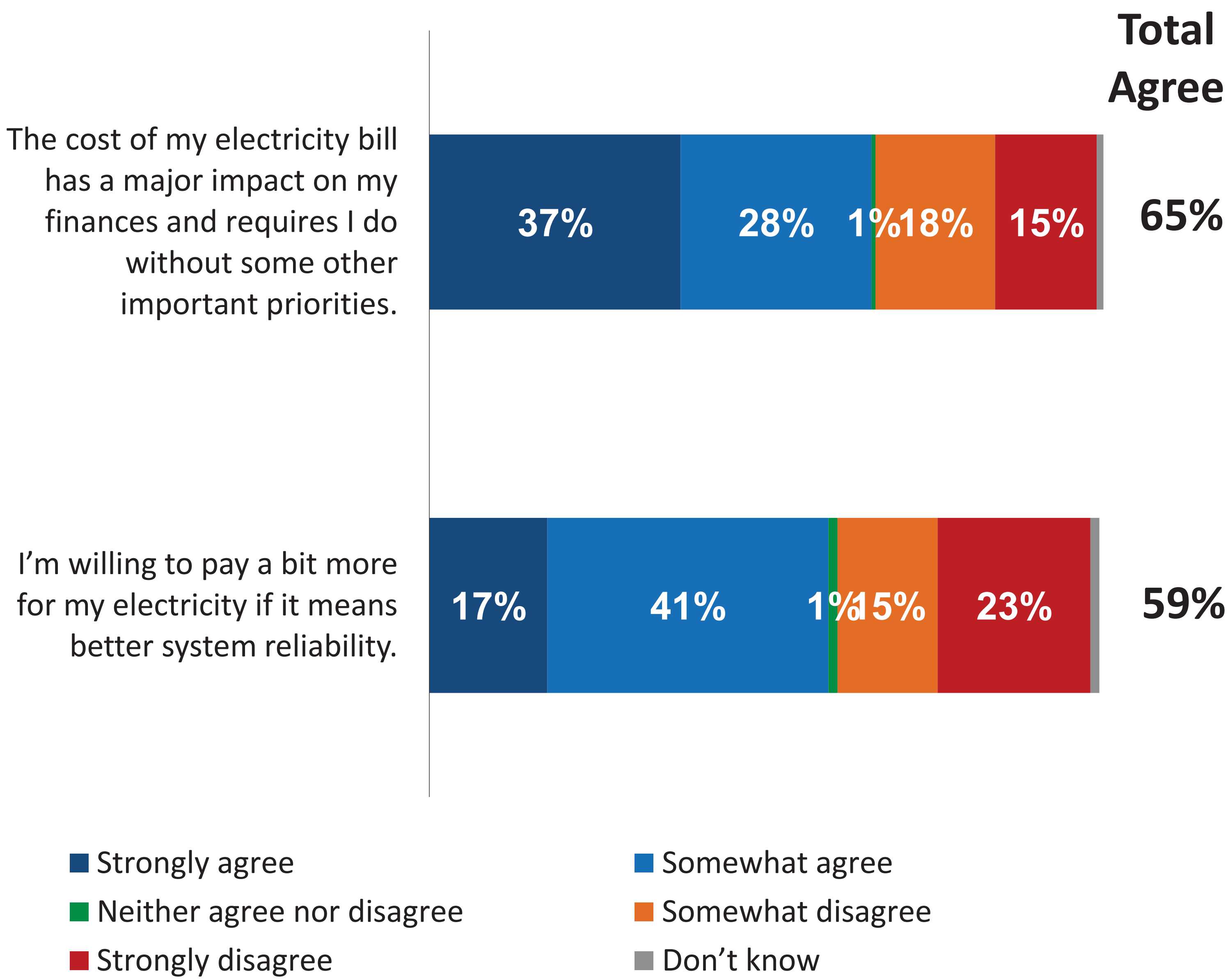
Note: 'Refused' (1%) not shown.

Paying for Electricity:

While most (65%) say their hydro bill has a major impact on their finances, more than half (59%) would pay more for improved reliability

Residential

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=500]



INNOVATIVE RESEARCH GROUP

Note: 'Refused' (1%) not shown.

Familiarity:

Approximately half (51%) are familiar with the local electricity distribution system; highest among those with high annual consumption

Residential

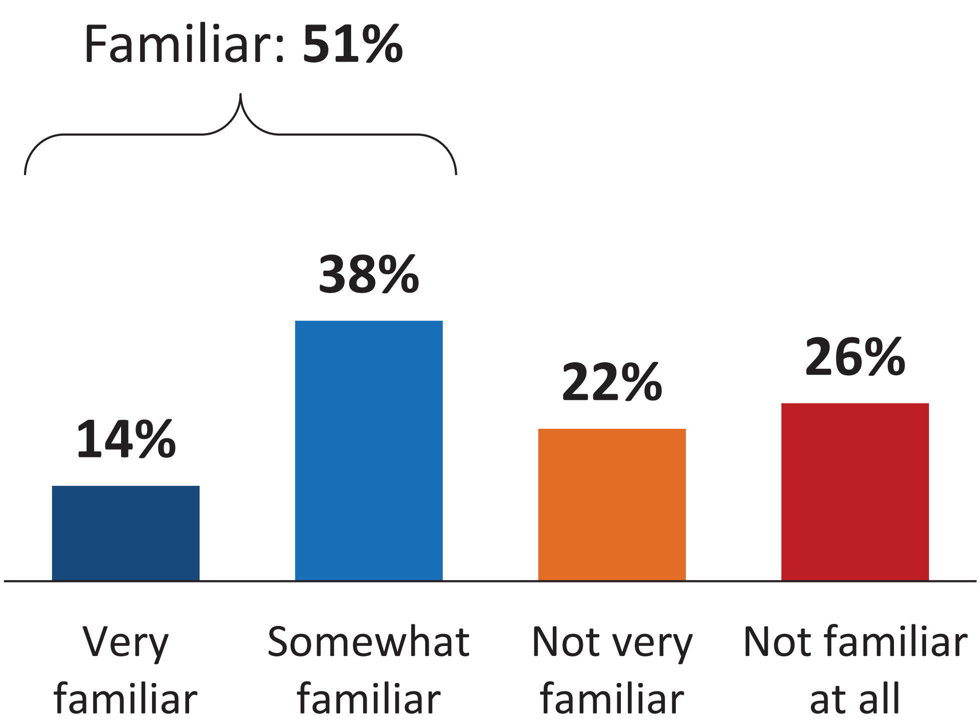
Q To start, I'd like to ask you a few questions about the electricity system… As you may know, Ontario's electricity system has three key components: **generation, transmission** and **distribution**.

- **Generating stations** convert various forms of energy into electric power;
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province; and
- **Distribution lines** carry electricity to the homes and businesses in our communities.

Today we're going to talk about your local distribution system which, in your community, is maintained and operated by Essex Powerlines.

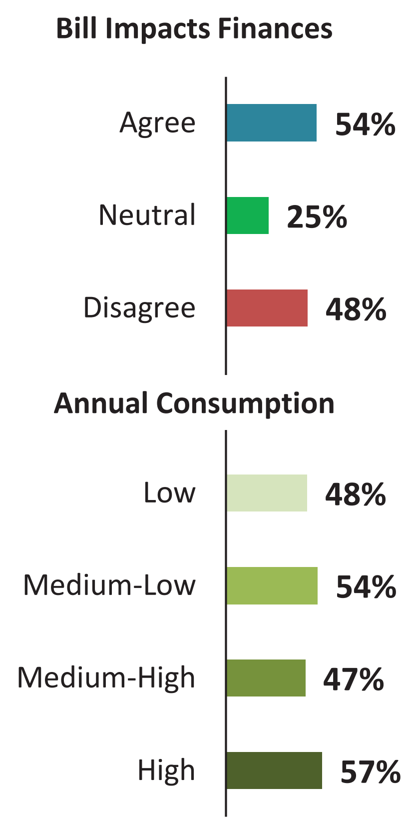
How familiar are you with the local electricity distribution system? Would you say …

[asked all respondents, n=500]



Segmentation

*Those who say "**Familiar**":*



Note: 'Don't know' (1%) not shown.

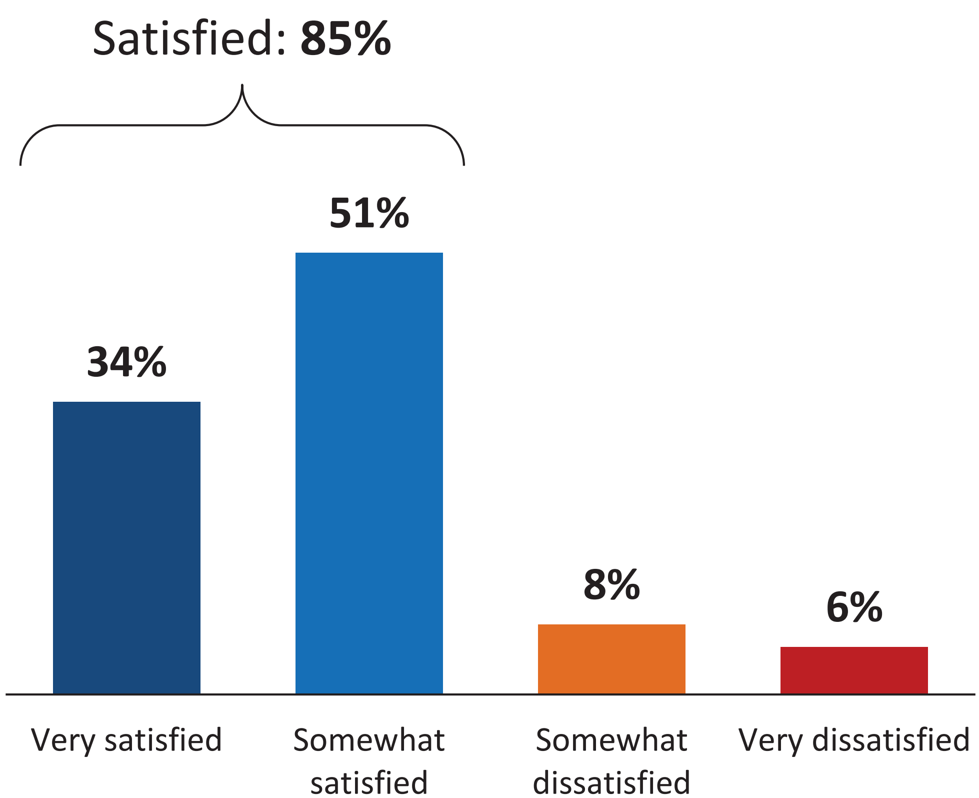
Satisfaction with Services:

Majority (85%) are satisfied with Essex Powerline's performance; highest among those with lowest annual consumption

Residential

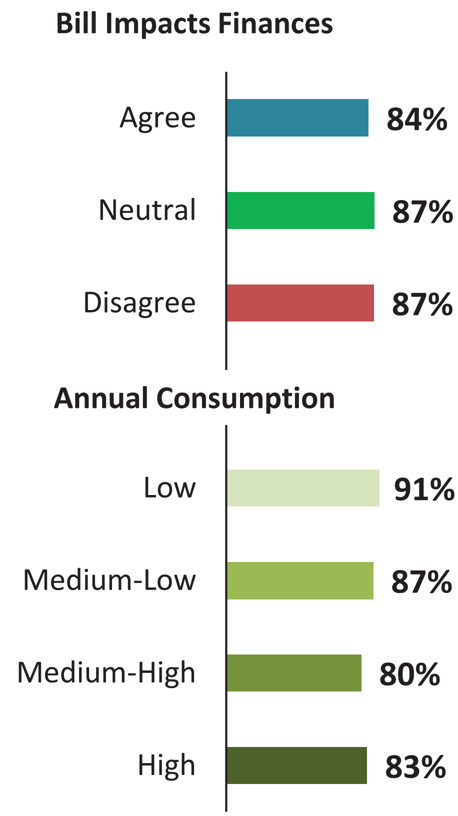
Q Generally speaking, how satisfied are you with the job **Essex Powerlines** is doing running your local distribution system? Would you say…

[asked all respondents, n=500]



Segmentation

*Those who say "**Satisfied**":*



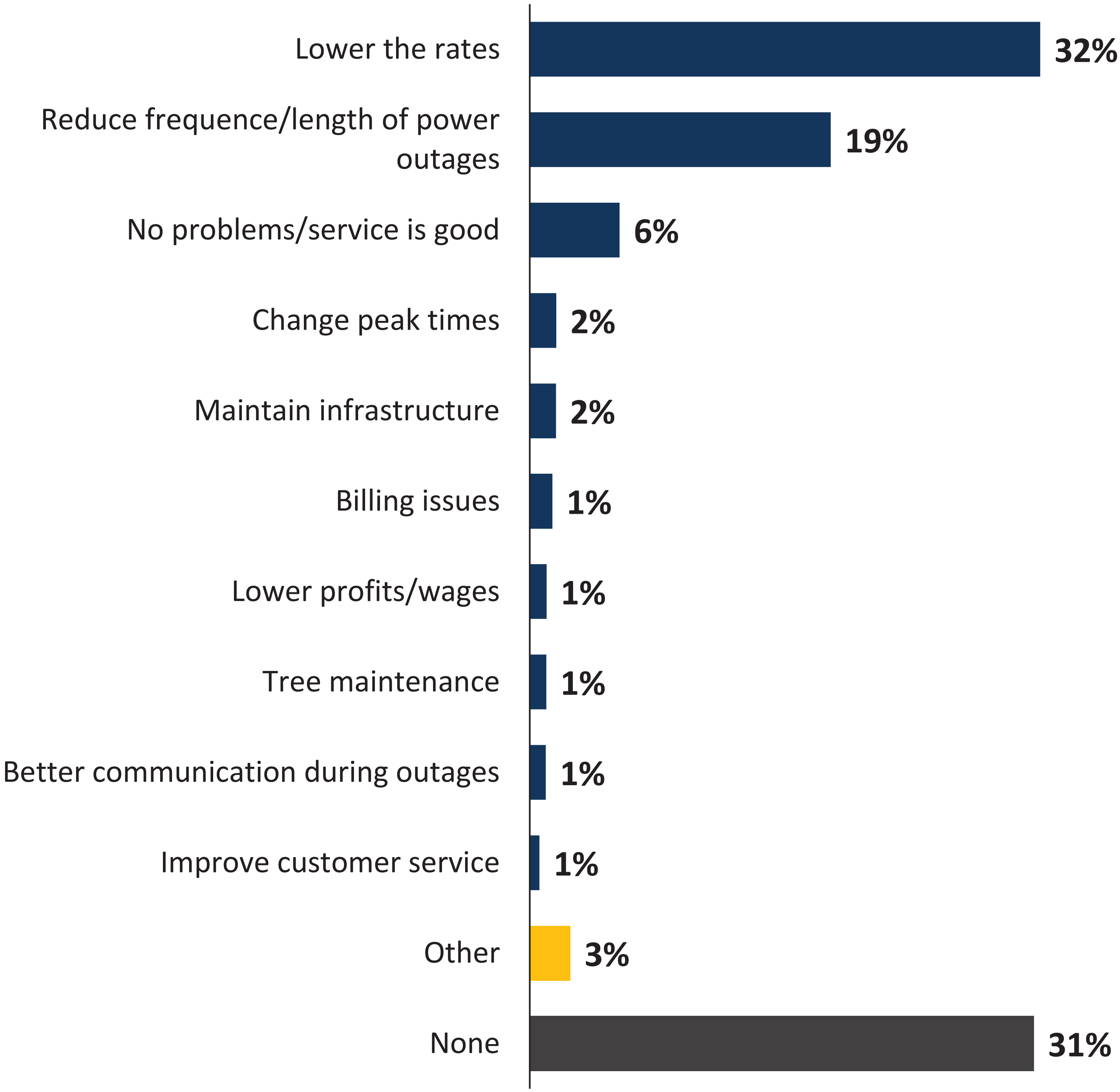
Note: 'Don't know' (1%) not shown.

Suggestions for Improvement:

Almost 1-in-3 (31%) do not have any suggestions for improvement; those who did identified lowering rates as the top suggestion

Residential

Q Is there anything in particular **Essex Powerlines** can do to improve its service to you?
[asked all respondents, n=500]



INNOVATIVE RESEARCH GROUP

Note: 'Don't know' (1%) not shown.

Customer Priorities:

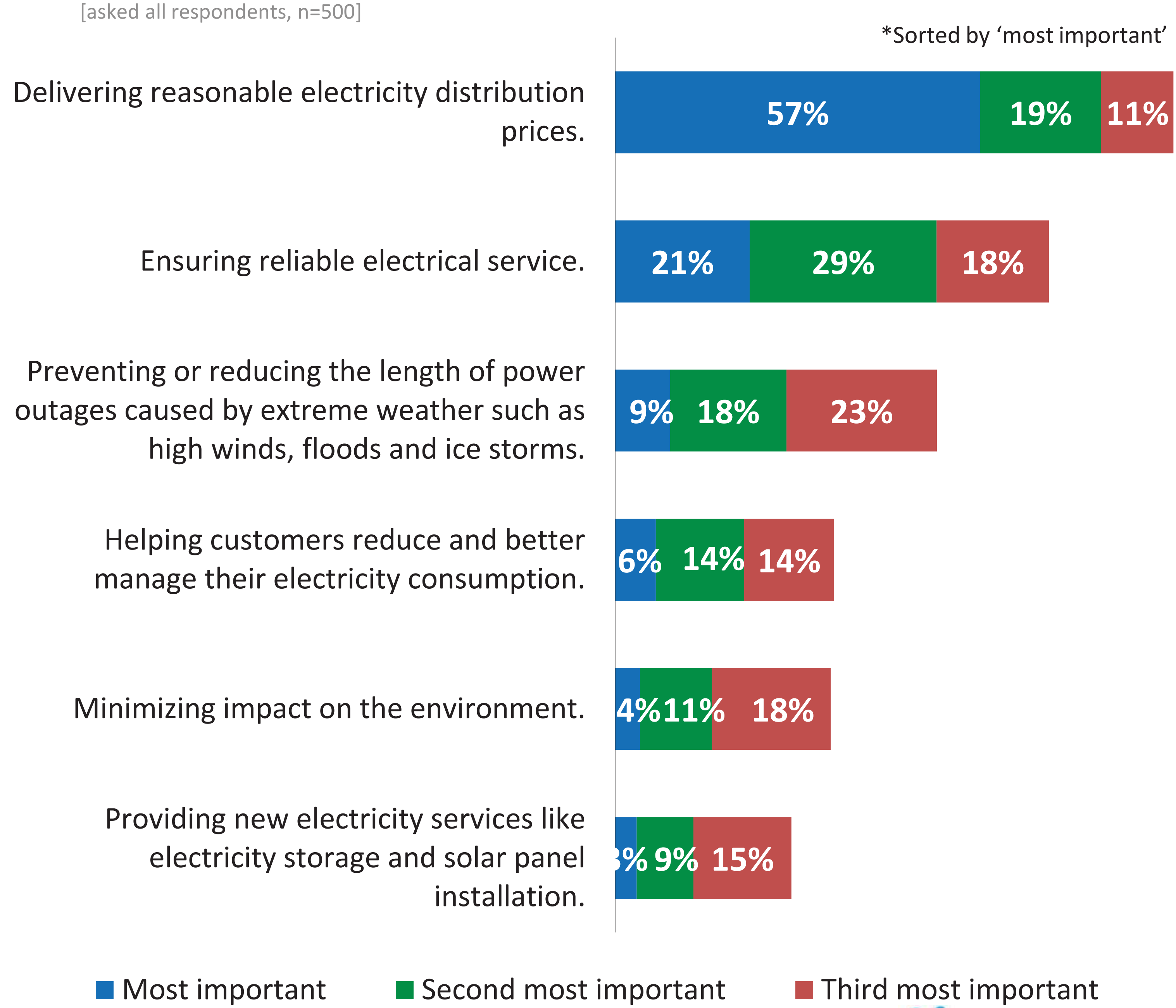
Majority (57%) identified 'delivering reasonable electricity distribution prices' as their most important priority

Residential

Q Essex Powerlines regularly holds discussions with its customers to better understand how it should set spending priorities with the money customers pay for service. In recent conversations with customers, a number of company goals were identified as key priorities for Essex Powerlines.

Among the following Essex Powerlines priorities, please tell me which one is most important to you. What is the next most important priority you think Essex Powerlines should focus on? And what do you consider the third most important priority?

[asked all respondents, n=500]

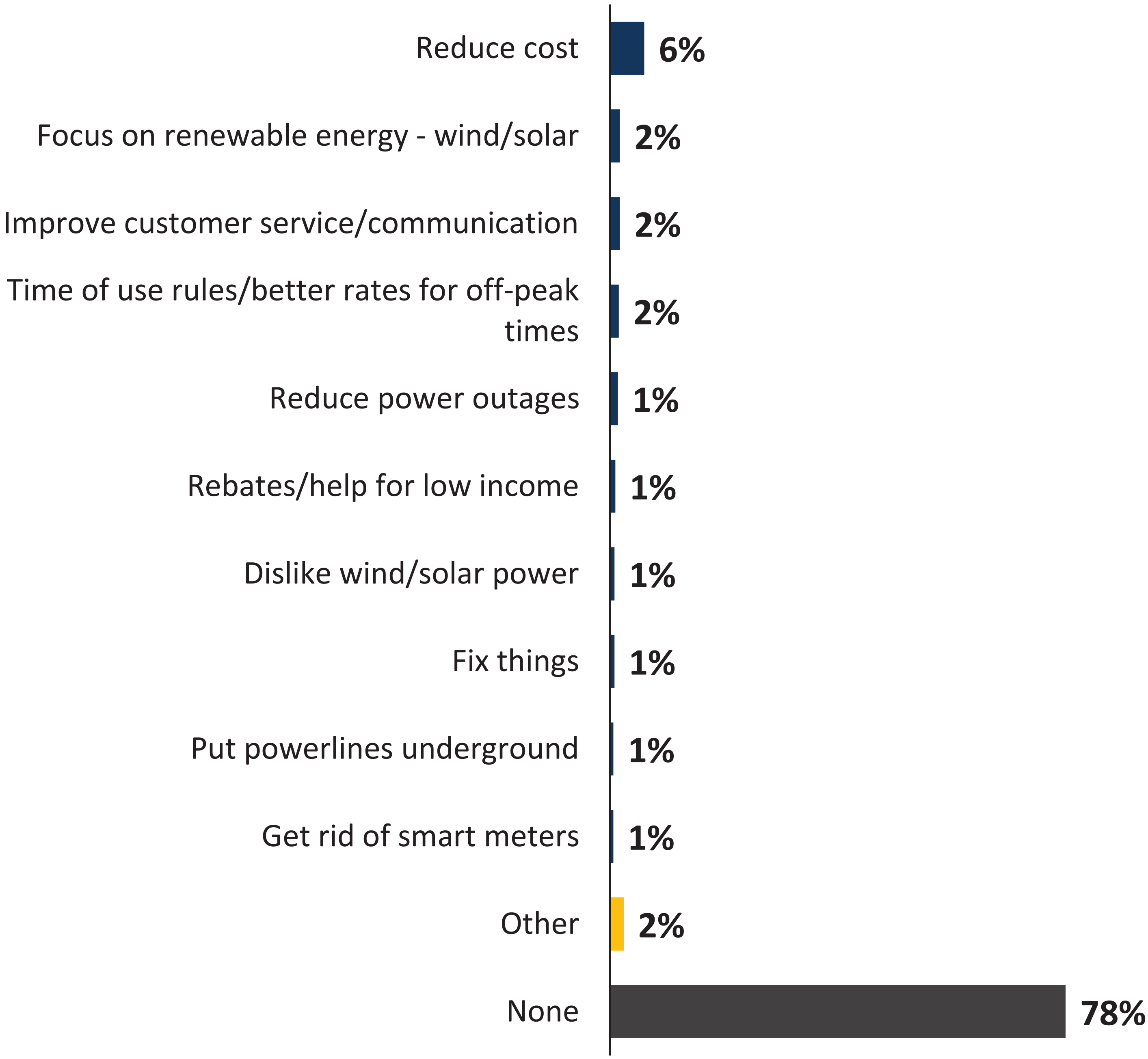


Additional Priorities:

Majority (78%) have no suggestions for missed priorities; those who did mentioned reducing cost (6%)

Residential

Q Are there any other important priorities that Essex Powerlines should be focusing on that weren't included in the previous list I read to you?
[asked all respondents, n=500]



INNOVATIVE RESEARCH GROUP

Note: 'Don't know' (1%), 'Refused' (2%) not shown.

Bill Knowledge & Impact:

Approximately 1-in-3 (34%) are familiar with the amount remitted; familiarity appears highest among those with highest annual consumption

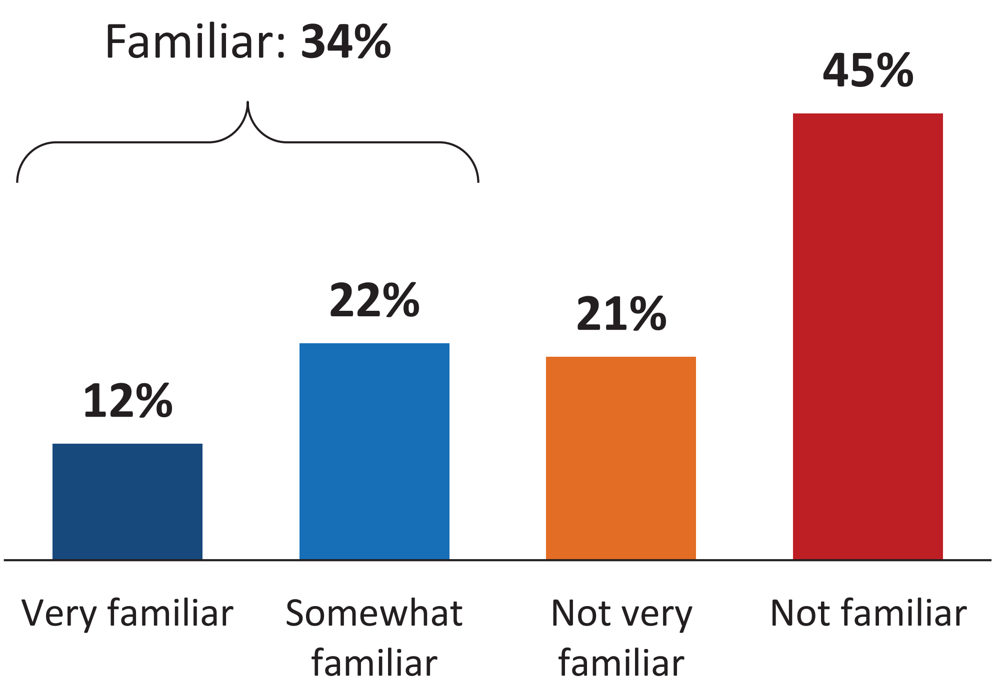
Residential

Q

I'd now like to talk with you about your electricity bill... While some customers pay more and others pay less, the **average residential customer pays about $145 a month** for electricity and other municipal services, of which **approximately $26 or 20% goes to Essex Powerlines**. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

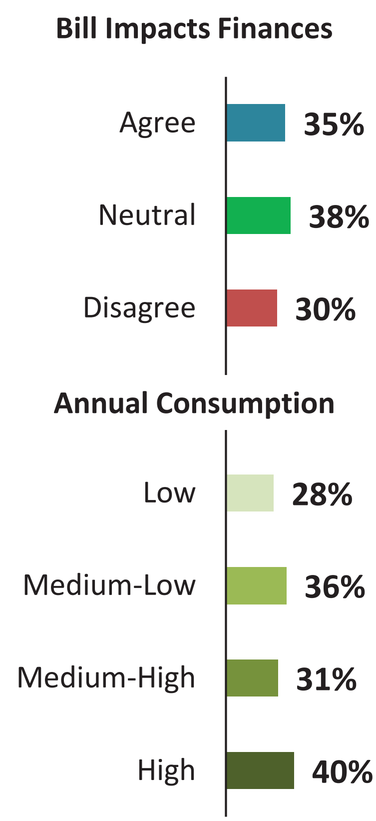
Before this survey, how familiar were you with the amount of your electricity bill that went to Essex Powerlines? Would you say...

[asked all respondents, n=500]



Segmentation

*Those who say "**Familiar**":*



Note: 'Don't know' (0%) not shown.

ESSEX POWERLINES CORPORATION

System Reliability

Residential

INNOVATIVE RESEARCH GROUP

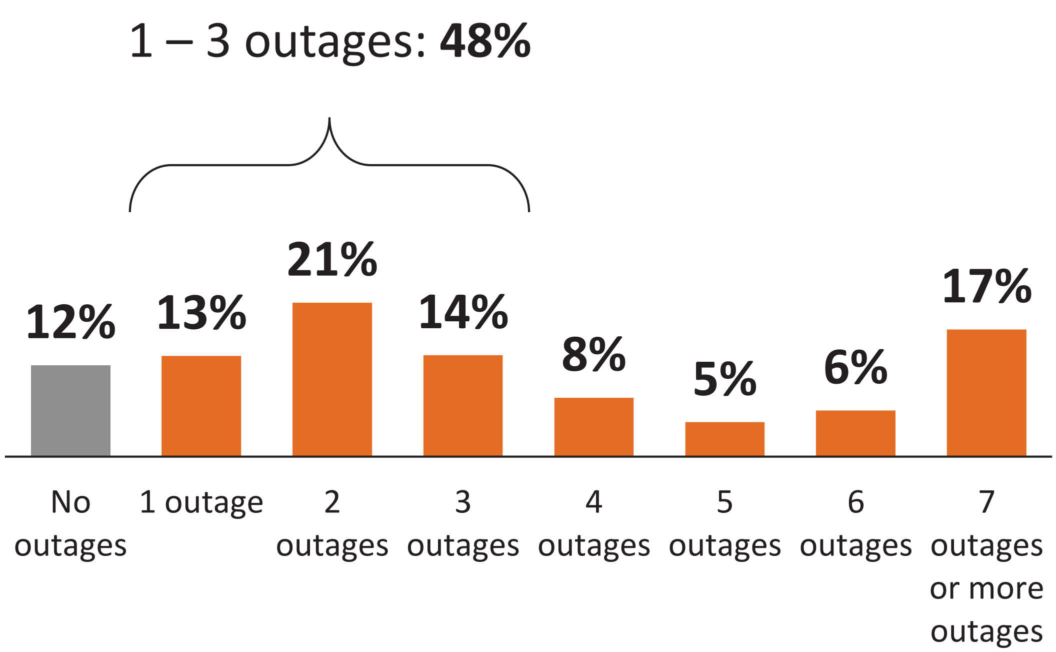
System Reliability:

A plurality (48%) have experienced 1-3 outages in the past 12 months; 17% report 7 outages or more; 12% report no outages

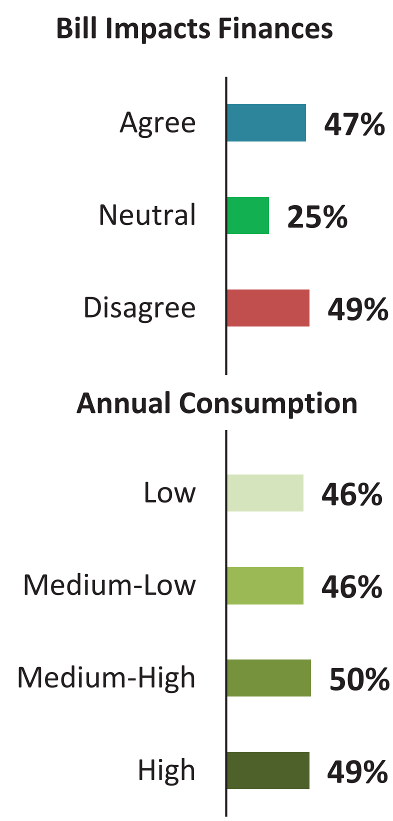
Residential

Q Despite best efforts, no electrical distribution system can deliver perfectly reliable electricity. As a general rule, the more reliable the system, the more expensive the system is to build and maintain. With that said, the average **Essex Powerlines** customer experiences one unexpected power outage per year.

Have you experienced any power outages in the past 12 months, and if so, approximately how many?
[asked all respondents, n=500]



Segmentation
Those who say "1-3 Outages":



INNOVATIVE RESEARCH GROUP

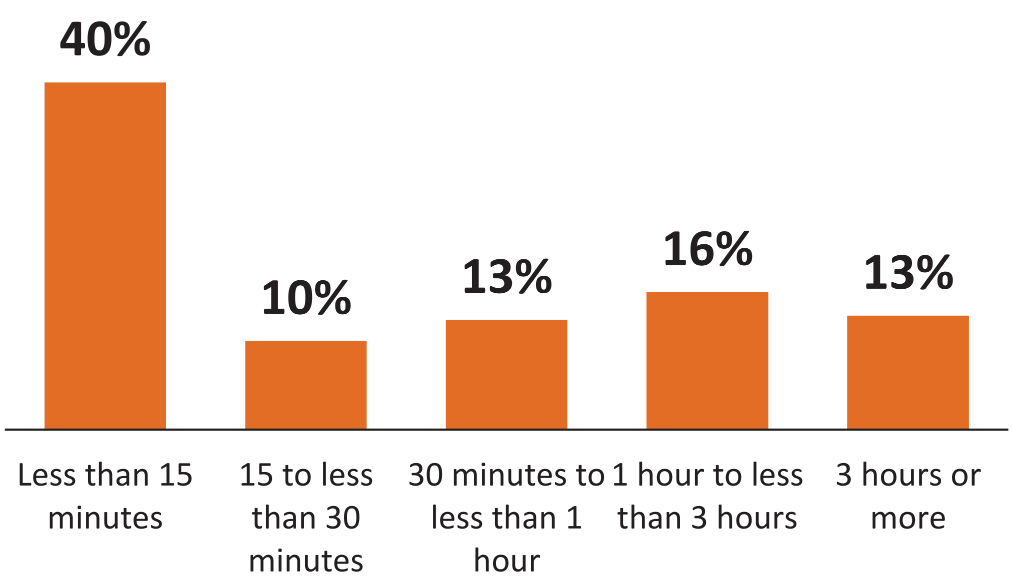
Note: 'Don't know' (4%) not shown.

System Reliability:

2-in-5 (40%) report that the most recent power outage they experienced lasted less than 15 minutes

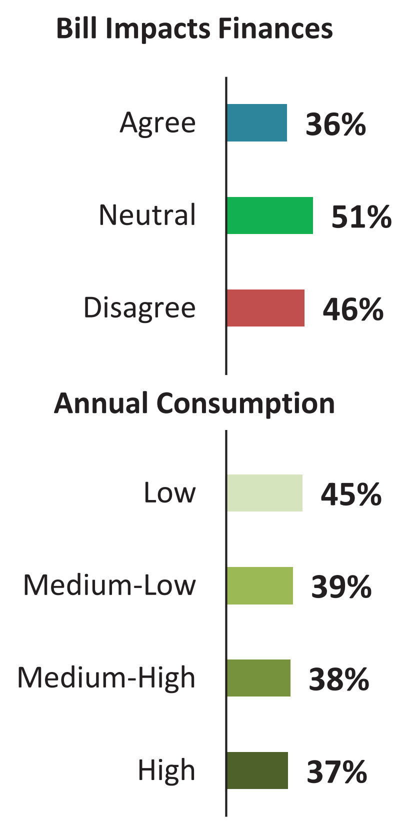
Residential

Q And approximately how many minutes did the most recent power outage last?
[asked of those who have experienced an outage, n=418]



Segmentation

*Those who say "**Less than 15 minutes**":*



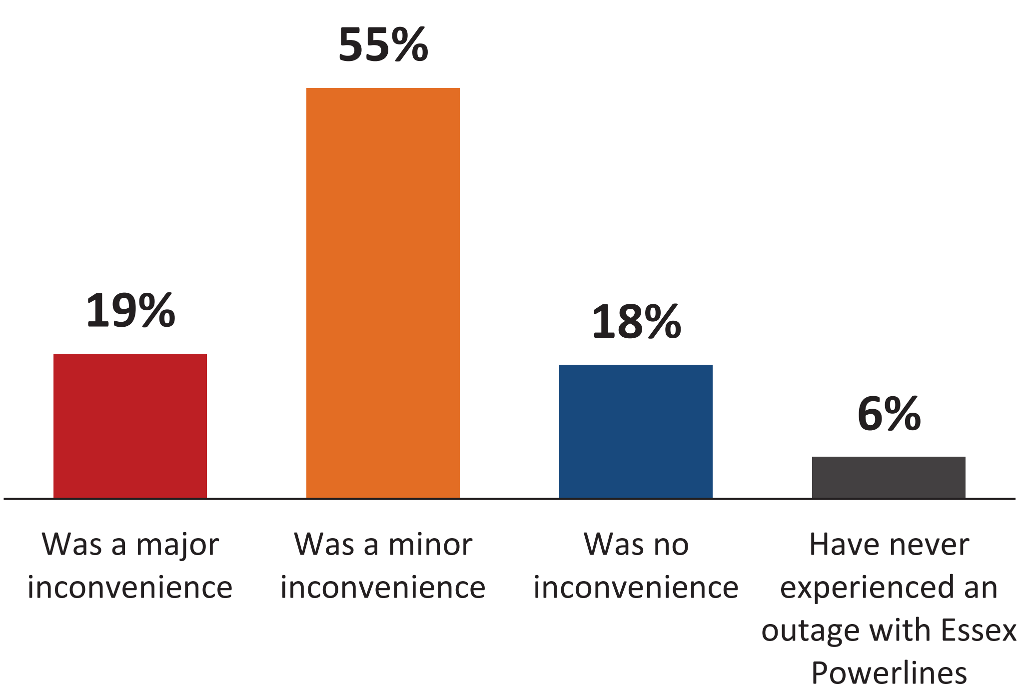
INNOVATIVE RESEARCH GROUP

Note: 'Don't know' (9%) not shown.

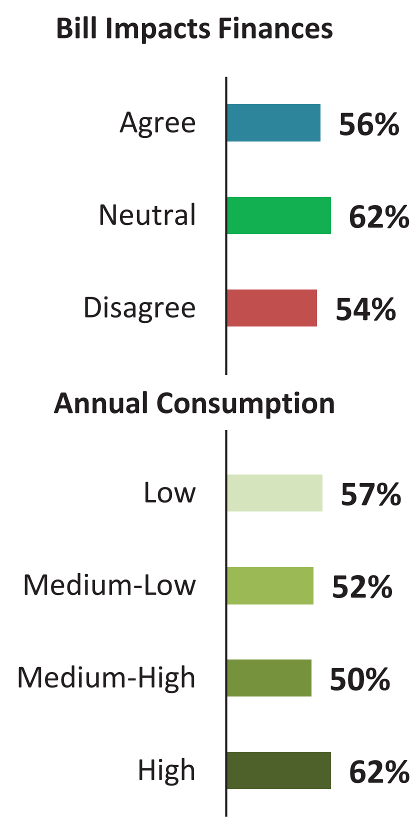
System Reliability:
When reflecting on their most recent power outage experience, more than half (55%) said it was a minor inconvenience

Residential

Q Thinking back to the most recent power outage you experienced as an Essex Powerlines customer, would you say the power outage…
[asked of those who have experienced an outage, n=500]



Segmentation
*Those who say "**Minor inconvenience**":*



Note: 'Don't know' (2%) not shown.

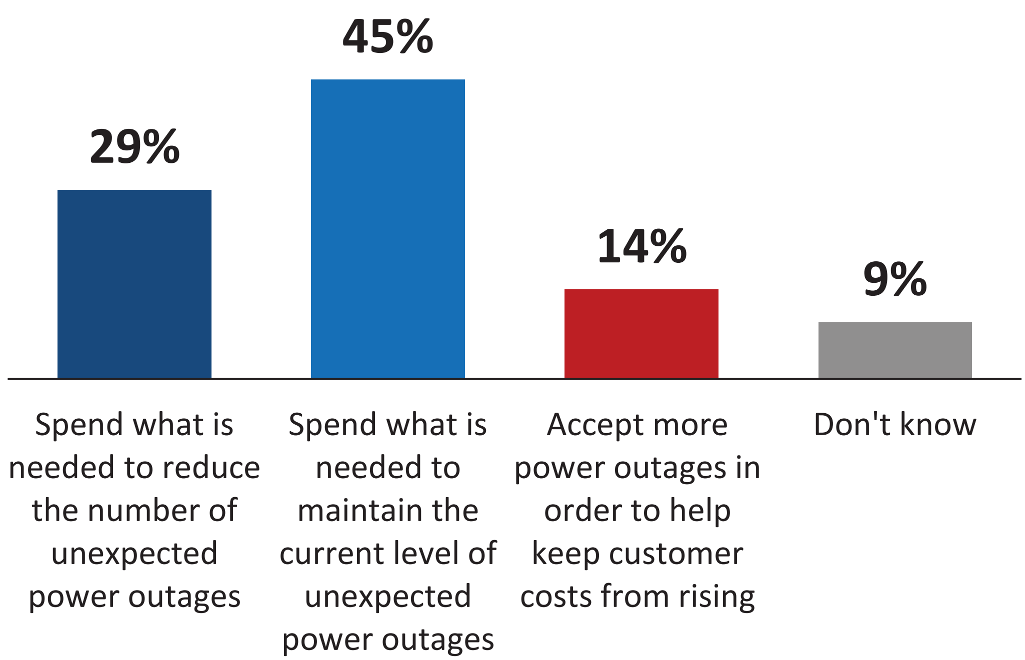
System Reliability:

A plurality (45%) say Essex Powerlines should spend what is needed to maintain the current level of unexpected power outages

Residential

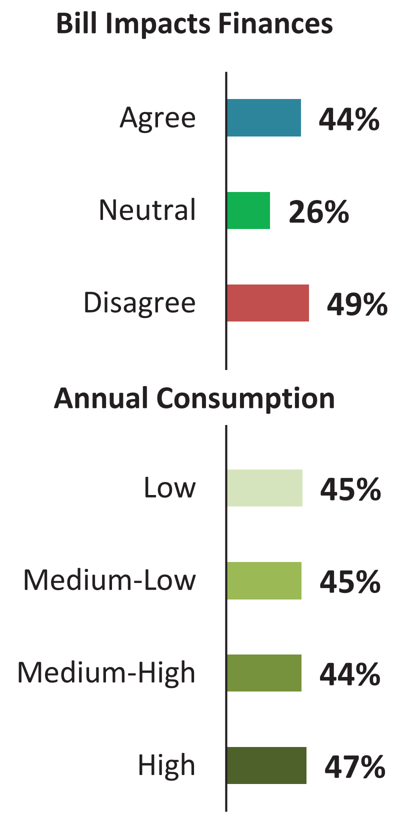
Q In your view, how do you think Essex Powerlines should address the **number** of customer power outages? Would you say…

[asked of those who have experienced an outage, n=500]



Segmentation

*Those who say "**Spend what is needed to maintain…**":*



Note: 'Refused' (4%) not shown.

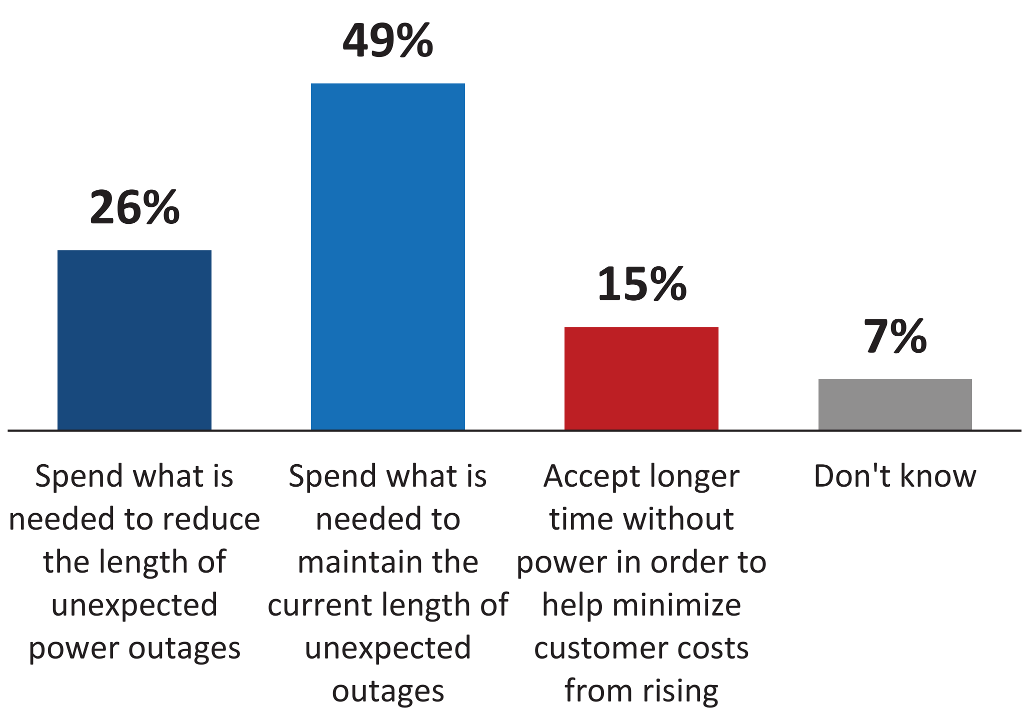
System Reliability:

Almost half (49%) say Essex Powerlines should spending what is needed to maintain the current length of unexpected outages

Residential

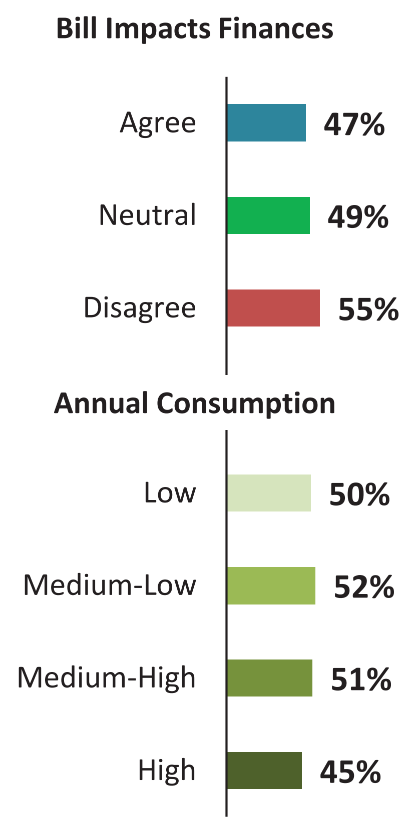
Q Overall, the average **Essex Powerlines** customer is without power for about **one hour per year**. In your view, how do you think Essex Powerlines should address the **length of time** customers are without power? Would you say…

[asked of those who have experienced an outage, n=500]



Segmentation

*Those who say "**Spend what is needed to maintain…**":*



INNOVATIVE RESEARCH GROUP

Note: 'Refused' (3%) not shown.

System Challenges & Priorities

Residential

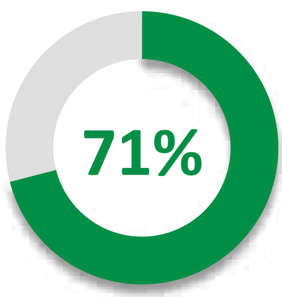
System Challenges & Priorities:

Majority (71%) hold the view that Essex Powerlines should invest what it takes to replace the system's aging infrastructure

Residential

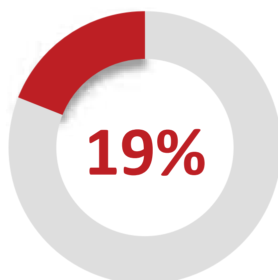
Q While **Essex Powerlines** believes it has done its best to prolong the life of the assets that make up the distribution system, many of these assets are approaching the end of their useful life. As part of its investment plan, Essex Powerlines is proposing an infrastructure renewal program. The estimated cost of this system renewal program is **$31 million** between 2018 and 2022. Although this plan will allow Essex Powerlines to make, what independent studies suggest are, the necessary investments needed to maintain system reliability, **it *may* have an impact on customer bills**.

Which of the following statements best represents your point of view?
[asked all respondents, n=500]



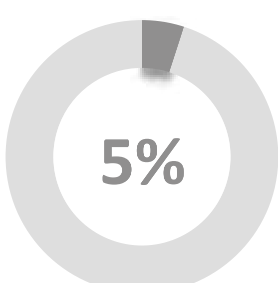
Invest What It Takes

Some customers have said…
Essex Powerlines should invest what it takes to replace the system's aging infrastructure to maintain system reliability, even if that increases my monthly electricity bill by less than a dollar over the next few years.



Lower Investment

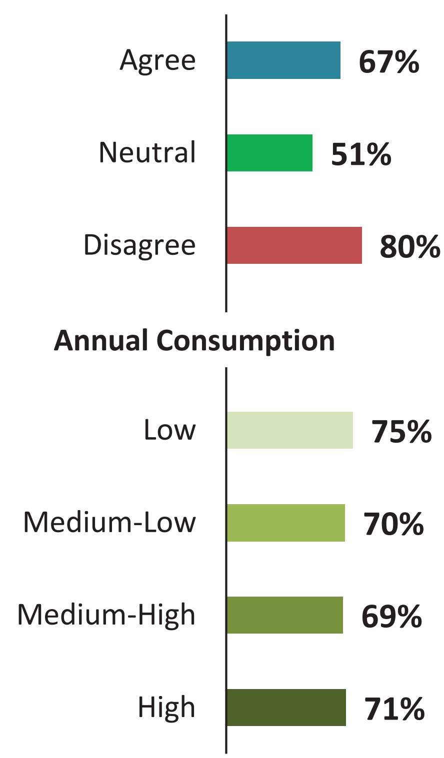
Others have said…
Essex Powerlines should lower its estimated investment in renewing the system's aging infrastructure to lessen possible bill increases, even if that means more or longer power outages.



Don't know

Segmentation

*Those who say "**Invest what it takes**":*



INNOVATIVE RESEARCH GROUP

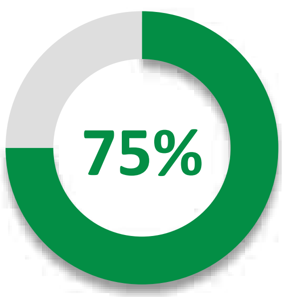
Note: 'Refused' (5%) not shown.

Run-to-Failure:
Majority (75%) feel the best approach is to replace the equipment before it breaks down

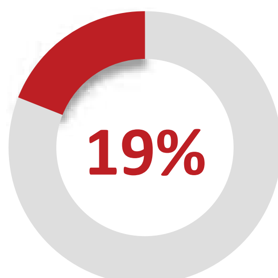
Residential

Q Thinking about the aging equipment in Essex Powerlines' distribution system, do you feel it's best to wait until non-critical infrastructure – that is, equipment that impacts a limited number of customers – breaks down to get full value from each piece of equipment, even if it means short power outages for some customers…

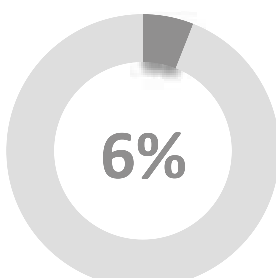
…Or do you feel the best approach is to replace the equipment before it breaks down to avoid unscheduled power outages, even if it means not getting the "full" value from each piece of equipment?
[asked all respondents, n=500]



Replace Equipment Before Breakdown

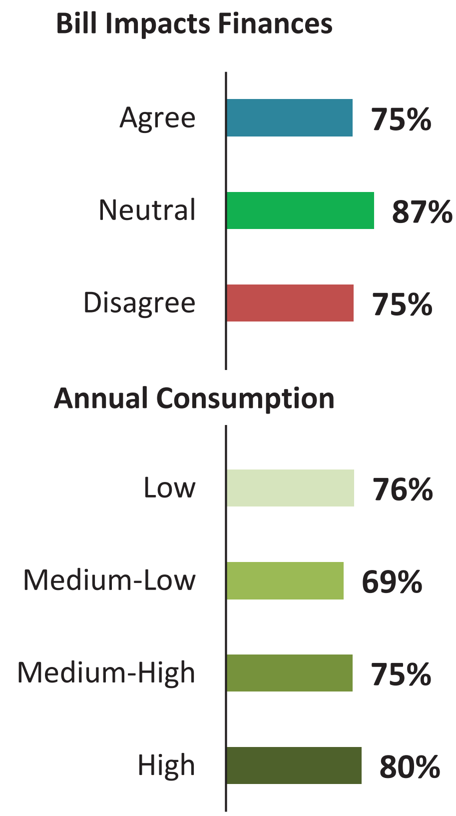


Wait Until Equipment Breakdown



Don't know

Segmentation
*Those who say "**Replace before equipment breakdown**":*



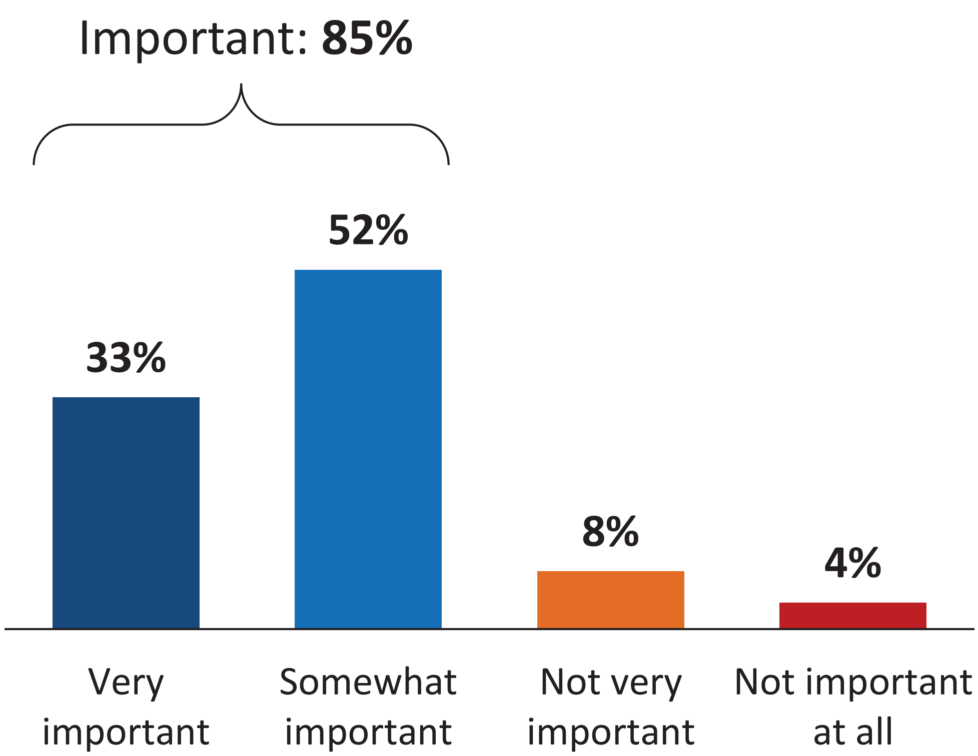
INNOVATIVE RESEARCH GROUP

System Service:
Majority (85%) feel investing in modernizing the distribution system is important; feelings appear strongest among medium-high annual consumers

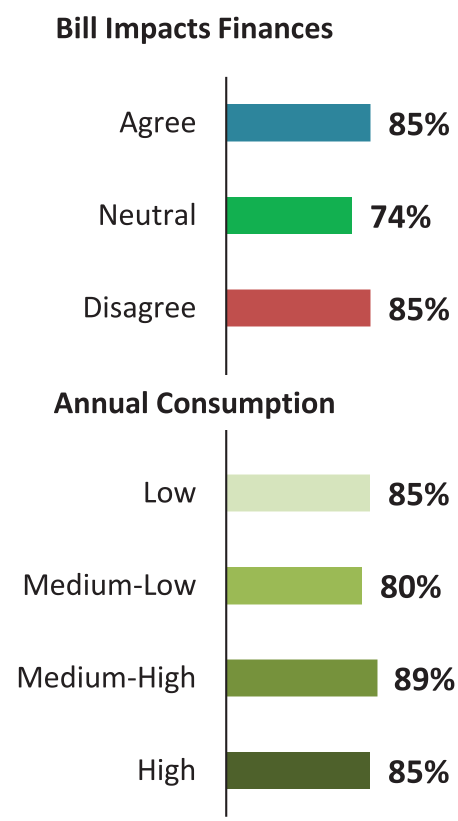
Residential

Q Modernizing the distribution system can allow Essex Powerlines to improve reliability. Investments, such as automated switches, may allow Essex Powerlines to minimize the number of people impacted by outages and to restore electricity to many customers in a matter of seconds.

Given there are many other areas of needed investments, such as connecting new customers, replacing aging equipment and expanding capacity for long-term growth, how important do you feel it is for Essex Powerlines to invest now in modernizing the distribution system?
[asked all respondents, n=500]



Segmentation
*Those who say "**Important**"*



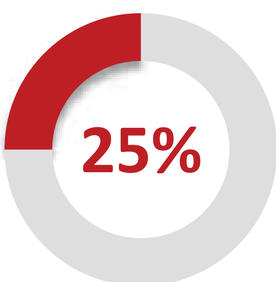
Note: 'Don't know' (3%) not shown.

General Plant:
Majority (75%) say Essex Powerlines should be wise with spending but acknowledge the importance of proper tools and equipment

Residential

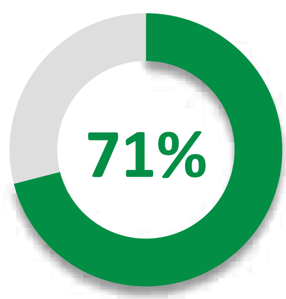
Q Essex Powerlines is not just the local electricity distribution system itself, but a company that operates the system. As a company, Essex Powerlines needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the electrical system and customer information.

Again, customers have made a number of statements about this sort of investment. Which of the following statements best represents your point of view?
[asked all respondents, n=500]



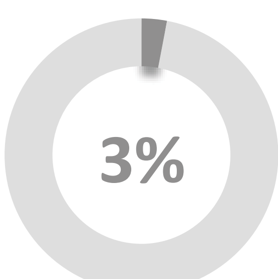
Find Ways To Make Due

Some customers have said…
Essex Powerlines should find ways to make do with the buildings, equipment and IT systems it already has.



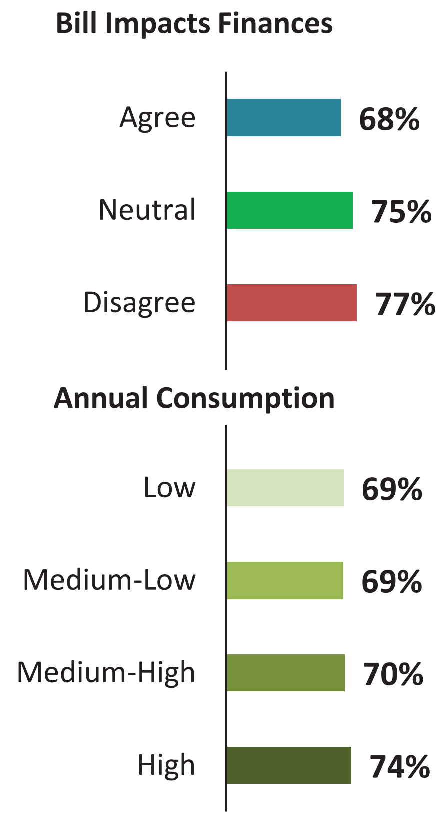
Be Wise With Spending

Others have said…
While Essex Powerlines should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably.



Don't know

Segmentation ▶▶
*Those who say "**Be wise with spending**"*



Note: 'Refused' (2%) not shown.

Reaction to Customer Input

Residential

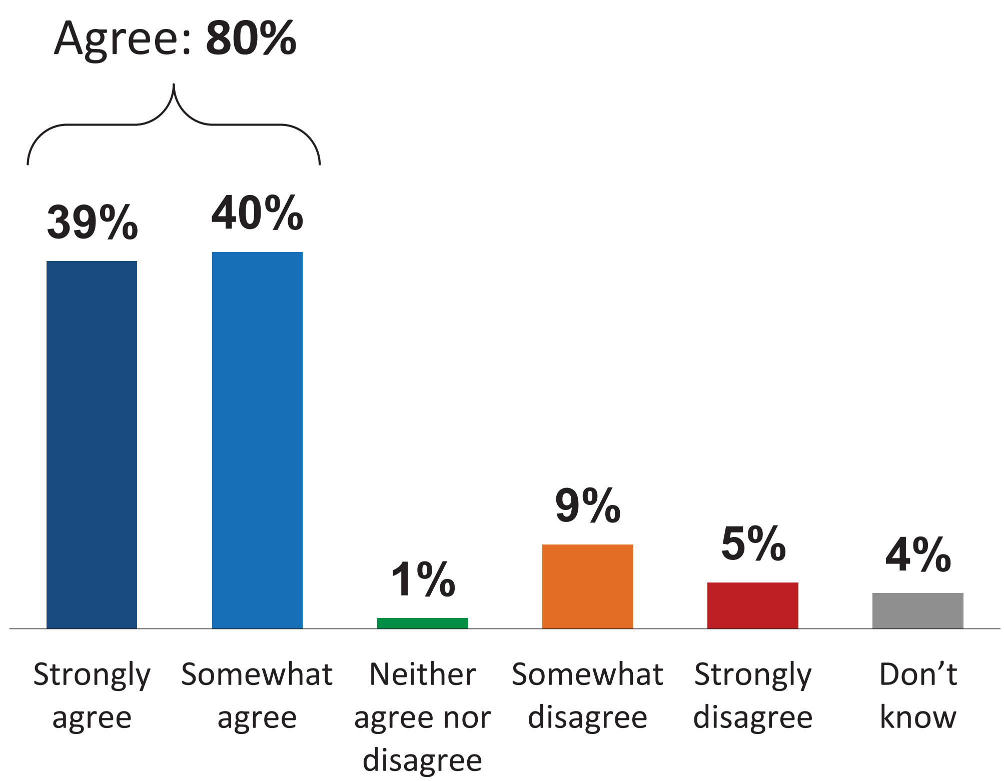
Pay Now or Later:

Majority (80%) agree that delaying infrastructure investments will result in having to pay more in the future

Residential

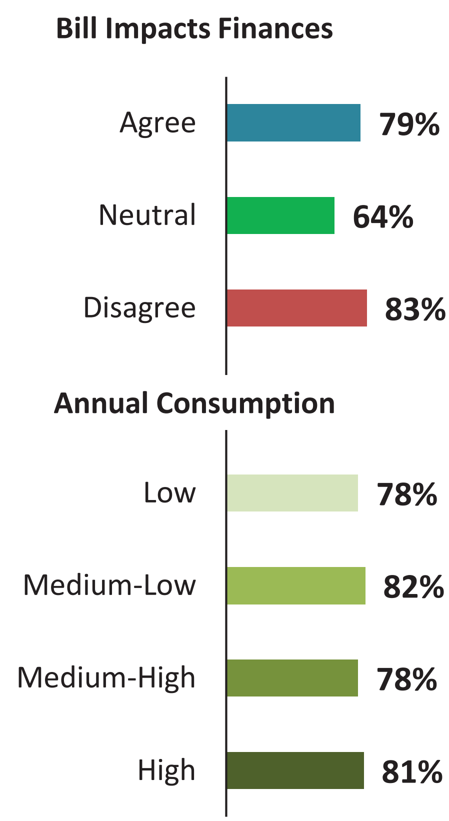
Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=500]

We should invest in our electricity system infrastructure now or we will end up paying more the longer we delay our system renewal.



Segmentation

*Those who say "**Agree**"*



Note: 'Refused' (1%) not shown.

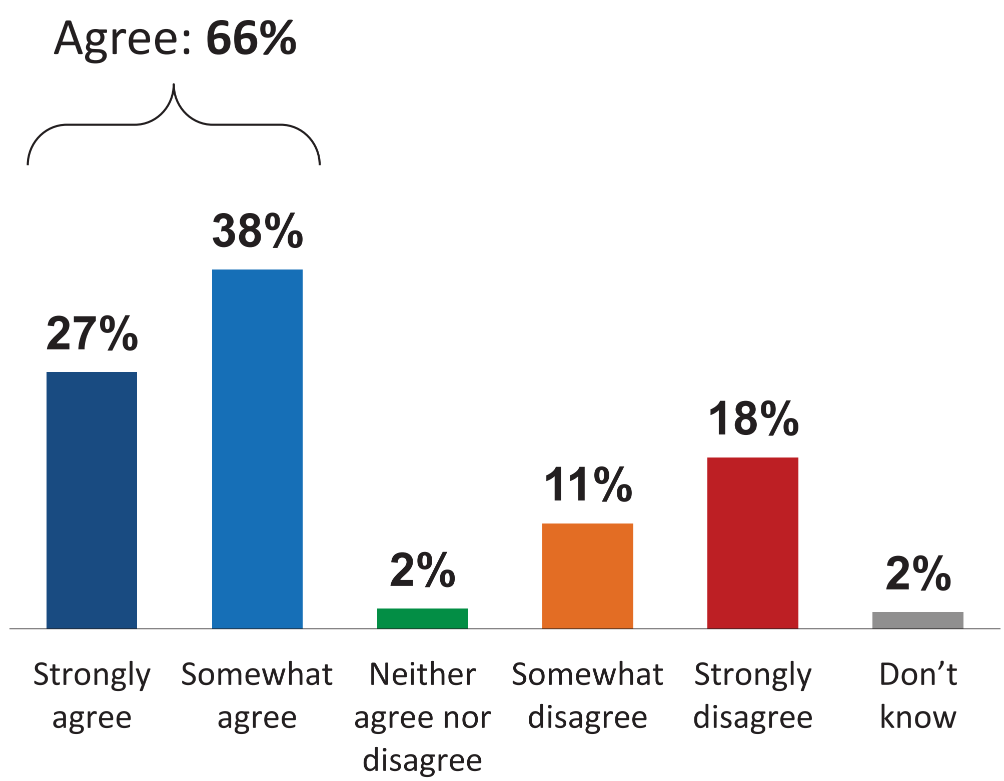
Deferring to the Experts:

Majority (66%) agree that there is a need to trust the experts to balance costs, investments, and spending decisions

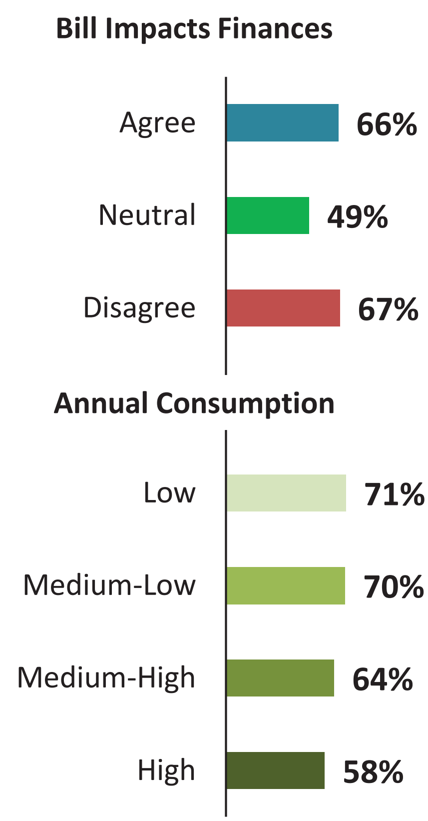
Residential

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=500]

The electricity sector is so complicated and confusing; we just have to trust that the experts will find the right balance in keeping cost down while making the right investments and spending decisions.



Segmentation
*Those who say "**Agree**"*



INNOVATIVE RESEARCH GROUP

Note: 'Refused' (1%) not shown.

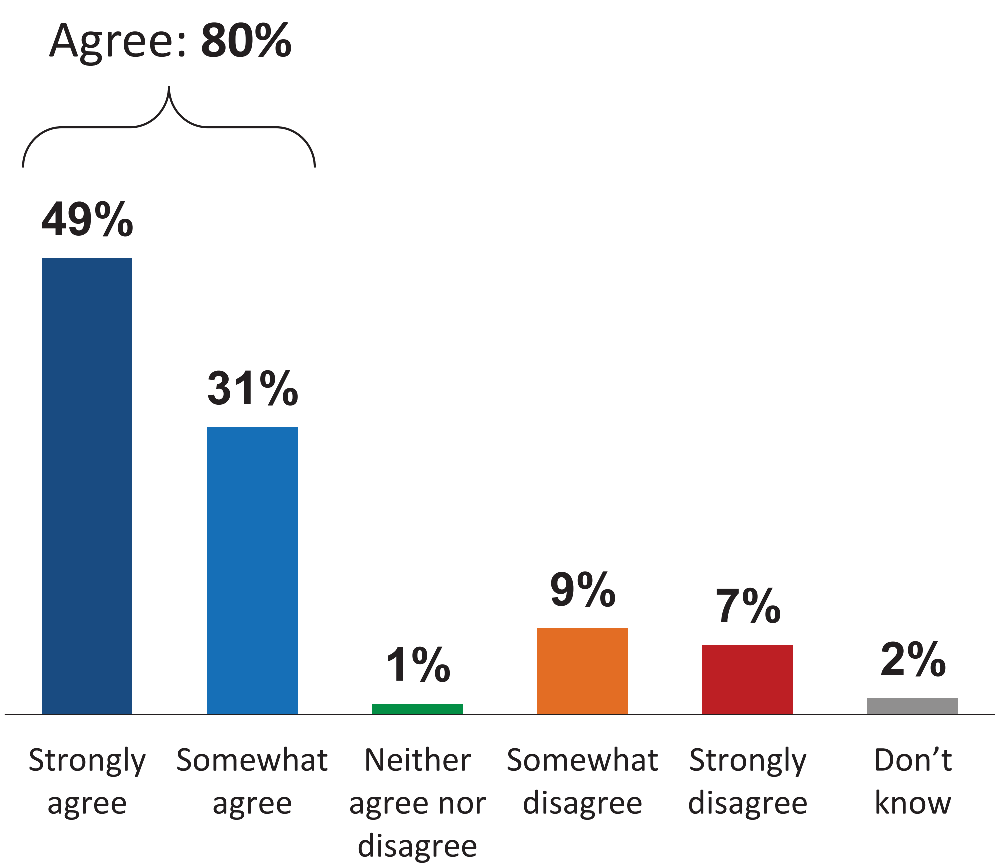
Conservation Demand Management:

Majority (80%) agree that Essex Powerlines should do more to help customers find ways to reduce electricity consumption and costs

Residential

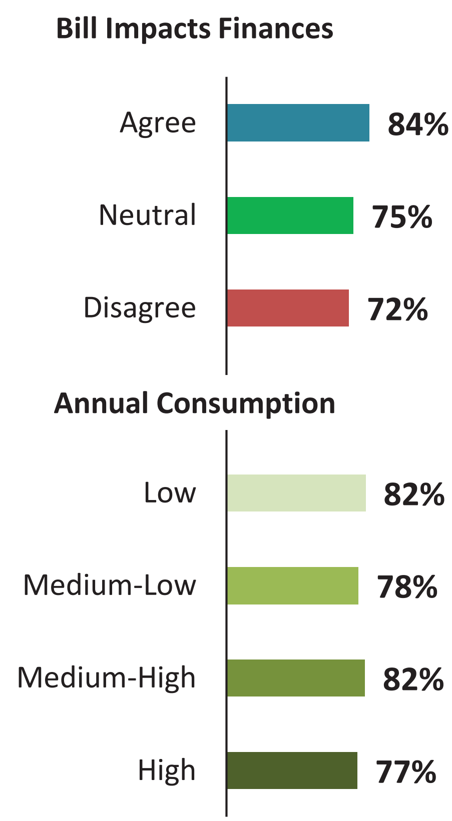
Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=500]

I think Essex Powerlines should do more to help customers find ways to reduce their electricity consumption and costs.



Segmentation

*Those who say "**Agree**"*



INNOVATIVE RESEARCH GROUP

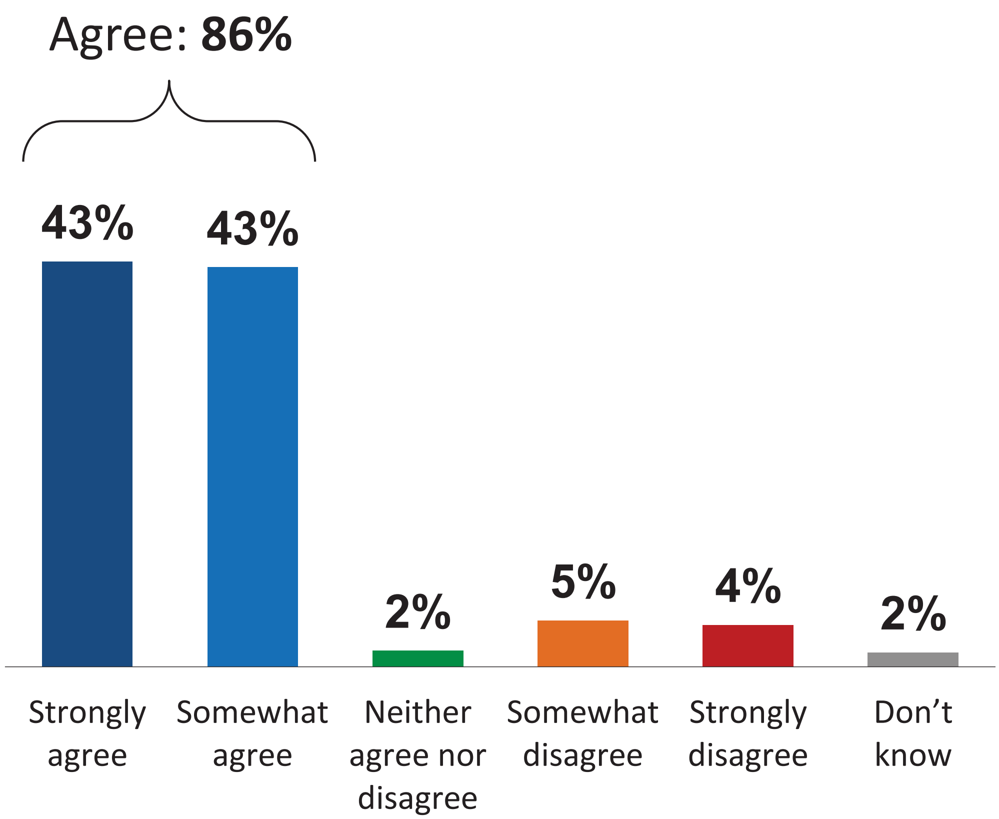
Note: 'Refused' (1%) not shown.

Legacy:
Majority (86%) agree that there is an obligation to maintain the reliability of our local electrical system for future generations

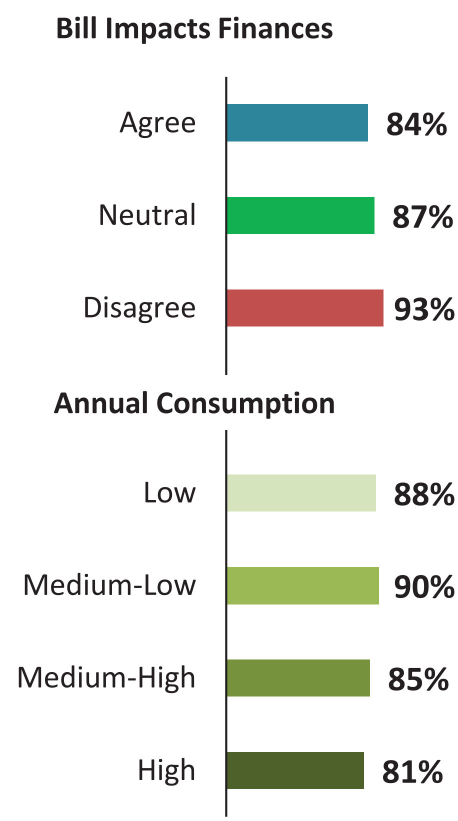
Residential

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=500]

Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations.



Segmentation
*Those who say "**Agree**"*



INNOVATIVE RESEARCH GROUP

Note: 'Refused' (1%) not shown.

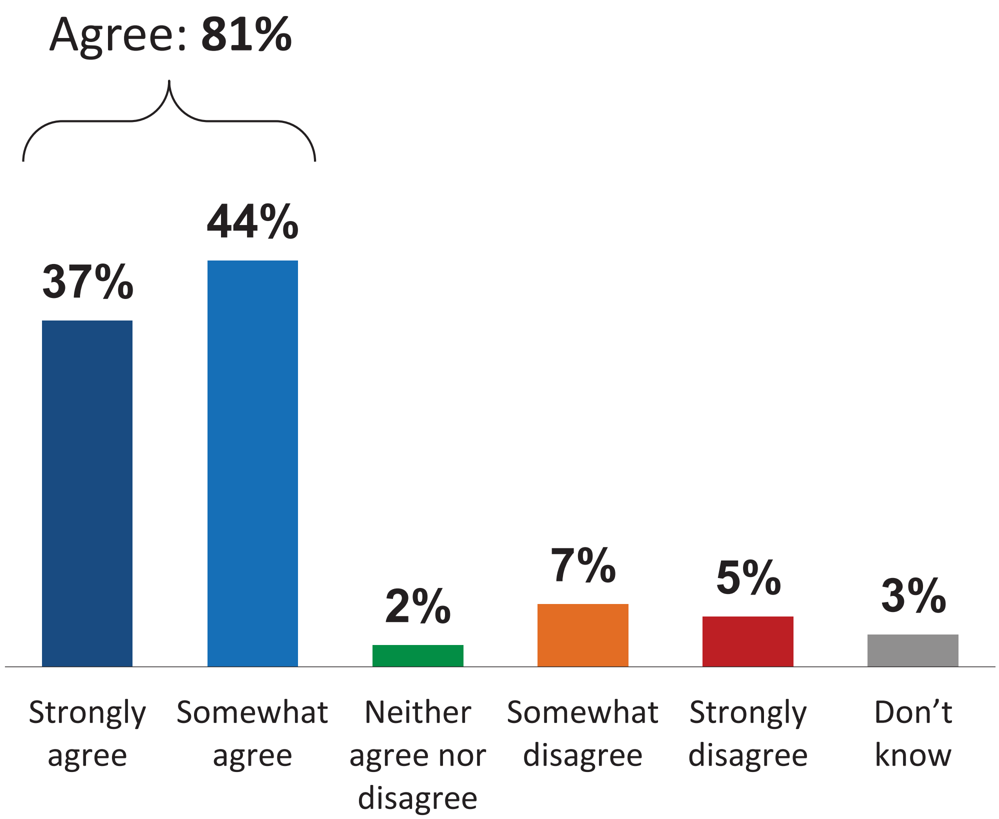
Modernizing the Grid:

Majority (81%) agree that there is a need to modernize the local electricity system so consumers can better control their usage

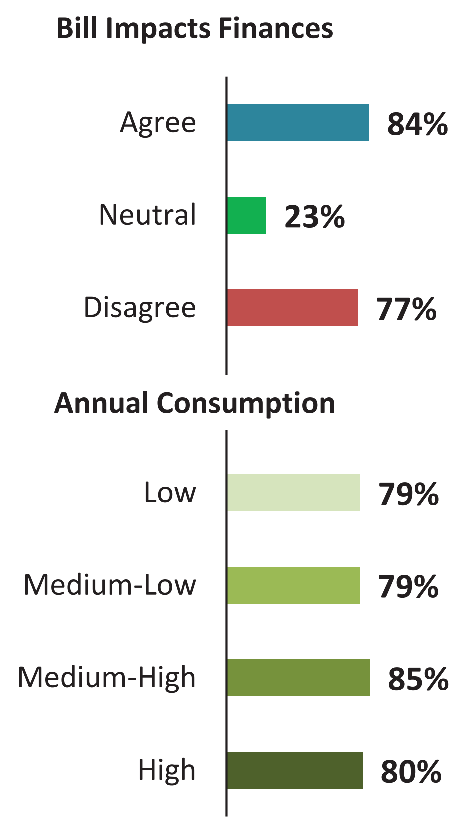
Residential

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=500]

We need to modernize the local electricity system so consumers can have greater control over their electricity usage.



Segmentation
*Those who say "**Agree**"*



INNOVATIVE RESEARCH GROUP

Note: 'Refused' (2%) not shown.

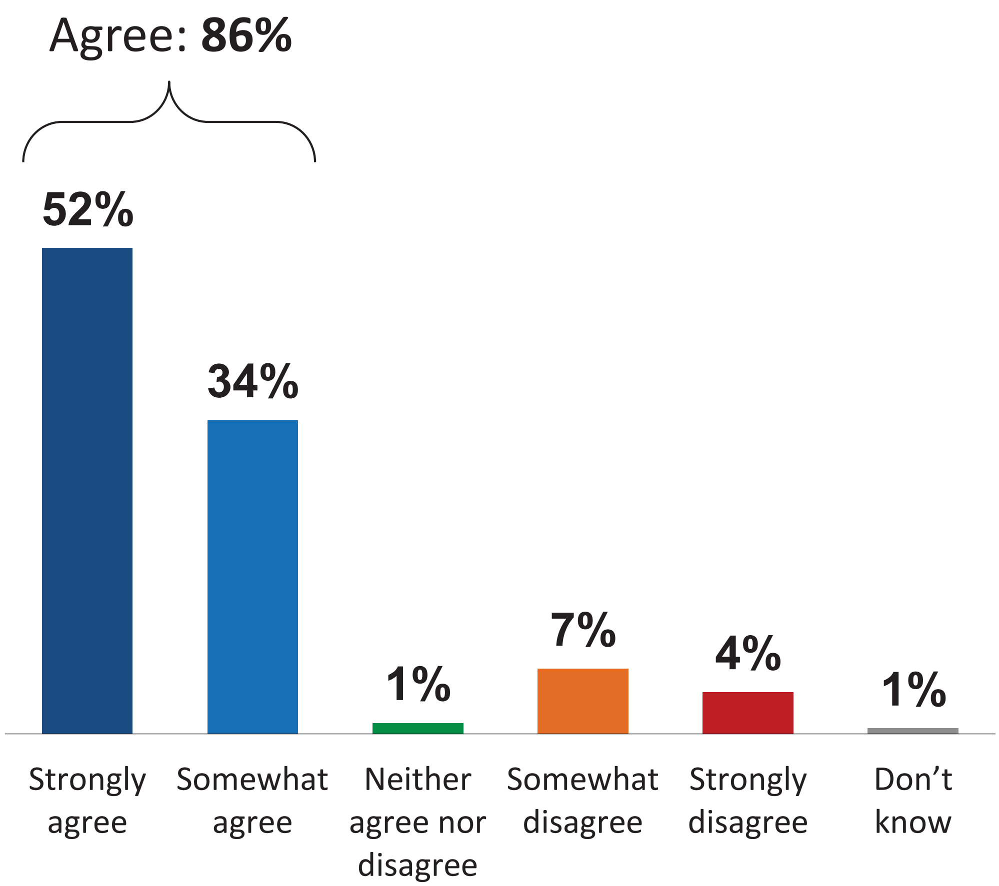
System Reliability:

Majority (86%) agree that they worry about the impact outages have on vulnerable people; more than half (52%) *strongly* agree

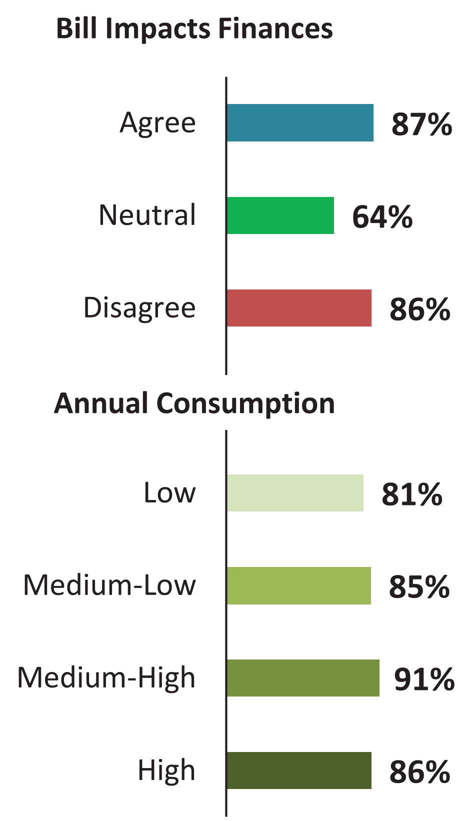
Residential

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=500]

A few power outages are fine for me personally, but I worry about the impact this has on more vulnerable people, such as the elderly.



Segmentation
*Those who say "**Agree**"*



Note: 'Refused' (1%) not shown.

Assessment of Plan:

82% give social permission for rate increase; those with limited bill impact most likely to find it reasonable

Residential

Q **Essex Powerlines** believes that proactive renewal and consistent maintenance is needed to maintain system performance, while keeping the impact on customer bills manageable over the long-term. Over its proposed 5 year plan, **Essex Powerlines** will…

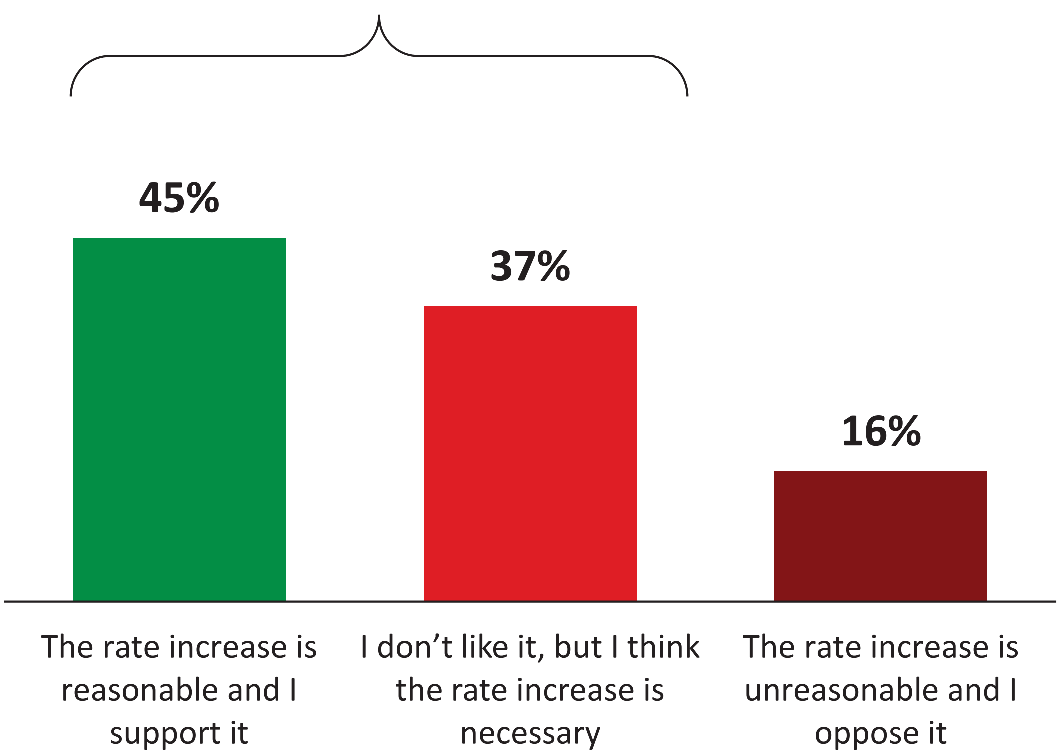
- spend an estimated **$15 million** on on-going maintenance and the operation of the distribution system; and
- invest an estimated **$16 million** in new equipment and infrastructure priorities that will help ensure system reliability.

To fund this proposed plan, the **average residential customer in Essex Powerlines service area will see their rates increase by approximately $0.30 per month** on the distribution portion of their bill over the next five years. So, by 2022, the average residential household will be paying an **estimated $1.53 more per month** on the distribution portion of its electricity bill, which is roughly the rate of inflation.

Considering the cost of Essex Powerlines plan, would you say …

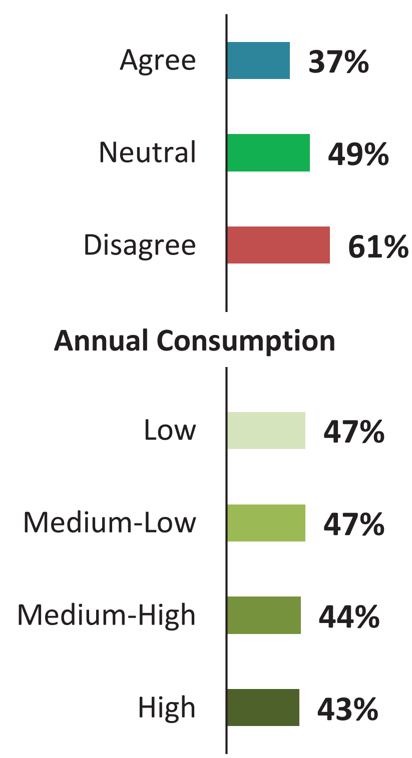
[asked all respondents, n=500]

Social Permission: **82%**



Segmentation

*Those who say "**The rate increase is reasonable and I support it**"*



INNOVATIVE RESEARCH GROUP

Note: 'Don't know' (1%), 'Refused' (2%) not shown.

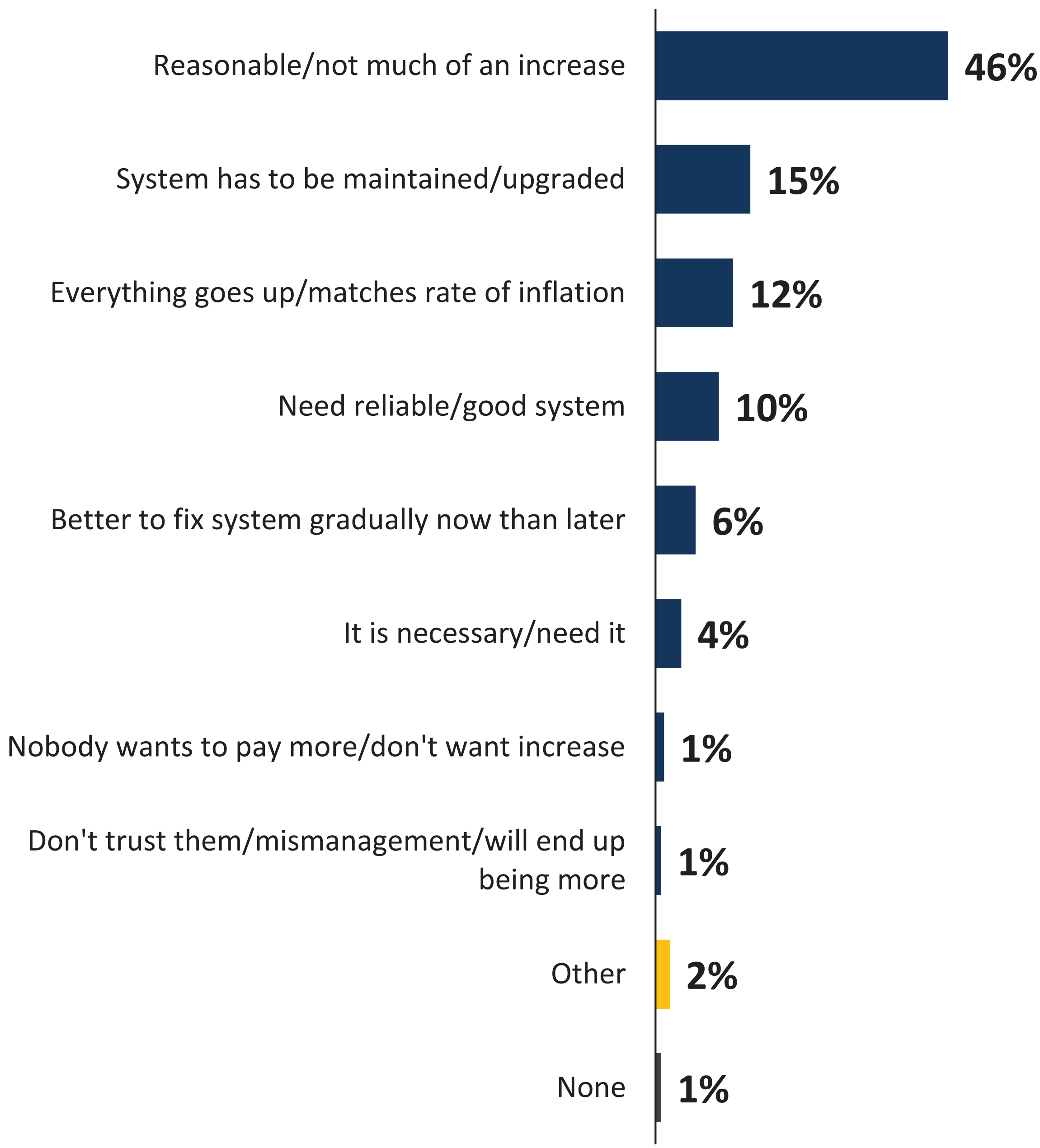
Rationale:

Almost half (46%) of those who support the rate increase do so because it is 'reasonable/not much of an increase'

Residential

Q And why do you say that?
[asked only of those who have an opinion on the assessment of plan, n=488]

Among those who say…
"The rate increase is reasonable and I support it." *(n=225)*



INNOVATIVE RESEARCH GROUP

Note: 'Don't know' (0%), 'Refused' (0%) not shown.

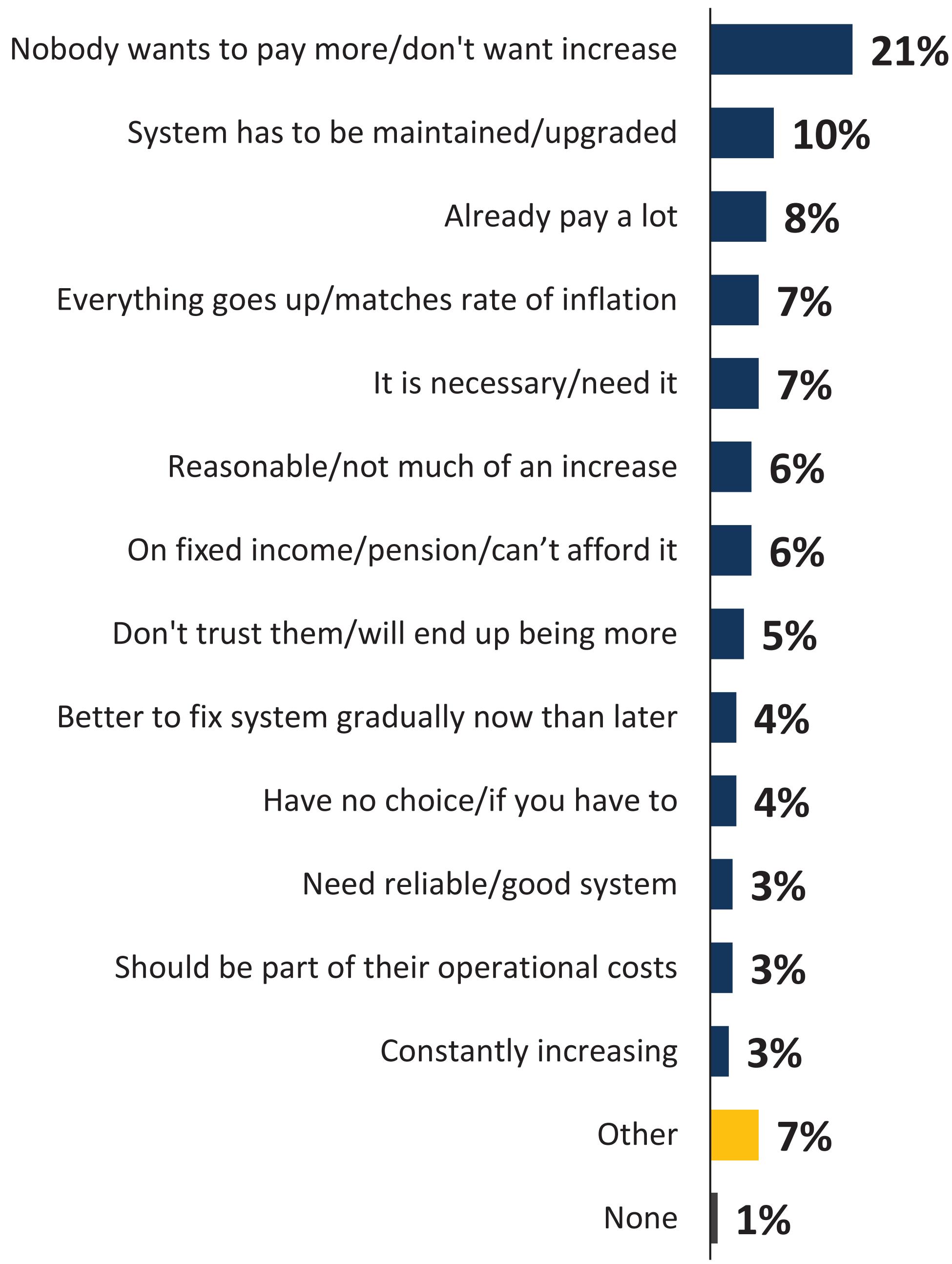
Rationale (2):

1-in-5 (21%) of those who don't like the rate increase but think it's necessary say 'nobody wants to pay more/don't want increase'

Residential

Q And why do you say that?
[asked only of those who have an opinion on the assessment of plan, n=488]

Among those who say…
"I don't like it, but I think the rate increase is necessary." *(n=183)*



INNOVATIVE RESEARCH GROUP

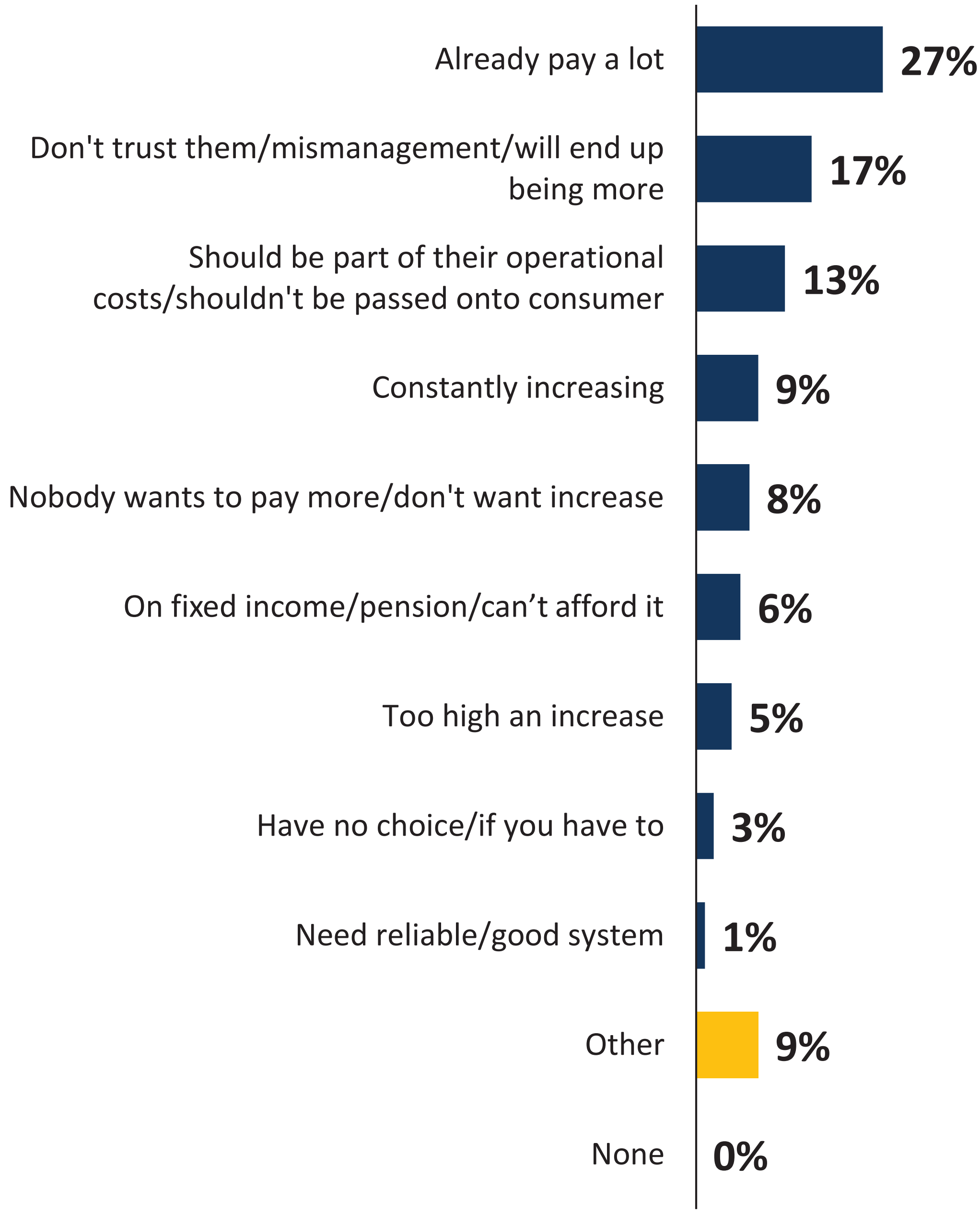
Note: 'Don't know' (1%), 'Refused' (2%) not shown.

Rationale (3):
Top reasons for opposition are ‘already pay a lot’ and ‘don’t trust them/mismanagement/will end up being more’

Residential

Q And why do you say that?
[asked only of those who have an opinion on the assessment of plan, n=488]

Among those who say…
“The rate increase is unreasonable and I oppose it.” *(n=81)*



INNOVATIVE RESEARCH GROUP

Note: ‘Don’t know’ (0%), ‘Refused’ (0%) not shown.

ESSEX POWERLINES CORPORATION

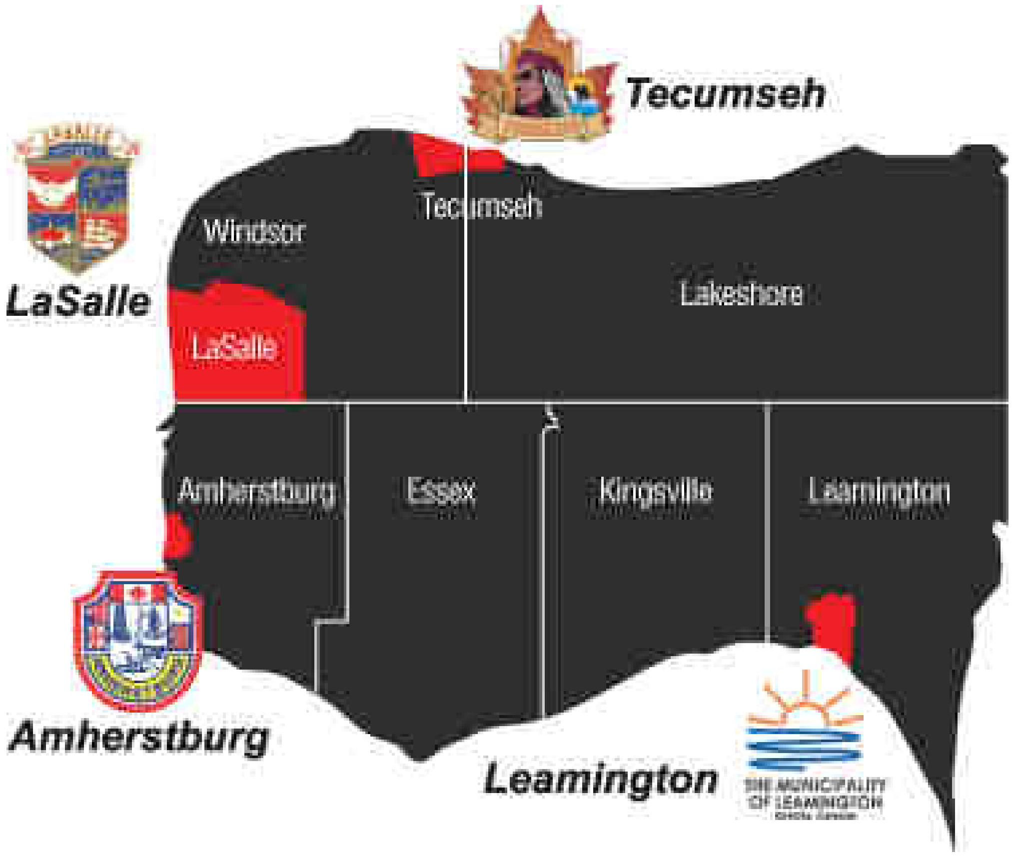
General Service

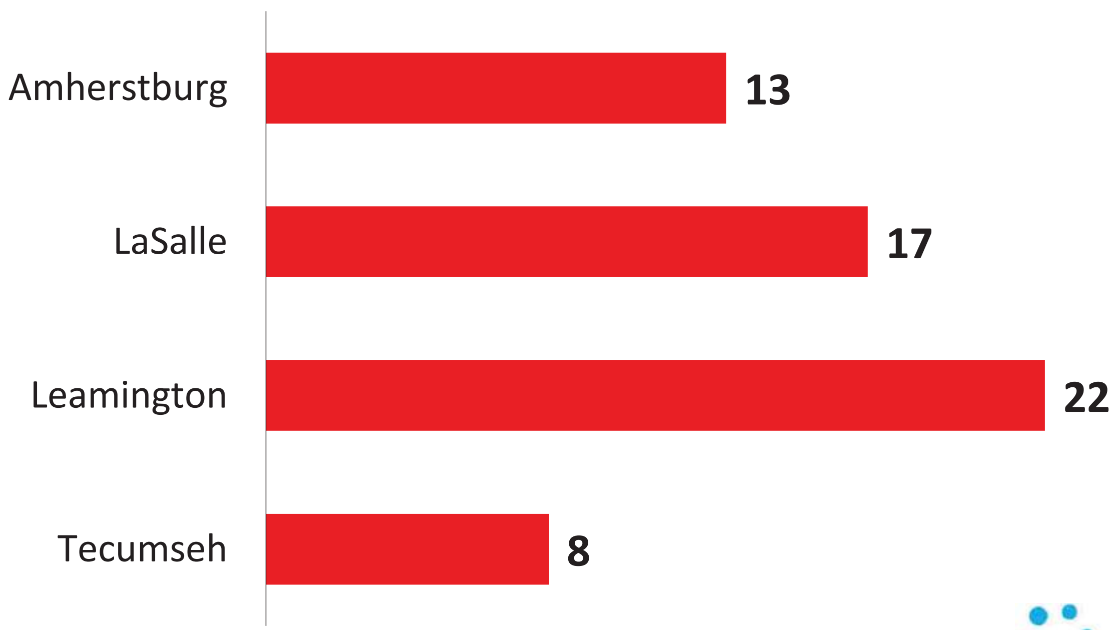
Under & Over 50 kWh Rate Classes

INNOVATIVE RESEARCH GROUP

General Service

Regional Segmentation

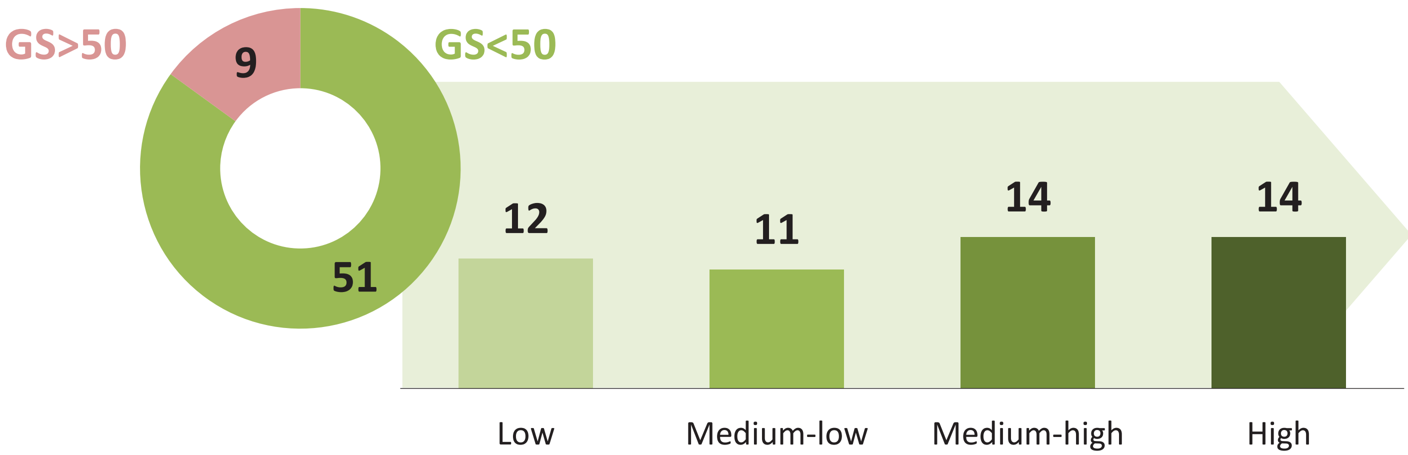




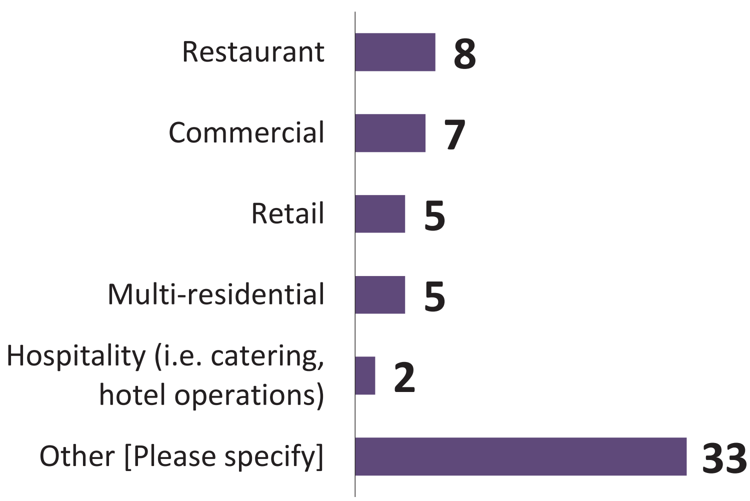
INNOVATIVE RESEARCH GROUP

Firmographics

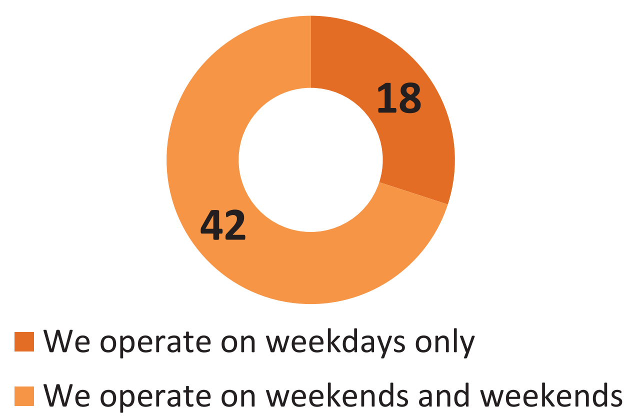
Annual Consumption



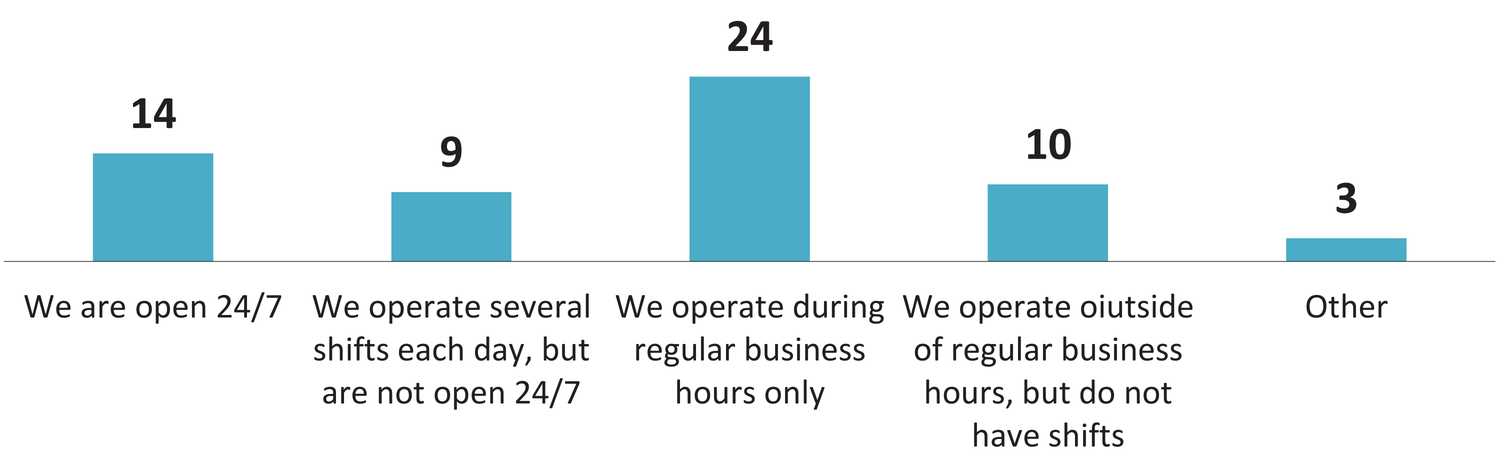
Sector



Schedule



Hours of Operation

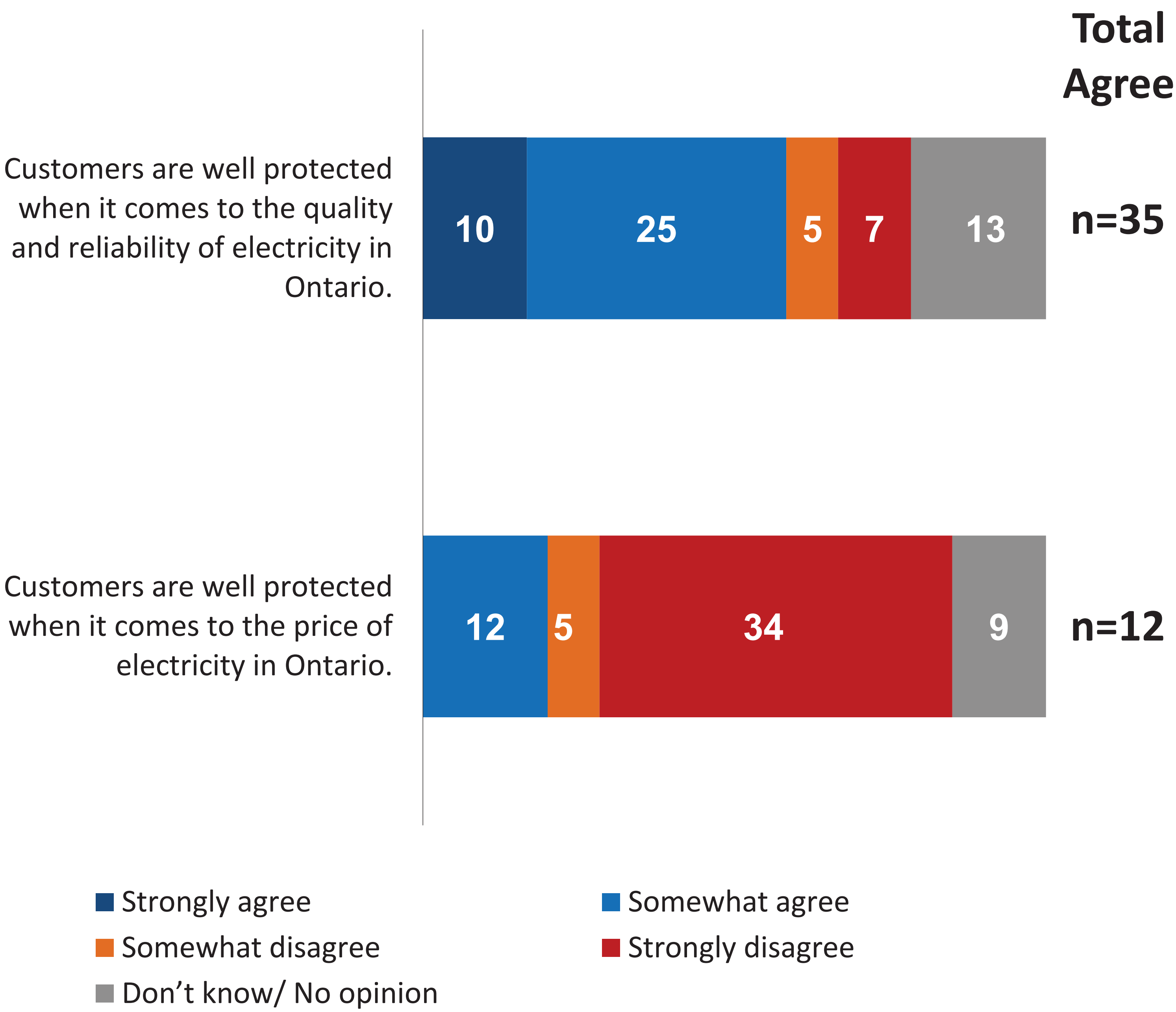


Attitudes Toward Electricity in Ontario:

More than half feel well protected on quality and reliability, but most do no feel protected on price

General Service

Q Lastly, I'd like to ask you some general questions about the electricity system in Ontario.
For each statement please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree. If you don't know enough to say or don't have an opinion just let me know.
[asked all respondents, n=60]



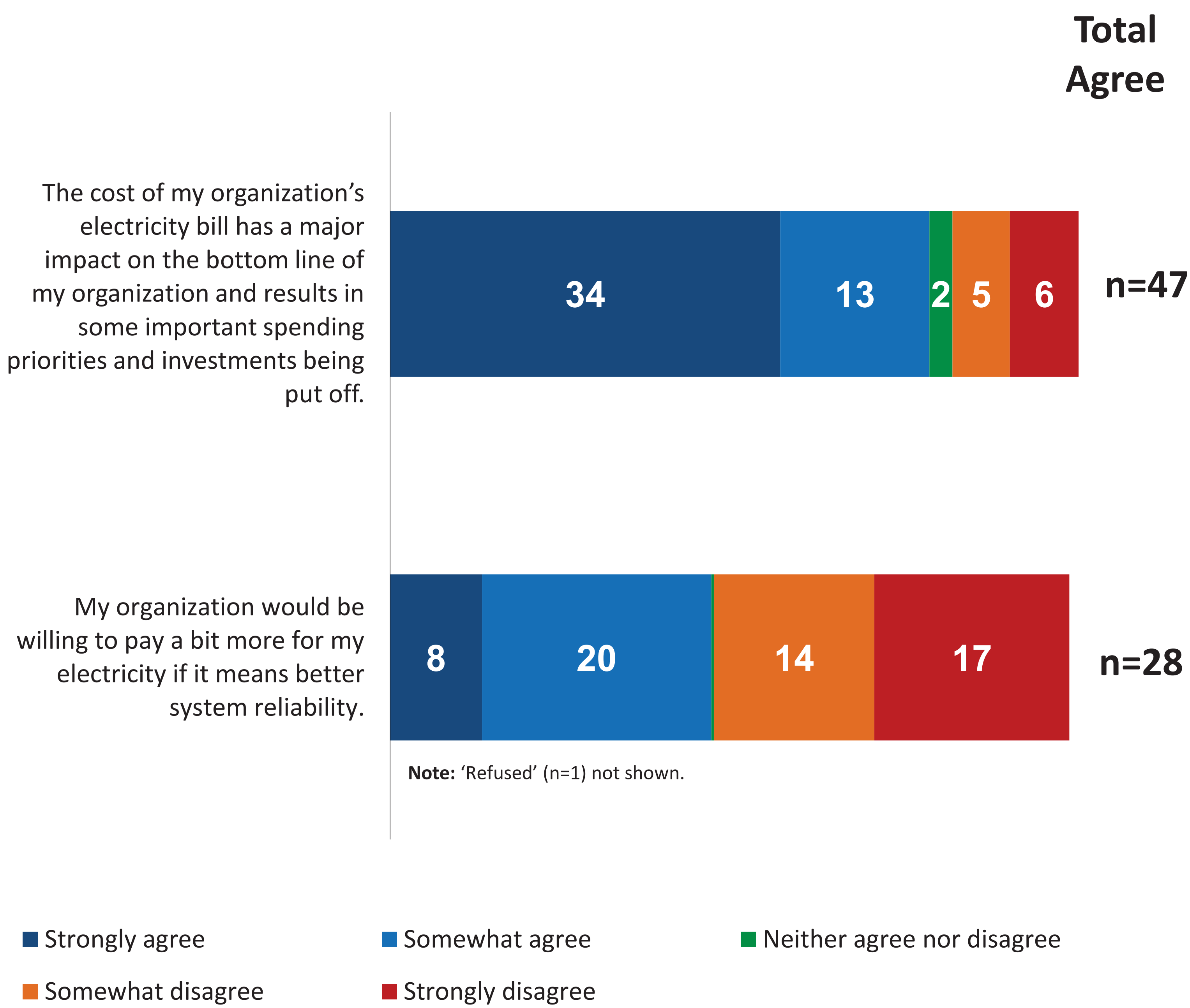
INNOVATIVE RESEARCH GROUP

Paying for Electricity:

Most report the electricity bill has a major impact, and fewer than half would pay more if it meant improved reliability

General Service

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=60]



Note: 'Refused' (n=1) not shown.

INNOVATIVE RESEARCH GROUP

Familiarity:

Just under half of respondents (n=29) are familiar with the local electricity distribution system

General Service

Q

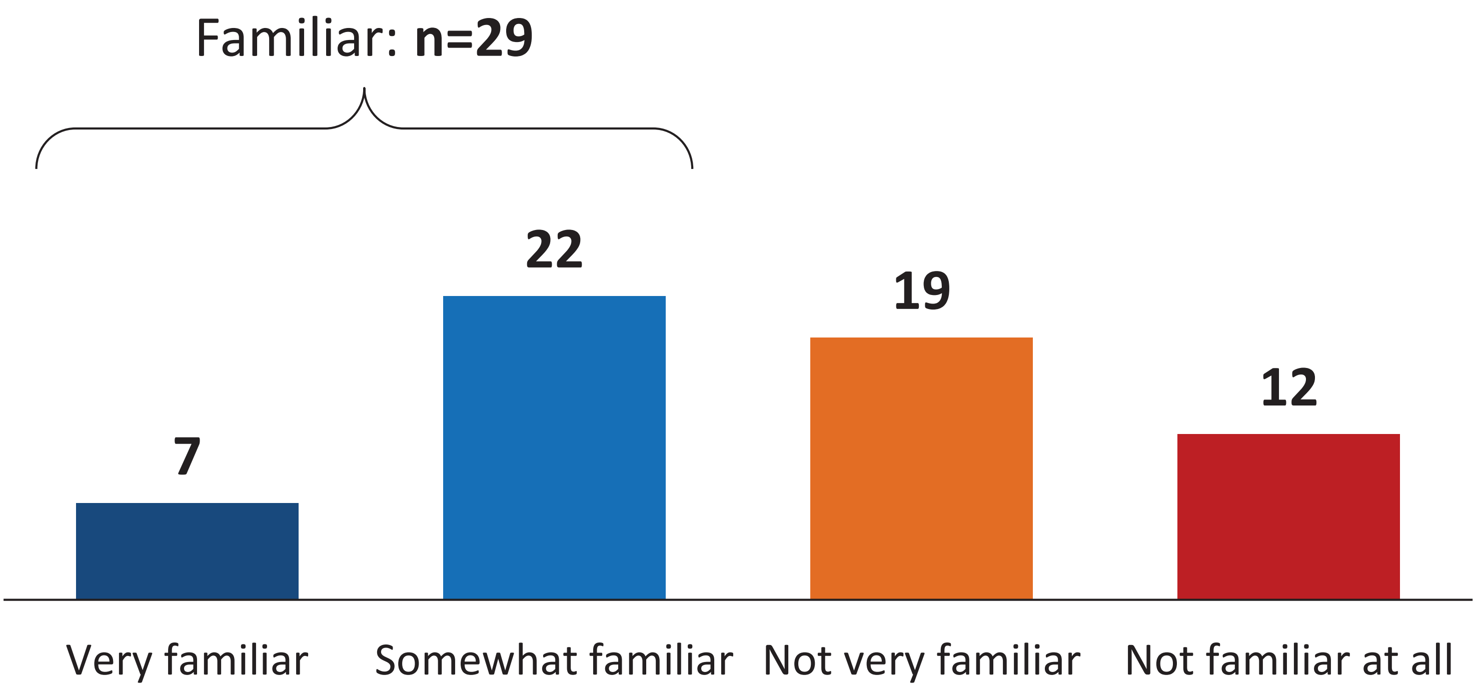
To start, I'd like to ask you a few questions about the electricity system… As you may know, Ontario's electricity system has three key components: generation, transmission and distribution.

- Generating stations convert various forms of energy into electric power;
- Transmission lines connect the power produced at generating stations to where it is needed across the province; and
- Distribution lines carry electricity to the homes and businesses in our communities.

Today we're going to talk about your local distribution system which, in your community, is maintained and operated by Essex Powerlines.

How familiar are you with the local electricity distribution system? Would you say…

[asked all respondents, n=60]



INNOVATIVE RESEARCH GROUP

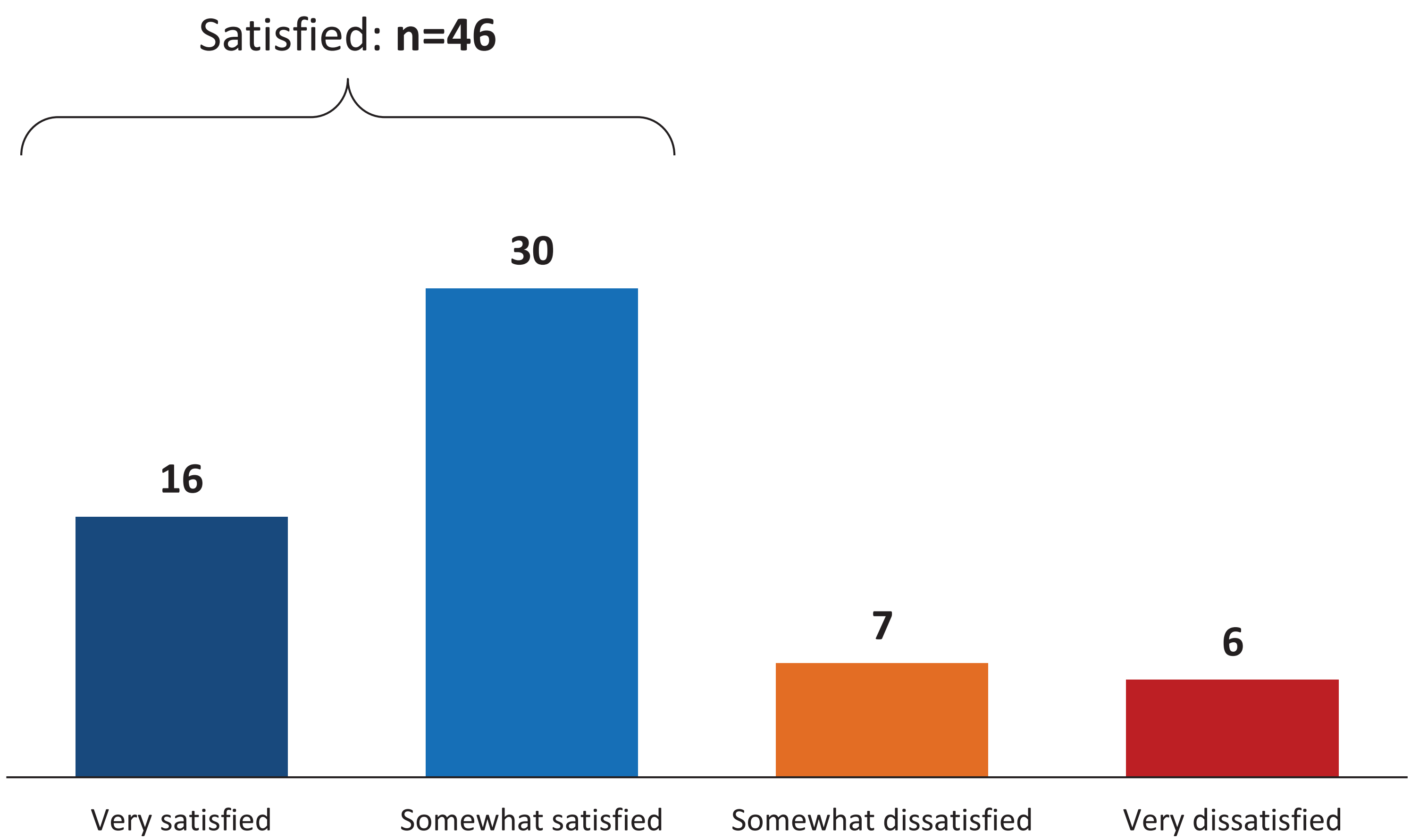
Satisfaction with Services:

Majority of respondents (n=46) are satisfied with Essex Powerline's performance

General Service

Q Generally speaking, how satisfied are you with the job Essex Powerlines is doing running your local distribution system? Would you say…

[asked all respondents, n=60]



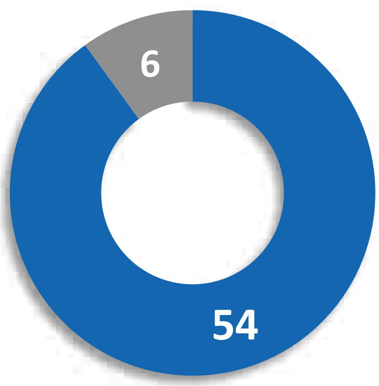
Note: 'Don't know' (n=1) not shown.

Suggestions for Improvement:

Those who had suggestions noted improvements regarding lower rates/prices/costs/bills

General Service

Q Is there anything in particular **Essex Powerlines** can do to improve its service to your organization?
[asked all respondents, n=60]



■ **Comment provided** ■ **No response**

Lower rates/prices/costs

- cheaper hydro give us
- constantly power going out, too much money
- cut the bill down
- give us service we want, but too costly
- I feel I am paying too much money.
- I would like them to lower the prices.
- I would like them to lower their costs, make it cheaper.
- lower bills
- Lower the bill.
- lower the cost of electricity
- Lower the cost.
- Lower the prices
- lower the rates
- rates are way too high and sometimes power has gone out
- reduce the pricing
- reducing rates
- they should lower the rates. It is a small town
- I would like them to lower their electricity rates.
- Lower the prices.
- Prices
- I've got billing on my mind not services.

No/Nothing/Don't know

- I have no complaints.
- I have no opinions.
- No
- No
- No, they have been very good working with us regarding power outages with upgrading of cables.
- nothing
- nothing
- not sure
- not that I can think about it.
- not that I'm aware of
- nothing
- Nothing comes to mind
- nothing I can think of off of the top of my head
- don't think so
- everything is fine so far

Suggestions for Improvement (Cont'd):

Topics of reliability were mentioned a number of times; a few mentioned improvements to customer services and time-of-use

General Service

Q Is there anything in particular **Essex Powerlines** can do to improve its service to your organization?
[asked all respondents, n=60]

Other

- have to wait very long on the phone
- occasional billing delays
- should collect rent from tenants and not landlords
- When Essex Powerlines come on my property. They need to contact us first. They need to communicate with their business customers. Their communication skills are very poor.
- I would like them to take care of the power outages sooner and the hotline number provided should actually get some results. Commercial properties should be prioritized based on the emergency situation.
- Lost power in between transmission or in traffic. Eliminate times of use for businesses. Hitting me with higher rates because I have to operate during prime to keep customers.
- The peak times for the businesses we are paying peak rates. If you could change peak times for businesses.
- I think they could meet with us to save money or save on our systems. Like to have a meeting with conserving energy for the building.
- new infrastructure is key, not solar panels, wind. New poles, TR cables, are required
- provide maybe upgraded thermostats
- replace the 3 phase power that keeps shorting

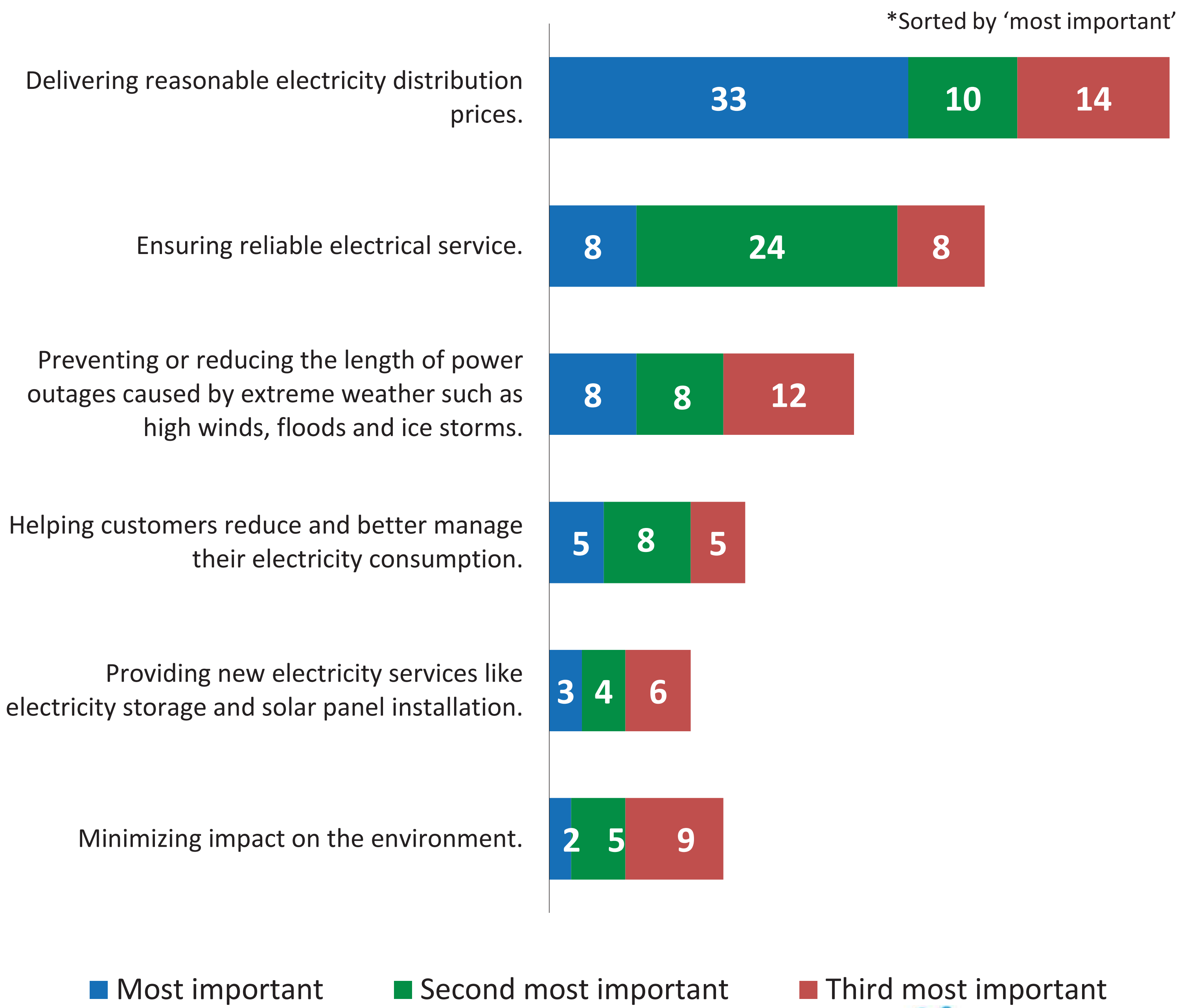
Reliability

- goes out a little too often
- I have a lot of brownouts and lots of flickering in the electricity. Like to see improvements in that area.
- not adding so much power interruptions
- They should have better control of there level of control of there voltage supply. It draws too much and I burn out of equipment.
- We have a lot of brownouts. Like improvements of the system.
- we have trouble transitioning the builders name to the new home owners name. and paperwork to fill out for new customers is not conducive to home builder

Customer Priorities:
'Delivering reasonable electricity distribution prices' is identified as most important priority

General Service

Q Essex Powerlines regularly holds discussions with its customers to better understand how it should set spending priorities with the money customers pay for service. In recent conversions with customers, a number of company goals were identified as key priorities for Essex Powerlines.
Among the following Essex Powerlines priorities, please tell me which one is most important to your organization. What is the next most important priority you think Essex Powerlines should focus on? And what do you consider the third most important priority?
[asked all respondents, n=60]



INNOVATIVE RESEARCH GROUP

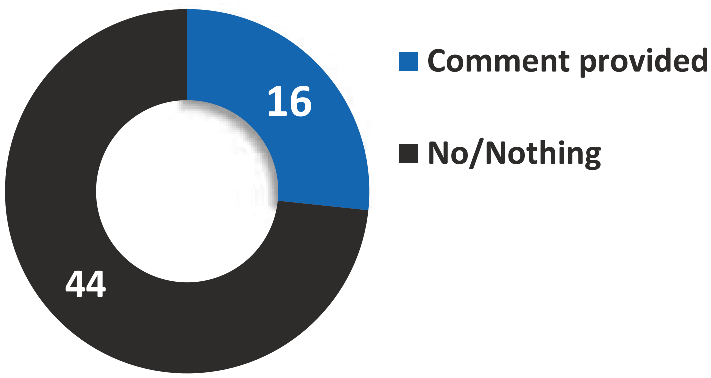
Additional Priorities:

Most respondents (n=44) had nothing to offer regarding additional priorities

General Service

Q Are there any other important priorities that Essex Powerlines should be focusing on that weren't included in the previous list I read to you?

[asked all respondents, n=60]



- these are my top priorities
- cost - a small business has to open there business and have to pay for the premium, and we have to provide services to our community. and theses facilities cannot work at midnight. And we have to work on peak time, so we should have a fixed cost, or some sort of discount so we are not penalized.
- Energy conservation
- put programs and grants in place for solar programs.
- incentives, making businesses aware of yearly incentives
- making equipment affordable
- the business does not have a choice of using off peak hours because the business is not open at that time. If they could make it different between residential and business.
- lower their rate during peak times
- they can extend the time of use. Extend the low peak a bit.
- They cut their pay raises with management at the top. They have reasonable prices.
- new infrastructure, staff efficiency (do not waste time eating lunch)
- I think they should have better sense of responsibility for their commercial customers. They should invest in stronger infrastructure to reduce power outages which is a normal occurrence in my area.
- to help businesses they should change the peak times
- lobby provincial government to deregulate the infrastructure and hire Canadians to do it
- stop outsourcing it to companies, used a different piece and fried the transformer
- customer service in general

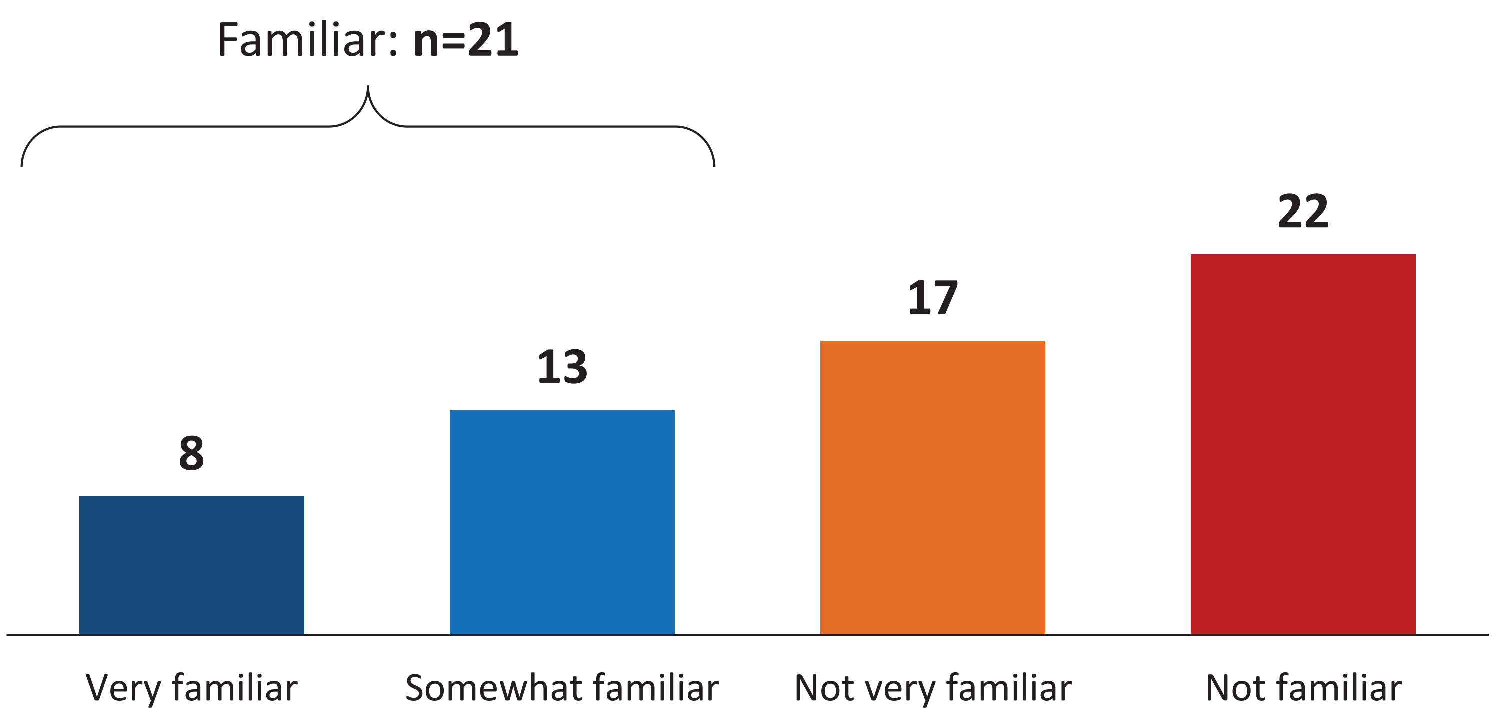
Bill Knowledge & Impact:
Fewer than half (n=21) were familiar with their bill breakdown

General Service

Q I'd now like to talk with you about your electricity bill... While some customers pay more and others pay less, the **average small business or general service customer pays about $387 a month** for electricity and other municipal services, of which **approximately $59 or 17% goes to Essex Powerlines**. The rest of the 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 Essex Powerlines? Would you say...

[asked all respondents, n=60]



ESSEX POWERLINES CORPORATION

System Reliability

General Service

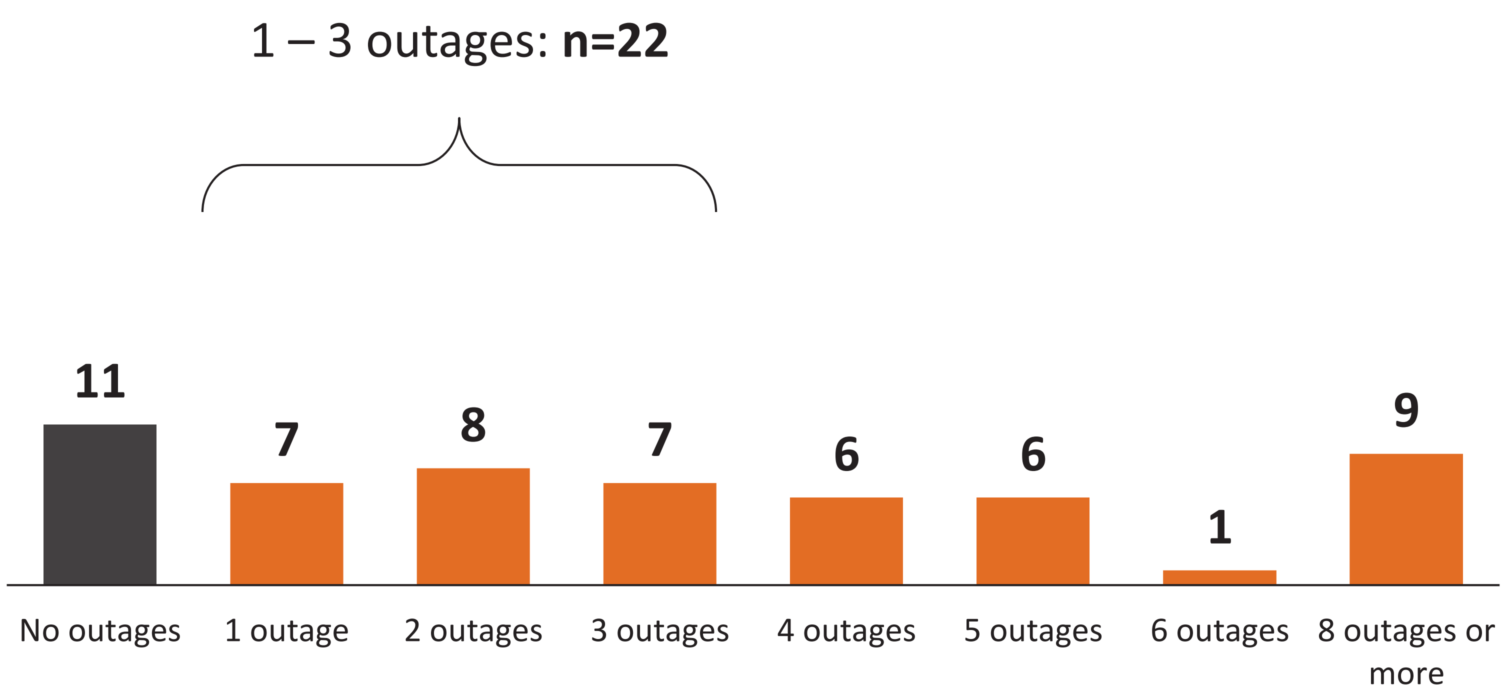
INNOVATIVE RESEARCH GROUP

System Reliability:

About a third (n=22) experienced 1-3 outages; n=9 experienced 8 or more; n=11 experienced no outages

Q Despite best efforts, no electrical distribution system can deliver *perfectly reliable* electricity. As a general rule, the more reliable the system, the more expensive the system is to build and maintain. With that said, the average **Essex Powerlines** customer experiences <u>**one**</u> unexpected power outage per year.

Has your organization experienced any power outages in the past 12 months, and if so, approximately how many?
[asked all respondents, n=60]



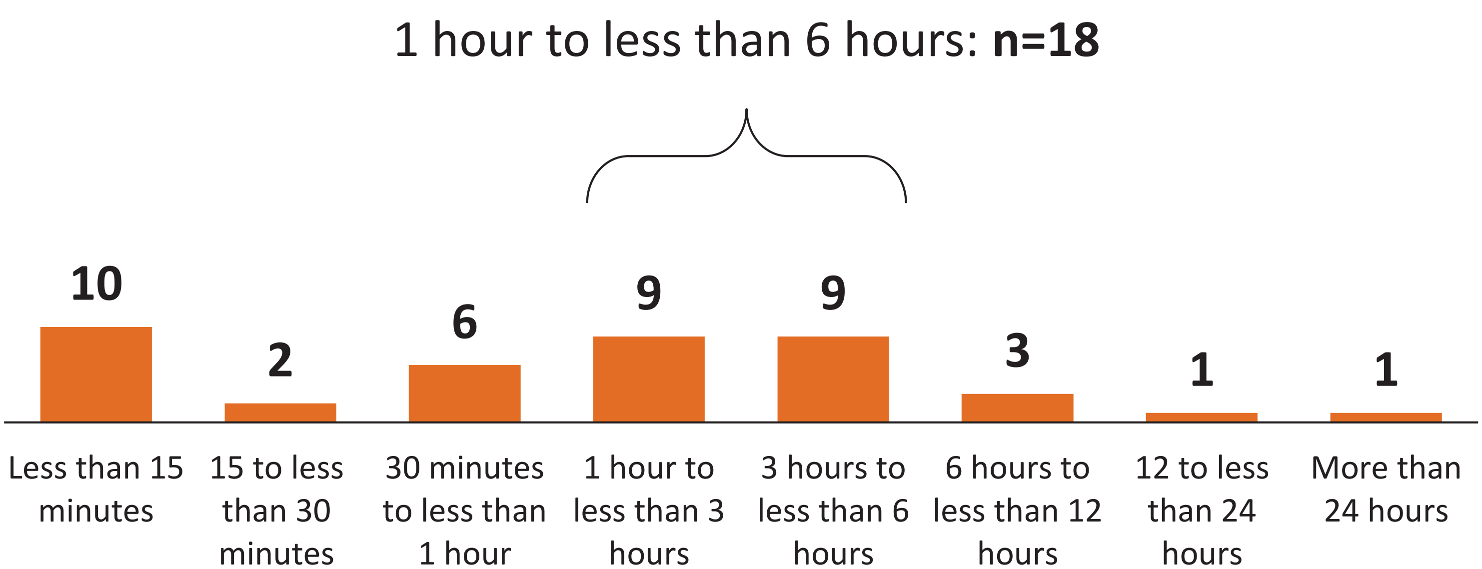
Note: ‘Don’t know’ (n=4), ‘Refused’ (n=1) not shown.

System Reliability:

Some (n=10) experienced outages lasting less than 15 minutes, but n=18 experienced outages ranging from 1 to less than 6 hours

General Service

Q And approximately how many minutes did the <u>most recent power outage</u> last at your organization?
[asked of those who have experienced an outage, n=44]



INNOVATIVE RESEARCH GROUP

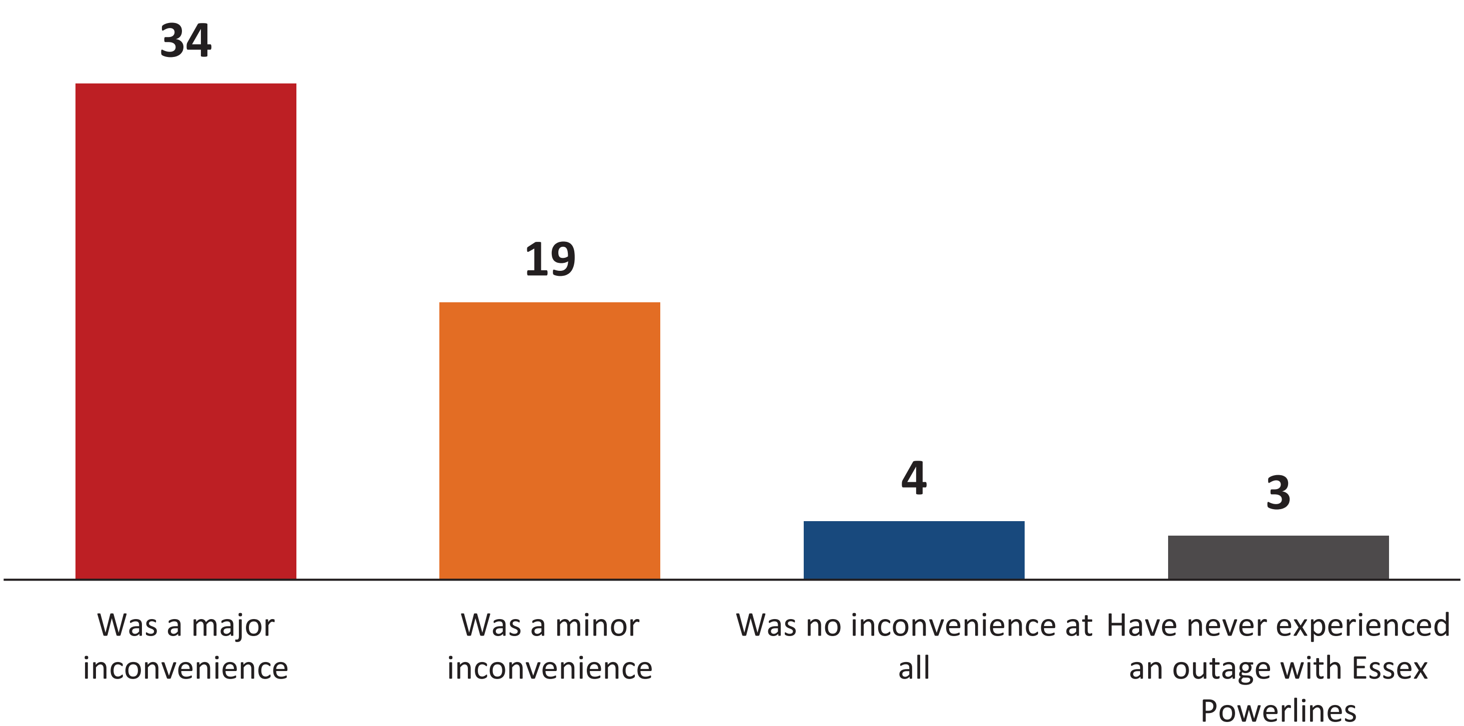
Note: 'Don't know' (n=3) not shown.

System Reliability:

More than half (n=34) of respondents report that the most recent outage was a major inconvenience

Q Thinking back to the **most recent** power outage you experienced as an Essex Powerlines small business customer, would you say the power outage…

[asked all respondents, n=60]



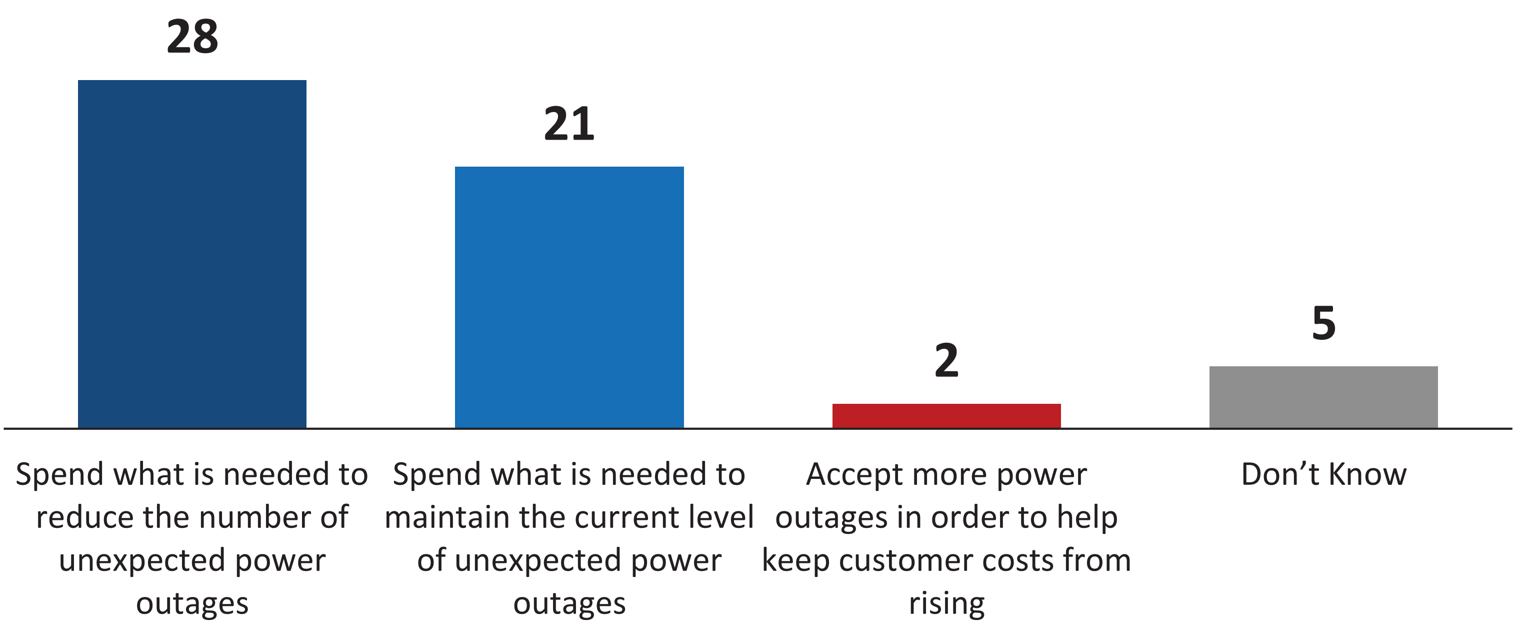
System Reliability:

Approximately half (n=28) think Essex Powerlines should spend what is needed to reduce the number of unexpected power outages

General Service

Q In your view, how do you think Essex Powerlines should address the **number** of customer power outages? Would you say…

[asked all respondents, n=60]



Note: 'Refused' (n=4) not shown.

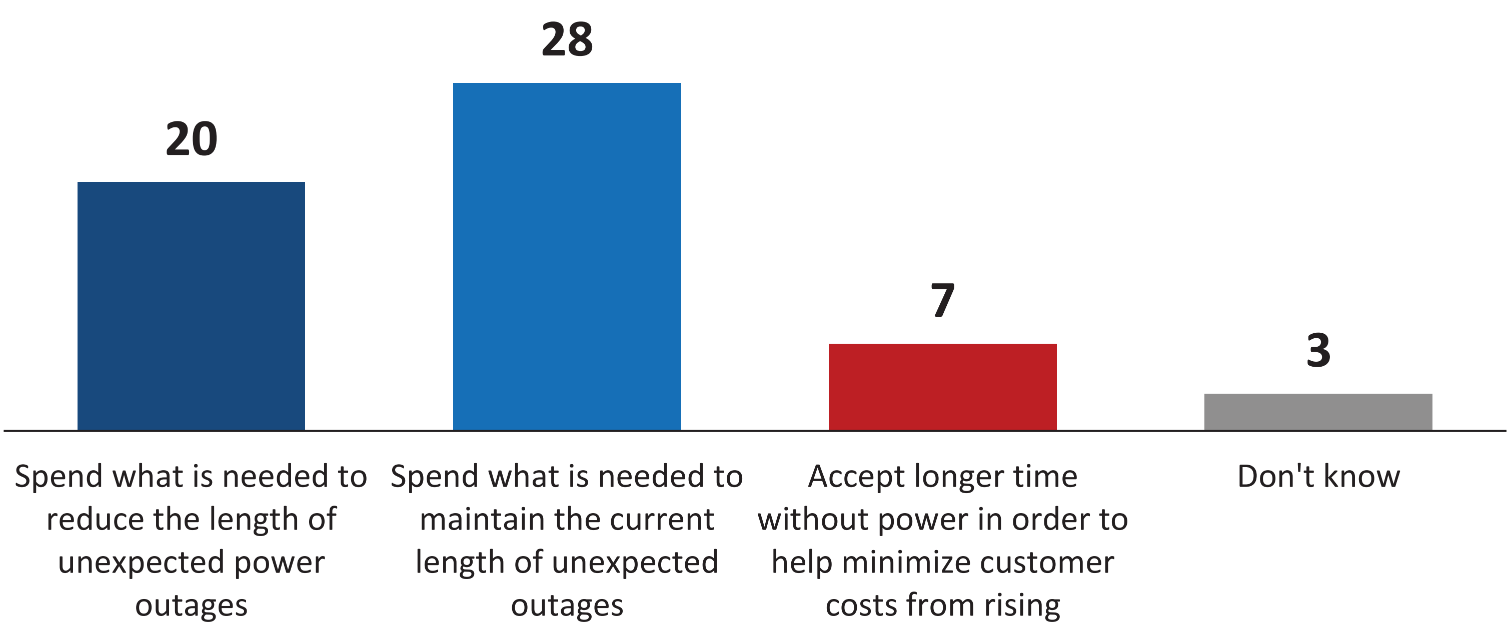
System Reliability:

Approximately half (n=28) say Essex Powerlines should spend what is needed to maintain the current length of unexpected outages

General Service

Q Overall, the average **Essex Powerlines** customer is without power for about **one hour per year**. In your view, how do you think Essex Powerlines should address the **length of time** customers are without power? Would you say…

[asked all respondents, n=60]



Note: 'Refused' (n=2) not shown.

System Challenges & Priorities

General Service

System Challenges & Priorities:

Most (n=48) think Essex Powerlines should invest what it takes to replace the system's aging infrastructure

General Service

Q While **Essex Powerlines** believes it has done its best to prolong the life of the assets that make up the distribution system, many of these assets are approaching the end of their useful life. As part of its investment plan, Essex Powerlines is proposing an infrastructure renewal program. The estimated cost of this system renewal program is **$31 million** between 2018 and 2022. Although this plan will allow Essex Powerlines to make, what independent studies suggest are, the necessary investments needed to maintain system reliability, **it *may* have an impact on customer bills**.

Which of the following statements best represents your point of view?
[asked all respondents, n=60]

Invest What It Takes

Some customers have said…
Essex Powerlines should invest what it takes to replace the system's aging infrastructure to maintain system reliability, even if that increases my organization's monthly electricity bill by less than a dollar over the next few years.

Lower Investment

Others have said…
Essex Powerlines should lower its estimated investment in renewing the system's aging infrastructure to lessen possible bill increases, even if that means more or longer power outages.

Note: 'Don't know' (n=1), 'Refused' (n=2) not shown.

Run-to-Failure:

Most (n=40) feel the best approach is to replace the equipment before it breaks down

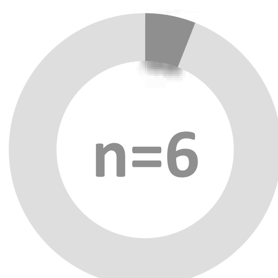
General Service

Q Thinking about the aging equipment in Essex Powerlines' distribution system, do you feel it's best to wait until non-critical infrastructure – that is, equipment that impacts a limited number of customers – breaks down to get full value from each piece of equipment, even if it means short power outages for some customers…

…Or do you feel the best approach is to replace the equipment before it breaks down to avoid unscheduled power outages, even if it means not getting the "full" value from each piece of equipment?
[asked all respondents, n=60]

Replace Equipment Before Breakdown

Wait Until Equipment Breakdown



Don't know

System Service:

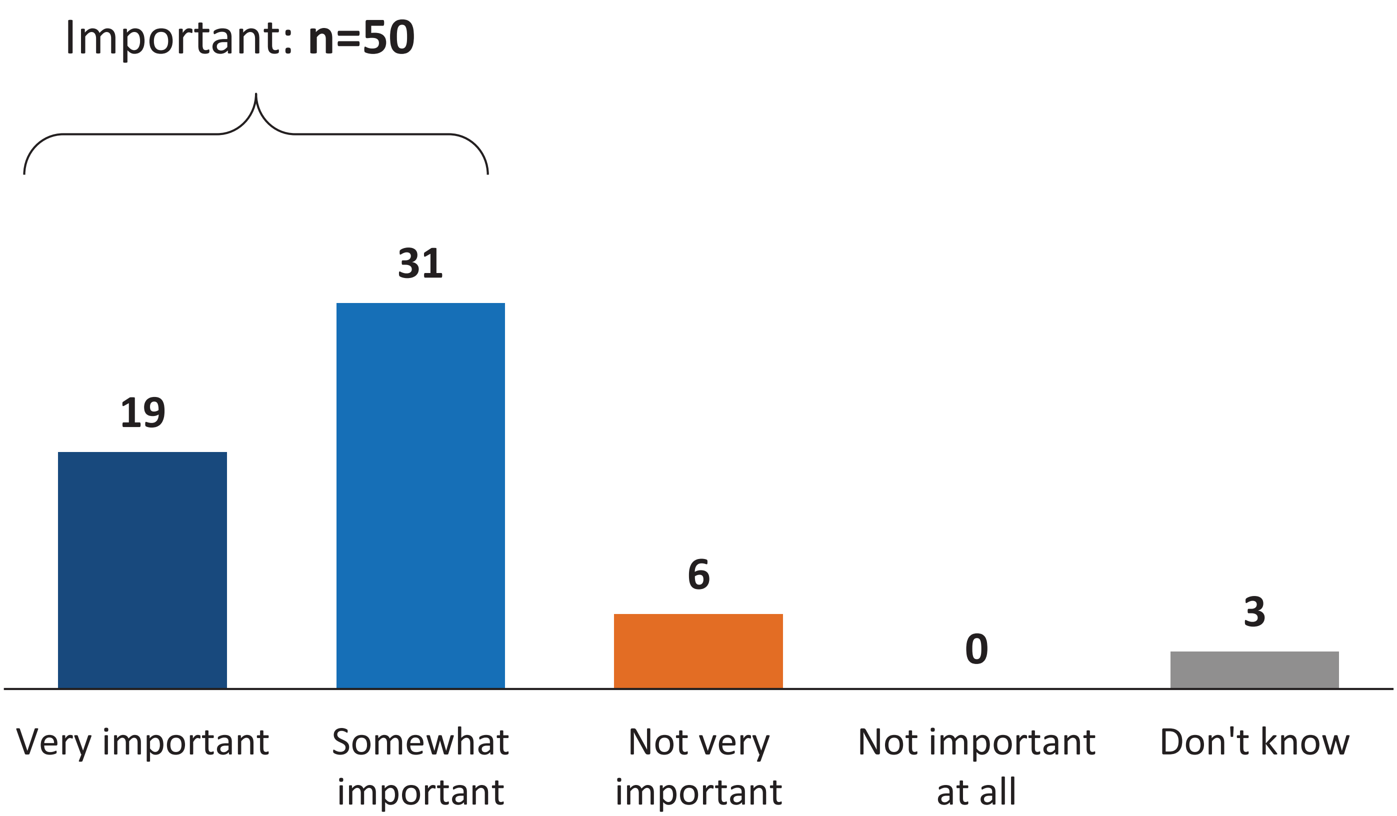
Most (n=50) feel that investing in modernizing the distribution system now is important

General Service

Q Modernizing the distribution system can allow Essex Powerlines to improve reliability. Investments, such as automated switches, may allow Essex Powerlines to minimize the number of people impacted by outages and to restore electricity to many customers in a matter of seconds.

Given there are many other areas of needed investments, such as connecting new customers, replacing aging equipment and expanding capacity for long-term growth, how important do you feel it is for Essex Powerlines to invest now in modernizing the distribution system?

[asked all respondents, n=60]



Note: 'Refused' (n=1) not shown.

General Plant:

Most (n=43) say Essex Powerlines should be wise with spending but acknowledge the importance of having the proper tools and equipment

General Service

Q Essex Powerlines is not just the local electricity distribution system itself, but a company that operates the system. As a company, Essex Powerlines needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the electrical system and customer information.

Again, customers have made a number of statements about this sort of investment. Which of the following statements best represents your point of view?

[asked all respondents, n=60]

Spend wisely, but it's important staff have what it needs

Others have said…

While Essex Powerlines should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably.

Make do with what it has

Some customers have said…

Essex Powerlines should find ways to make do with the buildings, equipment and IT systems it already has.

Note: 'Don't know' (n=2), 'Refused' (n=1) not shown.

Reaction to Customer Input

General Service

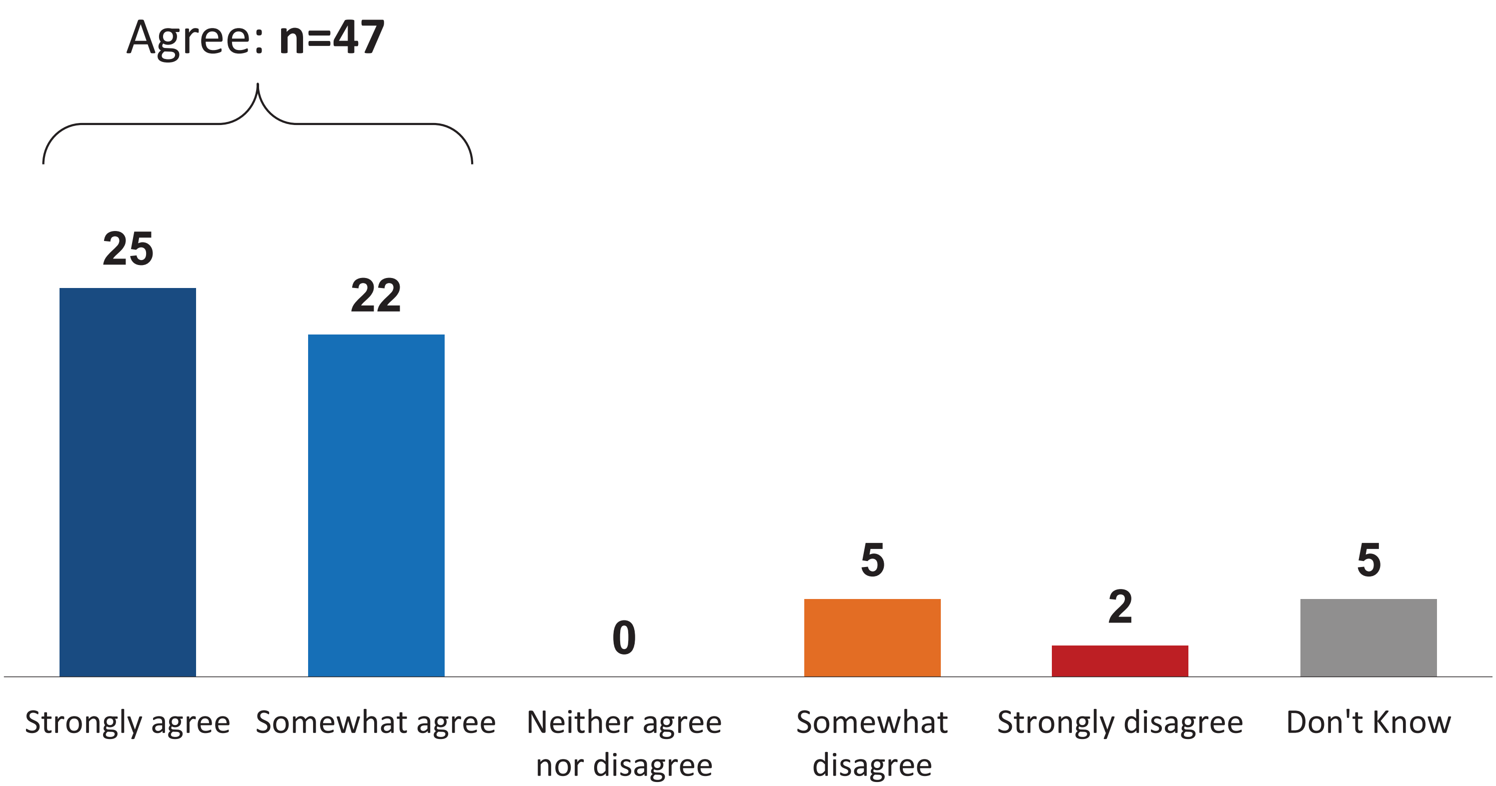
Pay Now or Later:

Most (n=47) agree to invest in infrastructure now to save down the line

General Service

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=60]

We should invest in our electricity system infrastructure now or we will end up paying more the longer we delay our system renewal.



Note: 'Refused' (n=1) not shown.

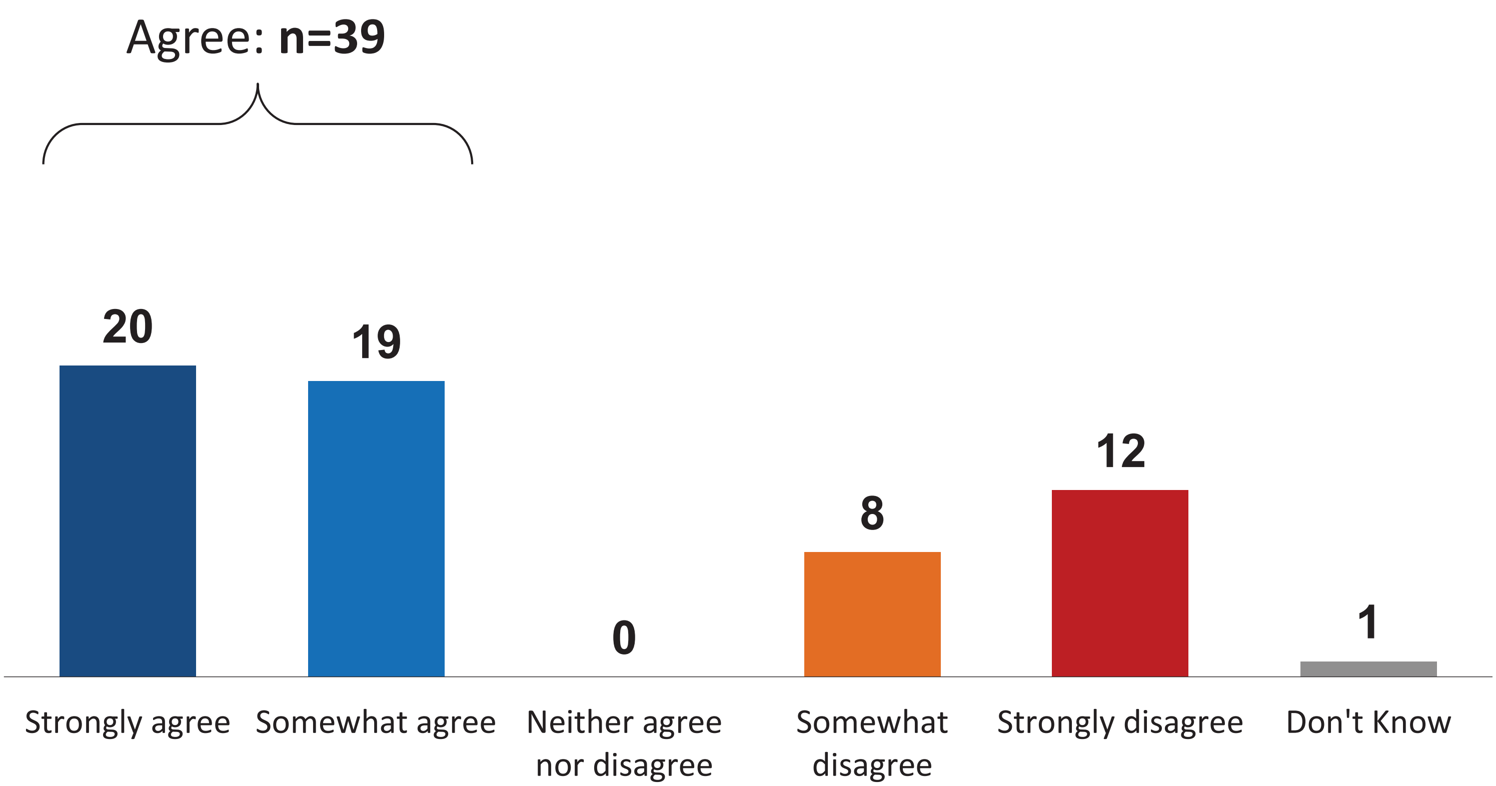
Deferring To The Experts:

Most (n=39) agree to trust that the experts will find the right balance between costs, investments, and spending decisions

General Service

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=60]

The electricity sector is so complicated and confusing; we just have to trust that the experts will find the right balance in keeping cost down while making the right investments and spending decisions.



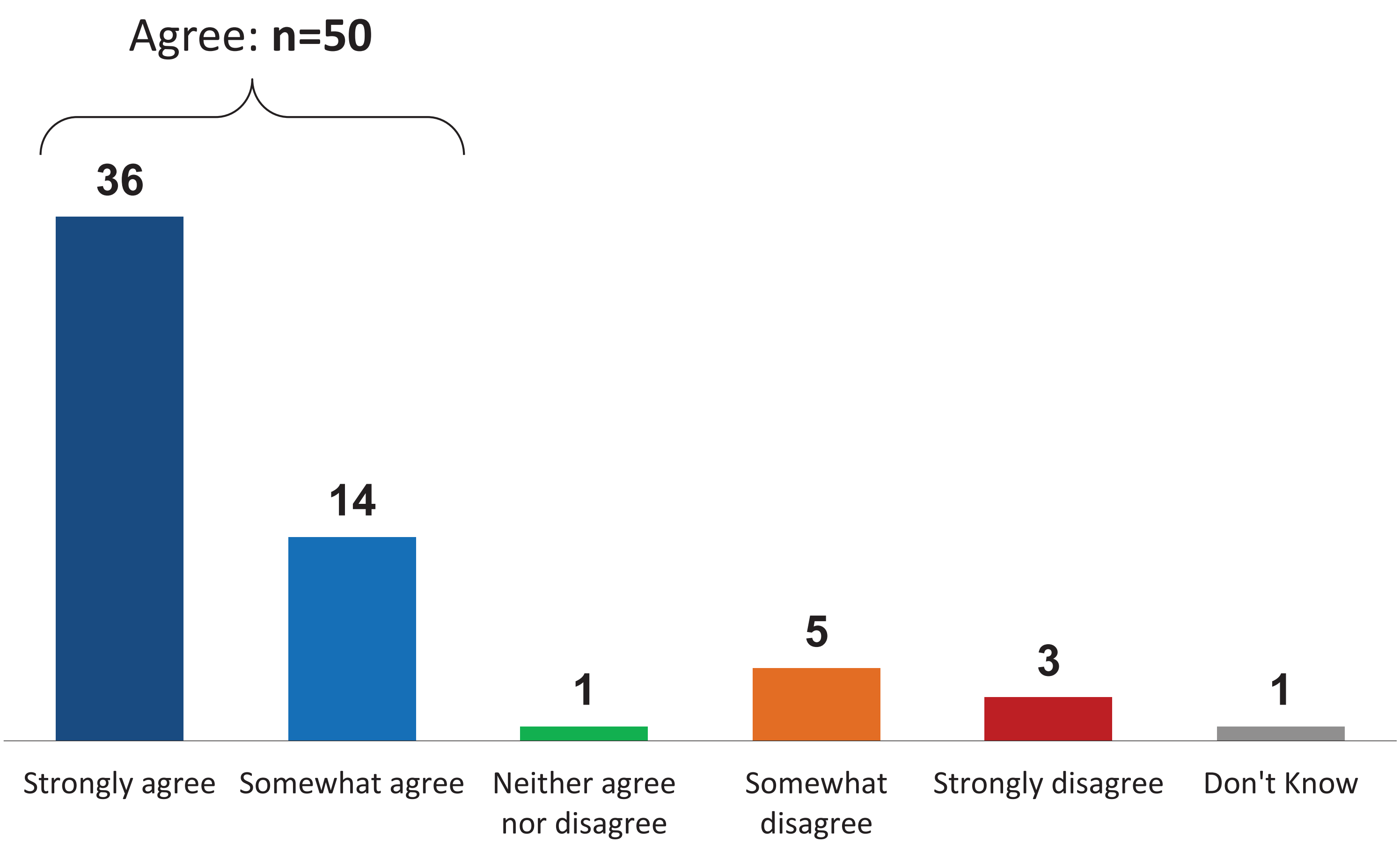
Note: 'Refused' (n=0) not shown.

Conservation Demand Management:
Most (n=50) agree that Essex Powerlines should do more to help customers find ways to reduce consumption and costs

General Service

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=60]

I think Essex Powerlines should do more to help customers find ways to reduce their electricity consumption and costs.



Note: 'Refused' (n=0) not shown.

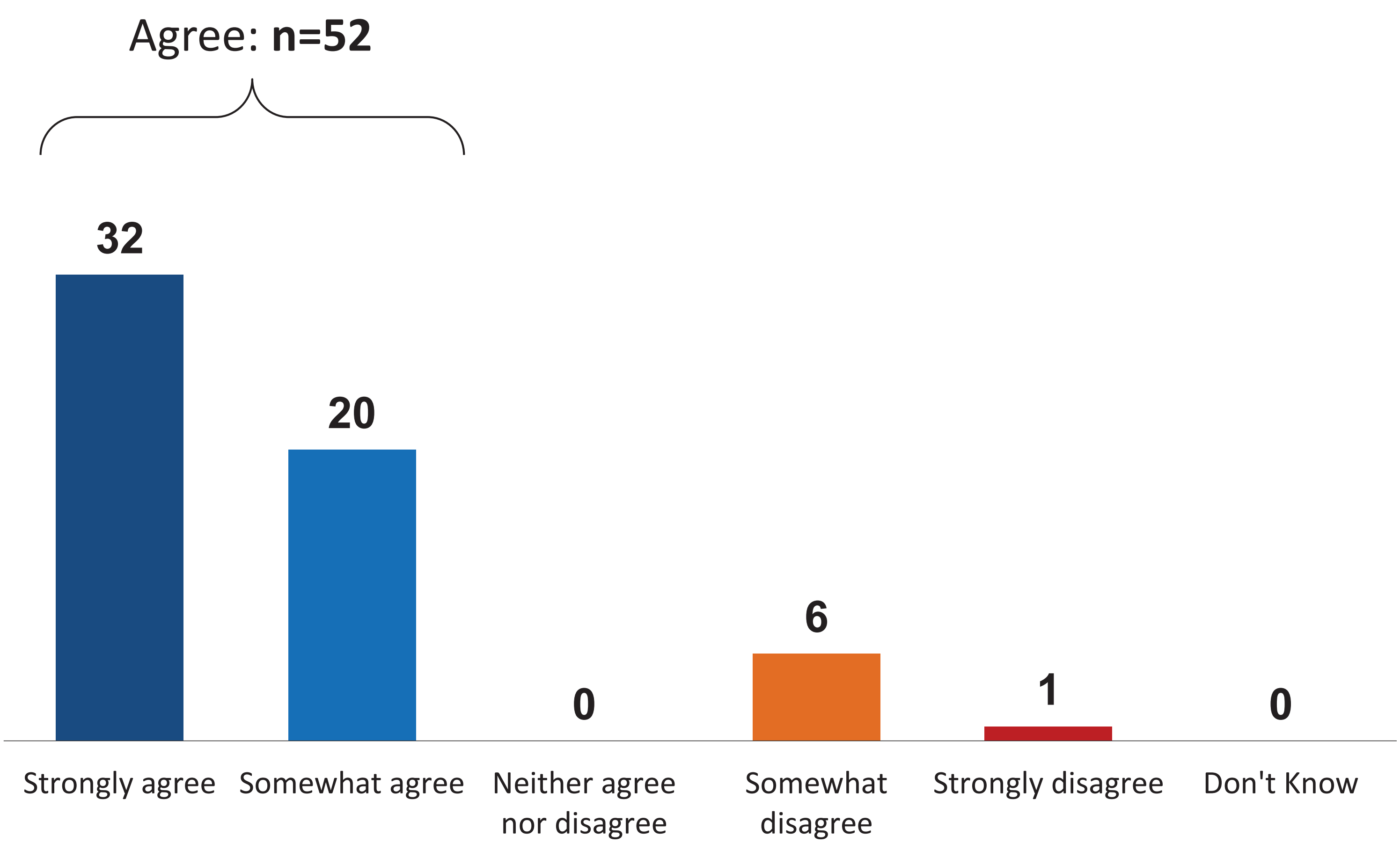
Legacy:

Most (n=52) agree that although nobody likes to pay more, there is an obligation to maintain reliability for future generations

General Service

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=60]

Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations.



Note: 'Refused' (n=1) not shown.

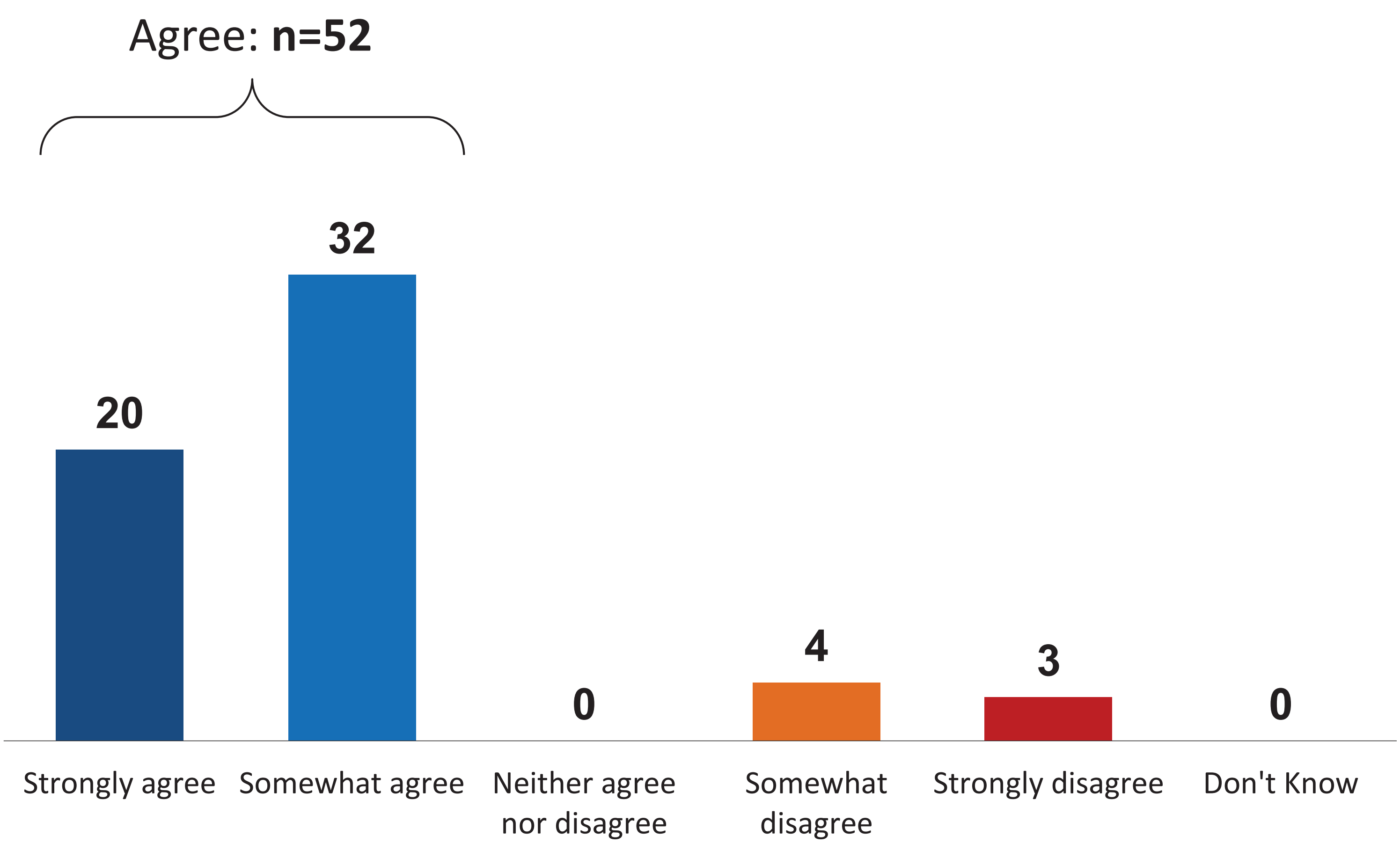
Modernizing The Grid:

Most (n=52) agree that modernizing the system will allow consumers to have greater control over usage

General Service

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=60]

We need to modernize the local electricity system so consumers can have greater control over their electricity usage.



Note: 'Refused' (n=1) not shown.

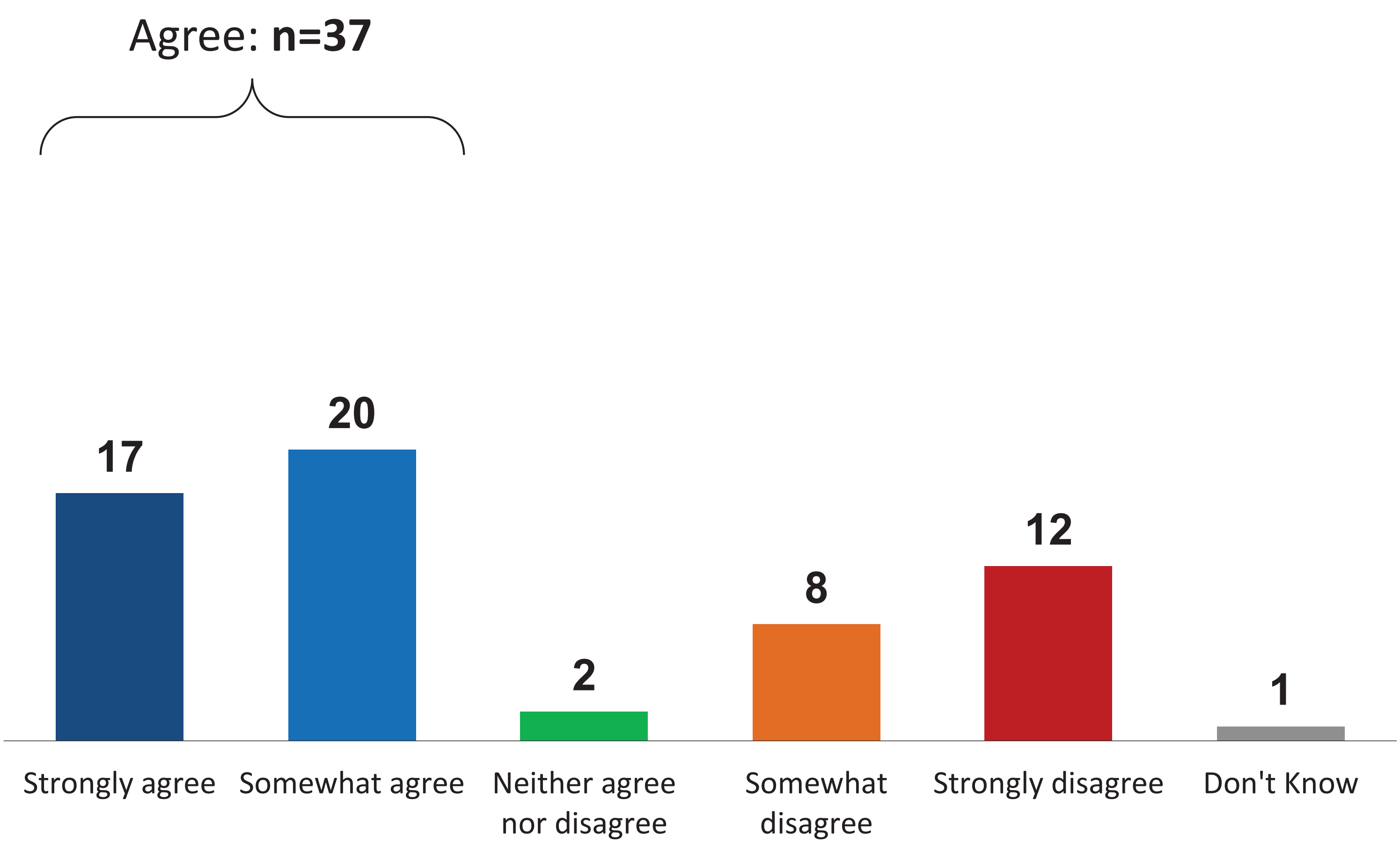
System Reliability:

Most (n=37) agree they worry about the impact outages have on vulnerable people

General Service

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=60]

A few power outages are fine for my organization, but I worry about the impact this has on more vulnerable people, such as the elderly.



Note: 'Refused' (n=0) not shown.

Assessment of Plan:

Some (n=10) think the rate increase is reasonable and support it; n=11 respondents do not like the increase but think it is necessary

General Service

Q

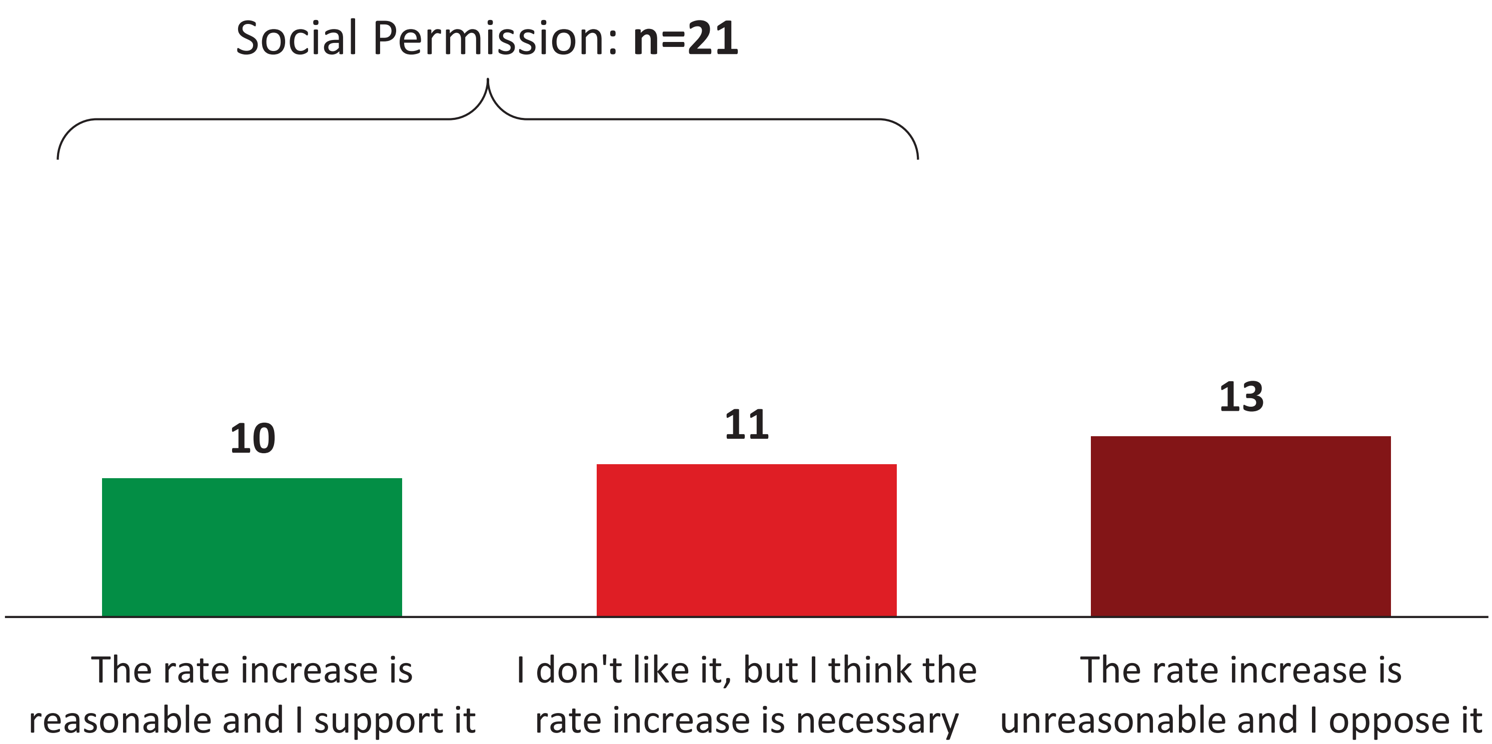
Essex Powerlines believes that proactive renewal and consistent maintenance is needed to maintain system performance, while keeping the impact on customer bills manageable over the long-term. Over its proposed 5 year plan, **Essex Powerlines** will…

- spend an estimated **$15 million** on on-going maintenance and the operation of the distribution system; and
- invest an estimated **$16 million** in new equipment and infrastructure priorities that will help ensure system reliability.

To fund this proposed plan, the average business customer in your rate class in Essex Powerlines service area will see their rates increase by approximately [$0.86 GS<50, $6.19 GS>50] per month on the distribution portion of their bill over the next five years. So, by 2022, the average business customer in your rate class will be paying an estimated [$4.92 GS <50, $42.67 GS >50] more per month on the distribution portion of its electricity bill, which is roughly the rate of inflation.

Considering the cost of Essex Powerlines plan, would you say…

[asked all respondents, n=34*]



** In the original interviews, respondents were provided inaccurate rate impact information. Callbacks were conducted to contact as many of the original respondents as possible to re-ask this question (and the follow-up open-ended question) with the corrected rate impact figures shown above.*

INNOVATIVE RESEARCH GROUP

Rationale:

Some who support appear to be motivated by the need to maintain; others think the proposed increase is a reasonable amount

General Service

Q And why do you say that?
[asked only of those who have an opinion on the assessment of plan, n=34]

Among those who say…
"The rate increase is reasonable and I support it." ***(n=10)***

- to fix something you have to spend money
- Because I think its is probably necessary to keep everything working and we need it
- has to be done, we need it
- over the 5 years it's reasonable
- they are spending that much so someone has to pay for it, it makes sense
- Because it's reasonable and I support it.
- because for what they will be doing the cost to the customer will be small and it will benefit to the customer
- I agree with it
- the increase is not that big and if it will contribute to maintenance it wont be that noticeable.
- It's a minimal amount of money

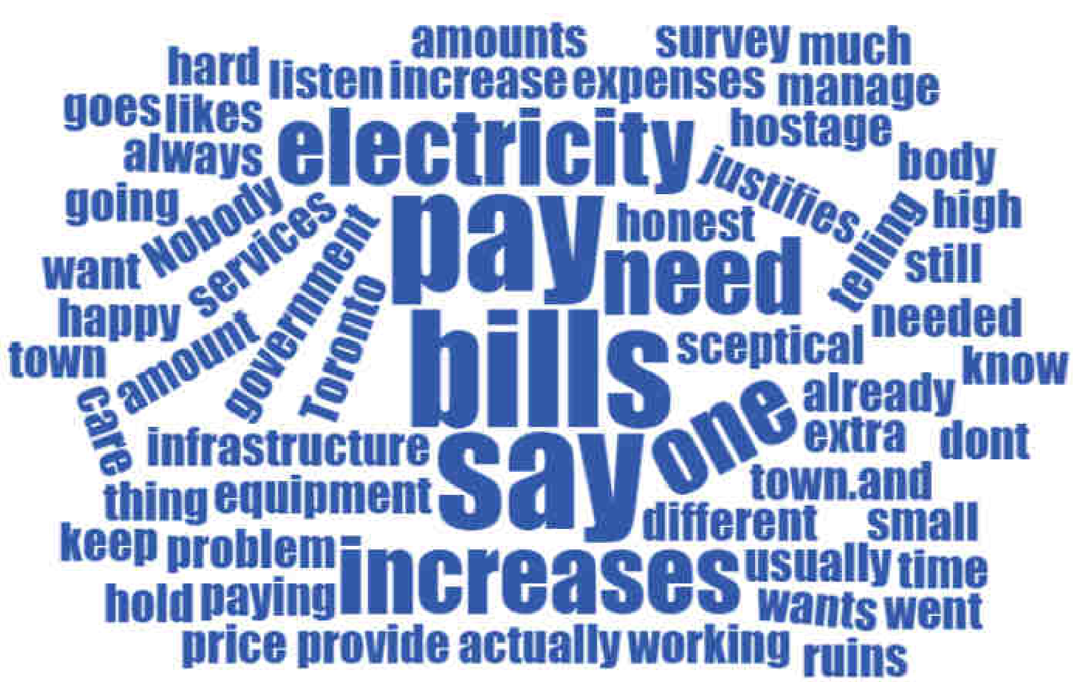
Rationale (2):
Most of the verbatim comments re-affirm that although some respondents don't want to pay more they acknowledge that it is a necessity

General Service

Q And why do you say that?
[asked only of those who have an opinion on the assessment of plan, n=34]

Among those who say…
"I don't like it, but I think the rate increase is necessary." ***(n=11)***

- who would be happy with a price increase?
- nobody wants increases but if it is needed
- it justifies the expenses
- it went up too high
- Because we are paying already too much.
- its hard for people to manage their bills, but I know they need to keep the infrastructure working
- Nobody likes to pay extra on their bills
- what they say it will be and what it actually will be are usually 2 different amounts. I'm sceptical that it will be that amount. the government has been telling us one thing and its not
- No one likes increases in any bills but if it is going to provide services that we need then it will have to be.
- because we always have a problem with our electricity. to be honest we pay more than any other town and our electricity goes out all the time and ruins our equipment. this is a small town and we pay more than Toronto
- they hold us hostage we have no say. Why do a survey when they do what they want. and they don't care what we say and still not listen to us



Rationale (3):
Some of those opposed to the rate increase feel the cost of electricity is already too much

General Service

Q And why do you say that?
[asked only of those who have an opinion on the assessment of plan, n=34]

Among those who say…
"The rate increase is unreasonable and I oppose it." ***(n=13)***

- long time customer and we have been paying for a long time and from all the bills we paid Essex should have put some money on the side to do these repairs. its like buying a car, you don't ask your boss for a raise to buy a car. you save towards it.
- we already pay a lot as it is
- that's quite a significant increase
- I don't think we should have to pay for it.
- my cost keeps going every up and we are a little place. I went form 130 to 160 to 190. and I'm on a budget
- It's the question you are not giving me any choices, the infrastructure is fine the way it is. There is very few power outages, there are no issues. Who said there was an issue? They did. take a poll and see if people think the infrastructure is fine.
- on the bill the delivery charges is more than the usage. we try to cut down on usage but the delivery charges goes up. this should be included in the rates and not be charged
- we are paying too much as it is and we can barely pay our bills
- they should maintain the system themselves, they are not a non profit organization.
- because I can not afford the way it is now
- we are getting hit with everything gas, hydro, wages. I don't know how we are going to afford it.
- I think anything they do with hydro is unreasonable. there are people who can't pay their bills, we are selling it cheaper to others. Hydro has been mismanaged and they need to fix it.
- Because I don't believe them, I think it will be more. We are not a normal business, and how do they figure that we are?

Building Understanding.

Personalized research to connect you and your audiences.

For more information, please contact:

Susan Oakes

Vice President
(t) 416-642-6341
(e) soakes@innovativeresearch.ca

Michelle Zeppieri

Consultant
(t) 416-640-4131
(e) mzeppieri@innovativeresearch.ca

Appendix E: Convergys Top Down Survey

CONVERGYS
ANALYTICS

ESSEX POWERLINES
Top Down Survey

Wave I Results

November 2016

SURVEY OVERVIEW & METHODOLOGY

Objective

- Gather Customer Satisfaction metrics to be used for OEB and scorecard reporting
- To measure Satisfaction in the following areas: Overall Satisfaction, Service/Brand Performance, Communication, Billing, and Contact Handling

Timing

- Surveying conducted October 3 – October 14, 2016

Methodology

- Telephone Survey conducted by a Convergys live agent

Sampling

- 500 total completed surveys – 400 Residential completes and 100 Business completes

Question Scales & Reporting

- Satisfaction asked on a 5 (Very Satisfied) to 1 (Not at all Satisfied) scale
- Top 3-Box (3, 4 and 5 ratings) reporting used for reporting of survey attributes

CONVERGYS ANALYTICS

OUR OBJECTIVE AS A BUSINESS PARTNER IS TO HELP ESSEX POWERLINES INCREASE CUSTOMER SATISFACTION

Increase customer satisfaction

How we do this…

- Outline what factors have the largest impact on satisfaction
- Identify differences in Business and Residential customer segments
- Identify underperforming areas to target for improvement
- Mine customer comments to determine what common themes reflect opportunities for improvement

Improve customer interactions

How we do this…

- Working smarter to serve customers better by identifying and optimizing self-service opportunities
- Provide recommendations to improve the customer's experience when they do need to contact customer service

AGENDA

Essex Powerlines Top Down Survey

EXECUTIVE SUMMARY

OEB Metric & Satisfaction Overview	Key Drivers	Touchpoint Satisfaction
• Overall Satisfaction is high (81%), but there are opportunities to improve service reliability, billing expectations, and customer service • Business customers are more satisfied (by 8% pts) compared to Residential customers	• Top Satisfaction drivers for Business customers are Reliability and Power Quality • Customer Service is a top Satisfaction driver for Residential customers	• Customers almost exclusively use the phone to contact Essex Powerlines where offering/enhancing self-service capabilities is a prime opportunity to reduce contacts • Residential customers generally have a preference for mail while Business customers opt for several methods

CONVERGYS ANALYTICS

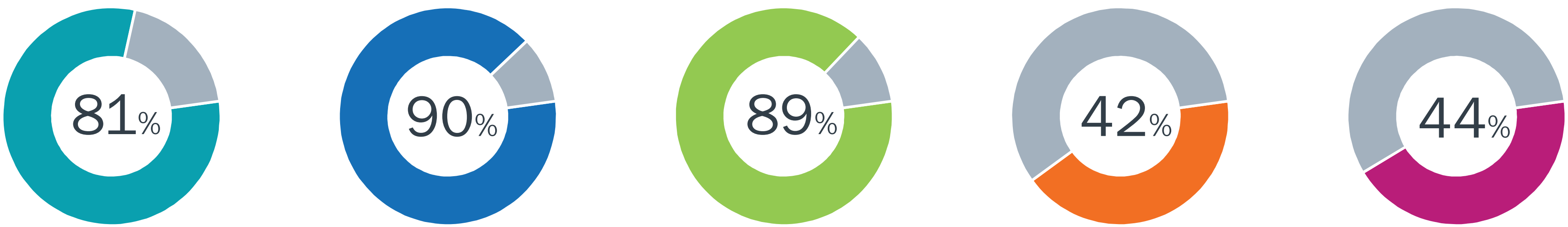
OEB METRIC & SATISFACTION OVERVIEW

THE MAJORITY OF CUSTOMERS ARE HIGHLY SATISFIED WITH ESSEX POWERLINES

KEY METRIC AND OEB REQUIREMENTS

Top 3 Box

Overall Satisfaction | Quality of Power Service | Quality of Customer Service | Affordability of Service | First Contact Resolution*



“Essex Powerlines is always very helpful and has a quick response. It is appropriate for the situation. If I have any questions about the service, Essex Powerlines answers those in a timely manner.” ~ ‘5’ Overall Satisfaction rating

“I gave Essex Powerlines a phone call and they were here within a half an hour and my problem was fixed within a few hours.” ~ ‘5’ Overall Satisfaction rating

*First Contact Resolution (FCR) = %Yes; Customers contacting Essex by phone and resolved on one contact

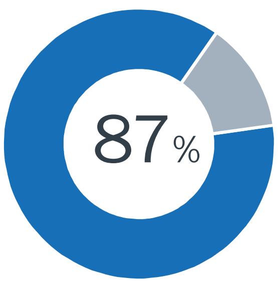
CONVERGYS ANALYTICS

OVERALL SATISFACTION IS HIGH, BUT OPPORTUNITIES FOR IMPROVEMENT EXIST, MORE SO FOR RESIDENTIAL CUSTOMERS

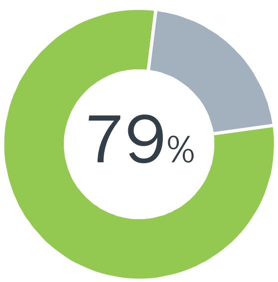
Customer Satisfaction

Top 3 Box

Business



Residential



2016 Reasons for Satisfaction

Positive Mentions

- No Issues/ Reliable
- Good Customer Service
- Good Service/ Satisfied

Negative Mentions

- Service Interruptions
- Price/Cost
- Poor Customer Service

CONVERGYS ANALYTICS

KEY SATISFACTION DRIVERS

CONVERGYS

WHAT IS A KEY DRIVER ANALYSIS?

Key Drivers represent what is most important to Customers and where to focus efforts to have the greatest impact on Overall Satisfaction.

1. What are the attributes' relationship to Overall Satisfaction?

   Action: Calculate each attributes' correlation to Overall Satisfaction

2. If several attributes have a moderate to strong relationship to Overall Satisfaction, how can attributes be prioritized?

   Action: Calculate the Relative Importance

3. Once a Relative Importance model is developed, how much does it explain Overall Satisfaction?

   Action: Calculate the proportion of variance that explains Overall Satisfaction

CONVERGYS ANALYTICS

BUSINESS CUSTOMERS WANT AN INTERRUPTION-FREE SERVICE WHILE RESIDENTIAL CUSTOMERS PRIORITIZE CARE WITHIN CUSTOMER SERVICE

Key Drivers to Overall Satisfaction

Business		Residential	
26%	Reliability	Customer Service	20%
21%	Power Quality	Value	12%
11%	Promotion of Energy Conservation Programs	Reliability	11%
8%	Customer Service	Power Quality	11%
7%	Leader in Community	Communication	10%

% Variance explained: 61% (Business)

% Variance explained: 56% (Residential)

Percentages represent the relative impact of each attribute on Overall Satisfaction.

CONVERGYS ANALYTICS

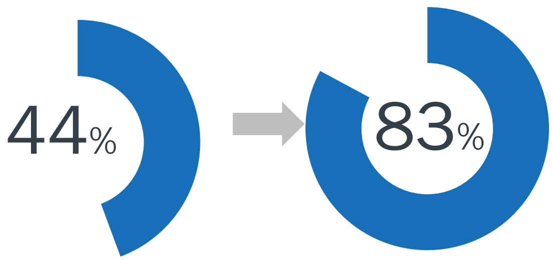
TOUCHPOINT SATISFACTION

CONTACT METHODS AND REASONS ARE SIMILAR FOR BOTH BUSINESS & RESIDENTIAL, HOWEVER, BUSINESS CUSTOMERS CALL MORE OFTEN

Business

Reported Contacts in Past 6 Months

Resolved



Contact Methods

- Telephone 98%
- Email: 5%

Contact Reasons

n=43

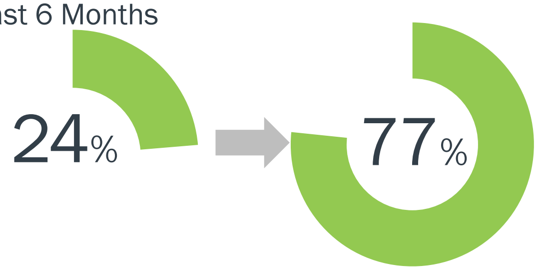
- Service Issue 44%
- Billing/Payments 40%
- Account Change 14%

Call Handling

Residential

Reported Contacts in Past 6 Months

Resolved



Contact Methods

- Telephone 97%
- Email: 1%

Contact Reasons

n=93

- Billing/Payments 39%
- Service Issue 37%
- Account Change 13%

Total may sum to more than 100% due to multiple responses

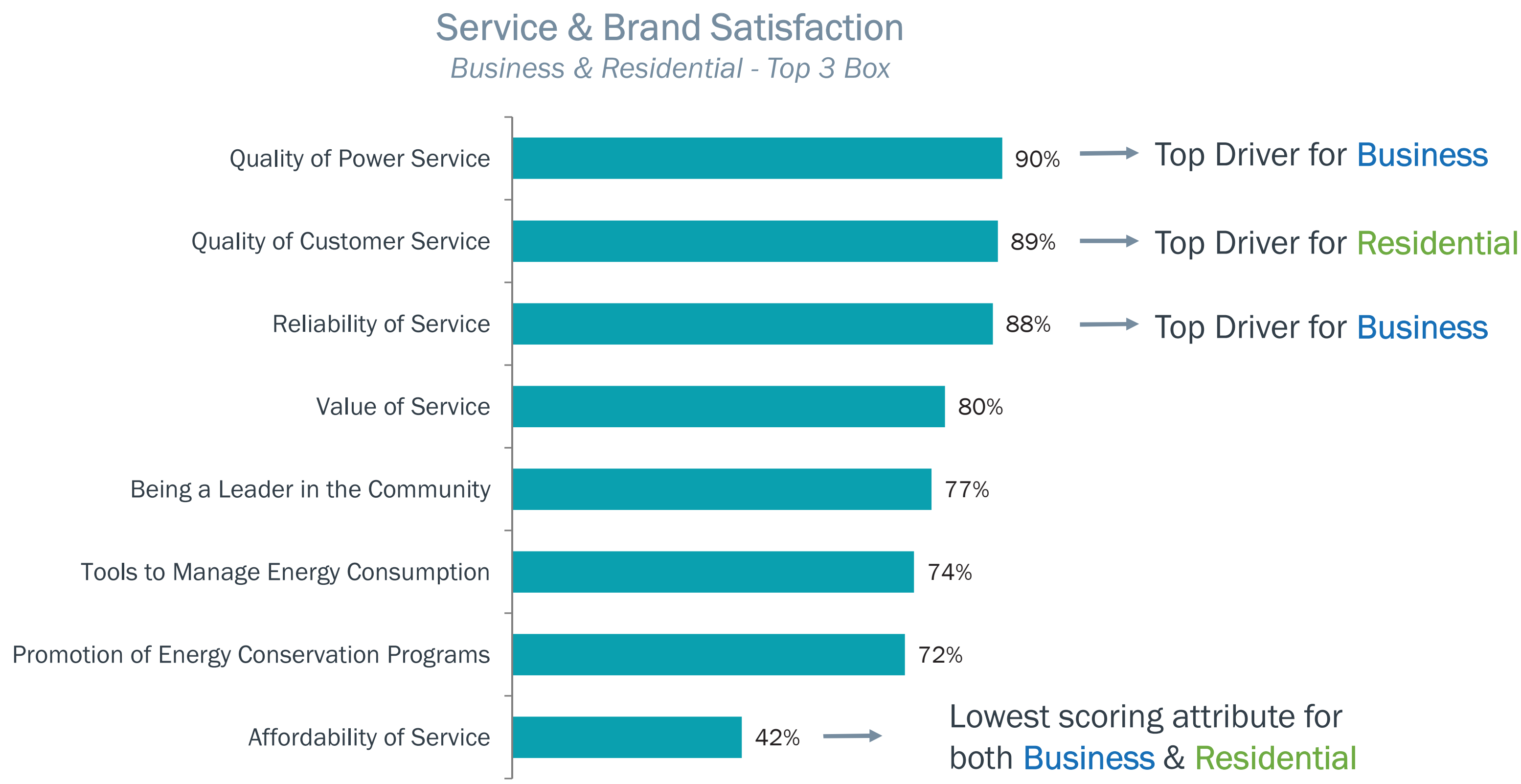
Based on customer comments, Q8.

CONVERGYS ANALYTICS

CONTACT HANDLING FINDINGS & OPPORTUNITIES

	Finding	Opportunity	Customer Feedback
Residential	*23% of Customers' inquiries were not resolved*	Follow through with services promised to avoid repeat contacts	*"We've had one issue here and the service through the employee was delayed by hours. We called around 8 and didn't see anyone till around midnight."*
Business & Residential	*Almost half of all customer contacts were for billing and payments*	Increase awareness and enhance online self-service options to reduce the need for contacts	*"I needed to make a payment arrangement."* *"We never received our bill in the mail. I wanted to see if I could receive a copy."*

CUSTOMERS ARE HIGHLY SATISFIED WITH THE TOP DRIVING MEASURES



Business & Residential data breakout in Appendix - Differences ratings are not statistically significant.

CONVERGYS ANALYTICS

SERVICE & BRAND FINDINGS & OPPORTUNITIES

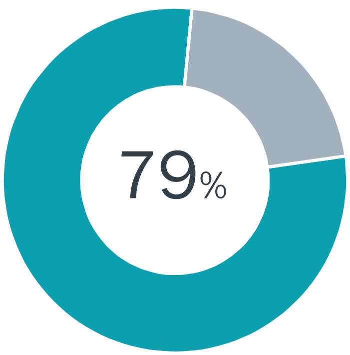
	Finding	Opportunity	Customer Feedback
Business	*Drivers: Power Service & Reliability*	Reduce recurring issues with loss of service	*"Our power seems to go out a lot, interruptions where the power is off for 5 minutes and the computers go off with no explanation."* *"I was looking at the number of times the hydro service was going out. It happens more than it has in previous years."*
Residential	*Driver: Customer Service*	Continue to focus on providing high quality customer service	*"They are very easy to work with and to talk to. They try not to interfere in your life, which to me, all are very good things."* *"They are very helpful with anything I need help with."*
Business & Residential	*Affordability of Service*	Educate Customers on rates and on fees charged	*"The price is too high. Even after we cut down on our hydro consumption it is still pretty high."* *"It is very hard to justify the rates that we have to pay for the services."*

RESIDENTIAL CUSTOMERS STRONGLY PREFER LETTERS; BUSINESS CUSTOMERS ARE LIKELY TO PREFER SEVERAL METHODS SIMILARLY

Business & Residential

Top 3 Box

Communication



Communication Preference

	Business	Residential
Letter in the Mail	41%	53%
Email	27%	24%
Telephone Call	30%	22%

CONVERGYS ANALYTICS

COMMUNICATION FINDINGS & OPPORTUNITIES

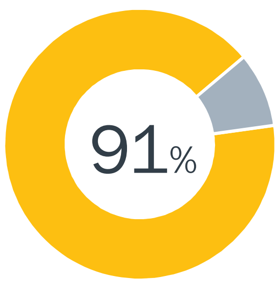
	Finding	Opportunity	Customer Feedback
Business	*Preference several methods – Mail, Email, and Telephone*	Important to leverage all touchpoints for communication	*"I wish they would go back to talking to people, instead of having everything be so automated. It's really annoying needing to talk to someone, and having to combat all these numbers. It's inconvenient for emergencies, but I understand how it's easy for the company."*

THE BILLING PROCESS APPEARS TO BE WELL RECEIVED BY ESSEX POWERLINES CUSTOMERS, BUT HAS ROOM FOR IMPROVEMENT

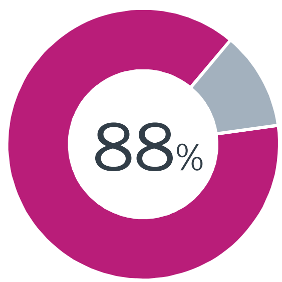
Business & Residential

Top 3 Box

Ease of Accessing Account Information



Billing Accuracy



"A few times, we have an overdue when our bill was already paid."

Continue to ensure billing is understandable and accurate

"Need to do something about the pricing. I have all this green energy but it's not helping anyone with their bill."

Leverage the use of current touchpoints to help Customers better understand how to manage their energy consumption

"I don't agree with people on fixed income having to pay a late fee for paying bill late. I have no control."

Endorse the benefits and feasibility of current payment options

RECOMMENDATIONS

TAKEAWAYS & RECOMMENDATIONS

1

PRIORITIZE KEY DRIVERS OF SATISFACTION

Investing in service reliability and customer service will help minimize the impact of the dissatisfaction triggers

2

PROMOTE SELF-SERVICE SOLUTIONS

Almost all customers are contacting Essex Powerlines via phone and about half are related to billing inquiries; if self-service options and other methods for communication are leveraged, the call center can see a reduction in call volume and costs associated with each call

3

BE PROACTIVE & REACTIVE WHEN COMMUNICATING BILLING

Customers are heavily critiquing their bills due to continuous rate increases; mailing/emailing a bill explanation, posting a bill tutorial to the website, and coaching key agent behaviors (i.e., empathy, clear explanations, etc.) within customer care are ways to effectively communicate billing accuracy and set billing expectations

CONVERGYS

TOOLS TO MANAGE ENERGY CONSUMPTION

Help Customers learn and better understand how to manage their energy consumption by:

Enhance the website. Add visibility and accessibility to “Save Energy” on the home page, and augment the graphics.

Send information. Send monthly email marketing messages to consenting customers containing tips or postcards that can direct them to more information; also, Customer Service Reps can ask customers if they are interested in learning about managing energy consumption and send them information via email/mailing.

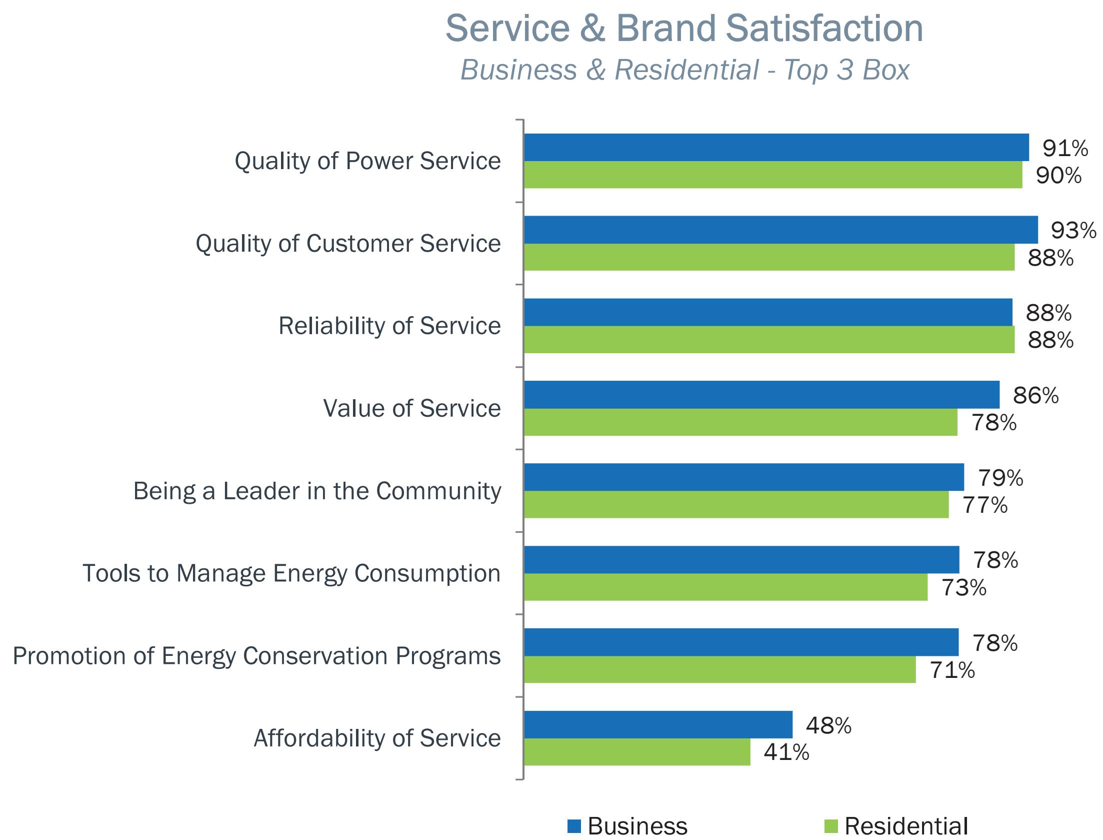
Leverage the social media space. Post information or “how-to” videos online, or create a blog for customers to subscribe to, to learn about managing energy consumption.

Interact with the community. Continue to issue press releases and work with local media (e.g., radio, news, etc.) to share information on managing energy consumption. Host events/seminars at Essex Powerlines so people can come in and learn more or have booths/tables at community events with information on available tools.

CONVERGYS ANALYTICS

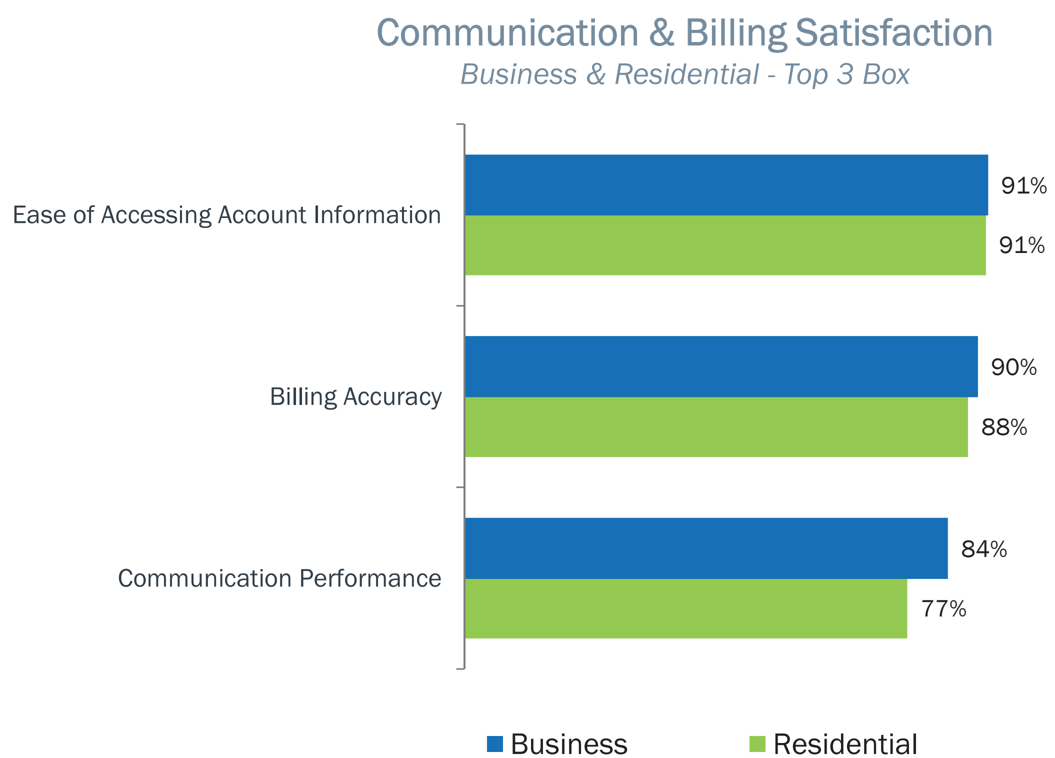
APPENDIX

SERVICE AND BRAND SATISFACTION



Differences in Business & Residential ratings are not statistically significant.

COMMUNICATION AND BILLING SATISFACTION



Differences in Business & Residential ratings are not statistically significant.

Appendix F: Customer Engagement Handbooks

2018 RATE APPLICATION REVIEW

Customer Consultation Workbook

ESSEX POWERLINES CORPORATION

For more information, visit www.essexpowerlines.ca/DSP

Essex Powerlines Corporation is the local distribution company responsible for providing reliable and safe power to Amherstburg, LaSalle, Leamington and Tecumseh.

With approximately 44 employees, Essex Powerlines operates and maintains a distribution system serving over 28,000 residential and business customers.

Essex Powerlines is owned by the Town of Tecumseh, Town of LaSalle, Town of Amherstburg and Municipality of Leamington.

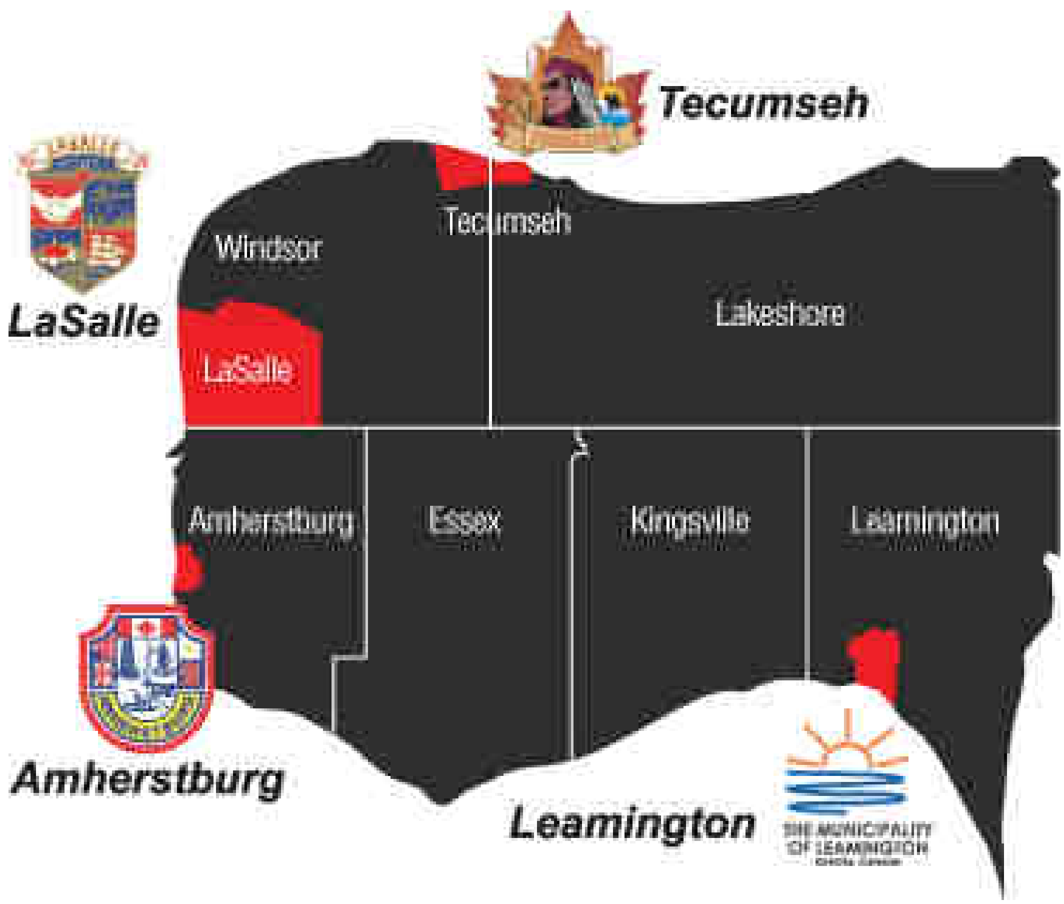


Table of Contents

What Is This Consultation?

The Purpose of this customer consultation is to collect your feedback on Essex Powerlines' investment and spending plan to maintain the local distribution system over the five year period from 2018 to 2022.

Essex Powerlines' goal is to deliver safe and reliable electricity to homes and local businesses as efficiently as possible and at an affordable price. However, there is a balancing act that all utilities must consider when planning for the future; system reliability vs. the cost to consumers. No distribution system delivers perfectly reliable electricity. Generally, the more reliable the system, the more expensive the system is to build and maintain.

This customer consultation is designed to collect your feedback on the reliability of the electricity distribution system and the spending decisions Essex Powerlines will need to make over the next five years. Ultimately, this consultation will help Essex Powerlines ensure alignment between its operational and capital investment plans and customers' needs and preferences.

As an Essex Powerlines customer, this is an opportunity for you to tell Essex Powerlines what you think about the plan and the cost implications for you. This is also an opportunity for Essex Powerlines to explain to its customers the challenges in operating and maintaining the local electricity distribution system, and more importantly how Essex Powerlines intends to meet those challenges.

To participate in this review, you do not need to be an expert. The workbook explains key parts of the electrical distribution system, the challenges facing the system, Essex Powerlines' recent work to maintain the system, and the company's budgetary plan for 2018 to 2022.

Essex Powerlines does not expect you to make electrical engineering decisions. Essex Powerlines wants to hear about the electricity issues that matter most to you and whether or not you feel the company's spending and investing priorities seem reasonable.

This workbook is designed to give you enough background about these issues for you to develop an informed opinion.

ESSEX POWERLINES CORPORATION

What's the Process that Essex Powerlines Must Follow?

How are electricity rates determined in Ontario?

The electricity industry in Ontario is regulated by the Ontario Energy Board (OEB), which recently developed regulatory requirements for electricity distributors, such as Essex Powerlines, to gather customer's preferences on distribution system investments.

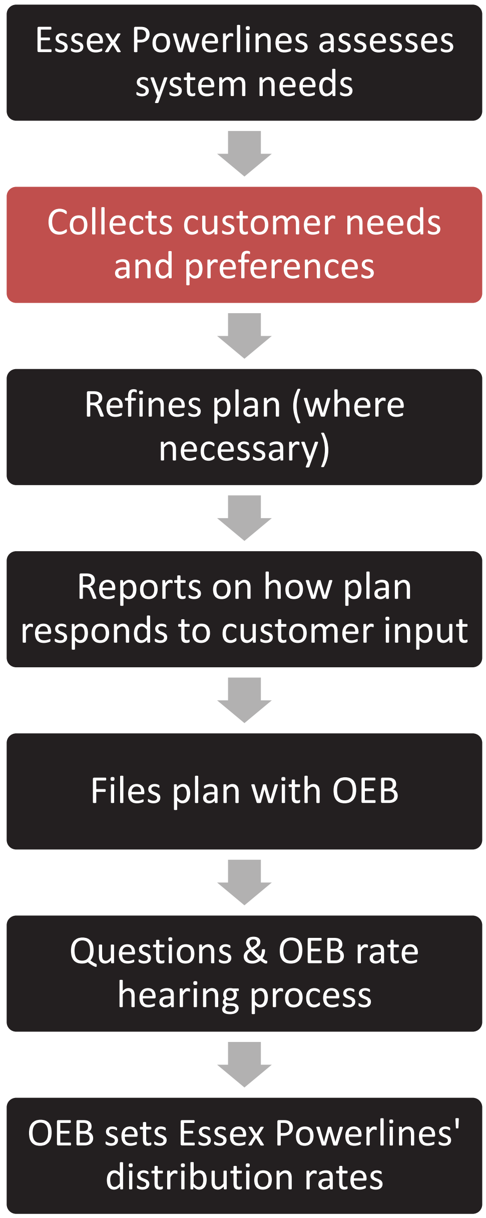
Essex Powerlines is funded by the distribution rates paid by its customers. Periodically, Essex Powerlines is required to file an application with the OEB to determine the funding available to operate and maintain the distribution system. Essex Powerlines must submit evidence to justify the amount of funding it needs to safely and reliably distribute electricity to its customers.

As a customer, how are my interests protected?

Essex Powerlines' evidence is assessed in an open and transparent public process known as a rate hearing. A number of public intervenors with electricity industry expertise submit their own evidence, in some cases challenging Essex Powerlines' plans and assumptions. At the end of the process, the OEB weighs the evidence and decides on the rates Essex Powerlines can charge for distribution.

Why is my feedback important?

Your feedback will be presented to the OEB and public intervenors (who represent various ratepayer groups) when Essex Powerlines files its rate application for 2018-2022. As part of the rate hearing process, the OEB will be reviewing how Essex Powerlines acquired and responded to customer feedback in its planning process.



Consumer Feedback on Ontario's Electricity System

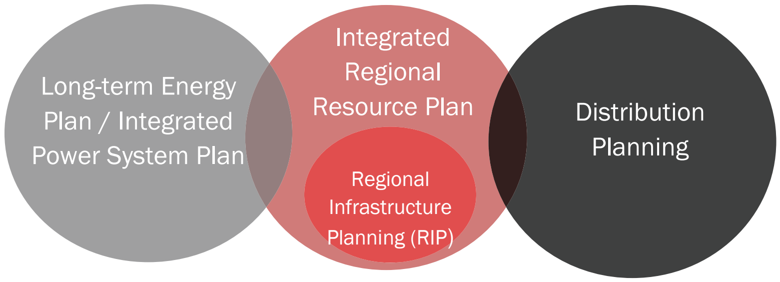
There are a number of ways for consumers to voice their opinions on provincial, regional and local electricity issues. However, this consultation is about your local distribution system and your preferences on how Essex Powerlines Corporation uses your money.

Distribution Planning: This workbook and consultation concentrates on the plan for Essex Powerlines' distribution system over the next five years. The graphic below shows the various planning initiatives ongoing across Ontario's electricity system. In addition to the short-term distribution plan being discussed in this workbook, there are other planning initiatives undertaken to ensure that the distribution system maintains reliability and works efficiently for the benefit of customers.

If you're interested in broader medium- and long-term electricity issues such as Ontario's Long-Term Energy Plan, regional planning, conservation planning and general energy policy in the province, there are other opportunities to provide your feedback.

Ontario's Long Term Energy Plan: The Ontario Government's plan details how electricity will be generated and the longer-term conservation strategy for the province. It can be found at this website: *http://www.energy.gov.on.ca/en/ltep/*

Regional Planning: The Independent Electricity System Operator (IESO) looks ahead to the future electricity needs of your region and how those needs can be addressed through conservation, local generation, and electricity from outside the region. You can follow the IESO's regional planning process at this website: *http://www.powerauthority.on.ca/power-planning/regional-planning*



Provincial System Planning

This involves more long-term planning on how Ontario's electricity system is designed and operated.

This includes planning on:

- Provincial electricity supply mix (e.g. greening the grid and phasing out coal power generation)
- System supply and demand forecasting
- Interconnections and grid design

Regional Planning

Regional planning involves near- and medium-term plans to meet the needs of a region of the province, and ensure all key players (i.e. transmission and distribution operators) are coordinated moving forward.

This planning process is focused on considering whether conservation & local generation options have been considered, in addition to core infrastructure ("wire") solutions.

Distribution System Planning

Distribution planning involves plans, both near- and long-term, to ensure the local distribution system has the adequate infrastructure to meet required reliability and safety standards, and to otherwise meet the needs of customers.

Customer Electricity Bills

Your Electricity Bill: Every item and charge on your bill is mandated by the provincial government or regulated by the OEB. There are two distinct cost areas that make up the "Delivery" charge on your bill: ***distribution*** and ***transmission***. While Essex Powerlines collects both, it remits the transmission charge to Hydro One. The distribution charges are what Essex Powerlines uses to fund its utility needs. Distribution costs make up about 20% of the typical customer's (750 kWh per month) total electricity bill.

SAMPLE MONTHLY BILL STATEMENT
Essex Powerlines Corporation

Sample Bill
1234 Main St.
Tecumseh, ON X1X 1X1

Billing Summary — Service Address: 1234 Main St.

Previous Balance			$134.89
Payment Received on Mar 02, 2017			$134.89 CR
Balance Forward			$0.00
Your Electricity Charges:			
ON Peak TOU - Winter	72.85 kWh x $0.180000		$13.11
MID Peak TOU - Winter	99.76 kWh x $0.132000		$13.17
OFF Peak TOU - Winter	260.39 kWh x $0.087000		$22.65
Delivery			$28.60
Regulatory Charges			$3.37
Debt Retirement Charge			$0.00
Your Total Electricity Charges:			**$80.90**
Your Municipal Charges:			
Water Base Charge			$13.38
Water Usage - Block 1	1.143200	10.0000	$11.43
Sewer Base Charge			$13.38
Sewer Usage - Block 1	1.185700	10.0000	$11.86
Your Total Municipal Charges:			**$50.05**
HST# 870066529			$10.52
8% Provincial Rebate			$6.47 CR
Total Current Charges			**$135.00**
Total Amount Due			**$135.00**
Debt Retirement Charge Exemption Saved You			$3.03

Bill Date: Mar 17, 2017 **Account Number:** 00000000-00

Read Date	Electric Consumption	Month Total	Day Avg	Off Peak	Mid Peak	On Peak
Mar-1-17		459.00	15.30	276.07	105.77	77.24
Jan-30-17		514.00	19.04	327.09	105.92	81.18
Jan-1-17		631.00	20.35	432.60	103.00	95.23
Dec-1-16		457.00	15.23	276.80	101.55	78.60
Nov-1-16		460.00	14.38	305.28	60.95	93.88
Sep-30-16		518.00	21.58	306.22	91.29	120.93
Sep-1-16		1672.00	53.94	998.58	275.04	398.32
Jul-29-16		1639.00	52.87	1007.69	268.40	362.98
Jun-28-16		1116.00	39.86	699.71	183.89	232.79
May-31-16		405.00	13.97	264.62	62.59	77.79
May-1-16		436.00	14.53	276.06	89.93	69.75
Apr-1-16		508.00	16.39	303.76	114.96	89.13
Feb-29-16		228.00	8.44	149.30	32.22	46.43

Messages:
The Debt Retirement Charge was removed for certain Residential consumption after December 31, 2015. Learn more at Ontario.ca/DRC. The Ontario government is providing a rebate on your electricity costs equal to the provincial portion of HST.

Service Class: RESIDENTIAL Cycle 0009

Essex Powerlines' distribution rates are subject to the review and approval of the OEB. The revenues collected from customers covered Essex Powerlines' capital investments and operating expenses. Current monthly distribution charges are approximately $26.16, $59.13, and $453.70 per month for a typical Essex Powerlines customer who consumes 750 kWh, 2,000 kWh, and 40,000 kWh in a month, respectively.

It is estimated that – all things being equal – distribution charges will increase gradually with inflation from 2018 – 2022. This includes the cost of the Essex Powerlines plans to operate, maintain, and modernize its electricity distribution system.

Understanding Essex Powerlines' Role in Ontario's Electricity System

There are three main components to all electricity systems: generation, transmission, and distribution

Where Electricity Comes From

In Ontario, 70% of electricity is generated by Ontario Power Generation (OPG). This provincially-owned organization has generation stations across Ontario that produce electricity from hydroelectric, nuclear and fossil fuel sources.

Once electricity is generated, it must be delivered to urban and rural areas in need of power. This happens by way of high voltage transmission stations and interconnected lines that serve as highways for electricity. The province has more than 30,000 kilometres of transmission lines, owned mostly by Hydro One.

Essex Powerlines Corporation

Essex Powerlines is responsible for the last step of the journey: distributing electricity to customers in the region through our distribution system.

Every distribution system is unique with its own history and challenges. In order to better understand Essex Powerlines' current system, we first have to understand all of the different components and how they impact the way in which you receive electricity when you need it.

Essex Powerlines' power is supplied at high voltage levels to 4 transmission stations (TS) owned by Hydro One. The high voltage electricity is then reduced and connected through 27.6kV feeder circuits. Some of these feeder circuits are used to distribute power to various substations located throughout the communities Essex Powerlines serves. These substations further transform the electricity voltage to lower voltage levels for distribution to the neighbourhoods within the communities. Some customers receive power directly from the 27.6kV system while others receive power via these substations. In either case, additional transformers are located near each customer, and transform the voltage one final time to levels safe to distribute through a home or business.

Essex Powerlines' Overhead System

The overhead system is made up of distribution lines that operate at 4kV, 8kV, or 27.6kV. By 2018, Essex Powerlines' overhead system will be mainly made up of distribution lines that operate at 27.6 kV. Along the line, pole-top transformers step the voltage down. From there, the electricity is delivered to customers.

Essex Powerlines' Underground System

The underground system consists of a complex network of cables, vaults, cable chambers and transformers situated on concrete pads (padmount transformers). In residential areas, underground cables distribute electricity from substations (or TS's as the case may be) to padmount transformers located on customer boulevards. Like the overhead system, these transformers step the electricity down to a lower voltage, and electricity is delivered to customers.

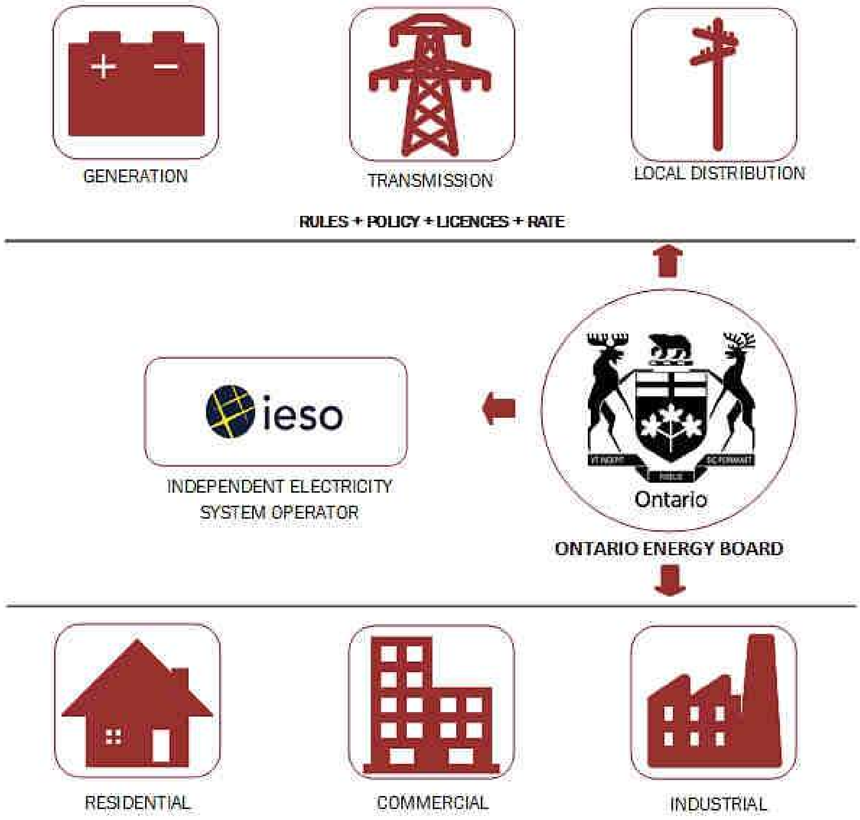
Electricity Grid:
How is Ontario's Electricity System Regulated?

The electricity system in Ontario is regulated by the following bodies:

Ontario Ministry of Energy:
The Ontario Ministry of Energy sets energy policy. It sets the rules and establishes key planning and regulatory agencies through legislation.

Ontario Energy Board:
The mission of the Ontario Energy Board (OEB) is to promote a viable, sustainable and efficient energy sector that serves the public interest and assists consumers to obtain reliable energy services at reasonable cost. It is an independent body established by legislation that sets the rules and regulations for the provincial electricity sector. One of the OEB's roles is to review the distribution plans of all electricity distributors and set their rates.

The Independent Electricity System Operator:
The Independent Electricity System Operator (IESO) is responsible for short, medium and long-term electricity planning to ensure an adequate supply of electricity is available for Ontario residents and businesses. It operates the grid in real-time to ensure that Ontario has the electricity it needs, where and when it needs it. The IESO receives directives from the Ministry of Energy (i.e. energy supply mix, Green Energy Act), but otherwise works at arm's-length from the government.



Customer Feedback

1. Given what you know and what you have read so far, how well do you feel you understand the parts of the electricity system, how they work together and which services Essex Powerlines is responsible for?

   - ☐ Very well
   - ☐ Somewhat well
   - ☐ Not very well
   - ☐ I don’t understand at all

2. Generally, how satisfied are you with the service you receive from Essex Powerlines?

   - ☐ Very satisfied
   - ☐ Somewhat satisfied
   - ☐ Somewhat dissatisfied
   - ☐ Very dissatisfied
   - ☐ Not sure

3. Is there anything in particular that Essex Powerlines can do to improve its service to you?

Essex Powerlines' Grid Today

This section describes the construction of Essex Powerlines' distribution grid including its substations, overhead and underground systems. It also explains the company's historical growth and current electrical infrastructure.

Background on Essex Powerlines' Distribution System

Restructuring of the utility industry presented many challenges and opportunities when Bill 35 was passed. Existing public utility commissions had to change to standard Ontario business corporations, owned by the local municipalities. The new corporations answered to the Ontario Energy Board and were responsible for regulatory, rate setting and licensing matters in the electricity market.

The four municipalities of Amherstburg, LaSalle, Leamington and Tecumseh made a strategic decision to pool the resources of their utilities together and avoid many deregulation costs. In the new electricity market new business models would have to be put into place. If the municipalities chose to go alone into the new environment, the local rate base could not have supported the new costs of the business model and the utilities may not have had the expertise and knowledge to become market ready.

On June 1, 2000, the Towns of Amherstburg, LaSalle, Leamington and Tecumseh amalgamated their Utilities to form the Essex Power Group of Companies. Essex Powerlines owns and operates the physical electricity infrastructure in these areas. Essex Powerlines is the default company from which consumers purchase electricity from the provincial grid.

In 2016, Essex Powerlines hired the consulting firm METSCO to help establish a formalized asset management program. Using international engineering standards, METSCO is reviewing all the data Essex Powerlines currently maintains for its assets, evaluating the integrity of that information, recommending additional information for collection, assessing the health of the individual asset classes, and, using a risk-based approach, assisted Essex Powerlines' engineering team in ranking and prioritizing the asset replacement work required in order to minimize Essex Powerlines' operating costs.

This process helped confirm that Essex Powerlines' approach to capital renewal and preventative maintenance was successful in keeping the system up to date. The new approach to asset management will help Essex Powerlines' create better and more focused plans to continue to keep the system updated and deliver a better quality of service.

Every distribution system is unique with its own history and challenges. In order to better understand the current Essex Powerlines system, we first have to understand all of the different components and how they impact the way in which you receive electricity when you need it. The diagram and terms below will help guide you through the system.

Essex Powerlines' distribution system is made up of a number of components which work together to transport electricity to homes and businesses across the communities it serves.

TECUMSEH AMHERSTBURG LaSalle

Essex Powerlines' service territory covers 66 square kilometers of urban area, encompassed within a 38 square kilometer geographic area.

The distribution system contains 186 km of overhead lines, 263 km of underground, and 0 municipal substations to step down voltage from 27.6 kV to the remaining old 4 kV and 8 kV systems. (The remainder of the old 4 kV and 8 kV systems will be converted to the 27.6 kV system by 2018.)

Essex Powerlines is served by a total of 4 transmission stations which are owned and operated by Hydro One.

Hydro One's Transmission System

High Voltage Transmission – Connects our distribution system to electricity generating stations across the province.

Transmission Station – Reduces high voltage electricity from transmission lines to medium voltage which is fed into Essex Powerlines' distribution stations.

Essex Powerlines' Distribution System:

Municipal Substations: Municipal substations are a critical element of the electricity distribution system—they are the local hubs from where electricity is distributed to an area. Municipal substations contain:

> **Transformers** – Important pieces of equipment that reduce the voltage of electricity from a high level to a level that can be safely distributed to your area.
>
> **Feeder Circuits** – The wires that connect the transmission station to the broader distribution system in order to deliver electricity to customers.
>
> **Breakers** – Devices that protect the distribution system by interrupting a circuit if a higher than normal amount of electricity is detected.
>
> **Switches** – Control the flow of electricity and steer the current to the correct circuits.

Overhead System: The overhead system includes the wires that are commonly seen across Essex Powerlines' service area. The voltage of the overhead system can range from 4 kV (4,000 volts) to 27.6kV, however, Essex Powerlines is mainly 27.6kV.

> **Wires** – There are 186 km of wire that carry electricity across the overhead distribution system.
>
> **Poles** – Wires are suspended from these, usually wooden (sometimes concrete), poles.
>
> **Pole Top Transformers** – These transformers are mounted near the top of utility poles and are needed to further step-down the voltage from the lines to the final connection to customers.

Underground System: The underground system includes 261 km of cable, which is directly buried and or installed in ducts. At certain intervals, underground service chambers (with manholes) are required to permit cables to be spliced together and to allow underground equipment such as switches to be housed.

An advantage of underground systems is that they are affected to a lesser extent by extreme weather. The disadvantage is that they are more expensive to install and maintain, and when there is a power outage it often takes longer to locate and repair a problem compared to overhead wires.

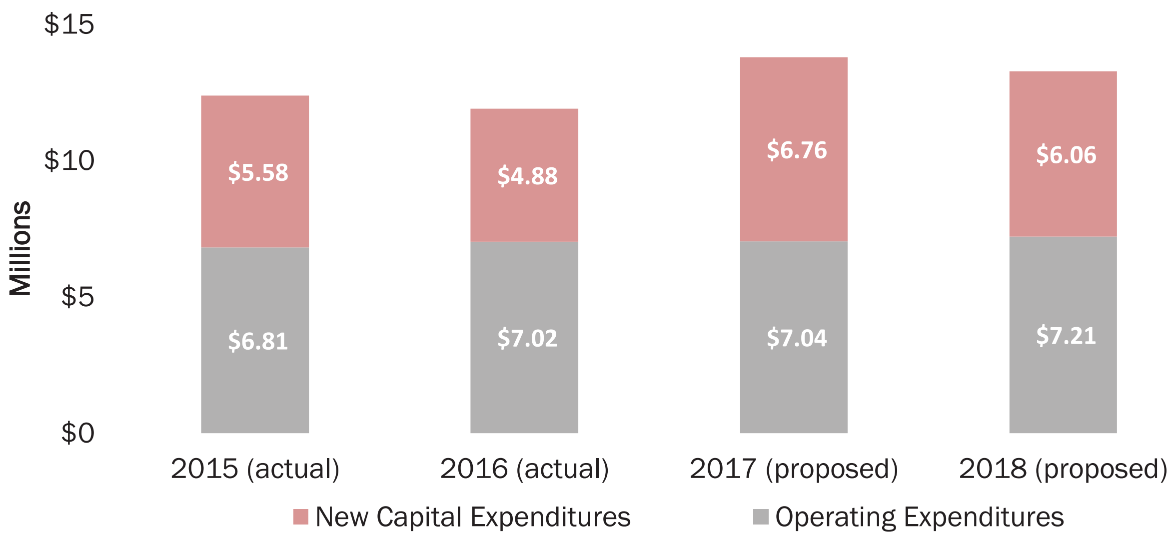
Underground Cables – Convey the electricity in the underground system. Cables that connect the distribution stations and major industrial users to the distribution station are significantly larger than cables used to connect residential neighbourhoods.
Padmount Transformers – Similar to transformers in the overhead system, these reduce the voltage to a lower level before final connection to customers. In the underground system there are concrete padmounted transformers, which are above ground transformers that are supplied by underground cable, and vault transformers, which are housed in underground chambers.

Paying for the Distribution System?

As anyone who runs their own business would expect, Essex Powerlines' manages its spending in two budgets – an operating budget and a capital budget.

Essex Powerlines' operating budget covers regularly recurring expenses such as the costs of running service vehicles, the payroll for employees, and the maintenance of distribution equipment and buildings.

Its capital budget covers items that, when purchased, do not need to be repurchased for some time and that have lasting benefits over many years. This can include much of the equipment that is part of the distribution system, such as poles, wires and transformers, major computer systems and vehicles.



Managing the distribution system requires millions of dollars in maintenance, system renewable and running the day-to-day operations. In its last fiscal year (2016), Essex Powerlines' operating expenses and capital expenditure totalled $11.9 million.

4. How well do you feel you understand the important parts of the electricity system, how they work together, and which services Essex Powerlines is responsible for?

- ☐ Very well
- ☐ Somewhat well
- ☐ Not very well
- ☐ I don't understand at all

5. The average Essex Powerlines customer experiences one power outage per year. Do you recall how many outages you experiences in the past year?

- ☐ None
- ☐ One
- ☐ Two
- ☐ Three
- ☐ Four
- ☐ More than four
- ☐ Not sure

No system delivers perfectly reliable electricity. There is a balancing act between reliability and the cost of running the system. Please answer the following questions:

6. How acceptable were the number of power outages you experiences over the last 12 months?

- ☐ Very acceptable
- ☐ Somewhat acceptable
- ☐ Not very acceptable
- ☐ Did not have any power outages
- ☐ Not sure

7. How many power outages do you feel are reasonable in a year?

- ☐ No outage is acceptable
- ☐ One
- ☐ Two
- ☐ Three
- ☐ Four
- ☐ More than four
- ☐ Not sure

8. What do you feel is a reasonable duration for a power outage?

- ☐ No outage is acceptable
- ☐ 30 minutes
- ☐ 1 hour
- ☐ 2 hours
- ☐ 3 hours
- ☐ 4 hours or more
- ☐ Not sure

Cost Pressures

From the day-to-day to major storm events, there are a variety of ever-present pressures on Essex Powerlines' operating and capital budget.

Many of these expenditures are items over which Essex Powerlines has little or no control over – major storms, and the implementation of Smart Meters, for example.

Other costs are associated with preventative maintenance like replacing aging equipment. Essex Powerlines has already undertaken several large scale projects, and more are planned.

How does Essex Powerlines determine the appropriate amount of capital spending related to existing infrastructure?

Essex Powerlines monitors the health of its electric infrastructure very closely. As part of its rate application, it must show the OEB third party reviews of the health of its system's assets. These asset health reviews help Essex Powerlines prioritize which parts of its system get upgraded or rebuilt first.

Has Essex Powerlines previously set aside funds for required upgrades?

The OEB does not allow utilities in Ontario (including Essex Powerlines) to create reserve funds. If reserve funds were allowed, a utility would have to charge customers a premium on their rates to set money aside. Under OEB regulation, a utility can only charge customers the rate required to run the distribution system at a reliability standard set by regulatory bodies.

Capital Investment Drivers

Essex Powerlines has developed a list of capital investment drivers and proposes investment programs based on these key drivers.

Reliability: There are two main measures of reliability in the distribution system:

1. How often does the power go out?
2. How long does it stay out?

To achieve maintained or improved reliability, projects are developed to improve asset performance and decrease the frequency and duration of power outages.

Service Requests: Essex Powerlines has a legal obligation to connect customers to its distribution system. This includes both traditional demand customers (new homes and businesses) and distributed generation customers (e.g. micro-FIT customers who have contracts to sell electricity back to the grid such as rooftop solar panels). Requests can also include system modifications to support infrastructure development by government agencies, road authorities and developers.

Support Capacity Delivery: Where there are forecasted changes in demand that will limit the ability of the system to provide consistent service delivery or where it is incapable of meeting the demand requirements, new builds or expansion is required. This is the fundamental infrastructure that allows new customers to be hooked up to the distribution system and is paid for by new customers served over time.

System Efficiency: To provide customers with the best service possible, there is always a need to improve power outage restoration capability.

Mandated Compliance: Compliance with all legal and regulatory requirements and government directives, such as compliance with the Ministry of Energy, the Ontario Energy Board, the Independent Electricity System Operator and other regulations.

Obsolescence: Asset installations that no longer align with Essex Powerlines' current operating practices or current standards. This can include those assets that:

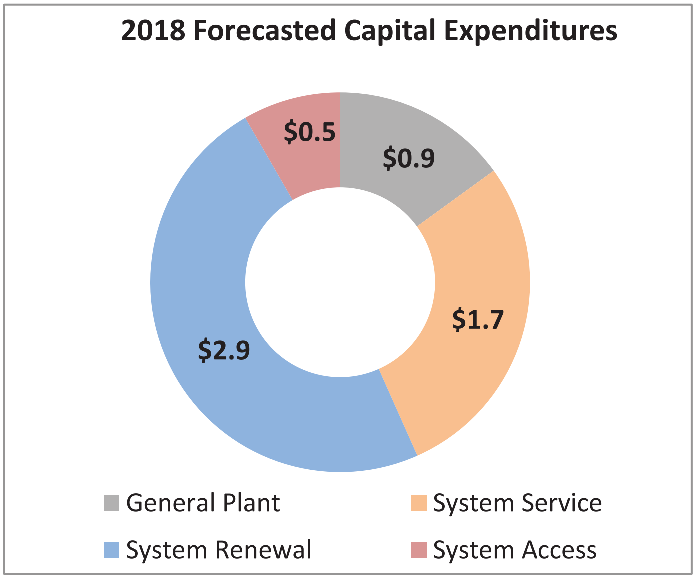
- Are no longer manufactured,
- Lack spare parts,
- Cannot be accessed,
- Lack the ability to have maintenance performed on them,
- Have operational constraints or conflicts, which can result in increased reliability and/or safety related risks.

Aging or Poor Performing Equipment: Where there is the imminent risk of failure due to age or condition deterioration, and these potential failures will result in severe reliability impacts to customers as well as potential safety risks to crew workers or to the public, remediation, through refurbishment or replacement, is required.

Business Support Costs: Essex Powerlines is not just the local electricity distribution system itself, but a company that operates the system. As a company, it needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the system and customer information.

What are the major issues Essex Powerlines needs to address?

Over the years, Essex Powerlines has worked hard to keep its equipment working well beyond its originally expected life, to get maximum value for money. However, Essex Powerlines' key challenge still comes from the need to replace aging equipment.



In 2018, the capital expenditures required to address system renewal, maintain system reliability and invest in other infrastructure priorities are estimated by Essex Powerlines to be $6 million which is consistent with historical spending.

To assist us in prioritizing what needs to be replaced and by when, Essex Powerlines uses an asset management model to drive replacement decisions. Using the information provided by the asset management model, Essex Powerlines plans for four types of capital investment costs:

System Access

Definition: Projects that respond to customer requests for new connections or new infrastructure development. These are usually a high priority, "must do" type of request.

Programs (e.g.): Customer Connections, Relocating assets based on infrastructure needs

System Renewal

Definition: Projects focused on replacing aging equipment in poor condition.

Programs (e.g.): Distribution Station Refurbishment, Voltage Conversion, Underground Cable Replacement, Overhead Wire Replacement

System Service

Definition: Primarily consisting of projects that improve system reliability.

Programs (e.g.): Automated Switches, better distribution system monitoring equipment

General Plant

Definition: Investments in supporting assets, such as tools, vehicles, buildings and information technology (IT) equipment that are needed so that we may perform our task to operate and maintain the distribution system

Programs (e.g.): IT, facilities, fleet

Cost Drivers

Capital Investments

The challenges impacting the Essex Powerlines distribution system can be broken down into 4 broad categories:

Aging Infrastructure

1

- Essex Powerlines completes a variety of field services on a yearly basis to determine the health of its equipment across the four communities that we serve.
- There is a variety of equipment within Essex Powerlines' distribution system that is aging and beyond its useful life requiring replacement ranging from replacements that require immediate action to replacements that need to be addressed in 1-5 years.
- Through its rigorous asset management plan, Essex Powerlines plans to continuously replace aging and equipment in danger of failure through various reactive and preventive maintenance programs.

Voltage Conversion

2

- Essex Powerlines is in the process of finalization its voltage conversion program that will position Essex Powerlines as a single voltage utility in 2017/2018. Instead of supplying electricity at multiple voltages, Essex Powerlines will be supplying its customers with electricity at 27.6kV only. This will reduce inventory, system complexity and system losses; all things that will save Essex Powerlines customers money in the long run.

Economic Development

3

- One of Essex Powerlines' top priorities is to enable economic development in our 4 shareholder communities that we serve through the facilitation of system connection and by keeping our rates at reasonable levels.
- Power quality and reliability has been mentioned by our commercial and industrial customers as a growing concern which is why Essex Powerlines is investing in technology like SmartMAP and the Self-Healing grid to improve visibility of our system and provide faster response times for outages as they incur.

Increasing Cost of Electricity

4

- With energy costs rising and forecasted to continue rising for the foreseeable future, Essex Powerlines has made it a priority to champion Conservation & Demand Management, facilitate customer connection of behind-the-meter generation or simply providing customers with the tools necessary to monitor and control their consumption.

Cost Drivers

Operating Expenses

In addition to its capital budget, Essex Powerlines needs to consider its operating budget which also impacts customer bills.

Cost drivers contributing to the operating budget can largely be attributed to on-going maintenance and management of the distribution system. An example of this cost driver is Essex Powerlines' tree trimming service, designed to lessen the impact of falling tree branches on power lines.

Customer Focus

- It is now an industry requirement for all utilities to demonstrate that they have consulted customers before applying for new rates
- Essex Powerlines embraces this concept and wants to gather ongoing customer feedback and input through website surveys and focus groups.
- Essex Powerlines continues to enhance its online customer service offerings; this has included updating the website as well as increasing social media presence. Essex Powerlines has launched automatic outage updates on our Twitter account. This allows customers to get real-time updates on any outages that they may be experiencing.
- Further, in 2017 Essex Powerlines enhanced the look of the monthly customer bill and made it much easier to read and understand.

Industry Focus

- Industry regulation requires that Essex Powerlines maintain compliance with various regulatory bodies in a complex provincial environment.
- The requirements to implement Smart Meters and to adopt the International Financial Reporting Standard ("IFRS") of accounting are examples of recent industry change.
- Meters are now more complex and require specialized troubleshooting. Essex Powerlines installed many of its Smart Meters in 2009 and 2010. As these meters age, more focus is required on re-verification. Essex Powerlines is now testing groups of these meters at intervals throughout their life span rather than waiting for them to cease operating at end-of-life.
- To ensure that Essex Powerlines is in compliance with all regulatory codes, including new requirements and reporting, additional staffing and support resources have been added since 2010.

Operational Effectiveness & Power Quality

- Consistent with industry best practice, Essex Powerlines has established a formalized asset plan for distribution system assets. This includes asset health assessments and replacement prioritization rules.
- The plan will also include voltage conversion work to modernize the system in order to identify the causes of outages more quickly and reduce line losses.
- Essex Powerlines will incur expenses for additional software and engineering resources as the distribution system plan is continuously updated.

Finding Efficiencies and Cost Savings

Where possible, Essex Powerlines has extended the life of its equipment through rigorous repair and maintenance program in order to get maximum value for money. Some of this aging equipment can be "run to failure", meaning we can replace it after it ceases to function without significant customer impact. However, other end-of-life equipment is more mission critical and cannot be "run to failure" because failure could result in a public safety hazard or an unsupportable economic burden for our customers.

There are several other ways in which Essex Powerlines works to find efficiencies and cost savings in the system:

Enhanced Power Quality Metering: Installing power quality meters at select commercial and industrial sites helps major customers resolve power quality issues so they can better understand and control their energy usage.

Voltage Conversion Program: Converting to a single higher voltage will eliminate antiquated equipment, reduce system losses, and reduce ongoing maintenance costs.

Estimated and Scheduling Tool: A new estimating and scheduling tool means Essex Powerlines can more quickly and more accurately assemble an estimate and lay out work for construction crews.

"Kitting": Warehouse staff pre-assemble parts and equipment needed for specific repairs, which reduces the time needed for crews to complete maintenance and service tasks, thereby reducing costs.

Group Buying Program: Essex Powerlines save money by participating in a group buying program with other local utilities. This means some types of equipment and materials can be purchased much less expensive.

Remote Fault Indication: Allows Essex Powerlines to better diagnose outages before dispatching work crews. Reduces expensive after-hours crew visits.

Labour Saving Equipment: Specialized trucks and other equipment reduce manual labour, which reduces time and costs.

Smart Meter Data: Using Smart Meter data to diagnose outages and power quality issues reduces time and guess work, and helps resolve issues faster.

Targeted Capital Projects: These projects eliminate equipment from the system that is known to be high maintenance.

Outage Management System: Quickly and automatically identifies faults, notifies crews and provides information to help troubleshoot and identify the cause.

SmartMAP: Innovative technology that improves reliability and service and reduces the number of outages as they can be address proactively.

Social Media: Essex Powerlines uses social media to send automated updates to customers about outages and keep them informed about the progress toward restoration.

9. With regards to projects focused on replacing aging equipment in poor condition, which of the following statements best represents your point of view?
   - ☐ Essex Powerlines should invest what it takes to replace the system's aging infrastructure to maintain system reliability, even if that increases my monthly electricity bill by a few dollars over the next few years.
   - ☐ Essex Powerlines should lower its investment in renewing the system's aging infrastructure to lessen the impact of any bill increase, even if that means more or longer power outages.
   - ☐ Not sure

10. As a company, Essex Powerlines needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the system and customer information. Which of the following statements best represents your point of view?
    - ☐ Essex Powerlines should find ways to make do with the buildings, equipment and IT systems it already has.
    - ☐ While Essex Powerlines should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system safely, efficiently and reliably.
    - ☐ Not sure

11. How well do you feel you understand the cost drivers that Essex Powerlines is responding to?
    - ☐ Very well
    - ☐ Somewhat well
    - ☐ Not very well
    - ☐ Not well at all
    - ☐ Not sure

12. How well do you think Essex Powerlines is managing these cost drivers while meeting customer expectations and keeping rates reasonable?
    - ☐ Very well
    - ☐ Somewhat well
    - ☐ Not very well
    - ☐ Not well at all
    - ☐ Not sure

13. How satisfied are you with the efforts Essex Powerlines has made to find efficiencies and cost savings in the distribution system?
    - ☐ Very satisfied
    - ☐ Somewhat satisfied
    - ☐ Not very satisfied
    - ☐ Not at all satisfied
    - ☐ Not sure

What Essex Powerlines Corporation's Plan Means for You

Residential – 750 kWh per month

In 2018, it is anticipated that residential customers with an average monthly consumption of 750 kWh will see a moderate increase on the distribution portion of their electricity bills. It is expected that – all things being equal – distribution rates will increase in line with the rate of inflation.

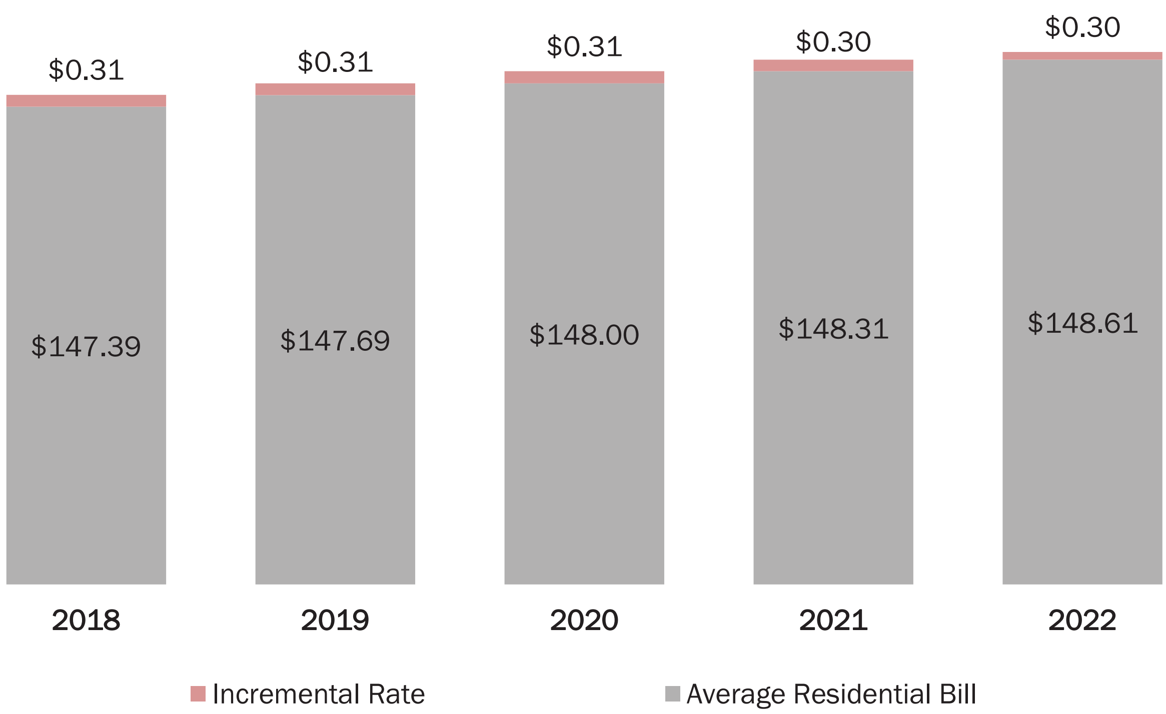
Essex Powerlines considered gradual inflationary increases, consistent with the industry rate-setting process, to determine a one-time rate increase between 2018 until 2022. Essex Powerlines' forecasted increase over the next five years may see an average annual increase of $0.31 per month or 0.2% on the total bill for a residential customer with an average monthly consumption of 750 kWh.

By 2020, Essex Powerlines forecasts that the average residential household will be paying an estimated $1.79 more (6.84%) per month on the distribution portion of their electricity bill; however, this incorporates an average yearly increase of 1.37% each year through 2020.

The illustrations below will provide better understanding of the one-time change in rates.

	Current	Proposed	Increase	5 Year % Increase	Average Yearly Increase
Distribution	$26.16	$27.95	$1.79	6.84%	1.37%
Total Bill	$147.08	$148.61	$1.53	1.04%	0.21%

Estimated Residential Annual Increase in Monthly Bill (5 year forecast)



What Essex Powerlines Corporation's Plan Means for You

GS<50 kW – 2,000 kWh per month

In 2018, it is anticipated that GS<50 kW customers with an average monthly consumption of 2,000 kWh will see a moderate increase on the distribution portion of their electricity bills. It is expected that – all things being equal – distribution rates will increase in line with the rate of inflation.

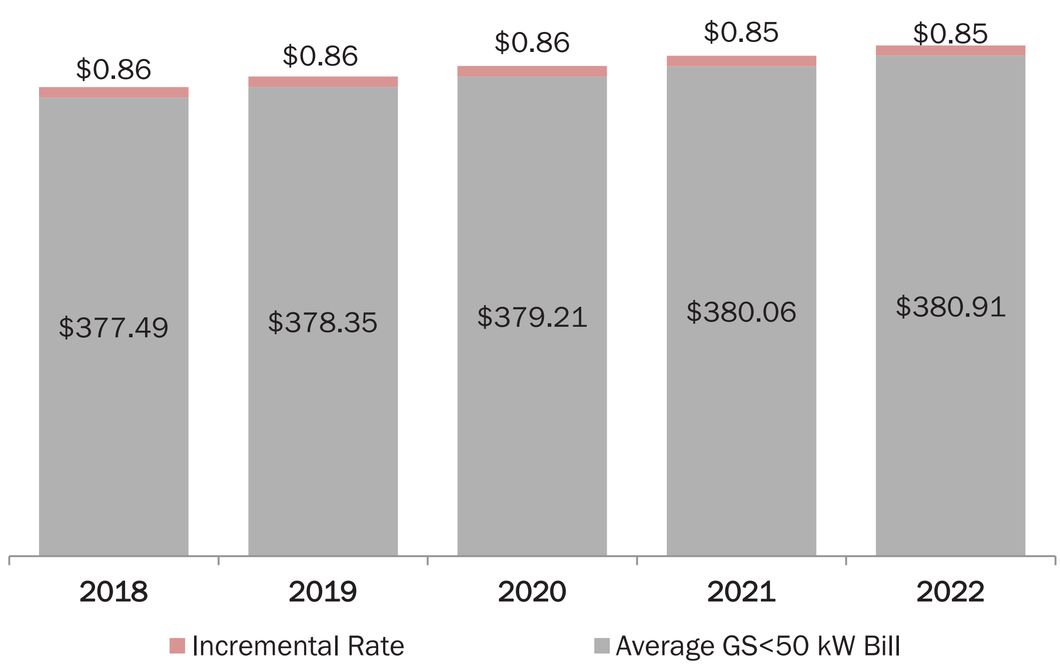
Essex Powerlines considered gradual inflationary increases, consistent with the industry rate-setting process, to determine a one-time rate increase between 2018 until 2022. Essex Powerlines' forecasted increase over the next five years may see an average annual increase of $0.86 per month or 0.2% on the total bill for a GS<50 kW customer with an average monthly consumption of 2,000 kWh.

By 2020, Essex Powerlines forecasts that the average GS<50 kW customer will be paying an estimated $4.92 more (8.32%) per month on the distribution portion of their electricity bill; however, this incorporates an average yearly increase of 1.66% each year through 2020.

The illustrations below will provide better understanding of the one-time change in rates.

	Current	Proposed	Increase	5 Year % Increase	Average Yearly Increase
Distribution	$59.13	$64.05	$4.92	8.32%	1.66%
Total Bill	$376.63	$380.91	$4.28	1.14%	0.23%

Estimated GS<50 kW Annual Increase in Monthly Bill (5 year forecast)



What Essex Powerlines Corporation's Plan Means for You

GS>50 kW – 40,000 kWh & 100 kW per month

In 2018, it is anticipated that GS>50kW customers with an average monthly consumption of 40,000 kWh will see a moderate increase on the distribution portion of their electricity bills. It is expected that – all things being equal – distribution rates will increase in line with the rate of inflation.

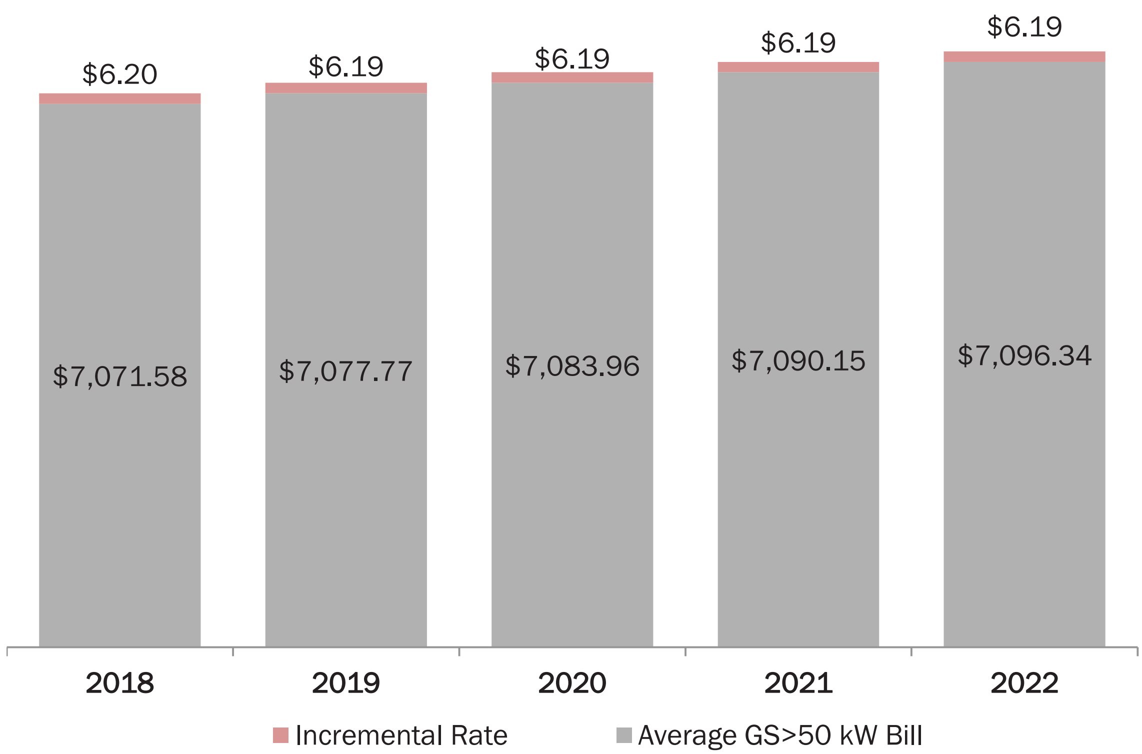
Essex Powerlines considered gradual inflationary increases, consistent with the industry rate-setting process, to determine a one-time rate increase between 2018 until 2022. Essex Powerlines' forecasted increase over the next five years may see an average annual increase of $6.19 per month or 0.08% on the total bill for a GS>50 kW customer with an average monthly consumption of 40,000 kWh.

By 2020, Essex Powerlines forecasts that the average GS>50 kW customer will be paying an estimated $42.67 more (9.40%) per month on the distribution portion of their electricity bill; however, this incorporates an average yearly increase of 1.88% each year through 2020.

The illustrations below will provide better understanding of the one-time change in rates.

	Current	Proposed	Increase	5 Year % Increase	Average Yearly Increase
Distribution	$453.70	$496.37	$42.67	9.40%	1.88%
Total Bill	$7,065.38	$7,096.34	$30.96	0.44%	0.09%

Estimated GS>50 kW Annual Increase in Monthly Bill (5 year forecast)



14. Now that you have a better sense of the operations of Essex Powerlines, including the cost drivers, do you feel the proposed budget is reasonable?
   - ☐ Yes
   - ☐ No
   - ☐ Not sure

15. From what you have read here and what you may have heard elsewhere, does Essex Powerlines' investment plan seem like it is going in the right direction or the wrong direction?
   - ☐ Right direction
   - ☐ Wrong direction
   - ☐ Not sure

16. How well did Essex Powerlines' plan cover the topics you expected?
   - ☐ Very well
   - ☐ Somewhat well
   - ☐ Not very well
   - ☐ Not well at all
   - ☐ Not sure

If not very or not at all, what is missing?

17. How well do you think Essex Powerlines is planning for the future?
   - ☐ Very well
   - ☐ Somewhat well
   - ☐ Not very well
   - ☐ Not well at all
   - ☐ Not sure

18. Considering what you know about the local distribution system, which of the following best represents your point of view?
   - ☐ The rate increase is reasonable and I support it
   - ☐ I don't like it, but I think the rate increase is necessary
   - ☐ The rate increase is unreasonable and I oppose it
   - ☐ Not sure

Final Thoughts

Essex Powerlines values your feedback. This is the first time the utility has conducted a review about its upcoming investment plan in this type of format.

Overall Impression: What did you think about the workbook?

Volume of Information: Did Essex Powerlines provide too much information, not enough, or just the right amount?

Content Covered: Was there any content missing that you would have liked to have seen included?

Outstanding Questions: Is there anything that you would still like answered?

Suggestions for Future Consultations: How would you prefer to participate in these consultations?

Glossary

Breakers: Devices that protect the distribution system by interrupting a circuit if a higher than normal amount on power flow is detected.

Distribution Station: These substations are located near to the end-users. Distribution station transformers change the voltage to lower levels for use by end-users.

Feeder Circuit: Is a wire that connects the transmission station to the broader distribution system in order to deliver electricity to customers.

General Plant: Investments in things like tools, vehicles, buildings and information technology (IT) equipment that are needed to support the distribution system.

Generation Station: A facility designed to produce electric energy from another form of energy, such as fossil fuel, nuclear, hydroelectric, geothermal, solar thermal, and wind.

Kilovolt (kV): 1,000 volts (see volt below).

Kilowatt (kW): 1,000 watts.

Local Distribution Company (LDC): In Ontario, these are the companies that take electricity from the transmission grid and distribute it around a community.

OM&A: Operations, Maintenance and Administration or operating budget.

Substations: Used to change AC voltages from one level to another and to switch generators, equipment and circuits and lines in and out of an electrical system.

Switches: These control the flow of electricity—they direct which supply of electricity is used and which circuits are energized. Distribution systems have switches installed at strategic locations to redirect power flows for load balancing or sectionalizing.

System Access: Projects required to respond to customer requests for new connections or new infrastructure development. These are usually a regulatory requirement to complete.

System Renewal: Projects to replace aging infrastructure in poor condition.

System Service: Primarily projects that improve reliability.

Transmission lines: Transmit high-voltage electricity from the generation source or substation to another substation in the electricity grid.

Transformer: Is an important piece of equipment that reduces the voltage of electricity from a high level to a level that can be safely distributed to your area or to your residence/business.

Underground Cable: A conductor with insulation, or a stranded conductor with or without insulation and other coverings (single-conductor cable), or a combination of conductors insulated from one another (multiple-conductor cable) with an intended use of being buried.

Volt (V): A unit of measure of the force, or 'push,' given the electrons in an electric circuit. One volt produces one ampere of current when acting on a resistance of one ohm.

Watt (W): the unit of electric power, or amount of work (J), done in a unit of time. One ampere of current flowing at a potential of one volt produces one watt of power.

Wire: A conductor wire or combination of wires not insulated from one another, suitable for carrying electric current.

Additional Comments

Appendix G: Infrared Inspection Report

ESSEXENERGY CORPORATION

Infrared Inspection
- Electrical Distribution System -

Essex Power Lines

Date

June 15-30, 2015

Report Completed By

Essex Energy Corporation
2199 Blackacre Drive /Suite 2
Oldcastle Ontario N0R 1L0
Tel: 519 946 2000
Fax: 1 866291 5317


FLIR-Systems Ltd. Canada
This identification certifies that
Fred Brefka
has completed the necessary course work and has met or exceeded the established requirements to be an ITC Certified Infrared Thermographer to level as indicated
10/24/2016
Examining Officer   Expiry Date
ITC – FLIR Canada
920 Sheldon Court
Burlington, Ontario, L7L 5K6
itc INFRARED TRAINING CENTER

Infrared Report Summary

Purpose: Infrared inspection to identify thermal anomalies on electrical distribution equipment that suggest an unwanted condition exists and repairs are required.

Method: Complete infrared inspection of selected Essex Powerlines distribution system equipment. Save infrared images of all noted anomalies. Report on findings.

Conditions: Equipment operating under normal daytime loading conditions.

Inspection Equipment: FLIR model T300 thermal imaging systems, serial #

Observations

Note: Essex Energy Corporation is in no way responsible for any expenses resulting in actions or repair of reported anomalies. This report is not a warranty or guarantee of any equipment condition or reliability.

Please see report for details on all noted suspect conditions. All anomalies classified as follows:
HIGH Priority: High temperature rise over other components. Immediate corrective action required.
Do not ignore. Component temperature over 50 C rise over ambient.

MEDIUM Priority: Intermediate temperature rise. Corrective action required at next opportunity. Do not ignore. Component temperature 20 to 50 C rise over ambient.

LOW Priority: Low temperature rise. Condition should be investigated further and corrected at next convenient opportunity, if applicable.
Do not ignore. Component temperature below 20 C rise over ambient.

No Problems Noted (N/A): No anomalies noted. Condition good.

All reported condition should be investigated further as soon as possible to verify the reported condition. Use all safety procedures. Electrical hazards exist.

CONTENTS OF REPORT Priority H= High M= Medium L= Low N/A= Not Applicable				
Equipment	**Area**	**Problem**	**Priority**	**Page**
HYDRO ONE Substation	LaSalle	Heating Contact	M	4
TX7B140	LaSalle	Heating Secondary Connections	M	5
TX7B425	LaSalle	Heating Secondary Connections	H	6
FS10073	Tecumseh	Heating Primary Connection	M	7
P01810	Tecumseh	Heating Connection	M	8
TX10528	Tecumseh	Heating Secondary Connection	M	9
TX10619 (New TX installed)	Tecumseh	Heating Secondary Connections	M	10
TX10902	Tecumseh	Heating Secondary Connections	M	11
TX31537	Leamington	Heating Secondary Connection	H	12

Identification:	HYDRO ONE Substation	Date
Area:	LaSalle	15/06/2015

Description: Line Switch

INFRARED IMAGE:

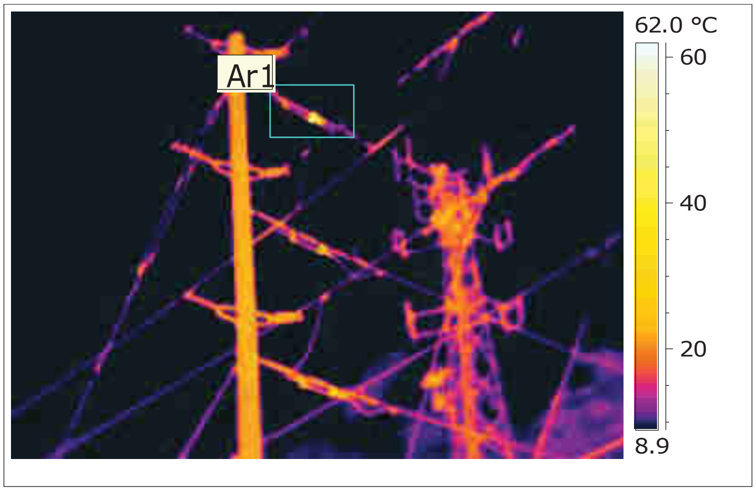


Photo:

Temperature rise: 40.8 °C (over ambient)

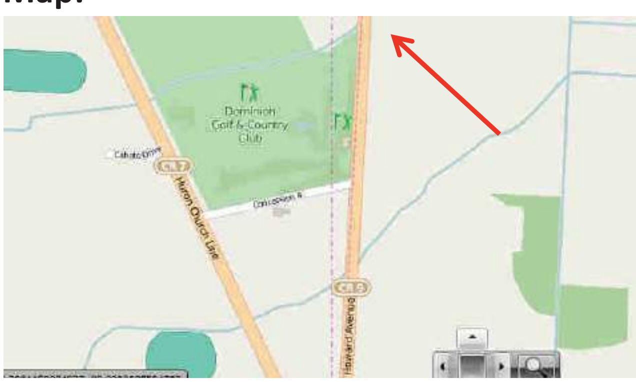
IR Information	
Date of creation	6/15/2015
Time of creation	8:35:30 AM
Object parameter	
Ambient temperature	20.0 °C
Label	
Ar1.Max	60.8 °C

Status:

Repair Date:

Notes:

Map:



Details:
Infrared image of Hydro One Substation Line Switch.
At Pole # 86HMM6
Located at Howard Ave in LaSalle
Heating noted at Line Switch connection at arrow in photo.
See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium X Low

ANOMALY: Heating contact

Identification:	TX7B140	Date
Area:	LaSalle	19/06/2015

Description: O/H Transformer Bushing

INFRARED IMAGE:

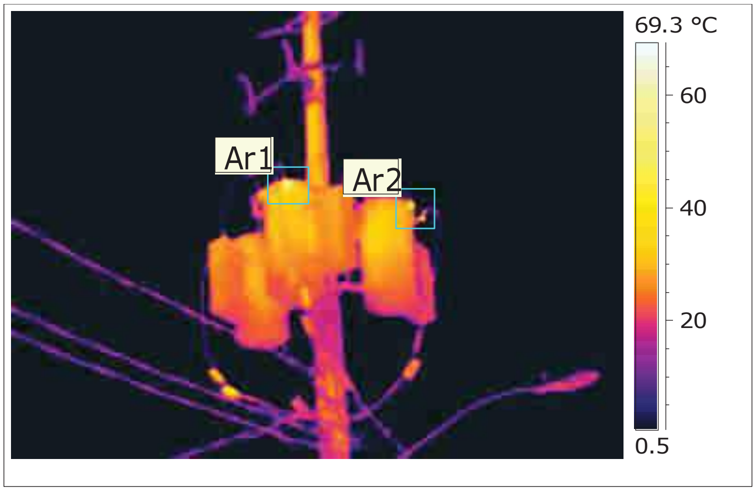


Photo:

Temperature rise: 42.6 & 20.9°C (over ambient)

IR Information	
Date of creation	6/19/2015
Time of creation	9:55:21 AM
Object parameter	
Ambient temperature	24.0 °C
Label	
Ar1.Max	66.6 °C
Ar2.Max	44.9 °C

Status:

Repair Date:

Notes:

Map:

Details:
Infrared image of transformer TX7B140. On Hydro One pole.
Located at 6260 Morton Industrial Road in Lasalle.
Heating noted at the center & road-side secondary bushing connection.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR1 AR2 Max).

PRIORITY: High Medium X Low

ANOMALY: Heating Secondary Connections

Identification:	TX7B425	Date
Area:	LaSalle	19/06/2015

Description: O/H Transformer Bushing

INFRARED IMAGE:

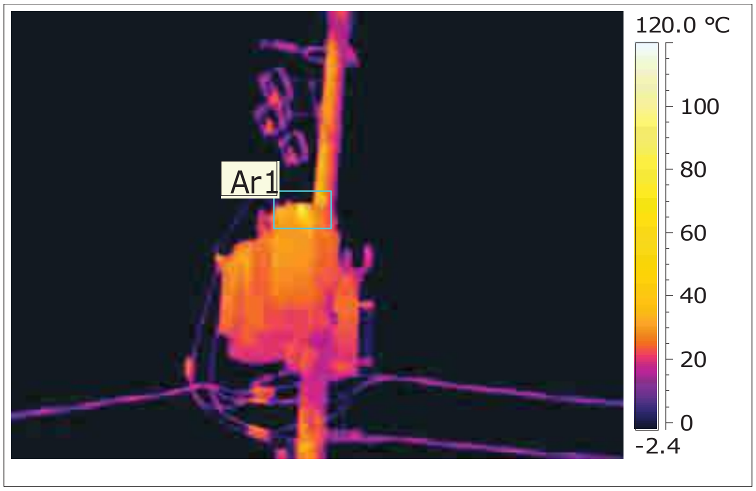


Photo:

Temperature rise: 95.3 °C (over ambient)

IR Information	
Date of creation	6/19/2015
Time of creation	9:40:32 AM
Object parameter	
Ambient temperature	24.0 °C
Label	
Ar1.Max	119.3 °C

Status:

Repair Date:

Notes:

Map:

Details:
Infrared image of transformer TX7B425. On Hydro One pole.

Located at 6280 Morton Industrial Road in LaSalle. Heating noted at the road-side secondary bushing connection. At arrow in photo.

See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High X Medium Low

ANOMALY: Heating Connection

Identification:	FS10073	Date
Area:	Tecumseh	25/06/2015

Description: Primary Fuse Connection

INFRARED IMAGE:

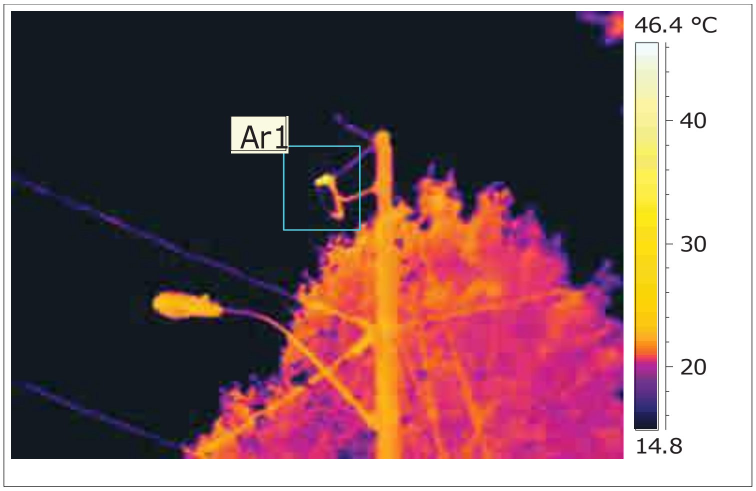


Photo:

Temperature rise: 24.4 °C (over ambient)

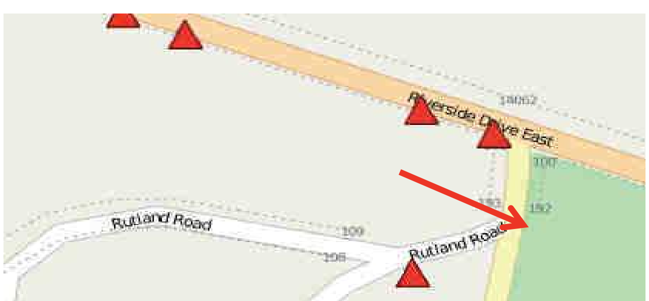
IR Information	
Date of creation	6/25/2015
Time of creation	12:44:54 PM
Object parameter	
Ambient temperature	20.0 °C
Label	
Ar1.Max	44.4 °C

Status:

Repair Date:

Notes:

Map:



Details:
Infrared image of Fuse FS10073
Located at Rutland Rd and Kensington Boulevard in Tecumseh

Heating noted at Fuse upper primary connection. At arrow in photo.

See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium X Low

ANOMALY: Heating Primary Connection

Identification:	P01810 (TX10527 not in use)	Date
Area:	Tecumseh	25/06/2015

Description: Line Switch

INFRARED IMAGE:

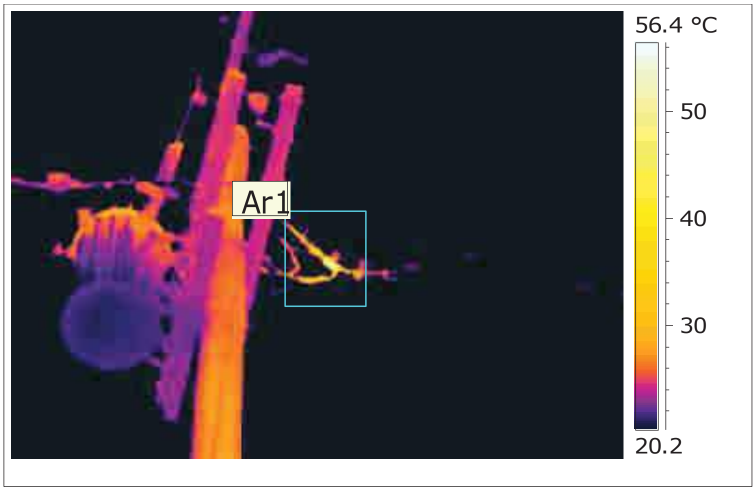


Photo:

Temperature rise: 33.1 °C (over ambient)

IR Information	
Date of creation	6/25/2015
Time of creation	2:35:15 PM
Object parameter	
Ambient temperature	22.0 °C
Label	
Ar1.Max	55.1 °C

Status:

Repair Date:

Notes:

Map:

Details:
Infrared image of transformer TX10527.
Located at 12417 Arbour Sreet in Tecumseh

Heating noted at secondary connection at arrow in photo. It is an Ampact point on Wire. TX is disconnected

See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium X Low

ANOMALY: Heating Connection

Identification:	TX10528	Date
Area:	Tecumseh	25/06/2015

Description: O/H Transformer Bushing

INFRARED IMAGE:

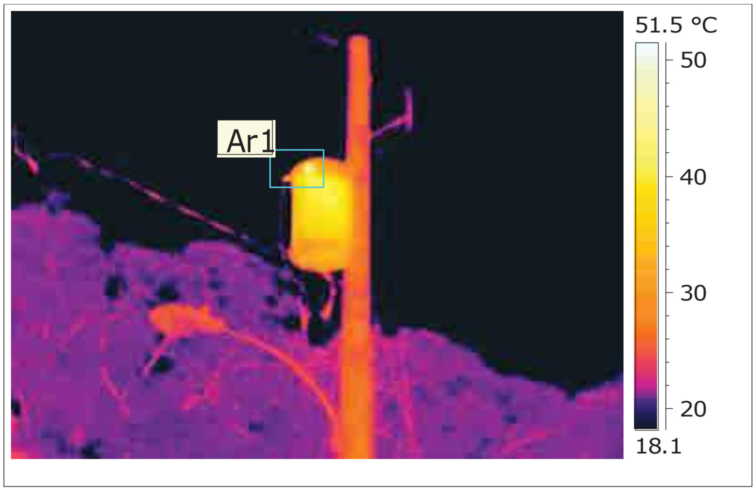


Photo:

Temperature rise: 29.1 °C (over ambient)

IR Information	
Date of creation	6/25/2015
Time of creation	2:30:29 PM
Object parameter	
Ambient temperature	22.0 °C
Label	
Ar1.Max	51.1 °C

Status:

Repair Date:

Notes:

Map:

Details:
Infrared image of transformer TX10528.
Located at 12425 Renaud Street in Tecumseh

Heating noted at secondary bushing connection at arrow in photo.

See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium X Low

ANOMALY: Heating Secondary Connection

Identification:	TX10619 (New TX installed)	Date
Area:	Tecumseh	25/06/2015

Description: O/H Transformer Bushings

INFRARED IMAGE:

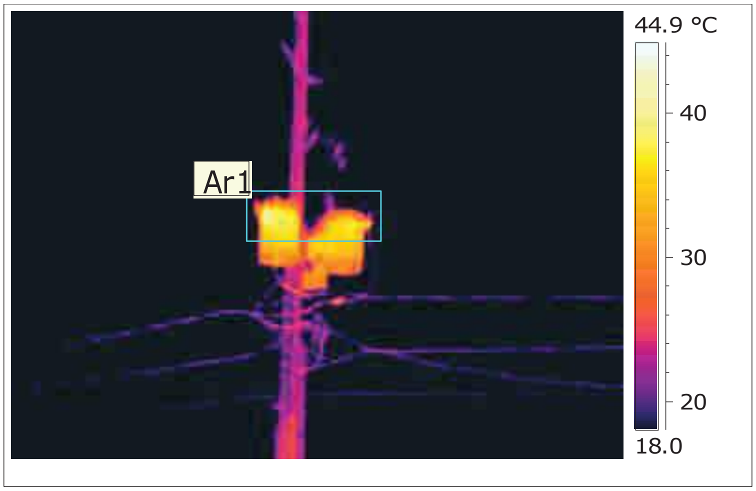
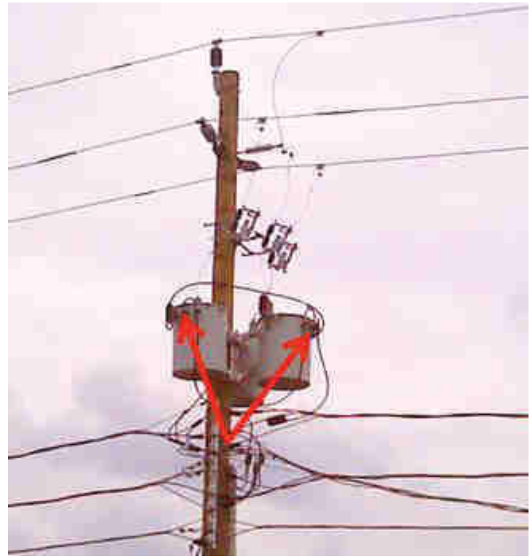


Photo:



Temperature rise: 23.3 °C (over ambient)

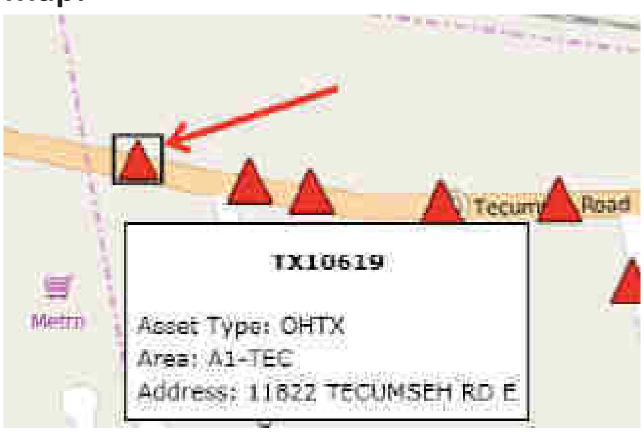
IR Information	
Date of creation	6/25/2015
Time of creation	2:07:23 PM
Object parameter	
Ambient temperature	22.0 °C
Label	
Ar1.Max	45.3 °C

Status:

Repair Date:

Notes:

Map:



Details:
Infrared image of transformer TX10619 new.
Located at 11822 Tecumseh Road in Tecumseh

Heating noted at two secondary bushing connection at arrow in photo.

See IR information chart above for maximum temperature inside area box (AR1 Max).

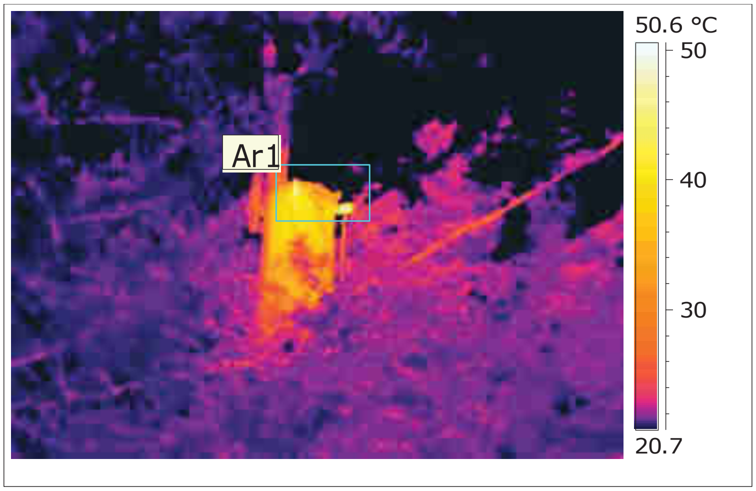
PRIORITY: High Medium X Low

ANOMALY: Heating Secondary Connections

Identification:	TX10902	Date
Area:	Tecumseh	25/06/2015

Description: O/H Transformer Bushings

INFRARED IMAGE: **Photo:**



Temperature rise: 30.8 °C (over ambient)

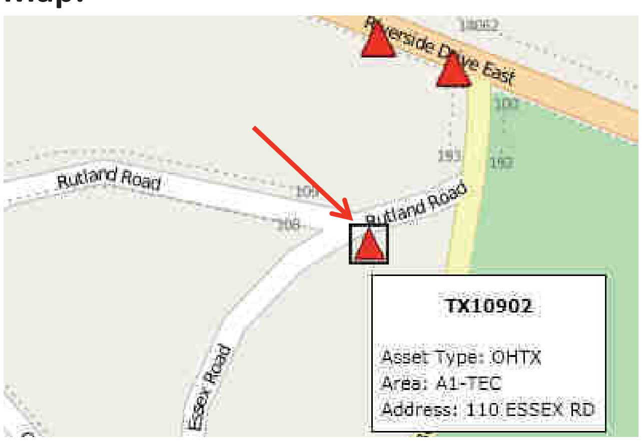
IR Information	
Date of creation	6/25/2015
Time of creation	12:48:22 PM
Object parameter	
Ambient temperature	20.0 °C
Label	
Ar1.Max	50.8 °C

Status:

Repair Date:

Notes:

Map:



Details:
Infrared image of transformer TX10902.
Located at 110 Essex Road in Tecumseh

Heating noted at two secondary bushing connections and Tree trimming is required at arrow in photo.

See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium X Low

ANOMALY: Heating Secondary Connections

Identification:	TX31537	Date
Area:	Leamington	29/06/2015

Description: **O/H Transformer Bushings**

INFRARED IMAGE:

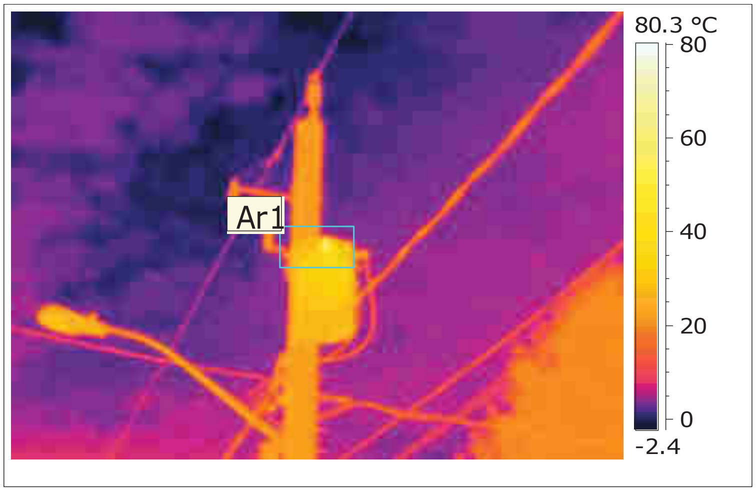


Photo:

Temperature rise: 59.6 °C (over ambient)

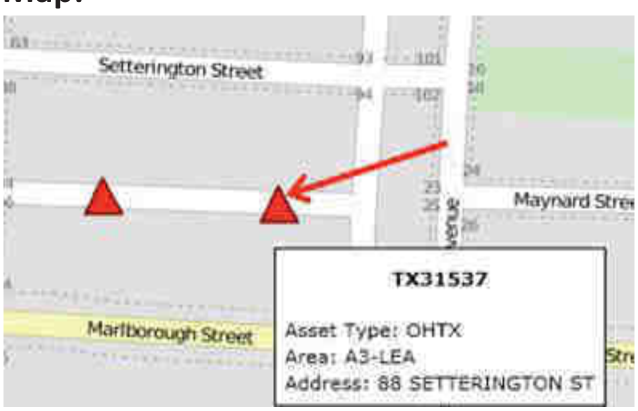
IR Information	
Date of creation	6/29/2015
Time of creation	12:23:07 PM
Object parameter	
Ambient temperature	20.0 °C
Label	
Ar1.Max	79.6 °C

Status:

Repair Date:

Notes:

Map:



Details:
Infrared image of transformer TX31537.
Located at 88 Setterington Street in Leamington

Heating noted at secondary bushing connection at arrow in photo.

See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High X Medium Low

ANOMALY: Heating Secondary connection

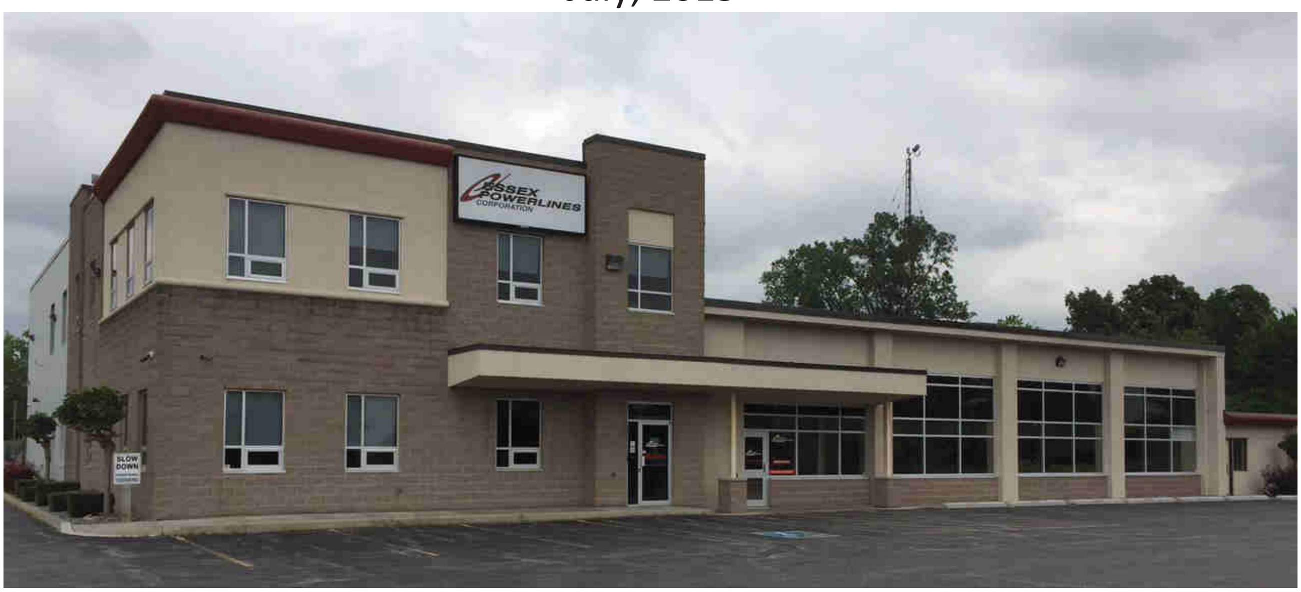
Infrared Inspection

- Electrical Distribution System -

Essex Power Lines

Date

July, 2015



Report Completed By

Essex Energy Corporation
2199 Blackacre Drive /Suite 2
Oldcastle Ontario N0R 1L0
Tel: 519 946 2000
Fax: 1 866291 5317

FLIR-Systems Ltd. Canada
This identification certifies that
Fred Brefka
has completed the necessary course work and has met or exceeded the established requirements to be an ITC Certified Infrared Thermographer to level as indicated

Examining Officer
10/24/2016
Expiry Date

ITC – FLIR Canada
920 Sheldon Court
Burlington, Ontario, L7L 5K6

itc INFRARED TRAINING CENTER

Infrared Report Summary

Purpose: Infrared inspection to identify thermal anomalies on electrical distribution equipment that suggest an unwanted condition exists and repairs are required.

Method: Complete infrared inspection of selected Essex Powerlines distribution system equipment. Save infrared images of all noted anomalies. Report on findings.

Conditions: Equipment operating under normal daytime loading conditions.

Inspection Equipment: FLIR model T300 thermal imaging systems, serial #

Observations

Note: Essex Energy Corporation is in no way responsible for any expenses resulting in actions or repair of reported anomalies. This report is not a warranty or guarantee of any equipment condition or reliability.

Please see report for details on all noted suspect conditions. All anomalies classified as follows:
HIGH Priority: High temperature rise over other components. Immediate corrective action required.
Do not ignore. Component temperature over 50 C rise over ambient.

MEDIUM Priority: Intermediate temperature rise. Corrective action required at next opportunity. Do not ignore. Component temperature 20 to 50 C rise over ambient.

LOW Priority: Low temperature rise. Condition should be investigated further and corrected at next convenient opportunity, if applicable.
Do not ignore. Component temperature below 20 C rise over ambient.

No Problems Noted (N/A): No anomalies noted. Condition good.

All reported condition should be investigated further as soon as possible to verify the reported condition. Use all safety procedures. Electrical hazards exist.

CONTENTS OF REPORT

Priority H= High M= Medium L= Low N/A= Not Applicable

Identification:	**TX50440**	**Date**
Area:	**Amherstburg**	**06/07/2015**

Description: Secondary Terminal Strip

INFRARED IMAGE:

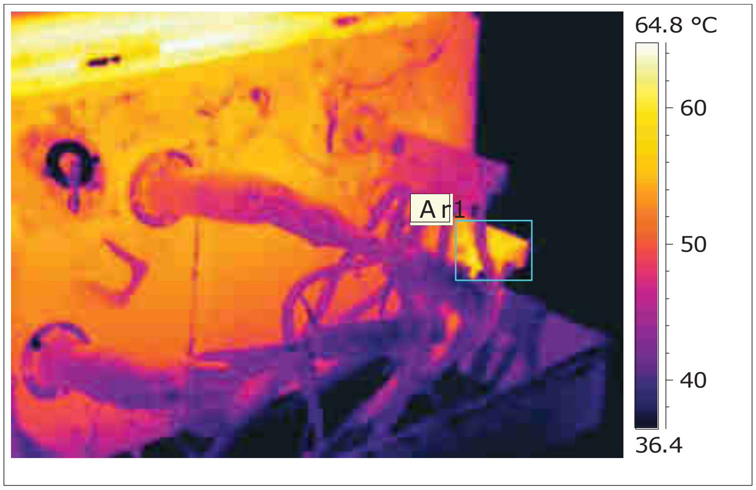


Photo:

Temperature rise: 34.1 °C (over ambient)

IR Information	
Date of creation	7/6/2015
Time of creation	3:01:47 PM
Object parameter	
Ambient temperature	26.0 °C
Label	
Ar1.Max	60.1 °C

Status:

Repair Date:

Notes:

Map:

Details:
Infrared image of TX50440
Located at Virginia Ave in Amherstburg
Heating noted at one off the secondary Terminal Strips on the centre Terminal Strip indicated by the red arrow in photo.
See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium X Low

ANOMALY: Heating Secondary Connection

Identification:	TX50446	Date
Area:	Amherstburg	06/07/2015

Description: Secondary Terminal Strip

INFRARED IMAGE:

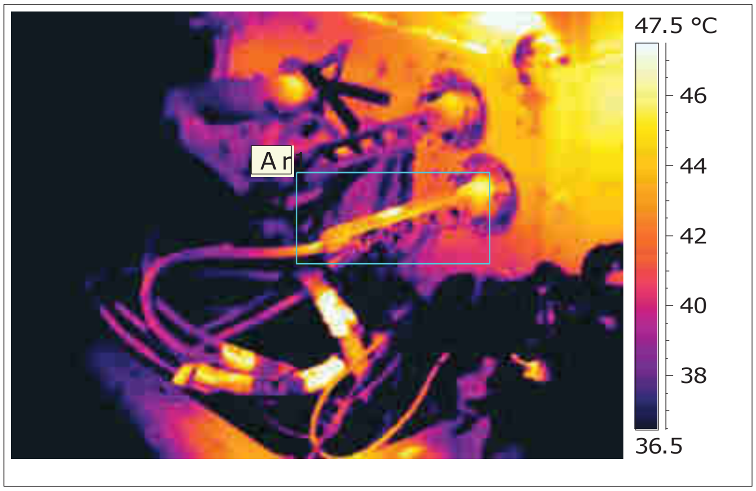
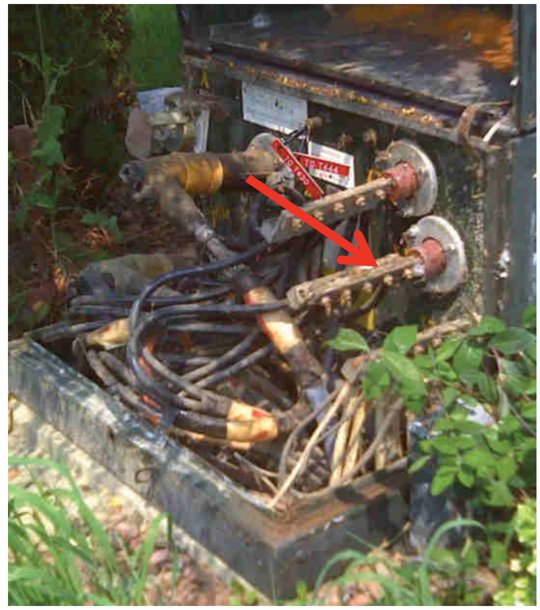


Photo:



Temperature rise: 21.6°C (over ambient)

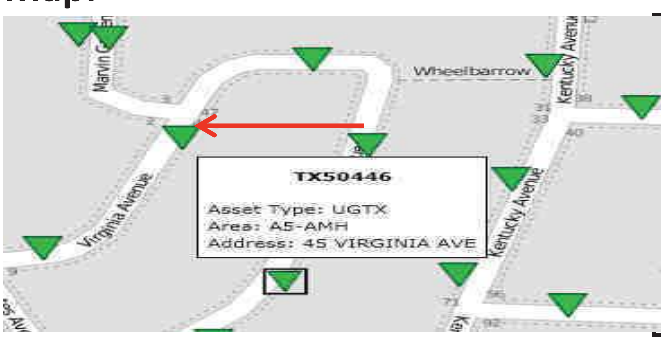
IR Information	
Date of creation	7/6/2015
Time of creation	3:38:01 PM
Object parameter	
Ambient temperature	26.0 °C
Label	
Ar1.Max	Ar1.Max Temperature 47.6 °C

Status:

Repair Date:

Notes:

Map:



Details:
Infrared image of TX50446
Located at 45 Virginia Ave in Amherstburg
Heating noted at one off the secondary Terminal Strips on the centre Terminal Strip at arrow in photo.
See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium X Low

ANOMALY: Heating Secondary Connection

Identification:	TX50925	Date
Area:	Amherstburg	07/07/2015

Description: **Secondary Terminal Strip**

INFRARED IMAGE:

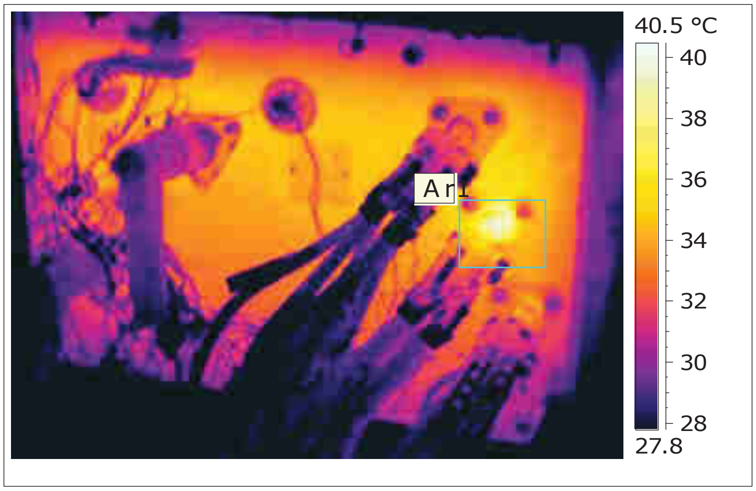


Photo:

IR Information	
Date of creation	7/7/2015
Time of creation	2:37:33 PM
Object parameter	
Ambient temperature	24.0 °C
Label	
Ar1.Max	40.2 °C

Temperature rise: 16.2°C (over ambient)

Status:

Repair Date:

Notes:

Map:

Details:
Infrared image of TX50925
Located at 102 Lowes Sdrd in Amherstburg
Heating noted at one off the secondary bushing identified by the red arrow in photo.
See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium Low X

ANOMALY: Heating Connection

Identification:	TX30597	Date
Area:	Leamington	07/10/2015

Description: Secondary fuse for streetlight

INFRARED IMAGE:

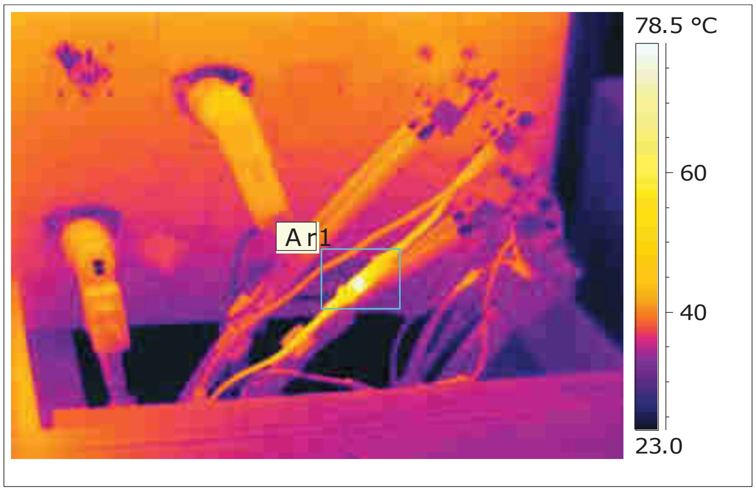


Photo:

IR Information	
Date of creation	7/10/2015
Time of creation	1:13:23 PM
Object parameter	
Ambient temperature	23.0 °C
Label	
Ar1.Max	78.7 °C

Temperature rise: 55.1°C (over ambient)

Status:

Repair Date:

Notes:

Map:

Details:
Infrared image of TX30597
Located at 9 Albert ST in Leamington
Heating noted at secondary wire in the streetlight fuse (indicated by red arrow).
See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High X Medium Low

ANOMALY: Heating Contact

Identification:	TX31010	Date
Area:	Leamington	07/10/2015

Description: Secondary Bushing

INFRARED IMAGE:

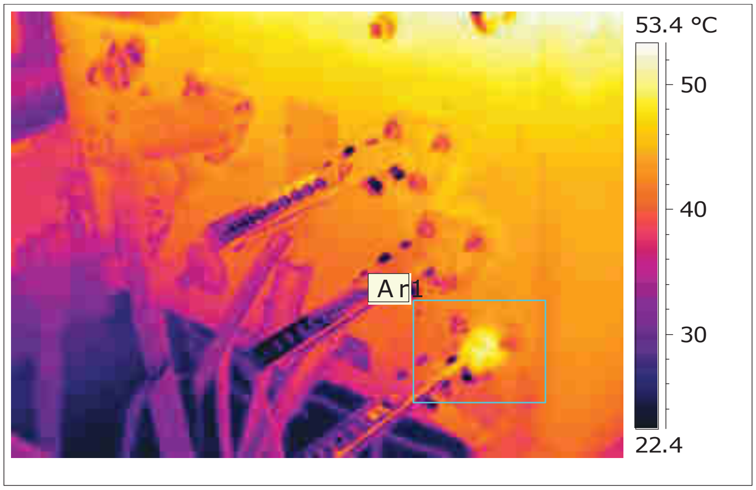


Photo:

IR Information	
Date of creation	7/10/2015
Time of creation	11:39:24 AM
Object parameter	
Ambient temperature	23.0 °C
Label	
Ar1.Max	51.0 °C

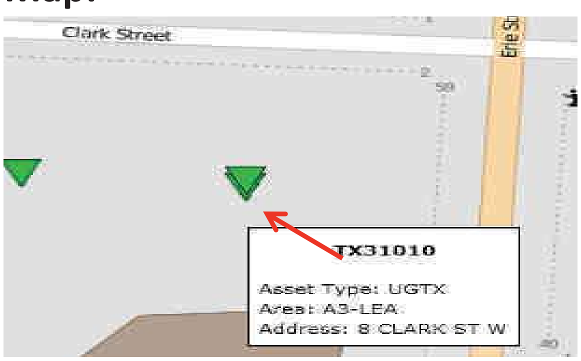
Temperature rise: 28°C (over ambient)

Status:

Repair Date:

Notes:

Map:



Details:
Infrared image of TX31010
Located at 8 Clark St W in Leamington
Heating noted at one off the secondary bushing at arrow in photo.
See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium Low X

ANOMALY: Heating Connection

Identification:	TX31011	Date
Area:	Leamington	07/10/2015

Description: Secondary Terminal Strip

INFRARED IMAGE:

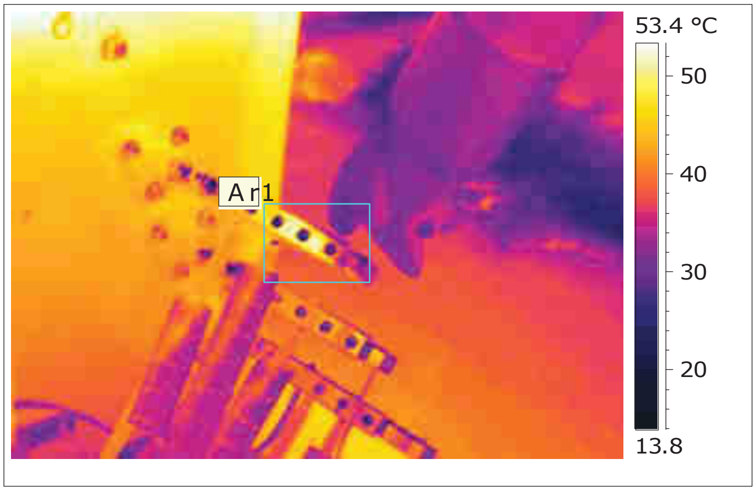
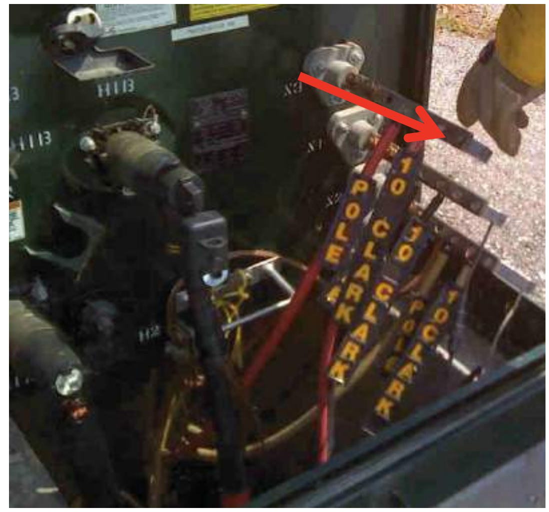


Photo:



IR Information	
Date of creation	7/10/2015
Time of creation	11:24:51 AM
Object parameter	
Ambient temperature	23.0 °C
Label	
Ar1.Max	52.4 °C

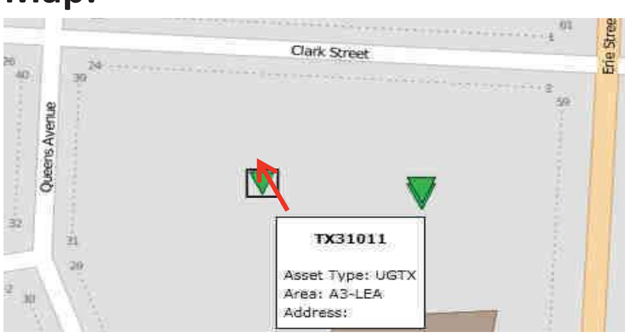
Temperature rise: 29.4°C (over ambient)

Status:

Repair Date:

Notes:

Map:



Details:
Infrared image of TX31011
Located at Clark Street in Leamington
Heating noted at one off the secondary Terminal Strips at arrow in photo.
See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium X Low

ANOMALY: Heating Secondary Connection

Identification:	TX30083	Date
Area:	Leamington	07/15/2015

Description: Secondary Terminal Strip

INFRARED IMAGE:

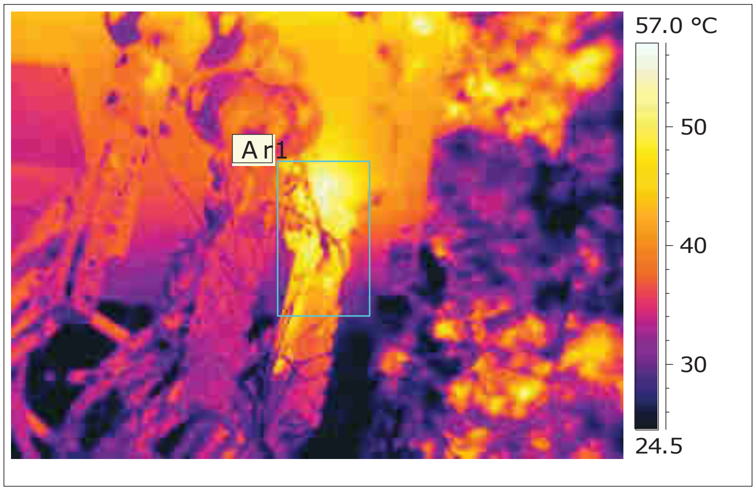


Photo:

IR Information	
Date of creation	7/15/2015
Time of creation	3:01:00 PM
Object parameter	
Ambient temperature	28.0 °C
Label	
Ar1.Max	55.1 °C

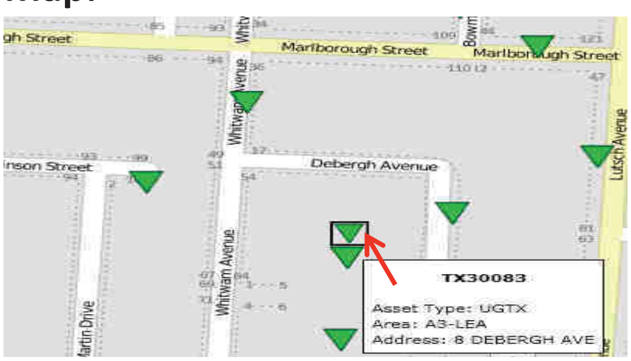
Temperature rise: 27.1°C (over ambient)

Status:

Repair Date:

Notes:

Map:



Details:
Infrared image of TX30083
Located at 8 Debergh Ave in Leamington
Heating noted at one off the secondary Terminal Strips at arrow in photo.
See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium X Low

ANOMALY: Heating Secondary Connection

Infrared Inspection
- Electrical Distribution System -

Essex Power Lines

Date : May, 2016

Report Completed By:

Essex Energy Corporation
2199 Blackacre Drive / Suite 2
Oldcastle Ontario N0R 1L0
Tel: 519 946 2000
Fax: 1 866291 5317

Sheldon Tracey

HAS SUCCESSFULLY COMPLETED
THE FOLLOWING REQUIREMENTS FOR CERTIFICATION:
ATTENDING OUR TRAINING COURSE,
PASSING THE REQUIRED EXAMS, AND
SUBMITTING A PRACTICAL FIELD ASSIGNMENT.

Certified Instructor

CERTIFICATION NO. CDN-2016177
EXPIRATION DATE: 2021-03-07

Infrared Training Center - FLIR Canada

Infrared Summary Report

Purpose: Infrared inspection to identify thermal anomalies on electrical distribution equipment that suggest an unwanted condition exists and repairs are required.

Method: Complete infrared inspection of selected Essex Powerlines distribution system equipment. Save infrared images of all noted anomalies. Report on findings.

Conditions: Equipment operating under normal daytime loading conditions.

Inspection Equipment: FLIR model T300 thermal imaging systems, serial # 453000429

Observations

Note: Essex Energy Corporation is in no way responsible for any expenses resulting in actions or repair of reported anomalies. This report is not a warranty or guarantee of any equipment condition or reliability.

Please see report for details on all noted suspect conditions. All anomalies classified as follows:
HIGH Priority: High temperature rise over other components. Immediate corrective action required.
Do not ignore. Component temperature over 50 C rise over ambient.

MEDIUM Priority: Intermediate temperature rise. Corrective action required at next opportunity. Do not ignore. Component temperatures 20 to 50 C rise over ambient.

LOW Priority: Low temperature rise. Condition should be investigated further and corrected at next convenient opportunity, if applicable.
Do not ignore. Component temperatures below 20 C rise over ambient.

No Problems Noted (N/A): No anomalies noted. Condition good.

All reported conditions should be investigated further as soon as possible to verify the reported condition. Use all safety procedures. Electrical hazards exist.

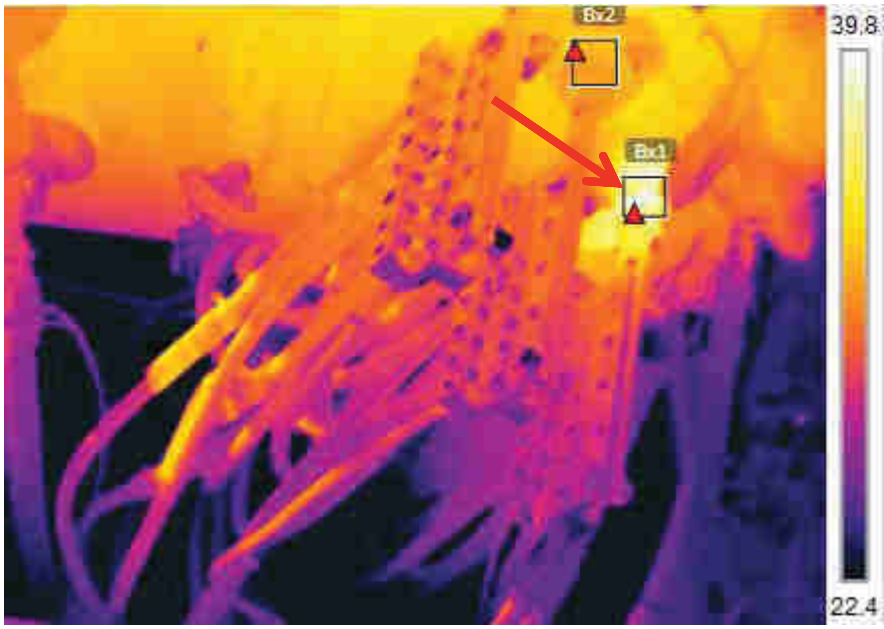
CONTENTS OF REPORT

Priority H= High M= Medium L= Low N/A= Not Applicable

Asset ID:	TX7P511
Address:	2955 Brooklyn Avenue, Lasalle
Date:	16-05-25

ANOMALY: SECONDARY BUSHING

INFRARED IMAGE:



IR INFORMATION:

Ambient	22 °C
Bx 1 Temp	39.9 °C
Bx 2 Temp	33.7 °C
ΔTemp	6.2 °C
IR Image(s)	IR #12366-70

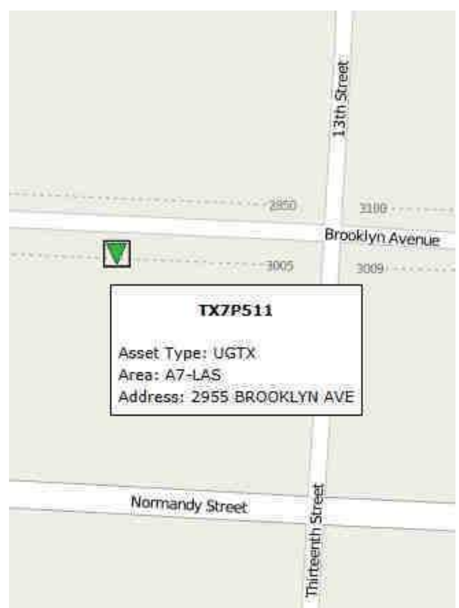
DETAILS:

There was an increase in temperature noted on the bottom secondary bushing. A qualitative comparison between the other secondary bushing indicates an issue. The issue is identified by the red arrow in each image.

For another view of issue, please review IR image # 12368 & 12370.

DIGITAL IMAGE:

MAP:



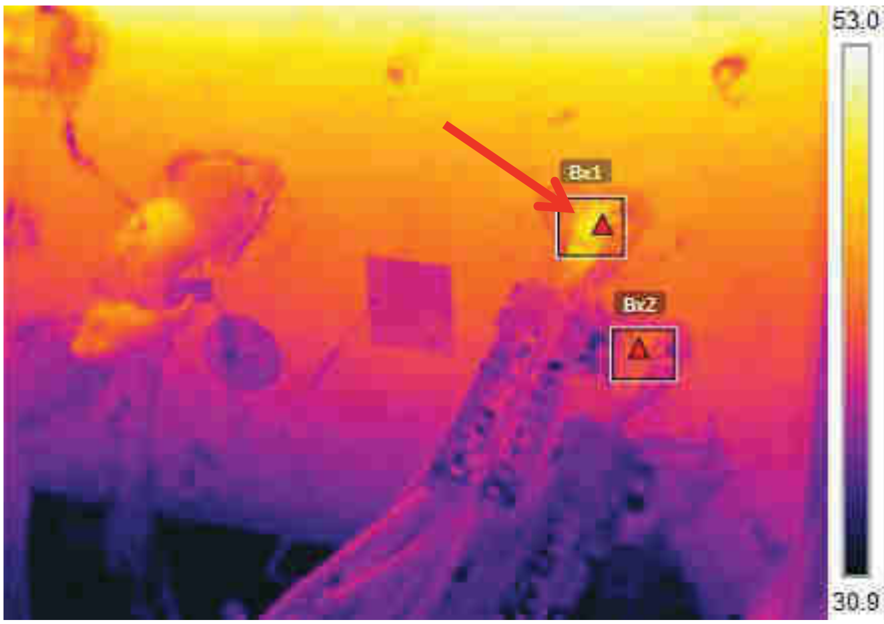
PRIORITY:	HIGH	MEDIUM	LOW - X

Asset ID:	TX7P454
Address:	2565 Skinner St., Lasalle
Date:	16-05-25

ESSEXENERGY CORPORATION

ANOMALY: SECONDARY BUSHING

INFRARED IMAGE:



IR INFORMATION:

Ambient	25 °C
Bx 1 Temp	49.3 °C
Bx 2 Temp	43.4 °C
ΔTemp	5.9 °C
IR Image(s)	12482-84

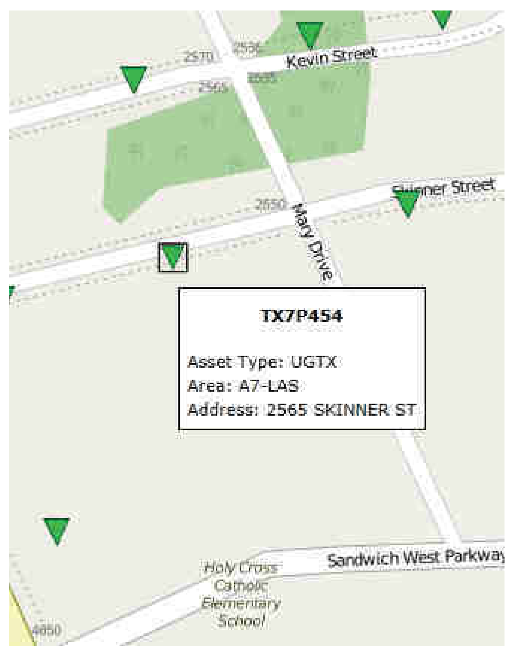
DETAILS:

There was an increase in temperature noted on the top secondary bushing. A qualitative comparison between the other secondary bushing indicates an issue. The issue is identified by the red arrow in each image.

For another view of issue, please review IR image # 12484.

DIGITAL IMAGE:

MAP:



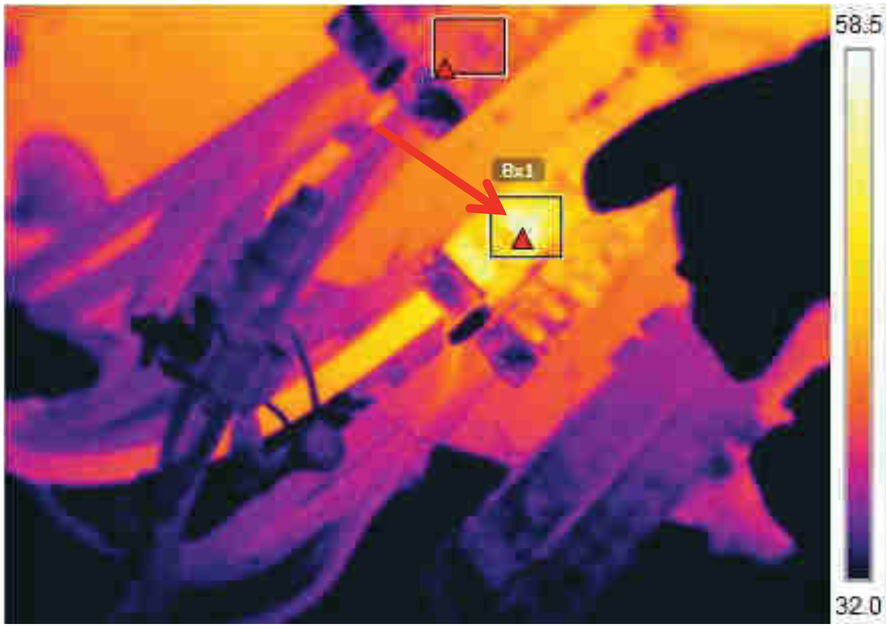
PRIORITY:	HIGH	MEDIUM	LOW - X

Asset ID:	TX7P169
Address:	5909 Baxter Cres., Lasalle
Date:	16-05-26

ESSEXENERGY CORPORATION

ANOMALY: SECONDARY CONNECTION

INFRARED IMAGE:



IR INFORMATION:

Ambient	20 °C
Bx 1 Temp	58.4 °C
Bx 2 Temp	42.8 °C
ΔTemp	15.6 °C
IR Image(s)	12580-82

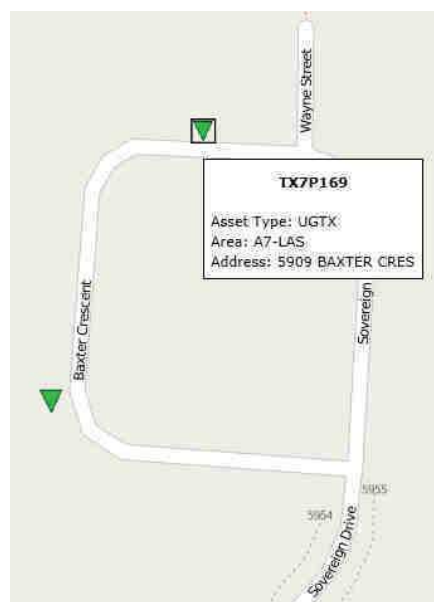
DETAILS:

There was an increase in temperature noted on a secondary connection. A quantitative comparison between the other secondary connections indicates that there is an issue on the secondary connection indicated by the red arrow.

For another view of issue, please review IR image # 12582.

DIGITAL IMAGE:

MAP:

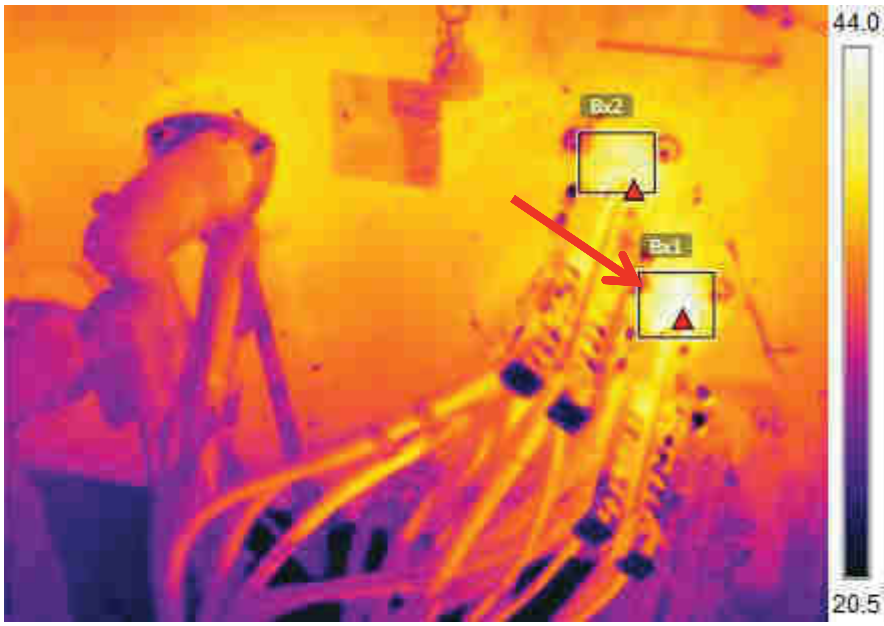


PRIORITY:	HIGH	MEDIUM	LOW - X

Asset ID: TX7P421
Address: 231 Tyler Rd., Lasalle
Date: 16-05-26

ANOMALY: SECONDARY BUSHING

INFRARED IMAGE:



IR INFORMATION:

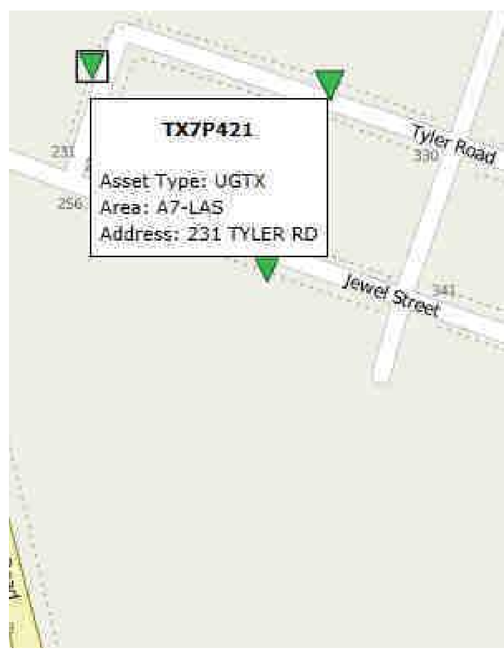
Ambient	18 °C
Bx 1 Temp	43.9 °C
Bx 2 Temp	42.4 °C
ΔTemp	1.5 °C
IR Image(s)	12824-26

DETAILS:

There was an increase in temperature noted on the middle secondary bushing. A qualitative comparison between the other secondary bushing indicates an issue. The issue is identified by the red arrow in each image.

DIGITAL IMAGE:

MAP:

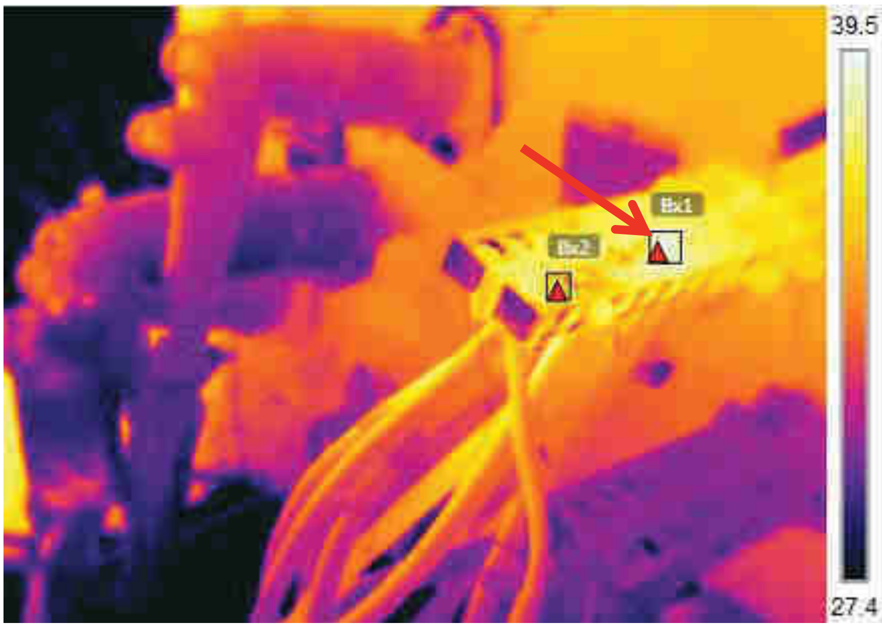


PRIORITY:	HIGH	MEDIUM	LOW - X

Asset ID: TX7P121
Address: 892 Huron St., Lasalle
Date: 16-05-26

ANOMALY: SECONDARY CONNECTION

INFRARED IMAGE:



IR INFORMATION:

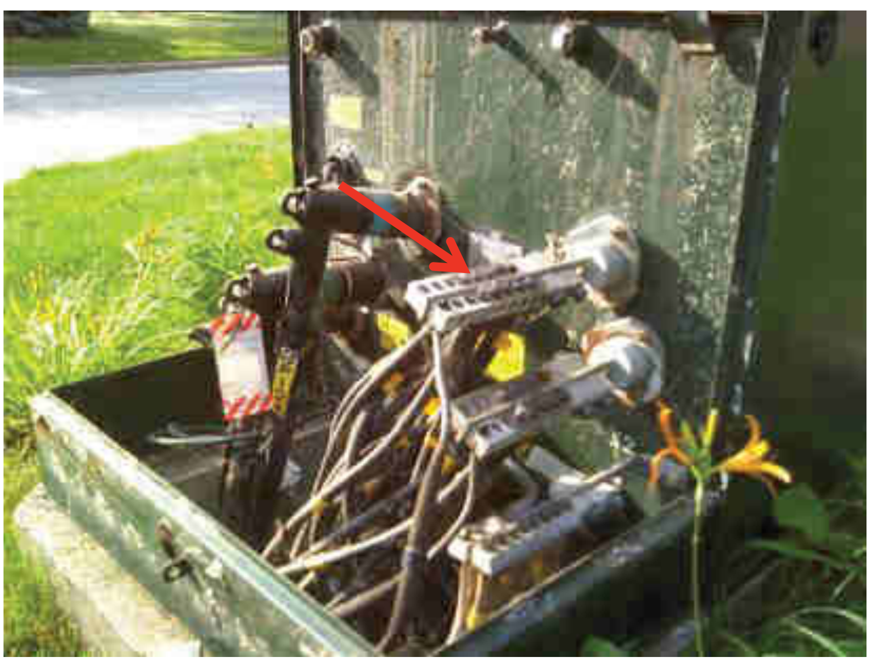
Ambient	19 °C
Bx 1 Temp	40.1 °C
Bx 2 Temp	37.3 °C
ΔTemp	2.8 °C
IR Image(s)	13052-56

DETAILS:

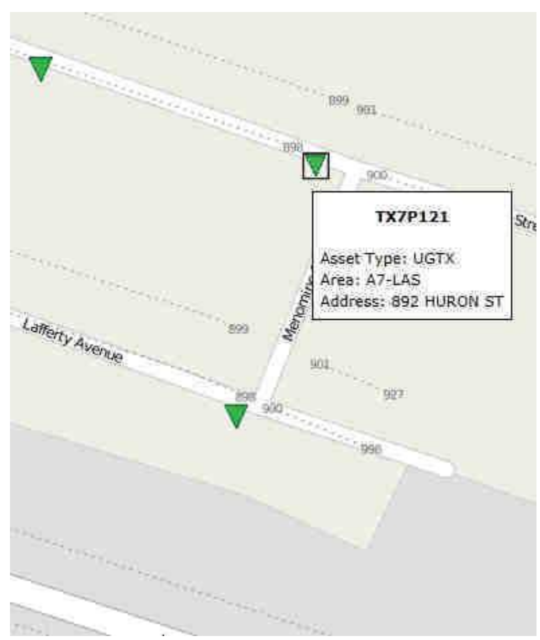
There was an increase in temperature noted on one of the secondary connections. A qualitative comparison between the other secondary connections indicates an issue. The issue is identified by the red arrow in each image.

For another view of issue, please review IR image # 13052 & 13054.

DIGITAL IMAGE:



MAP:

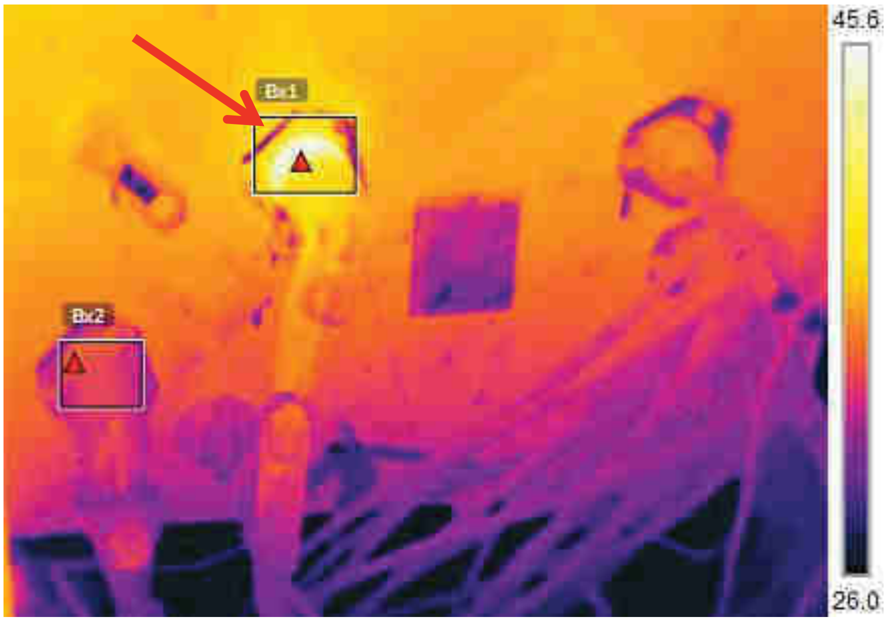


PRIORITY:	HIGH	MEDIUM	LOW - X

Asset ID:	TX7P120
Address:	944 Huron St., Lasalle
Date:	16-05-28

ANOMALY: **HIGH VOLTAGE ELBOW / BUSHING WELL**

INFRARED IMAGE:



IR INFORMATION:

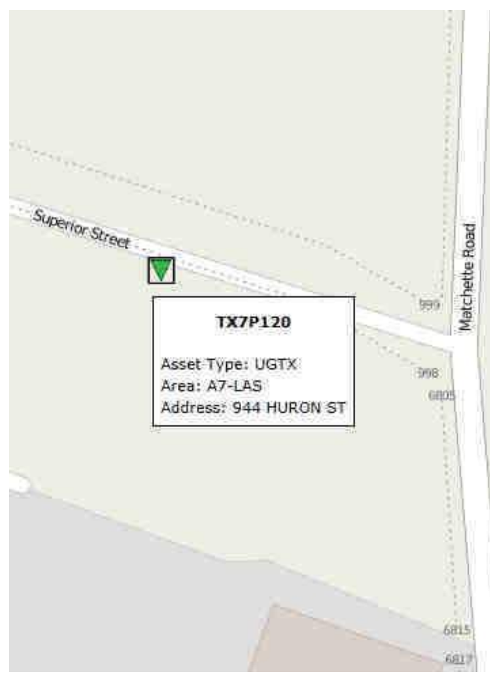
Ambient	19 °C
Bx 1 Temp	45.6 °C
Bx 2 Temp	34.6 °C
ΔTemp	11 °C
IR Image(s)	13064-66

DETAILS:

There was an increase in temperature noted on one of the high voltage elbows. A quantitative comparison between the other high voltage connections indicates an issue. The issue is identified by the red arrow in each image.

DIGITAL IMAGE:

MAP:

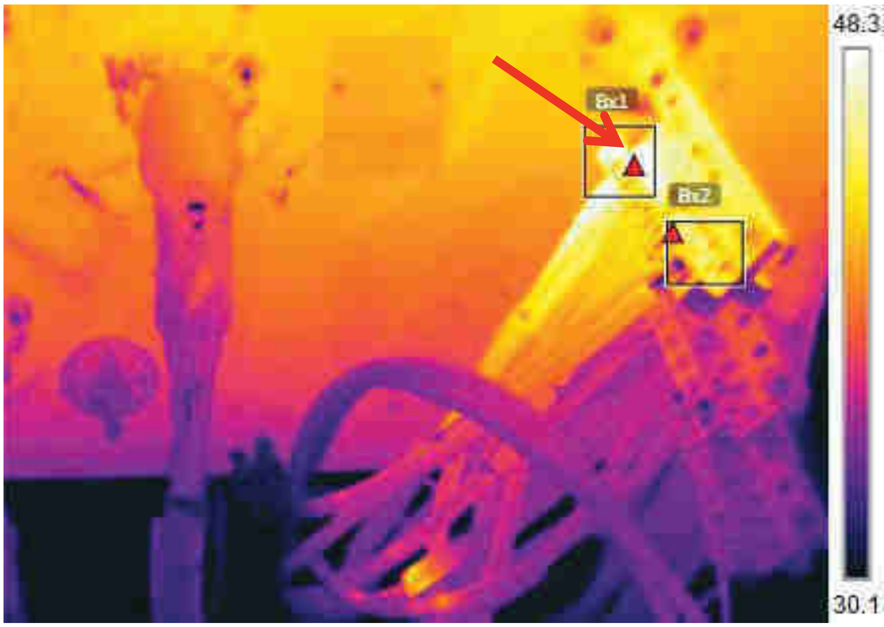


PRIORITY:	HIGH	MEDIUM	LOW - X

Asset ID:	TX7P540
Address:	1140 Deerview Dr., Lasalle
Date:	16-05-28

ANOMALY: SECONDARY CONNECTION

INFRARED IMAGE:



IR INFORMATION:

Ambient	25 °C
Bx 1 Temp	52.7 °C
Bx 2 Temp	45.9 °C
ΔTemp	6.8 °C
IR Image(s)	13130-32

DETAILS:

There was an increase in temperature noted on one of the secondary connections. A qualitative comparison between the other secondary connections indicates an issue. The issue is identified by the red arrow in each image.

For another view of issue, please review IR image # 13130.

DIGITAL IMAGE:

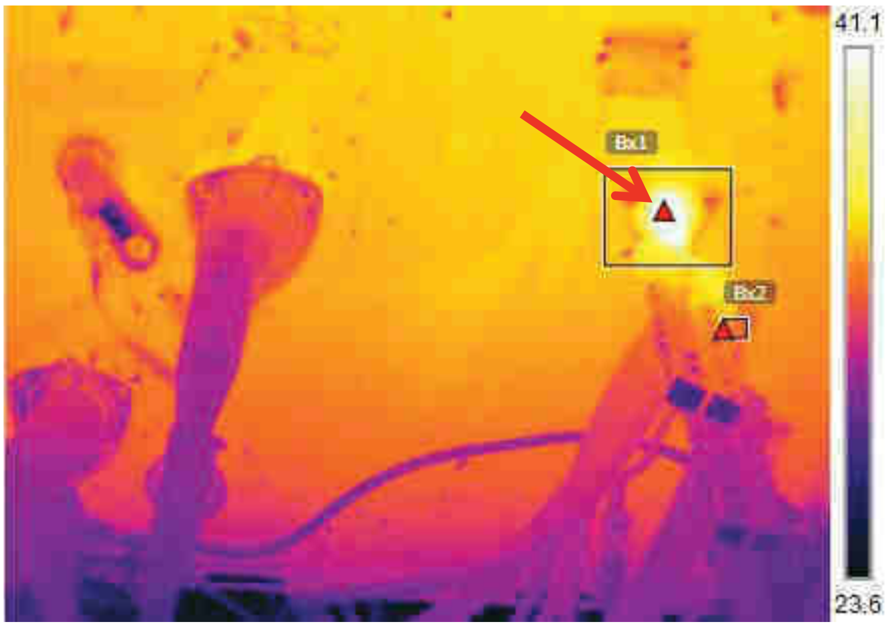
MAP:

PRIORITY:	HIGH	MEDIUM	LOW - X

Asset ID: TX7P341
Address: 165 Rivervilla Crt., Lasalle
Date: 16-05-28

ANOMALY: SECONDARY BUSHING

INFRARED IMAGE:



IR INFORMATION:

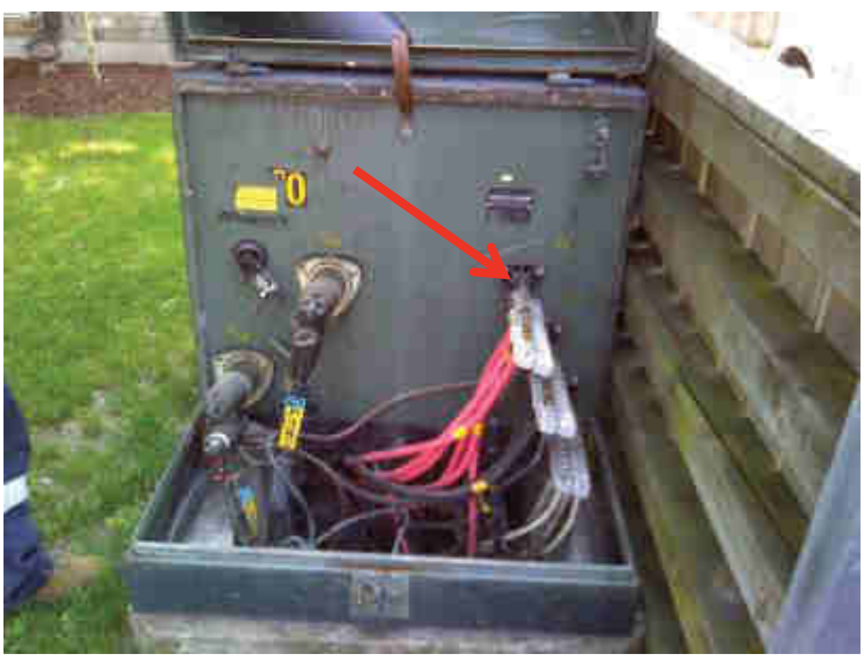
Ambient	25 °C
Bx 1 Temp	47 °C
Bx 2 Temp	34.9 °C
ΔTemp	12.1 °C
IR Image(s)	13162-64

DETAILS:

There was an increase in temperature noted on the top secondary bushing. A quantitative comparison between the other secondary bushings indicates an issue. The issue is identified by the red arrow in each image.

For another view of issue, please review IR image # 13162.

DIGITAL IMAGE:



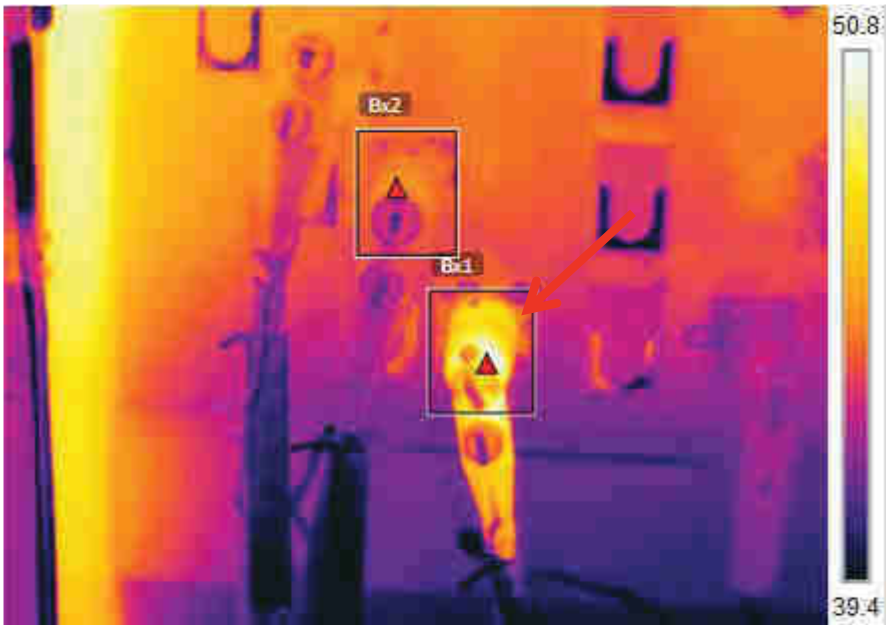
MAP:

PRIORITY:	HIGH	MEDIUM	LOW - X

Asset ID:	TX72000
Address:	415 Morton Dr., Lasalle
Date:	16-05-28

ANOMALY: HIGH VOLTAGE ELBOW

INFRARED IMAGE:



IR INFORMATION:

Ambient	25 °C
Bx 1 Temp	50.6 °C
Bx 2 Temp	45.3 °C
ΔTemp	5.3 °C
IR Image(s)	13168-70

DETAILS:

There was an increase in temperature noted on the bottom-left high voltage elbow. A quantitative comparison between the other high voltage elbows indicates an issue. The issue is identified by the red arrow in each image.

For another view of issue, please review IR image # 13170.

DIGITAL IMAGE:

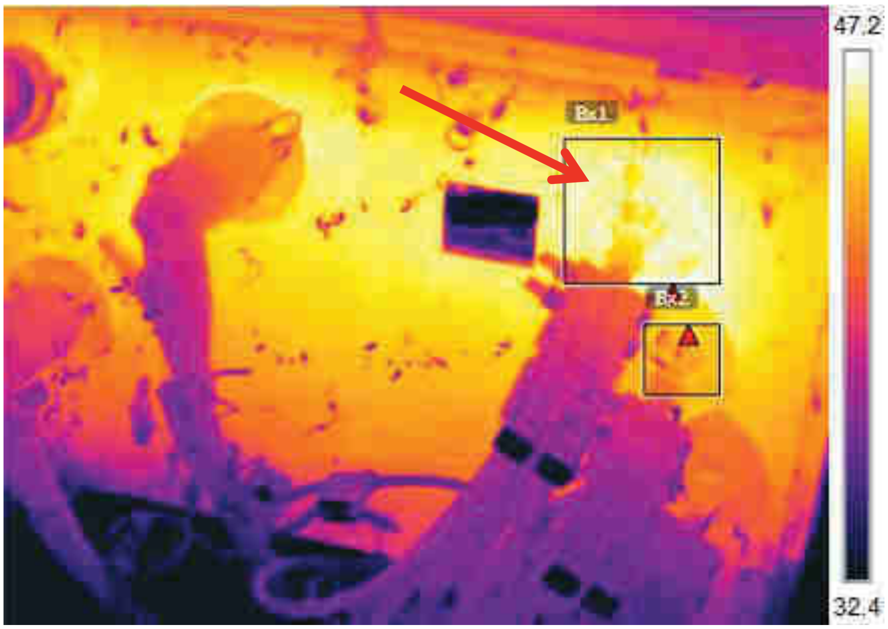
MAP:

PRIORITY:	HIGH	MEDIUM	LOW - X

Asset ID:	TX700P3
Address:	437 Darlene Pl., Lasalle
Date:	16-05-28

ANOMALY: SECONDARY BUSHING

INFRARED IMAGE:



IR INFORMATION:

Ambient	25 °C
Bx 1 Temp	47.1 °C
Bx 2 Temp	44.9 °C
ΔTemp	2.2 °C
IR Image(s)	13180

DETAILS:

There was an increase in temperature noted on the top secondary bushing. A quantitative comparison between the other secondary bushings indicates an issue. The issue is identified by the red arrow in each image.

DIGITAL IMAGE:

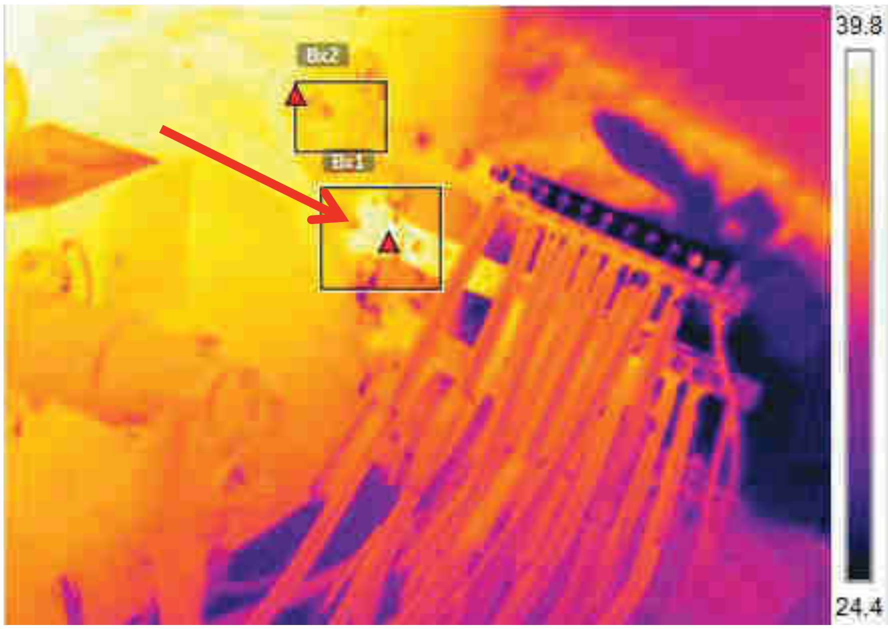
MAP:

PRIORITY:	HIGH	MEDIUM	LOW - X

Asset ID:	TX7P568
Address:	1252 Naccarato St., Lasalle
Date:	16-06-01

ANOMALY: SECONDARY BUSHING / TERMINAL

INFRARED IMAGE:



IR INFORMATION:

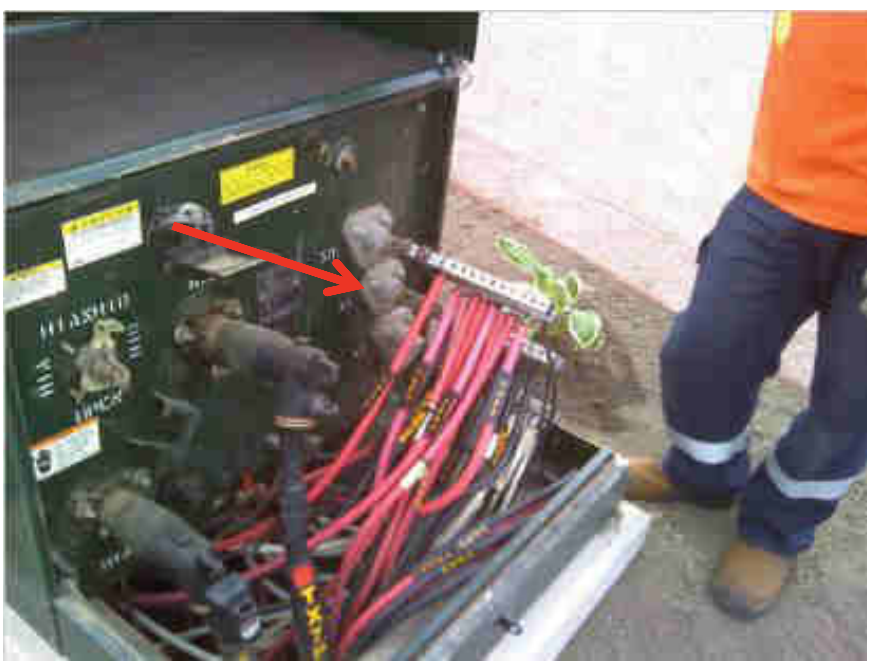
Ambient	25 °C
Bx 1 Temp	40 °C
Bx 2 Temp	38 °C
ΔTemp	2 °C
IR Image(s)	13410-12

DETAILS:

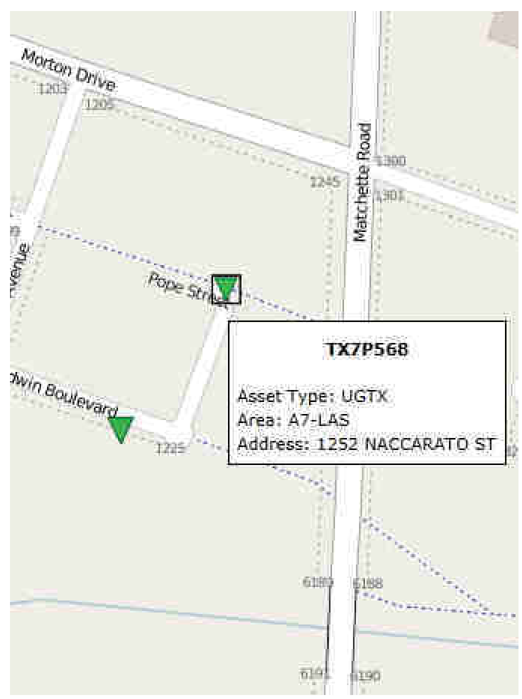
There was an increase in temperature noted on the middle secondary bushing. A qualitative comparison between the other secondary bushings indicates an issue. The issue is identified by the red arrow in each image.

For another view of issue, please review IR image # 13412.

DIGITAL IMAGE:



MAP:

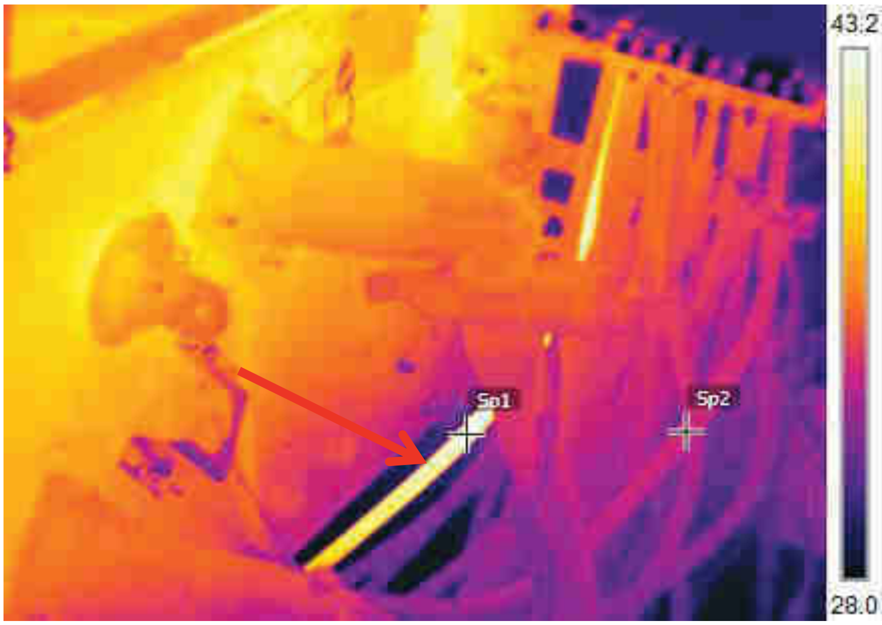


PRIORITY:	HIGH	MEDIUM	LOW - X

Asset ID:	TX7P239
Address:	750 River Ave., Lasalle
Date:	16-06-01

ANOMALY: SECONDARY WIRE

INFRARED IMAGE:



IR INFORMATION:

Ambient	26 °C
Sp 1 Temp	42.7 °C
Sp 2 Temp	34.1 °C
ΔTemp	8.6 °C
IR Image(s)	13424-26

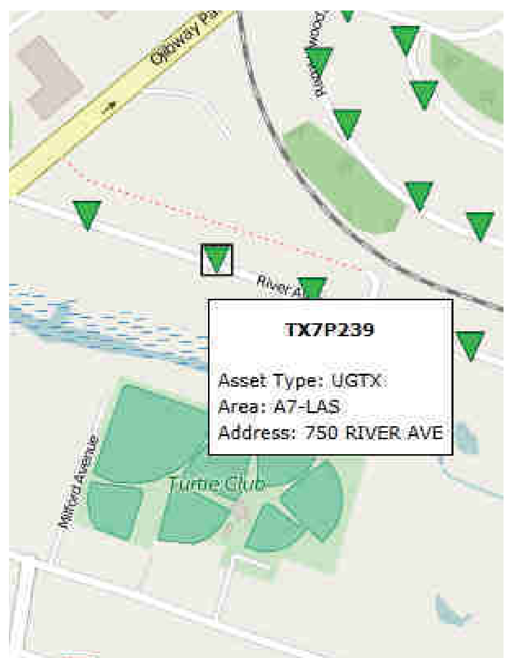
DETAILS:

There was an increase in temperature noted on one of the secondary wires. A quantitative comparison between the other secondary wires indicates an issue. The issue is identified by the red arrow in each image.

For another view of issue, please review IR image # 13426.

DIGITAL IMAGE:

MAP:



PRIORITY:	HIGH	MEDIUM	LOW - X

Infrared Inspection
- Electrical Distribution System -

Essex Power Lines

Date : April 18, 2017

Report Completed By:

Essex Energy Corporation
2199 Blackacre Drive / Suite 2
Oldcastle Ontario N0R 1L0
Tel: 519 946 2000
Fax: 1 866291 5317

Austin Crough
Engineering Support
acrough@essexenergy.ca

Infrared Summary Report

Purpose: Infrared inspection completed to identify thermal anomalies on electrical distribution equipment that suggest an unwanted condition exists and repairs are required.

Method: Completed infrared inspection of selected Essex Powerlines distribution system equipment. Save infrared images of all noted anomalies. Report on findings.

Conditions: Equipment operating under normal daytime loading conditions.

Inspection Equipment: FLIR model T300 thermal imaging systems, serial # 453000429

Observations

Note: Essex Energy Corporation is in no way responsible for any expenses resulting in actions or repair of reported anomalies. This report is not a warranty or guarantee of any equipment condition or reliability.

Please see report for details on all noted suspect conditions. All anomalies classified as follows:
HIGH Priority: High temperature rise over other components. Immediate corrective action required. Do not ignore. Component temperature was over 50° C higher than properly working equipment.

MEDIUM Priority: Intermediate temperature rise. Corrective action required at next opportunity. Do not ignore. Component temperature was 20 to 50° C higher than properly working equipment.

LOW Priority: Low temperature rise. Condition should be investigated further and corrected at next convenient opportunity, if applicable. Do not ignore. Component temperature was less than 20° C higher than properly working equipment

No Problems Noted (N/A): No anomalies noted. Condition good.

All reported conditions should be investigated further as soon as possible to verify the reported condition. Use all safety procedures. Electrical hazards exist.

CONTENTS OF REPORT

Priority: H= High / M= Medium / L= Low / N/A= Not Applicable

Asset ID: TX10180
Address: 1499 Heatherglen Cres, Tecumseh
Date: 17-03-07

ANOMALY: HIGH VOLTAGE ELBOW
PRIORITY: LOW

INFRARED IMAGE:

IR INFORMATION:

Ambient	10 °C
Bx 1 Temp	26.1 °C
Bx 2 Temp	14.4 °C
ΔTemp	11.7 °C
IR Image(s)	IR #14159, 14160

DETAILS:

There was an increase in temperature noted on the left high voltage elbow. A quantitative comparison with the other high voltage elbow indicated an issue. The issue is identified by the white arrow in each image.

For another view of the issue, please review IR image # 14157 & 14158.

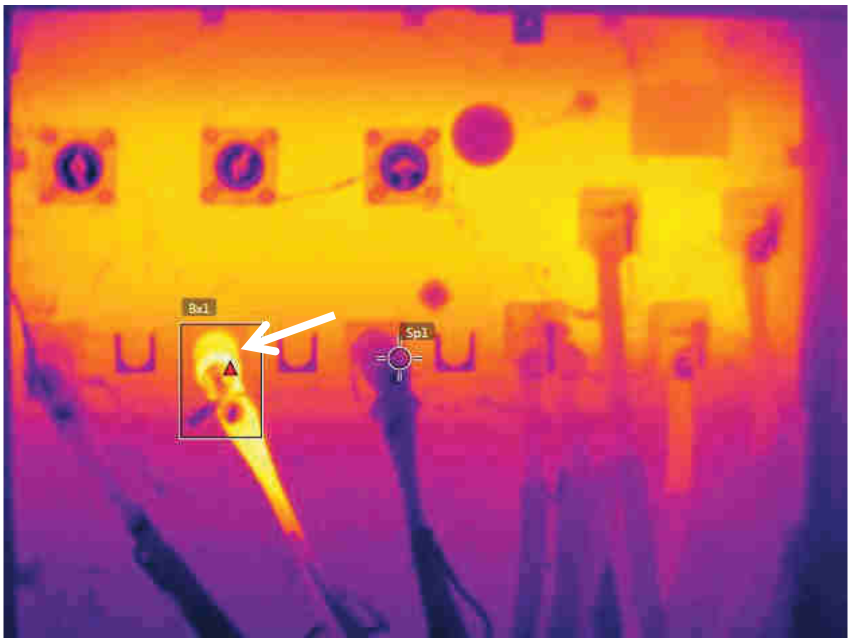
DIGITAL IMAGE:

MAP:

Asset ID:	TX10508
Address:	11873 Tecumseh Rd E, Tecumseh
Date:	17-03-07

ANOMALY: HIGH VOLTAGE ELBOW
PRIORITY: LOW

INFRARED IMAGE:



IR INFORMATION:

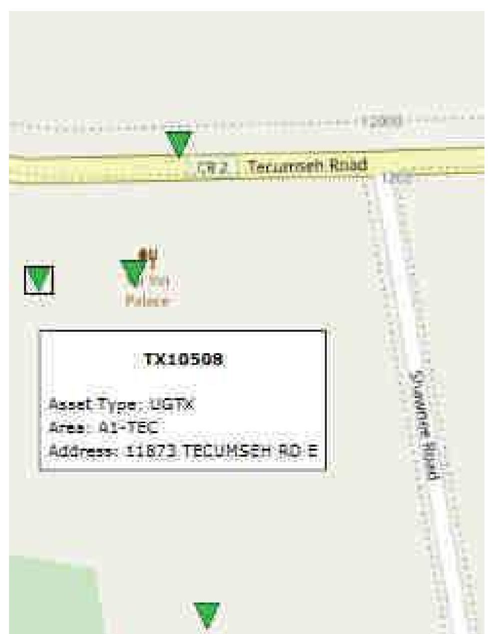
Ambient	11 °C
Bx 1 Temp	23.8 °C
Sp 1 Temp	12.7 °C
ΔTemp	11.1 °C
IR Image(s)	14205, 14206

DETAILS:

There was an increase in temperature noted on the center high voltage elbow. A quantitative comparison with another high voltage elbow indicated an issue. The issue is identified by the white arrow in each image.

DIGITAL IMAGE:

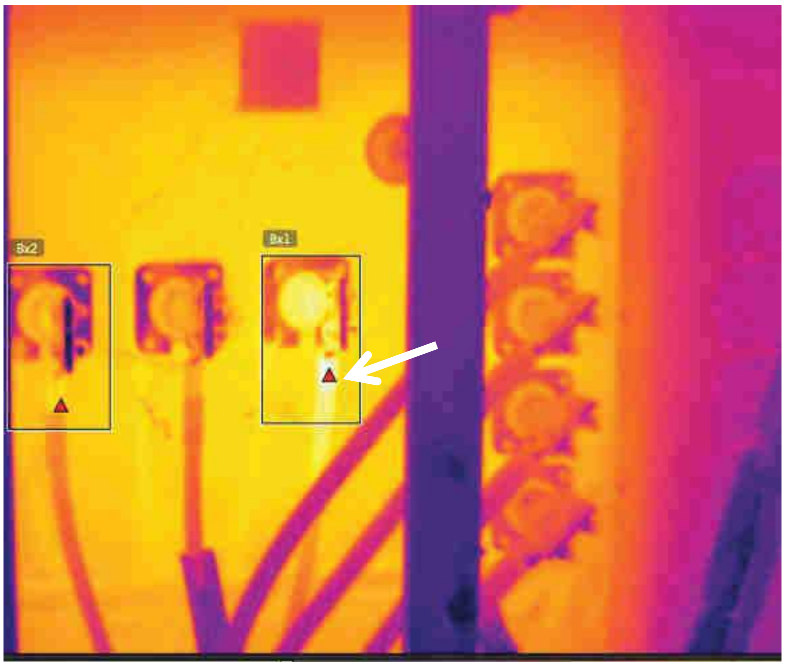
MAP:



Asset ID: TX10936
Address: 917 Lesperance Rd, Tecumseh
Date: 17-03-07

ANOMALY: HIGH VOLTAGE WIRE CONNECTION
PRIORITY: LOW

INFRARED IMAGE:



IR INFORMATION:

Ambient	11 °C
Bx 1 Temp	22.8 °C
Bx 2 Temp	17.8 °C
ΔTemp	5.0 °C
IR Image(s)	14217, 14218

DETAILS:

There was an increase in temperature noted on the wire connection of the right high voltage elbow. A quantitative comparison with another connection indicated that there was an issue. The issue is identified by the white arrow in each image.

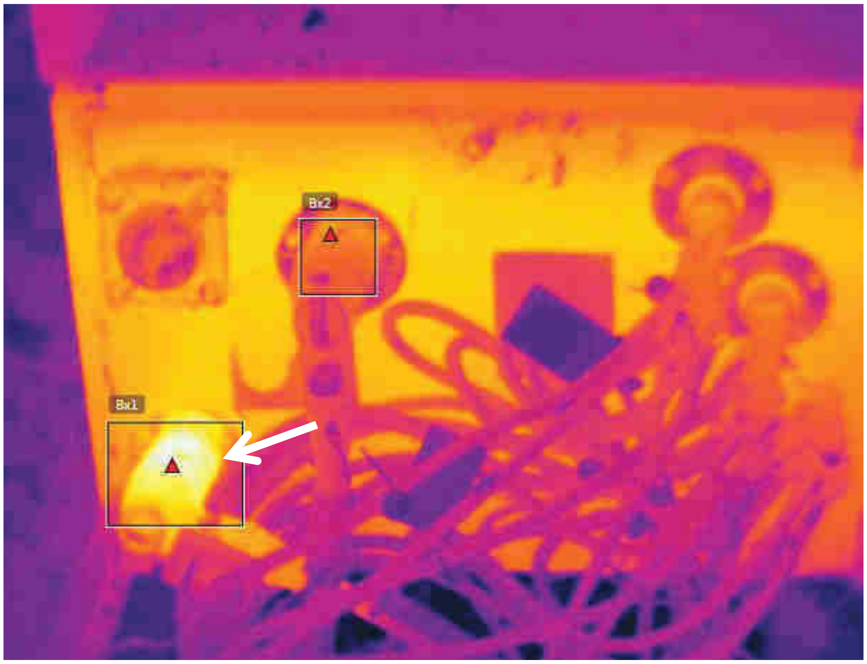
DIGITAL IMAGE:

MAP:

Asset ID: TX10102
Address: 12229 Valente Crt, Tecumseh
Date: 17-03-07

ANOMALY: HIGH VOLTAGE ELBOW
PRIORITY: LOW

INFRARED IMAGE:



IR INFORMATION:

Ambient	12 °C
Bx 1 Temp	33.5 °C
Bx 2 Temp	19.4 °C
ΔTemp	14.1 °C
IR Image(s)	14287, 14288

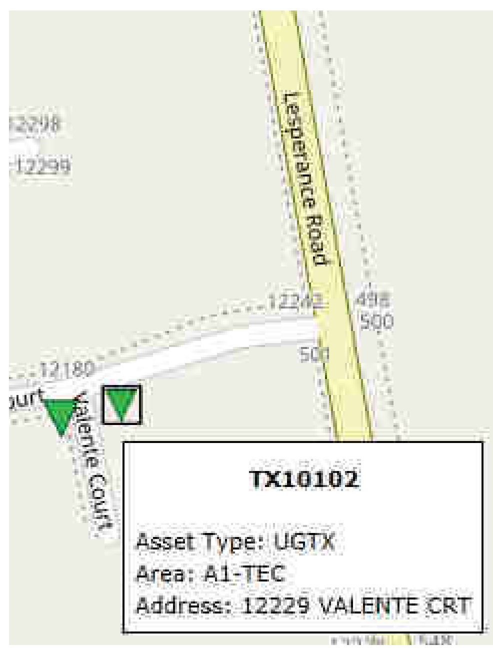
DETAILS:

There was an increase in temperature noted on the left high voltage elbow. A quantitative comparison with another high voltage elbow indicated an issue. The issue is identified by the white arrow in each image.

For another view of the issue, please review IR image #14285 & 14286

DIGITAL IMAGE:

MAP:



Asset ID: TX10909
Address: 13275 Tecumseh Rd, Tecumseh
Date: 17-03-08

ANOMALY: SECONDARY CONNECTION
PRIORITY: LOW

INFRARED IMAGE:

IR INFORMATION:

Ambient	10 °C
Bx 1 Temp	16.3 °C
Bx 2 Temp	10.6 °C
ΔTemp	5.7 °C
IR Image(s)	14479, 14480

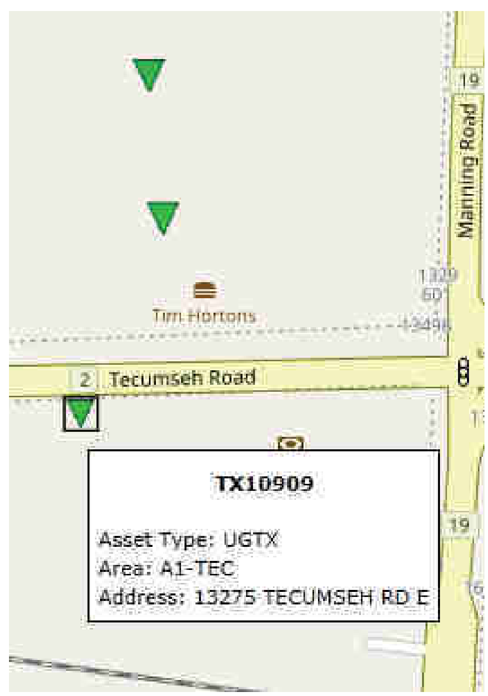
DETAILS:

There was an increase in temperature noted on the bottom right secondary connection. A quantitative comparison between the other secondary connections indicated an issue. The issue is identified by the white arrow in each image.

For another view of the issue, please review IR image # 14481 &14482.

DIGITAL IMAGE:

MAP:



Asset ID: TX10390
Address: 595 Michael Dr, Tecumseh
Date: 17-03-08

ANOMALY: SECONDARY CONNECTION
PRIORITY: LOW

INFRARED IMAGE:

IR INFORMATION:

Ambient	11 °C
Bx 1 Temp	25.9 °C
Sp 1 Temp	13.7 °C
ΔTemp	12.1 °C
IR Image(s)	14509, 14510

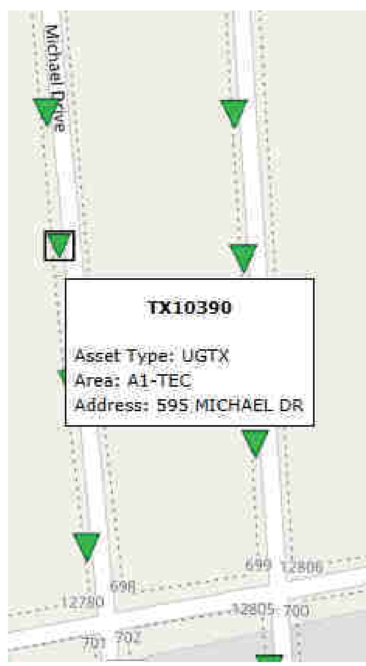
DETAILS:

There was an increase in temperature noted on one of the secondary connections. A quantitative comparison between the other secondary connections indicated an issue. The issue is identified by the white arrow in each image.

For another view of the issue, please review IR image #14507 &14508.

DIGITAL IMAGE:

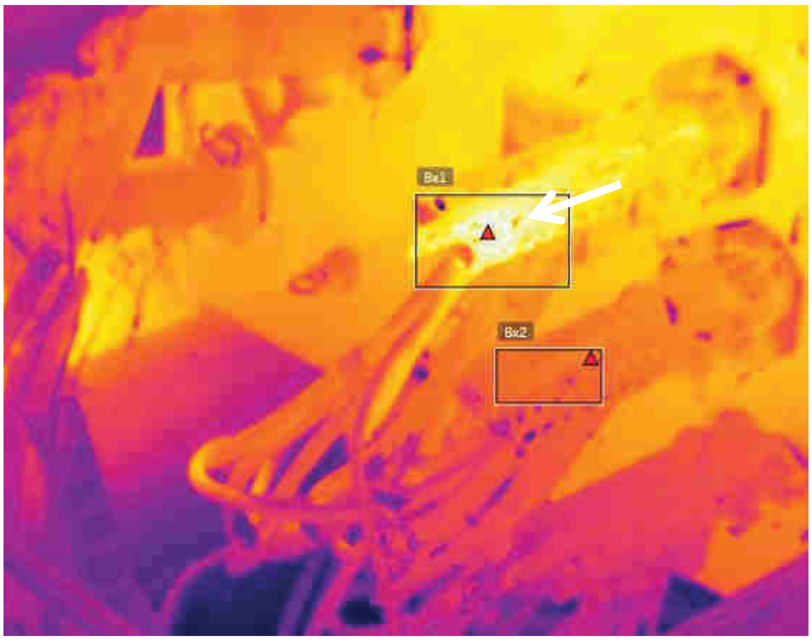
MAP:



Asset ID: TX10389
Address: 555 Michael Dr, Tecumseh
Date: 17-03-08

ANOMALY: SECONDARY CONNECTION
PRIORITY: LOW

INFRARED IMAGE:



IR INFORMATION:

Ambient	11 °C
Bx 1 Temp	23.3 °C
Bx 2 Temp	15.4 °C
ΔTemp	8.0 °C
IR Image(s)	14513,14514

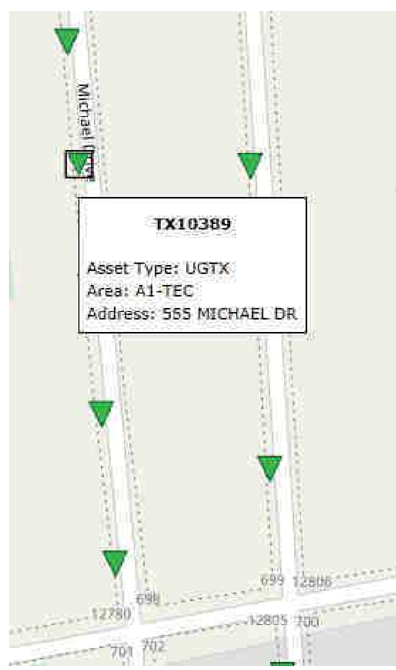
DETAILS:

There was an increase in temperature noted on one of the secondary connections. A quantitative comparison between the other secondary connections indicated an issue. The issue is identified by the white arrow in each image.

For another view of the issue, please review IR image # 14511 & 14512.

DIGITAL IMAGE:

MAP:

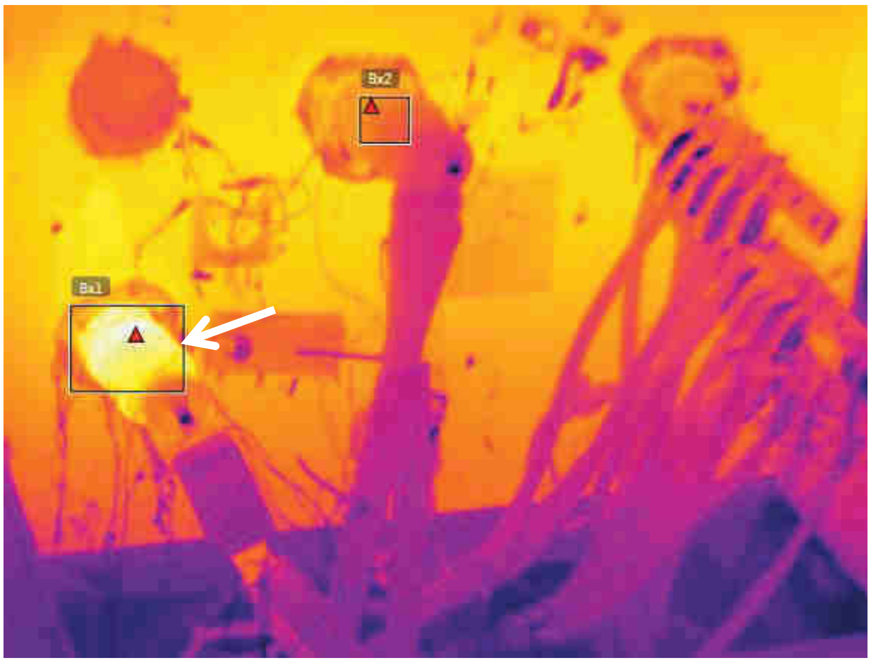


Asset ID:	TX10021
Address:	512 Collier Cres, Tecumseh
Date:	17-03-09

ESSEXENERGY CORPORATION

ANOMALY: HIGH VOLTAGE ELBOW
PRIORITY: LOW

INFRARED IMAGE:



IR INFORMATION:

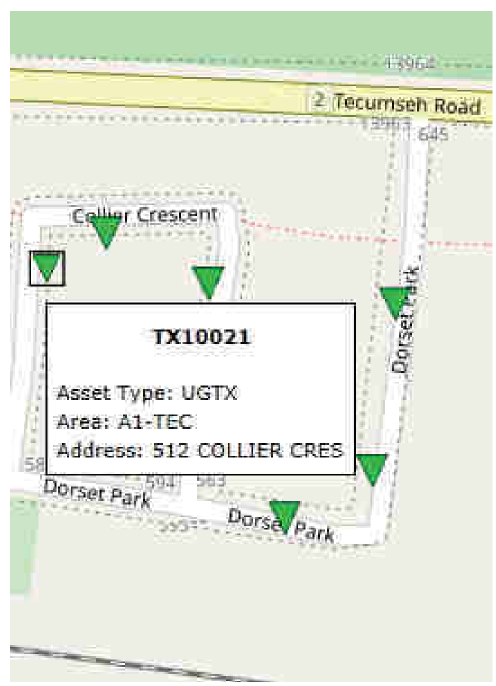
Ambient	4 °C
Bx 1 Temp	27.7 °C
Bx 2 Temp	15.1 °C
ΔTemp	12.6 °C
IR Image(s)	14599, 14600

DETAILS:

There was an increase in temperature noted on the left high voltage elbow. A quantitative comparison with the other high voltage elbow indicated an issue. The issue is identified by the white arrow in each image.

DIGITAL IMAGE:

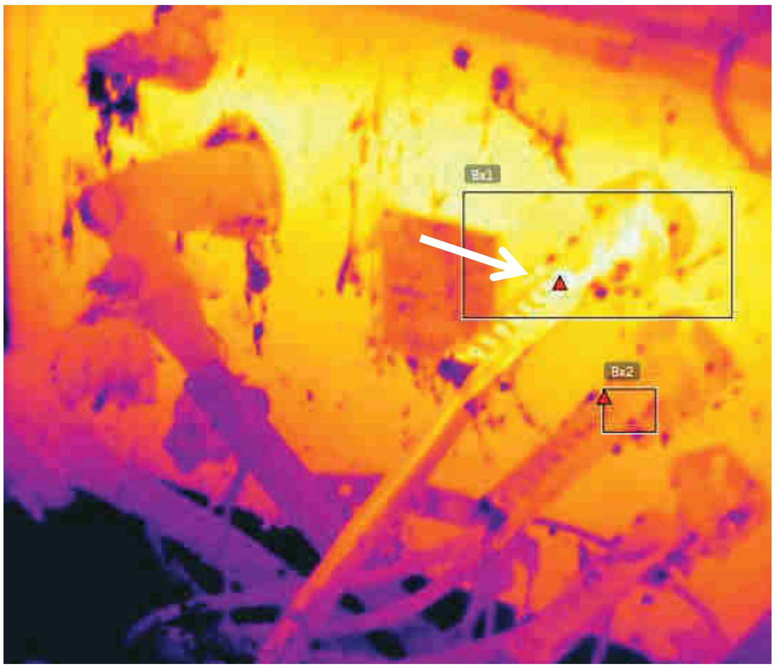
MAP:



Asset ID: TX10404
Address: 260 Clovelly Rd, Tecumseh
Date: 17-03-09

ANOMALY: SECONDARY CONNECTION
PRIORITY: LOW

INFRARED IMAGE:



IR INFORMATION:

Ambient	4 °C
Bx 1 Temp	18.7 °C
Bx 2 Temp	14.4 °C
ΔTemp	4.3 °C
IR Image(s)	14675, 14676

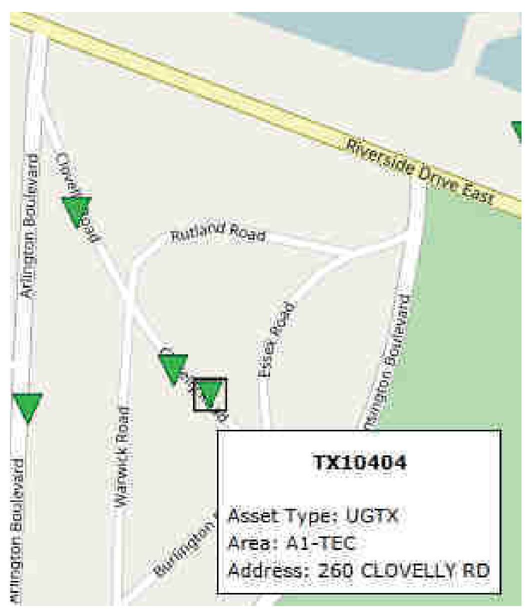
DETAILS:

There was an increase in temperature noted on a secondary connection on the top terminal. A quantitative comparison with another secondary connection indicated an issue. The issue is identified by the white arrow in each image.

For another view of issue, please review IR image # 14677 &14678.

DIGITAL IMAGE:

MAP:

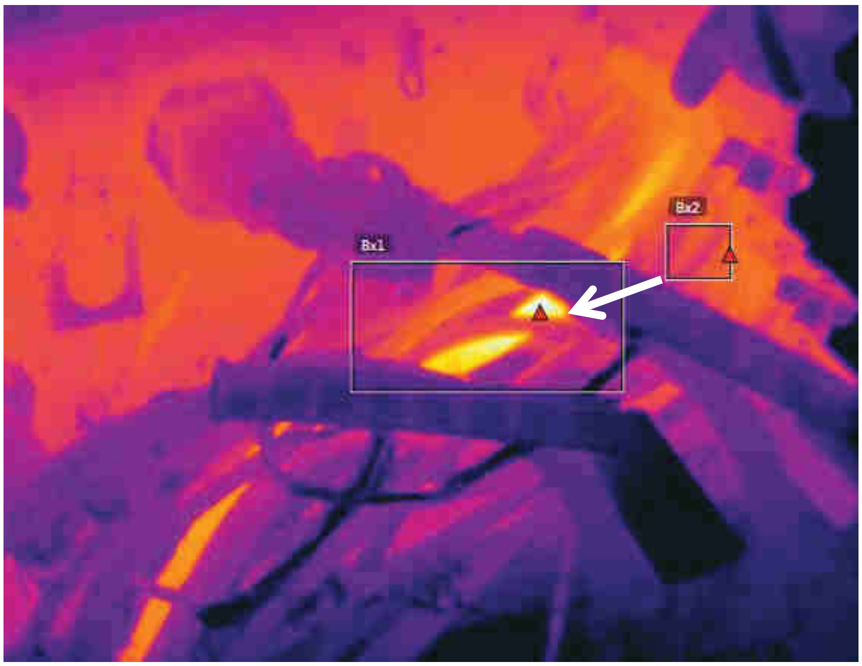


Asset ID:	TX10079
Address:	310 Cada Cres, Tecumseh
Date:	17-03-09

ANOMALY: **SECONDARY WIRE**

PRIORITY: HIGH

INFRARED IMAGE:



IR INFORMATION:

Ambient	4 °C
Bx 1 Temp	107.4°C
Bx 2 Temp	23.9 °C
ΔTemp	83.5 °C
IR Image(s)	14693, 14694

DETAILS:

There was an increase in temperature noted on a secondary wire on the top terminal. A quantitative comparison between the other secondary wires indicated an issue. The issue is identified by the white arrow in each image.

For another view of the issue, please review IR image # 14695, 14696.

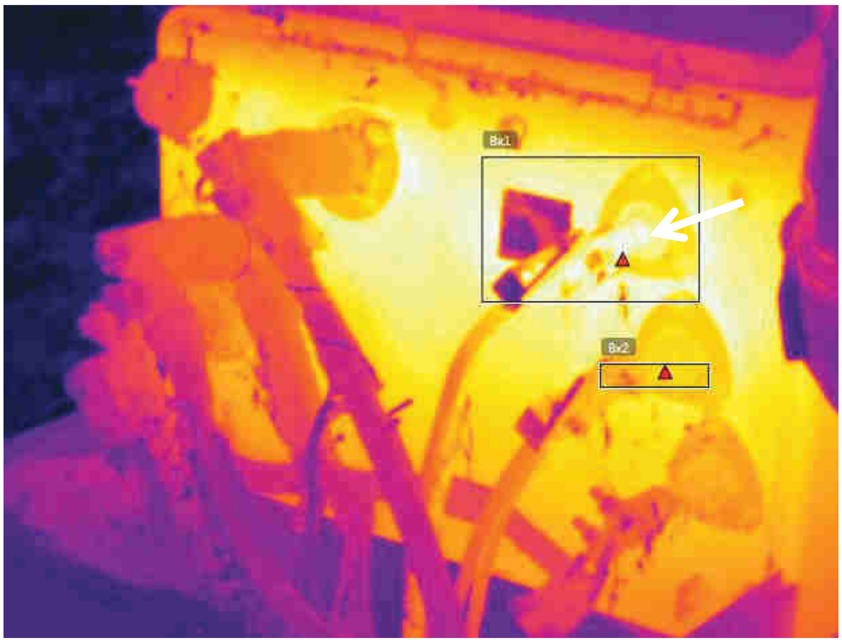
DIGITAL IMAGE:

MAP:

Asset ID: TX10398
Address: 184 Hayes Ave, Tecumseh
Date: 17-03-09

ANOMALY: **SECONDARY BUSHING / TERMINAL**
PRIORITY: LOW

INFRARED IMAGE:



IR INFORMATION:

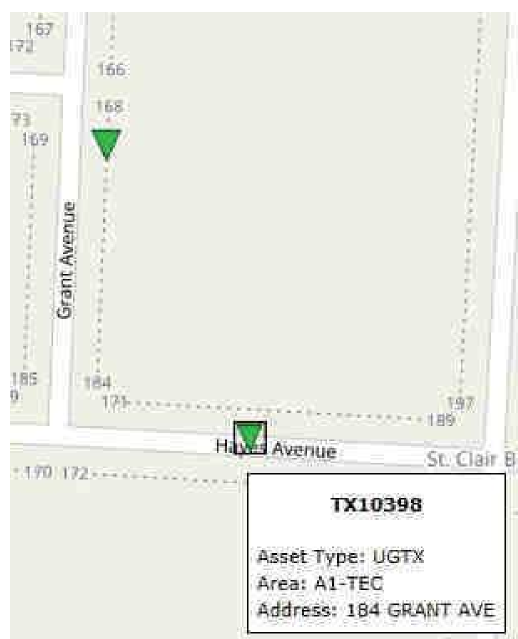
Ambient	3 °C
Bx 1 Temp	25.6 °C
Bx 2 Temp	21.9 °C
ΔTemp	3.7 °C
IR Image(s)	14729,14730

DETAILS:

There was an increase in temperature noted on the top secondary terminal. A qualitative comparison with another secondary terminal indicated an issue. The issue is identified by the white arrow in each image.

DIGITAL IMAGE:

MAP:

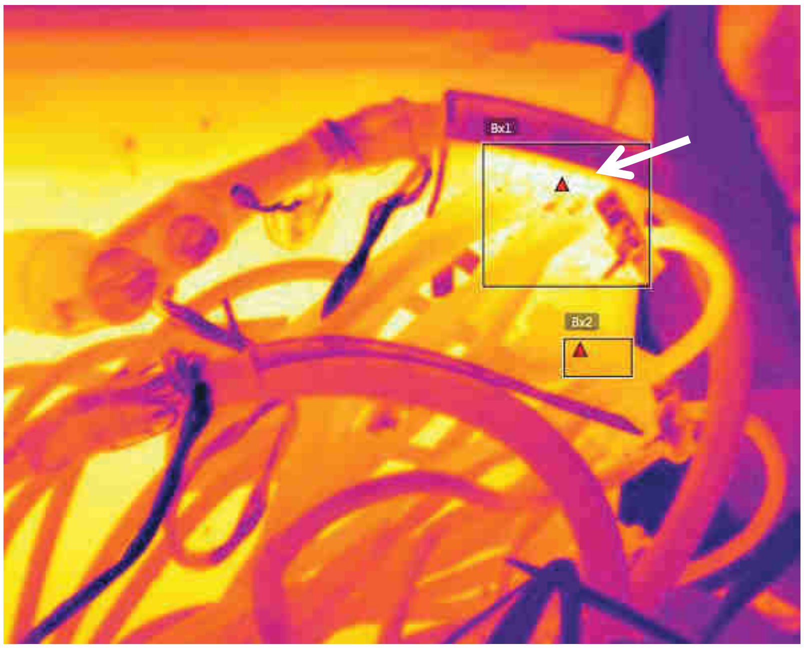


Asset ID:	TX10059	
Address:	160 David Cres, Tecumseh	
Date:	17-03-09	

ANOMALY: **SECONDARY TERMINAL**

PRIORITY: LOW

INFRARED IMAGE:



IR INFORMATION:

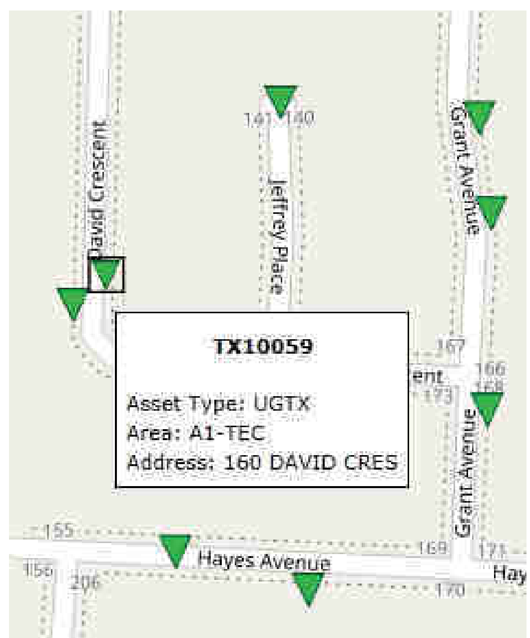
Ambient	5°C
Bx 1 Temp	25.1 °C
Bx 2 Temp	18.8 °C
ΔTemp	6.3 °C
IR Image(s)	14745,14746

DETAILS:

There was an increase in temperature noted on the top secondary terminal. A quantitative comparison with another secondary terminal indicated an issue. The issue is identified by the white arrow in each image.

DIGITAL IMAGE:

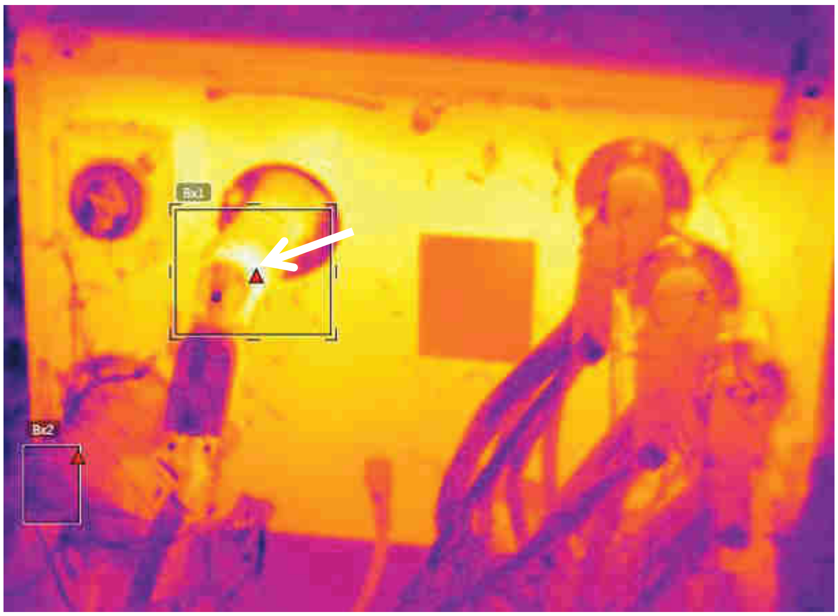
MAP:



Asset ID: TX10016
Address: 503 Harbourne Cres, Tecumseh
Date: 17-03-10

ANOMALY: HIGH VOLTAGE ELBOW
PRIORITY: LOW

INFRARED IMAGE:



IR INFORMATION:

Ambient	1°C
Bx 1 Temp	18.3 °C
Bx 2 Temp	5.7 °C
ΔTemp	12.6 °C
IR Image(s)	14589, 14590

DETAILS:

There was an increase in temperature noted on the top high voltage elbow. A quantitative comparison with the other high voltage elbow indicated an issue. The issue is identified by the white arrow in each image.

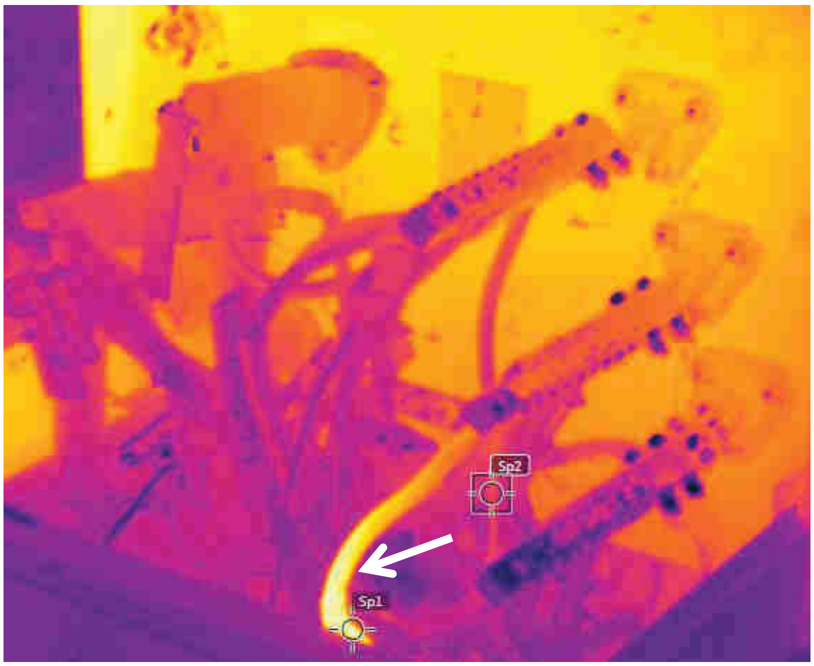
DIGITAL IMAGE:

MAP:

Asset ID:	TX10308
Address:	441 Green Valley Dr, Tecumseh
Date:	17-03-10

ANOMALY: SECONDARY WIRE
PRIORITY: LOW

INFRARED IMAGE:



IR INFORMATION:

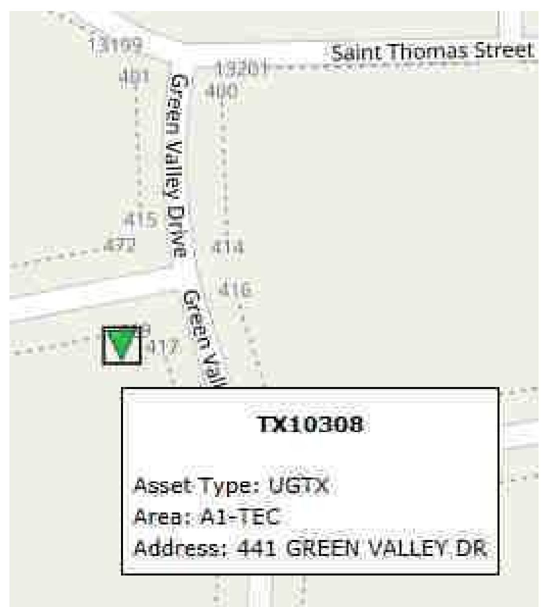
Ambient	1°C
Sp 1 Temp	19.9 °C
Sp 2 Temp	1.8 °C
ΔTemp	18.1 °C
IR Image(s)	14853, 14854

DETAILS:

There was an increase in temperature noted on a secondary wire of the middle terminal. A quantitative comparison between the other secondary wires indicated an issue. The issue is identified by the white arrow in each image.

DIGITAL IMAGE:

MAP:



Appendix H: Building Condition Review

November 3

2730 Highway 3

2016

Revised - Nov 9, 2016

BUILDING CONDITION REPORT

Submission by:
ROAstudio inc.

67 King street
Chatham, Ontario N7M 1C7
www.roastudio.com

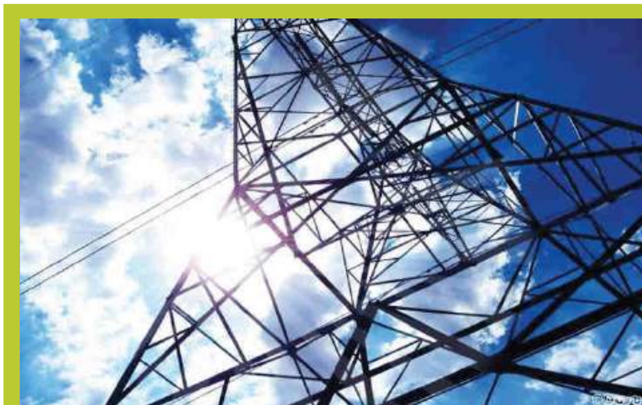
E: info@roastudio.com
P: 519-397-0943
F: 519-480-0645

Submission to:

ESSEX POWERLINES CORPORATION

2730 Highway 3
Oldcastle , Ontario N0R 1L0

INDEX



2730 Highway 3

Building Condition Review

ARCHITECTURE

ROA studio

67 king street, west
Chatham, ON
N7M 1C7

ph. 519.397.0943
fx. 519.480.0645
e. joseph@roastudio.com

CIVIL ENG.

Haddad Morgan & Associates.

24 Sheppard Street East
Windsor, ON
N8X 2J8

ph. 519.973.1177
fx. 519.253.2740
e. haddad@haddadmorgan.com

STRUCTURAL ENG.

Haddad Morgan & Associates.

24 Sheppard Street East
Windsor, ON
N8X 2J8

ph. 519.973.1177
fx. 519.253.2740
e. haddad@haddadmorgan.com

MECHANICAL ENG.

VRM Eng.

7242 colonel talbot road
London, ON
P.O.Box 1149

ph. 519.652.5047
fx. 519.652.5058
e. vr@vrmeng.com

ELECTRICAL ENG.

VRM Eng.

7242 colonel talbot road
London, ON
P.O.Box 1149

ph. 519.652.5047
fx. 519.652.5058
e. vr@vrmeng.com

Executive Summary

ROA Studio Inc, along with associated consultants, was engaged to provide observations and report the physical conditions of the property located at 2730 Highway 3, Oldcastle Ontario. This review addresses item that are significant for the continued operations of the facility in its current usage and occupancy, consistent with comparable properties of similar age.

The report observes the general physical condition of the subject property, material systems and components, and identifies deficiencies and any unusual features or inadequacies.

The consultant team visited the site on various September 7, 2016 and conducted a visual inspection of building systems.

The following building systems were reviewed and the following is our professional opinion of the found condition of the building:

Site	☐ Good	☑ fair	☐ Poor
Building Exterior	☑ Good	☐ fair	☐ Poor
Windows & Doors	☑ Good	☐ fair	☐ Poor
Roofing | Skylight	☐ Good	☑ fair	☐ Poor
Interior finishes	☑ Good	☐ fair	☐ Poor
Structural systems	☑ Good	☐ fair	☐ Poor
Fire Protection	☑ Good	☐ fair	☐ Poor
Plumbing Systems	☑ Good	☐ fair	☐ Poor
Natural Gas	☑ Good	☐ fair	☐ Poor
HVAC	☐ Good	☑ fair	☐ Poor
Electrical Systems	☑ Good	☐ fair	☐ Poor
Lighting Systems	☑ Good	☐ fair	☐ Poor
Fire Alarm System	☑ Good	☐ fair	☐ Poor
Security Systems	☑ Good	☐ fair	☐ Poor
Works Garage	☑ Good	☐ fair	☐ Poor

Opinions of Probable Costs

These opinions of probable costs are to assist the client in developing a general understanding of the physical condition of the subject property.

The following summarizes the cost per building systems.

Site ....$	477,000.00
Building Exterior.......................................$	3,000.00
Windows & Doors ....$	14,500.00
Roofing | Skylights..................................$	229,000.00*
Interior finishes...$	4,000.00
Structural Systems ....$	10,000.00
Fire Protection..$	0.00
Plumbing Systems ....$	0.00
Natural Gas Systems...............................$	1,000.00
HVAC......... ....$	18,000.00
Electrical Systems ....$	1,000.00
Lighting Systems.....................................$	0.00
Fire Alarm Systems..................................$	0.00
Security Systems....................................$	0.00
Works Garage..$	0.00
Total..................................$	757,500.00

*Refer to report, Roof Replacement of 220,000.00 will be required in 5 to 7 years.

The following summaries the cost for floor drains in the works garage:

Floor Drains..$ 75,000.00

Opinions of probable costs should only be construed as preliminary budgets.

SECTION 1 PROJECT DETAILS

1.1 Purpose

ROA Studio I nc, along with associated consultants, were engaged to provide observations and report the physical conditions of the property located at 2730 Highway 3, Oldcastle Ontario. This review addresses item that are significant for the continued operations of the facility in its current usage and occupancy, consistent with comparable properties of similar age. The intent of this report is to determine anticipated capitol and maintenance cost over a five (5) to ten (10) year period. All inspections were non-destructive and based on visual inspections of representative portions of the various systems. This report should not be considered a guarantee or warranty of any kind. Unexpected repairs should still be anticipated.

1.2 Scope of Work

Observe the general physical condition of the subject property, observe material systems and components, and identify deficiencies and any unusual features or inadequacies observed by conducting specific or representative observations, as appropriate. Visually inspect the building systems based on representative samples to be review include but not limited to:

Site - Asphalt Paving, Concrete Curbing and sidewalks, Parking and exterior egress. Conduct a site inspection related to the existing servicing infrastructure and trench drain system. Determine possible causes of sewer back-ups into trench drain system and offer possible solutions to correct existing problems.

Building Envelope - facades and curtain wall system, glazing system, exterior sealants, exterior loading docks, doors, stairways, etc.

Roofing - Identify and observe the roof systems (exposed membrane and flashings) including, parapets, slope, drainage, etc. Observe for evidence and/or the need for material repairs, evidence of significant ponding, or evidence of roof leaks.

Interior Elements - common areas including, but not limited to, lobbies, corridors, assembly areas, offices and restrooms. Identify and observe typical finishes for flooring, ceilings, and walls.

Structural Systems - Perform structural design spot checks. Observe the building substructure, building's superstructure and structural framing (floor framing system).

Mechanical Systems - Heating, ventilating and air conditioning systems, plumbing fixtures, exhaust systems and other mechanical systems.

Electrical Systems - Main electrical service, electrical panels, emergency lighting, fire alarm systems and emergency power systems.

Written Report - Subsequent to the visual inspection, prepare a comprehensive list of deficiencies and provide photo evidence of such deficiencies. A estimated budget cost to be associated with any corrective work required over a 5-10 year period.

Opinions of Probable Costs - are to be prepared for the suggested remedy of the material physical deficiencies observed. These opinions of probable costs are to assist the client in developing a general understanding of the physical condition of the subject property.

Opinions of probable costs are provided for material physical deficiencies and not for repairs or improvements that could be classified as: (1) cosmetic or decorative; (2) part or parcel of a building renovation program or tenant improvements/finishes; (3) enhancements to reposition the subject property in the marketplace; (4) for warranty transfer purposes; or a combination thereof.

Opinions of probable costs should only be construed as preliminary budgets. Actual costs may vary from the consultant's opinions of probable costs depending on such matters as type and design of suggested remedy, quality of materials and installation, manufacturer and type of equipment or system selected, field conditions, whether a physical deficiency is repaired or replaced in whole, phasing of the work (if applicable), quality of contractor, quality of project management exercised, market conditions, and whether competitive pricing is solicited.

1.3 Exclusions to Scope of Work

Providing an environmental assessment or opinion on the presence of any environmental issues such as asbestos, hazardous wastes, toxic materials, the location and presence of designated substances or mould.

Preparing engineering calculations (civil, structural, mechanical, electrical, etc.) to determine any system's, component's, or equipment's adequacy or compliance with any specific or commonly accepted design requirements or preparing designs or specifications to remedy any physical deficiency.

1.4 Conventions Used in this Report

GOOD - Indicates the component is functionally consistent with its original purpose but may show signs of normal wear and tear and deterioration.

FAIR - Indicates the component will probably require repair or replacement anytime within five years.

POOR - Indicates the component will need repair or replacement now or in the very near future.

MAJOR CONCERNS - A system or component that is considered significantly deficient or is unsafe and in need of prompt attention.

1.5 Documents Provided

The documents made available to the consultants by Essex Powerlines to assist in the preparations of this report are as follows:

- Architectural Drawings by Sfera Architectural Associates Inc. dated March 16, 2012

1.6 Interview of Associated Persons

At various time through during the site visit on September 7, 2015. Mr. Brandon Chartier was made available to provide information regarding history of work on premises.

1.7 Project Site & Building History

The project site is located on the North side of Highway 3 in Oldcastle, Ontario. The site neighbors teh Chrysler Greenway to the east and agricultural land to west. The site has three (2) main structures, the main office facility, and works garage.

The Main Office building is a partial 2 storey facility and has been added numerous time. The facility was converted from the old Tecumseh fire hall. Major renovations were completed in 2012 along with the construction of the Works garage. The training room was renovated in 2016.

1.8 Building Description | Data

Main Office

- First floor contains admin space, warehouse space and staff areas
- Second floor contains Administrative office areas
- The facility is constructed of masonry load bearing walls and structural steel roof system.

Building Areas

Main Floor	1,365 m²
Second Floor	400 m²
Total	1,765 m²

OBC Classification

Group D - Office

Group F Division 3 Warehouse

Works Garage

- Constructed in 2012
- 1 single storey, slab on grade construction containing truck storage garage. The facility was constructed as a Pre-Eng building with concrete block infill.

Building Areas

Total 618 m2

OBC Classification

Group F Division 2 - Garage

1.9 Site Survey Date & Conditions.

ROA Studio, along with consultants, visited the site on September 7, 2016. Temperatures ranged from 32°C as a high to 23°C. While on site, it was mostly sunny skies.

SECTION 2 BUILDING SURVEY

2.1.1 Site

Description
This section will review the exterior site work including sidewalks, pavement, drainage, and parking systems in general.

Sidewalks	☑	Good	☐	fair	☐	Poor
Asphalt pavement Front	☐	Good	☐	fair	☑	Poor
Asphalt pavement Back Lot	☑	Good	☐	fair	☐	Poor
Curbing	☐	Good	☑	fair	☐	Poor
Drainage	☐	Good	☐	fair	☑	Poor

General Comments
The overall site condition was reviewed to the south of the building (front parking lot) and along the north of the building to the edge of the asphalt within the service yard. A review of the pavement around the pre-engineered storage building was also undertaken. The current configuration provides parking for staff and visitors to the south of the building with a driveway access extending to Highway 3 to the north. Currently, this parking area is abutted on most sides by concrete curb, changing to parking bumpers along the easterly limit. Extending to the north, along the west side of the building is a service access way (paved) which provides gated access to the rear (north) service yard. Within the service yard, asphalt pavement is provided around the pre-engineered storage building and for a distance to the north of the main administration building. Areas north of the edge of the asphalt are granular and were not evaluated

Specific to the south parking lot (front of building), the current pavement structure is viewed as being at the extent of its service life. The current pavement is cracked significantly with the presence of vegetation growing up between these cracks. Where present, the existing catch basin system has settled. With regard to the curbs, several cracks and areas of damage were identified. While not at a point that mandates full replacement at this time, consideration should be given to their replacement during re-pavement especially if consideration is given to upgrading the storm water management system.

With regard to the sidewalks along the front (south) of the building, while limited in overall footprint the only notable issue related to its separation from the pavement could be addressed during asphalt work.

In reviewing the paved area to the north of the building, its overall condition is poor. At some point during its service life a trench has been cut into the pavement along the east edge. This repair appears to be extending to a pump chamber. Much like the front parking area, the pavement is cracked and in need of full replacement. It is important to note a settled catch basin in the south-east corner of this service parking area. This catch basin has settled to such a point it now possess a fall/tripping risk due to its sudden elevation change.

Recommendations | Observations

- It is recommended that all asphalt pavements (north and South) be removed inclusive of the granular layer and reconstructed to ensure maximum design life.
- It is recommended that the site drainage be upgraded to ensure maximum longevity of the pavement structure
- Should the storm water management strategy require the curb, it can be replaced, otherwise local repairs should be made during any new construction activities.

Opinion of Probable Cost
Allow $397,000 for Pavement Replacement
Allow $65,000 for storm water system upgrades
Allow $15,000 for local curb repair

Images

Catch Basin
Location: South Parking Area

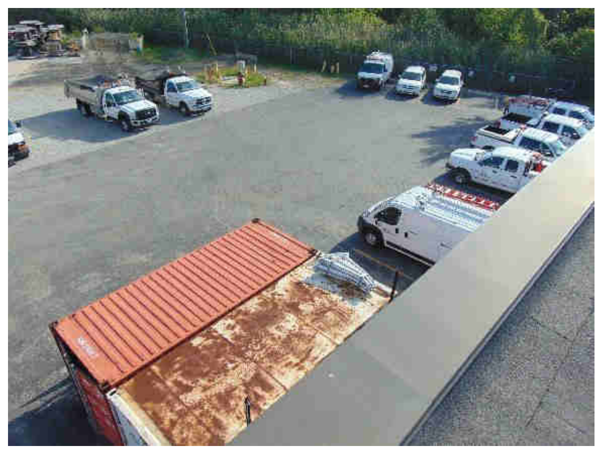
Asphalt to Sidewalk interface
Location: Main Entrance

Images

Catch Basin Settlement
Location: North Service Area

View of South-West Parking Lot

View of South-East Parking Lot



North Service Area facing East

2.2.1 Building Exterior

Description
This section reviews the exterior cladding including wall coverings, eaves, soffits and flashings.

Masonry Block	☐ Good	☑ fair	☐ Poor
Pre-fin Metal Siding	☐ Good	☑ fair	☐ Poor
EIFS	☑ Good	☐ fair	☐ Poor
Sealants & Caulking	☑ Good	☐ fair	☐ Poor
Works Garage	☑ Good	☐ fair	☐ Poor

General Comments
The exterior of the building is in generally good condition. Area of concern is along the west and south facade where there appears to be moisture in the masonry units. Recommendation would be to clean and monitor block for suture discoloring. The pre-fin metal siding is in fair condition. The Exterior Insulation Finish System (EIFS) is in good condition with no visible signs of damage. The works Garage is in good condition.

Recommendations | Observations
- Possible moisture intrusion into the masonry block in various locations.
- Asphalt is paved above Metal Siding
- Grade is above Metal Siding,
- A penetration is not sealed in Storage room (Interior side)

Opinion of Probable Cost

Allow $3,000 to clean and monitor Masonry Block

Images

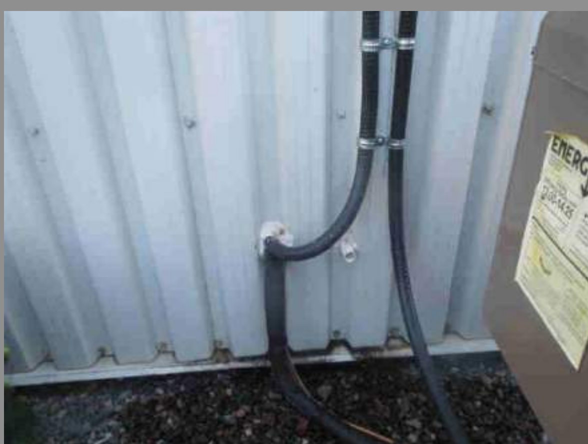
Monitor: Possible moisture intrusion
Location: Front Entrance

Monitor: Possible moisture intrusion
Location: Southwest Wall

Sample: Metal Siding, EFIS and Masonry Facade
Location: Looking at Main Entrance

Images

Repair: Abandoned penetration not sealed
Location: Inventory Storage Room



Repair: Penetrations Sealed at HVAC Equipment
Location: West Wall

Repair: Minor holes in Masonry
Location: West Wall

Sample: South Façade, EFIS and Masonry
Location: South Facade

Sample: Caulking at Metal Siding | Masonry
Location: West Wall

Sample Metal Siding
Location: West Wall

Images

Sample: EFIS and Masonry Joint
Location: Main Entrance

Sample: Masonry Pier | Sidewalk
Location: South Wall

Sample: EFIS in good condition
Location: South Wall

Sample: EFIS in good condition
Location: South Wall

Sample: EFIS in good condition
Location: South Wall

Sample: EFIS in good condition
Location: South Wall

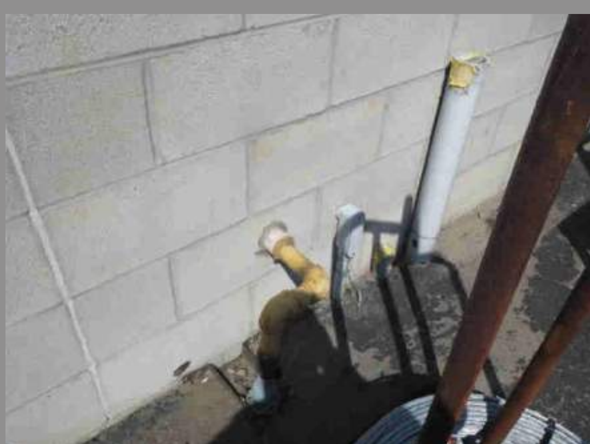
Images

Repair: Grade over Metal Siding
Location: Outside Training Room

Repair: Asphalt over Metal Siding
Location: outside Meter Shop

Front View of Works Garage
Location: Works Garage

Sample: Siding in good Condition
Location: Works Garage



Sample: Penetration sealed
Location: Works Garage

Sample: Conc. Block, Louver
Location: Works Garage

2.2.2 Windows | Exterior Doors

Description
This section reviews current state of the windows and doors in the buildings. This includes a visual inspection of the frames, sealing, glazing and hardware.

Window Frames	☑ Good	☐ fair	☐ Poor
Glazing	☑ Good	☐ fair	☐ Poor
Door & Frames	☑ Good	☐ fair	☐ Poor
Over Head Door & Frames	☐ Good	☑ fair	☐ Poor
Sealants | caulking	☐ Good	☑ fair	☐ Poor

General Comments
The main building has all new aluminum frames and glazing. The majority of the frames and thermal units were installed in 2012 and most recently 2016 in the Training room. The frames and glazing are generally in good condition. 2 window's gaskets are failing on the west wall (in a Private offices) and a window in a second floor office show water damage.

The Exterior doors are a mix of hollow metal and aluminum entrance framing. The shipping and receiving door on the west wall has damaged weatherstripping and does not close properly. Weatherstripping should be replaced. The frames at Stair No. 3 and Stair to gym are starting to rust at the bottom frame.

The Overhead doors were installed about 20 years ago however are in fair working order and condition. There is minor rusting on the steel frame at the inventory storage door. Regular maintenance is recommended to extend the life of the doors.

The Caulking in and sealants are in fair shape. The caulking at the southwest corner windows has or starting to fail. There is no caulking around the employee entrance door.

Recommendations | Observations
- Overhead Door Jamb rusting - monitor.
- Door Frames rusting on north wall. Items consider in poor condition.
- Shipping | Receiving weatherstripping damaged.
- 2 Window units need gaskets repaired | replaced
- 1 Window on Second floor shows signs of leaking
- Sealant | caulking around doors & windows starting to deteriorate.
- Works Garage Metal Frames are not sized for Opening. Potential for water infiltration – Monitor.

Opinion of Probable Cost
Allow $6,000 for new caulking | sealants
Allow $8,500 for new door and frames and new weatherstriping

Images


Repair: Caulking failing
Location: Southwest Wall


Repair: Gasket Failing and lintel rusting
Location: west Wall


Repair: Window Leaking
Location: Second Floor Office

Images

Sample: Window and Caulking in Good shape
Location: Southwest Wall

Sample: New window at Training Room
Location: New Training Room

Sample: Window and Flashing in good condition
Location: west Wall of Main Building

Repair: Weatherstripping Damaged
Location: Shipping & Receiving

Repair: Weatherstripping missing
Location: Shipping & Receiving

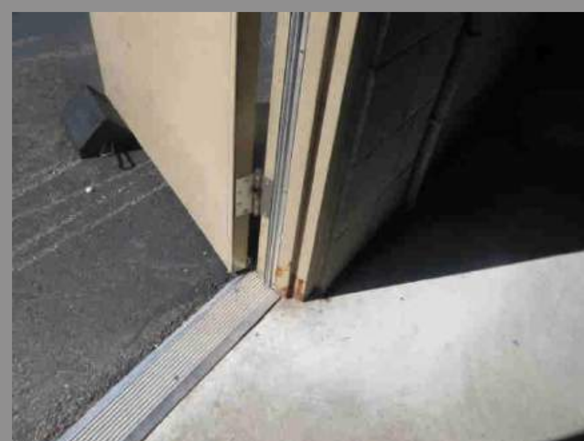
Repair: No Caulking around door frame
Location: Employee Entrance

Images

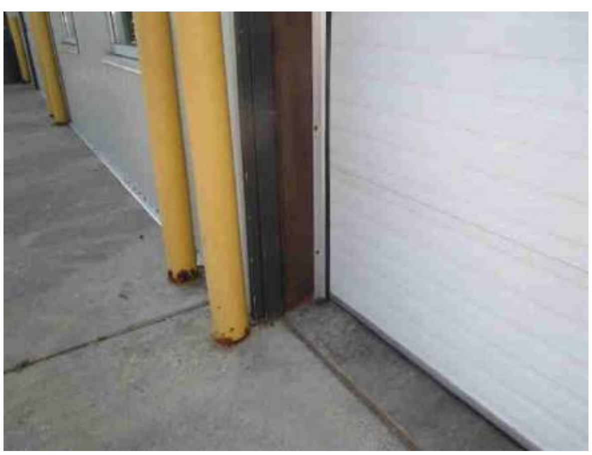
Repair: Door Frame starting to rust
Location: Stair No 3

Repair: Door Frame starting to rust
Location: Stair by Gym

Repair: Frame does not suit masonry opening
Location: Works Garage



Repair: Door Frame rusting – frame does not fit masonry opening
Location: Works Garage



Repair: Rust at overhead doors
Location: Inventory door (No. 5)

Weatherstripping in good condition
Location: Works Garage

2.2.3 Roofing | Skylights

Description
This section reviews current state of roofing including the roofing material, parapets and drainage.

	Good	fair	Poor
Mod-Bit Roof	☐	☑	☐
Roof Hatch	☐	☐	☑
Parapets	☑	☐	☐
Roof Drains	☑	☐	☐
Skylights	☐	☑	☐

General Comments - Main Office

The roof system is a mob-bit roofing membrane. The roof is in fair condition with some cracking of the top surface starting to show. The roof has a few areas where there it is starting to bubble. The roof may need to be replaced in the next 5 to 7 years. The roof hatch is in poor condition at requires immediate attention. The original roof hatch was damaged and a makeshift cover was installed without proper handle and opening | hold open hardware. This is a safety concern. The parapets are in good condition with no signs of leaking or damage. The roof drains are in good working order. The skylights are older but do not show signs of leaking. Flashing of high wall showing oxidization, requires painting or to be replaced.

Recommendations | Observations
- Roof membrane showing age | cracks
- Roof Drains clear and appear working
- Few visual sign of leaks in building. Staff indicated no roof leaks present.
- Skylights did not show evidence of leaking.
- Counter flashing at High wall starting to rust

General Comments - Works Garage

The roof of the works garage addition was inaccessible, visually inspected from Main Office. Sloped Steel roof in good condition.

Opinion of Probable Cost

<u>Immediate Actions</u>

New roof Hatch	$5,000.00
Paint | Replace Flashing at High Wall	$4,000.00

<u>Within 5-7 years</u>

New roof	$220,000.00

Images

Roof Hatch
Location: Over second Storey Office

Roof starting to Bubble
Location: One Storey Office Area - By Training Room

Roof inFair Condition – Cracking on surface
Location: Over Second Floor Office

Images

Roof Drain Clear – Small Ponding
Location: Over Second Floor Office

Exhaust fan c\w new seals on curbing
Location: Over First Floor Office Area

Rusted Counter Flashing at High Wall Transition
Location: At Meter Shop – Office

Roof Drain Clear – small ponding
Location: Over Meter Bay

Skylight
Location: Over Second Floor Office

Pitched metal roof
Location: Works Garage

2.3.1 Interior Finishes

Description
This section reviews the current state of interior finishes including ceilings, walls, flooring and interior doors.

	Good	fair	Poor
Flooring	☑	☐	☐
Ceilings	☐	☑	☐
Doors	☑	☐	☐
Walls	☑	☐	☐

General Comments - Main Office

As an overview, the interior finishes of the building are in good condition. The office space has been renovated throughout the building approximately 4 years ago. The flooring is a carpet, and sheet flooring for the office, concrete for the warehouse and ceramic tile in the washrooms. The walls consist stud partitions and some demountable walls in the office areas while the warehouse space is concrete block. The floors are relatively level and the walls are relatively plumb. The ceilings are comprised of suspended acoustical ceiling systems with some minor staining. The doors are in good condition and the barrier free door operators are in working condition. Office Washrooms have been renovated in the past few year and are in good condition. The shower room ceiling is paint on precast concrete planks, the paint is peeling significantly in this area.

The interior finishes of the works garage are in good condition.

Recommendations | Observations
- Finishes are in good condition (recently renovated)
- Some Ceiling tiles to be replaced due to water damage
- Monitor for Roof Leaks at Damaged Ceiling Tiles
- Ceiling paint in Men's Change Room and Shower in poor condition
- Penetrations in Mechanical room not Fire Caulked
- Works Garage in good Condition

Opinion of Probable Cost
Allow $500 for ceiling Tile Replacement
Allow $3000 to scrape and paint change room | shower ceiling
Allow $500 for misc Fire Caulking

Images

Sample: Doors, Walls and carpet in good condition
Location: Front Open Office

Door Operator In working Condition
Location: Customer Entrance

Penetration not fire caulked.
Location: Mechanical Room

Images

Sample: Flooring, Walls, in good condition
Location: Reception

Sample: Floor transition in good condition
Location: First Floor Open Office

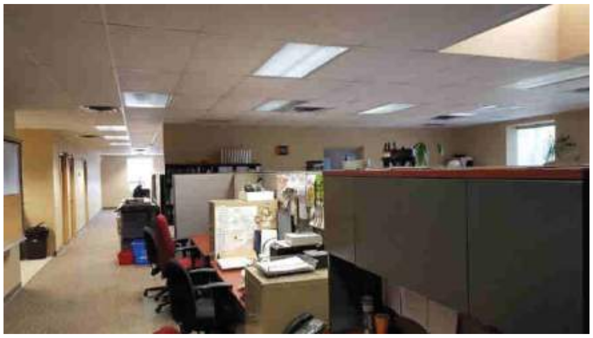
Sample: Demountable partition in good condition.
Location: Second Floor Office

Sample: Floor level Transition
Location: Stair No. 1

Sample: flooring in good condition
Location: First Floor Open Office Area

Sample: Block Walls and Concrete floor in good condition.
Location: Stores

Images



Sample: Interior Finishes in good condition
Location: Second Floor Office Area

Sample: Interior Finishes in good condition
Location: Second Floor Office Area

Ceiling tiles water damage
Location: Office Space

Sample: Ceiling tiles water damage
Location: 1 storey First Floor

Concrete slab in good condition
Location: Truck Bay

Sample- Cleanout missing cap – trip hazard
Location: First Floor Kitchen

Images

Partition Damaged due to plumbing repair
Location: Office -Men's Washroom

Repair: Water damaged ceiling tiles
Location: Second Floor

Repair: Paint peeling
Location: Men's Shower | Change Room

Repair: Paint peeling
Location: Men's Shower | Change Room

Sample- Ceiling tile damaged (condensation from HVAC Equipment)
Location: Second Floor Communication Room

Sample: Interior
Location: Works Garage

2.4.1 Structural Elements

Description
This section will review the overall structural condition of the building based on a visual inspection

Framing Elements	☑	Good	☐	fair	☐	Poor
Masonry	☐	Good	☑	fair	☐	Poor
Exterior Facade	☑	Good	☐	fair	☐	Poor
Misc Metals	☐	Good	☑	fair	☐	Poor
Decking	☑	Good	☐	fair	☐	Poor

General Comments - Main Office

The current site contains two buildings which were reviewed, specifically the main building (administration) and a detached pre-engineered storage building to the west of the main building. The following will outline the observations made for each building.

While reviewing the pre-engineered building, it was noted that this building is relatively new in its construction and does not exhibit any structural defects. It was noted that there is no floor drainage which could allow for winter time icing which could damage the concrete surface.

The main administrative building is made up of various phases of construction. In general each phase demonstrates itself to be in good to fair condition. Only minor issues in general were observed overall while touring this building. The construction of the building was a combination of masonry, steel and precast systems to form the single storey and the two storey portion to the building. Each of the main gravity and lateral loading components appeared to be in good condition with no visible signs of distress.

The Works Garage was in good condition.

While touring the administrative building the following minor defects were observed:

- Various hairline cracks were observed within the masonry joints.
- Within the north stairwell to the second floor area it was noted that the masonry wall (west) has sheared likely due to the movement of the roof diaphragm. The specific cause of this appears to be during construction the masonry was placed tight to the roof framing preventing free movement.
- At the second floor landing of the north stairwell the concrete fill at the precast core has broken free and can be freely moved by hand.
- Roof ladders have signs of rusting on their connection to the building structure.
- Within the maintenance bay at the north end of the building a chain fall has been secured to the center roof beam. There is no markings or signage on the beam to indicate that it has been rated for this additional load.
- Within the storage area located at the north end of the building, interior masonry walls extended from the second floor to the roof within the high bay area of the storage area appear to be missing any form of lateral connection to the roof deck.
- Around the exterior of the building, various cracks in the masonry façade were observed.
- At the second floor mezzanine, a door opens to the service garage area. Currently on the garage side wood framing is used to create a railing system to prevent falls. However, in its current condition it is unable to support the loads required of a guard.

Recommendations and Observations

- It is recommended that all existing cracks in the masonry, inclusive of those in the façade be monitored on a regular basis. Should the cracks worsen, a licensed Professional Engineer should re-evaluate the condition and recommend any repairs deemed appropriate.
- All roof ladders should be painted as part of the maintenance protocol for the building to ensure longevity.
- The crack in the wall at the north stairwell should be remediated immediately, with mortar around the cross-bracing and joist being cut back to avoid reoccurrence.
- The loose fill in the hollow core plank at the north stairwell should be removed and replaced with new when maintenance staff can address this issue.
- A detailed review of the lateral connection of all walls should be undertaken with use of lifts as required to access the areas noted.
- The railing system present at the mezzanine doors should be replaced with a system able to carry the loads or the doors should be permanently sealed.
- The chain fall in the service garage should be removed until the beam is analyzed and certified by a licensed Professional Engineer for the additional load.

Opinion of Probable Cost
Allow $10,000 Engineering Services
Note: Miscellaneous repairs per maintenance staff value undefined.

Images

Cracking in Exterior Facade
Location: South Wall

Cracking in Wall
Location: North Stairwell

Possible Lateral stability issue
Location: Storage Area

Cracking in Wall
Location: North Stairwell

Typical Roof Ladder
Location: Roof

2.5.1 Fire Protection

Description
This section reviews Fire Protection related systems, including sprinkler, standpipe and fire extinguishers.

Fire Extinguishers ☑ Good ☐ fair ☐ Poor

General Comments - Main Office

The building is not sprinklered nor does it have a standpipe system with fire hose cabinets.

There are fire extinguishers installed throughout the building. Fire extinguishers are ABC dry chemical type, 10lb and are well marked and appropriate for the areas they serve. Inspection tags were attached to each extinguisher.

Recommendations | Observations
No Comment

Opinion of Probable Cost
No Comment

2.5.2 Plumbing - General

Description
This section reviews general plumbing systems including plumbing fixtures.

Plumbing Systems ☑ Good ☐ fair ☐ Poor

General Comments

The existing plumbing systems appear to be in good condition reflective of the age of the building. The water distribution is primarily copper with some PEX piping added recently to service a new sink in the Board Room.

There is a variety of plumbing fixtures throughout the building and appear in good condition. Water closets are floor mounted, tank type, urinals are wall mounted flush valve type.

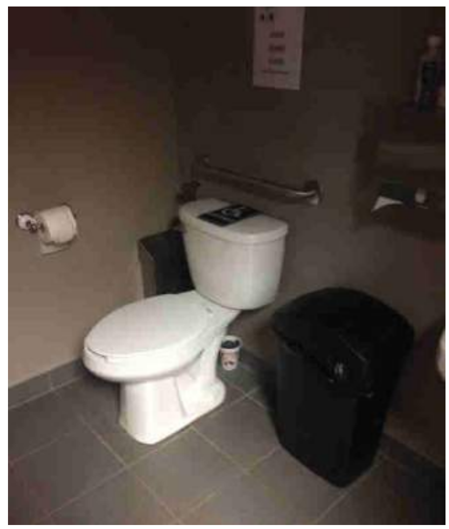
The lavatories are wall or counter mounted and there are counter mounted stainless steel sinks in local kitchenettes.

Recommendations | Observations
- The fixtures are not low flow consumption nor are they accessible for barrier free standards.
- Hot and cold water line are insulated and some minor repairs to insulation is recommended.
- The plumbing systems are in good working condition.

Opinion of Probable Cost
No Comment

Images

Images



2.5.3 Plumbing | Domestic Water

Description
This section reviews Domestic Water related systems, including Domestic Cold Water, Domestic Hot Water and Domestic Hot Water Re-Circulation systems.

Dom. Cold Water	☑ Good	☐ fair	☐ Poor
Dom. Hot Water	☑ Good	☐ fair	☐ Poor
Dom. HW Re-Circ	☑ Good	☐ fair	☐ Poor

General Comments - Main Office

Incoming water service is 1-¼" diameter and enters the building at the Mechanical/Electrical Room.

The 1-1/4" service is complete with shutoff valve, water meter and backflow preventer.

Water is distributed to the hot water heater, plumbing fixtures and hose bibbs.
Cold water is extended to the separate Garage Building. Water piping throughout the building is copper with one fixture served by PEX piping. Water piping has a life expectancy of 35 to 40 years.

Domestic hot water supply is provided by a conventional gas fired hot water heater which appears to have been in service for some time. The heater is A.O. Smith Model BTR-120 with 71 gallons of storage.

Recommendations | Observations

- The water heater may require replacing in the next two to four years.

Opinion of Probable Cost
No Comment

2.5.4 Sanitary Drainage System

Description
This section reviews Sanitary Drainage systems

Sanitary System	☑ Good	☐ fair	☐ Poor

General Comments - Main Office

Sanitary and vent piping is a mix of cast iron, copper & small portions of PVC piping. It appears to be mainly original piping with small amounts of new piping in areas where washrooms were renovated and where new fixtures have been added. Sanitary systems appear to be gravity fed with a sanitary lift pump serving new sink in training room.

Underground sanitary piping condition is hard to evaluate. Typically, an estimate of 35-40 year replacement life is found to be acceptable with buildings of this type. Through our discussions with the maintenance staff it appears there has not been any reported back-ups in the system.

Original building included a septic system and this has been replaced by connection to municipal sanitary sewer. It is unclear were the sanitary leaves the building or the size of the piping.

Recommendations | Observations
No Comment

Opinion of Probable Cost
No Comment

Images

2.5.5 Storm Drainage System

Description
This section reviews Storm Drainage systems

Storm Systems ☑ Good ☐ fair ☐ Poor

General Comments - Main Office

The building is primarily drained with the use of roof drains and scuppers which are piped to rain water leader inside the building. The storm piping is mostly concealed so condition could not be assessed.

The storm water from office area is discharged to underground storage tank and is pumped to nearby creek.

Maintenance staff report that this is in good working order.

Recommendations | Observations
No Comment

Opinion of Probable Cost
No Comment

2.5.6 Gas Service

Description
This section reviews Gas Service and distribution.

Gas Systems ☑ Good ☐ fair ☐ Poor

General Comments - Main Office

The building is provided with an outdoor gas pressure regulating station with gas meter which is located on the South-East corner of the building adjacent to Highway 3. Pressure is currently being reduced down to 7" to 14 W.C. and is distributed with dedicated branch lines to the mechanical room and to the roof.

Three gas lines rise from the manifold to the roof of the building where the distribution piping is located.

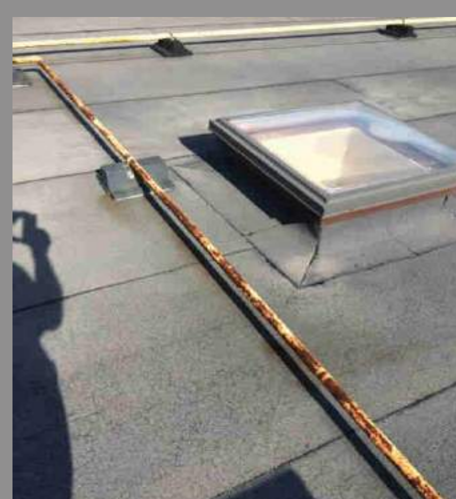
Gas piping is either threaded or welded depending on the pipe size.
Gas is distributed to all roof mounted HVAC units, water heater, gas fired unit heaters located inside the building. In addition to the original piping system a newer dedicated gas line feeds the new garage building.

In general, the original gas piping has come deterioration of the yellow paint identification.

Recommendations | Observations
- Paint gas piping

Opinion of Probable Cost
Allow $1,000.00 for gas line painting

Images



2.6.1 Heating Ventilating and Air Conditioning

Description

	Good	fair	Poor
Roof Top Units	☐	☑	☐
Controls	☑	☐	☐
Split Systems	☑	☐	☐
Exhaust Fans	☑	☐	☐

General Comments

The office building is served by roof mounted packaged, gas fired HVAC units of various manufacturers and ages.

The conditioned air is distributed to the occupied areas served and is introduced to the conditioned space through ceiling mounted diffusers. Return grilles, also ceiling mounted transfer room air into the ceiling space which is utilized as a return air plenum.

A split HVAC system consisting of a fan coil unit and condensing unit mounted on grade serve the Inventory Storage Area. A second split system serves the computer/I.T. Room.

All roof mounted units and split system are controlled through local master thermostats.

The renovated ground floor has further sub zoning thermostats controlling local motorized volume dampers.

Unconditioned Meter Repair Room is heated and ventilated by gas fired unit heaters, roof ventilators and ante-stratification paddle fans.

Electric cabinet heaters are located at entrance vestibules.

Local roof mounted exhaust fans serve washrooms.

The Vehicle Storage Garage is heated and ventilated by gas fired vacuum tube type radiant heaters.

Ventilation consists of two wall mounted propeller fans and related fresh air intakes.

Anti-stratification paddle fans circulate the air within the garage.

Roof Top Units

There are eight roof mounted, packaged gas fired heating, electric cooling units serving the building.

A list of the units with name plate information is provided in Appendix A. The roof plan is schematically drawn to locate approximate location of the units.

Images

The units range in size and capacity according to the requirements of the area served.
As there were no mechanical drawings available we contacted the company who have serviced the equipment

Cardinal Service Group has serviced and replaced units as they became problematic or exceeded their service life cycle. Cardinal Service Group reported that six units have been replaced and those are in excellent operating condition.

Recommendations | Observations

- Two remaining units need to be replaced within the next budget year.

Opinion of Probable Cost
Allow $18,000.00 to replace two remaining units.

<u>Controls</u>

The building controls are standalone master thermostats controlling each roof top unit.

In the ground floor renovated office area there are local thermostats providing sub-zone temperature control.

The ductwork distribution serving the rooftop units distribute supply air through ceiling mounted diffusers. Return grilles in the ceiling transfer return air fan the occupied space to the ceiling space which is utilized as a return air plenum.

The condensing unit is connected via refrigeration piping to a fan coil filter unit located in the Inventory Storage Area.

Supply air from the fan coil unit is ducted to supply air grilles which area exposed within the room.

A local thermostat controls the cooling.
This equipment is in good working condition.

The Meter Repair Room is not air conditioned. The space is heated by local thermostats.

There are ceiling mounted, anti-stratification paddle fans throughout this space.
Roof mounted gravity ventilators provide summer ventilation.

Recommendations | Observations

- The systems serving the Meter Repair Room are in good operating condition.

Opinion of Probable Cost
No Comment

Images




Split Systems

There are two split systems serving the building. One system serves the I.T. Room. It consists of a room mounted Mr. Slim condenser unit as manufactured by Mitsubishi connected via refrigeration piping to a wall mounted fan coil terminal in the I.T. Room.

The second split system serves the Inventory Storage Area. The condenser unit is located on grade.

York Manufacture
Model YCD60B215A
Serial WIB6352679
Cooling Capacity 60,000 BTUH

The condensing unit is connected via refrigeration piping to a fan coil filter unit located in the Inventory Storage Area.

Supply air from the fan coil unit is ducted to supply air grilles which area exposed within the room.

A local thermostat controls the cooling.
This equipment is in good working condition.

The Meter Repair Room is not air conditioned. The space is heated by local thermostats.

There are ceiling mounted, anti-stratification paddle fans throughout this space.
Roof mounted gravity ventilators provide summer ventilation.

Recommendations | Observations

- The systems serving the Meter Repair Room are in good operating condition.

Images

Exhaust Fans

There are local roof mounted exhaust fans serving washrooms and some general areas, locker rooms etc.

Recommendations | Observations

- Exhaust systems are in good working condition.

Opinion of Probable Cost
No Comment

The Vehicle Storage/Work Garage

The Vehicle Storage/Work Garage is heated by gas fired vacuum tube type radiant heaters.
This is an efficient method of heating large open spaces which have overhead doors.

Ventilation of this area is provided by two sidewall propeller type exhaust fans and related louvered fresh air intake.

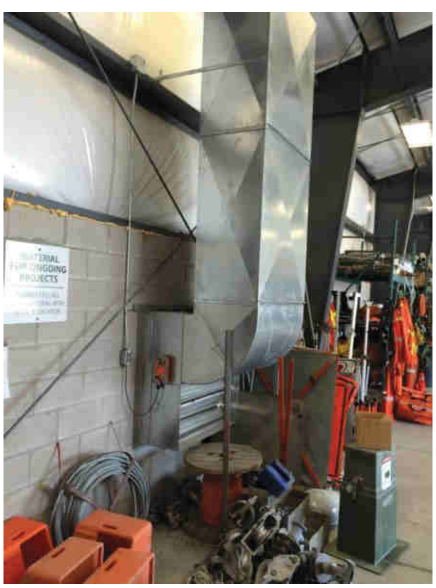
Ceiling mounted anti-stratification paddle fans circulate the air within the Garage.

Recommendations | Observations

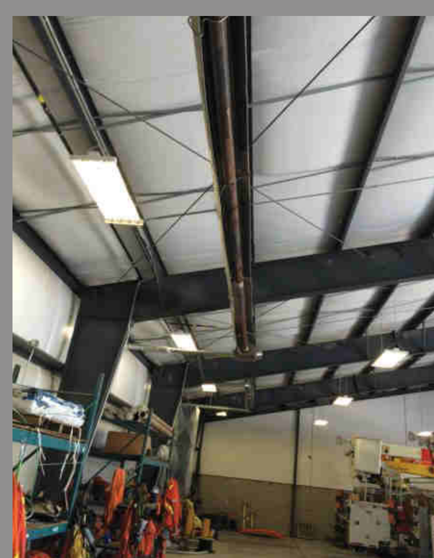
- The building was constructed in 2012 and the mechanical equipment is in good working condition.

Opinion of Probable Cost
No Comment

Images



Images



2.7.1 Electrical Service & Distribution

General Comments

The electrical service to the building comes via an underground feeder from the east side of the building.

The electrical service is rated at 100 Amp, 347/600 Volt, three phase. Revenue metering is provided. The peak demand is not known but since historically there has never been any over load tripping and service breakdown it can safely be assumed the existing is withing the 100A Service capacity.

Service & Distribution	☑ Good	☐ fair	☐ Poor

Recommendations | Observations

The main service equipment consists of a 100A 600 Volts 3 pole 4 wire Siemens Disconnect switch, integrated revenue meter, and a 150A, 600V 3 pole, 4 wire Thompson Technology Automatic Transfer Switch.

There is a 105 kW (131kVA) Diesel engine driven standby generator set located outside in a weather proof mobile enclosure. The standby power supports the entire building load.

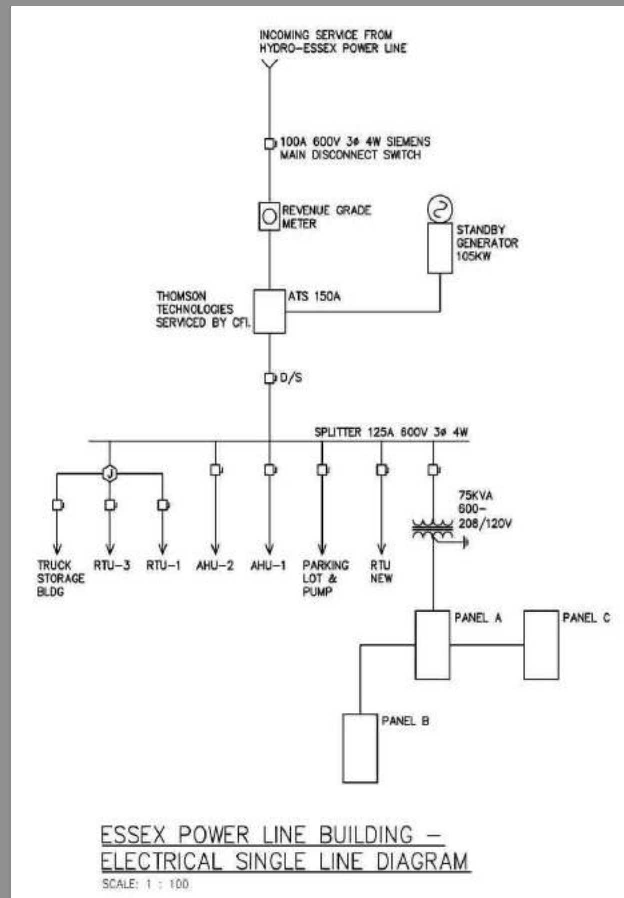
The rest of the distribution is configured through a splitter and multiple fused disconnect switches.

The electrical equipment is generally in good operating condition with no obvious signs or problems such as heating of terminations, excessive corrosion, or rust. Building maintenance personnel reported no overloading or unusual tripping of breakers. Cabling runs also appeared to be in good condition. Only the well pump control panel located remotely outdoors appears to be rusted and needs replacement.

Opinion of Probable Cost

No Comment

Images



2.7.2 Emergency Power

Description
This section reviews the emergency power systems.

Emergency Power	☑ Good	☐ fair	☐ Poor

General Comments

There is a 105 kW (131 kVA), Kohler, 600V, 3 phase diesel engine driven standby generator supporting the entire building load. This unit is in good working condition and is maintained and serviced by CF Industrial, Leamington.

Recommendations | Observations
The generator and the associated 150A Automatic Transfer Switch by Thomson Technologies is expected to support the maximum demand load of the building. The generator is in a weather proof enclosure and is on wheels with a socket-plug arrangement.

Opinion of Probable Cost
No comment

2.7.3 Electrical Room & Generator Room

Description
This section reviews electrical transformers, electrical room equipment and generator room equipment.

Equipment	☑ Good	☐ fair	☐ Poor
Dry Transformers	☑ Good	☐ fair	☐ Poor

General Comments
The main Electrical Room is to be provided with 1-hour fire separation ratings from the remainder of the building. It would be prudent to ascertain this is provided in the existing block walls and steel roof deck.

There are no Motor Control Centres in the facility, however, there are several smaller enclosed magnetic starters provided for the ON-OFF control of fans and pumps which appears to be original equipment.

There are two (2) dry type transformers manufactured by FPE and seem to be in good operating condition and did not feel hot to the touch; which signifies that they are not over loaded.

Wiring is a combination of wire in conduit installations and BX cable installations. Some feeders are TECK cable installation strapped directly to walls and other structural supports

Panelboards are Siemens and generally have spaces available, other smaller ones appear to be fully utilized with little spare circuits except where noted.

Panel A has 19 spaces available (28%).

Panel C has 12 spaces available (18%)

Panelboards in the metering room appear to be new and are utilized for the purpose of testing of meters.

Recommendations | Observations
No Comment

Opinion of Probable Cost
No Comment

Images

2.7.4 Lighting

Description
This section reviews lighting systems

Lighting	☑ Good	☐ fair	☐ Poor

General Comments

Most of the original lighting has been replaced with T8 or T5 linear fluorescent and compact fluorescent in the Main Building and the existing remote garage. Generally, the lighting level is good between 400-600 lux in offices and general circulation areas. Where the lighting level is less it was at the preference of the users of the spaces.

There are a few fluorescent fixtures with small cell egg crate diffusers. These appear to be old and do not allow regular cleaning, therefore are recommended for replacement.

There are a few (six only) building mounted Metal Halide fixtures which are not as efficient as the new LED sourced fixtures. These fixtures must be replaced.

Recommendations | Observations
No Comments

Opinion of Probable Cost
No Comments

2.7.5 Emergency Lighting

Description
This section reviews Emergency lighting systems

Emergency Lighting	☑ Good	☐ fair	☐ Poor

General Comments

The entire building lighting is supported by standby power generator. This more than meets the standards.

Exit sign lighting is present and these are Red LED sign lights. Emergency battery operated lighting is also present in the Electrical room and I.T. Room in conformance with the code. Exit sign lighting is of the RED EXIT fixture which is no longer in conformance with the current code, where the green running man pictograph is required.

Recommendations | Observations
No Comments

Opinion of Probable Cost
No Comments

Images

2.7.6 Fire Alarm System

Description
This section reviews fire alarm systems

Fire Alarm ☑ Good ☐ fair ☐ Poor

General Comments

Fire Alarm System is not required for this facility, however there are smoke and heat detectors installed at selected location and rooms and connected to security systems. There are horns to sound when smoke and heat detection initiate FA condition. This system does not conform to Fire Alarm installation code.

Recommendations | Observations
No Comments

Opinion of Probable Cost
No Comments

2.7.7 Security Access and Surveillance System

Description
This section reviews Security Access and Surveillance System

Security System ☑ Good ☐ fair ☐ Poor

General Comments

There appears to be CCTV Cameras and motion detectors networked together to provide a security system for the building. A “terago” Antenna was installed on the roof appeared to be in good condition and installed recently in the life of the building.

Recommendations | Observations
No Comments

Opinion of Probable Cost
No Comments

2.7.8 Storm Water Storage Pump Alarm

Description
This section reviews the Pump Alarms.

Pump Alarm ☑ Good ☐ fair ☐ Poor

General Comments

This is a remote storm water storage with pump control panel outdoors over the well. The control panel enclosure is old and rusted, and is recommended for replacement. There is a pump failure alarm located in the truck storage area.

Recommendations | Observations
No Comments

Opinion of Probable Cost
No Comments

Images

2.7.9 Communications

Description
This section reviews the communication systems.

Communications ☑ Good ☐ fair ☐ Poor

General Comments

Voice and Data: Communication is provided via Cat 6 structural cabling between IT Closets and voice/data drop. Rack and switching equipment belongs to the Owner.

Recommendations | Observations
No Comments

Opinion of Probable Cost
No Comments

2.7.10 Remote Garage

Description
This section reviews the remote Garage doors

Remote Garage ☑ Good ☐ fair ☐ Poor

General Comments

This is a separate building built of steel and insulated and provided with a steel deck roof. This is built to the south of the main building. Being only 10 years old, most of the electrical equipment including lighting appears to be in order. Lighting is high-bay T5 sourced pendant luminaries, providing adequate lighting.

Recommendations | Observations
No Comments

Opinion of Probable Cost
No Comments

2.7.11 Receptacles & Switches

Receptacles & Switches ☑ Good ☐ fair ☐ Poor

General Comments

Grounded receptacles are installed throughout the building. Receptacles are recesses with the exception of garage and service rooms. These appear to be sufficient in number as not many power cords extensive were observed on site.

There are manual toggle switches as well as occupancy sensor switches on site. Bulk lighting in garages and truck parking is controlled via manual switches.

Recommendations | Observations
No Comment

Opinion of Probable Cost
No Comment

Images

SECTION 3 Statement of Limitations

3.1 Statement of Limitations

The building condition assessment conducted was a visual assessment only. No physical, destructive testing or measurements of existing building structure were taken during the site visit. No assessment can be made where building structure and elements were either not exposed or easily accessible. Connections, fastenings and anchorage of building structure were not reviewed in detail. Existing structural and architectural drawings were provided for review but may not reflect the actual built construction. Comments and conclusions are therefore based on the visual and/or the apparent physical condition of the building elements. Any design and/or construction deficiencies that are not recorded in this report were not evident given the level of study undertaken.

The costing information presented here has been prepared from the engineers' experience and from past projects of a similar nature. The amount given are opinions only and must not be taken as a guarantee of price. If guaranteed pricing is required then the full scope of work needs to be detailed and appropriate contractor(s) approached for a quotation.

This study is intended for the client named and should not be distributed further without our consent.

SECTION 4 Works Garage Floor Drains

2.8.1 Works Garage - Floor Drains

Description
This section reviews the requirement to have a floor drain for the existing Works Garage Slab.

General Comments

Floor Drains are not required by the Ontario Building Code for the Works Garage. It is good practice to have floor drains due to the use of the facility. The powerline trucks will have snow melt and rain drip onto the floor as well as potential for washing of the vehicles.

Recommendations | Observations

If Client requires | requests floor drains to be installed the following would be recommended.

- (1) Catch basin installed in each bay and piped to exterior of building.
- If washing | repair of vehicles required in bays, an Oil interceptor is required

Opinion of Probable Cost
Allow $55,000.00 for installation of Catch Basins and associated work.
Allow $20,000.00 for installation of Oil interceptor.

Images

APPENDIX 'A'

SECTION 5

Roof Top Unit Schedule

RTU No. 1
On Upper Roof
Carrier 48TFE006-A-111HQ
Serial 4902G10127
Natural Gas / Electric Cooling
Heating
Input 115,000 BTUH
Output 92,000 BTUH
Cooling
48,000 BTUH

RTU No. 2
On Upper Roof
York Model ZXG075SC1AA1A111A2
Serial N1M5169256
Natural Gas / Electric Cooling
Heating
Input 145,000 BTUH
Output 116,000 BTUH
Cooling
72,000 BTUH

RTU No. 3
On Upper Roof
Allied Commercial - No Name Plate
Natural Gas /Electric Cooling Estimated
Capacities 3 to 4 Ton Cooling
65000 to 100,000 BTUH
Input – Heating

RTU No. 4
On Low Roof
Lennox KGA 036S4DMIJ
Serial 5611GO1963
Natural Gas / Electric Cooling
Heating
Input 105,000 BTUH
Output 84,000 BTUH
Cooling
36,000 BTUH

RTU No. 5
On Low Roof
Lennox KGA060S4DH3J
Serial 5612C08673
Natural Gas / Electrical Cooling
Heating
Input 150,000 BTUH
Output 120,000 BTUH
Cooling
59,000 BTUH

Appendix I: Fleet Purchasing Policy

Approved by: Dan Charron P. Eng, Operations Manager	Approval date:
Joe Barile, General Manager Reviewed by:	Reviewed date: March 3, 2017
Brandon Chartier, Facility Operations & Risk Mitigation Supervisor	

I. Purpose

The purpose of this procedure is to describe Essex Powerlines' (EPL) policy with regards to when new vehicle are to be purchased and existing vehicles should be considered for replacement.

II. Scope

This policy applies to all of departments within EPL who use EPL vehicles as part of their assigned work.

III. Responsibilities

1. Risk Mitigation Supervisor is responsible for:
   - (a) Filing a current version of this policy
   - (b) Periodically reviewing and updating this policy as required.
   - (c) Making copies available to any Operational personnel, upon request.
   - (d) Disseminating copies to all impacted employees whenever this policy is revised.
2. *Managers* and *Supervisors* of the organization are responsible for:
   - (a) Providing input for periodic review of this policy.
   - (b) Approving any amendments to this policy.
3. *Senior Management* of the organization is responsible for:
   - (a) Ensuring this policy is periodically revised.
   - (b) Providing oversight over any and all policy changes.

IV. Process

As of Jan 1st 2017, EPL has a fleet of 23 vehicles that range in age from 1996 to 2016. Of the 23 vehicles, 10 are greater than 4500kgs and 13 are under 4500Kgs
EPL uses the following criteria when a vehicle needs to be replaced, either for sale or replacement.

1. Fleet (Diesel Engines)

   a. Single/Double Truck/RBD Line Truck/Dump Trucks/Service Trucks (all having diesel engines)

- Recorded mileage of 300,000 kilometers and/or more than 15 years of service
- Maintenance costs
- Its usefulness to the organization
- Annual test results (i.e. electrical and stress testing)
- The impact of new technology that may greatly decrease the vehicles usefulness/productivity
- Changing emission, weight and road safety regulations
- Departmental needs
- Operating costs are more than 50% of a year's depreciation value. (e.g. Chassis condition/Body condition/Boom condition and technical assessment)

If a vehicle with 15 years of service has considerably less than 300,000 kilometers logged, consideration will be made to refurbish the unit only if an assessment determines a remaining useful life of at least 5 years.

In order to cap annual capital expenditures, generally only one large truck (over 4500kg) will be replaced in any given fiscal year, unless an emergency occurs in the fleet.(i.e. incident/accident)

If there are two trucks that need replacing in the same year, the truck with the greater mileage will be first and the second truck will come the following year.

b. Gas Powered Vehicles (Pickups/Mini Vans/Cars)(Under 4500Kgs)
   - Recorded mileage of 200,000 kilometers and/or more than 7 years of service

   If a vehicle with 7 years of service has considerably less than 200,000 kilometers logged, consideration will be made to refurbish the unit only if an assessment arranged, by the Facility Operations & Risk Mitigation Supervisor, determines a remaining useful life of at least 3 years.

ESSEX POWERLINES FLEET

TYPE	UNIT #	JOB #	ACT	YEAR	DESCRIPTION	PLATE #	VIN #	TOTAL WEIGHT (KG)	GVW (KG)	FUEL	LIKELY REPLACEMENT DATE	Petro Canada Card #	PETRO LOG IN #
SINGLE BUCKET	100	80	9072	2006	INTERNATIONAL SINGLE BUCKET-42' POSI	6273RT	1HTMKAAR66H319947	17,000		DIESEL	2020	993-145-132-3-0002	8906
SINGLE BUCKET	103	392	9072	2007	INTERNATIONAL SINGLE BUCKET-55' POSI	9918WX	3HTWGAAR47N484204	15,072		DIESEL	2022	993-145-132-3-0007	7343
SINGLE BUCKET	107	1127	9072	2011	FREIGHTLINER - 46' SINGLE BUCKET	4165ZJ	1FVACYBS9BHBA2347	12,078		DIESEL	2026	993-145-132-3-0005	2400
SINGLE BUCKET	108	12-1185	9072	2012	FREIGHTLINER - 42' SINGLE BUCKET	AC68159	1FVACYBS6CHBS3730	17,000		DIESEL	2027	993-145-132-3-0044	
SINGLE BUCKET	111	14-1281	9072	2014	FREIGHTLINER - 46' SINGLE BUCKET	AH17507	1FVACYCDEHFU9211	18,000		DIESEL		993-145-132-3-0001	7521
DOUBLE BUCKET	351	86	9072	1996	FRHT DOUBLE BUCKET - 57' TELECT	8867AF	1FVXJLBB1TL556949	19,000		DIESEL	2016	993-145-132-3-0008	5322
RBD	110	12-1198	9072	2013	FREIGHTLINER RBD - 50 '	AE13684	1FVHCYBS0DHFE3673	27,250		DIESEL	2028	993-145-132-3-0009	2107
RBD	104	88	9072	1996	INTERNATIONAL LINE TRUCK	8568CF	1HTSDAAR8TH343650	15,000		DIESEL	2015	993-145-132-3-0040	1445
RBD	113	14-1404	9072	2015	FREIGHTLINER RBD - 50 '	AL 92881	3ALHCYCY4FDGR7982	27,250		DIESEL	2030	993-145-132-3-0011	8924
PICK-UP	65	502	9072	2009	GMC SIERRA-EXT CAB	AM46588	1GTEC19X592149337	3,000		GAS	2017	993 145 132 3 0030	2308
PICK-UP	66	507	9072	2010	FORD-150 SUPER CAB 2 X 4	408-8YD	1FTEX1C85AFB19881	3,000		GAS	2018	993 145 132 3 0031	1267
PICK-UP	67	717	9072	2010	FORD-250 CREW CAB 4 X 4	465-6YF	1FTSW2BR3AEB22886	4,400		DIESEL	2018	993 145 132 3 0033	4677
PICK-UP	68	718	9072	2010	FORD-250 CREW CAB 4 X 4	AF 48094	1FTSW2BR3AEB22887	4,400		DIESEL	2018	993 145 132 3 0026	1777
PICK-UP	69	719	9072	2010	FORD-250 CREW CAB 4 X 4	AL 48283	1FTSW2BR3AEB22888	4,400		DIESEL	2018	993 145 132 3 0035	1777
PICK-UP	76	1032	9072	2016	CHEV SILVERADO 2500HD	AN 82039	1GC1KUEG0GF198940	3,022		GAS	2024	993 145 132 3 0012	76
VAN	70	1024	9072	2010	DODGE JOURNEY	BKNN-044	3D4PG5FV3AT217267			GAS	2018	993 145 132 3 0036	8481
VAN	71	1025	9072	2010	DODGE JOURNEY	BKNN-045	3D4PG5FV3AT217266			GAS	2018	993 145 132 3 0037	1492
VAN	72	12-1165	9072	2012	DODGE RAM 1500 4X4	AK 24845	1C6RD7FTOCS226772	3,000		GAS	2020	993 145 132 3 0024	4277
VAN	73	13-1439	9072	2014	DODGE RAM CV	AF 34706	2C4RRGAG4ER179710	3,000		GAS	2022	993 145 132 3 0004	5023
VAN	74	1030	9072	2016	RAM PROMASTER	AN85444	3C6TRVAG4GE129086	2,061		GAS	2024		
VAN	75	1026	9072	2016	RAM PROMASTER	AN85445	3C6TRVAG8GE130029	2,061		GAS	2024		
DUMP TRUCK	109	12-1184	9072	2012	DODGE RAM 3500 DUMP	AC 28214	3C7WDTAL6CG240813	8,000		DIESEL	2022	993 145 132 3 0038	4677
DUMP TRUCK	112	14-1291	9072	2015	FORD SUPER DUTY F550 DUMP	AH 65653	1FDUF5HT2FEA19524			DIESEL	2025	993 145 132 3 0038	4677
TRAILER	730	107	9072	1930	UTILITY TRAILER	E9209L	FILE #165984361	760	6,401				
TRAILER	731	108	9072	1992	TRAILER	L45405	2F9PR6426NF043005	1,660	5,443				
TRAILER		13-1085	9072	2013	LANDSCAPE TRAILER	K2350Y	2CPUSD2D6DA019085	977	4,491				
POLE TRAILER	735	111	9072	1997	60' FREIBURGER POLE TRAILER	S36022	2F9PT6516VF043010						
POLE TRAILER	736	112	9072	1997	POLE/REEL TRAILER	S94733	ZF9PR6426VF043012	1,740	5,443				
REEL TRAILER	733	110	9072	1968	REEL TRAILER	E9212L	13523	1,510	4,535				
BACKHOE	740	14-1351	9072	2014	CASE FARMALL 95C					DIESEL			
CHIPPER	361	242	9070	``	VEERNEER 12	E9210L	FILE #292343032			GAS			
PORTABLE TRANS.	737	113	9072	1961	PORTABLE TRANSFORMER	11953C	154TRANS	1,020					
GENERATOR	362	352	9072	2000	VILTECH	B89-03C	T5193512646049603						
PICK-UP	61	98	9072	2006	CHEV PICKUP	2283RX	3GCE14X36G153387	3,000		G	2014	993 145 132 3 0041	7608
PICK-UP	62	99	9072	2006	4 X 4 CHEV SIVERADO QUAD PICKUP	6984TA	1GCHK23DX6F224597	3,500		DIESEL	2014	993 145 132 3 0016	1154
PICK-UP	62	1062	9072	2006	CHEVY SILVERADO	698-4TA	1GCHK23DX6F224597	3,000		DIESEL	2015	993 145 132 3 0012	
VAN	63	100	9072	2007	GMC SAVANA	9951TS	1GTFG15X571150014	3,000		G	2015	993 145 132 3 0042	6694
VAN	64	101	9072	2007	GMC SAVANA	AM46587	1GTGG25V671140116	3,000		G	2015	993 145 132 3 0028	6711

Table 1 : Fleet Inventory - April - 2017

Appendix J: Asset Condition Assessment Report

Essex Powerlines Corporation
Asset Condition Assessment

Prepared by METSCO Energy Solutions Inc.

Report no. P-17-133-001-R0

August 11, 2017

DISCLAIMER

This report was prepared by METSCO Energy Solutions Inc. (METSCO) for the sole benefit of – Essex Powerlines Corporation - (the Client), in accordance with the terms of METSCO proposal and the Client's Purchase Order.

Neither the Client nor METSCO, nor any other person acting on their behalf makes any warranty, expressed or implied, or assumes any legal responsibility for the accuracy of any information or for the completeness or usefulness of any apparatus, product or process disclosed, or accept liability for the use, or damages resulting from the use, thereof. Neither do they represent that their use would not infringe upon privately owned rights.

Furthermore, the Client and METSCO HEREBY DISCLAIM ANY AND ALL WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING THE WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, WHETHER ARISING BY LAW, CUSTOM, OR CONDUCT, WITH RESPECT TO ANY OF THE INFORMATION CONTAINED IN THIS REPORT. In no event shall the Client or METSCO be liable for incidental or consequential damages because of use or any information contained in this report.

Summary

The Asset Condition Assessment is based on data compiled in June 2017 and covers the following classes of fixed assets owned by Essex Powerlines Corporation (EPL):

- Wood poles
- Concrete poles
- Steel poles
- Pad-mounted distribution transformers
- Pole-mounted distribution transformers
- Pad-mounted switchgear
- Dip poles (primary risers)
- Primary underground cables

Table 0-1 summarizes the assessment criteria and Typical Useful Life (TUL) for each asset class. Age demographics are not tracked for dip poles. The condition was determined for all asset classes except primary underground cables, for which only age demographics are known. Statistics for primary underground cable failures were used to support an age-based replacement plan.

Table 0-1: Assessment Criteria and TUL for each Asset Class

Asset Class	Assessment Criteria	TUL (years)
Wood poles	Test results (Resistograph), visual inspection results, service age	50
Concrete poles	Visual inspection results, service age	50
Steel poles	Visual inspection results, service age	60
Pad-mounted distribution transformers	Visual inspection results, service age	40
Pole-mounted distribution transformers	Visual inspection results, service age	40
Pad-mounted switchgear	Visual inspection results, service age	30
Dip poles (primary risers)	Visual inspection results	N/A
Direct-buried primary underground cables	Service age, reliability statistics	30
Primary underground cables in conduit	Service age, reliability statistics	40

The assets are assessed to be in one of five conditions: Very Good, Good, Fair, Poor, or Very Poor. The results of the Asset Condition Assessment, including the number of assets in each class, are summarized in Figure 0-1.

Figure 0-1: Asset Condition Summary

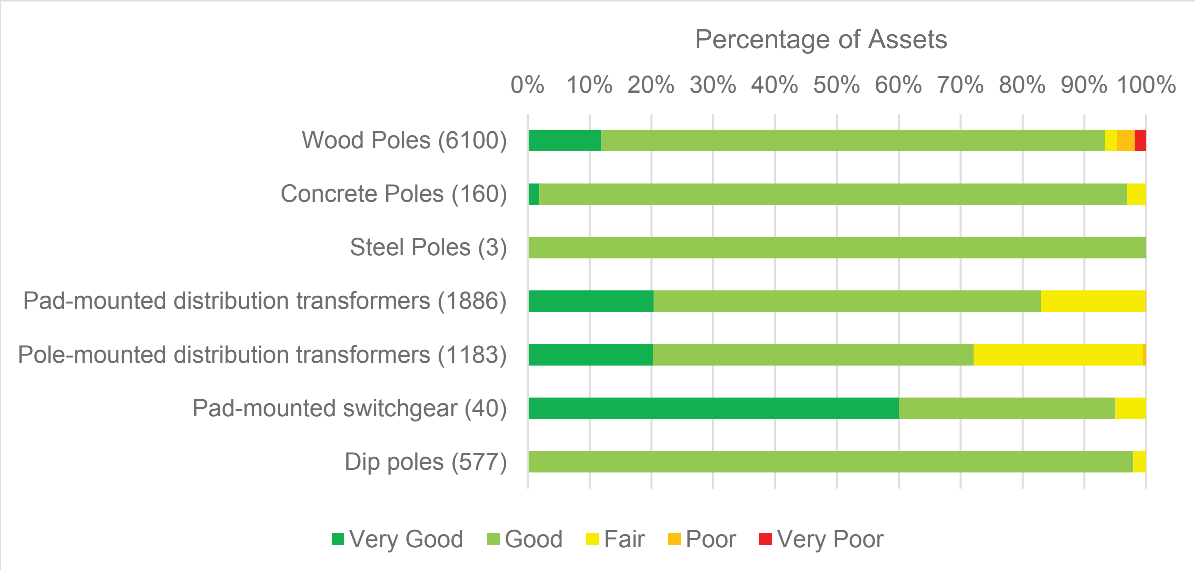


Figure 0-2 presents the service age of EPL's primary underground cables with respect to the TUL. A total of 48.9 km of cables are past TUL and an additional 16.9 km will reach TUL by 2026 (a ten-year planning window). Cables installed in conduits for which the exact installation date is unknown are presumed to have been installed after 1986 and are, therefore, not expected to require replacement before 2026. The approximate age of these cables should be determined and subsequent analyses.

Figure 0-2: Service Age of Primary Underground Cables Relative to TUL

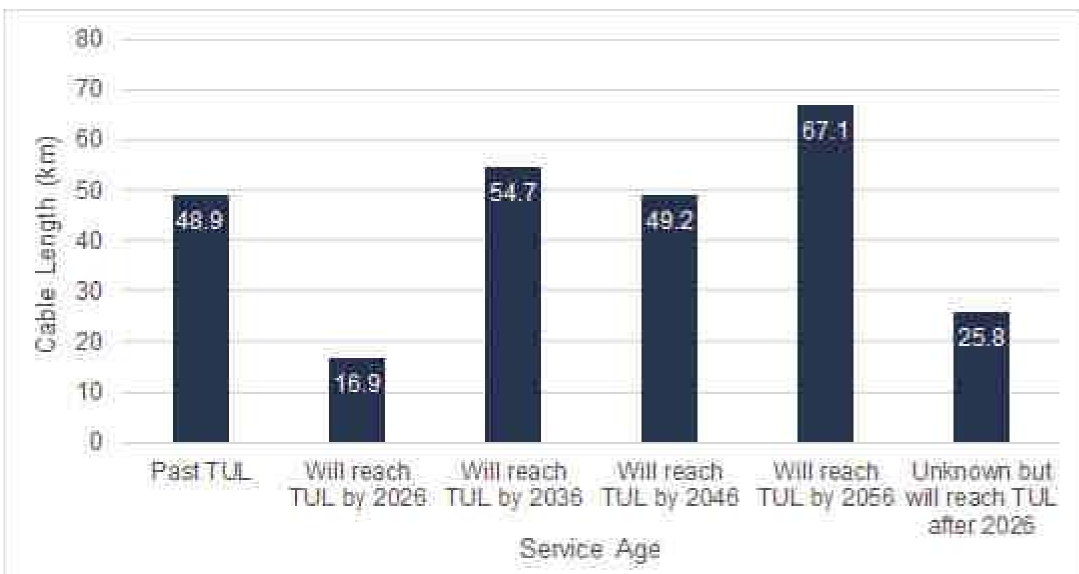


Table of Contents

List of Tables

List of Figures

1 Introduction

This report summarizes the results of an Asset Condition Assessment study carried out by METSCO Energy Solutions Inc. (METSCO) on behalf of Essex Powerlines Corporation (EPL), with the objective of establishing the health and condition of fixed assets employed in the distribution systems.

The Asset Condition Assessment methodology was applied for different categories of fixed assets that are employed on EPL's distribution system. Adoption of this methodology would require periodic asset inspections and recording of their condition to identify the assets most at risk, requiring focused investments into risk mitigation.

Computing the Health Index for distribution assets requires developing end-of-life criteria for various components associated with each individual asset type. Each criterion represents a factor that is critical in determining the component's condition relative to potential failure. These components and tests shown in the tables are weighted based on their importance in determining the assets end-of-life.

For the purpose of scoring the condition assessment, the letter condition ratings are assigned the following numbers shown as "factors":

- A = 4
- B = 3
- C = 2
- D = 1
- E = 0

These condition rating numbers (i.e., A = 4, B = 3, etc.) are multiplied by the assigned weights to compute weighted scores for each component and test. The weighted scores are totaled for each asset.

Totaled scores are used in calculating final Health Indices for each asset. For each component, the Health Index calculation involves dividing its total condition score by its maximum condition score and expressing it as a percentage. This step normalizes scores by producing a number from 0 to 100% for each asset. For example, a transformer in perfect condition would have a Health Index of 100% while a completely degraded transformer would have a Health Index of 0. The condition of the asset based on the Health Index is interpreted using Table 1-1.

Table 1-1: Description and Interpretation of Asset Condition

Health Index	Condition	Description	Interpretation
[85%, 100%]	Very Good	Asset is in “like-new” condition; some aging or minor deterioration	Normal maintenance
[70%, 85%)	Good	Significant deterioration of some components	Normal maintenance
[50%, 70%)	Fair	Widespread significant deterioration or serious deterioration of specific components	Possible remedial work or replacement depending on criticality
[30%, 50%)	Poor	Widespread serious deterioration	Start planning process to replace or refurbish depending on criticality
[0%, 30%)	Very Poor	Extensive serious deterioration	Asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

The assets covered in the report include the following fixed assets:

- Wood poles
- Concrete poles
- Steel poles
- Pad-mounted distribution transformers
- Pole-mounted distribution transformers
- Pad-mounted switchgear
- Dip poles (primary risers)
- Primary underground cables

The information contained within this report was compiled based on data available in June 2017.

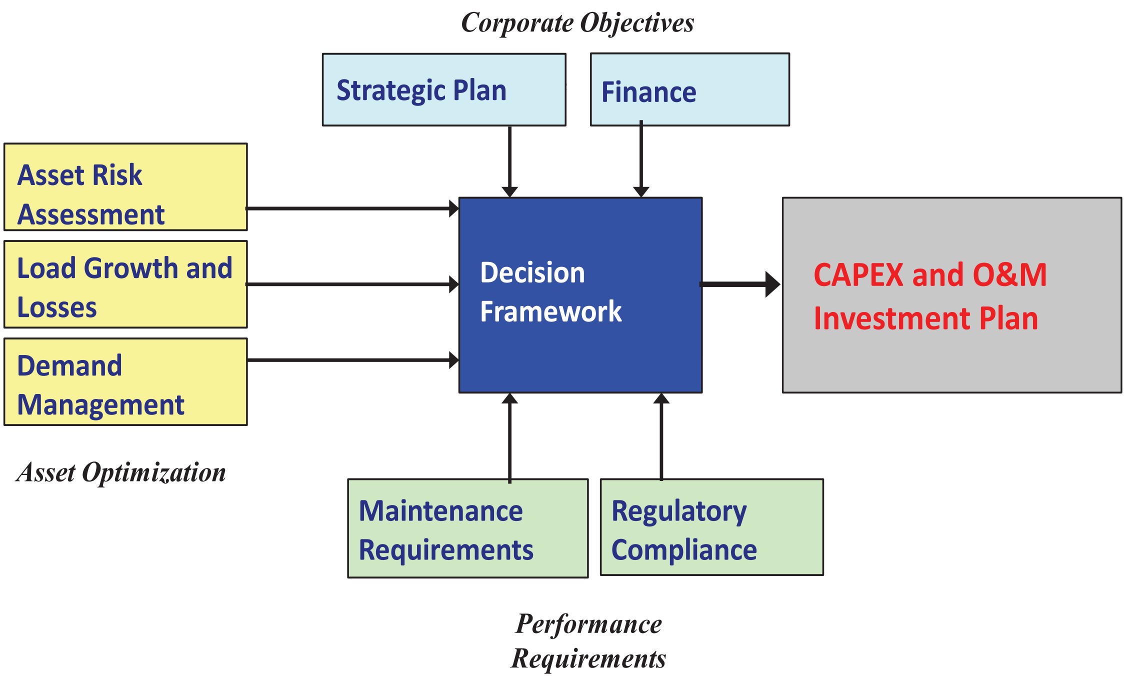
2 Strategic Management of Distribution Fixed Assets

Decisions involving investment into fixed assets play a major role in determining the optimal performance of distribution system fixed assets. A majority of the investments in fixed assets are triggered by declining performance in the areas of supply system reliability, power quality or safety; or increasing operating and maintenance costs associated with aging assets; or anticipated growth in demand requiring capacity upgrades. In any case, investments that are either oversized or made too far in advance of the actual system need may result in non-optimal operation. On the other hand, investment not made on time when warranted by the system needs raise the risk of performance targets not being achieved and would also result in non-optimal operation. Optimal operation of the distribution system is achieved when “right sized” investments into renewal and replacement (capital investments) and into asset repair, rehabilitation, and preventative maintenance are planned and implemented based on a “just-in-time” approach. In summary, the overarching objective of the Asset Management Strategy is to find the right balance between capital investments in new infrastructure and operating and maintenance costs so that the combined total cost over the life of the asset is minimized.

A risk-based Asset Management Strategy, therefore, determines the risk of asset failure based on the condition of the asset – commonly using Health Indices – computes the valuation of the risk based on consequences of asset failure, and identifies the optimal risk mitigation alternative through an evaluation of all available options. Asset management covers the full lifecycle of a fixed asset, from preparation of the asset specification and installation standards, to the scope and frequency of preventative maintenance during the asset’s service life, and finally to the determination of the assets end-of- life and retirement from service. At each stage of an asset’s lifecycle, decisions are made to achieve the right balance between achieving maximum life expectancy, highest operating performance, lowest initial investment (capital costs), and lowest operating costs. The best-in-class asset management strategies employ integrated processes that allow optimal levels of financial and operating performance to be achieved, using transparent and objective criteria that can easily be audited and inspected by regulators.

The overarching objective is to develop capital and preventative maintenance investment plans, which could be implemented over a period of ten to twenty-five years to achieve optimal system performance by placing appropriate weights on corporate objectives and performance requirements, as shown in Figure 2-1.

Figure 2-1: Multi-Point Decision Framework

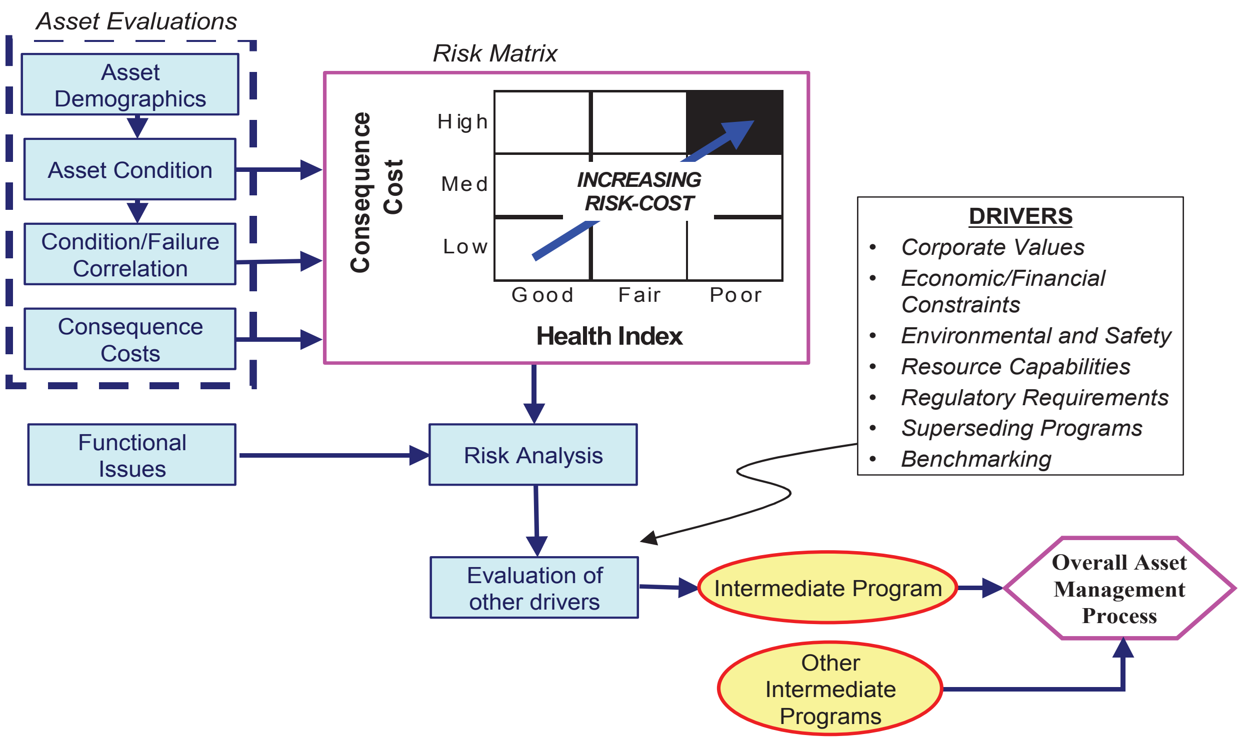


For regulated transmission and distribution (T&D) businesses, the key considerations in development of a Strategic Asset Management Plan include:

a) Public and Employee Safety
b) Regulatory Compliance
c) Protecting Brand Name and Image
d) Operating Efficiency
e) Reliability and Supply System Security
f) Customer Service Quality
g) Minimizing Asset Life Cycle Costs
h) Minimizing Environmental Risks
i) Getting Full Life out of Assets
j) Return on Investment
k) Risk Based Maintenance Strategy
l) Minimizing Risk of Premature Failures

Figure 2-2 summarizes a practical matrix to sift through a large number of assets, typically employed on T&D systems to objectively identify assets that present the highest risk of in-service failures so that the investments could be targeted into assets that present the highest risk. Numeric Health Indices, typically normalized to a scale of 100, are commonly used to express the health and condition of assets, differentiating the assets in good condition that require minimal risk mitigation from those in poor condition, requiring a higher level of investments. This exercise allows development of an investment plan that could be implemented over a medium- or long-term planning hoizon.

Figure 2-2: Model to Identify Assets with Highest Risks



3 Health Indices

3.1 Wood Poles

3.1.1 Condition Assessment Methodology

3.1.1.1 Health Index Calculation

The Health Index for wood poles is calculated by considering a combination of service age, visual inspection results, and pole testing results (cavity and decay determined from a Resistograph test). Table 3-1 summarizes the methodology to combine these criteria into an overall Health Index for wood poles. The methodology employs a "gateway" if the pole fails the cavity test, forcing the pole condition to Very Poor by halving the Health Index.

Table 3-1: Wood Poles – Health Index

Condition Criteria	Weight	Possible Ratings	Possible Scores	Max Grade
Cavity test (Resistograph)*	8	A,B,C,D,E	4,3,2,1,0	32
Decay test (Resistograph)	6	A,B,C,D,E	4,3,2,1,0	24
Outstanding issues (visual inspection)	4	A,B,C,D,E	4,3,2,1,0	16
Service age	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	84

*If E, divide Health Index by two.

EPL considers a Typical Useful Life (TUL) of fifty years for wood poles, which is consistent with common industry practice. Table 3-2 is used to translate age into a condition rating.

Table 3-2: Wood Poles – Age Condition Grading

Condition Rating	Age
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 50 years
E	51 years or older

Visual inspections are performed on a three-year cycle, checking for:

- Hollow pole sound when struck with hammer
- Bent, cracked, or broken poles
- Pole positioned in hazardous location
- Leaning pole in unstable soil
- Loose or unattached guy wires or studs
- Slack, broken, or damaged guys
- Guy positioned close to primary conductors or equipment
- Guy strain insulators pulled apart or broken

- Guy guards missing or out of position
- Loose, cracked, or broken crossarms and brackets
- Woodpecker, bird nests, or insect damage
- Grading changes or washouts
- Other problems (e.g. dirty insulators, crossarm damage)

The pole inspector ranks the issues as high, medium, or low priority depending on the severity. High priority issues generally require immediate follow-up, while other identified issues are prioritized accordingly. If an issue is resolved via corrective maintenance or capital replacement, the inspection database is updated. Table 3-3 presents the condition rating based on the outstanding issues for the wood pole.

Table 3-3: Wood Poles – Outstanding Issues Condition Grading

Condition Rating	Corresponding Condition
A	No outstanding issues
B	One low priority issue outstanding
C	Multiple low priority issues or one medium priority issue outstanding
D	Multiple medium priority issues outstanding
E	One or more high priority issues outstanding

EPL started its pole testing program in 2014. Poles are drilled using a Resistograph to determine the amount of decay and size of cavities within the wood. Each pole is tested twice: once at the groundline and once five feet from the ground. The Resistograph automatically determines the percentage of decay and cavity relative to the size of the pole. If the cavity exceeds 40% of the pole, then the pole requires immediate replacement in accordance with CSA C22.3 No.1-15. Both test locations are compared to ensure the worst condition poles are prioritized for replacement. Table 3-4 summarizes the condition rating based on the tested cavity size. Decay percentages obtained from the Resistograph tests are also used to assess the condition of wood poles as presented in Table 3-5.

Table 3-4 Wood Poles – Cavity Test Condition Grading

Condition Rating	Corresponding Condition
A	Cavity < 10% for both tests
B	Cavity ≥ 10% for either test
C	Cavity ≥ 20% for either test
D	Cavity ≥ 30% for either test
E	Cavity ≥ 50% for one test and ≥ 40% for second test

Table 3-5: Wood Poles – Decay Test Condition Grading

Condition Rating	Corresponding Condition
A	Decay < 10% for both tests
B	Minor decay ≥ 10% for one test
C	Significant decay ≥ 20% for one test
D	Major decay ≥ 30% for one test
E	Severe decay ≥ 40% for one test

3.1.1.2 Translating Health Index into Asset Condition

The condition of each wood pole is determined based on its Health Index and service age. As noted in Table 3-6, service age is only used to distinguish between Good and Very Good condition poles when the Health Index is 85% or greater. When the Health Index is less than 85%, it is directly translated into asset condition. If the age is unknown, then the pole is assumed to be in Good condition if the Health Index is greater than or equal to 70%.

Table 3-6: Wood Pole Condition Determined Using Health Index and Service Age

Health Index	Service Age	Wood Pole Condition
≥ 85%	≤ 10 years	Very Good
≥ 85%	> 10 years	Good
≥ 70%, < 85%	-	Good
≥ 50%, < 70%	-	Fair
≥ 30%, < 50%	-	Poor
< 30%	-	Very Poor

3.1.2 Results of Analysis

3.1.2.1 Age Demographics

EPL owns 6100 wood poles across its four service territories. The service age is known for 2903 – or 48% – of EPL's wood poles. Figure 3-1 presents the age distribution of the known set. The distribution is skewed towards newer poles since modern data collection processes are more accurate.

Figure 3-1: Consolidated Age Demographics of Wood Poles

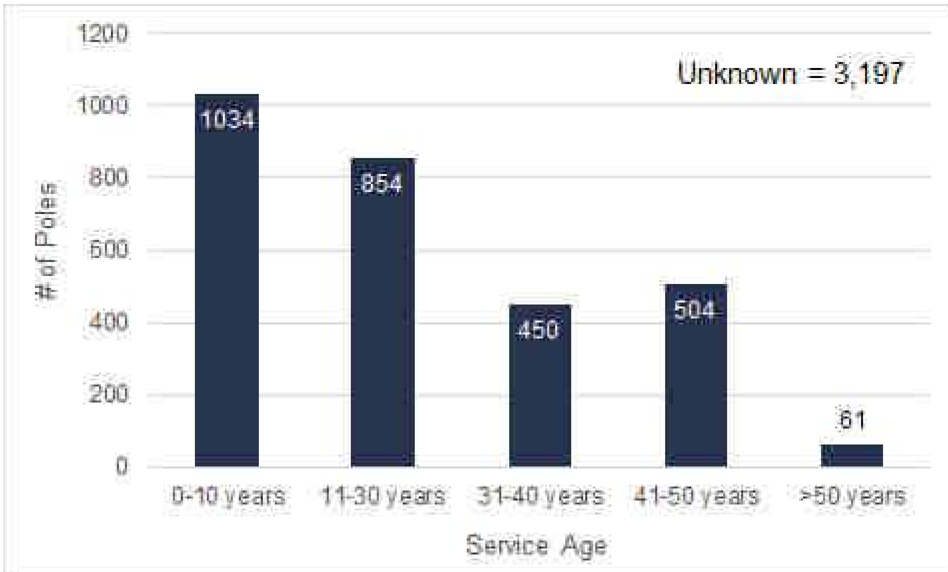


Table 3-7 presents the wood poles age demographics by community. The percentage of poles with unknown service ages varies between communities depending on the pre-amalgamation records.

Table 3-7: Wood Pole Age Demographics by Community

Age	Number of Poles				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
0-10 years	98	211	100	625	**1034**
11-30 years	134	237	48	435	**854**
31-40 years	50	226	27	147	**450**
41-50 years	25	382	27	70	**504**
>50 years	2	3	17	39	**61**
Unknown	649	502	438	1608	**3197**
Total	**958**	**1561**	**657**	**2924**	**6100**

3.1.2.2 Condition Assessment

Pole testing commenced in 2014 and EPL has tested 4146 of its in-service poles to date (68%). The Health Index is calculated for all wood poles that have been tested and translated into condition using Table 3-6. If the age is unknown, then the Health Index is calculated based on the test results and the results of visual inspections. The condition is calculated for 4146 wood poles (the known set), as summarized in Table 3-8, and then extrapolated to the entire population, as shown in Table 3-9.

Table 3-8: Wood Pole Asset Condition – Known Set

Condition	Number of Poles				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
Very Good	66	61	34	333	**494**
Good	609	465	221	2086	**3381**
Fair	16	10	3	54	**83**
Poor	42	24	8	34	**108**
Very Poor	26	16	6	32	**80**
Unknown	199	985	385	385	**1954**
Total	**958**	**1561**	**657**	**2924**	**6100**

Table 3-9: Wood Pole Asset Condition – Extrapolation

Condition	Number of Poles*				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
Very Good	83	165	82	383	**714**
Good	769	1260	534	2402	**4965**
Fair	20	27	7	62	**117**
Poor	53	65	19	39	**177**
Very Poor	33	43	14	37	**128**
Total	**958**	**1561**	**657**	**2924**	**6100**

*Integers may be off by 1 due to extrapolation.

The pole testing results includes failed poles from 2015 and 2016 that were changed out; therefore, the extrapolation must be adjusted to reflect these change-outs. Table 3-10 presents the extrapolated pole condition as of 2017 after the adjustments.

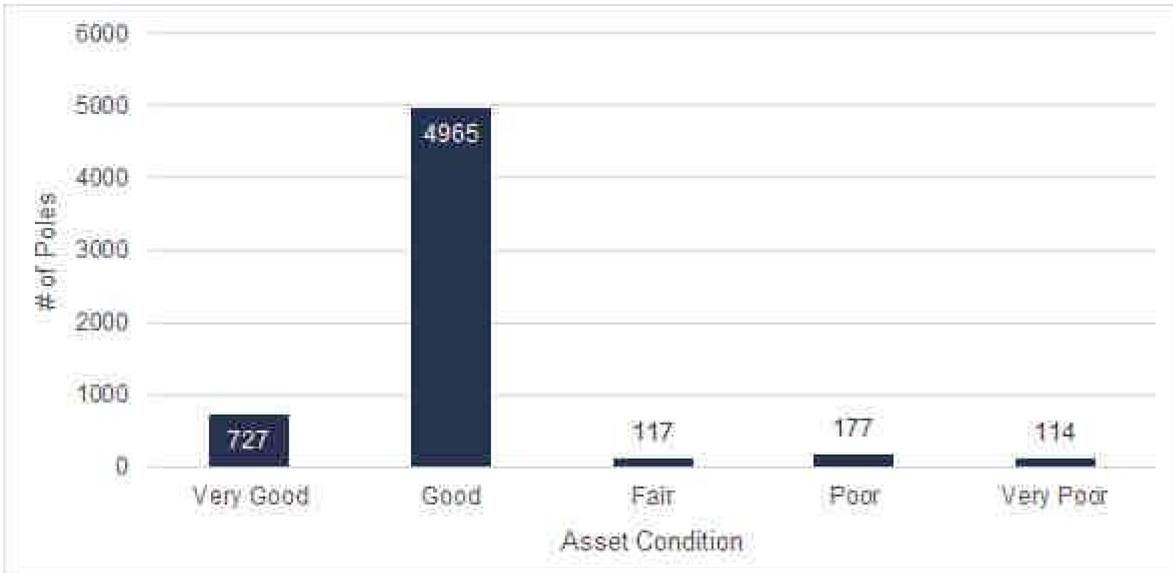
Table 3-10: Wood Pole Asset Condition – 2017 Extrapolation

Condition	Number of Poles*				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
Very Good	83	165	84	394	**727**
Good	769	1260	534	2402	**4965**
Fair	20	27	7	62	**117**
Poor	53	65	19	39	**177**
Very Poor	33	43	12	26	**114**
Total	**958**	**1561**	**657**	**2924**	**6100**

*Integers may be off by 1 due to extrapolation.

The overall distribution consolidated between the four service areas is presented in Figure 3-1. The results suggest a pole replacement rate of 1.5-2% per year, depending on the final results of the risk analysis, which is reflective of a fifty-year TUL.

Figure 3-2: Condition Assessment Results for Wood Poles



3.2 Concrete/Steel Poles

3.2.1 Condition Assessment Methodology

3.2.1.1 Health Index Calculation

The Health Index for both concrete and steel poles is calculated by considering a combination of service age and visual inspection results. Table 3-11 summarizes the methodology to combine these criteria into an overall Health Index for concrete and steel poles. Concrete and steel poles are not tested.

Table 3-11: Concrete/Steel Poles – Health Index

Condition Criteria	Weight	Possible Ratings	Possible Scores	Max Grade
Outstanding issues (visual inspection)	4	A,B,C,D,E	4,3,2,1,0	16
Service age	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	28

EPL considers a TUL of fifty years for concrete poles, which is consistent with common industry practices. Table 3-12 is used to translate the concrete pole service age into a condition rating.

Table 3-12: Concrete Poles – Age Condition Grading

Condition Rating	Age
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 50 years
E	51 years or older

EPL owns just three metal poles, which have a TUL of sixty years based on common industry practice. Table 3-13 is used to translate the steel pole service age into a condition rating.

Table 3-13: Steel Poles – Age Condition Grading

Condition Rating	Age
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 60 years
E	61 years or older

Visual inspections are performed on a three-year cycle, checking for:

- Guy guards missing or out of position
- Guy strain insulators pulled apart or broken
- Leaning pole in unstable soil
- Loose or unattached guy wires or studs
- Slack, broken, or damaged guys
- Other problems (e.g. discoloured insulators, grounding issues)

The pole inspector ranks the issues as high, medium, or low priority depending on the severity. High priority issues generally require immediate follow-up, while other identified issues are prioritized accordingly. If an issue is resolved via corrective maintenance or capital replacement, the inspection database is updated. Table 3-14 presents the condition rating based on the outstanding issues for the concrete or steel pole.

Table 3-14: Concrete/Steel Poles – Outstanding Issues Condition Grading

Condition Rating	Corresponding Condition
A	No outstanding issues
B	One low priority issue outstanding
C	Multiple low priority issues or one medium priority issue outstanding
D	Multiple medium priority issues outstanding
E	One or more high priority issues outstanding

3.2.1.2 Translating Health Index into Asset Condition

The condition of each concrete and steel pole is determined based on its Health Index and service age. As noted in Table 3-6, service age is only used to distinguish between Good and Very Good condition poles when the Health Index is 85% or greater. When the Health Index is less than 85%, it is directly translated into asset condition. If the age is unknown, then the pole is assumed to be in Good condition if the Health Index is greater than or equal to 70%.

Table 3-15: Concrete/Steel Pole Condition Determined Using Health Index and Service Age

Health Index	Service Age	Pole Condition
≥ 85%	≤ 10 years	Very Good
≥ 85%	> 10 years	Good
≥ 70%, < 85%	-	Good
≥ 50%, < 70%	-	Fair
≥ 30%, < 50%	-	Poor
< 30%	-	Very Poor

3.2.2 Results of Analysis

3.2.2.1 Age Demographics

EPL owns 160 concrete poles across its four service territories. The service age is known for 136 – or 85% – of the concrete poles. Figure 3-3 presents the age distribution of the known set of concrete poles. There have been very few concrete pole installations in the past ten years.

Figure 3-3: Consolidated Age Demographics of Concrete Poles

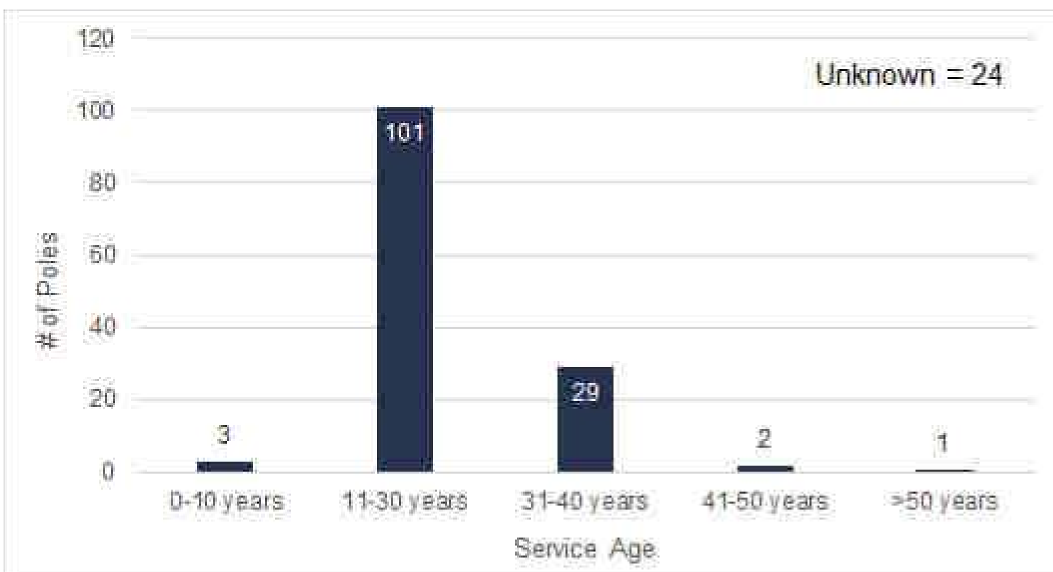


Table 3-16 presents the concrete pole age demographics by community. Over half of the concrete poles are located in LaSalle and most are less than thirty years old.

Table 3-16: Concrete Pole Age Demographics by Community

Age	Number of Poles				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
0-10 years	0	0	0	3	**3**
11-30 years	24	9	15	53	**101**
31-40 years	0	1	0	28	**29**
41-50 years	0	2	0	0	**2**
>50 years	0	0	1	0	**1**
Unknown	2	6	11	5	**24**
Total	**26**	**18**	**27**	**89**	**160**

EPL owns three steel poles: two in LaSalle and one in Leamington. The service age is known for just one of the poles, which is thirty-seven years old and situated in LaSalle.

3.2.2.2 Condition Assessment

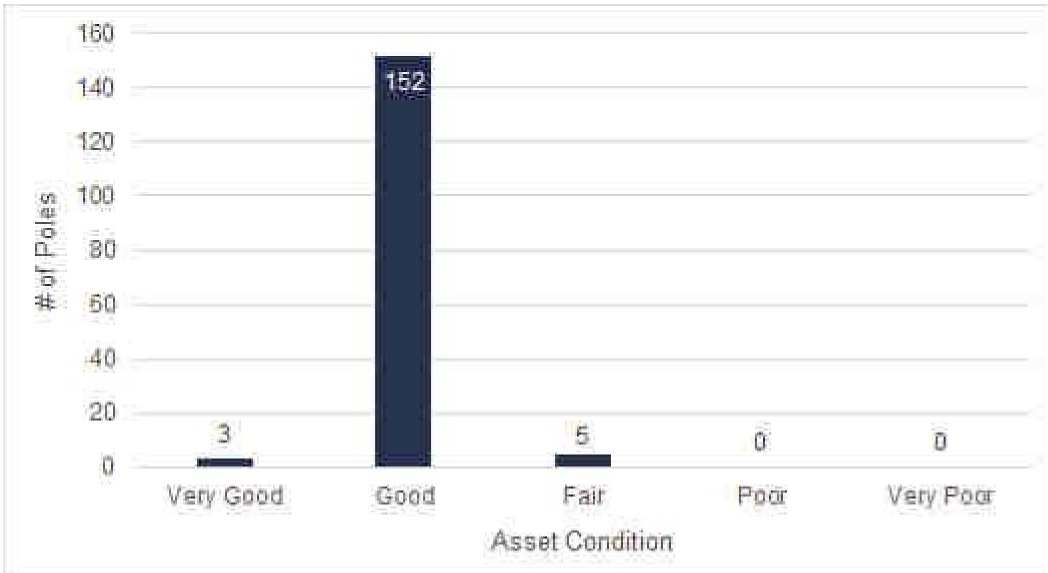
The Health Index is calculated for all concrete and steel poles and translated into condition using Table 3-15. If the age is unknown, then the Health Index is calculated solely based on the visual inspection results.

Table 3-17: Concrete Pole Asset Condition by Community

Condition	Number of Poles*				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
Very Good	0	0	0	3	**3**
Good	26	16	25	85	**152**
Fair	0	2	2	1	**5**
Poor	0	0	0	0	**0**
Very Poor	0	0	0	0	**0**
Total	**26**	**18**	**27**	**89**	**160**

The overall distribution of concrete pole condition consolidated between the four service areas is depicted in Figure 3-4. The results suggest that there are no immediate replacement needs for concrete poles, which is reflective of the visual inspection results that identified only a few low priority issues and no medium or high priority issues.

Figure 3-4: Condition Assessment Results for Concrete Poles



The three steel poles were all assessed to be in good condition. The results suggest that there are also no immediate replacement needs for steel poles, which is reflective of the fact that no issues were identified during visual inspections.

3.3 Distribution Transformers

3.3.1 Condition Assessment Methodology

3.3.1.1 Health Index Calculation

The pole-mounted and pad-mounted transformers on EPL's system step voltages down from primary (27.6/16.0 kV) to secondary (typically 120/240 V, but up to 600 V). The Health Index for both pole-mounted and pad-mounted distribution transformers is calculated by considering a combination of service age and inspection results. For pad-mounted transformers, the inspection includes an infrared scan. Table 3-18 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-18: Distribution Transformers – Health Index

Condition Criteria	Weight	Possible Ratings	Possible Scores	Max Grade
Outstanding issues (inspection results)	4	A,B,C,D,E	4,3,2,1,0	16
Service age	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	28

EPL considers a TUL of forty years for distribution transformers, which is consistent with common industry practices. Table 3-19 is used to translate the distribution transformer service age into a condition rating.

Table 3-19: Distribution Transformer – Age Condition Grading

Condition Rating	Age
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 50 years
E	51 years or older

Visual inspections are performed on a three-year cycle for both pad-mounted and pole-mounted transformers. Pad-mounted transformers are assessed for:

- Pad or vault secured in proper location
- Paint condition acceptable
- Corrosion
- Leaking oil
- Flashed or cracked insulators
- Damaged elbows
- Pad-mount lid damage, public security lock damage assembly
- Vegetation problem
- Access problem
- Other issues (e.g. grounding)

Pole-mounted transformers are checked for:

- Contamination/discolouration of bushings
- Issues with H1 primary bushing
- Rust
- Leaking oil
- Issues with ground lead attachment
- Switch contact not properly closed
- Ground wires on arrestors unattached
- Issues with lightning arrestor
- Issues with bird/animal nests
- Vine/bush growth interface
- Tree trimming required
- Access problem
- Other issues (e.g. wire cover, secondary services)

The inspector ranks the issues as high, medium, or low priority depending on the severity. High priority issues generally require immediate follow-up, while other identified issues are prioritized accordingly.

Pad-mounted transformers also undergo infrared scanning on a three-year cycle. As with visual inspections, detected hotspots are prioritized as high, medium, or low issues by the inspector.

Table 3-20 presents the condition rating based on the outstanding issues for the pad-mounted or pole-mounted distribution transformer.

Table 3-20: Distribution Transformers – Outstanding Issues Condition Grading

Condition Rating	Corresponding Condition
A	No outstanding issues
B	One low priority issue outstanding
C	Multiple low priority issues or one medium priority issue outstanding
D	Multiple medium priority issues outstanding
E	One or more high priority issues outstanding

3.3.1.2 Translating Health Index into Asset Condition

The condition of each distribution transformer is determined based on its Health Index and service age. As noted in Table 3-21, service age is only used to distinguish between Good and Very Good condition poles when the Health Index is 85% or greater. When the Health Index is less than 85%, it is directly translated into asset condition. If the age is unknown, then the pole is assumed to be in Good condition if the Health Index is greater than or equal to 70%.

Table 3-21: Transformer Condition Determined Using Health Index and Service Age

Health Index	Service Age	Wood Pole Condition
≥ 85%	≤ 10 years	Very Good
≥ 85%	> 10 years	Good
≥ 70%, < 85%	-	Good
≥ 50%, < 70%	-	Fair
≥ 30%, < 50%	-	Poor
< 30%	-	Very Poor

3.3.2 Results of Analysis

3.3.2.1 Age Demographics

EPL owns 1886 pad-mounted distribution transformers across its four service territories. The service age is known for 1785 – or 95% – of the pad-mounted transformers. Figure 3-5 presents the age distribution of the known set of pad-mounted transformers, while Table 3-22 presents the age demographics of pad-mounted transformers by community.

Figure 3-5: Consolidated Age Demographics of Pad-mounted Transformers

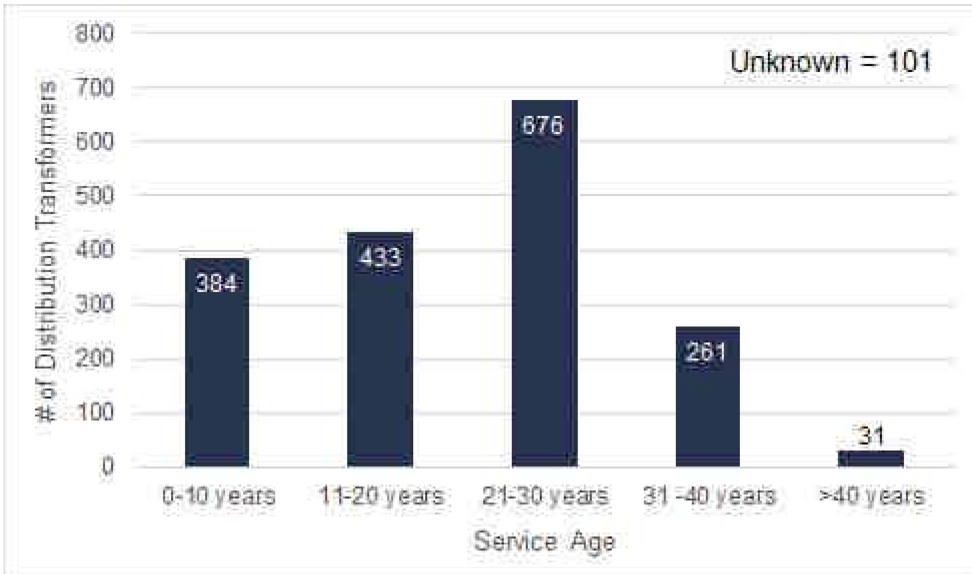


Table 3-22: Pad-mounted Transformer Age Demographics by Community

Age	Number of Distribution Transformers				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
0-10 years	69	80	88	147	**384**
11-30 years	53	114	60	206	**433**
31-40 years	177	132	129	238	**676**
41-50 years	112	87	10	52	**261**
>50 years	15	10	4	2	**31**
Unknown	70	4	15	12	**101**
Total	**496**	**427**	**306**	**657**	**1886**

EPL owns 1183 pole-mounted distribution transformers across its four service territories. The service age is known for 991 – or 84% – of the pole-mounted transformers. Figure 3-6 presents the age distribution of the known set of pole-mounted transformers, while Table 3-22 presents the age demographics of pole-mounted transformers by community.

Figure 3-6: Consolidated Age Demographics of Pole-mounted Transformers

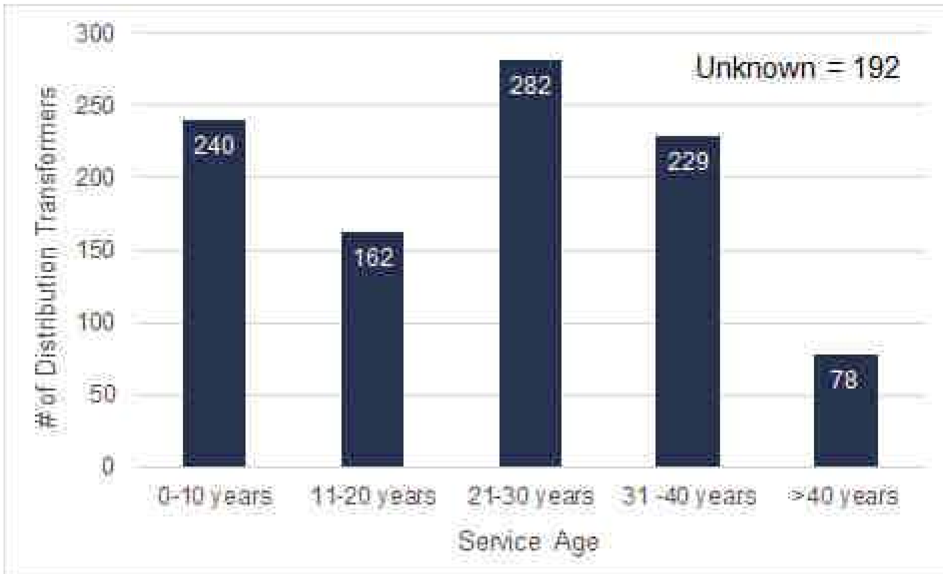


Table 3-23: Pole-mounted Transformer Age Demographics by Community

Age	Number of Distribution Transformers				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
0-10 years	12	45	25	158	**240**
11-30 years	14	49	10	89	**162**
31-40 years	31	73	6	172	**282**
41-50 years	31	71	3	124	**229**
>50 years	6	49	0	23	**78**
Unknown	75	11	89	17	**192**
Total	**169**	**298**	**133**	**583**	**1183**

3.3.2.2 Condition Assessment

The Health Index is calculated for all pad-mounted and pole-mounted distribution transformers and then translated into condition using Table 3-21. If the age is unknown, then the Health Index is calculated solely based on the inspection results. Table 3-24 presents the pad-mounted transformer condition assessment for each community.

Table 3-24: Pad-mounted Transformer Asset Condition by Community

Condition	Number of Poles*				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
Very Good	69	80	88	147	**384**
Good	297	241	199	445	**1182**
Fair	128	106	19	65	**318**
Poor	2	0	0	0	**2**
Very Poor	0	0	0	0	**0**
Total	**496**	**427**	**306**	**657**	**1886**

The overall distribution of pad-mounted transformer condition consolidated between the four service areas is depicted in Figure 3-7. The majority of the pad-mounted distribution transformers are in Good condition, while just two are in Poor condition.

Figure 3-7: Condition Assessment Results for Pad-mounted Transformers

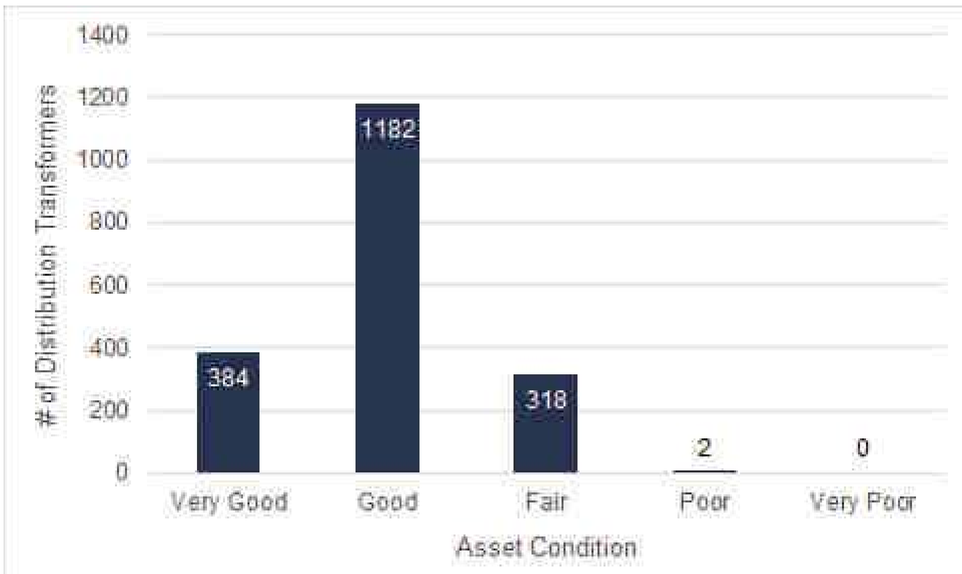


Table 3-25 presents the pole-mounted transformer condition assessment for each community, while Figure 3-8 depicts the overall distribution of pole-mounted transformer condition consolidated between the four service areas. Five pole-mounted distribution transformers are in Poor condition and one is in Very Poor condition. Similar to the pad-mounted transformers, the majority of the pole-mounted distribution transformers are in Good condition.

Table 3-25: Pole-mounted Transformer Asset Condition by Community

Condition	Number of Poles*				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
Very Good	12	45	25	158	**240**
Good	120	127	96	270	**613**
Fair	37	124	12	151	**324**
Poor	0	1	0	4	**5**
Very Poor	0	1	0	0	**1**
Total	**169**	**298**	**133**	**583**	**1183**

Figure 3-8: Condition Assessment Results for Pole-mounted Transformers

3.4 Pad-mounted Switchgear

3.4.1 Condition Assessment Methodology

3.4.1.1 Health Index Calculation

The Health Index for pad-mounted switchgear is calculated by considering a combination of service age and inspection results. For pad-mounted transformers, the inspection includes an infrared scan. Table 3-26 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-26: Pad-mounted Switchgear – Health Index

Condition Criteria	Weight	Possible Ratings	Possible Scores	Max Grade
Outstanding issues (inspection results)	4	A,B,C,D,E	4,3,2,1,0	16
Service age	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	84

EPL considers a TUL of thirty years for pad-mounted switchgear, which is consistent with common industry practices. Table 3-27 is used to calculate the condition rating based on the service age of the pad-mounted switchgear.

Table 3-27: Pad-mounted Switchgear – Age Condition Grading

Condition Rating	Age
A	0 to 10 years
B	11 to 20 years
C	21 to 25 years
D	26 to 30 years
E	31 years or older

Visual inspections are performed on a three-year cycle for pad-mounted switchgear, checking for:

- Overall condition of the pad/foundation
- Paint on metal surfaces of the gear
- Cabinet doors bolted shut
- Switches, fuses, and other internal equipment
- Vegetation problem
- Access problem
- Other issues (e.g. hotspots)

The inspector ranks the issues as high, medium, or low priority depending on the severity. High priority issues generally require immediate follow-up, while other identified issues are prioritized accordingly. Table 3-28 presents the condition rating based on the outstanding issues for the pad-mounted or pole-mounted distribution transformer.

Table 3-28: Pad-mounted Switchgear – Outstanding Issues Condition Grading

Condition Rating	Corresponding Condition
A	No outstanding issues
B	One low priority issue outstanding
C	Multiple low priority issues or one medium priority issue outstanding
D	Multiple medium priority issues outstanding
E	One or more high priority issues outstanding

3.4.1.2 Translating Health Index into Asset Condition

The condition of each distribution transformer is determined based on its Health Index and service age. As noted in Table 3-21, service age is only used to distinguish between Good and Very Good condition poles when the Health Index is 85% or greater. When the Health Index is less than 85%, it is directly translated into asset condition. If the age is unknown, then the pole is assumed to be in Good condition if the Health Index is greater than or equal to 70%.

Table 3-29: Switchgear Condition Determined Using Health Index and Service Age

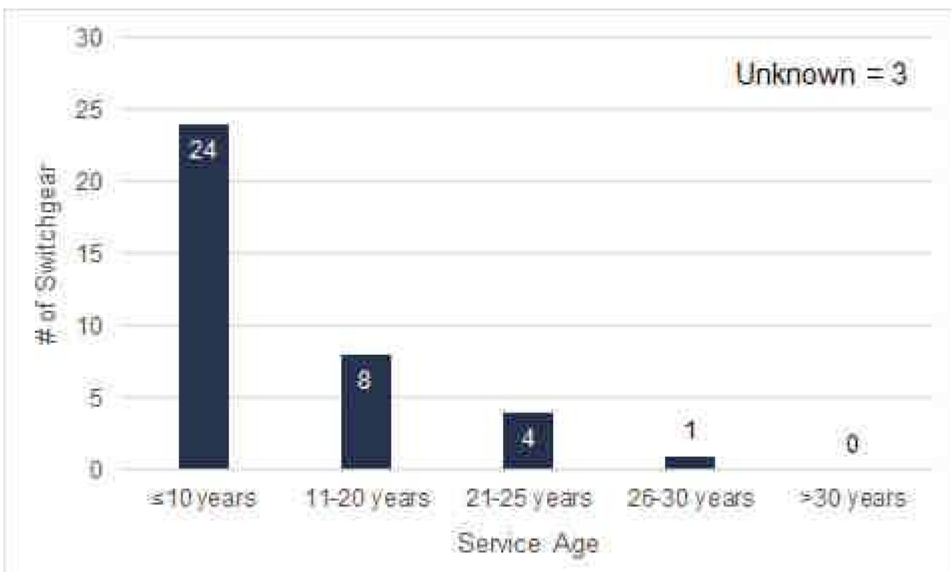
Health Index	Service Age	Wood Pole Condition
≥ 85%	≤ 10 years	Very Good
≥ 85%	> 10 years	Good
≥ 70%, < 85%	-	Good
≥ 50%, < 70%	-	Fair
≥ 30%, < 50%	-	Poor
< 30%	-	Very Poor

3.4.2 Results of Analysis

3.4.2.1 Age Demographics

EPL owns forty pad-mounted switchgear and the service age is known for thirty-seven of them. Figure 3-9 presents the age distribution of the known set of pad-mounted switchgear.

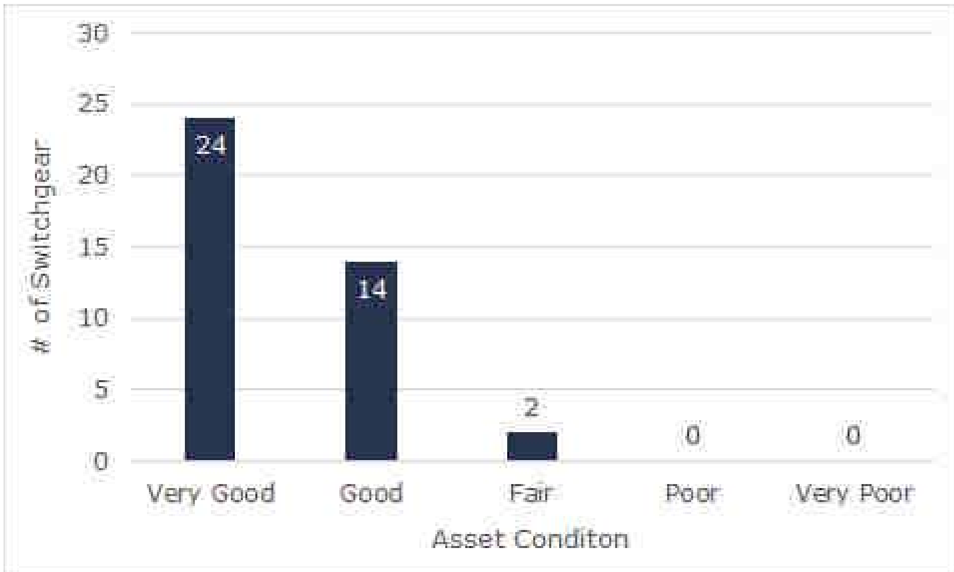
Figure 3-9: Consolidated Age Demographics of Pad-mounted Switchgear



3.4.2.2 Condition Assessment

The Health Index is calculated for all pad-mounted switchgear and then translated into condition using Table 3-29. If the age is unknown, then the Health Index is calculated solely based on the inspection results. The condition assessment results for pad-mounted switchgear are presented in Figure 3-10. Two of the switchgear are in Fair condition, while the rest are in Good or Very Good condition.

Figure 3-10: Condition Assessment Results for Pad-mounted Switchgear



3.5 Dip Poles (Primary Risers)

3.5.1 Condition Assessment Methodology

Dip poles include the protective equipment, cable potheads/terminations, and hardware installed on primary risers (the transition point between the overhead and underground system). EPL does not track age demographics for the dip poles. Instead, the condition of the asset is assessed based on the inspection results. Visual inspections are performed on a three-year cycle for dip poles, checking for:

- Insulator condition
- Problematic switch bracket
- Metal/PVC cable guard condition
- Concerns with lightning arrestors
- Concerns with riser cable and potheads/termination
- Concerns with grounding condition
- Concerns with disconnect switches and/or fused cut-outs
- Concerns with concentric neutral and arrestors
- Leads intact
- Other issues (e.g. vegetation)

The inspector ranks the issues as high, medium, or low priority depending on the severity. High priority issues generally require immediate follow-up, while other identified issues are prioritized accordingly. Table 3-30 presents the condition rating based on the outstanding issues for the pad-mounted or pole-mounted distribution transformer.

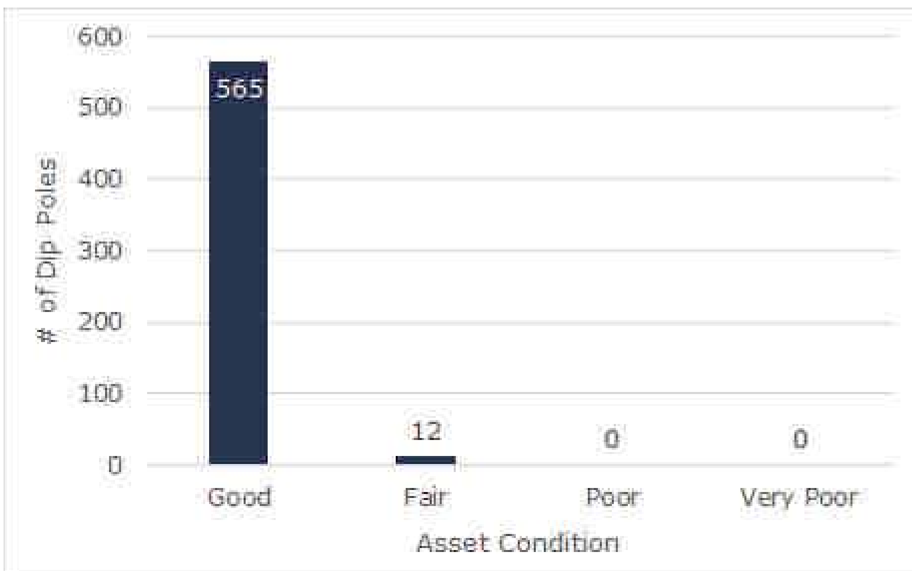
Table 3-30: Dip Poles – Condition Assessment Methodology

Asset Condition	Inspection Results
Good	No outstanding issues
Fair	One/two low priority issue(s) outstanding
Poor	More than two low priority issues or one/two medium priority issue(s) outstanding
Very Poor	One or more high priority issues or more than two medium priority issues outstanding

3.5.2 Results of Analysis

EPL has dip poles at 577 locations. Figure 3-11 presents the results of the condition assessment. Twelve dip poles are in Fair condition, while the rest are in Good condition.

Figure 3-11: Condition Assessment Results for Dip Poles



3.6 Primary Underground Cables

3.6.1 Age Demographics

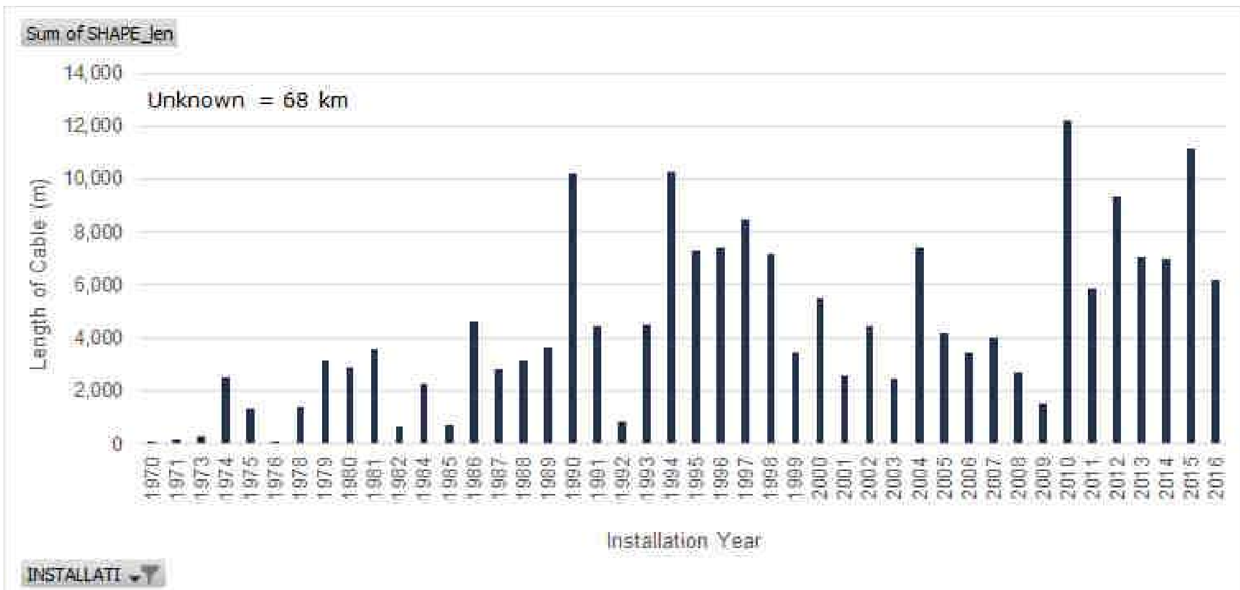
Underground cable length is measured in kilometres of circuit, where a 1-km run of three-phase cable is measured as 1 km rather than 3 km. EPL owns 263 km of primary underground cables across its four service areas. The installation year is known for 194.9 km of the cables – or 74%. Table 3-31 presents the length and number of phases of primary underground cable for each service area.

Table 3-31: Primary Underground Cable Length by Area and Number of Phases

Number of Phases	Length of Cable (km)				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
Single-phase	62.4	40.4	33.7	90.8	**227.3**
Three-phase	7.5	8.3	9.0	10.5	**35.3**
Total	**69.9**	**48.7**	**42.7**	**101.3**	**262.6**

Figure 3-12 presents the cable length by installation year. EPL uses a TUL of thirty years for direct-buried cables and forty years for cables in conduits, which is consistent with common industry practices for primary TR XLPE cables. Since 1986, all primary cables were installed in conduits; therefore, the significant amount of cable installed in 1990 and from 1994 to 1997 will reach their TUL beginning in 2030.

Figure 3-12: Installation Year of Primary Underground Cable



Out of the 67.7 km for which the installation date is unknown, 25.8 km was installed in conduit and is most likely less than thirty years old. The remaining 41.9 km direct-buried cable was presumably installed prior to 1986 and has exceeded its TUL. Based on this analysis, 48.9 km – or 19% – of EPL's underground cable have exceeded TUL. Table 3-32 summarizes the service age of EPL's primary underground cable relative to TUL.

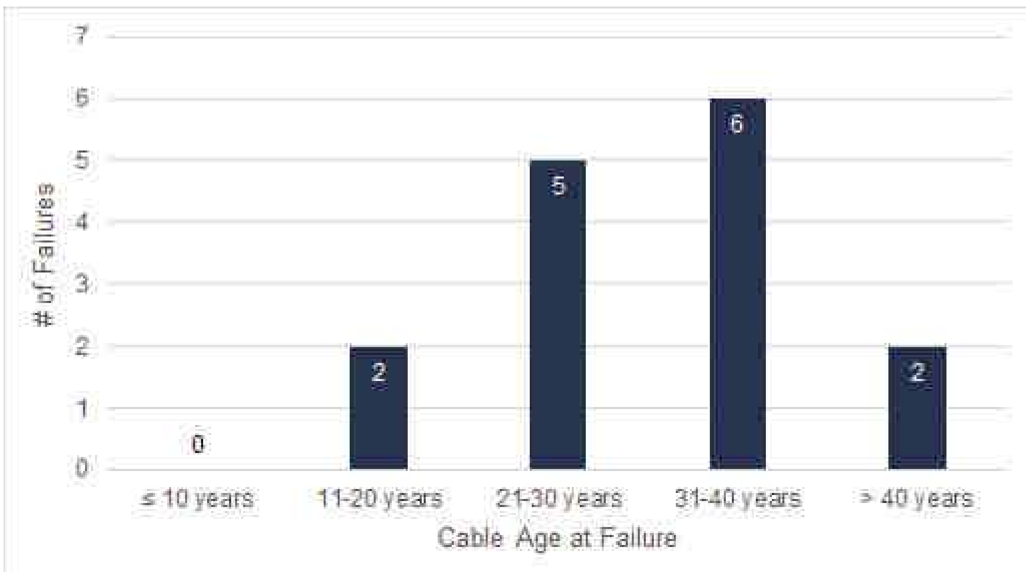
Table 3-32: Primary Underground Cable Service Age Relative to TUL

Service Age	Cable Length (km)
Past TUL	48.9
Will reach TUL by 2026	16.9
Will reach TUL by 2036	54.7
Will reach TUL by 2046	49.2
Will reach TUL by 2056	67.1
Unknown but will reach TUL after 2026	25.8
Total	262.6

3.6.2 Failure History

EPL has experienced eighteen primary cable failures over the past five years (2012 through 2016). The cable's age at failure is known for fifteen of the failures. Figure 3-13 summarizes the age distribution of failed cables. Most of the failed cabled segments were direct-buried cables, especially since cables installed in conduits starting in 1986 have been in service for thirty-one years or less. The failure history supports a TUL of thirty years for direct-buried cables.

Figure 3-13: Age of Primary Underground Cable at Failure



3.6.3 Levelized Cable Replacement

Although 49 km of underground cable has exceeded TUL, replacement should be spread out over many years to avoid rate shock. Adequately addressing this backlog of underground cable replacements over the next ten years will prepare EPL for the significant length of cable that will reach TUL by 2030. A ten-year replacement plan (2017 through 2026) should also consider the 16.9 km of cable that has not yet reached TUL, but will do so by 2026.

Table 3-33: Levelized, Ten-year Replacement Plan of Primary Underground Cables

Year	2017	2018	2019	2020	2021
Cable Length (km)	6.6	6.6	6.6	6.6	6.6
Year	2022	2023	2024	2025	2026
Cable Length (km)	6.6	6.6	6.6	6.6	6.6
Total Length of Cable Replacement (km)					66.0

Attachment 2-D

Capital Expenditure Summary

File Number:	EB-2017-0039
Exhibit:	2
Attachment	2-D
Page:	1 of 1
Date:	August 28th, 2017

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

First year of Forecast Period: *2018*

CATEGORY	**Historical Period** (previous plan[1] & actual)											
	2010			2011			2012			2013		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	Note 1	1,928	--	Note 1	1,502	--	Note 1	1,717	--	Note 1	1,766	--
System Renewal	Note 1	1,675	--	Note 1	1,833	--	Note 1	2,698	--	Note 1	3,113	--
System Service	Note 1	693	--	Note 1	940	--	Note 1	885	--	Note 1	185	--
General Plant	Note 1	960	--	Note 1	251	--	Note 1	1,272	--	Note 1	450	--
TOTAL EXPENDITURE	-	5,255	--	-	4,526	--	-	6,572	--	-	5,513	--
System O&M	Note 1	$ 2,264	--	Note 1	$ 2,618	--	Note 1	$ 3,203	--	Note 1	$ 2,722	--

CATEGORY	**Historical Period** (previous plan[1] & actual)												**Forecast Period** (planned)				
	2014			2015			2016			2017			2018	2019	2020	2021	2022
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	Note 1	2,532	--	Note 1	2,341	--	Note 1	1,759	--	Note 1	1,712	--	1,746	1,781	1,816	1,853	1,835
System Renewal	Note 1	3,012	--	Note 1	2,695	--	Note 1	2,125	--	Note 1	2,655	--	2,693	1,362	2,304	2,248	2,195
System Service	Note 1	177	--	Note 1	2,196	--	Note 1	1,005	--	Note 1	787	--	707	2,186	1,126	1,243	1,342
General Plant	Note 1	487	--	Note 1	547	--	Note 1	384	--	Note 1	1,504	--	1,037	856	976	927	968
TOTAL EXPENDITURE	-	6,208	--	-	7,779	--	-	5,274	--	-	6,658	--	6,183	6,185	6,222	6,270	6,339
System O&M	Note 1	$ 2,994	--	Note 1	$ 3,141	--	Note 1	$ 3,171	--	Note 1	$ 2,794	--	$ 3,067	$ 3,116	$ 3,162	$ 3,213	$ 3,264

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.

2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year): 0

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
1. Historical "previous plan" data is not required unless a plan has previously been filed
Notes on year over year Plan vs. Actual variances for Total Expenditures
Notes on Plan vs. Actual variance trends for individual expenditure categories

Attachment 2-E

Capital Projects Table

File Number:	EB-2017-0039
Exhibit:	2
Attachment:	2-E
Page:	1 of 1
Date:	August 28th, 2017

Appendix 2-AA
Capital Projects Table

Projects	2011	2012	2013	2014	2015	2016	2017 Bridge Year	2018 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access								
Subdivisions	$ 540,677	$ 728,506	$ 240,014	$ 150,424	$ 1,020,249	$ 446,196	$ 375,000	$ 382,500
Residential Connection/Extension	$ 188,901	$ 471,954	$ 429,496	$ 677,866	$ 872,062	$ 1,050,696	$ 386,636	$ 394,369
Municipal Requests	$ 721,963	$ 140,953	$ 1,048,671	$ 1,577,009	$ 311,344	$ 12,336	$ 600,000	$ 612,000
New Service Upgrades - C&I	$ 120,392	$ 226,150	$ 100,871	$ 21,124	$ 3,767	$ 99,080	$ 349,960	$ 356,959
Miscellaneous	-$ 69,558	$ 149,705	-$ 53,546	$ 105,509	$ 133,539	$ 150,961	$ -	$ -
Sub-Total	$ 1,502,375	$ 1,717,268	$ 1,765,507	$ 2,531,933	$ 2,340,960	$ 1,759,269	$ 1,711,596	$ 1,745,828
System Renewal								
Pole Replacement Program	$ 115,417	$ 194,333	$ 478,275	$ 193,281	$ 335,898	$ 513,973	$ 460,478	$ 114,062
O/H Reactive Replacements	$ 110,554	$ 6,908	$ -	$ 6,145	$ -	$ 104,563	$ 80,784	$ 82,400
U/G Reactive Replacements	$ 8,785	$ 53,159	$ 10,765	$ -	$ 6,890	$ -	$ 63,690	$ 64,964
Install/Replace Load Breaks	$ 34,236	$ 3,612	$ -	$ -	$ -	$ 64,119	$ 58,752	$ 59,927
Direct Buried Cable Replacement Program	$ 346,712	$ 1,100,768	$ 851,290	$ 299,670	$ 88,733	$ 43,582	$ 1,229,416	$ 2,224,410
PMH Replacement Program	$ 162,024	$ 27,180	$ 122,012	$ 63,630	$ 55,209	$ 135,236	$ 144,432	$ 147,321
Single Voltage Utility - Conversion	$ 423,196	$ 929,490	$ 935,091	$ 852,182	$ 547,174	$ 85,942	$ 617,735	$ -
Replacement - Lithgow Livefront Transformers	$ -	$ -	$ 389,704	$ -	$ -	$ -	$ -	$ -
Conversion - Monopoly Subdivisions	$ -	$ -	$ -	$ 675,210	$ 259,837	$ 312,264	$ -	$ -
Insulator Replacement	$ -	$ -	$ -	$ -	$ 132,486	$ 145,399	$ -	$ -
Conversion - Howard/6th Concession	$ -	$ -	$ -	$ -	$ 744,587	$ -	$ -	$ -
Primary Cable Replacement	$ 522,882	$ 24,495	$ -	$ 713,295	$ 113,618	$ 93,316	$ -	$ -
Transformer Replacement Program	$ 57,308	$ 47,978	$ 108,721	$ 143,405	$ 178,078	$ 424,720	$ -	$ -
Miscellaneous	$ 51,431	$ 310,092	$ 216,870	$ 65,157	$ 232,675	$ 202,228	$ -	$ -
Sub-Total	$ 1,832,545	$ 2,698,015	$ 3,112,729	$ 3,011,974	$ 2,695,184	$ 2,125,343	$ 2,655,287	$ 2,693,082
System Service								
FIT & Generation Connections	$ 463,599	$ 30,227	$ 91,689	$ 25,824	$ 67,577	$ 80,085	$ 188,892	$ 181,370
HONI Asset Purchases	$ 468,859	$ 232,123	$ 13,222	$ 89,077	$ 21,142	$ -	$ 170,360	$ 89,474
Metering Upgrade & Replacement Program	$ -	$ 56,878	$ 100,139	$ 7,712	$ 8,460	$ 156,282	$ 163,037	$ 166,297
Smart Metering Initiative	$ -	$ 515,559	$ -	$ -	$ 2,051,075	$ 87,921	$ -	$ -
Self Healing Grid Reclosers	$ -	$ -	$ -	$ 61,005	$ -	$ 633,057	$ 264,843	$ 270,140
Miscellaneous	$ 7,314	$ 50,649	-$ 20,282	-$ 7,117	$ 47,571	$ 48,019	$ -	$ -
Sub-Total	$ 939,772	$ 885,435	$ 184,769	$ 176,502	$ 2,195,825	$ 1,005,363	$ 787,132	$ 707,281
General Plant								
Bldgs & Fixtures	$ 13,214	$ 844,622	$ 21,981	$ -	$ 48,914	$ 42,469	$ 286,800	$ 370,000
Office Furniture/Equip	$ -	$ 29,967	$ 6,711	$ 876	$ 5,980	$ 20,672	$ 10,000	$ 10,000
Computer Equipment HW	$ 27,112	$ -	$ 13,501	$ 25,333	$ 5,837	$ 117,329	$ 356,150	$ 161,809
Computer Software	$ 17,981	$ 34,572	$ 52,989	$ 166,960	$ 17,043	$ 4,632	$ 254,500	$ 115,000
Transportation Equip	$ 156,970	$ 198,529	$ 307,516	$ 248,438	$ 401,244	$ 136,662	$ 487,000	$ 270,000
Tools & Equipment	$ 35,577	$ 163,983	$ 47,415	$ 45,486	$ 68,451	$ 62,365	$ 110,000	$ 110,000
Miscellaneous	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total	$ 250,855	$ 1,271,673	$ 450,112	$ 487,094	$ 547,468	$ 384,129	$ 1,504,450	$ 1,036,809
Miscellaneous								
Total	**$ 4,525,547**	**$ 6,572,392**	**$ 5,513,117**	**$ 6,207,502**	**$ 7,779,437**	**$ 5,274,104**	**$ 6,658,465**	**$ 6,183,000**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***								
Total	**4,525,547**	**6,572,392**	**5,513,117**	**6,207,502**	**7,779,437**	**5,274,104**	**6,658,465**	**6,183,000**

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

<u>Attachment 2-F</u>

Capitalization Policy & Amortization Policy

Essex Powerlines Corporation
Capital Assets – Amortization Policy
For the year ending December 31, 2015 (IFRS adoption on Jan 1, 2015) ***updated April 16, 2016* MP**

Process Owner – Max Picco (EPL) – this policy is for Essex Powerlines

Distribution system assets that are self-constructed are recorded in a job costing system (Wennsoft Job Cost now Signature Job Cost), and the process followed is outlined below:

1. job is created in job cost to capture the costs associated with the creation of the asset:
    a. Labour (Code 1)
        i. When employees work on the job they code their time into the job through the Penny Timesheet entry system.
    b. Material (Code 2)
        i. When materials are taken from inventory, or purchased directly to be used for a project it is coded to the job through either an inventory entry or an accounts payable entry.
    c. Equipment (Code 3)
        i. When a vehicle is used for a job the time it was used is coded into the job through the Penny Timesheet entry system.
    d. Sub-Contractors (Code 4)
        i. If sub-contractors are used for a job their invoice is entered into the job through the Accounts Payable module.
    e. Other (Code 5)
        i. If other A/P vendor charges are used for a job the invoice is entered into the job through the Accounts Payable module.
    f. Consultants (Code 6)
        i. If consultants are used for a job their invoice is entered into the job through the Accounts Payable module.

2. Once the job is completed the job is analyzed by supervisors and the Senior clerk (Usually by using the WSJC reporting tool to compare the Estimate created by the estimator in UTILIDE to the actual Job Costs) by both the Operations Supervisor and by the senior clerk to ensure that the costs entered into the job are valid.

3. The Senior Clerk then closes the job in WennSoft which transfers the associated WIP job costs carried in the WIP G/L account to the Fixed Asset Acquisition Clearing G/L account. This posting is summarized by Job and by charge type (the 6 codes noted above).

4. At month-end, the FAAC (fixed asset auto creator) is used to pull the amounts out of the Fixed Asset Acquisition Clearing G/L account and redistribute the capital amounts based on component types or fixed asset classes (e.g. poles, wire, conduit, etc) to the appropriate G/L accounts. At the same time the individual assets are created in the Fixed Asset Books (New IFRS & OEB, etc.) depending on the class (e.g. poles, wire, conduit, etc) and will have the appropriate life and depreciation rate attributed to the assets for future monthly depreciation calculations.

Summary

All assets meeting the definition of a fixed asset shall be considered a long-term asset and shall be recorded in the GP Fixed Asset Module. Such assets shall be systematically and accurately recorded; properly classified; and adequately documented in the GP Fixed Asset Module using Book “NEW IFRS” starting January 1, 2015. Since IFRS is being adopted effective January 1, 2015 the new fixed asset book “NEW IFRS” will be created with gross asset values that reflect the Net Book Value of the original asset costs less accumulated amortization less a pro-rata allocation of the contributed capital (net of amortization) as of December 31, 2014.

Policy

Asset Valuation

Fixed assets shall be recorded at historic cost (not to include administrative overhead) after December 31, 2014. All costs shall be documented, including methods and sources used to establish any estimated costs.

1. Purchased Assets – The recording of purchased assets shall be made on the basis of actual costs, including all ancillary costs, based on vendor invoice or other supporting documentation.
2. Constructed Assets – All direct costs (including labor, but not administrative overhead as was the practice until December 31, 2014 under CGAAP) associated with the construction project shall be included in establishing the asset valuation.

Asset Decommissioning Costs and Salvage Value

The company maintains that any endo of life decommissioning costs net of any salvage value amount to immaterial amounts when discounted to present. As such Essex Powerlines does not add decommissioning costs to capitalized assets.

Asset Classification and amortization periods

Fixed assets should be categorized and amortized as follows:

		FA Module Book Class set-up	
		Useful Lives	
		Used till Dec 2014 = Book ID "OEB"	New starting Jan 1, 2015 = Book ID "NEW IFRS"
1612	Land Rights (intangible)	50	50
1830	Poles	25	50
1835	O/H Conductor	25	50
1840	U/G Conduit	25	40
1845	U/G Conductor	25	30
1850	U/G Transf	25	40
1850	O/H Transf	25	40
1855	Services (Overhead/Underground)	25	50 & 40
1860	Meters Std.	25	25
1860	Meters Interval	25	25
1860	Meters Wholesale	25	25
1860	Meters - Smart	25	15
1865	Other Insall on Cust. Premises	25	25
1908	Buildings & Fixtures	25	50
1915	Office Furniture/Equipment	10	10
1920	Computer Equipment	5	5
1611	Compter Software (intangible)	5	5
1930	Transportation Equipment (Small/Large)	5 & 8	7 & 10
1935	Stores Equipment	10	10
1940	Tools & Equip	10	10
1945	Pwr Measure & Test Equip	10	10
1955	Communication Equipment	10	10
2075	Non-Utility Prop Owned (solar)	20	20

General Policy for Capitalization

Fixed assets should be capitalized as follows:

- All land acquisitions
- All buildings/facilities acquisitions and new construction
- Facility renovation and improvement projects costing more than $1,000
- Equipment and assets costing more than $500 with a useful life beyond a single reporting period (generally one year)
- Purchases of equipment and facilities acquired through a debt financing arrangement meeting the capital lease
- Intangible assets of purchased or internally generated computer software and all other intangible assets costing more than $500 with a useful life beyond a single reporting period (generally one year)
- Construction in Progress (CIP) for capital projects with a budget in excess of $500 shall be presented as part of PP&E but not amortized

Capitalized Interest Costs:

As per IAS 16, the company capitalizes any directly attributable borrowing costs for qualifying assets (construction period in excess of 1 year). The objective of capitalizing interest is to obtain a measure of the acquisition cost that more closely reflect the total investment in the asset.

The capitalization period begins when the following four considerations are present:

- Expenditures for the capital asset have been made.
- Activities necessary to get the capital asset ready for its intended use are in progress.
- Interest costs are being incurred.
- The construction period of cost accumulation exceeds 1 year.

A weighted average of the rates on other borrowings is to be applied to expenditures not covered by specific new borrowings.

Intangible Assets

Intangible assets are those that lack physical substance, are non-financial in nature and have an initial useful life extending beyond a single reporting period (land use rights or easements, and software). Software costing more than $500 with a useful life beyond a single reporting period (generally one-year) should be capitalized.

General and administrative costs and overhead expenditures associated with intangible assets are not to be capitalized as part of the cost.

Construction in Progress (CIP)

A listing of CIP assets reflect the cost of construction work undertaken, but not yet completed. For construction in progress assets, no depreciation is recorded until the asset is placed in service. When construction is completed, the assets are reclassified under the appropriate categories, capitalized and amortized over their useful lives.

Amortization Method

Essex Powerlines has established the straight-line methodology for amortizing all fixed assets using the half-year convention.

Asset Retirement or Disposition and the Derecognition of those Assets

Asset retirement will be transacted when assets are prematurely replaced or there are no more future economic benefits expected from use or planned disposal. Retiring an entire asset will require the removal of the entire asset and related accumulated depreciation from the fixed asset module in GP. Any undepreciated balance will be reported as a loss on disposition.

Disposition of an entire asset will require the removal of the entire asset and related accumulated depreciation from the fixed asset module in GP. Any proceeds will be applied against the NBV and a gain or loss on disposition recorded.

Attachment 2-G

Overhead Expense

File Number:	EB-2017-0039
Exhibit:	2
Attachment:	2-G
Page:	1 of 1
Date:	August 28th, 2017

Appendix 2-D
Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	**2011 Historical Year**	**2012 Historical Year**	**2013 Historical Year**	**2014 Historical Year**	**2015 Historical Year**	**2016 Historical Year**	**2017 Bridge Year**	**2018 Test Year**
Distribution	$ 2,311,983	$ 2,769,624	$ 2,288,897	$ 2,573,946	$ 2,768,874	$ 2,489,996	$ 2,112,492	$ 2,200,339
Billing & Collecting	$ 1,131,257	$ 1,174,568	$ 1,329,771	$ 1,158,128	$ 1,229,676	$ 1,348,249	$ 1,499,880	$ 1,550,150
Community Relations	$ 11,394	$ 8,539	$ 8,451	$ 10,016	$ 12,013	$ 6,482	$ 23,442	$ 23,396
Administrative & General	$ 2,092,295	$ 2,240,566	$ 2,400,175	$ 2,962,130	$ 2,753,655	$ 3,136,895	$ 3,579,949	$ 3,796,390
Labour Burden	$ 229,006	$ 293,809	$ 370,247	$ 375,867	$ 420,809	$ 426,466	$ 486,528	$ 496,528
Material Burden	$ 415,547	$ 451,614	$ 117,111	$ 94,162	$ 92,905	$ 79,266	$ 88,476	$ 90,246
Vehicle Burden	$ 153,393	$ 234,821	$ 251,570	$ 216,004	$ 263,029	$ 228,808	$ 240,000	$ 250,000
Total OM&A Before Capitalization (B)	$ 6,344,875	$ 7,173,540	$ 6,766,223	$ 7,390,252	$ 7,540,961	$ 7,716,163	$ 8,030,767	$ 8,407,049

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	**2011 Historical Year**	**2012 Historical Year**	**2013 Historical Year**	**2014 Historical Year**	**2015 Historical Year**	**2016 Historical Year**	**2017 Bridge Year**	**2018 Test Year**	**Directly Attributable? (Yes/No)**	**Explanation for Change in Overhead Capitalized**
Labour Burden	$ 229,006	$ 293,809	$ 370,247	$ 375,867	$ 420,809	$ 426,466	$ 486,528	$ 496,528	Yes	Training no longer capitalized under IFRS/MIFRS.
Material Burden	$ 415,547	$ 451,614	$ 117,111	$ 94,162	$ 92,905	$ 79,266	$ 88,476	$ 90,246	Yes	Removed the Admin OH layer of our burdens due to IFRS/MIFRS
Vehicle Burden	$ 153,393	$ 234,821	$ 251,570	$ 216,004	$ 263,029	$ 228,808	$ 240,000	$ 250,000	Yes	No changes necessary under MIFRS/IFRS.
Total Capitalized OM&A (A)	$ 797,946	$ 980,244	$ 738,928	$ 686,033	$ 776,743	$ 734,540	$ 815,004	$ 836,774		

% of Capitalized OM&A (=A/B)	13%	14%	11%	9%	10%	10%	10%	10%		

Attachment 2-H

Service Reliability Indicators

File Number:	EB-2017-0039
Exhibit:	2
Attachment:	2-H
Page:	1 of 1
Date:	August 28th, 2017

Appendix 2-G
Service Reliability and Quality Indicators
2011 - 2015

Service Reliability

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply					Excluding Major Event Days				
	2012	2013	2014	2015	2016	2012	2013	2014	2015	2016	2012	2013	2014	2015	2016
SAIDI	4.530	5.370	3.820	2.230	2.540	0.890	2.240	1.160	1.340	0.630	4.530	5.370	3.820	2.230	2.540
SAIFI	3.830	3.580	2.460	1.840	3.200	0.610	1.120	0.660	0.830	0.500	3.830	3.580	2.460	1.840	3.200

5 Year Historical Average

SAIDI		3.698		1.252		3.698
SAIFI		2.982		0.744		2.982

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

Service Quality

Indicator	OEB Minimum Standard	2012	2013	2014	2015	2016
Low Voltage Connections	90.0%	93.2%	92.7%	93.0%	92.3%	90.5%
High Voltage Connections	90.0%	N/A	N/A	N/A	N/A	N/A
Telephone Accessibility	65.0%	68.5%	66.4%	78.0%	79.2%	73.6%
Appointments Met	90.0%	95.7%	94.3%	94.7%	94.8%	90.8%
Written Response to Enquires	80.0%	93.9%	91.2%	91.7%	84.7%	96.3%
Emergency Urban Response	80.0%	91.2%	92.9%	96.3%	100.0%	97.7%
Emergency Rural Response	80.0%	N/A	N/A	N/A	N/A	N/A
Telephone Call Abandon Rate	10.0%	7.0%	1.7%	1.2%	1.4%	0.8%
Appointment Scheduling	90.0%	96.8%	96.5%	95.5%	98.5%	98.8%
Rescheduling a Missed Appointment	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Reconnection Performance Standard	85.0%	96.7%	93.3%	95.3%	93.7%	97.5%

Exhibit 3:

Operating Revenue

Table of Contents

List of Attachments

3.1 Overview

Exhibit 3 is intended to provide details of Essex Powerlines Corporation's ("EPLC") operating revenues for 2010 (Board Approved), 2010 through 2016 (Actual), 2017 (Bridge Year) and 2018 (Test Year). Further, this Exhibit provides a detailed analysis of variances by rate classification for the components of operating revenue.

EPLC is proposing a total Service Revenue Requirement of $13,162,895 for the 2018 Test Year which includes a Base Revenue Requirement of $12,471,074 plus Other Revenue of $691,821. Further details are included in Section 3.4.

3.2 Load Forecast

3.2.1 Overview

EPLC retained Elenchus Research Associates Inc. ("Elenchus") to complete a detailed load forecast for 2017 (Bridge Year) and 2018 (Test Year). The load forecast model and associated write-up provided by Elenchus can be found as Attachment 3-A.

3.2.2 Load and Customer/Connection Forecasts

Elenchus utilized a regression analysis to normalize and forecast EPLC's weather sensitive load using monthly heating degree days and cooling degree days as measured at Environment Canada's Windsor Riverside weather station.

Further details about Elenchus' methodology can be found in Attachment 3-A of this Exhibit.

Figure 2 below summarize the forecasted (2017 Bridge Year, 2018 Test Year) consumption, normalized for weather, against 2010 Board-Approved and historical actual billed consumption for 2010-2016.

Figure 2 – Summary of Load and Customer/Connection Forecasts

Rate Class	Billed kWh	kWh Change	% Change	Customer / Connection Count	Change	% Change
2010 Board Approved	541,118,333					
2010	561,345,855	20,227,522	3.74%	30,981		
2011	544,653,615	(16,692,240)	-2.97%	31,122	141	0.46%
2012	527,521,454	(17,132,161)	-3.15%	31,249	127	0.41%
2013	526,053,625	(1,467,829)	-0.28%	31,521	272	0.87%
2014	523,146,226	(2,907,399)	-0.55%	31,743	222	0.70%
2015	528,742,855	5,596,629	1.07%	31,985	242	0.76%
2016	547,976,676	19,233,821	3.64%	32,346	361	1.13%
2017 Forecast	528,989,785	(18,986,891)	-3.46%	32,550	204	0.63%
2018 Forecast	529,961,552	971,767	0.18%	32,736	186	0.57%

Figure 3 below summarizes the forecasted (2017 Bridge Year, 2018 Test Year) consumption against 2010 Board-Approved and historical actual billed consumption for 2010-2016 by rate class.

Figure 3 – Historical Billed Consumption & Forecast by Rate Class

Rate Class	Residential	GS<50	GS>50	Intermediate	Street Light	Sentinel Light	USL	ED	Total
2010 Board Approved	271,379,498	72,012,960	186,712,098	3,087,555	5,929,910	390,941	1,605,371	-	541,118,333
2010	265,216,568	68,742,430	216,691,454	2,963,603	5,780,507	393,141	1,558,152	-	561,345,855
2011	258,339,185	66,985,205	208,671,393	2,747,562	5,969,304	382,814	1,558,152	-	544,653,615
2012	256,003,979	67,056,278	193,368,936	2,944,410	6,205,705	383,994	1,558,152	-	527,521,454
2013	250,406,105	65,663,990	199,814,450	2,004,795	6,271,491	342,834	1,549,960	-	526,053,625
2014	245,551,952	65,242,011	203,591,284	568,157	6,286,758	350,518	1,555,546	-	523,146,226
2015	244,757,239	65,329,579	210,477,740	51,946	6,227,063	341,136	1,558,152	-	528,742,855
2016	255,390,421	66,808,993	219,618,448	-	4,268,688	335,758	1,554,368	-	547,976,676
2017 Forecast	247,700,344	65,087,892	211,511,541	-	2,799,882	335,758	1,554,368	-	528,989,785
2018 Forecast	246,544,006	65,487,649	183,374,335	-	2,799,882	335,758	1,554,368	29,865,554	529,961,552

Figure 4 below summarizes the forecasted (2017 Bridge Year, 2018 Test Year) customer/connection counts against 2010 Board-Approved and historical customer/connection counts for 2010-2016 by rate class.

Figure 4 – Customers/Connections Forecast

Rate Class	Residential	GS<50	GS>50	Intermediate	Street Light	Sentinel Light	USL	ED	Total
2010 Board Approved	25,902	1,852	222	2	2,643	168	151	-	30,940
2010	26,075	1,895	220	1	2,475	174	141		30,981
2011	26,182	1,921	228	1	2,474	175	141		31,122
2012	26,337	1,906	215	1	2,474	175	141	-	31,249
2013	26,466	1,904	214	1	2,621	175	140	-	31,521
2014	26,590	1,910	217	1	2,713	172	140	-	31,743
2015	26,815	1,936	217	1	2,701	174	141	-	31,985
2016	27,137	1,953	223	-	2,720	173	140	-	32,346
2017 Forecast	27,310	1,965	222	-	2,740	173	140	-	32,550
2018 Forecast	27,484	1,977	219	-	2,740	173	140	3	32,736

3.2.3 Billed Demand Load Forecast

Figure 5 below summarizes the forecasted (2017 Bridge Year, 2018 Test Year) Billed demand against 2010 Board-Approved and historical actual billed demand for 2010-2016 by rate class.

Figure 5 – Historical Billed Demand & Forecast by Rate Class

Rate Class	GS>50	Intermediate	Street Light	Sentinel Light	ED	Total
2010 Board Approved	467,092	19,537	18,024	1,076	-	505,729
2010	423,400	17,115	17,543	883	-	458,941
2011	519,529	17,226	16,576	2,100	-	555,431
2012	514,811	10,850	18,742	2,100	-	546,503
2013	480,276	15,019	19,025	2,100	-	516,420
2014	473,538	5,529	15,872	2,068	-	497,007
2015	561,575	4,376	18,023	2,088	-	586,062
2016	563,949	-	13,490	2,080	-	579,519
2017 Forecast	541,026	-	8,848	2,080	-	551,954
2018 Forecast	464,212	-	8,848	2,080	80,869	556,009

3.2.4 CDM Related Adjustments

Elenchus further adjusted for forecasted Conservation & Demand Management ("CDM") savings. To isolate the impact of CDM, persisting CDM related savings that are measured and verified by the IESO are added back to rate class consumption to simulate class specific consumption assuming there had been no CDM activity. Included as Attachments 3-B and 3-C are EPLC's Load Forecast CDM Adjusted Work Form as well as EPLC's 2015-2020 CDM Plan.

Figures 6 and 7 below outline EPLC's proposed adjustment for CDM for both consumption (kWh) and demand (kW).

Figure 6 – Test Year CDM Adjustment - kWh

kWh	2018 Weather Normal Forecast	CDM Adjustment	2018 CDM Adjusted Forecast
Residential	246,544,006	1,169,888	245,374,118
GS<50	65,487,649	2,780,199	62,707,450
GS>50	183,374,335	7,094,029	176,280,306
Embedded Distributor	29,865,554	-	29,865,554
Street Light	2,799,882	-	2,799,882
Sentinel Light	335,758	-	335,758
USL	1,554,368	-	1,554,368
Total	529,961,552	11,044,116	518,917,436

Figure 7 – Test Year CDM Adjustment - kW

kW	2018 Weather Normal Forecast	CDM Adjustment	2018 CDM Adjusted Forecast
GS>50	464,212	17,959	446,253
Embedded Distributor	80,869	-	80,869
Street Light	8,848	-	8,848
Sentinel Light	2,080	-	2,080
Total	556,010	17,959	538,051

3.2.5 LRAMVA Baseline Calculation

Elenchus further adjusted for forecasted Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA)" adjustments. Included as Attachments 3-B and 3-C are EPLC's Load Forecast CDM Adjusted Work Form as well as EPLC's 2015-2020 CDM Plan.

Figure 8 – EPLC LRAMVA Baseline

Description	Residential	GS<50	GS>50	Embedded Distributor	Street Light	Sentinel Light	USL	Total
2016 Program Persistence	584,944	1,390,100	3,547,015	-	-	-	-	5,522,058
2017 Program Persistence	584,944	1,390,100	3,547,015	-	-	-	-	5,522,058
2018 Program Persistence	584,944	1,390,100	3,547,015	-	-	-	-	5,522,058
Total LRAMVA Baseline	1,754,832	4,170,299	10,641,044	-	-	-	-	16,566,174

3.2.6 Wholesale Market Participants

EPLC currently has three (3) Wholesale Market Participant ("WMP") loads operating within EPLC's service territory. These WMP customers purchase power directly from the IESO however use EPLC's distribution system to delivery electricity to their place of business. EPLC charges these customers transmission and distribution charges however charges such as commodity, Wholesale Market Service and Global Adjustment are billed by the IESO directly to the customer. For the purpose of this Load Forecast, EPLC has included these WMP customers in the GS>50 rate class which is where they qualified prior to registering as a WMP with the IESO. The forecast does not specifically break out these loads from the GS>50 rate class.

Figure 9 below shows the historical aggregated WMP load from August 2012 to December 2016.

Figure 9 – Historical WMP Consumption & Demand

WMP in GS>50	WMP Aggregated Consumption	WMP Aggregated Demand
2012	4,864,322	8,690
2013	11,548,939	20,616
2014	11,509,409	20,054
2015	11,537,201	20,062
2016	11,323,656	19,965
Total	50,783,527	89,387

3.2.7 Summary of 2017 and 2018 Load Forecast

Figure 10 below summarizes EPLC's proposed consumption, demand and customer/connection Forecast for the 2017 Bridge Year and 2018 Test Year, which were used for the purpose of rate design.

Figure 10 – Summary of Load Forecast Used in Rate Design

Rate Class	2017			2018		
	Cust/Conn	kWh	kW	Cust/Conn	kWh	kW
Residential	27,310	247,700,344	-	27,484	245,374,118	-
GS<50	1,965	65,087,892	-	1,977	62,707,450	-
GS>50	222	211,511,541	541,026	222	176,280,306	446,253
Embedded Distributor	-	-	-	3	29,865,554	80,869
Street Light	2,740	2,799,882	8,848	2,740	2,799,882	8,848
Sentinel Light	173	335,758	2,080	173	335,758	2,080
USL	140	1,554,368	-	140	1,554,368	-
Total	32,550	528,989,785	551,954	32,739	518,917,436	538,051

3.3 Accuracy of Load Forecast and Variance Analysis

3.3.1 Overview

This section is intended to provide an overview of EPLC's analysis of its historical load forecast from 2010 BAP to 2016 Actual as well as forecasted values for the 2017 Bridge Year and 2018 Test Year.

EPLC has completed its analysis based on Distribution Revenue, Billing Determinants (customer/connection counts, billed kWh and billed kW) as well as Distribution Revenue calculated based on existing and proposed rates. EPLC also included Appendix 2-IB as Attachment 3-D of this Exhibit.

3.3.2 Distribution Revenue Variance Analysis

The following outlines EPLC's historical variance analysis for the 2010 BAP through 2016 actual years for Distribution Revenue and Billing Determinants. EPLC has provided brief commentary for all variances that exceed its materiality threshold as calculated in Exhibit 1 of this Application. For the purpose of this analysis, the materiality threshold of $65,000 has been used.

2010 BAP Vs. 2010 Actual

Figure 11 – Distribution Revenue – 2010 BAP Vs. 2010 Actual

Rate Class	2010 BAP	2010 Actual	Variance
Residential	$ 7,972,558	$ 7,561,421	$ (411,137)
General Service < 50 kW	$ 970,265	$ 858,010	$ (112,255)
General Service >= 50 kW	$ 2,135,934	$ 2,051,654	$ (84,281)
Embedded Distributor	$ -	$ -	$ -
Street Lighting Connections	$ 148,803	$ 125,104	$ (23,699)
Sentinel Lighting Connections	$ 10,938	$ 10,820	$ (118)
Unmetered Scattered Load Connections	$ 61,206	$ 61,055	$ (151)
Total	**$ 11,299,703**	**$ 10,668,063**	**$ (631,640)**

The primary drivers for the variance between 2010 BAP and 2010 Actual are primarily related to a decrease in consumption from the Residential and General Service < 50 kW customer classes and demand outlined in Figure 12 below driven by the 2008 recession as well as CDM related savings outlined in section 3.2.4 of this Exhibit.

Figure 12 – Billing Determinants – 2010BAP Vs. 2010 Actual

Rate Class	Customers/Connections			kWh		kW		Variance
	2010 BAP	2010 Actual	Variance	2010 BAP	2010 Actual	2010 BAP	2010 Actual	
Residential	25,902	26,075	173	271,379,498	265,216,568	-	-	(6,162,930)
General Service < 50 kW	1,852	1,895	43	72,012,960	68,742,430	-	-	(3,270,530)
General Service >= 50 kW	222	220	(2)	186,712,098	216,691,454	467,092	423,400	(43,692)
General Service > 3000 to 4999 kW	2	1	(1)	3,087,555	2,963,603	19,537	17,115	(2,422)
Embedded Distributor	-	-	-	-	-	-	-	-
Street Lighting Connections	2,643	2,475	(168)	5,929,910	5,780,507	18,024	17,543	(481)
Sentinel Lighting Connections	168	174	6	390,941	393,141	1,076	883	(193)
Unmetered Scattered Load Connections	151	141	(10)	1,605,371	1,558,152	-	-	(47,219)
Total	**30,940**	**30,981**	**41**	**541,118,333**	**561,345,855**	**505,729**	**458,941**	**(9,527,467)**

2010 Actual Vs. 2011 Actual

Figure 13 – Distribution Revenue – 2010 Actual Vs. 2011 Actual

Rate Class	2010 Actual	2011 Actual	Variance
Residential	$ 7,561,421	$ 7,721,301	$ 159,880
General Service < 50 kW	$ 858,010	$ 1,100,408	$ 242,398
General Service >= 50 kW	$ 2,051,654	$ 1,921,392	$ (130,262)
Embedded Distributor	$ -	$ -	$ -
Street Lighting Connections	$ 125,104	$ 166,260	$ 41,156
Sentinel Lighting Connections	$ 10,820	$ 13,212	$ 2,392
Unmetered Scattered Load Connections	$ 61,055	$ 60,726	$ (329)
Total	**$ 10,668,063**	**$ 10,983,299**	**$ 315,236**

EPLC experienced an increase in distribution revenue of $315,236 in 2011 when compared to 2010 Actual as summarized in Figure 13 above.

In 2011, EPLC's total kWh and kW continued to decrease slightly, compared to 2010 Actual. This is a result of the economic recession as well as significant CDM efforts by EPLC as outlined in section 3.2.4 of this Exhibit.

EPLC attributes the variances in Figure 13 and 14 as a result of:

- An overall increase in number of residential, GS<50 and GS>50 customers;
- Full year of Cost of Service rates in effect for all EPLC customers;
- Annual mechanistic IRM inflation of rates as in effect as of May 1st, 2011 as per EB-2010-0082;

Figure 14 – Billing Determinants – 2010 Actual Vs. 2011 Actual

Rate Class	Customers/Connections			kWh		kW		Variance
	2010 Actual	2011 Actual	Variance	2010 Actual	2011 Actual	2010 Actual	2011 Actual	
Residential	26,075	26,182	107	265,216,568	258,339,185	-	-	(6,877,383)
General Service < 50 kW	1,895	1,921	26	68,742,430	66,985,205	-	-	(1,757,225)
General Service >= 50 kW	220	228	8	216,691,454	208,671,393	423,400	519,529	96,129
General Service > 3000 to 4999 kW	1	1	-	2,963,603	2,747,562	17,115	17,226	111
Embedded Distributor	-		-	-	-	-	-	-
Street Lighting Connections	2,475	2,474	(1)	5,780,507	5,969,304	17,543	16,576	(967)
Sentinel Lighting Connections	174	175	1	393,141	382,814	883	2,100	1,217
Unmetered Scattered Load Connections	141	141	-	1,558,152	1,558,152	-	-	-
Total	**30,981**	**31,122**	**141**	**561,345,855**	**544,653,615**	**458,941**	**555,431**	**(8,538,118)**

2011 Actual Vs. 2012 Actual

Figure 15 – Distribution Revenue – 2011 Actual Vs. 2012 Actual

Rate Class	2011 Actual	2012 Actual	Variance
Residential	$ 7,721,301	$ 7,804,704	$ 83,403
General Service < 50 kW	$ 1,100,408	$ 1,437,971	$ 337,563
General Service >= 50 kW	$ 1,921,392	$ 1,588,021	$ (333,371)
Embedded Distributor	$ -	$ -	$ -
Street Lighting Connections	$ 166,260	$ 203,924	$ 37,664
Sentinel Lighting Connections	$ 13,212	$ 14,310	$ 1,098
Unmetered Scattered Load Connections	$ 60,726	$ 60,158	$ (568)
Total	**$ 10,983,299**	**$ 11,109,090**	**$ 125,791**

EPLC experienced an increase in distribution revenue of $125,791 in 2012 when compared to 2011 Actual as summarized in Figure 15 above.

In 2012, EPLC's total kWh and kW continued to decrease slightly, compared to 2011 Actual. This is a result of the economic recession as well as significant CDM efforts by EPLC as outlined in section 3.2.4 of this Exhibit.

EPLC attributes the variances in Figure 15 and 16 as a result of:

- An overall increase in number of residential customers;
- An overall decrease in the number of GS<50 and GS>50 customers;
- Annual mechanistic IRM inflation of rates as in effect as of May 1st, 2012 as per EB-2011-0166;

Figure 16 – Billing Determinants – 2011 Actual Vs. 2012 Actual

Rate Class	Customers/Connections			kWh		kW		Variance
	2011 Actual	2012 Actual	Variance	2011 Actual	2012 Actual	2011 Actual	2012 Actual	
Residential	26,182	26,337	155	258,339,185	256,003,979	-	-	(2,335,206)
General Service < 50 kW	1,921	1,906	(15)	66,985,205	67,056,278	-	-	71,073
General Service >= 50 kW	228	215	(13)	208,671,393	193,368,936	519,529	514,811	(4,718)
General Service > 3000 to 4999 kW	1	1	-	2,747,562	2,944,410	17,226	10,850	(6,376)
Embedded Distributor	-		-	-	-	-	-	-
Street Lighting Connections	2,474	2,474	-	5,969,304	6,205,705	16,576	18,742	2,166
Sentinel Lighting Connections	175	175	-	382,814	383,994	2,100	2,100	-
Unmetered Scattered Load Connections	141	141	-	1,558,152	1,558,152	-		-
Total	**31,122**	**31,249**	**127**	**544,653,615**	**527,521,454**	**555,431**	**546,503**	**(2,273,061)**

2012 Actual Vs. 2013 Actual

Figure 17 – Distribution Revenue – 2012 Actual Vs. 2013 Actual

Rate Class	2012 Actual	2013 Actual	Variance
Residential	$ 7,804,704	$ 7,876,390	$ 71,685
General Service < 50 kW	$ 1,437,971	$ 1,591,911	$ 153,939
General Service >= 50 kW	$ 1,588,021	$ 1,415,445	$ (172,576)
Embedded Distributor	$ -	$ -	$ -
Street Lighting Connections	$ 203,924	$ 242,863	$ 38,939
Sentinel Lighting Connections	$ 14,310	$ 15,810	$ 1,499
Unmetered Scattered Load Connections	$ 60,158	$ 59,767	$ (391)
Total	**$ 11,109,090**	**$ 11,202,185**	**$ 93,095**

EPLC experienced an increase in distribution revenue of $93,095 in 2013 when compared to 2012 Actual as summarized in Figure 17 above.

In 2013, EPLC's total kWh and kW continued to decrease slightly, compared to 2012 Actual. This is a result, in small part, to the economic recession as well as significant CDM efforts by EPLC as outlined in section 3.2.4 of this Exhibit.

EPLC attributes the variances in Figure 17 and 18 as a result of:

- An overall increase in number of residential customers;
- An overall decrease in the number of GS<50 and GS>50 customers;
- Annual mechanistic IRM inflation of rates as in effect as of May 1st, 2013 as per EB-2012-0123;

Figure 18 – Billing Determinants – 2012 Actual Vs. 2013 Actual

Rate Class	Customers/Connections			kWh		kW		Variance
	2012 Actual	2013 Actual	Variance	2012 Actual	2013 Actual	2012 Actual	2013 Actual	
Residential	26,337	26,466	129	256,003,979	250,406,105	-	-	(5,597,874)
General Service < 50 kW	1,906	1,904	(2)	67,056,278	65,663,990	-	-	(1,392,288)
General Service >= 50 kW	215	214	(1)	193,368,936	199,814,450	514,811	480,276	(34,535)
General Service > 3000 to 4999 kW	1	1	-	2,944,410	2,004,795	10,850	15,019	4,169
Embedded Distributor	-	-	-	-	-	-	-	-
Street Lighting Connections	2,474	2,621	147	6,205,705	6,271,491	18,742	19,025	283
Sentinel Lighting Connections	175	175	-	383,994	342,834	2,100	2,100	-
Unmetered Scattered Load Connections	141	140	(1)	1,558,152	1,549,960	-	-	(8,192)
Total	**31,249**	**31,521**	**272**	**527,521,454**	**526,053,625**	**546,503**	**516,420**	**(7,028,437)**

2013 Actual Vs. 2014 Actual

Figure 19 – Distribution Revenue – 2013 Actual Vs. 2014 Actual

Rate Class	2013 Actual	2014 Actual	Variance
Residential	$ 7,876,390	$ 7,711,531	$ (164,859)
General Service < 50 kW	$ 1,591,911	$ 1,537,373	$ (54,538)
General Service >= 50 kW	$ 1,415,445	$ 1,499,281	$ 83,835
Embedded Distributor	$ -	$ -	$ -
Street Lighting Connections	$ 242,863	$ 266,073	$ 23,210
Sentinel Lighting Connections	$ 15,810	$ 17,431	$ 1,621
Unmetered Scattered Load Connections	$ 59,767	$ 59,384	$ (383)
Total	**$ 11,202,185**	**$ 11,091,071**	**$ (111,114)**

EPLC experienced a decrease in distribution revenue of $111,114 in 2014 when compared to 2013 Actual as summarized in Figure 19 above.

In 2014, EPLC's total kWh and kW continued to decrease slightly, compared to 2013 Actual. This is a result, in small part, to the economic recession (for which the area has relatively rebounded) as well as significant CDM efforts by EPLC as outlined in section 3.2.4 of this Exhibit.

EPLC attributes the variances in Figure 19 and 20 as a result of:

- An overall increase in number of residential, GS<50 and GS>50 customers;
- Tax change rate rider which credited customers in effect until April 30th, 2015;
- LRAMVA rate rider which charged customers in effect until April 30th, 2015;
- Other DVA/GA rate riders which credited customers in effect until April 30th, 2015;
- Annual mechanistic IRM inflation of rates as in effect as of May 1st, 2014 as per EB-2013-0128;

Figure 20 – Billing Determinants – 2013 Actual Vs. 2014 Actual

Rate Class	Customers/Connections			kWh		kW		Variance
	2013 Actual	2014 Actual	Variance	2013 Actual	2014 Actual	2013 Actual	2014 Actual	
Residential	26,466	26,590	124	250,406,105	245,551,953	-	-	(4,854,152)
General Service < 50 kW	1,904	1,910	6	65,663,990	65,242,011	-	-	(421,979)
General Service >= 50 kW	214	217	3	199,814,450	203,591,284	480,276	473,538	(6,738)
General Service > 3000 to 4999 kW	1	1	-	2,004,795	568,157	15,019	5,529	(9,490)
Embedded Distributor	-	-	-	-	-	-	-	-
Street Lighting Connections	2,621	2,713	92	6,271,491	6,286,758	19,025	15,872	(3,153)
Sentinel Lighting Connections	175	172	(3)	342,834	350,518	2,100	2,068	(32)
Unmetered Scattered Load Connections	140	140	-	1,549,960	1,555,546	-	-	5,586
Total	**31,521**	**31,743**	**222**	**526,053,625**	**523,146,227**	**516,420**	**497,007**	**(5,289,958)**

2014 Actual Vs. 2015 Actual

Figure 21 – Distribution Revenue – 2014 Actual Vs. 2015 Actual

Rate Class	2014 Actual	2015 Actual	Variance
Residential	$ 7,711,531	$ 9,894,481	$ 2,182,950
General Service < 50 kW	$ 1,537,373	$ 1,919,833	$ 382,460
General Service >= 50 kW	$ 1,499,281	$ 1,598,368	$ 99,087
Embedded Distributor	$ -	$ -	$ -
Street Lighting Connections	$ 266,073	$ 272,332	$ 6,259
Sentinel Lighting Connections	$ 17,431	$ 17,371	$ (59)
Unmetered Scattered Load Connections	$ 59,384	$ 60,378	$ 994
Total	**$ 11,091,071**	**$ 13,762,763**	**$ 2,671,692**

EPLC experienced an increase in distribution revenue of $2,671,692 in 2015 when compared to 2014 Actual as summarized in Figure 21 above.

In 2015, EPLC's total kWh and kW continued to decrease slightly, compared to 2014 Actual. This is a result of significant CDM efforts by EPLC as outlined in section 3.2.4 of this Exhibit.

EPLC attributes the variances in Figure 21 and 22 as a result of:

- An overall increase in number of residential, GS<50 and GS>50 customers;
- Approval of disposition of the Smart Metering Initiative costs which greatly affected residential and GS<50 variances;

Figure 22 – Billing Determinants – 2014 Actual Vs. 2015 Actual

Rate Class	Customers/Connections			kWh		kW		Variance
	2014 Actual	2015 Actual	Variance	2014 Actual	2015 Actual	2014 Actual	2015 Actual	
Residential	26,590	26,815	225	245,551,953	244,757,239	-	-	(794,714)
General Service < 50 kW	1,910	1,936	26	65,242,011	65,329,579	-	-	87,568
General Service >= 50 kW	217	217	-	203,591,284	210,477,740	473,538	561,575	88,037
General Service > 3000 to 4999 kW	1	1	-	568,157	51,946	5,529	4,376	(1,153)
Embedded Distributor	-	-	-	-	-	-	-	-
Street Lighting Connections	2,713	2,701	(12)	6,286,758	6,227,063	15,872	18,023	2,151
Sentinel Lighting Connections	172	174	2	350,518	341,136	2,068	2,088	20
Unmetered Scattered Load Connections	140	141	1	1,555,546	1,558,152	-	-	2,606
Total	31,743	31,985	242	523,146,227	528,742,855	497,007	586,062	(615,485)

2015 Actual Vs. 2016 Actual

Figure 23 – Distribution Revenue – 2015 Actual Vs. 2016 Actual

Rate Class	2015 Actual	2016 Actual	Variance
Residential	$ 9,894,481	$ 8,394,579	$ (1,499,903)
General Service < 50 kW	$ 1,919,833	$ 1,795,691	$ (124,142)
General Service >= 50 kW	$ 1,598,368	$ 1,603,629	$ 5,262
Embedded Distributor	$ -	$ -	$ -
Street Lighting Connections	$ 272,332	$ 232,782	$ (39,550)
Sentinel Lighting Connections	$ 17,371	$ 17,204	$ (167)
Unmetered Scattered Load Connections	$ 60,378	$ 59,476	$ (902)
Total	**$ 13,762,763**	**$ 12,103,362**	**$ (1,659,402)**

EPLC experienced a decrease in distribution revenue of $1,659,402 in 2016 when compared to 2015 Actual as summarized in Figure 23 above.

In 2016, EPLC's total kWh and kW increased as a result of increases in demand and an overall hotter year which drove an increase in distribution revenue; especially in the summer.

EPLC attributes the variances in Figure 23 and 24 as a result of:

- An overall increase in number of residential, GS<50 and GS>50 customers;
- The primary variance is a correction from the one-time approval of disposition of Smart Metering Initiative costs in 2015 which greatly affected residential and GS<50 variances;
- Annual mechanistic IRM inflation of rates as in effect as of May 1st, 2016 as per EB-2015-0005;

Figure 24 – Billing Determinants – 2015 Actual Vs. 2016 Actual

Rate Class	Customers/Connections			kWh		kW		Variance
	2015 Actual	2016 Actual	Variance	2015 Actual	2016 Actual	2015 Actual	2016 Actual	
Residential	26,815	27,137	322	244,757,239	255,390,422	-	-	10,633,183
General Service < 50 kW	1,936	1,953	17	65,329,579	66,808,993	-	-	1,479,414
General Service >= 50 kW	217	223	6	210,477,740	219,618,449	561,575	563,949	2,374
General Service > 3000 to 4999 kW	1	-	(1)	51,946	-	4,376	-	(4,376)
Embedded Distributor	-	-	-	-	-	-	-	-
Street Lighting Connections	2,701	2,720	19	6,227,063	4,268,688	18,023	13,490	(4,533)
Sentinel Lighting Connections	174	173	(1)	341,136	335,758	2,088	2,080	(8)
Unmetered Scattered Load Connections	141	140	(1)	1,558,152	1,554,368	-	-	(3,784)
Total	**31,985**	**32,346**	**361**	**528,742,855**	**547,976,678**	**586,062**	**579,519**	**12,102,270**

3.3.3 2017/2018 Distribution Revenue at Existing Rates

Figure 25 – Distribution Revenue – 2017 Bridge Vs. 2018 Test

Rate Class	2017 Bridge	2018 Test	Variance
Residential	$ 8,588,056	$ 8,612,319	$ 24,263
General Service < 50 kW	$ 1,609,420	$ 1,585,914	$ (23,507)
General Service >= 50 kW	$ 1,551,690	$ 1,528,407	$ (23,283)
Embedded Distributor	$ 197,973	$ 187,106	$ (10,867)
Street Lighting Connections	$ 187,615	$ 187,611	$ (4)
Sentinel Lighting Connections	$ 27,447	$ 27,447	$ -
Unmetered Scattered Load Connections	$ 62,175	$ 62,175	$ -
Total	**$ 12,224,376**	**$ 12,190,979**	**$ (33,397)**

EPLC calculated Distribution Revenue for the 2017 Bridge Year and 2018 Test Year, as summarized above in Figure 25, based on existing Board approved rates and the Billing Determinants summarized in Figure 26 below. EPLC is anticipating a very small decrease in Distribution Revenue based on projected decreases in kWh and kW. These projections are summarized in EPLC's load forecast which is included as Attachment 3-A of this Exhibit.

Figure 26 – Billing Determinants – 2017 Bridge Vs. 2018 Test

Rate Class	Customers/Connections			kWh		kW		Variance
	2017 Bridge	2018 Test	Variance	2017 Bridge	2018 Test	2017 Bridge	2018 Test	
Residential	27,310	27,484	174	247,700,344	245,374,118	-	-	(2,326,226)
General Service < 50 kW	1,965	1,977	12	65,087,892	62,707,450	-	-	(2,380,442)
General Service >= 50 kW	219	219	-	179,829,958	176,280,306	455,239	446,253	(8,986)
General Service > 3000 to 4999 kW	-	-	-	-	-	-	-	-
Embedded Distributor	3	3	-	31,681,583	29,865,554	85,786	80,869	(4,917)
Street Lighting Connections	2,740	2,740	-	2,799,882	2,799,882	8,848	8,848	-
Sentinel Lighting Connections	173	173	-	335,758	335,758	2,080	2,080	-
Unmetered Scattered Load Connections	140	140	-	1,554,368	1,554,368	-	-	-
Total	**32,550**	**32,736**	**186**	**528,989,785**	**518,917,436**	**551,954**	**538,051**	**(4,720,571)**

3.3.4 Test Year Distribution Revenue at Proposed Rates

EPLC calculated Distribution Revenue for the 2018 Test Year, as summarized below in Figure 27, based on the proposed rates summarized in this Application and the Billing Determinants previously summarized in Figure 26 above.

Figure 27 – Distribution Revenue – 2017 Bridge @ Existing Rates Vs. 2018 Test @ Proposed Rates

Rate Class	2017 Bridge @ Existing Rates	2018 Test @ Proposed Rates	Variance
Residential	$ 8,588,056	$ 8,883,696	$ 295,640
General Service < 50 kW	$ 1,609,420	$ 1,623,942	$ 14,522
General Service >= 50 kW	$ 1,551,690	$ 1,563,530	$ 11,840
Embedded Distributor	$ 197,973	$ 118,094	$ (79,879)
Street Lighting Connections	$ 187,615	$ 192,059	$ 4,444
Sentinel Lighting Connections	$ 27,447	$ 26,662	$ (785)
Unmetered Scattered Load Connections	$ 62,175	$ 58,609	$ (3,566)
Total	**$ 12,224,376**	**$ 12,466,592**	**$ 242,216**

3.4 Other Revenue

3.4.1 Overview

Other Revenue refers to revenue that is distribution in nature however is not received through distribution rates. Other Revenues consists of four primary categories:

- Specific Service Charges;
- Late Payment Charges;
- Other Operating Revenues;
- Other Income or Deductions

EPLC made some minor, immaterial changes across the categories to better align with the APH as summarized below in Figure 28.

Figure 28 – Other Revenue Adjustment

Description	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual
Specific Service Charges	$ (191,738)	$ (172,297)	$ (183,389)	$ (189,503)	$ (162,399)	$ (177,244)	$ (177,950)
Adjustment	$ 28,960	$ 27,413	$ 27,379	$ 26,348	$ 16,061	$ 22,559	$ 24,654
Adjusted Specific Service Charges	**$ (162,778)**	**$ (144,884)**	**$ (156,010)**	**$ (163,155)**	**$ (146,338)**	**$ (154,685)**	**$ (153,296)**
Late Payment Charges	$ (170,398)	$ (248,885)	$ (232,732)	$ (255,410)	$ (248,723)	$ (246,472)	$ (239,495)
Adjustment	$ (22,710)	$ (20,580)	$ (20,100)	$ (19,015)	$ (10,890)	$ (15,155)	$ (27,240)
Adjusted Late Payment Charges	**$ (193,108)**	**$ (269,465)**	**$ (252,832)**	**$ (274,425)**	**$ (259,613)**	**$ (261,627)**	**$ (266,735)**
Other Operating Revenue	$ (232,674)	$ (230,182)	$ (228,063)	$ (228,608)	$ (247,219)	$ (230,529)	$ (243,002)
Adjustment	$ (6,250)	$ (6,833)	$ (7,279)	$ (7,333)	$ (5,171)	$ (7,404)	$ 2,586
Adjusted Other Operating Revenue	**$ (238,925)**	**$ (237,015)**	**$ (235,342)**	**$ (235,941)**	**$ (252,390)**	**$ (237,933)**	**$ (240,416)**

EPLC's Other Revenue is calculated below as Figure 29 for the 2010 BAP, historical years 2010 through 2016 and the 2017 Bridge and 2018 Test Years.

Figure 29 – Other Revenue Summary

Description	2010 BAP	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge Year	2018 Test Year
Specific Service Charges	$(167,415)	$ (162,778)	$ (144,884)	$ (156,010)	$ (163,155)	$ (146,338)	$ (154,685)	$ (153,296)	$ (166,480)	$ (166,480)
Late Payment Charges	$(148,511)	$ (193,108)	$ (269,465)	$ (252,832)	$ (274,425)	$ (259,613)	$ (261,627)	$ (266,735)	$ (260,400)	$ (260,400)
Other Operating Revenues	$(228,355)	$ (238,925)	$ (237,015)	$ (235,342)	$ (235,941)	$ (252,390)	$ (237,933)	$ (240,416)	$ (225,155)	$ (225,155)
Other Income or Deductions	$(225,176)	$ (559,961)	$ (814,058)	$ (934,108)	$ (569,531)	$ (487,875)	$ (127,215)	$ 657,281	$ (354,035)	$ (176,486)
Total	**$(769,457)**	**$ (1,154,772)**	**$ (1,465,422)**	**$ (1,578,292)**	**$ (1,243,052)**	**$ (1,146,216)**	**$ (781,460)**	**$ (3,166)**	**$ (1,006,070)**	**$ (828,521)**

For the purpose of calculating Revenue Requirement, EPLC excluded revenues and expenses relating from its solar PV assets. Figure 30 below outlines EPLC's proposed Adjusted Other Revenue for the purpose of calculating Revenue Requirement.

Figure 30 – Adjusted Other Revenue Summary

Description	2010 BAP	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge Year	2018 Test Year
Total Other Revenue	$(769,457)	$ (1,154,772)	$ (1,465,422)	$ (1,578,292)	$ (1,243,052)	$ (1,146,216)	$ (781,460)	$ (3,166)	$ (1,006,070)	$ (828,521)
Exclude:										
Non-Regulated Solar Revenue	$ -	$ -	$ (398,812)	$ (590,368)	$ (586,822)	$ (401,920)	$ (390,198)	$ (394,876)	$ (369,700)	$ (366,700)
Non-Regulated Solar Expense	$ -	$ -	$ 35,901	$ 49,173	$ 49,131	$ 34,807	$ 204,896	$ 252,183	$ 212,000	$ 230,000
DVA Interest (Account 4405)	$ -	$ (22,245)	$ (67,938)	$ (103,056)	$ (215,535)	$ (299,988)	$ (63,816)	$ (121,510)	$ -	$ -
Total Adjusted Other Revenue	**$(769,457)**	**$ (1,154,772)**	**$ (1,102,511)**	**$ (1,037,097)**	**$ (705,361)**	**$ (779,103)**	**$ (596,158)**	**$ 139,526**	**$ (848,370)**	**$ (691,821)**

EPLC has included Board Appendix 2-H as Attachment 3-E of this Exhibit.

3.4.2 Other Revenue Variance Analysis

The variance analysis in this Section has been completed consistent with EPLC's materiality threshold calculated in Exhibit 1 of this Application. For the purpose of this analysis, EPLC's materiality threshold is $65,000.

Figure 31 below shows the variances by Other Revenue category for the 2010 BAP, historical years 2010 through 2016 and the 2017 Bridge and 2018 Test Years.

Figure 31 – Other Revenue Variance Summary

Description	2010 BAP	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge Year	2018 Test Year
Specific Service Charges	$(167,415)	$ (162,778)	$ (144,884)	$ (156,010)	$ (163,155)	$ (146,338)	$ (154,685)	$ (153,296)	$ (166,480)	$ (166,480)
Late Payment Charges	$(148,511)	$ (193,108)	$ (269,465)	$ (252,832)	$ (274,425)	$ (259,613)	$ (261,627)	$ (266,735)	$ (260,400)	$ (260,400)
Other Operating Revenues	$(228,355)	$ (238,925)	$ (237,015)	$ (235,342)	$ (235,941)	$ (252,390)	$ (237,933)	$ (240,416)	$ (225,155)	$ (225,155)
Other Income or Deductions	$(225,176)	$ (559,961)	$ (814,058)	$ (934,108)	$ (569,531)	$ (487,875)	$ (127,215)	$ 657,281	$ (354,035)	$ (176,486)
Total	**$(769,457)**	**$(1,163,413)**	**$(1,501,323)**	**$(1,578,292)**	**$(1,243,052)**	**$(1,146,216)**	**$ (781,460)**	**$ (3,166)**	**$(1,006,070)**	**$ (828,521)**

Description	2010 BAP vs. 2010 Actual	2010 Act Vs. 2011 Act	2011 Act Vs. 2012 Act	2012 Act Vs. 2013 Act	2013 Act Vs. 2014 Act	2014 Act Vs. 2015 Act	2015 Act Vs. 2016 Act	2016 Act Vs. 2017 Bridge	2017 Bridge Vs. 2018 Test
Specific Service Charges	$ 4,637	$ 17,894	$ (11,126)	$ (7,145)	$ 16,817	$ (8,347)	$ 1,389	$ (13,184)	$ -
Late Payment Charges	$ (44,597)	$ (76,357)	$ 16,633	$ (21,593)	$ 14,812	$ (2,014)	$ (5,108)	$ 6,335	$ -
Other Operating Revenues	$ (10,570)	$ 1,909	$ 1,673	$ (599)	$ (16,449)	$ 14,457	$ (2,483)	$ 15,261	$ -
Other Income or Deductions	$ (334,785)	$ (254,097)	$ (120,051)	$ 364,577	$ 81,656	$ 360,661	$ 784,495	$(1,011,316)	$ 177,549
Total	**$ (385,315)**	**$ (310,651)**	**$ (112,870)**	**$ 335,240**	**$ 96,836**	**$ 364,757**	**$ 778,293**	**$(1,002,904)**	**$ 177,549**

2010 BAP Vs. 2010 Actual

EPLC experienced an overall increase of $393,956 in Other Revenue between the 2010 BAP and 2010 Actual. Figure 32 below details the variances by USoA account.

Figure 32 – 2010 BAP Vs. 2010 Actual Variance Analysis

USoA #	Description	2010 BAP	2010 Actual	Variance
	Reporting Basis	CGAAP	CGAAP	
4235	Specific Service Charges	$ (167,415)	$ (162,778)	$ 4,637
4225	Late Payment Charges	$ (148,511)	$ (193,108)	$ (44,597)
4080	SSS Revenue	$ (91,250)	$ (78,655)	$ 12,595
4082	Retail Services Revenues	$ (33,424)	$ (45,485)	$ (12,061)
4084	Service Tax Requests	$ (1,357)	$ (12,374)	$ (11,017)
4090	Electric Services Incidental to Energy Sales	$ -	$ -	$ -
4205	Interdepartmental Rents	$ -	$ -	$ -
4210	Rent from Electric Property	$ (102,324)	$ (102,337)	$ (13)
4215	Other Utility Operating Income	$ -	$ -	$ -
4220	Other Electric Revenues	$ -	$ (74)	$ (74)
4240	Provision for Rate Refunds	$ -	$ -	$ -
4245	Government Assistance Directly Credited to Income	$ -	$ -	$ -
4305	Regulatory Debits	$ -	$ -	$ -
4310	Regulatory Credits	$ -	$ -	$ -
4315	Revenues from Electric Plant Leased to Others	$ -	$ -	$ -
4320	Expenses of Electric Plant Leased to Others	$ -	$ -	$ -
4325	Revenues from Merchandise, Jobbing, Etc.	$ -	$ -	$ -
4330	Costs and Expenses from Merchandise, Jobbing, Etc.	$ -	$ -	$ -
4335	Profits and losses from Financial Instrument Hedges	$ -	$ -	$ -
4340	Profits and losses from Financial Instrument Investments	$ -	$ -	$ -
4345	Gains from Disposition of Future Use Utility Plant	$ -	$ -	$ -
4350	Losses from Disposition of Future Use Utility Plant	$ -	$ -	$ -
4355	Gain on Disposition of Utility and Other Property	$ (10,000)	$ (23,879)	$ (13,879)
4360	Loss on Disposition of Utility and Other Property	$ -	$ -	$ -
4365	Gains from Disposition of Allowances for Emission	$ -	$ -	$ -
4370	Losses from Disposition of Allowances for Emission	$ -	$ -	$ -
4375	Revenues from Non-Utility Operations	$ (1,787,240)	$ (2,196,295)	$ (409,055)
4375	Generation Facility Revenues - Sub-Account	$ -	$ -	$ -
4380	Expenses from Non-Utility Operations	$ 1,628,857	$ 1,711,586	$ 82,729
4380	Generation Facility Expenses - Sub-Account	$ -	$ 8,641	$ 8,641
4385	Expenses of Non-Utility Operations	$ -	$ -	$ -
4390	Miscellaneous Non-Operating Income	$ (21,300)	$ (8,611)	$ 12,689
4395	Rate-Payer Benefit Including Interest	$ -	$ -	$ -
4398	Foreign Exchange Gains and Losses, Including Amortization	$ -	$ 36,067	$ 36,067
4405	Interest and Dividend Income	$ (35,493)	$ (87,470)	$ (51,977)
4415	Equity in Earnings of Subsidiary Companies	$ -	$ -	$ -
	Total	**$ (769,457)**	**$ (1,154,772)**	**$ (385,315)**

Account 4375 – Revenue from Non-Utility Operations

EPLC experienced an increase in account 4375 as a result of non-budgeted items related to Conservation & Demand Management. CDM revenues and expenses are largely and mostly timing related variances as EPLC is not affected either positively or negatively by the administration of CDM programs.

Account 4380 – Expenses from Non-Utility Operations

EPLC experienced an increase in account 4380 as a result of non-budgeted items related to Conservation & Demand Management. CDM revenues and expenses are largely and mostly timing related variances.

2010 Actual Vs. 2011 Actual

EPLC experienced an overall increase of $337,910 in Other Revenue between the 2010 Actual and 2011 Actual. Figure 33 below details the variances by USoA account.

Figure 33 – 2010 Actual Vs. 2011 Actual Variance Analysis

USoA #	Description	2010 Actual	2011 Actual	Variance
Reporting Basis		CGAAP	CGAAP	
4235	Specific Service Charges	$ (162,778)	$ (144,884)	$ 17,894
4225	Late Payment Charges	$ (193,108)	$ (269,465)	$ (76,357)
4080	SSS Revenue	$ (78,655)	$ (76,745)	$ 1,910
4082	Retail Services Revenues	$ (45,485)	$ (38,946)	$ 6,539
4084	Service Tax Requests	$ (12,374)	$ (14,114)	$ (1,740)
4090	Electric Services Incidental to Energy Sales	$ -	$ -	$ -
4205	Interdepartmental Rents	$ -	$ -	$ -
4210	Rent from Electric Property	$ (102,337)	$ (105,058)	$ (2,721)
4215	Other Utility Operating Income	$ -	$ -	$ -
4220	Other Electric Revenues	$ (74)	$ (2,152)	$ (2,079)
4240	Provision for Rate Refunds	$ -	$ -	$ -
4245	Government Assistance Directly Credited to Income	$ -	$ -	$ -
4305	Regulatory Debits	$ -	$ -	$ -
4310	Regulatory Credits	$ -	$ -	$ -
4315	Revenues from Electric Plant Leased to Others	$ -	$ -	$ -
4320	Expenses of Electric Plant Leased to Others	$ -	$ -	$ -
4325	Revenues from Merchandise, Jobbing, Etc.	$ -	$ -	$ -
4330	Costs and Expenses from Merchandise, Jobbing, Etc.	$ -	$ -	$ -
4335	Profits and losses from Financial Instrument Hedges	$ -	$ -	$ -
4340	Profits and losses from Financial Instrument Investments	$ -	$ -	$ -
4345	Gains from Disposition of Future Use Utility Plant	$ -	$ -	$ -
4350	Losses from Disposition of Future Use Utility Plant	$ -	$ -	$ -
4355	Gain on Disposition of Utility and Other Property	$ (23,879)	$ (120,531)	$ (96,653)
4360	Loss on Disposition of Utility and Other Property	$ -	$ -	$ -
4365	Gains from Disposition of Allowances for Emission	$ -	$ -	$ -
4370	Losses from Disposition of Allowances for Emission	$ -	$ -	$ -
4375	Revenues from Non-Utility Operations	$ (2,196,295)	$ (1,807,744)	$ 388,552
4375	Generation Facility Revenues - Sub-Account	$ -	$ (398,812)	$ (398,812)
4380	Expenses from Non-Utility Operations	$ 1,711,586	$ 1,640,066	$ (71,520)
4380	Generation Facility Expenses - Sub-Account	$ 8,641	$ 35,901	$ 27,259
4385	Expenses of Non-Utility Operations	$ -	$ -	$ -
4390	Miscellaneous Non-Operating Income	$ (8,611)	$ (26,161)	$ (17,550)
4395	Rate-Payer Benefit Including Interest	$ -	$ -	$ -
4398	Foreign Exchange Gains and Losses, Including Amortization	$ 36,067	$ 41	$ (36,026)
4405	Interest and Dividend Income	$ (87,470)	$ (136,817)	$ (49,347)
4415	Equity in Earnings of Subsidiary Companies	$ -	$ -	$ -
Total		$ (1,154,772)	$ (1,465,422)	$ (310,651)

Account 4355 – Gain on Disposition of Utility and Other Property

EPLC realized an increase of $96,653 in account 4355 from 2010 Actual to 2011 Actual. Changes in 2011 relate to:

- Sale of bucket truck – $81k;
- Sale of property at Mill St. Parking Lot to Municipality of Leamington- $39k;

Account 4375 – Revenue from Non-Utility Operations

EPLC experienced a decrease in account 4375 as a result of items related to Conservation & Demand Management as well as an increase in street lighting and traffic lighting services. CDM revenues and expenses are largely and mostly timing related variances.

EPLC also began tracking solar photovoltaic revenues in 2011. All revenues and expenses relating to solar projects owned by EPLC are not considered in this Application and will not be described further.

Account 4380 – Expenses from Non-Utility Operations

EPLC experienced an increase in account 4380 as a result of items related to Conservation & Demand Management. CDM revenues and expenses are largely and mostly timing related variances.

EPLC also began tracking solar photovoltaic expenses in 2011. All revenues and expenses relating to solar projects owned by EPLC are not considered in this Application and will not be described further.

2011 Actual Vs. 2012 Actual

EPLC experienced an overall increase of $76,970 in Other Revenue between the 2011 Actual and 2012 Actual. Figure 34 below details the variances by USoA account.

Figure 34 – 2011 Actual Vs. 2012 Actual Variance Analysis

USoA #	Description	2011 Actual	2012 Actual	Variance
Reporting Basis		CGAAP	CGAAP	
4235	Specific Service Charges	$ (144,884)	$ (156,010)	$ (11,126)
4225	Late Payment Charges	$ (269,465)	$ (252,832)	$ 16,633
4080	SSS Revenue	$ (76,745)	$ (82,855)	$ (6,110)
4082	Retail Services Revenues	$ (38,946)	$ (35,298)	$ 3,648
4084	Service Tax Requests	$ (14,114)	$ (15,068)	$ (954)
4090	Electric Services Incidental to Energy Sales	$ -	$ -	$ -
4205	Interdepartmental Rents	$ -	$ -	$ -
4210	Rent from Electric Property	$ (105,058)	$ (102,121)	$ 2,937
4215	Other Utility Operating Income	$ -	$ -	$ -
4220	Other Electric Revenues	$ (2,152)	$ -	$ 2,152
4240	Provision for Rate Refunds	$ -	$ -	$ -
4245	Government Assistance Directly Credited to Income	$ -	$ -	$ -
4305	Regulatory Debits	$ -	$ -	$ -
4310	Regulatory Credits	$ -	$ -	$ -
4315	Revenues from Electric Plant Leased to Others	$ -	$ -	$ -
4320	Expenses of Electric Plant Leased to Others	$ -	$ -	$ -
4325	Revenues from Merchandise, Jobbing, Etc.	$ -	$ -	$ -
4330	Costs and Expenses from Merchandise, Jobbing, Etc.	$ -	$ -	$ -
4335	Profits and losses from Financial Instrument Hedges	$ -	$ -	$ -
4340	Profits and losses from Financial Instrument Investments	$ -	$ -	$ -
4345	Gains from Disposition of Future Use Utility Plant	$ -	$ -	$ -
4350	Losses from Disposition of Future Use Utility Plant	$ -	$ -	$ -
4355	Gain on Disposition of Utility and Other Property	$ (120,531)	$ (37,915)	$ 82,616
4360	Loss on Disposition of Utility and Other Property	$ -	$ -	$ -
4365	Gains from Disposition of Allowances for Emission	$ -	$ -	$ -
4370	Losses from Disposition of Allowances for Emission	$ -	$ -	$ -
4375	Revenues from Non-Utility Operations	$ (1,807,744)	$ (1,961,905)	$ (154,161)
4375	Generation Facility Revenues - Sub-Account	$ (398,812)	$ (590,368)	$ (191,556)
4380	Expenses from Non-Utility Operations	$ 1,640,066	$ 1,802,020	$ 161,955
4380	Generation Facility Expenses - Sub-Account	$ 35,901	$ 49,173	$ 13,272
4385	Expenses of Non-Utility Operations	$ -	$ -	$ -
4390	Miscellaneous Non-Operating Income	$ (26,161)	$ (31,371)	$ (5,210)
4395	Rate-Payer Benefit Including Interest	$ -	$ -	$ -
4398	Foreign Exchange Gains and Losses, Including Amortization	$ 41	$ 11	$ (30)
4405	Interest and Dividend Income	$ (136,817)	$ (163,754)	$ (26,937)
4415	Equity in Earnings of Subsidiary Companies	$ -	$ -	$ -
Total		$ (1,465,422)	$ (1,578,292)	$ (112,870)

Account 4355 – Gain on Disposition of Utility and Other Property

EPLC realized a decrease of $82,616 in account 4355 from 2011 Actual to 2012 Actual. Changes in 2012 relate to decreased year over year activity relating from property sales described in 2011 above.

Account 4375 – Revenue from Non-Utility Operations

EPLC experienced a decrease in account 4375 as a result of items related to Conservation & Demand Management as well as an increase in street lighting and traffic lighting services. EPLC also experienced a small increase in municipal water billing revenue.

CDM revenues and expenses are largely and mostly timing related variances.

Account 4380 – Expenses from Non-Utility Operations

EPLC experienced an increase in account 4380 as a result of items related to Conservation & Demand Management. CDM revenues and expenses are largely and mostly timing related variances. EPLC also experienced rising (mainly inflationary) cost of services such as billing and traffic/street lighting.

2012 Actual Vs. 2013 Actual

EPLC experienced an overall decrease of $335,240 in Other Revenue between the 2012 Actual and 2013 Actual. Figure 35 below details the variances by USoA account.

Figure 35 – 2012 Actual Vs. 2013 Actual Variance Analysis

USoA #	Description	2012 Actual	2013 Actual	Variance
	Reporting Basis	CGAAP	CGAAP	
4235	Specific Service Charges	$ (156,010)	$ (163,155)	$ (7,145)
4225	Late Payment Charges	$ (252,832)	$ (274,425)	$ (21,593)
4080	SSS Revenue	$ (82,855)	$ (83,263)	$ (408)
4082	Retail Services Revenues	$ (35,298)	$ (27,420)	$ 7,878
4084	Service Tax Requests	$ (15,068)	$ (15,224)	$ (156)
4090	Electric Services Incidental to Energy Sales	$ -	$ -	$ -
4205	Interdepartmental Rents	$ -	$ -	$ -
4210	Rent from Electric Property	$ (102,121)	$ (110,034)	$ (7,913)
4215	Other Utility Operating Income	$ -	$ -	$ -
4220	Other Electric Revenues	$ -	$ -	$ -
4240	Provision for Rate Refunds	$ -	$ -	$ -
4245	Government Assistance Directly Credited to Income	$ -	$ -	$ -
4305	Regulatory Debits	$ -	$ 465,810	$ 465,810
4310	Regulatory Credits	$ -	$ -	$ -
4315	Revenues from Electric Plant Leased to Others	$ -	$ -	$ -
4320	Expenses of Electric Plant Leased to Others	$ -	$ -	$ -
4325	Revenues from Merchandise, Jobbing, Etc.	$ -	$ -	$ -
4330	Costs and Expenses from Merchandise, Jobbing, Etc.	$ -	$ -	$ -
4335	Profits and losses from Financial Instrument Hedges	$ -	$ -	$ -
4340	Profits and losses from Financial Instrument Investments	$ -	$ -	$ -
4345	Gains from Disposition of Future Use Utility Plant	$ -	$ -	$ -
4350	Losses from Disposition of Future Use Utility Plant	$ -	$ -	$ -
4355	Gain on Disposition of Utility and Other Property	$ (37,915)	$ (79,457)	$ (41,542)
4360	Loss on Disposition of Utility and Other Property	$ -	$ -	$ -
4365	Gains from Disposition of Allowances for Emission	$ -	$ -	$ -
4370	Losses from Disposition of Allowances for Emission	$ -	$ -	$ -
4375	Revenues from Non-Utility Operations	$ (1,961,905)	$ (2,218,439)	$ (256,534)
4375	Generation Facility Revenues - Sub-Account	$ (590,368)	$ (586,822)	$ 3,546
4380	Expenses from Non-Utility Operations	$ 1,802,020	$ 2,132,501	$ 330,481
4380	Generation Facility Expenses - Sub-Account	$ 49,173	$ 49,131	$ (42)
4385	Expenses of Non-Utility Operations	$ -	$ -	$ -
4390	Miscellaneous Non-Operating Income	$ (31,371)	$ (48,106)	$ (16,734)
4395	Rate-Payer Benefit Including Interest	$ -	$ -	$ -
4398	Foreign Exchange Gains and Losses, Including Amortization	$ 11	$ (468)	$ (479)
4405	Interest and Dividend Income	$ (163,754)	$ (283,682)	$ (119,928)
4415	Equity in Earnings of Subsidiary Companies	$ -	$ -	$ -
	Total	**$ (1,578,292)**	**$ (1,243,052)**	**$ 335,240**

Account 4305 – Regulatory Debits

Effective January 1st, 2013, EPLC transitioned from reporting in CGAAP to reporting in MIFRS for the purpose of annual RRR reporting, as directed by the Board in "*Accounts Procedures Handbook Frequently Asked Questions July 2012*". The amount $465,810 represents the offsetting entry to Account 1576.

Account 4375 – Revenue from Non-Utility Operations

EPLC experienced an increase in account 4375 as a result of items related to Conservation & Demand Management.

CDM revenues and expenses are largely and mostly timing related variances.

Account 4380 – Expenses from Non-Utility Operations

EPLC experienced an increase in account 4380 as a result of items related to Conservation & Demand Management. CDM revenues and expenses are largely and mostly timing related variances. EPLC also experienced rising (mainly inflationary) cost of services such as billing and traffic/street lighting.

Account 4405 – Interest and Dividend Income

Interest income increased materially in 2013 as a result of EPLC carrying relatively large regulatory balances. This revenue decreases accordingly in 2015 once EPLC received the necessary approval for disposition of these regulatory balances.

1 ## 2013 Actual Vs. 2014 Actual

2 EPLC experienced an overall decrease of $96,836 in Other Revenue between the 2013 Actual
3 and 2014 Actual. Figure 36 below details the variances by USoA account.

4 **Figure 36 – 2013 Actual Vs. 2014 Actual Variance Analysis**

USoA #	Description	2013 Actual	2014 Actual	Variance
Reporting Basis		CGAAP	CGAAP	
4235	Specific Service Charges	$ (163,155)	$ (146,338)	$ 16,817
4225	Late Payment Charges	$ (274,425)	$ (259,613)	$ 14,812
4080	SSS Revenue	$ (83,263)	$ (84,366)	$ (1,103)
4082	Retail Services Revenues	$ (27,420)	$ (27,350)	$ 70
4084	Service Tax Requests	$ (15,224)	$ (10,688)	$ 4,536
4090	Electric Services Incidental to Energy Sales	$ -	$ -	$ -
4205	Interdepartmental Rents	$ -	$ -	$ -
4210	Rent from Electric Property	$ (110,034)	$ (129,986)	$ (19,952)
4215	Other Utility Operating Income	$ -	$ -	$ -
4220	Other Electric Revenues	$ -	$ -	$ -
4240	Provision for Rate Refunds	$ -	$ -	$ -
4245	Government Assistance Directly Credited to Income	$ -	$ -	$ -
4305	Regulatory Debits	$ 465,810	$ 160,213	$ (305,597)
4310	Regulatory Credits	$ -	$ -	$ -
4315	Revenues from Electric Plant Leased to Others	$ -	$ -	$ -
4320	Expenses of Electric Plant Leased to Others	$ -	$ -	$ -
4325	Revenues from Merchandise, Jobbing, Etc.	$ -	$ -	$ -
4330	Costs and Expenses from Merchandise, Jobbing, Etc.	$ -	$ -	$ -
4335	Profits and losses from Financial Instrument Hedges	$ -	$ -	$ -
4340	Profits and losses from Financial Instrument Investments	$ -	$ -	$ -
4345	Gains from Disposition of Future Use Utility Plant	$ -	$ -	$ -
4350	Losses from Disposition of Future Use Utility Plant	$ -	$ -	$ -
4355	Gain on Disposition of Utility and Other Property	$ (79,457)	$ (30,602)	$ 48,855
4360	Loss on Disposition of Utility and Other Property	$ -	$ -	$ -
4365	Gains from Disposition of Allowances for Emission	$ -	$ -	$ -
4370	Losses from Disposition of Allowances for Emission	$ -	$ -	$ -
4375	Revenues from Non-Utility Operations	$ (2,218,439)	$ (1,906,609)	$ 311,830
4375	Generation Facility Revenues - Sub-Account	$ (586,822)	$ (401,920)	$ 184,902
4380	Expenses from Non-Utility Operations	$ 2,132,501	$ 2,013,171	$ (119,330)
4380	Generation Facility Expenses - Sub-Account	$ 49,131	$ 34,807	$ (14,324)
4385	Expenses of Non-Utility Operations	$ -	$ -	$ -
4390	Miscellaneous Non-Operating Income	$ (48,106)	$ (22,396)	$ 25,710
4395	Rate-Payer Benefit Including Interest	$ -	$ -	$ -
4398	Foreign Exchange Gains and Losses, Including Amortization	$ (468)	$ 642	$ 1,110
4405	Interest and Dividend Income	$ (283,682)	$ (335,181)	$ (51,499)
4415	Equity in Earnings of Subsidiary Companies	$ -	$ -	$ -
Total		$ (1,243,052)	$ (1,146,216)	$ 96,836

5

Account 4305 – Regulatory Debits

Effective January 1st, 2013, EPLC transitioned from reporting in CGAAP to reporting in MIFRS for the purpose of annual RRR reporting, as directed by the Board in "*Accounts Procedures Handbook Frequently Asked Questions July 2012*". The amount $160,213 represents the offsetting entry to Account 1576.

Account 4375 – Revenue from Non-Utility Operations

EPLC experienced a decrease in account 4375 as a result of items related to Conservation & Demand Management.

CDM revenues and expenses are largely and mostly timing related variances.

Account 4380 – Expenses from Non-Utility Operations

EPLC experienced a small decrease in account 4380 as a result of non-budgeted items related to Conservation & Demand Management. CDM revenues and expenses are largely and mostly timing related variances. EPLC also experienced rising (mainly inflationary) cost of services such as billing and traffic/street lighting.

2014 Actual Vs. 2015 Actual

EPLC experienced an overall decrease of $364,757 in Other Revenue between the 2014 Actual and 2015 Actual. Figure 37 below details the variances by USoA account.

Figure 37 – 2014 Actual Vs. 2015 Actual Variance Analysis

USoA #	Description	2014 Actual	2015 Actual	Variance
Reporting Basis		CGAAP	MIFRS	
4235	Specific Service Charges	$ (146,338)	$ (154,685)	$ (8,347)
4225	Late Payment Charges	$ (259,613)	$ (261,627)	$ (2,014)
4080	SSS Revenue	$ (84,366)	$ (84,690)	$ (324)
4082	Retail Services Revenues	$ (27,350)	$ (23,454)	$ 3,896
4084	Service Tax Requests	$ (10,688)	$ (15,118)	$ (4,430)
4090	Electric Services Incidental to Energy Sales	$ -	$ -	$ -
4205	Interdepartmental Rents	$ -	$ -	$ -
4210	Rent from Electric Property	$ (129,986)	$ (114,671)	$ 15,315
4215	Other Utility Operating Income	$ -	$ -	$ -
4220	Other Electric Revenues	$ -	$ -	$ -
4240	Provision for Rate Refunds	$ -	$ -	$ -
4245	Government Assistance Directly Credited to Income	$ -	$ -	$ -
4305	Regulatory Debits	$ 160,213	$ -	$ (160,213)
4310	Regulatory Credits	$ -	$ -	$ -
4315	Revenues from Electric Plant Leased to Others	$ -	$ -	$ -
4320	Expenses of Electric Plant Leased to Others	$ -	$ -	$ -
4325	Revenues from Merchandise, Jobbing, Etc.	$ -	$ -	$ -
4330	Costs and Expenses from Merchandise, Jobbing, Etc.	$ -	$ -	$ -
4335	Profits and losses from Financial Instrument Hedges	$ -	$ -	$ -
4340	Profits and losses from Financial Instrument Investments	$ -	$ -	$ -
4345	Gains from Disposition of Future Use Utility Plant	$ -	$ -	$ -
4350	Losses from Disposition of Future Use Utility Plant	$ -	$ -	$ -
4355	Gain on Disposition of Utility and Other Property	$ (30,602)	$ (17,612)	$ 12,990
4360	Loss on Disposition of Utility and Other Property	$ -	$ 104,845	$ 104,845
4365	Gains from Disposition of Allowances for Emission	$ -	$ -	$ -
4370	Losses from Disposition of Allowances for Emission	$ -	$ -	$ -
4375	Revenues from Non-Utility Operations	$ (1,906,609)	$ (2,316,678)	$ (410,069)
4375	Generation Facility Revenues - Sub-Account	$ (401,920)	$ (390,198)	$ 11,722
4380	Expenses from Non-Utility Operations	$ 2,013,171	$ 2,415,303	$ 402,132
4380	Generation Facility Expenses - Sub-Account	$ 34,807	$ 204,896	$ 170,090
4385	Expenses of Non-Utility Operations	$ -	$ -	$ -
4390	Miscellaneous Non-Operating Income	$ (22,396)	$ (11,371)	$ 11,025
4395	Rate-Payer Benefit Including Interest	$ -	$ -	$ -
4398	Foreign Exchange Gains and Losses, Including Amortization	$ 642	$ (17,576)	$ (18,218)
4405	Interest and Dividend Income	$ (335,181)	$ (98,824)	$ 236,357
4415	Equity in Earnings of Subsidiary Companies	$ -	$ -	$ -
Total		$ (1,146,216)	$ (781,460)	$ 364,757

Account 4305 – Regulatory Debits

Effective January 1st, 2013, EPLC transitioned from reporting in CGAAP to reporting in MIFRS for the purpose of annual RRR reporting, as directed by the Board in "*Accounts Procedures Handbook Frequently Asked Questions July 2012*". EPLC did not record an entry in 4305 in 2015.

Account 4360 – Loss on Disposition of Utility and Other Property

EPLC retired its remaining distribution substations in 2015 as part of its Single Voltage Utility initiative described further in Exhibit 2 of this Application.

Account 4375 – Revenue from Non-Utility Operations

EPLC experienced an increase in account 4375 as a result of items related to Conservation & Demand Management.

CDM revenues and expenses are largely and mostly timing related variances.

Account 4380 – Expenses from Non-Utility Operations

EPLC experienced a small decrease in account 4380 as a result of items related to Conservation & Demand Management. CDM revenues and expenses are largely and mostly timing related variances. EPLC also experienced rising (mainly inflationary) cost of services such as billing and traffic/street lighting.

Account 4405 – Interest and Dividend Income

Interest income increased materially in 2013 as a result of EPLC carrying relatively large regulatory balances. This revenue decreases accordingly in 2015 once EPLC received the necessary approval for disposition of these regulatory balances.

2015 Actual Vs. 2016 Actual

EPLC experienced an overall decrease of $778,293 in Other Revenue between the 2015 Actual and 2016 Actual. Figure 38 below details the variances by USoA account.

Figure 38 – 2015 Actual Vs. 2016 Actual Variance Analysis

USoA #	Description	2015 Actual	2016 Actual	Variance
Reporting Basis		MIFRS	MIFRS	
4235	Specific Service Charges	$ (154,685)	$ (153,296)	$ 1,389
4225	Late Payment Charges	$ (261,627)	$ (266,735)	$ (5,108)
4080	SSS Revenue	$ (84,690)	$ (86,653)	$ (1,963)
4082	Retail Services Revenues	$ (23,454)	$ (21,106)	$ 2,348
4084	Service Tax Requests	$ (15,118)	$ (15,464)	$ (346)
4090	Electric Services Incidental to Energy Sales	$ -	$ -	$ -
4205	Interdepartmental Rents	$ -	$ -	$ -
4210	Rent from Electric Property	$ (114,671)	$ (117,193)	$ (2,522)
4215	Other Utility Operating Income	$ -	$ -	$ -
4220	Other Electric Revenues	$ -	$ -	$ -
4240	Provision for Rate Refunds	$ -	$ -	$ -
4245	Government Assistance Directly Credited to Income	$ -	$ -	$ -
4305	Regulatory Debits	$ -	$ 781,900	$ 781,900
4310	Regulatory Credits	$ -	$ -	$ -
4315	Revenues from Electric Plant Leased to Others	$ -	$ -	$ -
4320	Expenses of Electric Plant Leased to Others	$ -	$ -	$ -
4325	Revenues from Merchandise, Jobbing, Etc.	$ -	$ -	$ -
4330	Costs and Expenses from Merchandise, Jobbing, Etc.	$ -	$ -	$ -
4335	Profits and losses from Financial Instrument Hedges	$ -	$ -	$ -
4340	Profits and losses from Financial Instrument Investments	$ -	$ -	$ -
4345	Gains from Disposition of Future Use Utility Plant	$ -	$ -	$ -
4350	Losses from Disposition of Future Use Utility Plant	$ -	$ -	$ -
4355	Gain on Disposition of Utility and Other Property	$ (17,612)	$ (122,721)	$ (105,109)
4360	Loss on Disposition of Utility and Other Property	$ 104,845	$ 85,458	$ (19,387)
4365	Gains from Disposition of Allowances for Emission	$ -	$ -	$ -
4370	Losses from Disposition of Allowances for Emission	$ -	$ -	$ -
4375	Revenues from Non-Utility Operations	$ (2,316,678)	$ (2,862,081)	$ (545,403)
4375	Generation Facility Revenues - Sub-Account	$ (390,198)	$ (394,876)	$ (4,677)
4380	Expenses from Non-Utility Operations	$ 2,415,303	$ 3,063,638	$ 648,335
4380	Generation Facility Expenses - Sub-Account	$ 204,896	$ 252,183	$ 47,287
4385	Expenses of Non-Utility Operations	$ -	$ -	$ -
4390	Miscellaneous Non-Operating Income	$ (11,371)	$ (12,176)	$ (805)
4395	Rate-Payer Benefit Including Interest	$ -	$ -	$ -
4398	Foreign Exchange Gains and Losses, Including Amortization	$ (17,576)	$ 7,335	$ 24,911
4405	Interest and Dividend Income	$ (98,824)	$ (141,380)	$ (42,556)
4415	Equity in Earnings of Subsidiary Companies	$ -	$ -	$ -
Total		$ (781,460)	$ (3,166)	$ 778,293

Account 4305 – Regulatory Debits

Effective January 1st, 2013, EPLC transitioned from reporting in CGAAP to reporting in MIFRS for the purpose of annual RRR reporting, as directed by the Board in "*Accounts Procedures Handbook Frequently Asked Questions July 2012*". The amount $781,900 represents the offsetting entry to Account 1576.

Account 4355 – Gain on Disposition of Utility and Other Property

EPLC sold property previously housing substations, now retired, back to the local municipalities. EPLC sold both pieces of property for approximately $105,000.

Account 4375 – Revenue from Non-Utility Operations

EPLC experienced an increase in account 4375 as a result of items related to Conservation & Demand Management.

CDM revenues and expenses are largely and mostly timing related variances.

Account 4380 – Expenses from Non-Utility Operations

EPLC experienced a small decrease in account 4380 as a result of items related to Conservation & Demand Management. CDM revenues and expenses are largely and mostly timing related variances. EPLC also experienced rising (mainly inflationary) cost of services such as billing and traffic/street lighting.

2016 Actual Vs. 2017 Bridge

EPLC is forecasting an overall increase of $734,302 in Other Revenue between the 2016 Actual and 2017 Bridge Year. Figure 39 below details the variances by USoA account.

Figure 39 – 2016 Actual Vs. 2017 Bridge Variance Analysis

USoA #	Description	2016 Actual	2017 Bridge	Variance
	Reporting Basis	MIFRS	MIFRS	
4235	Specific Service Charges	$ (153,296)	$ (166,480)	$ (13,184)
4225	Late Payment Charges	$ (266,735)	$ (260,400)	$ 6,335
4080	SSS Revenue	$ (86,653)	$ (80,000)	$ 6,653
4082	Retail Services Revenues	$ (21,106)	$ (28,000)	$ (6,894)
4084	Service Tax Requests	$ (15,464)	$ (7,640)	$ 7,824
4090	Electric Services Incidental to Energy Sales	$ -	$ -	$ -
4205	Interdepartmental Rents	$ -	$ -	$ -
4210	Rent from Electric Property	$ (117,193)	$ (109,515)	$ 7,678
4215	Other Utility Operating Income	$ -	$ -	$ -
4220	Other Electric Revenues	$ -	$ -	$ -
4240	Provision for Rate Refunds	$ -	$ -	$ -
4245	Government Assistance Directly Credited to Income	$ -	$ -	$ -
4305	Regulatory Debits	$ 781,900	$ -	$ (781,900)
4310	Regulatory Credits	$ -	$ -	$ -
4315	Revenues from Electric Plant Leased to Others	$ -	$ -	$ -
4320	Expenses of Electric Plant Leased to Others	$ -	$ -	$ -
4325	Revenues from Merchandise, Jobbing, Etc.	$ -	$ -	$ -
4330	Costs and Expenses from Merchandise, Jobbing, Etc.	$ -	$ -	$ -
4335	Profits and losses from Financial Instrument Hedges	$ -	$ -	$ -
4340	Profits and losses from Financial Instrument Investments	$ -	$ -	$ -
4345	Gains from Disposition of Future Use Utility Plant	$ -	$ -	$ -
4350	Losses from Disposition of Future Use Utility Plant	$ -	$ -	$ -
4355	Gain on Disposition of Utility and Other Property	$ (122,721)	$ -	$ 122,721
4360	Loss on Disposition of Utility and Other Property	$ 85,458	$ -	$ (85,458)
4365	Gains from Disposition of Allowances for Emission	$ -	$ -	$ -
4370	Losses from Disposition of Allowances for Emission	$ -	$ -	$ -
4375	Revenues from Non-Utility Operations	$ (2,862,081)	$ (1,865,253)	$ 996,828
4375	Generation Facility Revenues - Sub-Account	$ (394,876)	$ (369,700)	$ 25,176
4380	Expenses from Non-Utility Operations	$ 3,063,638	$ 1,784,228	$ (1,279,410)
4380	Generation Facility Expenses - Sub-Account	$ 252,183	$ 212,000	$ (40,183)
4385	Expenses of Non-Utility Operations	$ -	$ -	$ -
4390	Miscellaneous Non-Operating Income	$ (12,176)	$ (14,000)	$ (1,824)
4395	Rate-Payer Benefit Including Interest	$ -	$ -	$ -
4398	Foreign Exchange Gains and Losses, Including Amortization	$ 7,335	$ -	$ (7,335)
4405	Interest and Dividend Income	$ (141,380)	$ (101,310)	$ 40,070
4415	Equity in Earnings of Subsidiary Companies	$ -	$ -	$ -
	Total	**$ (3,166)**	**$ (1,006,070)**	**$ (1,002,904)**

Account 4305 – Regulatory Debits

Effective January 1st, 2013, EPLC transitioned from reporting in CGAAP to reporting in MIFRS for the purpose of annual RRR reporting, as directed by the Board in "*Accounts Procedures Handbook Frequently Asked Questions July 2012*". The variance is a result of no entry being required for 2016 and beyond for the MFIRS transition.

Account 4355 – Gain on Disposition of Utility and Other Property

The variance in account 4355 is a result of a one-time gain on disposition of property described in 2016 above.

Account 4360 – Loss on Disposition of Utility and Other Property

The positive variance in account 4360 is a result of the completion of retirement of distribution substations as part of EPLC's Single Voltage Utility initiative.

Account 4375 – Revenue from Non-Utility Operations

EPLC experienced a large decrease in account 4375 as a result of items related to Conservation & Demand Management as well as the loss of a water billing municipal customer which dramatically affected revenues. Many of the efficiencies that EPLC was able to offer as a result of servicing both water and electricity customers are no longer cost effective and/or feasible as a result.

CDM revenues and expenses are largely and mostly timing related variances.

Account 4380 – Expenses from Non-Utility Operations

EPLC experienced a large decrease in account 4380 as a result of items related to Conservation & Demand Management as well as the loss of a water billing municipal customer which dramatically affected revenues. Many of the efficiencies that EPLC was able to offer as a result of servicing both water and electricity customers are no longer cost effective and/or feasible as a result.

EPLC also experienced rising (mainly inflationary) cost of services such as billing and traffic/street lighting.

2017 Bridge Vs. 2018 Test

EPLC is forecasting an overall increase of $199,597 in Other Revenue between the 2017 Bridge and 2018 Test Years. Figure 40 below details the variances by USoA account.

Figure 40 – 2017 Bridge Vs. 2018 Test Variance Analysis

USoA #	Description	2017 Bridge	2018 Test	Variance
Reporting Basis		CGAAP	CGAAP	
4235	Specific Service Charges	$ (166,480)	$ (166,480)	$ -
4225	Late Payment Charges	$ (260,400)	$ (260,400)	$ -
4080	SSS Revenue	$ (80,000)	$ (80,000)	$ -
4082	Retail Services Revenues	$ (28,000)	$ (28,000)	$ -
4084	Service Tax Requests	$ (7,640)	$ (7,640)	$ -
4090	Electric Services Incidental to Energy Sales	$ -	$ -	$ -
4205	Interdepartmental Rents	$ -	$ -	$ -
4210	Rent from Electric Property	$ (109,515)	$ (109,515)	$ -
4215	Other Utility Operating Income	$ -	$ -	$ -
4220	Other Electric Revenues	$ -	$ -	$ -
4240	Provision for Rate Refunds	$ -	$ -	$ -
4245	Government Assistance Directly Credited to Income	$ -	$ -	$ -
4305	Regulatory Debits	$ -	$ -	$ -
4310	Regulatory Credits	$ -	$ -	$ -
4315	Revenues from Electric Plant Leased to Others	$ -	$ -	$ -
4320	Expenses of Electric Plant Leased to Others	$ -	$ -	$ -
4325	Revenues from Merchandise, Jobbing, Etc.	$ -	$ -	$ -
4330	Costs and Expenses from Merchandise, Jobbing, Etc.	$ -	$ -	$ -
4335	Profits and losses from Financial Instrument Hedges	$ -	$ -	$ -
4340	Profits and losses from Financial Instrument Investments	$ -	$ -	$ -
4345	Gains from Disposition of Future Use Utility Plant	$ -	$ -	$ -
4350	Losses from Disposition of Future Use Utility Plant	$ -	$ -	$ -
4355	Gain on Disposition of Utility and Other Property	$ -	$ -	$ -
4360	Loss on Disposition of Utility and Other Property	$ -	$ -	$ -
4365	Gains from Disposition of Allowances for Emission	$ -	$ -	$ -
4370	Losses from Disposition of Allowances for Emission	$ -	$ -	$ -
4375	Revenues from Non-Utility Operations	$ (1,865,253)	$ (1,875,456)	$ (10,203)
4375	Generation Facility Revenues - Sub-Account	$ (369,700)	$ (366,700)	$ 3,000
4380	Expenses from Non-Utility Operations	$ 1,784,228	$ 1,865,670	$ 81,442
4380	Generation Facility Expenses - Sub-Account	$ 212,000	$ 230,000	$ 18,000
4385	Expenses of Non-Utility Operations	$ -	$ -	$ -
4390	Miscellaneous Non-Operating Income	$ (14,000)	$ -	$ 14,000
4395	Rate-Payer Benefit Including Interest	$ -	$ -	$ -
4398	Foreign Exchange Gains and Losses, Including Amortization	$ -	$ -	$ -
4405	Interest and Dividend Income	$ (101,310)	$ (30,000)	$ 71,310
4415	Equity in Earnings of Subsidiary Companies	$ -	$ -	$ -
Total		$ (1,006,070)	$ (828,521)	$ 177,549

Account 4380 – Expenses from Non-Utility Operations

EPLC has been notified by one of its municipal water and sewer billing customers that they plan to no longer use EPLC as a service provider in 2018 or early 2019. As a result, EPLC adjusted expenses in account 4380 to account for this future loss of revenue. The remaining revenue offset between accounts 4375 and 4380 relate to miscellaneous traffic and streetlight work.

Account 4405 – Interest and Dividend Income

Interest income decreased materially in 2018 as a result of EPLC clearing out DVA related interest as part of this Application.

3.4.3 Specific Service Charges

EPLC proposes the following Specific Services Charges (“SSCs”) as described in Figure 41 below. Additional information related to SSCs can be found in Exhibit 8. It should be noted that EPLC is not proposing any rate increases related to SSCs for the purpose of this Application.

Figure 41 – EPLC Proposed SSCs

Description	Unit	Rate
Customer Administration		
Arrears Certificate	$	15.00
Statement of Account	$	15.00
Duplicate Invoices for Previous Billing	$	15.00
Request for Other Billing Information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Account History	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Legal Letter Charge	$	15.00
Account Set Up Charge/Change of Occupancy Charge (plus credit agency charge if applicable)	$	30.00
Special Meter Reads	$	30.00
Meter Dispute Charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non Payment of Account		
Late Payment - per Month	%	1.50
Late Payment - per Annum	%	19.56
Collection of Account Charge - No Disconnection	$	30.00
Collection of Account Charge - No Disconnection - After Regular Hours	$	165.00
Disconnect/Reconnect Charge - At Meter - During Regular Hours	$	65.00
Disconnect/Reconnect Charge - At Meter - After Regular Hours	$	185.00
Disconnect/Reconnect Charge - At Pole - During Regular Hours	$	185.00
Disconnect/Reconnect Charge - At Pole - After Regular Hours	$	415.00
Install/Remove Load Control Device - During Regular Hours	$	65.00
Install/Remove Load Control Device - After Regular Hours	$	185.00
Other Charges		
Service Call - Customer Owned Equipment	$	30.00
Service Call - After Regular Hours	$	165.00
Temporary Service Install & Remove - Overhead - No Transformer	$	500.00
Temporary Service Install & Remove - Overhead - With Transformer	$	300.00
Temporary Service Install & Remove - Underground - No Transformer	$	1,000.00
Specific Charge for Access to the Power Poles - per Pole/Year	$	22.35

3.4.4 Affiliate Transactions

EPLC currently provides water and wastewater billing, collecting and general customer service on behalf of three of its four Municipal Shareholders. The amounts received from these services are recorded in Account 4375. EPLC expects to continue services to only two out of four of its shareholders effective January 1st, 2018.

3.4.5 Generation Revenues

EPLC currently owns one 500 kW DC rooftop solar photovoltaic Feed In Tariff ("FIT") project as well as three 10 kW DC ground mounted microFIT projects. Revenues and expenses related to these projects are not considered in this Application and are tracked in Accounts 4375 (Sub-account Generation Facility Revenues) and 4380 (Sub-account Generation Facility Expenses) respectively in accordance with EB-2009-0411 (Distributor Owned Generation).

Attachment 3-A

EPLC Load Forecast

Weather Normalized Distribution System Load Forecast: 2018 Cost of Service

Report prepared by
Andrew Frank
Elenchus Research Associates Inc.

Prepared for:
Essex Powerlines

Page Intentionally Blank

Table of Contents

Page Intentionally Blank

1 INTRODUCTION

This report outlines the results and methodology used to derive the weather normal load forecast prepared for use in the Cost of Service application for 2018 rates for Essex Powerlines (“Essex”).

The regression equations used to normalize and forecast Essex’ weather sensitive load use monthly heating degree days and cooling degree days as measured at Environment Canada’s Windsor Riverside weather station to take into account temperature sensitivity. This location is central to the communities in Essex’s service territory, and has strong historical weather data. Essex experiences peak loads in both the summer and winter seasons. Environment Canada defines heating degree days and cooling degree days as the difference between the average daily temperature and 18°C for each day (below for heating, above for cooling).

To isolate the impact of CDM, persisting CDM as measured by the IESO is added back to rate class consumption to simulate the rate class consumption had there been no CDM program delivery. This is labelled as “Actual No CDM” throughout the model. The effect is to remove the impact of CDM from any explanatory variables which may capture a trend, and focus on the external factors. A weather normalized forecast is produced first based on no CDM delivery, and then CDM savings of historic programs are subtracted off to reflect the actual normal forecast.

While statistical regression is appropriate for estimating a relationship between explanatory variables and energy use, in the case of CDM, an independent measurement is available providing a greater level of accuracy than could be obtained through regression.

Overall economic activity also impacts energy consumption. There is no known agency that publishes monthly economic accounts on a regional basis for Ontario. However, regional employment levels are available. Given that income from employment and labour sources accounts for the largest portion of GDP on an income basis, and a study by Statistics Canada that has indicated that “turning points in the growth of output and employment appear to have been virtually the same over the past three decades”[1], employment has been chosen as the economic variable to incorporate into the analysis. Specifically, the monthly full-time employment level for Winsor, Ontario, as reported in Statistics Canada’s Monthly Labour Force Survey (CANSIM series Table 282-0135) was tested and used for the Residential, GS < 50, and GS > 50 rate classes.

---

[1] Philip Cross, “Cyclical changes in output and employment,” *Canadian Economic Observer*, May 2009.

In order to isolate demand determinants at the class specific level, equations to weather normalize and forecast kWh consumption for the Residential, GS<50, and GS>50 classes, have been estimated.

In addition to the weather and economic variables, 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. More details on the individual class specifications are provided in the next section.

Finally, for classes with demand charges, an annual kW to kWh ratio is calculated using actual observations for each historical year and applied to the normalized kWh to derive a weather normal kW observation. For forecast values, the average kW to kWh ratio for 2009-2016 is applied for all demand billed classes.

1.1 SUMMARIZED RESULTS

The following table summarizes the historic and forecast kWh for 2012-2018:

Normal Forecast

kWh	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2016 Normalized	2017 Forecast	2018 Forecast
Residential	256,003,979	250,406,105	245,551,953	244,757,239	255,390,422	249,168,165	247,700,344	246,544,006
GS < 50	67,056,278	65,663,990	65,242,011	65,329,579	66,808,993	64,675,919	65,087,892	65,487,649
GS > 50	160,883,812	164,887,609	166,100,613	171,874,066	187,031,606	175,310,400	179,829,958	183,374,335
Embedded Distributor	35,429,534	36,931,636	38,058,828	38,655,620	32,586,843	32,586,843	31,681,583	29,865,554
Street Light	6,205,705	6,271,491	6,286,758	6,227,063	4,268,688	4,268,688	2,799,882	2,799,882
Sentinel Light	383,994	342,834	350,518	341,136	335,758	335,758	335,758	335,758
USL	1,558,152	1,549,960	1,555,546	1,558,152	1,554,368	1,554,368	1,554,368	1,554,368
Total	527,521,454	526,053,625	523,146,226	528,742,855	547,976,676	527,900,141	528,989,785	529,961,552

Table 1 kWh forecast by class

The following table summarizes 2015-2020 CDM Adjusted Load Forecast kWh. Details for this calculation can be found in Schedule 6 of this report.

CDM Adjusted

kWh	2018 Weather Normal Forecast	CDM Adjustment	2018 CDM Adjusted Forecast
Residential	246,544,006	1,169,888	245,374,118
GS < 50	65,487,649	2,780,199	62,707,450
GS > 50	183,374,335	7,094,029	176,280,306
Embedded Distributor	29,865,554	0	29,865,554
Street Light	2,799,882	0	2,799,882
Sentinel Light	335,758	0	335,758
USL	1,554,368	0	1,554,368
Total	529,961,552	11,044,116	518,917,436

Table 2 CDM Adjusted kWh forecast

The following table summarizes the historic and forecast kW for 2012-2018. The calculations can be found as follows:

Normal Forecast

kW	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2016 Normalized	2017 Forecast	2018 Forecast
GS > 50	416,357	399,217	394,614	459,153	476,121	443,798	455,239	464,212
Embedded Distributor	109,304	96,078	84,453	106,798	87,828	88,238	85,786	80,869
Street Light	18,742	19,025	15,872	18,023	13,490	13,490	8,848	8,848
Sentinel Light	2,100	2,100	2,068	2,088	2,080	2,080	2,080	2,080
Total	546,503	516,420	497,007	586,062	579,519	547,606	551,954	556,009

Table 3 kW Forecast

The following table summarizes 2015-2020 CDM Adjusted Load Forecast kW. Details for this calculation can be found at the end of in Schedule 6 of this report.

CDM Adjusted

kW	2018 Weather Normal Forecast	CDM Adjustment	2018 CDM Adjusted Forecast
GS > 50	464,212	17,959	446,253
Embedded Distributor	80,869	0	80,869
Street Light	8,848	0	8,848
Sentinel Light	2,080	0	2,080
Total	556,009	17,959	538,051

Table 4 CDM Adjusted kW Forecast

The following table summarizes the historic and forecast customer/connections for 2012-2018:

Customer Connections

kW	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Forecast	2018 Forecast
Residential	26,337	26,466	26,590	26,815	27,137	27,310	27,484
GS < 50	1,906	1,904	1,910	1,936	1,953	1,965	1,977
GS > 50	208	208	211	212	220	219	219
Embedded Distributor	7	6	6	6	3	3	3
Street Light	2,474	2,621	2,713	2,701	2,720	2,740	2,740
Sentinel Light	175	175	172	174	173	173	173
USL	141	140	140	141	140	140	140
Total	31,249	31,521	31,742	31,984	32,345	32,550	32,736

Table 5 Customer / Connection Forecast for 2009-2020

2 CLASS SPECIFIC KWH REGRESSION

2.1 RESIDENTIAL

For the Residential Class kWh consumption the equation was estimated using 96 observations from 2009:01-2016:12.

Heating and Cooling Degree days were used, as measured at the Windsor Riverside weather station as described in the introduction. A Trend variable was used, indicating 1 in January 2009, and incrementing once each month, reaching 96 in the last month of the regression, December 2015. A count of the number of calendar days in the month was used. Finally, binary indicator variables for the Shoulder season months of March, April, May, September, October, and November, was used.

A count of customer connections was examined, and found to not show a statistically significant relationship to energy usage.

The following table outlines the resulting regression model:

Model 3: OLS, using observations 2009:01-2016:12 (T = 96)
Dependent variable: Gross_Res

	coefficient	std. error	t-ratio	p-value
const	(17,086,567)	4,123,062	-4.14414487	7.76E-05
HDD	6,467	500	12.94752018	3.54E-22
CDD	68,142	2,097	32.50110621	3.70E-51
Month_Days	828,171	95,188	8.700354107	1.57E-13
Shoulder	(1,891,036)	203,768	-9.280333545	9.87E-15
Trend	(20,583)	5,091	-4.043316991	1.12E-04
Windsor_FTE	65,415	22,171	2.950532571	0.004053762

Mean dependent var	21,389,786	S.D. dependent var	4559082.471
Sum squared resid	4.37176E+13	S.E. of regression	7.01E+05
R-squared	0.977860002	Adjusted R-squared	9.76E-01
F(6, 89)	655.1456358	P-value(F)	2.32E-71
Log-likelihood	-1424.750412	Akaike criterion	2863.500823
Schwarz criterion	2881.451261	Hannan-Quinn	2.87E+03
rho	-0.1490113	Durbin-Watson	2.284293989
Theil's U	0.18604		

Table 6 Residential Regression Model

Using the above model coefficients, we derive the following:

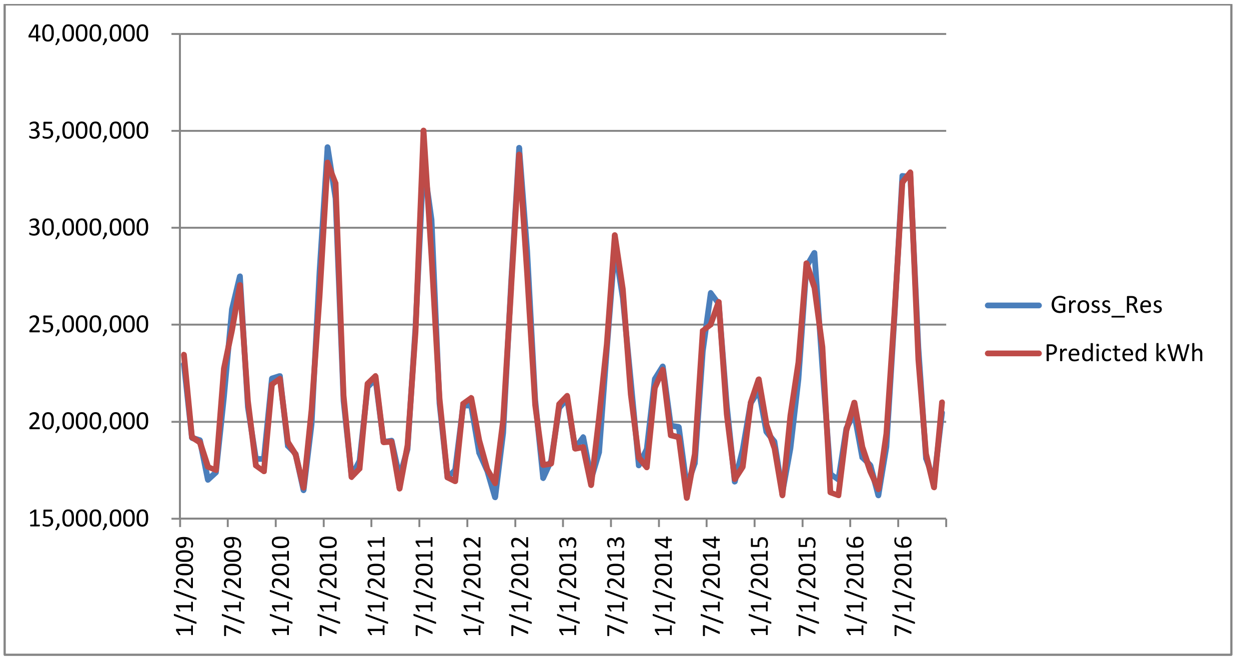


Figure 1 Residential Predicted vs Actual observations

Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 0.4%. Annual errors are calculated as the model is used to derive annual forecasts. However, in proceedings Elenchus has been involved in, intervenors and Board Staff have requested MAPE calculated on a monthly basis and this has been provided as well. The MAPE calculated monthly over the period is 2.4%.

	Res kWh		Absolute Error
Year	Actual+CDM	Predicted	(%)
2009	249,248,745	249,427,852	0.1%
2010	267,217,596	266,877,375	0.1%
2011	260,939,812	259,961,861	0.4%
2012	259,249,764	260,447,551	0.5%
2013	254,292,198	254,989,919	0.3%
2014	250,468,248	247,521,029	1.2%
2015	250,772,427	251,377,970	0.2%
2016	261,230,619	262,815,850	0.6%
Mean Absolute Percentage Error (Annual)			0.4%
Mean Absolute Percentage Error (Monthly)			2.4%

Table 7 Residential model error

2.2 GS < 50

For the GS < 50 class, the regression equation was estimated using 96 observations from 2009:01-2016:12.

Heating degree days and cooling degree days were used, as measured at the Windsor Riverside weather station as described in the introduction. Windsor employment "Windsor_FTE" has been included as an indicator of economic activity. A count of the number of calendar days 'MonthDays' in the month has been included.

Binary variables representing the Shoulder season months of March, April, May, September, October, and November, as well as indicators for the months of March and December have also been included.

The customer count and a trend variable were tested but found to not have a statistically significant relationship to energy usage.

The following table outlines the resulting regression model:

Model 5: OLS, using observations 2009:01-2016:12 (T = 96)
Dependent variable: Gross_GSlt50

	coefficient	std. error	t-ratio	p-value
Const	(1,088,732)	645,754	-1.685985699	9.53E-02
HDD	1,031	94	10.92181431	4.71E-18
CDD	7,674	401	19.14757281	3.93E-33
Windsor_FTE	11,407	2,057	5.545950918	3.03E-07
Month_Days	149,535	19,402	7.707080931	1.83E-11
Shoulder	(268,303)	42,581	-6.301026423	1.14E-08
March	178,697	54,524	3.277385468	1.50E-03
December	(197,901)	58,891	-3.360431276	1.15E-03

Mean dependent var	5,744,507	S.D. dependent var	530340.3969
Sum squared resid	1.37747E+12	S.E. of regression	1.25E+05
R-squared	0.948447653	Adjusted R-squared	0.944346898
F(7, 88)	231.2861104	P-value(F)	8.17E-54
Log-likelihood	-1258.790252	Akaike criterion	2.53E+03
Schwarz criterion	2554.095289	Hannan-Quinn	2.54E+03
rho	0.453793157	Durbin-Watson	1.081812078
Theil's U	0.25417		

Table 8 GS < 50 Regression Model

Using the above model coefficients we derive the following:

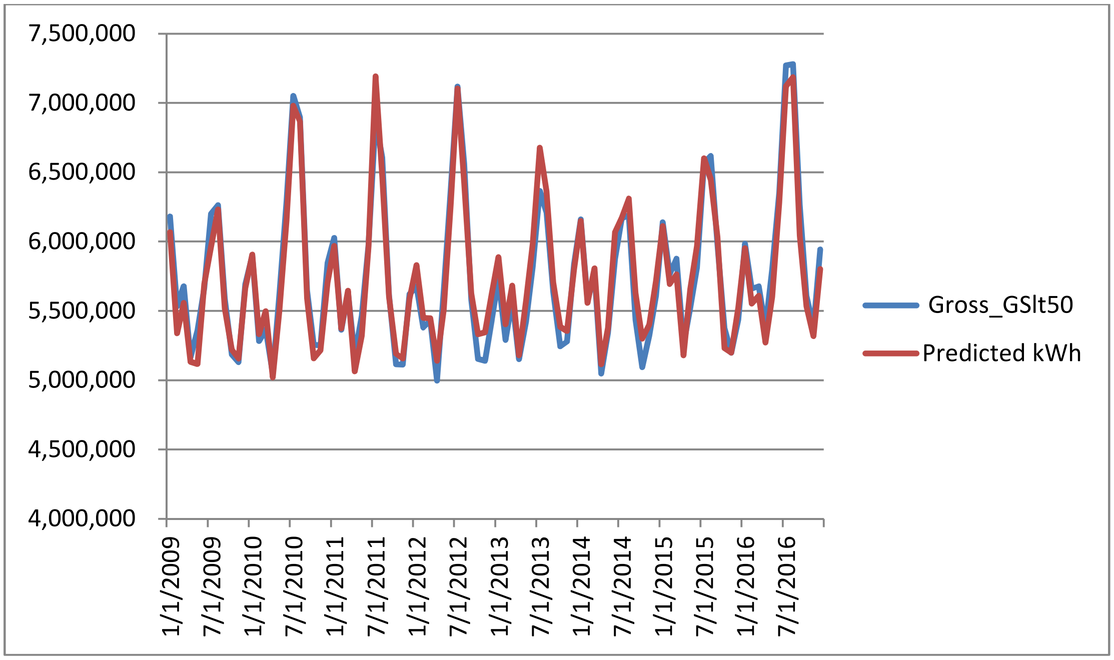


Figure 2 GS < 50 Predicted vs Actual observations

Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 1.1%. Annual errors are calculated as the model is used to derive annual forecasts. However, in recent proceedings Elenchus has been involved in, intervenors and Board Staff have requested MAPE calculated on a monthly basis and this has been provided as well. The MAPE calculated monthly over the period is 1.7%.

	GS<50 kWh		Absolute
Year	Actual+CDM	Predicted	Error (%)
2009	67,635,266	66,657,604	1.4%
2010	69,463,566	68,933,522	0.8%
2011	68,580,386	68,523,489	0.1%
2012	68,501,517	69,093,092	0.9%
2013	67,565,571	68,990,290	2.1%
2014	67,585,756	68,598,369	1.5%
2015	69,539,872	69,407,865	0.2%
2016	72,600,737	71,268,440	1.8%
Mean Absolute Percentage Error (Annual)			1.1%
Mean Absolute Percentage Error (Monthly)			1.7%

Table 9 GS < 50 model error

2.3 GS > 50

For the GS > 50 class, the regression equation was estimated using 96 observations from 2009:01-2016:12.

Heating degree days and cooling degree days were used, as measured at the Windsor Riverside weather station as described in the introduction. Windsor full time Employment "Windsor_FTE has been included as an indicator of economic activity. A trend variable indicating 1 in January 2009, incrementing by 1 each month, and reaching 96 in December 2016 has been included.

Binary variables representing the Spring and Fall season months were tested, however, separate binary indicators for February, August, September, October, and November were round to be much more statistically significant.

The customer count was tested, but found to not have a statistically significant relationship to energy usage.

The following table outlines the resulting regression model:

Model 1: OLS, using observations 2009:01-2016:12 (T = 96)
Dependent variable: Gross_GSgt50

	coefficient	std. error	t-ratio	p-value
const	(11,694,574)	3,877,080	-3.016335242	3.37E-03
GSgt50_Customers	50,679	10,133	5.001285381	3.03E-06
HDD	2,681	529	5.073220952	2.27E-06
CDD	14,782	1,992	7.419284304	8.23E-11
Windsor_FTE	83,819	23,664	3.542095955	6.47E-04
Trend	12,860	5,317	2.418708449	1.77E-02
February	(797,687)	286,470	-2.784539234	6.61E-03
August	1,257,541	297,286	4.230073151	5.87E-05
September	1,979,533	291,251	6.796646396	1.39E-09
October	1,466,842	305,152	4.806922215	6.54E-06
November	671,694	282,458	2.378033542	1.96E-02

Mean dependent var	14471630.8	S.D. dependent var	1.61E+06
Sum squared resid	4.1056E+13	S.E. of regression	694990.1813
R-squared	0.833314467	Adjusted R-squared	0.813704404
F(10, 85)	42.49422745	P-value(F)	7.15E-29
Log-likelihood	-1421.735334	Akaike criterion	2.87E+03
Schwarz criterion	2893.678498	Hannan-Quinn	2876.872734
Rho	0.254232178	Durbin-Watson	1.485514671
Theil's U	0.57872		

Table 10 GS > 50 Regression Model

Using the above model coefficients we derive the following:

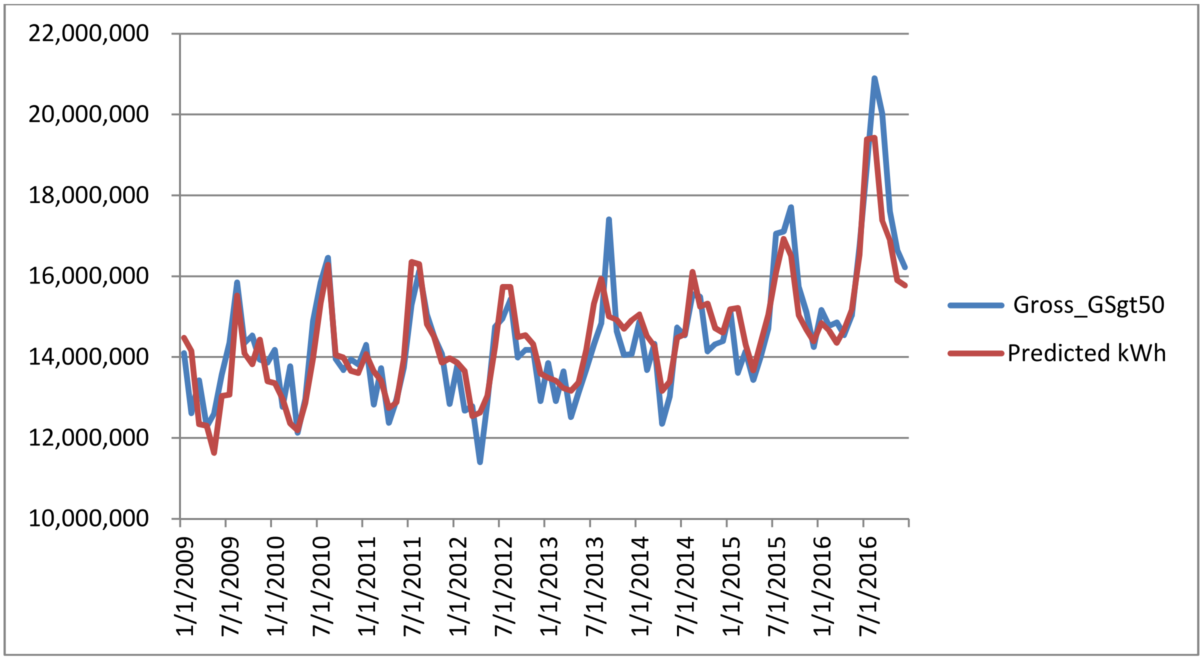


Figure 3 GS > 50 Predicted vs Actual observations

Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 1.8%. Annual errors are calculated as the model is used to derive annual forecasts. However, in recent proceedings Elenchus has been involved in, intervenors and Board Staff have requested MAPE calculated on a monthly basis and this has been provided as well. The MAPE calculated monthly over the period is 3.7%.

	GS>50 kWh		Absolute
Year	Actual+CDM	Predicted	Error (%)
2009	165,450,249	162,280,731	1.9%
2010	168,399,144	164,618,456	2.2%
2011	167,789,871	170,519,616	1.6%
2012	163,904,123	168,388,914	2.7%
2013	169,072,483	171,630,122	1.5%
2014	171,423,509	175,450,624	2.3%
2015	182,018,509	181,410,532	0.3%
2016	201,218,669	194,977,562	3.1%
Mean Absolute Percentage Error (Annual)			1.8%
Mean Absolute Percentage Error (Monthly)			3.7%

Table 11 GS > 50 model error

3 WEATHER NORMALIZATION AND ECONOMIC FORECAST

It is not possible to accurately forecast weather for months or years in advance. Therefore, one can only base future weather expectations on what has happened in the past. Individual years may experience unusual spells of weather (unusually cold winter, unusually warm summer, etc.). However, over time, these unusual spells "average" out. While there may be trends over several years (e.g., warmer winters for example), using several years of data rather than one particular year filters out the extremes of any particular year. While there are several different approaches to determining an appropriate weather normal, Essex has adopted the most recent 10 year monthly degree day average as the definition of weather normal, which to our knowledge, is consistent with many LDCs load forecast filings for cost-of-service rebasing applications.

The table below displays the most recent 10 year average of heating degree days and cooling degree days as reported by Environment Canada for Windsor Riverside, which is used as the weather station for Essex.

10 Year Average

		HDD	CDD
Windsor Riverside	January	661.19	0
Windsor Riverside	February	598.17	0
Windsor Riverside	March	451.34	0.88
Windsor Riverside	April	259.55	2.45
Windsor Riverside	May	88.88	43.8
Windsor Riverside	June	9.77	117.39
Windsor Riverside	July	0.58	179.71
Windsor Riverside	August	1.71	158.1
Windsor Riverside	September	32.68	67.34
Windsor Riverside	October	176.42	10.18
Windsor Riverside	November	364.23	0.05
Windsor Riverside	December	552.31	0

Table 12 10 Year Average HDD and CDD

As part of the minimum filing requirements the OEB has requested monthly degree days calculated using a trend based on 20 years. This is shown in the table below.

20 Year Trend

		HDD	CDD
Windsor Riverside	January	675.09	0.00
Windsor Riverside	February	644.95	0.00
Windsor Riverside	March	454.91	0.13
Windsor Riverside	April	263.92	1.76
Windsor Riverside	May	82.02	52.21

Windsor Riverside	June	3.64	113.38
Windsor Riverside	July	0.76	186.39
Windsor Riverside	August	1.34	169.95
Windsor Riverside	September	31.63	70.65
Windsor Riverside	October	170.95	8.69
Windsor Riverside	November	359.64	0.10
Windsor Riverside	December	534.71	0.00

Table 13 20 Year Trend HDD and CDD

4 CLASS SPECIFIC NORMALIZED FORECASTS

4.1 RESIDENTIAL

Incorporating the forecast economic variables, 10-yr weather normal heating and cooling degree days, and calendar variables, the following weather corrected consumption and forecast values are calculated:

			Res kWh			
Year	Actual	Cumulative Persisting CDM	Actual no CDM	Normalized no CDM	Cumulative Persisting CDM	Normalized
	A	B	C = A + B	D	E = B	F = D - E
2009	248,399,886	848,858	249,248,745	261,706,941	848,858	260,858,083
2010	265,216,568	2,001,028	267,217,596	259,318,714	2,001,028	257,317,686
2011	258,409,726	2,530,086	260,939,812	256,348,291	2,530,086	253,818,205
2012	256,003,979	3,245,785	259,249,764	258,425,322	3,245,785	255,179,537
2013	250,406,105	3,886,093	254,292,198	255,706,080	3,886,093	251,819,986
2014	245,551,953	4,916,295	250,468,248	253,278,603	4,916,295	248,362,308
2015	244,757,239	6,015,187	250,772,427	252,990,205	6,015,187	246,975,018
2016	255,390,422	5,840,197	261,230,619	255,008,362	5,840,197	249,168,165
2017				252,951,789	5,251,445	247,700,344
2018				251,127,941	4,583,936	246,544,006

Table 14 Actual vs Normalized Residential kWh

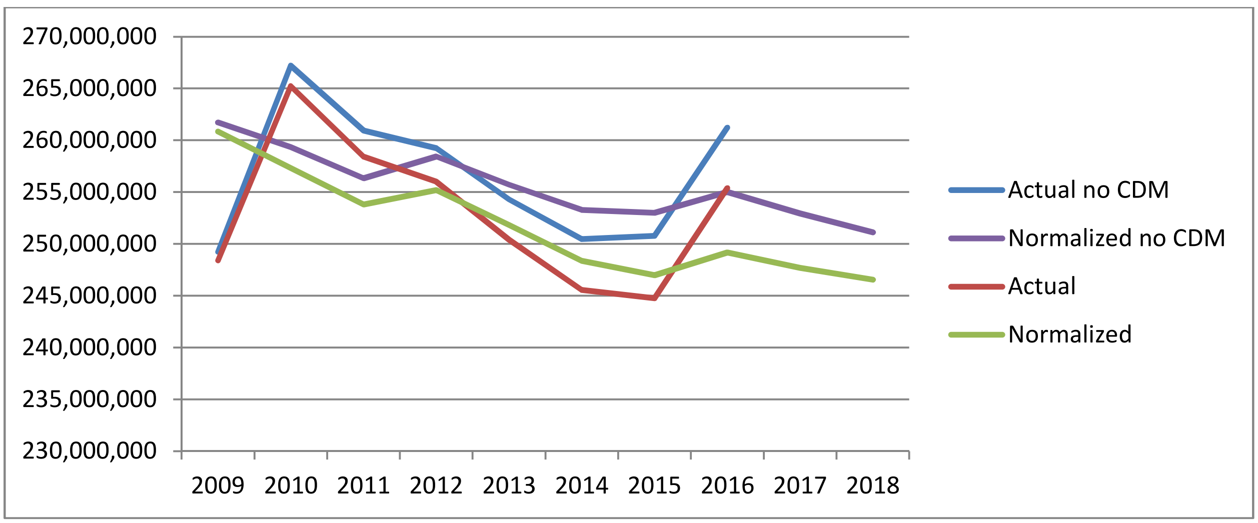


Figure 4 Actual vs Normalized Residential kWh

While Residential customer counts are not a component of the regression model, they are forecasted for the purpose of rate setting. The Geometric mean of the annual growth from 2009 to 2016 was used to forecast the growth rate from 2017 to 2018.

Year	Residential Customers	Percentage of Prior Year
2009	25,957	
2010	26,075	100.46%
2011	26,201	100.48%
2012	26,337	100.52%
2013	26,466	100.49%
2014	26,590	100.47%
2015	26,815	100.85%
2016	27,137	101.20%
2017	27,310	100.64%
2018	27,484	100.64%

Table 15 Forecasted Residential Customer Count

4.2 GS < 50

Incorporating the forecast economic variables, 10-yr weather normal heating and cooling degree days, and calendar variables, the following weather corrected consumption and forecast values are calculated:

			GS<50 kWh			
Year	Actual	Cumulative Persisting CDM	Actual no CDM	Normalized no CDM	Cumulative Persisting CDM	Normalized
	A	B	C = A + B	D	E = B	F = D - E
2009	67,411,402	223,864	67,635,266	68,012,729	223,864	67,788,865
2010	68,742,430	721,136	69,463,566	68,113,113	721,136	67,391,976
2011	67,558,143	1,022,244	68,580,386	68,111,972	1,022,244	67,089,728
2012	67,056,278	1,445,240	68,501,517	68,996,132	1,445,240	67,550,892
2013	65,663,990	1,901,582	67,565,571	69,033,675	1,901,582	67,132,094
2014	65,242,011	2,343,745	67,585,756	69,127,215	2,343,745	66,783,470
2015	65,329,579	4,210,293	69,539,872	69,593,770	4,210,293	65,383,477
2016	66,808,993	5,791,744	72,600,737	70,467,663	5,791,744	64,675,919
2017				70,620,764	5,532,872	65,087,892
2018				70,819,565	5,331,916	65,487,649

Table 16 Actual vs Normalized GS < 50 kWh

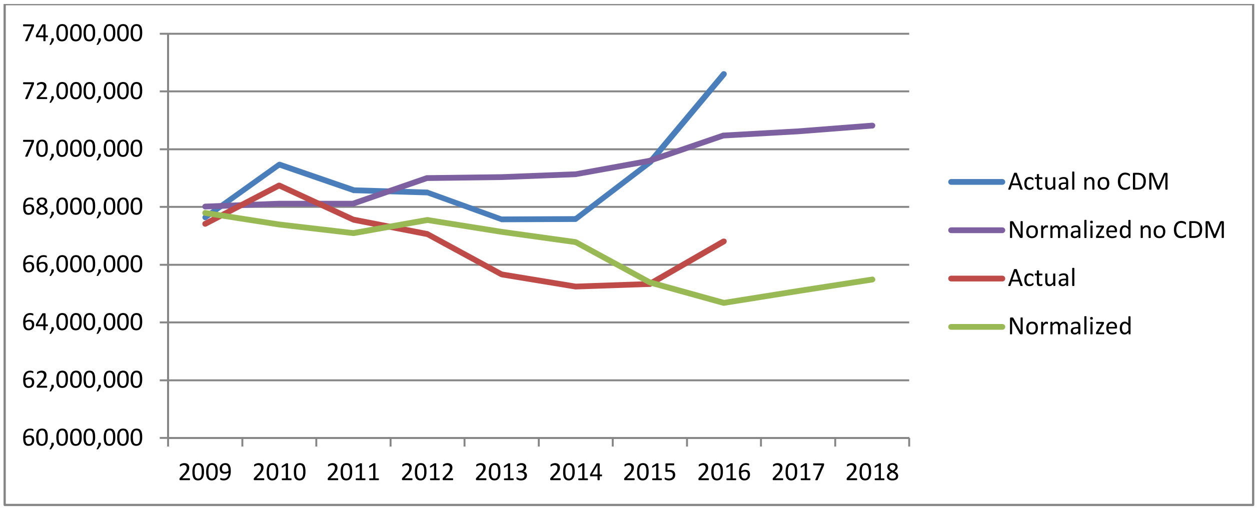


Figure 5 Actual vs Normalized GS < 50 kWh

While GS < 50 customer counts are not a component of the regression model, they are forecasted for the purpose of rate setting. The Geometric mean of the annual growth from 2009 to 2016 was used to forecast the growth rate from 2017 to 2018.

The following table includes the customer Actual / Forecast customer count on this basis:

Year	GS < 50 Customers	Percentage of Prior Year
2009	1,870	
2010	1,895	101.37%
2011	2,056	108.47%
2012	1,906	92.72%
2013	1,904	99.90%
2014	1,910	100.29%
2015	1,936	101.36%
2016	1,953	100.89%
2017	1,965	100.62%
2018	1,977	100.62%

Table 17 Forecasted GS < 50 Customer Count*

4.3 GS > 50

Incorporating the forecast economic variables, 10-yr weather normal heating and cooling degree days, and calendar variables, the following weather corrected consumption and forecast values are calculated:

			GS>50 kWh			
Year	Actual	Cumulative Persisting CDM	Actual no CDM	Normalized no CDM	Cumulative Persisting CDM	Normalized
	A	B	C = A + B	D	E = B	F = D - E
2009	164,879,032	571,217	165,450,249	160,709,213	571,217	160,137,995
2010	167,052,603	1,346,541	168,399,144	158,990,975	1,346,541	157,644,434
2011	165,850,872	1,938,999	167,789,871	165,598,376	1,938,999	163,659,377
2012	160,883,812	3,020,311	163,904,123	164,384,757	3,020,311	161,364,446
2013	164,887,609	4,184,874	169,072,483	167,509,941	4,184,874	163,325,067
2014	166,100,613	5,322,896	171,423,509	172,076,347	5,322,896	166,753,451
2015	171,874,066	10,144,443	182,018,509	177,660,533	10,144,443	167,516,090
2016	187,031,606	14,187,064	201,218,669	189,497,464	14,187,064	175,310,400
2017				193,414,587	13,584,630	179,829,958
2018				196,568,931	13,194,596	183,374,335

Table 18 Actual vs Normalized GS > 50 kWh

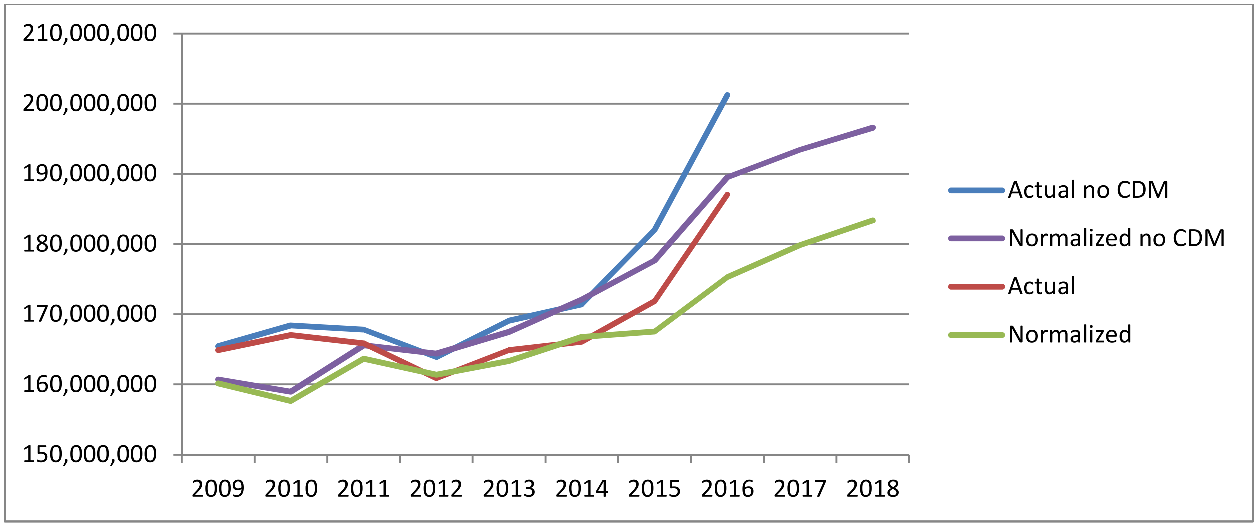


Figure 6 Actual vs Normalized GS > 50 kWh

Customer counts are forecasted and used for both the GS > 50 regression model, and for the purpose of rate setting. The Geometric mean of the annual growth from 2009 to 2016 was used to forecast the growth rate from 2017 to 2018.

The following table includes the customer Actual / Forecast customer count on this basis:

Year	GS > 50 Customers	Percentage of Prior Year
2009	221	
2010	214	96.80%
2011	222	103.65%
2012	208	93.74%
2013	208	99.92%
2014	211	101.60%
2015	212	100.24%
2016	220	103.62%
2017	219	99.88%
2018	219	99.88%

Table 19 Forecasted GS > 50 Customer Count

In order to normalize and forecast class kW for those classes that bill based on kW (demand) billing determinants, the relationship between billed kW and kWh is used. The average ratio from 2009-2016 is used to forecast kW for all future years.

		GS>50	
Year	kWh Actual	Ratio	kW Actual
	A	**C = B / A**	**B**
2009	164,879,032	0.002637102	434,803
2010	167,052,603	0.002534534	423,400
2011	165,850,872	0.002478392	411,044
2012	160,883,812	0.002587935	416,357
2013	164,887,609	0.002421144	399,217
2014	166,100,613	0.002375754	394,614
2015	171,874,066	0.002671453	459,153
2016	187,031,606	0.00254567	476,121
	kWh Normalized		
	D	**E**	**F = D * E**
2016	175,310,400	0.002531498	443,798
2017	179,829,958	0.002531498	455,239
2018	183,374,335	0.002531498	464,212

Table 20 Forecasted GS > 50 kW

4.4 EMBEDDED DISTRIBUTOR

The Embedded Distributor did not exhibit statistically significant heating, cooling, nor sensitivity to economic variables. It is common that regression would not be appropriate for larger volume rate classes, and occasionally embedded distributors depending on the attached loads. In this case, attempts at regression failed to produce an acceptable model. The Embedded Distributor class has exhibited a decreasing trend from 2009 to 2016, and was therefore forecasted by continuing the 8 year trend to 2017 and 2018.

Embedded Distributor

Year	Actual	Normalized
2009	44,707,890	44,707,890
2010	49,638,852	49,638,852
2011	42,820,521	42,820,521
2012	35,429,534	35,429,534
2013	36,931,636	36,931,636
2014	38,058,828	38,058,828
2015	38,655,620	38,655,620
2016	32,586,843	32,586,843
2017		31,681,583
2018		29,865,554

Table 21 Actual and Forecast Embedded Distributor kWh

The embedded distributor class has 3 connection points, and is projected to continue to be served at 3 connection points into 2018.

In order to normalize and forecast class kW for those classes that bill based on kW (demand) billing determinants, the relationship between billed kW and kWh is used. The average ratio from 2009-2016 is used to forecast kW for all future years.

Embedded Distributor

Year	kWh Actual	Ratio	kW Actual
	A	**C = B / A**	**B**
2009	44,707,890	0.002567453	114,785
2010	49,638,852	0.002795307	138,756
2011	42,820,521	0.002935759	125,711
2012	35,429,534	0.003085119	109,304
2013	36,931,636	0.002601512	96,078
2014	38,058,828	0.002219	84,453
2015	38,655,620	0.002762802	106,798
2016	32,586,843	0.002695211	87,828

	kWh Normalized		
	D	**E**	**F = D * E**
2016	32,586,843	0.00270777	88,238
2017	31,681,583	0.00270777	85,786
2018	29,865,554	0.00270777	80,869

Table 22 Forecasted GS > 50 kW

5 STREET LIGHT, SENTINEL AND USL FORECAST

The Street Lighting, Sentinel, and Unmetered Scattered Load Classes are non-weather sensitive classes. Connection counts are forecasted on the geometric mean growth rate from 2009 to 2016. Energy is forecasted on the basis of average energy per device or connection and connection growth.

In the case of Street Lighting, a significant LED conversion project was underway in 2016. As a result, the average demand from November and December 2016 and the average connection count from the same period were used in combination with the 2009-2016 demand to energy ratio to arrive at annual energy per street light.

The tables below summarize the historic connection counts and annual energy consumption for all classes and the anticipated consumption in the forecast period.

Street Light Year	Lamps / Devices
2009	7,634
2010	6,787
2011	2,896
2012	2,474
2013	2,621
2014	2,713
2015	2,701
2016	2,720
2017	2,740
2018	2,740

Table 23 Forecasted Street Light lamps (devices)

Sentinel Year	Connections
2009	174
2010	174
2011	174
2012	175
2013	175
2014	172
2015	174
2016	173
2017	173
2018	173

Table 24 Forecasted Sentinel connections

USL

Year	Connections
2009	140
2010	141
2011	141
2012	141
2013	140
2014	140
2015	141
2016	140
2017	140
2018	140

Table 25 Forecasted USL connections

	Street Light	
Year	Actual	Normalized
2009	5,814,688	5,814,688
2010	5,780,507	5,780,507
2011	5,969,304	5,969,304
2012	6,205,705	6,205,705
2013	6,271,491	6,271,491
2014	6,286,758	6,286,758
2015	6,227,063	6,227,063
2016	4,268,688	4,268,688
2017		2,983,574
2018		2,983,574

Table 26 Forecasted Street Light kWh

	Sentinel	
Year	Actual	Normalized
2009	398,171	398,171
2010	393,141	393,141
2011	382,814	382,814
2012	383,994	383,994
2013	342,834	342,834
2014	350,518	350,518
2015	341,136	341,136
2016	335,758	335,758
2017		335,758
2018		335,758

Table 27 Forecasted Sentinel kWh

Year	USL Actual	Normalized
2009	1,553,160	1,553,160
2010	1,558,152	1,558,152
2011	1,558,152	1,558,152
2012	1,558,152	1,558,152
2013	1,549,960	1,549,960
2014	1,555,546	1,555,546
2015	1,558,152	1,558,152
2016	1,554,368	1,554,368
2017		1,554,368
2018		1,554,368

Table 28 Forecasted USL kWh

Street Light

Year	kWh Actual	Ratio	kW Actual
	A	**C = B / A**	**B**
2009	5,814,688	0.003028579	17,610
2010	5,780,507	0.003034907	17,543
2011	5,969,304	0.003028805	18,080
2012	6,205,705	0.003020134	18,742
2013	6,271,491	0.003033639	19,025
2014	6,286,758	0.002524723	15,872
2015	6,227,063	0.002894251	18,023
2016	4,268,688	0.003160226	13,490
	kWh Normalized		
	D = F / E	**E**	**F**
2016	4,548,744	0.002965658	13,490
2017	2,983,574	0.002965658	8,848
2018	2,983,574	0.002965658	8,848

Table 29 Forecasted Street Light kW

Sentinel			
Year	kWh Actual	Ratio	kW Actual
	A	C = B / A	B
2009	398,171	0.005238961	2,086
2010	393,141	0.005313609	2,089
2011	382,814	0.0054439	2,084
2012	383,994	0.005468836	2,100
2013	342,834	0.006125411	2,100
2014	350,518	0.005899844	2,068
2015	341,136	0.006120733	2,088
2016	335,758	0.006194936	2,080
	kWh Normalized		
	D	E	F = D * E
2016	335,758	0.005725779	1,922
2017	335,758	0.005725779	1,922
2018	335,758	0.005725779	1,922

Table 30 Forecasted Sentinel kW

6 CDM ADJUSTMENT TO LOAD FORECAST

The current Chapter 2 OEB Minimum Filing requirements, consistent with the Board's CDM Guideline EB-2012-0003, expects the distributor to integrate an adjustment into its load forecast that takes into account the six-year (2015-2020) targets for kWh and kW reductions.

The filing requirements note that the distributors license condition targets and the LRAMVA balances are based on the IESO targets, which are annualized. It is recognized that the CDM programs in a year are not in effect for the full year, although persistence of previous year's programs will be. Therefore, the actual impact on the load forecast for the first year of the program should not be the full annualized amount. For this reason, the amount that will be used for the LRAMVA will be related to, but not necessarily equal to, the CDM adjustment for the load forecast.

The following is the proposed allocation of the CDM kWh load forecast adjustment and final proposed load forecast, based on a half-year of savings from 2016, a full year of savings from 2017 and 2018, and a half year of savings from 2018. The persisting savings observed in 2016 informed the apportionment of the commercial and industrial target.

For 2018 LRAMVA Elenchus reasons that the effects of 2016-2018 IESO CDM programs should be included in the LRAMVA calculation. In particular, full years of 2016-2018 are included.

	2015 Verified CDM	Share	CDM Adjustment	LRAMVA Target
Residential	1,356,938	10.6%	1,169,888	1,754,832
GS < 50	3,224,717	25.2%	2,780,199	4,170,299
GS > 50	8,228,273	64.2%	7,094,029	10,641,044
Total	12,809,928	100.0%	11,044,116	16,566,174

Table 31 Proposed CDM and LRAMVA kWh Adjustment

In order to calculate the kW Elenchus proposes using a proportional ratio utilizing the base load forecast kW and kWh.

	Weather Normalized 2018 Forecast (kWh)	CDM Adjustment (kWh)	% Savings	Weather Normalized 2018 Forecast (kW)	CDM Adjustment (kW)
GS > 50	183,374,335	7,094,029	3.9%	464,212	17,959
Total	183,374,335	7,094,029	0	464,212	17,959

Table 32 Proposed kW CDM adjustment

	Weather Normalized 2018 Forecast (kWh)	LRAMVA Target (kWh)	% Savings	Weather Normalized 2018 Forecast (kW)	LRAMVA Target (kW)
GS > 50	183,374,335	10,641,044	5.8%	464,212	26,938
Total	183,374,335	10,641,044	0	464,212	26,938

Table 33 LRAMVA kW threshold by class

<u>**Attachment 3-B**</u>

Load Forecast CDM Adjustment Work Form

2021

File Number:	EB-2017-0039
Exhibit:	3
Tab:	3-B
Page:	1 of 3
Date:	August 28th, 2017

Appendix 2-I
Load Forecast CDM Adjustment Work Form (2018)

Appendix 2-I was initially developed to help determine what would be the amount of CDM savings needed in each year to cumulatively achieve the four year 2011-2014 CDM target. This then determined the

2018 is the fourth year of the six-year (2015-2020) Conservation First program. Final results for the 2011-14 program were issued in the fall of 2015, and the program is completed, although in some instances

The new six year (2015-2020) CDM program works in a slightly different manner to the previous 2011-2014 CDM program. Distributors will offer programs each year that, over the six years (from January 1,

2015-2020 CDM Program - 2018 fourth year of the current CDM plan

For the first year of the new 2015-2020 CDM plan, it is assumed that each year's program will achieve an equal amount of new CDM savings. This results in each year's program being about 1/6 (16.67%) of

6 Year (2015-2020) kWh Target:							
31,430,000							
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
%							
2015 CDM Programs						12.15%	12.15%
2016 CDM Programs						17.57%	17.57%
2017 CDM Programs						17.57%	17.57%
2018 CDM Programs						17.57%	17.57%
2019 CDM Programs						17.57%	17.57%
2020 CDM Programs						17.57%	17.57%
Total in Year						**100.00%**	**100.00%**
kWh							
2015 CDM Programs	3,819,710.00	3,819,710.00	3,819,710.00	3,819,710.00	3,819,710.00	3,819,710.00	3,819,710.00
2016 CDM Programs		5,522,058.00	5,522,058.00	5,522,058.00	5,522,058.00	5,522,058.00	5,522,058.00
2017 CDM Programs			5,522,058.00	5,522,058.00	5,522,058.00	5,522,058.00	5,522,058.00
2018 CDM Programs				5,522,058.00	5,522,058.00	5,522,058.00	5,522,058.00
2019 CDM Programs					5,522,058.00	5,522,058.00	5,522,058.00
2020 CDM Programs						5,522,058.00	5,522,058.00
Total in Year	**3,819,710.00**	**9,341,768.00**	**14,863,826.00**	**20,385,884.00**	**25,907,942.00**	**31,430,000.00**	**31,430,000.00**

Note: The default formulae in the above table assume that the 2015-2020 kWh CDM target is achieved through persistence of CDM savings to the end of 2020. The distributor should enter measured CDM

File Number:	EB-2017-0039
Exhibit:	3
Tab:	3-B
Page:	2 of 3
Date:	August 28th, 2017

Determination of 2018 Load Forecast Adjustment

The Board determined that the "net" number should be used in its Decision and Order with respect to Centre Wellington Hydro Ltd.'s 2013 Cost of Service rates (EB-2012-0113). This approach has also been

From each of the 2006-2010 CDM Final Report, and the 2011 to 2016 CDM Final Reports, issued by the OPA/IESO for the distributor, the distributor should input the "gross" and "net" results of the cumulative

Net-to-Gross Conversion

Is CDM adjustment being done on a "net" or "gross" basis? net

Persistence of Historical CDM programs to 2015	**"Gross" kWh**	**"Net" kWh**	**Difference kWh**	**"Net-to-Gross" Conversion Factor ('g')**
2006-2010 CDM programs	**6,034,000**	**3,213,000**	**2,821,000**	
2011 CDM program	**2,911,673**	**1,762,640**	**1,149,033**	
2012 CDM program	**2,453,965**	**1,834,086**	**619,879**	
2013 CDM program	**3,231,110**	**1,595,768**	**1,635,342**	
2014 CDM program	**4,590,608**	**3,628,004**	**962,604**	
2015 CDM program	**17,262,381**	**12,809,928**	**4,452,453**	
2016 CDM program				
2006 to 2016 OPA CDM programs: Persistence to 2018.	36,483,737	24,843,426	11,640,311	0.00%

The default values below represent the factor used for how each year's CDM program is factored into the manual CDM adjustment. Distributors can choose alternative weights of "0", "0.5" or "1" from

These factors do not mean that CDM programs are excluded, but the assumption that impacts of previous year CDM programs are already implicitly reflected in the actual data for historical years that are

Weight Factor for Inclusion in CDM Adjustment to 2018 Load Forecast

	2015	**2016**	**2017**	**2018**	**2019**	**2020**	
Weight Factor for each year's CDM program impact on 2018 load forecast	**0**	**0.5**	**1**	**0.5**	**0**	**0**	Distributor can select "0", "0.5", or "1" from drop-down list
Default Value selection rationale.	*Full year impact of 2015 CDM is assumed to be reflected in the base forecast, as the full year persistence of 2015 CDM programs is in the 2016 historical actual data. No further impact is necessary for the manual adjustment to the load forecast.*	*Default is 0.5, but one option is for full year impact of persistence of 2016 CDM programs on 2018 load forecast, but 50% impact in base forecast (first year impact of 2016 CDM programs on 2016 actuals, which is part of the data underlying the base*	*Full year impact of persistence of 2017 programs on 2018 load forecast. 2017 CDM program impacts are not in the base forecast.*	*Only 50% of 2017 CDM programs are assumed to impact the 2018 load forecast based on the "half-year" rule.*	*2019 and 2020 are future years beyond the 2018 test year. No impacts of CDM programs beyond the 2018 test year are factored into the test year load forecast.*		

File Number:	EB-2017-0039
Exhibit:	3
Tab:	3-B
Page:	3 of 3
Date:	August 28th, 2017

2015-2020 LRAMVA and 2018 CDM adjustment to Load Forecast

One manual adjustment for CDM impacts to the 2018 load forecast is made. There is a different but related threshold amount that is used for the 2018 LRAMVA amount for Account 1568.

The amount used for the CDM threshold of the LRAMVA is the kWh that will be used to determine the base amount for the LRAMVA balance for 2018, for assessing performance against the six-year target.

If used to determine the manual CDM adjustment for the system purchased kWh, the proposed loss factor should correspond with the proposed total loss factor calculated in Appendix 2-R .

The Manual Adjustment for the 2018 Load Forecast is the amount manually subtracted from the system-wide load forecast (either based on a purchased or billed basis) derived from the base forecast from historical data. If the distributor has developed their load forecast on a system purchased basis, then the manual adjustment should be on a system purchased basis, including the adjustment for losses. If the load forecast has been developed on a billed basis, either on a system basis or on a class-specific basis, the manual adjustment should be on a billed basis, excluding losses.

The distributor should determine the allocation of the savings to all customer classes in a reasonable manner (e.g. taking into account what programs and what IESO-measured impacts were directed at specific customer classes), for both the LRAMVA and for the load forecast adjustment.

	2015	2016	2017	2018	2019	2020	Total for 2018
Amount used for CDM threshold for LRAMVA (2018)	3,819,710.00	5,522,058.00	5,522,058.00	5,522,058.00			**20,385,884.00**
Manual Adjustment for 2018 Load Forecast (billed basis)	-	2,761,029.00	5,522,058.00	2,761,029.00			11,044,116.00
Manual Adjustment for 2018 LDC-only CDM programs (billed basis)				-			
Total Manual Forecast to Load Forecast	-	2,761,029.00	5,522,058.00	2,761,029.00			**11,044,116.00**
Proposed Loss Factor (TLF)	3.55%	Format: X.XX%					
Manual Adjustment for 2018 Load Forecast (system purchased basis)	-	2,859,045.53	5,718,091.06	2,859,045.53			**11,436,182.12**

Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g). The Weight factor is also used to calculate the impact of each year's program on the CDM adjustment to the 2018 load

Attachment 3-C

EPLC CDM Plan 2015-2020

OVERVIEW OF CDM PLAN
This CDM Plan must be used by the LDC in submitting a CDM Plan to the IESO under the Energy Conservation Agreement between the LDC and the IESO The CDM Plan will consist of the information provided in this document and any additional information and supporting documents provided by the LDC to the IESO in support of this CDM Plan. Capitalized terms not otherwise defined herein have the meaning ascribed to them in the Energy Conservation Agreement as may be applicable.
Complete all fields within the CDM Plan that are applicable. Where additional space is required to complete a section of the CDM Plan, please append additional pages as required. The LDC should indicate that additional information has been attached in the related question field on the CDM Plan. Please refer to the CDM Plan Submission and Review Criteria Rules for further information.

A. General Information

1.

CDM Plan Submission Date: ***(DD-Mon-YYYY)***	30-Mar-2017
CDM Plan Version	4

2.

LDC INFORMATION										
	LDC 1	**LDC 2**	**LDC 3**	**LDC 4**	**LDC 5**	**LCD 6**	**LCD 7**	**LCD 8**	**LCD 9**	**LCD 10**
LDC Name:	Entegrus Powerlines Inc.	Essex Powerlines Corporation								
Company Representative:										
Name:	Tomo Matesic									
Title:	Conservation Officer									
Email Address:	tomo.matesic@entegrus.com									
Phone Number (XXX-XXX-XXXX):	519-352-6300 x 349									

3.

Primary Contact for CDM Plan	
Name:	Tomo Matesic
LDC Name:	Entegrus Powerlines
Title:	Conservation Officer
Email Address:	tomo.matesic@entegrus.com
Phone Number (XXX-XXX-XXXX):	519-352-6300 x 349

Estimated Start Date of CDM Plan: ***(DD-Mon-YYYY)***	1-May-2017

LDC CONFIRMATION FOR CDM PLAN	
Each LDC to this CDM Plan has executed the Energy Conservation Agreement.	
A completed Cost-Effectiveness Tool is attached and forms part of the CDM Plan.	
A completed Achievable Potential Tool is attached and forms part of the CDM Plan.	
All customer segments in each LDC's service area are served by the Programs set out in this CDM Plan.	
The CDM Plan includes all electricity savings attributable to all Programs and pilot programs that have in-service dates between Jan 1, 2015 and December 31, 2020.	
The CDM Plan Budget for each LDC includes all eligible funding under the full cost recovery and pay-for-performance mechanisms for Programs under its CDM Plan.	
Frequency of LDC Invoicing to IESO (subsequent changes to the frequency should be notified to us by email).	

COMPLETE FOR CDM PLAN AMENDMENTS ONLY		
Select the reason(s) for CDM Plan amendment, as per ECA.		
One time each calendar year of the term		Yes
LDC wishes to request an adjustment to the CDM Plan Budget		
The amendments to a provision of the ECA or any Rules will have a material effect on the CDM Plan		
LDC's actual spending under CDM Plan has exceeded (or is reasonably expected to exceed) the portion of the CDM Plan Budget allocated to the current year of the term		
Under a joint CDM Plan, LDCs that are parties to a joint CDM Plan reallocate any portion of their respective CDM Plan Targets and CDM Plan Budgets [*Reallocation not subject to IESO approval*]		
IESO has triggered remedies under Article 5 of the ECA		Yes
LDC seeking to change its selection of the type of funding that it wishes to receive for each Program in the CDM Plan [ECA, section 4.1]		
Other (Please specify reason)	submitting as a new joint plan	Yes

B. LDC Authorization

LDC DECLARATION
Please complete the declaration for each LDC that is listed in this CDM Plan. A separate page with each LDC's signed declaration should be included as part of the CDM Plan submission.

LDC	
I represent that the information contained in this CDM Plan as it relates to the LDC is complete, true, and accurate in all respects. I acknowledge and agree to the following terms and conditions: (1) if this CDM Plan is approved by the IESO and accepted by each LDC to this CDM Plan, the CDM Plan together with any conditions to that approval is incorporated by reference into the Energy Conservation Agreement between the LDC and the IESO (2) the LDC will offer the Programs set out in Table 2 of this CDM Plan to customers in its service area; and (3) the LDC of will implement this CDM Plan in accordance with the CDM Plan Budget.	
LDC's Legal Name:	Entegrus Powerlines Inc.
Company Representative:	Tomo Matesic
Signature	
	I/We have the authority to bind the Corporation.
Date (DD-Mon-YYYY)	

B. LDC Authorization

LDC DECLARATION
Please complete the declaration for each LDC that is listed in this CDM Plan. A separate page with each LDC's signed declaration should be included as part of the CDM Plan submission.

LDC	
I represent that the information contained in this CDM Plan as it relates to the LDC is complete, true, and accurate in all respects. I acknowledge and agree to the following terms and conditions: (1) if this CDM Plan is approved by the IESO and accepted by each LDC to this CDM Plan, the CDM Plan together with any conditions to that approval is incorporated by reference into the Energy Conservation Agreement between the LDC and the IESO (2) the LDC will offer the Programs set out in Table 2 of this CDM Plan to customers in its service area; and (3) the LDC of will implement this CDM Plan in accordance with the CDM Plan Budget.	
LDC's Legal Name:	Essex Powerlines
Company Representative:	
Signature	
	I/We have the authority to bind the Corporation.
Date (DD-Mon-YYYY)	

C. CDM Plan Summary

TABLE 1: SUMMARY OF CDM PORTFOLIO SAVINGS AND BUDGET

		CDM PLAN TOTAL	LDC 1	LDC 2	LDC 3	LDC 4	LDC 5	LCD 6	LCD 7	LCD 8	LCD 9	LCD 10
a.	**Allocated LDC CDM Plan Target (MWh)** *Indicate total CDM Plan Target allocated to LDC(s)*	**88,260**	56,830.0	31,430.0								
b.	**CDM Plan MWh Savings** *Calculated as part of CDM Plan*	**116,396**	69,513	46,883	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
c.	**Allocated LDC CDM Plan Budget ($)** *Indicate total budget allocated to LDC*	**$23,228,440**	$14,695,867.00	$8,532,573.00								
d.	**Total CDM Plan Budget ($)** *Calculated as part of CDM Plan*	**$22,370,503**	$14,661,028	7,709,475	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!

			Total Resource Cost (TRC)			Program Administrator Cost (PAC)			Levelized Cost
f.	**CDM Plan Cost Effectiveness**	**Program Year**	**Benefits ($)**	**Costs ($)**	**Ratio**	**Benefits ($)**	**Costs ($)**	**Ratio**	**($/kWh)**
	Indicate annual portfolio-level Cost Effectiveness for CDM Plan as determined by LDC(s) using output from Cost-Effectiveness Tool	2015	$39,646,000.66	$15,600,828.21	2.5	$34,677,960.83	$1,380,967.92	25.1	$0.002
		2016	$10,994,198.60	$7,695,699.71	1.4	$9,782,116.98	$4,755,888.75	2.1	$0.032
		2017	$8,025,206.85	$5,990,636.47	1.3	$6,841,039.99	$4,147,942.96	1.6	$0.053
		2018	$29,046,718.88	$6,438,052.71	4.5	$25,173,181.63	$4,753,161.53	5.3	$0.017
		2019	$6,406,627.31	$4,948,443.32	1.3	$5,478,931.59	$3,443,170.83	1.6	$0.056
		2020	$6,338,113.01	$4,809,446.90	1.3	$5,442,495.76	$3,509,658.08	1.6	$0.058
		CDM Plan Total	**$100,456,865**	**$45,483,107**	2.2	**$87,395,727**	**$21,990,790**	4.0	**$0.019**
g	**Plan Cost Effectiveness-Exceptions Rationale** *Complete this section if proposed plan does not meet minimum Cost-Effectiveness Thresholds set out in CDM Plan Submission and Review Criteria Rules.*								

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO could only be achieved with funding in addition to the CDM Plan Budget.

LDC 1:	Entegrus Powerlines Inc.

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (inc. Multi-F	Agricultural	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	Coupon Program			1-Oct-2015	Yes							$159,367	589.0	$426,568	1,753.3	$326,864	292.4	$328,335	291.7	$333,912	291.7	$339,600	291.7	$1,914,645	3,505.0
	Heating and Cooling			1-Oct-2015	Yes							$88,381	121.0	$274,193	310.0	$485,144	387.0	$434,758	423.0	$447,661	460.0	$369,373	450.0	$2,099,510	2,152.0
	New Construction Program			1-Oct-2015	Yes							$0	0.0	$25,102	0.0	$98,267	9.0	$105,145	9.0	$107,173	9.0	$109,241	9.0	$444,928	37.0
	Home Assistance Program			1-Oct-2015		Yes						$0	0.0	$76,653	38.0	$229,725	196.0	$183,022	196.0	$183,781	196.0	$162,546	157.0	$835,727	783.0
	Audit Funding Program			1-Oct-2015			Yes					$4,229	0.0	$34,942	0.0	$56,471	607.0	$45,070	379.0	$45,439	379.0	$35,160	228.0	$221,311	1,593.0
	Retrofit			1-Oct-2015			Yes	Yes	Yes	Yes	Yes	$109,617	274.0	$1,585,916	8,771.2	$1,382,315	2,837.7	$881,514	1,774.4	$1,187,544	2,766.8	$984,684	2,096.2	$6,131,590	18,511.0
	High Performance New Construction			1-Oct-2015				Yes		Yes		$0	0.0	$16,426	0.0	$32,571	57.0	$37,152	57.0	$37,521	57.0	$37,896	57.0	$161,566	228.0
	Process and Systems Upgrades Program			1-Oct-2015				Yes	Yes	Yes	Yes	$0	0.0	$190,711	0.0	$43,517	0.0	$1,077,220	1,021.0	$88,964	0.0	$490,744	1,021.0	$1,891,156	2,042.0
	Small Business Lighting						Yes					$0	0.0	$0	0.0	$208,898	582.0	$230,303	688.0	$231,409	688.0	$232,536	688.0	$903,146	2,647.0
		Instant Savings Program		1-May-2017	Yes							$0	0.0	$0	0.0	$56,109	390.0							$56,109	390.0
	Existing Building Commissioning			1-May-2017			Yes	Yes	Yes	Yes	Yes														
	Monitoring and Targeting Program			1-May-2017				Yes	Yes	Yes	Yes														
	Energy Manager Program			1-May-2017				Yes	Yes	Yes	Yes														
		Provincial BRI		1-May-2017			Yes	Yes	Yes	Yes	Yes					$335	1.0	$335	1.0	$335	1.0	$335	1.0	$1,340	3.0
FCR TOTAL												$361,594	984.0	$2,630,510	10,872.4	$2,920,216	5,359.0	$3,322,854	4,840.1	$2,663,739	4,848.5	$2,762,115	4,998.9	$14,661,028	31,891.0
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*	Conservation Instant Coupon Booklet												441.0												431.0
	Bi-Annual Retailer Event												0.0												
	Heating and Cooling Initiative												293.0												293.0
	Residential New Construction												0.0												0.0
	Low Income Home Assistance Program												249.0												183.0
	Audit Funding												143.0												
	Retrofit Initiative												7,797.0												7,764.0
	Direct Install Lighting												909.0												531.0
	Process and Systems Upgrades Program												28,291.0												28,291.0
	Other												102.0												0.0
	Energy Manager (PSUI)												129.0												129.0
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	38,354.0											0.0	37,622.0
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$361,594	39,338.0	$2,630,510	10,872.4	$2,920,216	5,359.0	$3,322,854	4,840.1	$2,663,739	4,848.5	$2,762,115	4,998.9	$14,661,028	69,513.0
MINIMUM ANNUAL SAVINGS CHECK													True		True		True		True		True		True		

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 2:	Essex Powerlines Corporation

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Customer Segments Targeted by Program — Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Residential	Low-income	Small business	Commercial (inc. Multi-F	Agricultural	Institutional	Industrial	2015 Anticipated Annual Budget ($)	2015 Energy Savings (MWh)	2016 Anticipated Annual Budget ($)	2016 Energy Savings (MWh)	2017 Anticipated Annual Budget ($)	2017 Energy Savings (MWh)	2018 Anticipated Annual Budget ($)	2018 Energy Savings (MWh)	2019 Anticipated Annual Budget ($)	2019 Energy Savings (MWh)	2020 Anticipated Annual Budget ($)	2020 Energy Savings (MWh)	Total 2015 - 2020 Total CDM Plan Budget ($)	Total 2015 - 2020 Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	Retrofit			1-Oct-2015								$25,546	152.0	$1,312,989	3,976.0	$699,500	2,097.0	$321,500	963.0	$583,000	1,555.0	$787,000	1,880.0	$3,729,535	10,624.0
	Small Business Lighting			1-Jun-2016								$0	0.0	$0	0.0	$120,000	180.0	$100,000	144.0	$60,000	72.0	$20,000	0.0	$300,000	396.0
	High Performance New Construction			1-Oct-2015								$0	0.0	$27,574	0.0	$27,500	57.0	$27,500	57.0	$7,500	0.0	$7,000	0.0	$97,074	114.0
	Audit Funding Program			1-Oct-2015								$0	0.0	$32,031	0.0	$15,000	76.0	$15,000	76.0	$15,000	76.0	$10,000	0.0	$87,031	228.0
	Process and Systems Upgrades Program			1-Oct-2015								$0	0.0	$39,264	0.0	$20,000	0.0	$720,866	17,527.0	$20,000	0.0	$20,000	0.0	$820,130	17,527.0
	Energy Manager Program			1-Jan-2017								$0	0.0	$0	0.0	$10,000	0.0	$10,000	0.0	$7,500	0.0	$7,500	0.0	$35,000	0.0
	Existing Building Commissioning			1-Oct-2015								$0	0.0	$0	0.0	$1	0.0	$1	0.0	$1	0.0	$1	0.0	$4	0.0
	Monitoring and Targeting Program			1-Oct-2015								$0	0.0	$0	0.0	$1	0.0	$1	0.0	$1	0.0	$1	0.0	$4	0.0
	Coupon Program			1-Oct-2015								$113,392	535.0	$280,162	1,156.0	$209,886	828.0	$183,653	704.0	$160,918	596.0	$139,932	497.0	$1,087,943	4,311.0
	Home Assistance Program			1-Oct-2015										$144,565	30.0	$44,597	3.0	$40,000	0.0	$40,000	0.0	$40,000	0.0	$309,162	33.0
	New Construction Program			1-Oct-2015								$0	0.0	$40,250	34.0	$22,500	28.0	$22,500	28.0	$22,500	28.0	$22,500	28.0	$130,250	147.0
	Heating and Cooling Program			1-Oct-2015								$59,560	80.0	$343,661	474.0	$192,635	311.0	$176,105	284.0	$147,251	232.0	$131,660	206.0	$1,050,872	1,587.0
		Provincial BRI		1-May-2017								$0	0.0	$0	0.0	$1	0.0	$1	0.0	$1	0.0	$1	0.0	$4	0.0
		Instant Savings Clotheslines		1-May-2017								$0	0.0	$0	0.0	$18,682	165.0	$15,610	103.0	$14,586	82.0	$13,572	62.0	$62,450	413.0
		Appliance Retirement		1-Oct-2015								$0	0.0	$0	0.0	$1	0.0	$1	0.0	$1	0.0	$1	0.0	$4	0.0
		Program Enabled Savings		1-Oct-2015								$0	8,572.0	$0	0.0	$1	0.0	$1	0.0	$1	0.0	$1	0.0	$4	8,572.0
			Smart T-stat	1-Oct-2017								$0	0.0	$0	0.0	$1	0.0	$1	0.0	$1	0.0	$1	0.0	$4	0.0
			Residential DIL	1-Oct-2017								$0	0.0	$0	0.0	$1	0.0	$1	0.0	$1	0.0	$1	0.0	$4	0.0
FCR TOTAL												$198,498	9,339.0	$2,220,496	5,670.0	$1,380,307	3,745.0	$1,632,741	19,886.0	$1,078,262	2,641.0	$1,199,171	2,673.0	$7,709,475	43,952.0
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*	Retrofit Initiative												2,175.0												2,170.0
	Direct Install Lighting												14.0												9.0
	Audit Funding												214.0												0.0
	Energy Manager (PSUI)												28.0												28.0
	Conservation Instant Coupon Booklet												402.0												393.0
	Residential New Construction												16.0												16.0
	Heating and Cooling Initiative												315.0												315.0
	Other												9.0												0.0
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	3,173.0											0.0	2,931.0
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$198,498	12,512.0	$2,220,496	5,670.0	$1,380,307	3,745.0	$1,632,741	19,886.0	$1,078,262	2,641.0	$1,199,171	2,673.0	$7,709,475	46,883.0
MINIMUM ANNUAL SAVINGS CHECK													True		True		True		True		True		True		

E. Proposed Local and Regional Pilot CDM Programs

Notes
Complete the following Table(s) for each proposed local and regional Program or Pilot Program in the CDM Plan for which a business case has NOT previously been approved by the IESO. Please refer to the Program Development and Rule Revision Guideline and the Business Case Template for full details on requirements and submission of a business case for approval of a local or regional Program. For the process for receiving funding for a Pilot Program, refer to the LDC Program Innovation Guideline.

TABLE 3a. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3b. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3c. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**	Smart Thermostat Program	*Use same "Program name" included in other worksheets*	
b.	**Program Type**	Proposed Regional Program		
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***	1-Aug-2017		
c.	**Customer Segment(s) Served by Programs**	Residential	Low Income	Small Business
d.	**Participating LDCs** ***(if applicable)***	Essex Powerlines Corporation		
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*	The objective of the program is to provide more detailed, relevant, and actionable energy consumption information to the end user by way of smart thermostat devices. The program would launch with rebates of $50 payable to consumers who purchase, install, and register a "NEST" brand thermostat. The smart thermostats will help reduce energy use in the occupied property, as well as allowing for possible participation in DR events. Rebate amounts are subject to periodic review and adjustment in accordance with cost effectiveness methodology. Other smart thermostats may be incorportaed into the program in future iterations. The program is anticipated to endure through 2020.		

TABLE 3d. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3e. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3f. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

E. Proposed Local and Regional Pilot CDM Programs

Notes
Complete the following Table(s) for each proposed local and regional Program or Pilot Program in the CDM Plan for which a business case has NOT previously been approved by the IESO. Please refer to the Program Development and Rule Revision Guideline and the Business Case Template for full details on requirements and submission of a business case for approval of a local or regional Program. For the process for receiving funding for a Pilot Program, refer to the LDC Program Innovation Guideline.

TABLE 3g. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3h. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3i. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3j. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

F. Detailed Information on Collaboration and Regional Planning

	ADDITIONAL DETAILED INFORMATION
Regional LDC(s) Collaboration *Description of how the LDC(s) will collaborate with other LDCs. If collaboration will not occur, description of why it will not occur.*	Entegrus Powerlines Inc. and Essex Energy are submitting a joint plan in an effort to maximize cost effectiveness and attain mid-term targets. Essex does retrofit technical review for Entegrus, and as partners, Entegrus will recieve a better rate for this service. Essex is not on track to meet their mid-term incentive, however, as a joint plan and because of the strong start Entegrus has had, we will collectively meet our mid-term target. Entegrus and Essex have been working collaboratively with the West LDC Collaboration group to offer the Small Business Lighting program. In 2016, the West LDC Collaboration group utilized the collaboration fund to offer a roving energy manager to industrial customers across the region. Entegrus and Essex will be offering the Clothesline Instant Savings program, which was developed and shared through CNP, a member of the Southwest group.
Gas Collaboration *Description of how the LDC(s) will collaborate with other gas utility programs delivered in service area (if applicable). If collaboration will not occur, description of why it will not occur.*	Entegrus is currently working with Union Gas on a potential pilot program for small business and multi-residential customers in our service territory. We have had two preliminary meetings in 2017, and there is a high desire to pursue this project from both utilities. Entegrus is also working with Union on a possible CHP project for their head office in Chatham. Essex has approched Union Gaws with regards to a proposed Smart Thermostat program. Discussions were shelved while Union Gas investigted the possibility of the Whole Home Program. Essex intends to re-engage with Union Gas in an effort to bring a smart thermostat incentive program to market locally.
CDM Contribution to Regional Planning *Description of how the CDM Plan considers the electricity needs and investments identified in other plans or planned initiatives, completed or underway within the LDC(s)' service area or region. This may included Integrated Regional Resource Plans or Municipal Community Energy Plans.*	Entegrus Powerlines participates in the IESO driven regional planning activities to develop integrated regional resource plans. These plans are developed in consultation with all affected LDC's and the IESO to ensure adequate electrical supply is available for the next 20 years. Entegrus' service territory straddles three IESO planning zones. One of these regional plans is now complete (Windsor-Essex), one is under way (London Region), and one is scheduled for next group (Chatham-Sarnia). Entegrus has been involved from the beginning, and continues to be involved in the Leamington SECTR application. Entegrus is a member of the planning committee for the development of the Chatham-Kent Community Energy Plan, and has reached out to the municipalities of Middlesex-Caradoc and Elgin to offer our support and expertise in the development of their Community Energy Plans as well. Entegrus will continue to align their efforts to meet provincially mandated CDM targets with their commitment to both informing the IESO regional planning processes as well as leveraging this resource to strengthen the regional impact of CDM. Essex Powerlines' CDM Plan directly supports the 2013 Windsor-Essex IRRP. The study identified two immediate needs in the Windsor-Essex region: 1) the need for additional supply in the Kingsville-Leamington area, and 2) the need for additional restoration capability in the broader region. To address these needs, the former OPA/IESO recommended an integrated solution, consisting specifically of Conservation and Demand Management, distributed generation resources, and transmission investments. The CDM activities proposed herein are a key element of the three-pronged solution to address the immediate reliability needs. Essex Powerlines' 2015-2020 CDM plan will serve as the lead mechanism by which needs shall be initially mitigated, and will be further supported by the build out of additional supply.

G. Additional Documentation for CDM Plan (If applicable)

ADDITIONAL INFORMATION AND DOCUMENTATION	
Programs *Opportunity to provide any additional information on assumptions used for budgets and/or savings for approved 2015-2020 province-wide programs*	Assumptions for program volumes were based on historical program performance, conservative increases in program participation rates and Entegrus' view on the evolution of certain programs. The majority of the plan and cost effectiveness testing is based on the IESO Archetypes provided in the Cost Effectiveness Testing Tool. Adjustments made to these archetypes are based on 2016 results, and are an attempt to increase accuracy. We would like to point out that many measures are out of date. This has a direct influence on savings and TRC results. Every attempt was made to provide accurate representation and forecasts, using the measures available. Please see the supplemental information document for more details. As for the administration budget, Entegrus's 2015 and 2016 costs were used as the baseline. As for labour costs, the budget was based on Entegrus' current staffing compliment along with planned headcount additions. Costs were increased over time based on inflation, forecasted large projects and studies, and an increase in application or customer volumes. We would like to point out that the administration to incentive ratio for 2016 dropped from an estimated 41:51, to an actual of 33:67. This ratio is top of mind at Entegrus, and we fully expect for the ratio to continue to improve as projects in the pipeline come to fruition, and labour allocations are honed with program experience. Essex Powerlines' assumptions are based on historical performance and participation, and internal forecasts for program participation levels. Forecasts take into account factors such as program marketing, market saturation, program fatigue, and anticipated adjustments to current program incentives.
Approved Local and/or Regional Programs and Pilot Programs *Opportunity to provide any additional information on assumptions used for budgets and/or savings for approved 2015-2020 local or regional programs or pilot programs*	The assumptions for the approved local Instant Savings program came from the approved business case.
Proposed Local and/or Regional Programs and Pilot Programs *Opportunity to provide additional information on assumptions used for forecast budgets and/or savings for proposed programs or pilot programs*	N/A
Programs from 2011-2014/2015 CDM Framework *Opportunity to provide any additional information on assumptions used for budgets and/or savings from existing 2011-2014/2015 CDM Programs*	The information for 2011-2014, and 2015 budget and savings came from the portfolio CET provided to the LDCs by the IESO. These values are final and have been verified by the IESO.
Programs funded through Pay-for-Performance *Opportunity to provide any additional information on assumptions used for budgets and/or savings for Pay for Performance Programs*	N/A
Other *Additional assumptions used in the CDM Plan*	Please see the supplemental information document for details.

Summary of Changes to CDM Template

Version No.	Date	Tab	Change Summary
2	20-Jan-15	A. General Information	Inclusion of "Company Name" for Primary Contact
			Inclusion of frequency of invoicing (monthly vs. quarterly)
			Update date format to eliminate confusion
			Change reference to OPA
			Additional LDCs for joint plan
		B. LDC Authorization	Update date format to eliminate confusion
		D. CDM Plan Milestone LDC 1-10	Additional line items for FRC program names
			Additional LDCs for joint plan
			Update on the program names
			Update date format to eliminate confusion
			Update column headers: - "Province Wide Program Name" - "Proposed Regional or Local CDM Program or Pilot Program Name"
			Change reference to OPA
			Update Header and Footer
		E.. Proposed Program&Pilots	Additional boxes for proposed programs
			Update date format to eliminate confusion
		Q. Detailed Information	Clarity if it is primary LDC or all LDCs in a joint CDM Plan.

Attachment 3-D

Summary of Variances of Actual and Forecast Data

Appendix 2-IB
Customer, Connections, Load Forecast and Revenues Data and Analysis

This sheet is to be filled in accordance with the instructions documented in section 2.3.2 of Chapter 2 of the Filing Requirements for Distribution Rate Applications, in terms of one set of tables per customer class.

Color coding for Cells:		Data input	Drop-down List
		No data entry required	Blank or calculated value

Distribution System (Total)

	Calendar Year (for 2018 Cost of Service		Consumption (kWh) (3)			
				Actual (Weather actual)	Weather-normalized	Weather-normalized
Historical	*2012*		Actual	527,521,454	527,521,454	
Historical	*2013*		Actual	526,053,625	526,053,625	
Historical	*2014*		Actual	523,146,227	523,146,227	
Historical	*2015*		Actual	528,742,855	528,742,855	
Historical	*2016*		Actual	547,976,678	527,900,141	
Bridge Year	*2017*		Forecast		528,989,785	
Test Year	*2018*		Forecast		518,917,436	

Variance Analysis	Year	Year-over-year		Versus Board-approved
	2012			
	2013	-0.3%	-0.3%	
	2014	-0.6%	-0.6%	
	2015	1.1%	1.1%	
	2016	3.6%	-0.2%	
	2017		0.2%	
	2018		-1.9%	
	Geometric Mean	1.3%	-0.3%	

File Number:	EB-2017-0039
Exhibit:	3
Attachment:	3-D
Page:	2 of 8
Date:	August 28th, 2017

Customer Class Analysis (one for each Customer Class, excluding MicroFIT and Standby)

1 Customer Class: Residential

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2018 Cost of Service	Customers		
Historical	*2012*	Actual	26,337	
Historical	*2013*	Actual	26,466	
Historical	*2014*	Actual	26,590	
Historical	*2015*	Actual	26,815	
Historical	*2016*	Actual	27,137	
Bridge Year	*2017*	Forecast	27,310	
Test Year	*2018*	Forecast	27,484	

	Calendar Year	Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized	Weather-normalized
Historical	*2012*	Actual	256,003,979	256,003,979	
Historical	*2013*	Actual	250,406,105	250,406,105	
Historical	*2014*	Actual	245,551,953	245,551,953	
Historical	*2015*	Actual	244,757,239	244,757,239	
Historical	*2016*	Actual	255,390,422	249,168,165	
Bridge Year	*2017*	Forecast		247,700,344	
Test Year	*2018*	Forecast		245,374,118	

	Calendar Year	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized	Weather-normalized
Historical	*2012*	Actual	9720.3166	9720.31663	
Historical	*2013*	Actual	9461.4262	9461.42617	
Historical	*2014*	Actual	9234.7481	9234.74814	
Historical	*2015*	Actual	9127.6241	9127.62405	
Historical	*2016*	Actual	9411.1516	9181.86111	
Bridge Year	*2017*	Forecast	0	9069.95035	
Test Year	*2018*	Forecast	0	8927.88961	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	0.5%	
	2014	0.5%	
	2015	0.8%	
	2016	1.2%	
	2017	0.6%	
	2018	0.6%	
	Geometric Mean	0.9%	

Variance Analysis	Year	Year-over-year		Test Year Versus Board-approved
	2012			
	2013	-2.2%	-2.2%	
	2014	-1.9%	-1.9%	
	2015	-0.3%	-0.3%	
	2016	4.3%	1.8%	
	2017		-0.6%	
	2018		-0.9%	
	Geometric Mean	-0.1%	-0.8%	

Variance Analysis	Year	Year-over-year		Test Year Versus Board-approved
	2012			
	2013	-2.7%	-2.7%	
	2014	-2.4%	-2.4%	
	2015	-1.2%	-1.2%	
	2016	3.1%	0.6%	
	2017		-1.2%	
	2018		-1.6%	
	Geometric Mean	-1.1%	-1.7%	

	Calendar Year (for 2018 Cost of Service	Revenues		
Historical	*2012*	Actual	$ 7,804,704	
Historical	*2013*	Actual	$ 7,876,390	
Historical	*2014*	Actual	$ 7,711,531	
Historical	*2015*	Actual	$ 9,894,481	
Historical	*2016*	Actual	$ 8,394,579	
Bridge Year (Forecast)	*2017*	Forecast	$ 8,588,056	
Test Year (Forecast)	*2018*	Forecast	$ 8,612,319	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	0.9%	
	2014	-2.1%	
	2015	28.3%	
	2016	-15.2%	
	2017	2.3%	
	2018	0.3%	
	Geometric Mean	2.0%	

File Number:	EB-2017-0039
Exhibit:	3
Attachment:	3-D
Page:	3 of 8
Date:	August 28th, 2017

2 Customer Class: GS < 50 kW | Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2018 Cost of Service	Customers		
Historical	*2012*	Actual	1,906	
Historical	*2013*	Actual	1,904	
Historical	*2014*	Actual	1,910	
Historical	*2015*	Actual	1,936	
Historical	*2016*	Actual	1,953	
Bridge Year	*2017*	Forecast	1,965	
Test Year	*2018*	Forecast	1,977	

	Calendar Year (for 2018 Cost of Service	Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized	Weather-normalized
Historical	*2012*	Actual	67,056,278	67,056,278	
Historical	*2013*	Actual	65,663,990	65,663,990	
Historical	*2014*	Actual	65,242,011	65,242,011	
Historical	*2015*	Actual	65,329,579	65,329,579	
Historical	*2016*	Actual	66,808,993	64,675,919	
Bridge Year	*2017*	Forecast		65,087,892	
Test Year	*2018*	Forecast		62,707,450	

	Calendar Year (for 2018 Cost of Service	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized	Weather-normalized
Historical	*2012*	Actual	35181.678	35181.6779	
Historical	*2013*	Actual	34487.39	34487.3897	
Historical	*2014*	Actual	34158.121	34158.1209	
Historical	*2015*	Actual	33744.617	33744.6173	
Historical	*2016*	Actual	34208.394	33116.19	
Bridge Year	*2017*	Forecast	0	33123.6092	
Test Year	*2018*	Forecast	0	31718.4876	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	-0.1%	
	2014	0.3%	
	2015	1.4%	
	2016	0.9%	
	2017	0.6%	
	2018	0.6%	
	Geometric Mean	0.7%	

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-2.1%	-2.1%	
2014	-0.6%	-0.6%	
2015	0.1%	0.1%	
2016	2.3%	-1.0%	
2017		0.6%	
2018		-3.7%	
Geometric Mean	-0.1%	-1.3%	

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-2.0%	-2.0%	
2014	-1.0%	-1.0%	
2015	-1.2%	-1.2%	
2016	1.4%	-1.9%	
2017		0.0%	
2018		-4.2%	
Geometric Mean	-0.9%	-2.1%	

	Calendar Year (for 2018 Cost of Service	Revenues		
Historical	*2012*	Actual	$ 1,437,971	
Historical	*2013*	Actual	$ 1,591,911	
Historical	*2014*	Actual	$ 1,537,373	
Historical	*2015*	Actual	$ 1,919,833	
Historical	*2016*	Actual	$ 1,795,691	
Bridge Year (Forecast)	*2017*	Forecast	$ 1,609,420	
Test Year (Forecast)	*2018*	Forecast	$ 1,585,914	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	10.7%	
	2014	-3.4%	
	2015	24.9%	
	2016	-6.5%	
	2017	-10.4%	
	2018	-1.5%	
	Geometric Mean	2.0%	

3 **Customer Class:** GS > 50 kW

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

Date: August 28th, 2017

	Calendar Year (for 2018 Cost of Service		Customers			Consumption (kWh) [3] Actual (Weather actual)	Weather-normalized	Weather-normalized		Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized	Weather-normalized
Historical	*2012*	Actual	215		Actual	193,368,936	193,368,936		Actual	899390.4	899390.4	
Historical	*2013*	Actual	214		Actual	199,814,450	199,814,450		Actual	933712.38	933712.383	
Historical	*2014*	Actual	217		Actual	203,591,284	203,591,284		Actual	938208.68	938208.682	
Historical	*2015*	Actual	217		Actual	210,477,740	210,477,740		Actual	969943.5	969943.502	
Historical	*2016*	Actual	223		Actual	219,618,449	207,897,243		Actual	984836.09	932274.632	
Bridge Year	*2017*	Forecast	219		Forecast		179,829,958		Forecast	0	821141.361	
Test Year	*2018*	Forecast	219		Forecast		176,280,306		Forecast	0	804932.904	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2012			*2012*				*2012*			
	2013	-0.5%		*2013*	3.3%	3.3%		*2013*	3.8%	3.8%	
	2014	1.4%		*2014*	1.9%	1.9%		*2014*	0.5%	0.5%	
	2015	0.0%		*2015*	3.4%	3.4%		*2015*	3.4%	3.4%	
	2016	2.8%		*2016*	4.3%	-1.2%		*2016*	1.5%	-3.9%	
	2017	-1.8%		*2017*		-13.5%		*2017*		-11.9%	
	2018	0.0%		*2018*		-2.0%		*2018*		-2.0%	
	Geometric Mean	0.4%		Geometric Mean	4.3%	-1.8%		Geometric Mean	3.1%	-2.2%	

	Calendar Year (for 2018 Cost of Service		Revenues			Demand (kW) Actual (Weather actual)	Weather-normalized	Weather-normalized		Demand (kW) per Customer Actual (Weather actual)	Weather-normalized	Weather-normalized
Historical	*2012*	Actual	$ 1,588,021		Actual	514,811	514,811		Actual	0.3241839	0.3241839	
Historical	*2013*	Actual	$ 1,415,445		Actual	480,276	480,276		Actual	0.3393109	0.3393109	
Historical	*2014*	Actual	$ 1,499,281		Actual	473,538	473,538		Actual	0.3158435	0.3158435	
Historical	*2015*	Actual	$ 1,598,368		Actual	561,575	561,575		Actual	0.3513428	0.35134283	
Historical	*2016*	Actual	$ 1,603,629		Actual	563,949	532,036		Actual	0.3516704	0.33176993	
Bridge Year (Forecast)	*2017*	Forecast	$ 1,551,690		Forecast		455,239		Forecast	0	0.29338269	
Test Year (Forecast)	*2018*	Forecast	$ 1,528,407		Forecast		446,253		Forecast	0	0.2919728	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2012			*2012*				*2012*			
	2013	-10.9%		*2013*	-6.7%	-6.7%		*2013*	4.7%	4.7%	
	2014	5.9%		*2014*	-1.4%	-1.4%		*2014*	-6.9%	-6.9%	
	2015	6.6%		*2015*	18.6%	18.6%		*2015*	11.2%	11.2%	
	2016	0.3%		*2016*	0.4%	-5.3%		*2016*	0.1%	-5.6%	
	2017	-3.2%		*2017*		-14.4%		*2017*		-11.6%	
	2018	-1.5%		*2018*		-2.0%		*2018*		-0.5%	
	Geometric Mean	-0.8%		Geometric Mean	3.1%	-2.8%		Geometric Mean	2.7%	-2.1%	

File Number:	EB-2017-0039
Exhibit:	3
Attachment:	3-D
Page:	5 of 8
Date:	August 28th, 2017

4 **Customer Class:** Streetlighting   Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

	Calendar Year (for 2018 Cost of Service	Connections		
Historical	2012	Actual	2,474	
Historical	2013	Actual	2,621	
Historical	2014	Actual	2,713	
Historical	2015	Actual	2,701	
Historical	2016	Actual	2,720	
Bridge Year	2017	Forecast	2,740	
Test Year	2018	Forecast	2,740	

	Consumption (kWh) [3] Actual (Weather actual)	Weather-normalized	Weather-normalized
Actual	6,205,705	6,205,705	
Actual	6,271,491	6,271,491	
Actual	6,286,758	6,286,758	
Actual	6,227,063	6,227,063	
Actual	4,268,688	4,268,688	
Forecast		2,799,882	
Forecast		2,799,882	

	Consumption (kWh) per Connection Actual (Weather actual)	Weather-normalized	Weather-normalized
Actual	2508.369	2508.36904	
Actual	2392.7856	2392.78558	
Actual	2317.2717	2317.27165	
Actual	2305.4658	2305.46575	
Actual	1569.3706	1569.37059	
Forecast	0	1021.85474	
Forecast	0	1021.85474	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	5.9%	
	2014	3.5%	
	2015	-0.4%	
	2016	0.7%	
	2017	0.7%	
	2018	0.0%	
	Geometric Mean	2.1%	

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	1.1%	1.1%	
2014	0.2%	0.2%	
2015	-0.9%	-0.9%	
2016	-31.4%	-31.4%	
2017		-34.4%	
2018		0.0%	
Geometric Mean	-11.7%	-14.7%	

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-4.6%	-4.6%	
2014	-3.2%	-3.2%	
2015	-0.5%	-0.5%	
2016	-31.9%	-31.9%	
2017		-34.9%	
2018		0.0%	
Geometric Mean	-14.5%	-16.4%	

	Calendar Year (for 2018 Cost of Service	Revenues		
Historical	2012	Actual	$ 203,924	
Historical	2013	Actual	$ 242,863	
Historical	2014	Actual	$ 266,073	
Historical	2015	Actual	$ 272,332	
Historical	2016	Actual	$ 232,782	
Bridge Year (Forecast)	2017	Forecast	$ 187,615	
Test Year (Forecast)	2018	Forecast	$ 187,611	

	Demand (kW) Actual (Weather actual)	Weather-normalized	Weather-normalized
Actual	18,742	18,742	
Actual	19,025	19,025	
Actual	15,872	15,872	
Actual	18,023	18,023	
Actual	13,490	13,490	
Forecast		8,848	
Forecast		8,848	

	Demand (kW) per Connection Actual (Weather actual)	Weather-normalized	Weather-normalized
Actual	0.0919066	0.09190664	
Actual	0.0783363	0.07833629	
Actual	0.0596529	0.05965286	
Actual	0.0661803	0.06618028	
Actual	0.0579513	0.0579513	
Forecast	0	0.04716257	
Forecast	0	0.04716133	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	19.1%	
	2014	9.6%	
	2015	2.4%	
	2016	-14.5%	
	2017	-19.4%	
	2018	0.0%	
	Geometric Mean	-1.7%	

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	1.5%	1.5%	
2014	-16.6%	-16.6%	
2015	13.6%	13.6%	
2016	-25.2%	-25.2%	
2017		-34.4%	
2018		0.0%	
Geometric Mean	-10.4%	-13.9%	

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-14.8%	-14.8%	
2014	-23.9%	-23.9%	
2015	10.9%	10.9%	
2016	-12.4%	-12.4%	
2017		-18.6%	
2018		0.0%	
Geometric Mean	-14.2%	-12.5%	

File Number:	EB-2017-0039
Exhibit:	3
Attachment:	3-D
Page:	6 of 8
Date:	August 28th, 2017

5 **Customer Class:** Unmetered Scattered Load

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2018 Cost of Service	Customers		
Historical	*2012*	Actual	141	
Historical	*2013*	Actual	140	
Historical	*2014*	Actual	140	
Historical	*2015*	Actual	141	
Historical	*2016*	Actual	140	
Bridge Year	*2017*	Forecast	140	
Test Year	*2018*	Forecast	140	

Consumption (kWh) [(3)]	Actual (Weather actual)	Weather-normalized	Weather-normalized
Actual	1,558,152	1,558,152	
Actual	1,549,960	1,549,960	
Actual	1,555,546	1,555,546	
Actual	1,558,152	1,558,152	
Actual	1,554,368	1,554,368	
Forecast		1,554,368	
Forecast		1,554,368	

Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized	Weather-normalized
Actual	11050.723	11050.7234	
Actual	11071.143	11071.1429	
Actual	11111.043	11111.0429	
Actual	11050.723	11050.7234	
Actual	11102.629	11102.6286	
Forecast	0	11102.6286	
Forecast	0	11102.6286	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	-0.7%	
	2014	0.0%	
	2015	0.7%	
	2016	-0.7%	
	2017	0.0%	
	2018	0.0%	
	Geometric Mean	-0.1%	

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	-0.5%	-0.5%	
2014	0.4%	0.4%	
2015	0.2%	0.2%	
2016	-0.2%	-0.2%	
2017		0.0%	
2018		0.0%	
Geometric Mean	-0.1%	0.0%	

Year	Year-over-year		Test Year Versus Board-approved
2012			
2013	0.2%	0.2%	
2014	0.4%	0.4%	
2015	-0.5%	-0.5%	
2016	0.5%	0.5%	
2017		0.0%	
2018		0.0%	
Geometric Mean	0.2%	0.1%	

	Calendar Year (for 2018 Cost of Service	Revenues		
Historical	*2012*	Actual	$ 60,158	
Historical	*2013*	Actual	$ 59,767	
Historical	*2014*	Actual	$ 59,384	
Historical	*2015*	Actual	$ 60,378	
Historical	*2016*	Actual	$ 59,476	
Bridge Year (Forecast)	*2017*	Forecast	$ 62,175	
Test Year (Forecast)	*2018*	Forecast	$ 62,175	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2012		
	2013	-0.7%	
	2014	-0.6%	
	2015	1.7%	
	2016	-1.5%	
	2017	4.5%	
	2018	0.0%	
	Geometric Mean	0.7%	

File Number:	EB-2017-0039
Exhibit:	3
Attachment:	3-D
Page:	7 of 8
Date:	August 28th, 2017

6 **Customer Class:** Sentinel Lighting — Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

	Calendar Year (for 2018 Cost of Service	Customers			Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized	Weather-normalized	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized	Weather-normalized
Historical	2012	Actual	175		Actual	383,994	383,994		Actual	2194.2514	2194.25143	
Historical	2013	Actual	175		Actual	342,834	342,834		Actual	1959.0514	1959.05143	
Historical	2014	Actual	172		Actual	350,518	350,518		Actual	2037.8953	2037.89535	
Historical	2015	Actual	174		Actual	341,136	341,136		Actual	1960.5517	1960.55172	
Historical	2016	Actual	173		Actual	335,758	335,758		Actual	1940.7977	1940.79769	
Bridge Year	2017	Forecast	173		Forecast		335,758		Forecast	0	1940.79769	
Test Year	2018	Forecast	173		Forecast		335,758		Forecast	0	1940.79769	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2012			2012				2012			
	2013	0.0%		2013	-10.7%	-10.7%		2013	-10.7%	-10.7%	
	2014	-1.7%		2014	2.2%	2.2%		2014	4.0%	4.0%	
	2015	1.2%		2015	-2.7%	-2.7%		2015	-3.8%	-3.8%	
	2016	-0.6%		2016	-1.6%	-1.6%		2016	-1.0%	-1.0%	
	2017	0.0%		2017		0.0%		2017		0.0%	
	2018	0.0%		2018		0.0%		2018		0.0%	
	Geometric Mean	-0.2%		Geometric Mean	-4.4%	-2.6%		Geometric Mean	-4.0%	-2.4%	

	Calendar Year (for 2018 Cost of Service	Revenues			Demand (kW)	Actual (Weather actual)	Weather-normalized	Weather-normalized	Demand (kW) per Customer	Actual (Weather actual)	Weather-normalized	Weather-normalized
Historical	2012	Actual	$ 14,310		Actual	2,100	2,100		Actual	0.1467487	0.14674868	
Historical	2013	Actual	$ 15,810		Actual	2,100	2,100		Actual	0.1328305	0.13283052	
Historical	2014	Actual	$ 17,431		Actual	2,068	2,068		Actual	0.1186426	0.11864261	
Historical	2015	Actual	$ 17,371		Actual	2,088	2,088		Actual	0.1201986	0.12019856	
Historical	2016	Actual	$ 17,204		Actual	2,080	2,080		Actual	0.1208987	0.12089874	
Bridge Year (Forecast)	2017	Forecast	$ 27,447		Forecast		2,080		Forecast	0	0.07578259	
Test Year (Forecast)	2018	Forecast	$ 27,447		Forecast		2,080		Forecast	0	0.07578259	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2012			2012				2012			
	2013	10.5%		2013	0.0%	0.0%		2013	-9.5%	-9.5%	
	2014	10.3%		2014	-1.5%	-1.5%		2014	-10.7%	-10.7%	
	2015	-0.3%		2015	1.0%	1.0%		2015	1.3%	1.3%	
	2016	-1.0%		2016	-0.4%	-0.4%		2016	0.6%	0.6%	
	2017	59.5%		2017		0.0%		2017		-37.3%	
	2018	0.0%		2018		0.0%		2018		0.0%	
	Geometric Mean	13.9%		Geometric Mean	-0.3%	-0.2%		Geometric Mean	-6.3%	-12.4%	

File Number:	EB-2017-0039
Exhibit:	3
Attachment:	3-D
Page:	8 of 8
Date:	August 28th, 2017

7 **Customer Class:** Embedded Distributor

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

	Calendar Year (for 2018 Cost of Service	Customers			Consumption (kWh) [3] Actual (Weather actual)	Weather-normalized	Weather-normalized	Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized	Weather-normalized
Historical	2012	Actual	-	Actual	0	0		Actual		
Historical	2013	Actual	-	Actual	0	0		Actual		
Historical	2014	Actual	-	Actual	0	0		Actual		
Historical	2015	Actual	-	Actual	0	0		Actual		
Historical	2016	Actual	-	Actual	0	0		Actual		
Bridge Year	2017	Forecast	3	Forecast		31,681,583		Forecast	0	10560527.7
Test Year	2018	Forecast	3	Forecast		29,865,554		Forecast	0	9955184.67

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year	Test Year Versus Board-approved
	2012			2012			2012		
	2013			2013			2013		
	2014			2014			2014		
	2015			2015			2015		
	2016			2016			2016		
	2017			2017			2017		
	2018	0.0%		2018	-5.7%		2018	-5.7%	
	Geometric Mean			Geometric Mean			Geometric Mean		

	Calendar Year (for 2018 Cost of Service	Revenues			Demand (kW) Actual (Weather actual)	Weather-normalized	Weather-normalized	Demand (kW) per Customer Actual (Weather actual)	Weather-normalized	Weather-normalized
Historical	2012	Actual	$ -	Actual	0	0		Actual		
Historical	2013	Actual	$ -	Actual	0	0		Actual		
Historical	2014	Actual	$ -	Actual	0	0		Actual		
Historical	2015	Actual	$ -	Actual	0	0		Actual		
Historical	2016	Actual	$ -	Actual	0	0		Actual		
Bridge Year (Forecast)	2017	Forecast	$ 197,973	Forecast		85,786		Forecast	0	0.43332294
Test Year (Forecast)	2018	Forecast	$ 187,106	Forecast		80,869		Forecast	0	0.43221099

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year	Test Year Versus Board-approved
	2012			2012			2012		
	2013			2013			2013		
	2014			2014			2014		
	2015			2015			2015		
	2016			2016			2016		
	2017			2017			2017		
	2018	-5.5%		2018	-5.7%		2018	-0.3%	
	Geometric Mean			Geometric Mean			Geometric Mean		

Attachment 3-E

Other Operating Revenue

File Number:	EB-2017-0039
Exhibit:	3
Attachment:	3-E
Page:	1 of 2
Date:	August 28th, 2017

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2010 Actual[2]	2011 Actual[2]	2012 Actual[2]	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	Actual Year	Bridge Year	Test Year
		2010	2011	2012	2013	2014	2015	2016	2017	2018
	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
4235	**Specific Service Charges**	$ 162,778	$ 144,884	$ 156,010	$ 163,155	$ 146,338	$ 154,685	$ 153,296	$ 166,480	$ 166,480
4225	**Late Payment Charges**	$ 193,108	$ 269,465	$ 252,832	$ 274,425	$ 259,613	$ 261,627	$ 266,735	$ 260,400	$ 260,400
4080	**SSS Revenue**	$ 78,655	$ 76,745	$ 82,855	$ 83,263	$ 84,366	$ 84,690	$ 86,653	$ 80,000	$ 80,000
4082	**Retail Services Revenues**	$ 45,485	$ 38,946	$ 35,298	$ 27,420	$ 27,350	$ 23,454	$ 21,106	$ 28,000	$ 28,000
4084	**Service Transaction Requests**	$ 12,374	$ 14,114	$ 15,068	$ 15,224	$ 10,688	$ 15,118	$ 15,464	$ 7,640	$ 7,640
4210	**Rent from Electric Property**	$ 102,337	$ 105,058	$ 102,121	$ 110,034	$ 129,986	$ 114,671	$ 117,193	$ 109,515	$ 109,515
4220	**Other Electric Revenues**	$ 74	$ 2,152	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4305	**Regulatory Debits**	$ -	$ -	$ -	-$ 465,810	-$ 160,213	$ -	-$ 781,900	$ -	$ -
4355	**Gain on Disposition of Utility and Other Property**	$ 23,879	$ 120,531	$ 37,915	$ 79,457	$ 30,602	$ 17,612	$ 122,721	$ -	$ -
4360	**Loss on Disposition of Utility and Other Property**	$ -	$ -	$ -	$ -	$ -	-$ 104,845	-$ 85,458	$ -	$ -
4375	**Revenues from Non-Utility Operations**	$ 2,196,295	$ 1,807,744	$ 1,961,905	$ 2,218,439	$ 1,906,609	$ 2,316,678	$ 2,862,081	$ 1,865,253	$ 1,875,456
4380	**Expenses from Non-Utility Operations**	-$ 1,711,586	-$ 1,473,362	-$ 1,604,419	-$ 1,936,340	-$ 1,879,975	-$ 2,415,303	-$ 3,063,638	-$ 1,784,228	-$ 1,865,670
4390	**Miscellaneous Non-Operating Income**	$ 8,611	$ 26,161	$ 31,371	$ 48,106	$ 22,396	$ 11,371	$ 12,176	$ 14,000	
4398	**Foreign Exchange Gains and Losses, Including Amortization**	-$ 36,067	-$ 41	-$ 11	$ 468	-$ 642	$ 17,576	-$ 7,335	$ -	$ -
4405	**Interest and Dividend Income**	$ 87,470	$ 136,817	$ 163,754	$ 283,682	$ 335,181	$ 98,824	$ 141,380	$ 101,310	$ 30,000
Specific Service Charges		$ 162,778	$ 144,884	$ 156,010	$ 163,155	$ 146,338	$ 154,685	$ 153,296	$ 166,480	$ 166,480
Late Payment Charges		$ 193,108	$ 269,465	$ 252,832	$ 274,425	$ 259,613	$ 261,627	$ 266,735	$ 260,400	$ 260,400
Other Operating Revenues		$ 238,925	$ 237,015	$ 235,342	$ 235,941	$ 252,390	$ 237,933	$ 240,416	$ 225,155	$ 225,155
Other Income or Deductions		$ 568,602	$ 617,850	$ 590,514	$ 228,001	$ 253,958	-$ 58,087	-$ 799,973	$ 196,335	$ 39,786
Total		$ 1,163,413	$ 1,269,214	$ 1,234,698	$ 901,522	$ 912,299	$ 596,158	-$ 139,526	$ 848,370	$ 691,821

Description	**Account(s)**
Specific Service Charges:	4235
Late Payment Charges:	4225
Other Distribution Revenues:	4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses:	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Note: Add all applicable accounts listed above to the table and include all relevant information.

Account Breakdown Details

For each "Other Operating Revenue" and "Other Income or Deductions" Account, a detailed breakdown of the account components is required. See the example below for Account 4405, Interest and Dividend Income.

Account 4080 - SSS Revenue

	2010 Actual[2]	2011 Actual[2]	2012 Actual[2]	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	Actual Year	Bridge Year	Test Year
	2010	2011	2012	2013	2014	2015	2016	2017	2018
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
SSS Administration	78,655	$ 76,745	$ 82,855	$ 83,263	$ 84,366	$ 84,690	$ 86,653	$ 80,000	$ 80,000
Total	$ 78,655	$ 76,745	$ 82,855	$ 83,263	$ 84,366	$ 84,690	$ 86,653	$ 80,000	$ 80,000

Account 4082 - Retail Services Revenues

	2010 Actual[2]	2011 Actual[2]	2012 Actual[2]	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	Actual Year	Bridge Year	Test Year
	2010	2011	2012	2013	2014	2015	2016	2017	2018
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Standard Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Monthly Fixed Charge	$ 4,240	$ 4,020	$ 5,400	$ 4,280	$ 5,260	$ 4,560	$ 4,460	$ 4,800	$ 4,800
Monthly Variable Charge	$ 28,971	$ 21,816	$ 18,686	$ 14,929	$ 13,340	$ 11,809	$ 10,404	$ 14,500	$ 14,500
DCB - Monthly Charge	$ 12,274	$ 13,110	$ 11,212	$ 8,211	$ 8,750	$ 7,085	$ 6,242	$ 8,700	$ 8,700
Total	$ 45,485	$ 38,946	$ 35,298	$ 27,420	$ 27,350	$ 23,454	$ 21,106	$ 28,000	$ 28,000

Account 4084 - Service Transaction Requests

	2010 Actual[2]	2011 Actual[2]	2012 Actual[2]	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	Actual Year	Bridge Year	Test Year
	2010	2011	2012	2013	2014	2015	2016	2017	2018
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Request Fee	$ 825	$ 348	$ 323	$ 225	$ 147	$ 160	$ 125	$ 150	$ 150
Processing Fee	$ 1,528	$ 264	$ 371	$ 361	$ 196	$ 204	$ 174	$ 200	$ 200
Easement Letter	$ 4,965	$ 6,735	$ 7,185	$ 7,320	$ 5,175	$ 7,380	$ 7,545	$ 60	$ 60
Arrears Certificate	$ 4,966	$ 6,737	$ 7,189	$ 7,318	$ 5,170	$ 7,374	$ 7,545	$ 7,200	$ 7,200
Statement of Account	$ 90	$ 30	$ -				$ 75	$ 30	$ 30
Total	$ 12,374	$ 14,114	$ 15,068	$ 15,224	$ 10,688	$ 15,118	$ 15,464	$ 7,640	$ 7,640

Account 4210 - Rent from Electric Property

	2010 Actual[2]	2011 Actual[2]	2012 Actual[2]	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	Actual Year	Bridge Year	Test Year
	2010	2011	2012	2013	2014	2015	2016	2017	2018
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Pole Joint Use	$ 102,337	$ 105,058	$ 102,121	$ 110,034	$ 129,986	$ 114,671	$ 117,193	$ 109,515	$ 109,515
Total	$ 102,337	$ 105,058	$ 102,121	$ 110,034	$ 129,986	$ 114,671	$ 117,193	$ 109,515	$ 109,515

Account 4220 - Other Electric Revenues

	2010 Actual[2]	2011 Actual[2]	2012 Actual[2]	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	Actual Year	Bridge Year	Test Year
	2010	2011	2012	2013	2014	2015	2016	2017	2018
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Other miscellaneous revenues	$ 74	$ 2,152	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 74	$ 2,152	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Account 4305 - Regulatory Debits

	2010 Actual[2]	2011 Actual[2]	2012 Actual[2]	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	Actual Year	Bridge Year	Test Year
	2010	2011	2012	2013	2014	2015	2016	2017	2018
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Accounting Change	$ -	$ -	$ -	$ 465,810	$ 160,213	$ -	$ 781,900	$ -	$ -
Total	$ -	$ -	$ -	$ 465,810	$ 160,213	$ -	$ 781,900	$ -	$ -

File Number:	EB-2017-0039
Exhibit:	3
Attachment:	3-E
Page:	2 of 2
Date:	August 28th, 2017

Account 4355 - Gain on Disposition of Utility and Other Property

	2010 Actual[2]	2011 Actual[2]	2012 Actual[2]	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	Actual Year	Bridge Year	Test Year
	2010	2011	2012	2013	2014	2015	2016	2017	2018
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Gain on Disposition of Utility and Other Property	-$ 23,879	-$ 120,531	-$ 37,915	-$ 79,457	-$ 30,602	-$ 17,612	-$ 122,721	$ -	$ -
Total	-$ 23,879	-$ 120,531	-$ 37,915	-$ 79,457	-$ 30,602	-$ 17,612	-$ 122,721	$ -	$ -

Account 4360 - Loss on Disposition of Utility and Other Property

	2010 Actual[2]	2011 Actual[2]	2012 Actual[2]	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	Actual Year	Bridge Year	Test Year
	2010	2011	2012	2013	2014	2015	2016	2017	2018
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Loss on Disposition of Utility and Other Property	$ -	$ -	$ -	$ -	$ -	$ 104,845	$ 85,458	$ -	$ -
Total	$ -	$ -	$ -	$ -	$ -	$ 104,845	$ 85,458	$ -	$ -

Account 4375 - Revenues from Non-Utility Operations

	2010 Actual[2]	2011 Actual[2]	2012 Actual[2]	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	Actual Year	Bridge Year	Test Year
	2010	2011	2012	2013	2014	2015	2016	2017	2018
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Municipal Water Billing & Collecting	$ 907,509	$ 971,321	$ 993,795	$ 993,795	$ 1,013,671	$ 1,013,671	$ 1,013,671	$ 755,253	$ 765,456
Streetlight & Traffic Light Services	$ 385,464	$ 227,512	$ 310,395	$ 286,520	$ 264,053	$ 219,650	$ 145,021	$ 110,000	$ 110,000
CDM Related	$ 903,322	$ 608,910	$ 657,714	$ 938,124	$ 628,885	$ 1,083,357	$ 1,703,389	$ 1,000,000	$ 1,000,000
Total	$ 2,196,295	$ 1,807,744	$ 1,961,905	$ 2,218,439	$ 1,906,609	$ 2,316,678	$ 2,862,081	$ 1,865,253	$ 1,875,456

Account 4380 - Expenses from Non-Utility Operations

	2010 Actual[2]	2011 Actual[2]	2012 Actual[2]	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	Actual Year	Bridge Year	Test Year
	2010	2011	2012	2013	2014	2015	2016	2017	2018
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Municipal Water Billing & Collecting	-$ 772,334	-$ 895,442	-$ 848,242	-$ 929,921	-$ 947,980	-$ 948,337	-$ 941,723	-$ 684,228	-$ 765,456
Streetlight & Traffic Light Services	-$ 336,434	-$ 195,947	-$ 322,698	-$ 274,929	-$ 302,680	-$ 216,869	-$ 142,872	-$ 100,000	-$ 100,214
CDM Related	-$ 602,818	-$ 548,677	-$ 631,081	-$ 927,651	-$ 762,512	-$ 1,083,357	-$ 1,703,389	-$ 1,000,000	-$ 1,000,000
Non-Recoverable	$ -	$ -	$ -	$ -	$ -	-$ 166,740	-$ 275,654	$ -	$ -
Total	-$ 1,711,586	-$ 1,640,066	-$ 1,802,020	-$ 2,132,501	-$ 2,013,171	-$ 2,415,303	-$ 3,063,638	-$ 1,784,228	-$ 1,865,670

Account 4390 - Miscellaneous Non-Operating Income

	2010 Actual[2]	2011 Actual[2]	2012 Actual[2]	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	Actual Year	Bridge Year	Test Year
	2010	2011	2012	2013	2014	2015	2016	2017	2018
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Miscellaneous Non-Operating Income	$ 8,611	$ 26,161	$ 31,371	$ 48,106	$ 22,396	$ 11,371	$ 12,176	$ 14,000	$ -
Total	$ 8,611	$ 26,161	$ 31,371	$ 48,106	$ 22,396	$ 11,371	$ 12,176	$ 14,000	$ -

Account 4398 - Foreign Exchange Gains and Losses, including Amortization

	2010 Actual[2]	2011 Actual[2]	2012 Actual[2]	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	Actual Year	Bridge Year	Test Year
	2010	2011	2012	2013	2014	2015	2016	2017	2018
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Gain/(Loss) on Foreign Exchange	-$ 36,067	-$ 41	-$ 11	$ 468	-$ 642	$ 17,576	-$ 7,335	$ -	$ -
Total	-$ 36,067	-$ 41	-$ 11	$ 468	-$ 642	$ 17,576	-$ 7,335	$ -	$ -

Account 4405 - Interest and Dividend Income

	2010 Actual[2]	2011 Actual[2]	2012 Actual[2]	2013 Actual[2]	2014 Actual[2]	2015 Actual[2]	Actual Year	Bridge Year	Test Year
	2010	2011	2012	2013	2014	2015	2016	2017	2018
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
DVA Balance Interest	$ 22,245	$ 67,938	$ 103,056	$ 215,535	$ 299,988	$ 63,816	$ 121,510	$ 71,300	$ -
Miscellaneous Interest Revenue	$ 65,225	$ 68,879	$ 60,698	$ 68,147	$ 35,192	$ 35,008	$ 19,870	$ 30,000	$ 30,000
Total	$ 87,470	$ 136,817	$ 163,754	$ 283,682	$ 335,181	$ 98,824	$ 141,380	$ 101,300	$ 30,000

Notes:

2 In the transition year to IFRS, the applicant is to present information in both MIFRS and CGAAP. For the typical applicant that adopted IFRS on January 1, 2015, 2014 must be presented in both a CGAAP and MIFRS basis.

Exhibit 4:

Operating Expense

Table of Contents

List of Attachments

4.1 Overview

This Exhibit provides a detailed summary of EPLC's Operations, Maintenance and Administration ("OM&A") expenses required to operate EPLC's distribution system. These costs are comprised of:

i) Operations;
ii) Maintenance;
iii) Admin & General;
iv) Billing & Collecting;
v) Community Relations;
vi) Health & Safety and employee training;
vii) Metering;
viii) Regulatory & compliance costs;

4.1.1 2010 Board Approved Recoverable OM&A Expenses

Figure 1 below outlines EPLC's 2010 Board Approved OM&A expenses.

Figure 1 – 2010 EPLC Board Approved OM&A Expenses

Description	2010 Board Approved
Operations	$ 1,111,126
Maintenance	$ 1,517,732
Subtotal	**$ 2,628,858**
Billing & Collecting	$ 1,480,565
Community Relations	$ 22,500
Admin & General	$ 2,068,443
Subtotal	**$ 3,571,508**
Total OM&A	**$ 6,200,366**

4.1.2 Test Year OM&A Expense Summary

EPLC's 2018 Test Year OM&A expenses are $7,710,275 inclusive of the Low Income Energy Assistance Program ("LEAP"). A summary of EPLC's OM&A expenses from the previous 2010 Board Approved to the 2018 Test Year can be found below in Figure 2.

Figure 2 – EPLC OM&A Expenses – 2010 BAP to 2018 Test Year

Description	2010 Board Approved	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge Year	2018 Test Year
Operations	$ 1,111,126	$ 767,608	$ 1,003,987	$ 1,190,375	$ 1,207,057	$ 1,545,489	$ 1,332,350	$ 1,337,677	$ 1,221,419	$ 1,518,208
Maintenance	$ 1,517,732	$ 1,496,651	$ 1,614,034	$ 2,013,059	$ 1,515,425	$ 1,448,980	$ 1,808,438	$ 1,833,650	$ 1,572,404	$ 1,548,463
Subtotal	**$ 2,628,858**	**$ 2,264,259**	**$ 2,618,021**	**$ 3,203,433**	**$ 2,722,482**	**$ 2,994,470**	**$ 3,140,788**	**$ 3,171,328**	**$ 2,793,823**	**$ 3,066,671**
Billing & Collecting	$ 1,480,565	$ 1,305,098	$ 1,131,257	$ 1,174,568	$ 1,329,771	$ 1,158,128	$ 1,229,676	$ 1,348,249	$ 1,499,880	$ 1,550,150
Community Relations	$ 22,500	$ 16,957	$ 11,394	$ 8,539	$ 8,451	$ 10,016	$ 12,013	$ 6,482	$ 23,442	$ 23,396
Admin & General	$ 2,068,443	$ 1,894,041	$ 1,786,257	$ 1,806,757	$ 1,966,590	$ 2,541,606	$ 2,381,742	$ 2,455,564	$ 2,950,224	$ 3,070,058
Subtotal	**$ 3,571,508**	**$ 3,216,096**	**$ 2,928,908**	**$ 2,989,863**	**$ 3,304,813**	**$ 3,709,749**	**$ 3,623,431**	**$ 3,810,295**	**$ 4,473,546**	**$ 4,643,604**
Total OM&A	**$ 6,200,366**	**$ 5,480,354**	**$ 5,546,929**	**$ 6,193,296**	**$ 6,027,295**	**$ 6,704,219**	**$ 6,764,218**	**$ 6,981,623**	**$ 7,267,369**	**$ 7,710,275**

As described in Exhibit 1 of this Application, EPLC has implemented core value alignment with the Board's Renewed Regulatory Framework for Electricity Distributor ("RRFE") outcomes. EPLC six (6) core values are:

i) Customer & Community Value ("C&C");
ii) Operational Excellence ("OE");
iii) Safety ("Saf");
iv) Employee Satisfaction ("ES");
v) Reasonable Rates ("RR");
vi) Financial & Environmental Sustainability ("F&ES");

Figure 3 below outlines the incremental changes to OM&A by major contributor and its respective alignment with EPLC's core values. Figure 3 is intended to capture the major drivers of OM&A increases between the 2010 BAP to the projected 2018 Test Year. A further explanation by category is also provided below.

Figure 3 – EPLC Test Year OM&A & Core Value Alignment

Line Item	Amount	EPLC Core Value
2010 BAP OM&A	**$ 6,200,366**	
Inflationary Increases on Labour & Non-Labour Items	$ 815,725	All
Impact of IFRS Changes on OM&A	$ 340,213	All
Regulatory Re-alignment	$ 217,000	OE, C&C, F&ES
Control Room Support	$ 186,000	OE, Saf, C&C
Cybersecurity Maintenance	$ 286,463	OE, C&C
Other Immaterial Adjustments	$ (335,492)	All
2018 Test Year OM&A	**$ 7,710,275**	

Inflationary Increase on Labour & Non-Labour Items

Inflationary increases of labour and non-labour items includes year over year inflationary increases to materials, equipment, transportation and other items required over the normal course of business as well as inflationary increases to employee wages and benefits. Inflationary increases to labour and non-labour OM&A items of $815,725 are reasonable given that EPLC has not re-based since 2010 (which represents eight years of inflationary adjustments).

Impact of IFRS Changes on OM&A

IFRS-compliant capitalization and depreciation policy has resulted in increases to OM&A. EPLC has adopted these changes effective 2013.

Further details about these increases are outlined in Exhibit 9 of this Application. Overheads that were previously capitalized are now required to be expensed which has resulted in a corresponding increase to OM&A of $340,213.

Regulatory Re-Alignment

EPLC did not previously have directly allocated resources dedicated to Regulatory accounting and compliance. EPLC has re-aligned its regulatory department to include a Manager of Regulatory Accounting in 2017 and a Regulatory Accounting Analyst in 2016. Further information about these positions is provided in Section 4.4 of this Exhibit. This re-alignment has resulted in an OM&A increase of $217,000 in the Test Year.

Control Room Support

EPLC has included $186,000, starting in the 2018 Test Year, for 3rd party Control Room support. EPLC initially wanted to create its own, internal control room in order to provide additional after hours support and increase the overall scope and ability of our operational team. EPLC originally estimated the annual cost of providing internal control room services and support at approximately $500,000 per year.

After completing its preliminary analysis and after consulting with customers (who have clearly indicated that keeping rates low was their primary concern but their second largest concern was reliability; see Exhibit 1 for customer consultation surveys), EPLC determined that instead of eliminating control room services from its budget, finding a more cost effective alternative could satisfy both customer demands. As a result, EPLC has consulted with several 3rd party alternatives and proposes to leverage their existing scale and knowledge as part of this Application.

As part of its Self-Healing Grid initiative (see Exhibit 2 for additional information) as well as through is SmartMAP software implementation (see Exhibit 1, section 1.4.2 for additional information), EPLC is planning to upgrade its current operation to include 3rd party control room support from industry experts. These experts will allow EPLC to add another layer of visibility to its system, enhance after-hours customer service, increase response times and with the implementation of the Self-Healing Grid initiative in the coming years, even optimize switching automation to reduce Loss of Supply incidents and severity for EPLC customers.

A major component of EPLC's Self-Healing Grid initiative is the addition of monitoring and automated devices to its distribution system. These devices help in the determination of the optimum distribution circuit topology to service the increasingly varying loads and DER's attached to the distribution system. These devices help by: maintaining reliability, balancing load among the individual circuit wires and cables, maintaining voltage fluctuations within acceptable limits, and limiting outage events to the smallest number of customers.

These devices collect vast amounts of data that is used to determine what actions to take (i.e. open, close, signal for more reactive or real load). Additionally, load and generation fluctuations are occurring very quickly and increasingly these devices are permitted to operate semi-autonomously and automatically within strict guidelines. In either case, responding to system alarms and notifications requires full time monitoring and the ability to interpret this data in order to appropriately respond to any eventuality. The need for human intervention in this process is important to correctly and quickly direct crews when a system event requires field repairs or intervention. Human intervention is most effective when trained knowledgeable people are in a position to view and interpret the data and react accordingly.

EPLC plans on finalizing these arrangements in 2018 and maximize its investment in Best-In Class solutions.

Cybersecurity Maintenance

In 2017, EPLC is investing in its Information Technology ("IT") infrastructure in order to be compliant with the Board's proposed Cybersecurity Framework (EB-2016-0032). For additional information about the capital requirements of the Cybersecurity Framework, please refer to Exhibit 2 of this Application. Planned OM&A increases related to the Cybersecurity Framework equate to approximately $286,463 in 2017 and will be required moving forward. These costs relate to the acquisition of 3rd party IT experts that will ensure/provide:

- Managed detection and response services;
- Network Interceptor Capabilities;
- Continuous Vulnerability Scanning;
- Threat Intelligence;
- Security Portal & Reporting;
- 24/7 Security Operations Centre;

4.2 Summary & Cost Drivers

4.2.1 OM&A Budgeting Process

EPLC budgets in the third and fourth quarters of the year prior and seeks approval from the Board of Directors in the fourth quarter or early first quarter.

EPLC takes the following steps when preparing its upcoming operating and capital budgets:

i) Senior management team meets early at the beginning stages of the budgeting process to lay the foundation of fundamental work, challenges and goals to be achieved in the upcoming year. When evaluating the proposed work, challenges and goals, EPLC senior management is continuously managing these requirements against rate and reliability impacts to its customers. The EPLC senior management team generally expects and requires adjustments to be in line with the rate of inflation unless detailed substantiation can be provided to support any incremental difference;

ii) Department managers/supervisors then complete their own respective operating and capital budgets for the upcoming budget years. Department managers/supervisors work closely with the EPLC finance team to ensure proper allocations to labour including, but not limited to, changes to wages and benefit costs, vehicle/material/equipment rates, burden/overhead rates, etc. Significant year over year variances are highlighted and explained. Budgeted third party expenditures are reviewed by finance for reasonability and opportunity for reduction;

iii) The EPLC finance team then consolidates all manager/supervisor budgets to form a preliminary draft budget for review. Finance independently and jointly reviews large variances with department managers/supervisors;

iv) The EPLC finance team reviews with senior management team to ensure that work, challenges and goals identified in item i) above are satisfied;

v) The senior management team submits budgets to EPLC board of directors for approval;

4.2.2 Summary of Recoverable OM&A Expenses

EPLC has prepared a summary of historical and forecasted OM&A expenses, consistent with Board Appendix 2-JA as Figure 4 below. A copy of Board Appendix 2-JA is also included as Attachment 2-A of this Exhibit.

Figure 4 – EPLC Recoverable OM&A Expenses

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Operations	$ 1,111,126	$ 767,608	$ 1,003,987	$ 1,190,375	$ 1,207,057	$ 1,545,489	$ 1,332,350	$ 1,337,677	$ 1,221,419	$ 1,518,208
Maintenance	$ 1,517,732	$ 1,496,651	$ 1,614,034	$ 2,013,059	$ 1,515,425	$ 1,448,980	$ 1,808,438	$ 1,833,650	$ 1,572,404	$ 1,548,463
SubTotal	**$ 2,628,858**	**$ 2,264,259**	**$ 2,618,021**	**$ 3,203,433**	**$ 2,722,482**	**$ 2,994,470**	**$ 3,140,788**	**$ 3,171,328**	**$ 2,793,823**	**$ 3,066,671**
%Change (year over year)			15.6%	22.4%	-15.0%	10.0%	4.9%	1.0%	-11.9%	9.8%
%Change (Test Year vs Last Rebasing Year - Actual)										**35.4%**
Billing and Collecting	$ 1,480,565	$ 1,305,098	$ 1,131,257	$ 1,174,568	$ 1,329,771	$ 1,158,128	$ 1,229,676	$ 1,348,249	$ 1,499,880	$ 1,550,150
Community Relations	$ 22,500	$ 16,957	$ 11,394	$ 8,539	$ 8,451	$ 10,016	$ 12,013	$ 6,482	$ 23,442	$ 23,396
Administrative and General	$ 2,068,443	$ 1,894,041	$ 1,786,257	$ 1,806,757	$ 1,966,590	$ 2,541,606	$ 2,381,742	$ 2,455,564	$ 2,950,224	$ 3,070,058
SubTotal	**$ 3,571,508**	**$ 3,216,096**	**$ 2,928,908**	**$ 2,989,863**	**$ 3,304,813**	**$ 3,709,749**	**$ 3,623,431**	**$ 3,810,295**	**$ 4,473,546**	**$ 4,643,604**
%Change (year over year)			-8.9%	2.1%	10.5%	12.3%	-2.3%	5.2%	17.4%	3.8%
%Change (Test Year vs Last Rebasing Year - Actual)										**44.4%**
Total	**$ 6,200,366**	**$ 5,480,354**	**$ 5,546,929**	**$ 6,193,296**	**$ 6,027,295**	**$ 6,704,219**	**$ 6,764,218**	**$ 6,981,623**	**$ 7,267,369**	**$ 7,710,275**

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Operations	$ 1,111,126	$ 767,608	$ 1,003,987	$ 1,190,375	$ 1,207,057	$ 1,545,489	$ 1,332,350	$ 1,337,677	$ 1,221,419	$ 1,518,208
Maintenance	$ 1,517,732	$ 1,496,651	$ 1,614,034	$ 2,013,059	$ 1,515,425	$ 1,448,980	$ 1,808,438	$ 1,833,650	$ 1,572,404	$ 1,548,463
Billing and Collecting	$ 1,480,565	$ 1,305,098	$ 1,131,257	$ 1,174,568	$ 1,329,771	$ 1,158,128	$ 1,229,676	$ 1,348,249	$ 1,499,880	$ 1,550,150
Community Relations	$ 22,500	$ 16,957	$ 11,394	$ 8,539	$ 8,451	$ 10,016	$ 12,013	$ 6,482	$ 23,442	$ 23,396
Administrative and General	$ 2,068,443	$ 1,894,041	$ 1,786,257	$ 1,806,757	$ 1,966,590	$ 2,541,606	$ 2,381,742	$ 2,455,564	$ 2,950,224	$ 3,070,058
Total	**$ 6,200,366**	**$ 5,480,354**	**$ 5,546,929**	**$ 6,193,296**	**$ 6,027,295**	**$ 6,704,219**	**$ 6,764,218**	**$ 6,981,623**	**$ 7,267,369**	**$ 7,710,275**
%Change (year over year)			1.2%	11.7%	-2.7%	11.2%	0.9%	3.2%	4.1%	6.1%

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	Variance 2010 BA – 2010 Actuals	2011 Actuals	Variance 2011 Actuals vs. 2010 Actuals	2012 Actuals	Variance 2012 Actuals vs. 2011 Actuals	2013 Actuals	Variance 2013 Actuals vs. 2012 Actuals	2014 Actuals	Variance 2014 Actuals vs. 2013 Actuals	2015 Actuals	Variance 2015 Actuals vs. 2014 Actuals	2016 Actuals	Variance 2016 Actuals vs. 2015 Actuals	2017 Bridge Year	Variance 2017 Bridge vs. 2016 Actuals	2018 Test Year	Variance 2018 Test vs. 2017 Bridge
Operations	$ 1,111,126	$ 767,608	$ 343,518	$ 1,003,987	$ 236,379	$ 1,190,375	$ 186,387	$ 1,207,057	$ 16,682	$ 1,545,489	$ 338,432	$ 1,332,350	-$ 213,140	$ 1,337,677	$ 5,328	$ 1,221,419	-$ 116,258	$ 1,518,208	$ 296,789
Maintenance	$ 1,517,732	$ 1,496,651	$ 21,081	$ 1,614,034	$ 117,384	$ 2,013,059	$ 399,024	$ 1,515,425	-$ 497,633	$ 1,448,980	-$ 66,445	$ 1,808,438	$ 359,457	$ 1,833,650	$ 25,212	$ 1,572,404	-$ 261,246	$ 1,548,463	-$ 23,941
Billing and Collecting	$ 1,480,565	$ 1,305,098	$ 175,467	$ 1,131,257	-$ 173,841	$ 1,174,568	$ 43,311	$ 1,329,771	$ 155,203	$ 1,158,128	-$ 171,643	$ 1,229,676	$ 71,548	$ 1,348,249	$ 118,573	$ 1,499,880	$ 151,631	$ 1,550,150	$ 50,270
Community Relations	$ 22,500	$ 16,957	$ 5,543	$ 11,394	-$ 5,564	$ 8,539	-$ 2,855	$ 8,451	-$ 88	$ 10,016	$ 1,564	$ 12,013	$ 1,997	$ 6,482	-$ 5,530	$ 23,442	$ 16,959	$ 23,396	-$ 46
Administrative and General	$ 2,068,443	$ 1,894,041	$ 174,402	$ 1,786,257	-$ 107,784	$ 1,806,757	$ 20,500	$ 1,966,590	$ 159,834	$ 2,541,606	$ 575,015	$ 2,381,742	-$ 159,864	$ 2,455,564	$ 73,822	$ 2,950,224	$ 494,660	$ 3,070,058	$ 119,834
Total OM&A Expenses	$ 6,200,366	$ 5,480,354	$ 720,012	$ 5,546,929	$ 66,575	$ 6,193,296	$ 646,367	$ 6,027,295	-$ 166,002	$ 6,704,219	$ 676,924	$ 6,764,218	$ 59,999	$ 6,981,623	$ 217,405	$ 7,267,369	$ 285,746	$ 7,710,275	$ 442,906
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)																			
Total Recoverable OM&A Expenses	**$ 6,200,366**	**$ 5,480,354**	**$ 720,012**	**$ 5,546,929**	**$ 66,575**	**$ 6,193,296**	**$ 646,367**	**$ 6,027,295**	**-$ 166,002**	**$ 6,704,219**	**$ 676,924**	**$ 6,764,218**	**$ 59,999**	**$ 6,981,623**	**$ 217,405**	**$ 7,267,369**	**$ 285,746**	**$ 7,710,275**	**$ 442,906**
Variance from previous year				$ 66,575		$ 646,367		-$ 166,002		$ 676,924		$ 59,999		$ 217,405		$ 285,746		$ 442,906	
Percent change (year over year)				1%		12%		-3%		11%		1%		3%		4%		6%	
Percent Change: Test year vs. Most Current Actual														10.44%					
Simple average of % variance for all years														40.69%					3.6%
Compound Annual Growth Rate for all years																			7.1%
Compound Growth Rate (2016 Actuals vs. 2010 Actuals)														8.40%					

4.2.3 Cost Driver Tables

EPLC has prepared a cost driver summary of historical and forecasted OM&A expenses consistent with Board Appendix 2-JB as Figure 5 below. A copy of Board Appendix 2-JB is also included as Attachment 2-B of this Exhibit.

Figure 5 – EPLC OM&A Cost Drivers

OM&A	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance	$ 6,200,366	$5,480,354	$5,546,929	$6,193,296	$6,027,295	$6,704,219	$ 6,764,218	$ 6,981,623	$7,267,369
Operations									
Reduction in Load Dispatching	$ (104,082)	$ (9,761)	$ 645	$ (6,206)	$ 5,797	$ 2,487	$ 6,016	$ 28,804	$ 51,959
Metering	$ (77,388)	$ 21,886	$ 223,114	$ 105,856	$ 182,221	$ (370,601)	$ (7,348)	$ 8,953	$ (5,348)
Customer Premises	$ (26,103)	$ (41,770)	$ 41,179	$ 2,023	$ 121,874	$ 141,961	$ (108,519)	$ (65,567)	$ 29,964
Changes in Supervision	$ 45,064	$ 36,373	$ 56,897	$ (14,704)	$ 30,810	$ (99,134)	$ (1,159)	$ (9,037)	$ (1,084)
Outside Services/Control Room									$ 186,000
Other Immaterial/Misc. Operational	$ (181,008)	$ 229,651	$ (135,448)	$ (70,286)	$ (2,269)	$ 112,148	$ 116,339	$ (79,411)	$ 35,298
Subtotal - Operations	$ (343,518)	$ 236,379	$ 186,387	$ 16,682	$ 338,432	$ (213,140)	$ 5,328	$ (116,258)	$ 296,789
Maintenance									
Changes in Supervision	$ 9,649	$ (170,198)	$ 97,609	$ (83,366)	$ 2,176	$ 356,113	$ (366,006)	$ 22,609	$ 9,813
O/H Right of Way - Conversion	$ (75,120)	$ 129,436	$ 392,541	$ (154,244)	$ 31,584	$ (22,812)	$ 146,708	$ (175,692)	$ 49,303
Other Immaterial/Misc. Maintenance	$ 44,390	$ 158,146	$ (91,125)	$ (260,024)	$ (100,205)	$ 26,157	$ 244,511	$ (108,164)	$ (83,056)
Subtotal - Maintenance	$ (21,081)	$ 117,384	$ 399,024	$ (497,633)	$ (66,445)	$ 359,457	$ 25,212	$ (261,246)	$ (23,941)
Billing & Collecting									
Customer Billing	$ (192,846)	$ 100,300	$ 38,451	$ 151,623	$ (118,082)	$ (24,488)	$ 138,637	$ 203,832	$ 36,004
Collecting	$ 3,344	$ (158,295)	$ 100,555	$ 33,225	$ 45,194	$ (13,614)	$ 52,485	$ 72,978	$ 7,987
Changes in Supervision	$ 24,651	$ (74,863)	$ (95,226)	$ 13,288	$ 11,196	$ 3,568	$ 4,575	$ 13,832	$ 3,627
Meter Reading	$ 43,481	$ (71,782)	$ (61,144)	$ 1,724	$ (52,098)	$ 51,382	$ (59,854)	$ (121,092)	$ (221)
Changes in Bad Debt Expense	$ (52,589)	$ 26,683	$ 67,625	$ (35,575)	$ (57,537)	$ 54,207	$ (39,837)	$ 9,352	$ (312)
Other Immaterial/Misc. B&C	$ (1,509)	$ 4,117	$ (6,951)	$ (9,082)	$ (315)	$ 494	$ 22,566	$ (27,270)	$ 3,184
Subtotal - Billing & Collecting	$ (175,467)	$ (173,841)	$ 43,311	$ 155,203	$ (171,643)	$ 71,548	$ 118,573	$ 151,631	$ 50,270
Community Relations									
Other Immaterial/Misc. Community Relations	$ (5,543)	$ (5,564)	$ (2,855)	$ (88)	$ 1,564	$ 1,997	$ (5,530)	$ 16,959	$ (46)
Subtotal - Community Relations	$ (5,543)	$ (5,564)	$ (2,855)	$ (88)	$ 1,564	$ 1,997	$ (5,530)	$ 16,959	$ (46)
Admin & General									
Change in Salaries & General Expenses	$ (100,670)	$ (264,122)	$ (153,124)	$ 313,788	$ 345,104	$ (65,931)	$ 20,243	$ (55,274)	$ 82,142
Change in Employee Pensions & Benefits	$ 46,599	$ (75,659)	$ 185,372	$ 7	$ 173,332	$ (9,459)	$ 11,582	$ 31,046	$ (457)
Regulatory Re-alignment								$ 236,958	$ 31,623
Outside Services/Cybersecurity								$ 231,463	$ 8,141
Other Immaterial/Misc. Admin & General	$ (120,332)	$ 231,998	$ (11,748)	$ (153,961)	$ 56,579	$ (84,474)	$ 41,997	$ 50,468	$ (1,615)
Subtotal - Admin & General	$ (174,402)	$ (107,784)	$ 20,500	$ 159,834	$ 575,015	$ (159,864)	$ 73,822	$ 494,660	$ 119,834
Closing Balance	$ 5,480,354	$5,546,929	$6,193,296	$6,027,295	$6,704,219	$6,764,218	$ 6,981,623	$ 7,267,369	$7,710,275

The following explanations are provided for year over year variances greater than EPLC's materiality threshold as calculated in Exhibit 1 of this Application. For the purposes of this analysis, the materiality threshold used is $65,000.

Operational Variances

Operational OM&A is projected to increase from 2010 BAP to the 2018 Test Year by $407,082 (36.6%). The primary driver of this increase is as a result of the implementation of 3rd party Control Room support. As part of its Self-Healing Grid initiative (see Exhibit 2 for additional information) as well as through is SmartMAP software implementation (see Exhibit 1, section

1.4.2 for additional information), EPLC is planning to upgrade its current operations to include 3rd party control room support from industry experts. These experts will allow EPLC to add another layer of visibility to its system, enhance after-hours customer service, increase response times and with the implementation of the Self-Healing Grid initiative in the coming years, even optimize switching automation to reduce Loss of Supply incidents and severity for EPLC customers. This increase is comprised of an incremental $186,000 investment in ongoing Control Room Operations and is further explained throughout this Exhibit. EPLC expects that the investment in ongoing control room operations will significantly upgrade EPLC's current after hours support, add 3rd party review and redundancy while also enhancing customer service and reliability. This expense is partially offset by EPLC reducing the number of line supervisors from two to one in 2017.

EPLC also re-allocated various 3rd party meter reading charges from Account 5010 (Load Dispatching) to 5315 (Customer Billing).

The remaining variance is largely the result of inflationary increases to employee wages, benefits and non-labour items related to operational programs described in Section 4.3.2 of this Exhibit.

Maintenance Related Variances

Maintenance related OM&A is projected to increase from 2010 BAP to the 2018 Test Year by $30,731 (2.02%). The primary driver of this variance is related to increase to employee wages, benefits and non-labour items and ongoing right of way and conversion work offset by supervision changes and other miscellaneous maintenance efficiencies.

EPLC also completed significant tree trimming and vegetation control in 2011 and 2012. This will result in lower Maintenance related expenses in 2017 and beyond.

Billing & Collecting Related Variances

Billing & Collecting is projected to increase from 2010 BAP to the 2018 Test Year by $69,585 (4.7%). This upward pressure on costs is driven primarily by inflationary increases in employee wages and benefits and inflationary increases to non-labour items such as postage and 3rd party billing and meter reading providers. EPLC also re-allocated various 3rd party meter reading charges from Account 5010 (Load Dispatching) to 5315 (Customer Billing) in 2010/2011 to better align with the APH.

In 2017, EPLC lost a water billing customer which has increased its net costs. EPLC has been able to offset a large portion of this impact with the re-negotiation of its meter reading costs. EPLC will continue to enhance and improve its Billing & Collecting department to ensure operational efficiency, especially where water services are further affected by additional customer loss.

Community Relations Variances

Community Relations spending is projected to increase from the 2010 BAP amount to the 2018 Test Year by $896 (4.0%). Despite inflation, spending related to Community Relations has been relatively flat.

Admin & General Related Variances

Admin & General is projected to increase from 2010 BAP to the 2018 Test Year by $1,001,615 (48.4%).

3rd party consulting costs are increasing in 2017 and 2018 as a result of one of EPLC's primary OM&A cost drivers identified in Section 4.1.2 of this Exhibit. In 2017, EPLC is investing in its IT infrastructure in order to be compliant with the Board's proposed Cybersecurity Framework (EB-2016-0032). For additional information about the capital requirements of the Cybersecurity Framework, please refer to Exhibit 2 of this Application. Planned OM&A increases related to the Cybersecurity Framework equate to $286,463 in 2017 and will be required moving forward. These costs relate to the acquisition of 3rd party IT experts that will ensure/provide:

- Managed detection and response services;
- Network Interceptor Capabilities;
- Continuous Vulnerability Scanning;
- Threat Intelligence;
- Security Portal & Reporting;
- 24/7 Security Operations Centre;

Further, Regulatory Affairs costs are increasing in 2017 and 2018 by $217,000 as a result of one of EPLC's primary OM&A cost drivers identified in Section 4.1.2 of this Exhibit. EPLC previously had partial FTEs allocated to various regulatory functions however did not previously have dedicated regulatory staff whose sole responsibility was regulatory accounting, review and compliance. EPLC has added the Regulatory Accounting Analyst position in 2016 and the

Manager of Regulatory Accounting in 2017. For additional information about these positions, please refer to section 4.4 of this Exhibit.

The remaining variance is primarily related to increases to OM&A relating to the transition to IFRS as well as inflationary increases to employee wages and benefits.

4.2.4 OM&A Cost Per Customer & Full-Time Equivalent

EPLC has prepared a recoverable cost per customer and FTE summary of historical and forecasted OM&A expenses consistent with Board Appendix 2-L as Figure 6 below. A copy of Board Appendix 2-L is also included as Attachment 2-C of this Exhibit.

Figure 6 – EPLC Recoverable Cost per Customer & FTE

	Last Rebasing Year - 2010- Board Approved	Last Rebasing Year - 2010- Actual	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Bridge Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
OM&A Costs										
O&M	$ 2,628,858	$ 2,264,259	$ 2,618,021	$ 3,203,433	$ 2,722,482	$ 2,994,470	$ 3,140,788	$ 3,171,328	$ 2,793,823	$ 3,066,671
Admin Expenses	$ 3,571,508	$ 3,216,096	$ 2,928,908	$ 2,989,863	$ 3,304,813	$ 3,709,749	$ 3,623,431	$ 3,810,295	$ 4,473,546	$ 4,643,604
Total Recoverable OM&A from Appendix 2-JB	**$ 6,200,366**	**$ 5,480,354**	**$ 5,546,929**	**$ 6,193,296**	**$ 6,027,295**	**$ 6,704,219**	**$ 6,764,218**	**$ 6,981,623**	**$ 7,267,369**	**$ 7,710,275**
Number of Customers	30,940	31,200	31,314	31,249	31,521	31,742	31,985	32,346	32,550	32,736
Number of FTEs	57	53	44	44	44	48	44	44	46	46
Customers/FTEs	539.02	588.68	711.68	710.20	716.39	661.29	726.93	735.14	707.61	711.65
OM&A cost per customer										
O&M per customer	$ 84.97	$ 72.57	$ 83.61	$ 102.51	$ 86.37	$ 94.34	$ 98.20	$ 98.04	$ 85.83	$ 93.68
Admin per customer	$ 115.43	$ 103.08	$ 93.53	$ 95.68	$ 104.84	$ 116.87	$ 113.29	$ 117.80	$ 137.44	$ 141.85
Total OM&A per customer	$ 200.40	$ 175.65	$ 177.14	$ 198.19	$ 191.22	$ 211.21	$ 211.48	$ 215.84	$ 223.27	$ 235.53
OM&A cost per FTE										
O&M per FTE	$ 45,798.92	$ 42,721.86	$ 59,500.49	$ 72,805.30	$ 61,874.59	$ 62,384.79	$ 71,381.54	$ 72,075.63	$ 60,735.29	$ 66,666.76
Admin per FTE	$ 62,221.39	$ 60,681.05	$ 66,566.08	$ 67,951.44	$ 75,109.38	$ 77,286.44	$ 82,350.69	$ 86,597.61	$ 97,251.00	$100,947.91
Total OM&A per FTE	**$ 108,020.31**	**$103,402.91**	**$126,066.57**	**$140,756.74**	**$136,983.97**	**$139,671.23**	**$153,732.23**	**$158,673.25**	**$157,986.29**	**$167,614.67**

4.3 Program Delivery and Variance Analysis

4.3.1 Overview

EPLC's various OM&A programs are summarized below as Figure 7. Figure 7 has been completed, consistent with Board Appendix 2-JC which is also included as Attachment 4-D of this Exhibit. All programs align with EPLC's Core Values outlined in Exhibit 1 of this Application and is also consistent with Figure 2 above.

Figure 7 – EPLC OM&A Programs

Description	Last Rebasing Year - 2010- Board Approved	Last Rebasing Year - 2010- Actual	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year	Variance (2018 Test Year vs. 2016 Actuals)	Variance (2018 Test Year vs. 2010 BAP)
Administration												
General Building Expenses	$ 241,203	$ 191,801	$ 384,048	$ 454,397	$ 282,679	$ 284,692	$ 287,490	$ 316,821	$ 338,503	$ 342,304	$ 25,483	$ 101,101
Insurance	$ 30,500	$ 23,911	$ 24,658	$ 16,320	$ 16,984	$ 27,449	$ 21,206	$ 18,944	$ 34,630	$ 34,562	$ 15,619	$ 4,062
Office Supplies	$ 269,633	$ 333,799	$ 368,589	$ 371,682	$ 396,385	$ 402,033	$ 443,140	$ 402,558	$ 448,399	$ 478,697	$ 76,140	$ 209,064
Audit, Legal and Consulting	$ 82,600	$ 101,643	$ 104,384	$ 47,788	$ 115,130	$ 118,220	$ 54,903	$ 64,135	$ 295,597	$ 303,738	$ 239,603	$ 221,138
Regulatory Affairs	$ 162,462	$ 126,894	$ 168,067	$ 168,224	$ 130,878	$ 108,565	$ 146,535	$ 124,953	$ 361,911	$ 393,533	$ 268,580	$ 231,071
Administration & HR Expenses	$ 1,282,045	$ 1,115,992	$ 736,511	$ 748,345	$ 1,024,535	$ 1,587,220	$ 1,415,040	$ 1,514,727	$ 1,457,756	$ 1,501,428	$ (13,299)	$ 219,383
Donations/LEAP Funding	$ -	$ -	$ -	$ -	$ -	$ 13,427	$ 13,427	$ 13,427	$ 13,427	$ 15,795	$ 3,394	$ 16,820
Sub-Total	$ 2,068,443	$ 1,894,041	$ 1,786,257	$ 1,806,757	$ 1,966,590	$ 2,541,606	$ 2,381,742	$ 2,455,564	$ 2,950,224	$ 3,070,058	$ 614,494	$ 1,001,615
Community Relations												
Community Relations	$ 22,500	$ 16,957	$ 11,394	$ 8,539	$ 8,451	$ 10,016	$ 12,013	$ 6,482	$ 23,442	$ 23,396	$ 16,914	$ 896
Sub-Total	$ 22,500	$ 16,957	$ 11,394	$ 8,539	$ 8,451	$ 10,016	$ 12,013	$ 6,482	$ 23,442	$ 23,396	$ 16,914	$ 896
Customer Service												
Bad Debt	$ 187,500	$ 134,911	$ 161,595	$ 229,220	$ 193,645	$ 136,108	$ 190,315	$ 150,478	$ 159,830	$ 159,518	$ 9,040	$ (27,982)
Customer Service & Billings	$ 1,212,670	$ 1,087,957	$ 1,041,611	$ 923,692	$ 1,090,327	$ 931,342	$ 961,804	$ 1,045,162	$ 1,141,734	$ 1,181,144	$ 135,981	$ (31,526)
Customer Collections	$ 80,395	$ 82,230	$ (71,948)	$ 21,656	$ 45,799	$ 90,677	$ 77,557	$ 152,609	$ 198,317	$ 209,488	$ 56,880	$ 129,093
Sub-Total	$ 1,480,565	$ 1,305,098	$ 1,131,257	$ 1,174,568	$ 1,329,771	$ 1,158,128	$ 1,229,676	$ 1,348,249	$ 1,499,880	$ 1,550,150	$ 201,901	$ 69,585
Maintenance												
Emergency Response	$ 273,360	$ 344,695	$ 363,959	$ 330,898	$ 253,549	$ 231,804	$ 286,063	$ 274,797	$ 263,708	$ 259,741	$ (15,056)	$ (13,619)
Field Service Maintenance	$ 106,726	$ 68,103	$ 43,253	$ 30,382	$ 73,450	$ 72,038	$ 51,518	$ 185,984	$ 127,766	$ 57,433	$ (128,551)	$ (49,293)
Meter Maintenance	$ 139,601	$ 85,225	$ 78,060	$ 95,844	$ 17,387	$ 2,848	$ 90,081	$ -	$ 574	$ 568	$ 568	$ (139,033)
Overhead/Underground Maintenance	$ 507,669	$ 640,148	$ 675,925	$ 614,525	$ 470,877	$ 430,493	$ 531,260	$ 510,337	$ 489,744	$ 482,377	$ (27,961)	$ (25,292)
Vegetation Control	$ 356,024	$ 271,632	$ 372,500	$ 812,584	$ 625,237	$ 660,465	$ 792,620	$ 778,165	$ 609,254	$ 666,029	$ (112,136)	$ 310,006
Transformer & Substation Maintenance	$ 134,352	$ 86,847	$ 80,338	$ 128,825	$ 74,925	$ 51,332	$ 56,896	$ 84,367	$ 81,358	$ 82,315	$ (2,053)	$ (52,037)
Sub-Total	$ 1,517,732	$ 1,496,651	$ 1,614,034	$ 2,013,059	$ 1,515,425	$ 1,448,980	$ 1,808,438	$ 1,833,650	$ 1,572,404	$ 1,548,463	$ (285,187)	$ 30,731
Operations												
Cable Locates	$ 356,155	$ 330,052	$ 288,282	$ 329,461	$ 331,484	$ 453,358	$ 595,318	$ 486,799	$ 421,232	$ 451,196	$ (35,603)	$ 95,041
General Customer Inquiries & Misc.	$ 184,215	$ 185,796	$ 370,563	$ 236,541	$ 164,099	$ 127,149	$ 127,633	$ 196,927	$ 229,406	$ 224,633	$ 27,706	$ 40,418
Meter Operations	$ 135,439	$ 58,051	$ 79,937	$ 303,051	$ 408,908	$ 591,129	$ 220,528	$ 213,180	$ 222,133	$ 216,785	$ 3,605	$ 81,346
Station Operations	$ 78,499	$ 17,932	$ 16,130	$ 26,197	$ 25,806	$ 95,716	$ 42,106	$ -	$ -	$ -	$ -	$ (78,499)
Operations Management	$ 160,174	$ 101,155	$ 127,767	$ 185,309	$ 164,399	$ 201,005	$ 104,358	$ 109,215	$ 128,982	$ 365,857	$ 256,642	$ 205,683
Overhead Operations	$ 42,013	$ 14,605	$ 29,826	$ 48,042	$ 38,702	$ 26,559	$ 132,482	$ 167,408	$ 124,519	$ 114,893	$ (52,515)	$ 72,880
Transformer Operations	$ 122,523	$ 40,324	$ 82,151	$ 49,935	$ 46,145	$ 39,021	$ 63,883	$ 52,888	$ 43,444	$ 86,805	$ 33,917	$ (35,718)
Underground Operations	$ 32,108	$ 19,692	$ 9,330	$ 11,838	$ 27,514	$ 11,552	$ 46,040	$ 111,261	$ 51,703	$ 58,040	$ (53,221)	$ 25,932
Sub-Total	$ 1,111,126	$ 767,608	$ 1,003,987	$ 1,190,375	$ 1,207,057	$ 1,545,489	$ 1,332,350	$ 1,337,677	$ 1,221,419	$ 1,518,208	$ 180,530	$ 407,082
Miscellaneous											$ -	$ -
Total	$ 6,200,366	$ 5,480,354	$ 5,546,929	$ 6,193,296	$ 6,027,295	$ 6,704,219	$ 6,764,218	$ 6,981,623	$ 7,267,369	$ 7,710,275	$ 728,652	$ 1,509,909

Administration

General Building Expense: This program relates to the overall expenses incurred to keep EPLC's Operations Centre, located at 4330 Highway #3, Oldcastle, ON functioning and safe. Costs include utilities, miscellaneous supplies required for maintenance, etc.

Insurance: This program relates to the business related insurance that EPLC requires to operate its business safely and reliably while providing the necessary legal safeguards to itself and its employees.

Office Supplies: This program relates to the general office supplies that EPLC requires in order to effectively manage its day to day business with its customers. Costs range from photocopiers, scanners, computer software and other miscellaneous office supplies.

Audit, Legal and Consulting: This program includes EPLC's cost of its yearly financial audit, the procurement of 3rd party legal assistance, where required and the engagement of any consultants if needed. EPLC has generally used limited legal services and uses various consulting services from time to time. As part of this Application, EPLC is requesting the ongoing use of 3rd party consultants to maintain compliance with the Board's Cybersecurity Framework.

Regulatory Affairs: This program includes all EPLC expenses relating to the connection with formal cases before the Board including fees assessed to EPLC for pay and expenses of the Board, its officers, agents and employees. As of 2017, this program also includes directly allocated and dedicated regulatory employees.

Administration & HR Expenses: This program relates to the compensation of administrative staff not specifically allocated to a specific job or activity as well as the HR related expenses associated with all EPLC staff.

Donations/LEAP Funding: This program includes the cost of administering the Low Income Energy Assistance Program to eligible EPLC electricity customers as well as any donations made to various eligible charities.

Community Relations

Community Relations: This program includes the cost of salaries and wages of employees, 3rd party services and materials directly involved in providing services to the community.

Customer Service

Bad Debt: This program relates to tracking amounts provided for losses on accounts receivable which have become uncollectible.

Customer Service & Billing: This program relates to EPLC's cost of answering various customer inquiries, maintaining a call center and creating and issuing a monthly electricity bill to each of EPLC's electricity customers.

Customer Collections: This program relates to EPLC's cost of collecting amounts receivable from customers related to electricity charges.

Maintenance

Emergency Response: This program relates to costs incurred for work that EPLC completes that is considered emergency. This includes dispatch by police, fire, paramedics or other entities that requires EPLC to respond to. Typical emergency response calls relates to motor vehicle accidents or damaged electrical plant due to weather or other foreign interference requiring immediate assistance.

Field Service Maintenance: This program relates to EPLC representatives performing various asset condition related testing in the field. This testing includes pole testing (hammer test, pole drilling), infrared scanning of various EPLC plant, vegetation growth review in a particular area, etc. Generally, the results of Field Service Maintenance work is used to validate or disprove the need for other, more specific maintenance.

Meter Maintenance: This program relates to various maintenance and upkeep work that EPLC completes on in relation to its metering assets. Typical Meter Maintenance work includes troubleshooting communication issues and investigating and/or replacing failed meters.

Overhead/Underground Maintenance: This program relates to various maintenance and upkeep work that EPLC completes on its distribution system (both overhead and underground plant). Typical Overhead/Underground Maintenance work includes miscellaneous conversion work, investigation of potential problem areas identified through Field Service Maintenance and cleaning and repair of damaged plant.

Vegetation Control: This program relates to the removal or trimming of vegetation on, close or near EPLC assets to prevent damage, interference or failure. EPLC's rigorous vegetation control program has led to substantial reductions in SAIDI and SAIFI identified in Exhibit 2 (Service Reliability Indicators) of this Application.

Transformer & Substation Maintenance: This program relates to various maintenance and upkeep work that EPLC completes on its transformers and previously on substations (prior to their retirement under the Single Voltage Utility initiative). Typical Transformer & Substation Maintenance work includes miscellaneous conversion work, investigation of potential problem areas identified through Field Service Maintenance, cleaning and repair of damaged plant.

Operations

Cable Locates: This program relates to EPLC's requirement to locate its assets where requested by its customers. Includes locates for all EPLC plant for all customer classifications.

General Customer Inquiries & Misc.: This program relates to EPLC assessing and responding to various customer inquiries including low voltage calls, power quality issues, high bill investigations, and other miscellaneous requests.

Meter Operations: This program relates to various operational work that EPLC completes in relation to its metering assets. Typical Meter Operations work includes troubleshooting meter reading issues, meter data management and ongoing metering compliance.

Station Operations: This program relates to the operational work that EPLC completes on its substations. Typical Station Operations work generally includes supervision, station adjustments (for power quality purposes), inspections and switching. It should be noted that EPLC no longer has any Station Operations effective in 2016 as a result of the Single Voltage Utility initiative.

Operations Management: This program relates to management and supervision required to effectively and safely operate the grid. Included are various health and safety initiatives, system modelling, system optimization and the proposed third party control room initiative planned for the 2018 Test Year.

Overhead Operations: This program relates to the operational work that EPLC completes in relation to its overhead plant. Typical Overhead Operations work includes switching, load transfers, inspections, line-testing and voltage analysis.

Transformer Operations: This program relates to the operational work that EPLC completes on its transformers. Typical Transformer Operations work generally includes testing, inspecting, resetting or removing various transformers (both overhead and underground) in EPLC's system.

Underground Operations: This program relates to the operational work that EPLC completes in relation to its underground plant. Typical Underground Operations work includes switching, load transfers, load tests, inspections, line-testing and voltage analysis.

4.3.2 Program Delivery Variance Analysis

For the purpose of this variance analysis, EPLC has identified variances highlighted in Figure 7 above, which are greater than EPLC's calculated materiality threshold. Further information about EPLC's materiality threshold calculation can be found in Exhibit 1 of this Application. For the following analysis, EPLC has used $65,000 as its materiality threshold.

Consistent with Board Appendix 2-JC, EPLC compared 2018 Test Year with 2010 BAP values and the 2016 Actuals with the 2010 BAP values.

General Building Expenses

2018 Test Year General Building expenses of $342,304 are $101,101 (41.9%) higher than 2010 BAP and $25,483 (8.0%) higher than 2016 Actual expenditures. EPLC consolidated all regulated activities to its Oldcastle Service Station in 2012 (outside staff were moved in 2003, all other positions moved in 2012). As EPLC moved out of the Essex Civic Centre in 2012, it reduced its rent expense however needed to invest more heavily in maintaining its sole service station located on Highway #3 in Tecumseh, Ontario.

Office Supplies

2018 Test Year Office Supplies expense of $478,697 are $209,064 (77.5%) higher than 2010 BAP and $76,140 (18.9% higher than 2016 Actual expenditures. This was as a result of increases beyond the rate of inflation on general and miscellaneous supplies as well as maintenance fees associated with various software solutions including but not limited to EPLC's financial system, GIS, work estimation and others.

Audit, Legal & Consulting

2018 Test Year Audit, Legal & Consulting expenses of $303,738 are $221,138 (267.7%) higher than 2010 BAP and $239,603 (373.6%) higher than 2016 Actual expenditures. 3rd party consulting costs are increasing in 2017 and 2018 as a result of one of EPLC's primary OM&A cost drivers identified in Section 4.1.2 of this Exhibit. In 2017, EPLC is investing in its IT infrastructure in order to be compliant with the Board's proposed Cybersecurity Framework (EB-2016-0032). For additional information about the capital requirements of the Cybersecurity Framework, please refer to Exhibit 2 of this Application. Planned OM&A increases related to the Cybersecurity Framework equate to $286,463 in 2017 and will be required moving forward. These costs relate to the acquisition of 3rd party IT experts that will ensure/provide:

- Managed detection and response services;
- Network Interceptor Capabilities;
- Continuous Vulnerability Scanning;
- Threat Intelligence;
- Security Portal & Reporting;
- 24/7 Security Operations Centre;

Regulatory Affairs

2018 Test Year Regulatory Affairs expense of $393,533 are $231,071 (142.2%) higher than 2010 BAP and $268,580 (214.9%) higher than 2016 Actual expenditures. Regulatory Affairs costs are increasing in 2017 and 2018 as a result of one of EPLC's primary OM&A cost drivers identified in Section 4.1.2 of this Exhibit. EPLC previously had partial FTEs allocated to various regulatory functions however did not previously have dedicated regulatory staff whose sole responsibility was regulatory accounting, review and compliance. EPLC has added the Regulatory Accounting Analyst position in 2016 and the Manager of Regulatory Accounting in 2017. For additional information about these positions, please refer to section 4.4 of this Exhibit.

Admin & HR Expenses

2018 Test Year Admin & HR expenses of $1,501,428 are $219,383 (17.1%) higher than 2010 BAP and $13,299 (-0.9%) lower than 2016 Actual expenditures.

The variance is primarily related to the inflationary increases in employee wages and benefits.

Customer Service & Billings

2018 Test Year Customer Service & Billing expenses of $1,181,144 are $31,526 (-0.3%) lower than 2010 BAP and $135,981 (13.0%) higher than 2016 Actual expenditures.

EPLC has controlled Customer Service & Billing costs reasonably since 2010 by working closely with 3rd party subject matter experts and consultants as well as revenue offsets from water billing. The reduction in Customer Service & Billings are due to productivity efficiencies and associated staff reductions, partially offset by increases in rates paid to EPLC's 3rd party meter reading provider along with its 3rd party billing provider. With water billing customers (ie. Municipalities) internalizing their own billing functions, EPLC is currently evaluating the cost structure of its Customer Service & Billing department to ensure optimization of cost and customer benefit.

Customer Collections

2018 Test Year Customer Collection expenses of $209,488 are $129,093 (160.6%) higher than 2010 BAP and $56,880 (37.3%) higher than 2016 Actual expenditures. This is a result of the loss of a water billing customer (which previously offset cost of approximately $70,000) and inflationary increases to wages as described in section 4.4 below.

Field Service Maintenance

2018 Test Year Field Service Maintenance expenses of $57,433 are $49,293 (-46.2%) lower than 2010 BAP and $128,551 (-69.1%) lower than 2016 Actual expenditures. EPLC has performed significant Field Service work since 2010 and plans to reduce spending going into the Test Year by $70,333. EPLC has identified that less spending in Field Service work can be achieved over the course of the next five years considering the amount of work completed in recent years.

Meter Maintenance

2018 Test Year Meter Maintenance expenses of $568 are $139,033 (-99.6%) lower than 2010 BAP and $568 higher than 2016 Actual expenditures. Meter maintenance costs have been reduced significantly by $139,159 as a result of a different allocation methodology applied by EPLC as well as reduced overall costs associated with the Smart Metering Initiative. Since 2014, EPLC has allocated most meter related OM&A costs to the Meter Operations work program.

Further, EPLC has seen an overall decrease to the number of metering hardware related issues since the implementation of the Smart Metering Initiative.

Vegetation Control

2018 Test Year Vegetation Control expenses of $666,029 are $310,006 (87.1%) higher than 2010 BAP and $112,136 (-14.4%) lower than 2016 Actual expenditures. EPLC has made significant investments in vegetation control since its last Cost of Service application in 2010 and has seen a corresponding improvement in reliability statistics. While EPLC does not believe that it will be required to continue spending at levels similar to 2012 through 2016, EPLC strongly believes that a rigorous vegetation control program is one of the primary programs that LDCs can offer to significantly improve reliability.

Cable Locates

2018 Test Year Cable Locate expense of $451,196 are $95,041 (26.7%) higher than 2010 BAP and $35,603 (-7.3%) lower than 2016 Actual expenditures. The 2010 to 2018 increase relates primarily to general inflationary increases for a 3rd party service provider along with a higher demand for locates as a result of the Herb Gray Parkway in 2014-2016.

Meter Operations

2018 Test Year Meter Operations expenses of $216,785 are $81,346 (60.1%) higher than 2010 BAP and $3,605 (1.7%) higher than 2016 Actual expenditures. A large portion of this variance relates to the Meter Maintenance re-allocation described in this section above along with general inflationary increases to employee wages and benefits.

Stations Operations

2018 Test Year Stations Operations expense of $0 are $78,499 (-100.0%) lower than 2010 BAP and $0 (0.0%) lower than 2016 Actual expenditures. As part of EPLC's Single Voltage Utility initiative (described further in Exhibit 2 of this Application), EPLC successfully retired all distribution substations feeding its customers in 2015. These retirements are the root cause of the variance. EPLC does not project any further cost associated with Station Operations in the 2018 Test Year and beyond.

Operations Management

2018 Test Year Operations Management expenses of $365,857 are $205,683 (128.4%) higher than 2010 BAP and $256,642 (235.0%) higher than 2016 Actual expenditures. Operations Management costs are increasing in 2018 as a result of one of EPLC's primary OM&A cost drivers identified in Section 4.1.2 of this Exhibit. The initiative driving OM&A increases to Operations Management is 3rd party Control Room support. As part of its Self-Healing Grid initiative (see Exhibit 2 for additional information) as well as through is SmartMAP software implementation (see Exhibit 1, section 1.4.2 for additional information), EPLC is planning to upgrade its current operations to include 3rd party control room support from industry experts. These experts will allow EPLC to add another layer of visibility to its system, enhance after-hours customer service, increase response times and with the implementation of the Self-Healing Grid initiative in the coming years, even optimize switching automation to reduce Loss of Supply incidents and severity for EPLC customers.

Overhead Operations

2018 Test Year Overhead Operations expenses of $114,893 are $205,683 (128.4%) higher than 2010 BAP and $52,515 (-31.4%) lower than 2016 Actual expenditures. This variance relates to a focus shift to Overhead plant as EPLC begins more overhead related conversion work, mainly in older residential areas.

4.4 Employee Compensation

4.4.1 Overview

EPLC's Employee Compensation is intended to be fair, competitive and equitable for all employees with the intent of attracting, retaining and training the best and most qualified people possible. EPLC's typical compensation package includes base wage and benefits as well as incentive based compensation for non-unionized staff.

Unionized Employees

EPLC's current and projected workforce is comprised of approximately 76% unionized employees. EPLC negotiates compensation with unionized employees through the collective bargaining process for both inside and outside employees. Unionized employees are represented by the International Brotherhood of Electrical Workers ("IBEW"), Local 636. IBEW represents approximately 750,000 unionized members across the construction, utilities, manufacturing, telecom, broadcasting, rail and government sectors.

Figure 8 below outlines EPLC's negotiated compensation increases for unionized employees, both inside and outside, from 2008 through to 2019.

Figure 8 – EPLC Collective Bargaining Agreement Summary

Effective Date	Wage Increase	Agreement Expiry
April 1st, 2008	3%	March 31st, 2011
April 1st, 2009	3%	
April 1st, 2010	3%	
April 1st, 2011	2%	March 31st, 2015
April 1st, 2012	2%	
April 1st, 2013	2%	
April 1st, 2014	2%	
April 1st, 2015	2%	March 31st, 2019
April 1st, 2016	2%	
April 1st, 2017	2%	
April 1st, 2018	2%	

EPLC has worked diligently and jointly with the IBEW and its unionized employees to ensure fair and reasonable wage increases while also minimize cost to EPLC ratepayers. In preparation for any re-negotiation of a collective bargaining agreement, EPLC management studies and assesses other local LDCs in Southwestern Ontario for the period of time in question. EPLC has been historically at or slightly below regional wage increase trends.

Management & Executive Employees

Prior to 2011, EPLC utilized a compensation structure that was largely the result of legacy policies from each of the previously existing municipal PUCs, prior to the formation of Essex Power Corporation. Since 2011, EPLC has been participating in yearly MEARIE salary benchmarking surveys. These confidential surveys benchmark a group of approximately 41 Ontario LDCs and 50 benchmark positions representing a cross-section of functions within each LDC. Participating southwestern LDCs include:

- Bluewater Power Distribution;
- Brantford Power Inc.;
- E.L.K. Energy Inc.;
- Entegrus Inc.;
- Enwin Utilities Inc.;
- Festival Hydro Inc.;
- London Hydro Inc.;

The 50 benchmark positions that the survey considers includes, but are not limited to:

- Senior Management (ie. President & CEO, COO, CFO, Head of Regulatory, etc.);
- Administration (ie. Executive Assistant, Administrative Assistant, etc.);
- Engineering (ie. Director of Engineering, Project Engineer, Distribution Engineer, etc.);
- Operations (ie. Director of Operations, Line Supervisor, etc.);
- Accounting/Finance (ie. Controller, Manager of Accounting, Financial Analyst, etc.);
- Customer Service (ie. Director of Customer Service, Supervisor of Customer Service, etc.);
- Conservation & Demand Management (Rate Analyst, Conservation and Demand Management Officer, etc.);
- Information Technology (Manager of Information System, Director of Information Systems, etc.);
- Communications (Director of Communications, Manager of Communications, etc.);

- Human Resources (Human Resources Manager, Human Resources Coordinator, etc.);

In 2012, EPLC also engaged HCI Consulting Inc. to complete a Compensation Program Review for its management and non-union employees. The key objectives of the Compensation Program Review include:

i) Assessment of market positioning and competitiveness of current compensation practices;
ii) Review appropriateness of EPLC's current compensation administration program;
iii) Identify internal pay relationships that require adjustments;
iv) Develop internally equitable and externally competitive compensation structure covering all jobs;

The Compensation Program Review also suggested updates to EPLC's job evaluation methodology. As a result, EPLC implemented the HCI Point Factor Job Evaluation System in 2012 which evaluated employees based on:

- Skill (Education, experience, problem solving, judgement & complexity);
- Effort (Mental and physical effort);
- Working Conditions (Disagreeable or hazardous conditions);
- Responsibility (Decision making, consequence of action/error, interpersonal skills/contacts, leadership, resource responsibility);

Pay Equity

EPLC complies with the *Ontario Pay Equity Act*. EPLC last updated its Pay Equity Policy in 2005, 2009 and 2011 respectively. EPLC is planning to review and update its Pay Equity Policy in 2018/2019 to ensure periodic review and compliance.

EPLC does not foresee any upcoming Pay Equity related issues in 2017 or 2018 and no additional cost has been included in this Application for Pay Equity related items.

Benefits

Benefits for EPLC management and unionized employees are different but largely the same. Unionized employees have benefit plans that are subject to the Collective Bargaining process and can change as a result. Generally, benefits for EPLC management and other non-union employees closely mirror the unionized employee benefits.

Current benefit packages generally include:

- Post-retirement benefits to age 65;
- Employer's portion of government taxes;
- Leave policies;
- Health & Safety protection and considerations;
- Disability and life insurance coverage;
- Health & dental coverage;
- Company sponsored retirement plan through OMERS;

Aging Demographics

Consistent with many distributors in Ontario, EPLC is dealing with a rapidly aging workforce. Figures 9 through 11 below outline the breakdown of EPLC Employee age distribution for union and non-union employees.

Figure 9 – Union Age Demographics

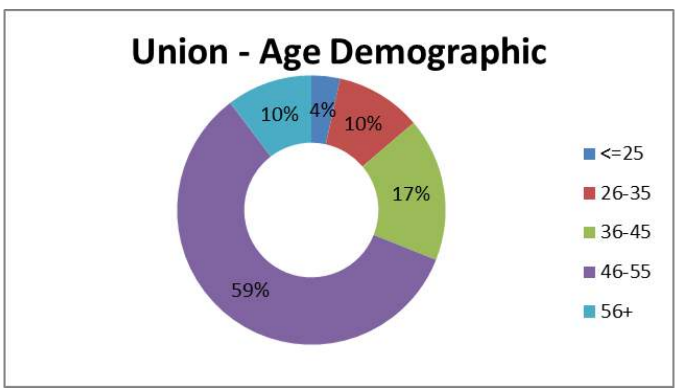
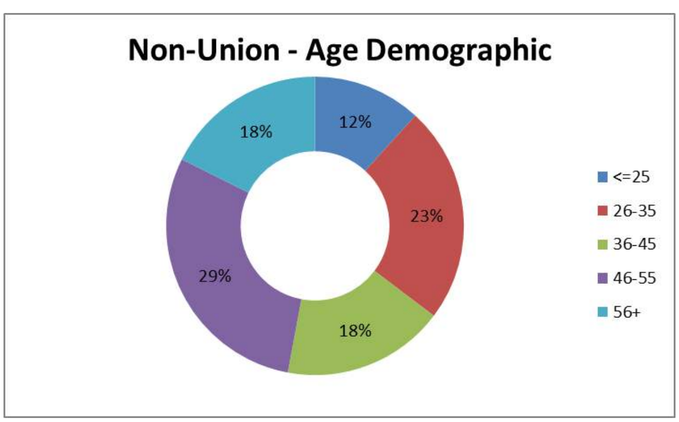


Figure 10 – Non-Union Age Demographics



EPLC is continually working to ensure that retiring and departing employees are replaced with competent and skilled equivalents. For lineman apprentices, EPLC has partnered with St. Clair College, along with other Southwestern LDCs in the development of the Powerline Technician program and is pleased to have recruited its first apprentice from that initiative.

Employee Turnover

Figure 11 below outlines EPLC's historical employee turnover.

Figure 11 – EPLC Employee Turnover

Deparment	2010 Actuals	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Bridge Year
Billing & Collecting	1	0	3	0	1	0	1	0	0
Engineering & Metering	0	0	0	0	0	2	0	0	0
Operations	1	3	1	1	2	1	1	1	0
IT	0	0	0	0	0	0	0	0	0
Regulatory	0	0	0	0	0	0	2	0	0
Finance	0	0	0	1	0	2	0	0	0
Administrative	0	0	0	0	0	0	0	0	0
Total	**2**	**3**	**4**	**2**	**3**	**5**	**4**	**1**	**0**

Of the twenty four historical departures identified above, approximately 80% were retirement related and the remaining 20% of departures were for other positions. EPLC continues to actively monitor retirements and employee departures closely as replacing key roles within the organization continues to be a major challenge for all LDCs, but even more so in southwestern Ontario with only a small number of regionally segregated LDCs still in operation.

EPLC is not forecasting any retirements in 2018 however EPLC also respects the fact that the decision to retire is private and personal for each individual employee. EPLC has had one operations department departure in 2017. Given EPLC's age demographic outlined above, EPLC is developing a detailed succession plan for 2019 and beyond for both unionized and management employees.

4.4.2 FTE & Employee Costs

Consistent with Board Appendix 2-K, EPLC has summarized its employee complement by FTE, compensation and benefits in Figure 12 below. EPLC has included historical years from 2010 through 2016 as well as the 2017 Bridge and 2018 Test years. A completed copy of Board Appendix 2-K is also included as Attachment 4-G of this Exhibit.

EPLC's employee structure has remained relatively consistent between 2011 and 2016. EPLC projects this level of consistency into the 2017 Bridge and 2018 Test Years as well.

Figure 12 – EPLC FTE & Employee Costs

Description	Last Rebasing Year - 2010- Board Approved	Last Rebasing Year - 2010- Actual	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Number of Employees (FTEs including Part-Time)										
Management (including executive)	12	15	15	12	12	13	12	10	11	11
Non-Management (union and non-union)	45	38	29	32	32	35	32	34	35	35
Total	**57**	**53**	**44**	**44**	**44**	**48**	**44**	**44**	**46**	**46**
Total Salary and Wages including ovetime and incentive pay										
Management (including executive)	$ 1,020,892	$ 1,235,240	$ 1,151,468	$ 1,067,030	$ 1,067,391	$ 1,110,844	$ 1,052,468	$ 969,389	$1,127,378	$ 1,149,926
Non-Management (union and non-union)	$ 3,086,722	$ 2,582,457	$ 1,916,942	$ 2,385,412	$ 2,382,334	$ 2,645,925	$ 2,721,429	$ 2,883,015	$2,838,207	$ 2,894,971
Total	**$ 4,107,614**	**$ 3,817,697**	**$ 3,068,410**	**$ 3,452,442**	**$ 3,449,725**	**$ 3,756,769**	**$ 3,773,897**	**$ 3,852,404**	**$3,965,585**	**$ 4,044,897**
Total Benefits (Current + Accrued)										
Management (including executive)	$ 210,560	$ 251,109	$ 294,304	$ 241,866	$ 237,232	$ 233,455	$ 223,354	$ 217,211	$ 266,096	$ 213,995
Non-Management (union and non-union)	$ 630,555	$ 524,981	$ 489,952	$ 540,707	$ 529,482	$ 556,068	$ 577,539	$ 645,996	$ 669,904	$ 683,005
Total	**$ 841,115**	**$ 776,090**	**$ 784,256**	**$ 782,573**	**$ 766,714**	**$ 789,523**	**$ 800,893**	**$ 863,207**	**$ 936,000**	**$ 897,000**
Total Compensation (Salary, Wages, & Benefits)										
Management (including executive)	$ 1,231,452	$ 1,486,349	$ 1,445,772	$ 1,308,896	$ 1,304,623	$ 1,344,299	$ 1,275,822	$ 1,186,600	$1,393,474	$ 1,363,920
Non-Management (union and non-union)	$ 3,717,277	$ 3,107,438	$ 2,406,894	$ 2,926,119	$ 2,911,816	$ 3,201,993	$ 3,298,968	$ 3,529,011	$3,508,111	$ 3,577,977
Total	**$ 4,948,729**	**$ 4,593,787**	**$ 3,852,666**	**$ 4,235,015**	**$ 4,216,439**	**$ 4,546,292**	**$ 4,574,790**	**$ 4,715,611**	**$4,901,585**	**$ 4,941,897**

Since the labour dispute in 2011, EPLC has been able to effectively re-structure its staffing requirements for both management and non-management positions to operate more efficiently. Since 2010, EPLC has been able to effectively reduce FTE counts by approximately 7 when compared to the 2016 Actuals, 2017 Bridge and 2018 Test Years. EPLC has been able to effectively reduce these heads counts through retirements and departures, restructuring job duties for management staff and by leveraging affiliate staff, where required. A summary of EPLC's affiliate usage, by department, is summarized below as Figure 13. It should be noted that FTE counts in Figure 13 are above and beyond what is reported in Figure 12.

Figure 13 – Affiliate Allocations

Deparment	2010 BAP	2010 Actuals	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Bridge Year
Billing & Collecting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Engineering & Metering	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IT	0.0	0.0	1.0	1.8	1.7	1.6	1.6	1.8	0.6	0.6
Regulatory	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.4	0.4	0.4
Finance	0.0	0.0	0.0	1.0	0.1	0.5	0.5	0.5	0.5	0.5
Administrative	2.3	1.9	1.6	2.6	3.2	3.2	2.4	2.0	1.2	1.2
Total	**2.3**	**2.9**	**2.6**	**5.4**	**5.0**	**5.7**	**4.9**	**4.7**	**2.7**	**2.7**

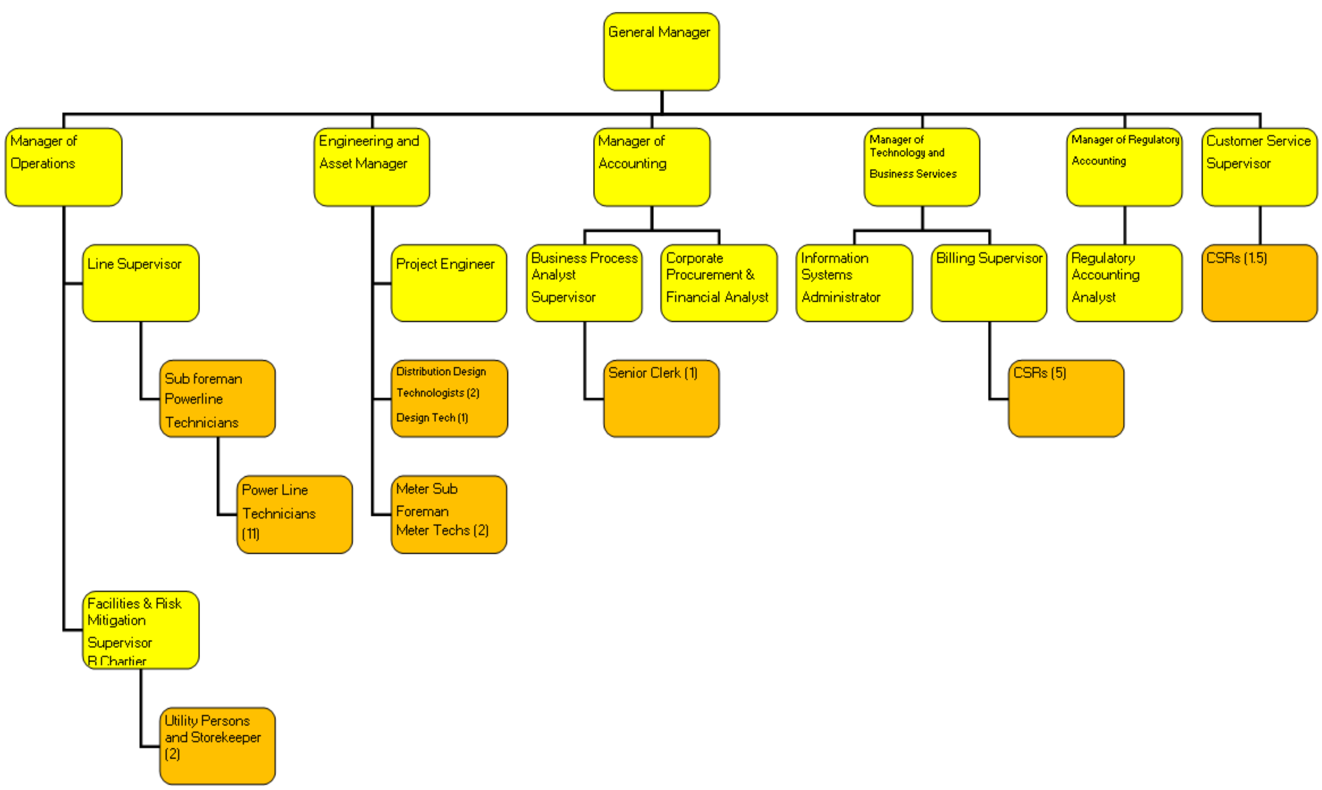
As a result of the efficiencies that EPLC has been able to attain through FTE re-alignment, EPLC estimates that it has been able to effectively reduce OM&A costs by approximately $400,000-500,000.

EPLC calculated the FTE totals in Figure 12 above by pro-rating new employees based on their starting month in a given year, pro-rating departing employees based on their last month of work. EPLC included co-op students and contract employees in this analysis. EPLC excluded Board of Directors and employees dedicated to non-rate regulated activities in affiliates.

The salary and wage figures above include all salaries and wages paid, including incentive pay, overtime, vacation, holidays, sick leave, bereavement and other miscellaneous paid leave. Further, the benefit figures above include EPLC's portion of all statutory benefits including CPP, EI, EHT, WSIB, OMERS, LTD insurance, life insurance, health benefits and other miscellaneous benefits. Further details relating to EPLC's paid benefits are summarized in section 4.4.5 of this Exhibit.

EPLC's current organizational chart is included below as Figure 14.

Figure 14 – EPLC Organizational Chart



4.4.3 FTE By Department

Figure 13 below outlines an EPLC estimated FTE count by department for 2010 BAP, historical years 2010 through 2016 and as projected for the 2017 Bridge and 2018 Test Years.

It should be noted that FTE counts are not consistent with values presented in Board Appendix 2-K , also included as Attachment 4-G of this Exhibit as only employees that are 100% allocated to EPLC and paid by EPLC counted in this Appendix. For clarity, partial FTEs allocated to EPLC via Shared Services (outlined below in section 4.5 of this Exhibit) are not included in Board Appendix 2-K. Figure 15 below includes FTE allocations and shared services from Essex Power Corporation, mainly IT, HR and admin. Allocations from EPC are detailed further in section 4.5.

Figure 15 – EPLC FTE By Department

Deparment	2010 BAP	2010 Actuals	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Bridge Year
Billing & Collecting	13.6	11.1	10.2	9.5	10.5	11.3	9.4	9.4	9.2	9.2
Engineering & Metering	10.3	10.2	7.5	7.7	8.0	8.8	7.2	7.0	7.7	7.7
Operations	27.5	26.7	21.0	20.7	21.6	23.5	21.0	21.4	20.7	20.7
IT	1.0	1.0	1.0	1.8	1.7	1.6	1.6	2.8	2.6	2.6
Regulatory	1.0	1.0	1.3	1.0	1.0	1.7	2.4	2.0	2.1	2.1
Finance	3.0	3.0	3.0	4.4	2.0	2.7	3.8	3.4	3.1	3.1
Administrative	3.3	2.9	1.6	3.6	4.2	4.2	3.4	3.0	3.2	3.2
Total	**59.7**	**55.8**	**45.5**	**48.6**	**49.0**	**53.8**	**48.7**	**48.8**	**48.4**	**48.4**

The FTE drop in Operations and Billing & Collecting from 2010 to 2011 is a result of the retirement of three individuals as well as a labour dispute in 2011.

Increases in 2014 are a result of incremental apprentices being hired in anticipation of known upcoming retirements and departures. Figure 11 above outlines EPLC's turnover rates.

Since 2016 and included in the 2018 Test Year, EPLC has included four new positions that reflect a re-alignment of previous positions and were not previously considered in EB-2009-0143. All new positions are offset by previous retirements, departures or re-structuring. These positions include:

i) **Manager of Technology & Business Services**: Re-aligned to EPLC from EPC in 2016, the Manager of Technology & Business Services is responsible for all IT functions for EPLC including Cyber Security, technology strategy, software/hardware implementation, etc. While portions of the Manager of Technology & Business Services were allocated to EPLC to oversee technology deployment and alignment, the Cyber Security Framework is the primary reason why this resource would need to be fully allocated to EPLC.

ii) **Manager of Regulatory Accounting:** With the restructuring of its Regulatory department in 2016, EPLC promoted its existing Regulatory Accounting Analyst (see description in item iii) below) to the position of Manager of Regulatory Accounting. Previously, EPLC had not had a dedicated resource solely responsible for regulatory compliance and reporting. Given the growing complexity of the industry, EPLC determined that it was necessary to invest in its Regulatory department to better enhance regulatory controls and oversight for the organization.

iii) **Regulatory Accounting Analyst:** EPLC previously had a regulatory analyst that was partially responsible and dedicated to operations as well as regulatory compliance. With the departure of this individual in 2016, EPLC hired a Regulatory Accounting Analyst whose sole responsibility was to oversee the regulatory compliance and reporting for EPLC.

iv) **Corporate Procurement & Financial Analyst:** With the operational vacancy created by the departure of the regulatory and operations analyst, EPLC hired a procurement and financial analyst to help with the daily complexities of purchasing, job packaging and financial analysis.

4.4.4 FTEs, Wages & Benefits Variance Analysis

Consistent with Board Appendix 2-K and included as Attachment 4-G of this Exhibit, EPLC has included Figure 16 below which outlines year over year variances of EPLC FTEs and wages & benefits. For the purpose of this analysis, EPLC has included the 2010 BAP, historical years 2010 through 2016 and the 2017 Bridge and 2018 Test years.

Figure 16 – EPLC FTE, Wages & Benefits Variance Analysis

Description	Last Rebasing Year - 2010- Board Approved	Last Rebasing Year - 2010- Actual	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Number of Employees (FTEs including Part-Time)										
Management (including executive)	12	15	15	12	12	13	12	10	11	11
Non-Management (union and non-union)	45	38	29	32	32	35	32	34	35	35
Total	57	53	44	44	44	48	44	44	46	46
Total Salary and Wages including ovetime and incentive pay										
Management (including executive)	$ 1,020,892	$ 1,235,240	$ 1,151,468	$ 1,067,030	$ 1,067,391	$ 1,110,844	$ 1,052,468	$ 969,389	$ 1,127,378	$ 1,149,926
Non-Management (union and non-union)	$ 3,086,722	$ 2,582,457	$ 1,916,942	$ 2,385,412	$ 2,382,334	$ 2,645,925	$ 2,721,429	$ 2,883,015	$ 2,838,207	$ 2,894,971
Total	$ 4,107,614	$ 3,817,697	$ 3,068,410	$ 3,452,442	$ 3,449,725	$ 3,756,769	$ 3,773,897	$ 3,852,404	$ 3,965,585	$ 4,044,897
Total Benefits (Current + Accrued)										
Management (including executive)	$ 210,560	$ 251,109	$ 294,304	$ 241,866	$ 237,232	$ 233,455	$ 223,354	$ 217,211	$ 266,096	$ 213,995
Non-Management (union and non-union)	$ 630,555	$ 524,981	$ 489,952	$ 540,707	$ 529,482	$ 556,068	$ 577,539	$ 645,996	$ 669,904	$ 683,005
Total	$ 841,115	$ 776,090	$ 784,256	$ 782,573	$ 766,714	$ 789,523	$ 800,893	$ 863,207	$ 936,000	$ 897,000
Total Compensation (Salary, Wages, & Benefits)										
Management (including executive)	$ 1,231,452	$ 1,486,349	$ 1,445,772	$ 1,308,896	$ 1,304,623	$ 1,344,299	$ 1,275,822	$ 1,186,600	$ 1,393,474	$ 1,363,920
Non-Management (union and non-union)	$ 3,717,277	$ 3,107,438	$ 2,406,894	$ 2,926,119	$ 2,911,816	$ 3,201,993	$ 3,298,968	$ 3,529,011	$ 3,508,111	$ 3,577,977
Total	$ 4,948,729	$ 4,593,787	$ 3,852,666	$ 4,235,015	$ 4,216,439	$ 4,546,292	$ 4,574,790	$ 4,715,611	$ 4,901,585	$ 4,941,897
Description		**2010 BAP vs. 2010 Act**	**2011 Act vs. 2010 Act.**	**2012 Act vs. 2011 Act.**	**2013 Act vs. 2012 Act.**	**2014 Act vs. 2013 Act.**	**2015 Act vs. 2014 Act.**	**2016 Act vs. 2015 Act.**	**2017 Bridge vs. 2016 Act**	**2018 Test vs. 2017 Bridge**
Number of Employees (FTEs including Part-Time)										
Management (including executive)		3.0	-	(3.0)	-	1.0	(1.0)	(2.0)	1.0	-
Non-Management (union and non-union)		(7.4)	(9.0)	3.0	-	3.0	(3.0)	2.0	1.0	-
Total		- 4	- 9	-	-	4	- 4	-	2	-
Total Salary and Wages including ovetime and incentive pay										
Management (including executive)		$ 214,348	$ (83,772)	$ (84,438)	$ 361	$ 43,453	$ (58,376)	$ (83,079)	$ 157,989	$ 22,548
Non-Management (union and non-union)		$ (504,265)	$ (665,515)	$ 468,470	$ (3,078)	$ 263,591	$ 75,504	$ 161,586	$ (44,808)	$ 56,764
Total		$ (289,917)	$ (749,287)	$ 384,032	$ (2,717)	$ 307,044	$ 17,128	$ 78,507	$ 113,181	$ 79,312
Total Benefits (Current + Accrued)										
Management (including executive)		$ 40,549	$ 43,195	$ (52,438)	$ (4,635)	$ (3,776)	$ (10,101)	$ (6,143)	$ 48,885	$ (52,101)
Non-Management (union and non-union)		$ (105,574)	$ (35,029)	$ 50,755	$ (11,224)	$ 26,585	$ 21,471	$ 68,457	$ 23,908	$ 13,101
Total		$ 776,090	$ 784,256	$ 782,573	$ 766,714	$ 789,523	$ 800,893	$ 863,207	$ 936,000	$ 897,000
Total Compensation (Salary, Wages, & Benefits)										
Management (including executive)		$ 254,897	$ (40,577)	$ (136,876)	$ (4,274)	$ 39,677	$ (68,477)	$ (89,222)	$ 206,874	$ (29,554)
Non-Management (union and non-union)		$ (609,839)	$ (700,544)	$ 519,225	$ (14,302)	$ 290,176	$ 96,975	$ 230,043	$ (20,900)	$ 69,865
Total		$ 776,090	$ 784,256	$ 782,573	$ 766,714	$ 789,523	$ 800,893	$ 863,207	$ 936,000	$ 897,000

2010 BAP vs. 2010 Actual

EPLC experienced two unexpected retirements in the 2010 Actual year when compared to the 2010 BAP values. 2010 Actual was also the year allocations from affiliates were formally changed. See Figure 13 above for additional information about EPLC allocations and FTEs by department. EPLC also hired a new Operations Manager in 2010. This position was vacant since 2008.

The compensation related variances are the result of the changes to EPLC's allocation changes as well as corresponding increases related to the hiring of the Operations Manager position.

2010 Actual vs. 2011 Actual

The majority of the variance from 2011 Actual to 2010 Actual for both FTE counts and total compensation are a result of a labour dispute for approximately three months (April 7th to July 9th, 2011) in 2011. As a result, union related compensation and FTE counts are down significantly. EPLC also experienced three departures/retirements in the Operations Department in 2011.

2011 Actual vs. 2012 Actual

The FTE variance from 2012 Actual to 2011 Actual is a result of four departures/retirements. Three of these retirements occurred in EPLC's Billing & Collecting department whereby the Senior Management responsible for Billing & Customer Care retired along with two longstanding customer service representatives. The unionized positions were replaced however the Manager, Customer Care was not replaced as EPLC attempted to reduce costs in this department. EPLC instead hired a Customer Service Supervisor.

The compensation related variances are a result of a return to normal levels of compensation for union employees which was tied to the labour dispute in 2011. Management compensation decreased due to decreased overtime, in relation to the 2011 labour dispute, as well as the retirement of the Manager, Customer Care.

2012 Actual vs. 2013 Actual

There are no material variances for the 2013 Actual to 2012 Actual time period.

2013 Actual vs. 2014 Actual

The FTE variance from 2014 Actual to 2013 Actual is a result of a maternity leave replacement in the finance department, a new customer service representative in the Billing & Collecting department and two new linemen to replace known and upcoming retirements/departures.

The compensation related variances are directly the result of the incremental hires described above and their resulting salary, wages and benefits.

2014 Actual vs. 2015 Actual

The FTE and compensation related variances from 2015 Actual to 2014 Actual are a result of the departure of the finance department maternity leave replacement, two retirements in the metering department and two departures/retirements in the finance department. Both finance department vacancies were filled the same year.

The compensation related variances are related to yearly increases in salary, wages and benefits for non-management employees. The decrease to management expenses are a result of having the vacant management positions described above for a period of time during the year.

2015 Actual vs. 2016 Actual

The FTE and compensation related variances from 2016 Actual to 2015 Actual are the result of two departures in EPLC's regulatory/finance departments as well as the resulting re-alignment additions of the following positions. EPLC's intention with the re-alignment of its regulatory department was to place a strategic emphasis on regulatory accounting, regulatory strategy and regulatory compliance.

- **Manager of Regulatory Accounting:** With the restructuring of its Regulatory department in 2016, EPLC promoted its existing Regulatory Accounting Analyst to the position of Manager of Regulatory Accounting. Previously, EPLC had not had a dedicated resource solely responsible for regulatory compliance and reporting. Given the growing complexity of the industry, EPLC determined that it was necessary to invest in its Regulatory department to better enhance regulatory controls and oversight for the organization.

- **Regulatory Accounting Analyst:** EPLC previously had a regulatory analyst that was partially responsible and dedicated to operations as well as regulatory compliance. With the departure of this individual in 2016, EPLC hired a Regulatory Accounting Analyst whose sole responsibility was to oversee the regulatory compliance and reporting for EPLC.

2016 Actual vs. 2017 Bridge

The FTE and compensation related variances from 2017 Bridge to 2016 Actual are the result of additions of the following positions:

- **Manager of Technology & Business Services**: Re-aligned to EPLC from EPC in 2016, the Manager of Technology & Business Services is responsible for all IT functions for EPLC including Cyber Security, technology strategy, software/hardware implementation, etc. While portions of the Manager of Technology & Business Services were allocated to EPLC to oversee technology deployment and alignment, the Cyber Security Framework is the primary reason why this resource would need to be fully allocated to EPLC;

- **Corporate Procurement & Financial Analyst:** With the operational vacancy created by the departure of the regulatory and operations analyst, EPLC hired a procurement and financial analyst to help with the daily complexities of purchasing, job packaging and financial analysis;

2017 Bridge vs. 2018 Test

There are no variances for the 2018 Test to 2017 Bridge relating to changes in FTEs.

The compensation related variances are solely related to yearly increases in salary, wages and benefits for non-management employees.

4.4.5 Employee Benefit Programs

EPLC offers the following statutory benefits summarized below:

- Canada Pension Plan (“CPP”);
- Employment Insurance (“EI”);
- Employer Health Tax (“EHT”);
- Workplace Safety Insurance Board (“WSIB”);

EPLC offers the following company benefits summarized below:

- **Ontario Municipal Employee Retirement Savings (“OMERS”);**
- **Long Term Disability (“LTD”)** – administered through the MEARIE Group;
- **Life Insurance** - administered through the MEARIE Group;
- **Health Care Benefits** – includes dental, vision, medical, etc. Administered through Green Shield Canada;
- **Employee Assistance Program (“EAP”)** – program offered to assist employees and/or their families with various health, work and life related issues;
- **Safety Equipment Allowance Program** – Reimbursement for various safety articles includes shoes, hardhat, reflective clothing, etc.;
- **Fitness Reimbursement Program** – incentive for employees to join various fitness related groups including gyms, running clubs, yoga classes, etc.;

Figure 17 below outlines EPLC’s Benefit Expenses by category. As evidenced below, year over year increases are mainly related to increases related to Health Care Benefits and the OMERS pension plan.

Figure 17 – EPLC Benefit Expenses

Description	2010 Actuals	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Employee Benefit Expense	$ -	$ 162,669	$ -	$ -	$ -	$ 441	$ (441)	$ -	$ -
EI - Employer Portion	$ 52,500	$ 49,111	$ 54,714	$ 56,322	$ 58,196	$ 55,347	$ 60,329	$ 60,000	$ 62,000
CPP - Employer Portion	$ 108,028	$ 95,436	$ 105,944	$ 105,084	$ 108,946	$ 103,828	$ 113,673	$ 120,000	$ 125,000
WSIB Premiums	$ 39,187	$ 28,124	$ 31,305	$ 30,271	$ 36,696	$ 32,306	$ 37,548	$ 40,000	$ 42,000
OMERS	$ 250,776	$ 220,482	$ 284,712	$ 320,005	$ 339,033	$ 325,677	$ 341,897	$ 380,000	$ 390,000
Banked OT	$ -	$ -	$ 288	$ 529	$ -	$ -	$ -	$ -	$ -
Health Care Benefits	$ 171,660	$ 112,613	$ 172,374	$ 122,809	$ 110,968	$ 150,483	$ 171,383	$ 190,000	$ 200,000
Life Insurance	$ 31,425	$ 16,313	$ 20,974	$ 16,994	$ 17,217	$ 16,944	$ 18,428	$ 18,000	$ 19,000
STD/LTD Premiums	$ 46,350	$ 35,159	$ 38,619	$ 39,053	$ 35,272	$ 31,848	$ 35,468	$ 39,000	$ 41,000
Employer Health Tax	$ 74,193	$ 56,246	$ 67,323	$ 67,034	$ 73,757	$ 73,591	$ 75,214	$ 80,000	$ 83,000
Safety Equipment Allowance Program	$ 1,972	$ 8,103	$ 6,319	$ 8,612	$ 9,437	$ 10,428	$ 8,692	$ 8,000	$ 9,000
Fitness Reimbursement Program	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,017	$ 1,000	$ 1,000
Total	**$ 776,090**	**$ 784,256**	**$ 782,573**	**$ 766,714**	**$ 789,522**	**$ 800,893**	**$ 863,206**	**$ 936,000**	**$ 972,000**

EPLC's post-employment benefit costs are actuarially determined using the projected benefit method pro-rated on service and based on assumptions that reflect management's best estimates at the time. As a result of this methodology, the projected post-retirement benefit is deemed to be earned on a pro-rata basis over the years of service in the relevant period commencing on the date of hire and ending at the earliest age the employee could retire and qualify for benefits. EPLC has procured K-W Actuarial Services Inc. in 2015 and Mondelis Actuarial in 2016 to complete full actuarial valuations of EPLC and its affiliate companies. EPLC's most recent Actuarial reports are attached as Attachment 4-H of this Exhibit.

4.5 Shared Services & Corporate Cost Allocation

4.5.1 Overview

EPLC currently has Shared Services arrangements with the following wholly-owned entities:

- Essex Power Corporation ("EPC") – EPLC parent company;
- Essex Power Services Corporation ("EPS") – wholly-owned subsidiary of EPC and sister company of EPLC;
- Essex Energy Corporation ("EE") - wholly-owned subsidiary of EPC and sister company of EPLC;
- Utilismart Corporation ("UC") - wholly-owned subsidiary of EE and sister company of EPLC;

EPLC also has Shared Services arrangements with its shareholders as follows:

- Municipality of Leamington – Municipal shareholder of EPC;
- Town of Amherstburg - Municipal shareholder of EPC;
- Town of LaSalle - Municipal shareholder of EPC;
- Town of Tecumseh - Municipal shareholder of EPC;

The services summarized below are setup accordingly for the provision of products or services to, or by EPLC, in order to benefit from cost savings due to increases in efficiency or by leveraging economics of scale.

Figures 18 through 26 below outline the shared services employed by EPLC from 2010 through to the 2018 Test Year. For the purpose of this analysis, it should be noted that EPLC does not have any corporate allocations. EPLC does have various HR, IT, procurement and executive services rendered from EPC listed as a shared service in Figures 18 through 26 below.

Figure 18 – Shared Services – 2010 Actual

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
EPLC	Municipalities of Tecumseh, Amherstburg, Leamington, LaSalle	Water billing & collection	Flat monthly service charge	$ 772,334	
EEC	EPLC	Engineering support service	Fully allocated cost		$ 67,734
EEC	EPLC	CDM services	Fully allocated cost		$ 340,824
EEC	EPLC	IT development services	Hourly Rate		$ 33,750
EPS	EPLC	Streetlight maintenance	Fully allocated cost		
EPC	EPLC	HR services, IT services, Procurement service and Executive Services	Fully allocated cost		$ 1,256,205
UC	EPLC	Wholesale settlement services and interval meter reading and communication	Negotiated contract with market tested rates		$ 6,541
Total				**$ 772,334**	**$ 1,705,055**

Figure 19 – Shared Services – 2011 Actual

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
EPLC	Municipalities of Tecumseh, Amherstburg, Leamington, LaSalle	Water billing & collection	Flat monthly service charge	$ 895,442	
EEC	EPLC	Engineering support service	Fully allocated cost		$ 157,951
EEC	EPLC	CDM services	Fully allocated cost		$ 519,841
EEC	EPLC	IT development services	Hourly Rate		$ 26,303
EPS	EPLC	Streetlight maintenance	Fully allocated cost		$ 1,229
EPC	EPLC	HR services, IT services, Procurement service and Executive Services	Fully allocated cost		$ 1,181,342
UC	EPLC	Wholesale settlement services and interval meter reading and communication	Negotiated contract with market tested rates		$ 255,865
Total				**$ 895,442**	**$ 2,142,532**

Figure 20 – Shared Services – 2012 Actual

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
EPLC	Municipalities of Tecumseh, Amherstburg, Leamington, LaSalle	Water billing & collection	Flat monthly service charge	$ 848,242	
EEC	EPLC	Engineering support service	Fully allocated cost		$ 281,005
EEC	EPLC	CDM services	Fully allocated cost		$ 429,535
EEC	EPLC	IT development services	Hourly Rate		$ 44,797
EPS	EPLC	Streetlight maintenance	Fully allocated cost		$ 10,410
EPC	EPLC	HR services, IT services, Procurement service and Executive Services	Fully allocated cost		$ 1,000,134
UC	EPLC	Wholesale settlement services and interval meter reading and communication	Negotiated contract with market tested rates		$ 242,403
Total				**$ 848,242**	**$ 2,008,285**

Figure 21 – Shared Services – 2013 Actual

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
EPLC	Municipalities of Tecumseh, Amherstburg, Leamington, LaSalle	Water billing & collection	Flat monthly service charge	$ 929,921	
EEC	EPLC	Engineering support service	Fully allocated cost		$ 315,299
EEC	EPLC	CDM services	Fully allocated cost		$ 835,318
EEC	EPLC	IT development services	Hourly Rate		$ 38,458
EPS	EPLC	Streetlight maintenance	Fully allocated cost		$ 97,556
EPC	EPLC	HR services, IT services, Procurement service and Executive Services	Fully allocated cost		$ 1,036,741
UC	EPLC	Wholesale settlement services and interval meter reading and communication	Negotiated contract with market tested rates		$ 254,677
Total				$ 929,921	$ 2,578,049

Figure 22 – Shared Services – 2014 Actual

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
EPLC	Municipalities of Tecumseh, Amherstburg, Leamington, LaSalle	Water billing & collection	Flat monthly service charge	$ 947,980	
EEC	EPLC	Engineering support service	Fully allocated cost		$ 195,214
EEC	EPLC	CDM services	Fully allocated cost		$ 628,122
EEC	EPLC	IT development services	Hourly Rate		$ 311,894
EPS	EPLC	Streetlight maintenance	Fully allocated cost		$ 94,257
EPC	EPLC	HR services, IT services, Procurement service and Executive Services	Fully allocated cost		$ 1,145,205
UC	EPLC	Wholesale settlement services and interval meter reading and communication	Negotiated contract with market tested rates		$ 272,267
Total				$ 947,980	$ 2,646,959

Figure 23 – Shared Services – 2015 Actual

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
EPLC	Municipalities of Tecumseh, Amherstburg, Leamington, LaSalle	Water billing & collection	Flat monthly service charge	$ 948,337	
EEC	EPLC	Engineering support service	Fully allocated cost		$ 281,927
EEC	EPLC	CDM services	Fully allocated cost		$ 970,799
EEC	EPLC	IT development services	Hourly Rate		$ 132,986
EPS	EPLC	Streetlight maintenance	Fully allocated cost		$ 34,975
EPC	EPLC	HR services, IT services, Procurement service and Executive Services	Fully allocated cost		$ 1,132,261
UC	EPLC	Wholesale settlement services and interval meter reading and communication	Negotiated contract with market tested rates		$ 371,231
Total				$ 948,337	$ 2,924,179

Figure 24 – Shared Services – 2016 Actual

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
EPLC	Municipalities of Tecumseh, Amherstburg, Leamington, LaSalle	Water billing & collection	Flat monthly service charge	$ 941,723	
EEC	EPLC	Engineering support service	Fully allocated cost		$ 249,758
EEC	EPLC	CDM services	Fully allocated cost		$ 639,590
EEC	EPLC	IT development services	Hourly Rate		$ 129,814
EPS	EPLC	Streetlight maintenance	Fully allocated cost		$ 71,497
EPC	EPLC	HR services, IT services, Procurement service and Executive Services	Fully allocated cost		$ 1,012,571
UC	EPLC	Wholesale settlement services and interval meter reading and communication	Negotiated contract with market tested rates		$ 343,123
Total				$ 941,723	$ 2,446,353

Figure 25 – Shared Services – 2017 Bridge

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
EPLC	Municipalities of Tecumseh, Amherstburg, Leamington	Water billing & collection	Flat monthly service charge	$ 684,228	
EEC	EPLC	Engineering support service	Fully allocated cost		$ 90,817
EEC	EPLC	CDM services	Fully allocated cost		$ 914,911
EEC	EPLC	IT development services	Hourly Rate		$ 32,489
EPS	EPLC	Streetlight maintenance	Fully allocated cost		$ 71,497
EPC	EPLC	HR services, IT services, Procurement service and Executive Services	Fully allocated cost		$ 873,740
UC	EPLC	Wholesale settlement services and interval meter reading and communication	Negotiated contract with market tested rates		$ 343,123
Total				$ 684,228	$ 2,326,577

Figure 26 – Shared Services – 2018 Test

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
EPLC	Municipalities of Tecumseh, Amherstburg, Leamington	Water billing & collection	Flat monthly service charge	$ 765,456	
EEC	EPLC	Engineering support service	Fully allocated cost		$ 90,817
EEC	EPLC	CDM services	Fully allocated cost		$ 914,911
EEC	EPLC	IT development services	Hourly Rate		$ 32,489
EPS	EPLC	Streetlight maintenance	Fully allocated cost		$ 71,497
EPC	EPLC	HR services, IT services, Procurement service and Executive Services	Fully allocated cost		$ 873,740
UC	EPLC	Wholesale settlement services and interval meter reading and communication	Negotiated contract with market tested rates		$ 343,123
Total				$ 765,456	$ 2,326,577

4.5.2 Shared Services to Affiliates

EPLC previously provided water and wastewater meter reading, billing, collecting and general customer administration services to its four shareholder Municipalities (Amherstburg, LaSalle, Leamington, Tecumseh). EPLC bills its Municipal client a flat, monthly service charge for services rendered.

The Town of LaSalle has recently internalized water billing effective January 1st, 2017.

EPLC is also preparing for the potential departure of other Municipal water billing client(s) by re-negotiating meter reading agreements and evaluating the re-alignment of department staff.

4.5.3 Shared Services from Affiliates

i. **Services from EPS:** EPS provides streetlight maintenance and MSP services to EPLC based on fully allocated costs required to complete the requisite work. Streetlight services include repairs, maintenance, inspection and customer service. MSP work relates to ongoing compliance, meter verification, meter reading and troubleshooting.

ii. **Services from UC:** UC provides EPLC with turnkey meter data management services and online display for its wholesale and interval metering customers, along with various other settlement services. Pricing is based on a negotiated agreement annually that is consistent with market rates.

iii. **Services from EE:** EE provides turnkey Conservation & Demand Management ("CDM") services to EPLC that eliminate any risk to EPLC. EE provides all services relating to CDM including regulatory, financial, customer meetings, engineering/technical reviews, program management, program delivery, 3rd party contract negotiation and compliance with IESO requirements and changes. EE also provides engineering & software development services, as needed, for EPLC.

iv. **Services from EPC:** EPC provides financial, human resource, communication and information technology support to EPLC. Financial services include financial reporting, banking, business planning and audit support. Human resource support includes recruitment, labour relations, training, benefit management and health & safety. Communication services include website updates, social media presence, branding and marketing. Information technology support includes various computer and network services.

4.5.4 Corporate Cost Allocations

All Corporate Costs from EPC are included as shared services described in Figures 16 through 24 above.

4.5.5 Variance Analysis

Figure 27 below outlines the variance between the 2018 Test Year and the 2010 BAP as well as 2016 Actuals for Shared Services and Corporate Cost Allocations.

Figure 27 – Shared Service Variances

Description	2010 BAP	2016 Actual	2018 Test Year	2018 Test vs. 2010 BAP	2018 Test vs. 2016 Actual
Services provided by EPLC	$ 546,515	$ 941,723	$ 765,456	$ 218,941	$ (176,267)
Services provided to EPLC	$1,146,011	$2,446,353	$ 2,326,577	$ 1,180,566	$ (119,775)
Corporate Cost Allocations	$ -	$ -	$ -	$ -	$ -

2010 BAP vs. 2018 Test Year

The services provided by EPLC to affiliates increased by $218,941 from the 2010 BAP to the 2018 Test Year as a result in year over year inflationary and growth related increases to the Municipalities that EPLC services for water and wastewater meter reading, billing, collecting and general customer administration services. Note that EPLC lost one of the four municipal water billing customers in 2017.

The services provided to EPLC by affiliates increased by $1,180,566 from the 2010 BAP to the 2018 Test Year as a result of Conservation & Demand Management services, increases related to meter data management and settlement charges.

2016 Actual vs. 2018 Test Year

The services provided by EPLC to affiliates decreased by $176,267 from the 2016 Actuals to the 2018 Test Year as a result of the loss of one of the four municipal customers that EPLC water and wastewater meter reading, billing, collecting and general customer administration services in 2017.

The services provided to EPLC by affiliates decreased by $119,775 from the 2016 Actuals to the 2018 Test Year as a result of a re-allocation of information technology services within EPLC in order to accommodate the Board's Cybersecurity framework and a reduction in planned engineering support from EE. EPLC will no longer be buying these specific IT services from EPC and instead will be completing this work internally.

4.6 Purchases of Non-Affiliate Services

EPC's Purchasing Policy, included as Attachment 4-J of this Exhibit, outlines and details EPLC's process relating to acquisition of 3rd party services. EPLC's policy also outlines the required approval process that must be adhered to in order to purchase goods and services from suppliers, vendors and contractors.

Figure 28 below outlines EPLC's historical purchases by vendor, above materiality (as calculated in Exhibit 1 of this Application) for historical years 2011 through 2016. EPLC anticipates using the same vendors for 2017 and 2018 however EPLC is continually assessing new suppliers and efficiencies. For the purpose of this analysis, EPLC used $65,000 as its materiality threshold. This Figure also indicates the method of selection employed in the acquisition of each specific purchase of goods and services, consistent with EPLC's purchasing policy.

Figure 28 – Purchases of Non-Affiliate Services

Vendor	Product/Service	Method of Selection	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual
1307749 ONTARIO LTD.	Tree Trimming	Quote	$ 285,412	$ 601,856	$ 517,789	$ 506,965	$ 493,452	$ 537,662
AFI INTERNATIONAL GROUP INC.	Security	Quote	$ 61,140	$ -	$ -	$ -	$ -	$ -
ANIXTER CANADA INC.	Inventory	Quote	$ 117,481	$ 221,459	$ -	$ 367,727	$ 414,090	$ -
ANIXTER POWER SOLUTIONS INC. (HD SUPP)	Inventory	Quote	$ 358,351	$ 607,398	$ 759,491	$ 402,877	$ 369,837	$ 574,232
BDO Canada LLP	Computer Software	Quote	$ 101,755	$ -	$ -	$ -	$ -	$ -
BELL CANADA	Phone Service	Quote	$ 71,260	$ 68,952	$ 99,318	$ -	$ 79,815	$ -
CANADA POST	Postage	Sole Source	$ 248,600	$ 253,000	$ 295,000	$ 280,000	$ 355,000	$ 350,000
CANADIAN ELECTRICAL SERVICES	Transformers	Quote	$ 199,185	$ 432,706	$ 666,389	$ 438,726	$ 358,329	$ 313,269
ECALIBER	Billing Software	Quote	$ 150,710	$ -	$ -	$ -	$ -	$ -
ELECTRICITY DISTRIBUTORS ASSOCIATION	Corporate Membership	Quote	$ 92,886	$ -	$ -	$ 74,715	$ -	$ -
ERTH HOLDINGS INC.	Billing Services	Quote	$ 95,432	$ 301,833	$ 281,131	$ 291,696	$ 491,556	$ 724,153
G&W CANADA	Inventory	Quote	$ -	$ -	$ -	$ -	$ 144,866	$ 148,160
GREEN SHIELD	Employee Benefits	Quote	$ 112,613	$ 172,374	$ 122,809	$ 110,968	$ 150,483	$ 171,383
G-TEL	Locate Services	Quote	$ 214,120	$ 239,463	$ 235,192	$ 321,620	$ 430,339	$ 232,500
J FORTIER & SON EXCAVAT.	Construction Services	Quote	$ 78,886	$ 152,652	$ 130,688	$ 129,469	$ 167,418	$ 211,840
KEN LAPAIN & SONS LTD.	Vehicle Repairs	Quote	$ 161,619	$ 121,384	$ 102,078	$ -	$ 110,035	$ 67,366
KPMG LLP	Accounting Services	Quote	$ -	$ -	$ -	$ -	$ -	$ 90,448
NETMON INC.	IT system monitoring	Quote	$ -	$ -	$ -	$ -	$ -	$ 170,018
OGILVY RENAULT LLP, in trust	Legal Services	Sole Source	$ 75,618	$ -	$ -	$ -	$ -	$ -
OLAMETER INC.	Meter Reading Services	Quote	$ 320,777	$ 286,076	$ 290,493	$ 284,440	$ 272,682	$ 218,497
PACHECOS CONTRACTORS LTD	Construction Services	Quote	$ 162,588	$ -	$ 210,972	$ 188,100		
PETRO-CANADA	Fuel	Sole Source	$ 99,678	$ 120,162	$ 124,567	$ 133,263	$ 121,658	$ 90,321
POSI PLUS TECHNOLOGIES INC	Vehicles	Quote	$ 290,527	$ 251,785		$ 325,835		
PRICEWATERHOUSECOOPERS LLP	Accounting Services	Quote	$ -	$ -	$ 99,101	$ -	$ -	$ 83,514
STELLA JONES INC (DBA-GUELPH UTILILITY POLE)	Poles	Quote	$ 62,965	$ 111,519	$ 84,570	$ 92,029	$ 96,145	$ 81,670
THE MEARIE GROUP	Insurance, Employee Benefits	Sole Source	$ 205,492	$ 250,871	$ 252,794	$ 200,672	$ 160,034	$ 158,797
THOMAS & BETTS LIMITED	Inventory	Quote	$ 174,111	$ 419,903	$ 287,985	$ -	$ 178,241	$ 116,983

4.7 Regulatory Costs

The regulatory department is currently staffed by the Manager of Regulatory Accounting and the Regulatory Accounting Analyst positions. These positions are currently responsible for the preparation of any and all regulatory reporting and associated filings, rate applications, reviewing and implementing change related to regulation and ensuring regulatory compliance. Due to the overall and growing complexity of these positions, the regulatory department is also often assisted by EPLC finance department. These costs are not included for recovery as part of EPLC Regulatory Costs.

For the purpose of this section, EPLC has completed Figures 29 and 30 below, in conjunction with Board Appendix 2-M which is also included with this Exhibit as Attachment 4-K.

Figure 29 – EPLC On-Going Regulatory Costs

Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost?	Last Rebasing Year (2010 Board Approved)	Most Current Actuals Year 2016	2017 Bridge Year	Annual % Change	2018 Test Year	Annual % Change
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
OEB Annual Assessment	5655		On-Going	$ 59,962	$ 119,310	$ 121,696	2.00%	$ 124,130	2.00%
OEB Section 30 Costs (Applicant-originated)									
OEB Section 30 Costs (OEB-initiated)	5655		On-Going		$ 5,643	$ 5,646	0.05%	$ 5,646	0.00%
Expert Witness costs for regulatory matters									
Legal costs for regulatory matters	5655		One-Time					$ 50,000	
Consultants' costs for regulatory matters	5655		One-Time			$ 140,812		$ 17,370	-87.66%
Operating expenses associated with staff resources allocated to regulatory matters	5610		On-Going	$ 50,000	$ 116,250	$ 195,688	68.33%	$ 217,000	10.89%
Operating expenses associated with other resources allocated to regulatory matters									
Other regulatory agency fees or assessments									
Any other costs for regulatory matters	5655		One-Time						
Application Costs	5655		One-Time	$ 52,500				$ 35,000	
Sub-total - Ongoing Costs 3		$ -		$ 162,462	$ 241,203	$ 323,030	33.92%	$ 346,776	7.35%
Sub-total - One-time Costs 4		$ -		$ -	$ -	$ 140,812		$ 102,370	-27.30%
Total		**$ -**		**$ 162,462**	**$ 241,203**	**$ 463,842**	**92.30%**	**$ 449,146**	**-3.17%**

Figure 30 – EPLC One-Time Cost of Service Application Costs

Regulatory Cost Category	2017 Bridge Year	2018 Test Year	Application Gross Cost	Amortized Over 5 Years
Expert Witness costs			$ -	$ -
Legal costs		$ 50,000	$ 50,000	$ 10,000
Consultants' costs	$ 101,931	$ 10,000	$ 111,931	$ 22,386
Incremental operating expenses associated with staff resources allocated to this application.			$ -	$ -
Incremental operating expenses associated with other resources allocated to this application. 1			$ -	$ -
Intervenor costs		$ 35,000	$ 35,000	$ 7,000
Total	**$ 101,931**	**$ 95,000**	**$ 196,931**	**$ 39,386**

Figure 29 above outlines EPLC's ongoing regulatory expenses which include OEB Annual Assessment, OEB Section 30 costs, operating expenses and ongoing application costs.

Figure 30 above outlines EPLC's cost associated with the creation of this Cost of Service application which is currently estimated at $196,931. This cost includes legal, consulting, administrative and intervenor costs. Consulting costs include costs for customer engagement (Convergys $17k, Innovative Research $25k), DSP (Metsco $60k) and third party application support and review (Elenchus $20k). EPLC also included $39,152 in incremental staffing required to generate the required information in support of this Application.

EPLC proposes to recover the amount of $196,931 in distribution rates over five (5) years. As a result, EPLC has included $39,386 in 2018 OM&A costs.

4.8 One-Time Costs

As described in section 4.7 above, EPLC has incurred $196,931 in one-time costs related to the preparation of this Application. EPLC seeks to recover this amount over a five (5) year period and has included $39,386 (1/5th) of one-time costs in its 2018 Test Year Revenue Requirement.

4.9 Low Income Energy Assistance Programs

The Board initiated public consultation in 2008 that led to the identification of three primary components that could assist low-income energy consumers in Ontario:

- Emergency Financial Assistance;
- Customer Service Rules;
- Targeted Conservation & Demand Management Programs;

EPLC, in partnership with local social service agencies within the communities that it services, contributes the Board recommended 0.12% of its Service Revenue Requirement annually (2016 - $13,427).

EPLC is committed to continuing with this form of financial assistance in the future. EPLC has included $15,795 in the 2018 Test Year which represents an estimated increase in line with the proposed increase to EPLC's Service Revenue Requirement. EPLC understands that this value can and will most likely change based on the final approved Service Revenue Requirement resulting from this Application.

EPLC confirms that the 2018 Test Year does not include any legacy low income energy assistance programs.

4.10 Charitable & Political Donations

4.10.1 Charitable Donations

EPLC confirms that it does not make any charitable donations and therefore there are no such contributions included for recovery in this Application.

Essex Power Corporation ("EPC") does make a variety of charitable donations within our community. There are no such contributions included for recovery in this Application.

4.10.2 Political Donations

EPLC confirms that it does not make political contributions and therefore there are no such contributions included for recovery in this Application.

4.11 Depreciation/Amortization/Depletion

4.11.1 Overview

EPLC has transitioned to IFRS accounting effective January 1st, 2015. Previously, EPLC's depreciation/amortization policy was based on CGAAP and direction issued by the Board. As a result, EPLC is compliant with MIFRS for the 2017 Bridge Year and 2018 Test Year.

The Board issued direction to LDCs on July 12th, 2012 that adoption of IFRS-compliant capitalization and depreciation accounting policies was mandatory effective January 1st, 2013. As a result, EPLC implemented changes to its capitalization and depreciation policies effective January 1st, 2013. EPLC implemented changes to useful lives based on guidance from the Kinetrics Report issued by the Board July 8th, 2010. EPLC also completed an assessment of remaining service lives for the purpose of determining depreciation expense on a go-forward basis which is outlined in the analysis below.

EPLC confirms that significant parts or components of each item of PP&E are being separately depreciated.

In accordance with Section 2.4.4 of the Board's Filing Requirements, EPLC confirms that capital assets and capital contributions are amortized on a straight-line basis over the deemed life of the asset. EPLC also applies the half-year rule in the first year of the addition.

EPLC confirms that it does not amortize construction in progress assets until the project is completed.

EPLC confirms that it does not capitalize interest to the cost of assets constructed and capitalized.

For the purpose of calculating depreciation in this Application and consistent with EPLC's depreciation/amortization policy attached in Exhibit 2 of this Application, EPLC applied the half-year rule for all in-service 2018 Test Year capital additions and capital contributions.

A historical summary of EPLC's depreciation expense is provided below in Figure 8. A detailed breakdown of depreciation expense by asset class and by year, is also provided below as Figures 31 through 40. These tables also show accumulated depreciation by USoA account and the rate of depreciation used for each respective year. All accumulated depreciation values are consistent with Board Appendix 2-BA (Fixed Asset Continuity Schedules).

Figure 31 – Summary of Depreciation/Amortization

Description	2010 BAP	2010 Actuals	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Accounting Standard	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Computer Software (Formally known as Account 1925)	$ (168,003)	$ (150,110)	$ (120,676)	$ (76,486)	$ (342,040)	$ (75,831)	$ (75,579)	$ (63,196)	$ (81,624)	$ (103,175)
Land Rights (Formally known as Account 1906)	$ (1,783)	$ (1,601)	$ (2,066)	$ (2,407)	$ (2,930)	$ (3,679)	$ (3,983)	$ (4,166)	$ (4,604)	$ (5,515)
Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Station Equipment <50 kV	$ (5,228)	$ (4,773)	$ (4,117)	$ (4,344)	$ (4,002)	$ (3,599)	$ -	$ -	$ -	$ -
Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Poles, Towers & Fixtures	$ (118,466)	$ (114,467)	$ (193,867)	$ (205,289)	$ (148,490)	$ (129,121)	$ (133,666)	$ (148,824)	$ (163,794)	$ (177,447)
Overhead Conductors & Devices	$ (339,927)	$ (312,857)	$ (228,956)	$ (252,579)	$ (95,859)	$ (73,359)	$ (73,557)	$ (89,922)	$ (104,679)	$ (118,491)
Underground Conduit	$ (221,090)	$ (210,276)	$ (274,681)	$ (313,087)	$ (199,739)	$ (122,833)	$ (226,513)	$ (232,711)	$ (243,945)	$ (263,932)
Underground Conductors & Devices	$ (458,511)	$ (450,575)	$ (423,812)	$ (448,094)	$ (229,618)	$ (365,105)	$ (287,646)	$ (293,497)	$ (314,089)	$ (341,450)
Line Transformers	$ (438,224)	$ (528,295)	$ (559,269)	$ (592,640)	$ (326,072)	$ (353,494)	$ (287,574)	$ (334,035)	$ (322,980)	$ (348,809)
Services (Overhead & Underground)	$ (290,015)	$ (277,135)	$ (289,810)	$ (322,721)	$ (144,526)	$ (166,800)	$ (158,272)	$ (178,610)	$ (197,036)	$ (213,267)
Meters	$ (116,088)	$ (148,395)	$ (155,889)	$ (202,596)	$ (198,723)	$ (202,705)	$(1,488,521)	$ (374,594)	$ (384,378)	$ (402,131)
Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Buildings & Fixtures	$ (79,410)	$ (78,512)	$ (64,818)	$ (79,682)	$ (42,858)	$ (27,100)	$ (41,157)	$ (42,169)	$ (45,350)	$ (51,918)
Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Office Furniture & Equipment (10 years)	$ (22,035)	$ (22,200)	$ (15,061)	$ (16,141)	$ (16,755)	$ (17,979)	$ (8,342)	$ (9,697)	$ (11,209)	$ (11,445)
Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Computer Equipment - Hardware	$ (13,778)	$ (33,616)	$ (51,907)	$ (50,831)	$ (141,384)	$ (4,346)	$ (35,385)	$ (11,815)	$ (73,917)	$ (121,790)
Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transportation Equipment	$ (149,278)	$ (92,823)	$ (161,612)	$ (185,945)	$ (157,920)	$ (146,305)	$ (189,589)	$ (213,884)	$ (211,990)	$ (273,932)
Stores Equipment	$ (4,671)	$ (4,448)	$ (3,204)	$ (3,572)	$ (3,670)	$ (2,673)	$ (2,198)	$ (2,701)	$ (5,708)	$ (10,101)
Tools, Shop & Garage Equipment	$ (24,411)	$ (25,181)	$ (22,882)	$ (28,086)	$ (58,184)	$ (63,233)	$ (42,042)	$ (46,828)	$ (52,011)	$ (49,066)
Measurement & Testing Equipment	$ (4,107)	$ (5,443)	$ (5,916)	$ (6,399)	$ (11,669)	$ (11,235)	$ (6,269)	$ (6,599)	$ (6,895)	$ (5,458)
Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Communications Equipment	$ (40,239)	$ (36,741)	$ (16,874)	$ (20,766)	$ (59,435)	$ (43,937)	$ (29,553)	$ (29,874)	$ (15,040)	$ (13,332)
Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions & Grants	$ 247,763	$ 219,928	$ 288,452	$ 344,643	$ 278,492	$ 247,371	$ 552,530	$ 589,771	$ 367,800	$ 398,418
Deferred Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$(2,247,501)**	**$ (2,277,521)**	**$(2,306,964)**	**$(2,467,021)**	**$(1,905,383)**	**$(1,565,964)**	**$ (2,537,316)**	**$(1,493,351)**	**$(1,871,449)**	**$(2,112,841)**

1 **Figure 32 – 2010 Actual – CGAAP – Gross Asset & Depreciation Summary**

USoA	Description	Gross Assets	Accumulated Amortization	Depreciation Expense	Depreciation Rate
1611	Computer Software (Formally known as Account 1925)	$ 1,037,697	$ (334,169)	$ (150,110)	20.00%
1612	Land Rights (Formally known as Account 1906)	$ 97,579	$ (3,399)	$ (1,601)	2.00%
1805	Land	$ 47,899	$ -	$ -	0.00%
1808	Buildings	$ -	$ -	$ -	0.00%
1810	Leasehold Improvements	$ -	$ -	$ -	0.00%
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	0.00%
1820	Distribution Station Equipment <50 kV	$ 102,722	$ (18,379)	$ (4,773)	4.00%
1825	Storage Battery Equipment	$ -	$ -	$ -	0.00%
1830	Poles, Towers & Fixtures	$ 5,731,639	$ (528,986)	$ (114,467)	4.00%
1835	Overhead Conductors & Devices	$ 5,495,913	$ (2,263,290)	$ (312,857)	4.00%
1840	Underground Conduit	$ 8,523,236	$ (1,575,660)	$ (210,276)	4.00%
1845	Underground Conductors & Devices	$ 10,289,850	$ (3,172,818)	$ (450,575)	4.00%
1850	Line Transformers	$ 13,356,674	$ (3,280,457)	$ (528,295)	4.00%
1855	Services (Overhead & Underground)	$ 6,818,570	$ (1,686,526)	$ (277,135)	4.00%
1860	Meters	$ 3,957,664	$ (805,475)	$ (148,395)	4.00%
1860	Meters (Smart Meters)	$ -	$ -	$ -	0.00%
1905	Land	$ 190,119	$ -	$ -	0.00%
1908	Buildings & Fixtures	$ 1,607,140	$ (156,568)	$ (78,512)	4.00%
1910	Leasehold Improvements	$ -	$ -	$ -	0.00%
1915	Office Furniture & Equipment (10 years)	$ 159,415	$ (57,171)	$ (22,200)	10.00%
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	0.00%
1920	Computer Equipment - Hardware	$ 251,403	$ (35,039)	$ (33,616)	20.00%
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	0.00%
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	0.00%
1930	Transportation Equipment	$ 982,829	$ (98,505)	$ (92,823)	12.50%
1935	Stores Equipment	$ 29,711	$ (8,435)	$ (4,448)	10.00%
1940	Tools, Shop & Garage Equipment	$ 214,968	$ (48,885)	$ (25,181)	10.00%
1945	Measurement & Testing Equipment	$ 54,338	$ (6,458)	$ (5,443)	10.00%
1950	Power Operated Equipment	$ -	$ -	$ -	0.00%
1955	Communications Equipment	$ 197,224	$ (89,671)	$ (36,741)	10.00%
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	0.00%
1960	Miscellaneous Equipment	$ -	$ -	$ -	0.00%
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	0.00%
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	0.00%
1980	System Supervisor Equipment	$ -	$ -	$ -	0.00%
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	0.00%
1990	Other Tangible Property	$ -	$ -	$ -	0.00%
1995	Contributions & Grants	$(10,063,338)	$ 157,227	$ 219,928	4.00%
2440	Deferred Revenue	$ -	$ -	$ -	0.00%
	Total	$ 49,083,253	$ (14,012,664)	$ (2,277,521)	

2

3

4

1 **Figure 33 – 2011 Actual – CGAAP – Gross Asset & Depreciation Summary**

USoA	Description	Gross Assets	Accumulated Amortization	Depreciation Expense	Depreciation Rate
1611	Computer Software (Formally known as Account 1925)	$ 946,329	$ (484,278)	$ (120,676)	20.00%
1612	Land Rights (Formally known as Account 1906)	$ 108,990	$ (5,000)	$ (2,066)	2.00%
1805	Land	$ 47,899	$ -	$ -	0.00%
1808	Buildings	$ -	$ -	$ -	0.00%
1810	Leasehold Improvements	$ -	$ -	$ -	0.00%
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	0.00%
1820	Distribution Station Equipment <50 kV	$ 103,107	$ (23,152)	$ (4,117)	4.00%
1825	Storage Battery Equipment	$ -	$ -	$ -	0.00%
1830	Poles, Towers & Fixtures	$ 6,006,615	$ (643,453)	$ (193,867)	4.00%
1835	Overhead Conductors & Devices	$ 5,684,239	$ (2,462,148)	$ (228,956)	4.00%
1840	Underground Conduit	$ 9,701,439	$ (1,785,936)	$ (274,681)	4.00%
1845	Underground Conductors & Devices	$ 10,917,707	$ (3,623,393)	$ (423,812)	4.00%
1850	Line Transformers	$ 14,233,655	$ (3,808,752)	$ (559,269)	4.00%
1855	Services (Overhead & Underground)	$ 7,692,638	$ (1,963,661)	$ (289,810)	4.00%
1860	Meters	$ 4,200,151	$ (953,871)	$ (155,889)	4.00%
1860	Meters (Smart Meters)	$ -	$ -	$ -	0.00%
1905	Land	$ 190,119	$ -	$ -	0.00%
1908	Buildings & Fixtures	$ 1,633,771	$ (235,080)	$ (64,818)	4.00%
1910	Leasehold Improvements	$ -	$ -	$ -	0.00%
1915	Office Furniture & Equipment (10 years)	$ 159,415	$ (79,371)	$ (15,061)	10.00%
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	0.00%
1920	Computer Equipment - Hardware	$ 306,043	$ (68,655)	$ (51,907)	20.00%
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	0.00%
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	0.00%
1930	Transportation Equipment	$ 1,172,081	$ (64,236)	$ (161,612)	12.50%
1935	Stores Equipment	$ 34,367	$ (12,883)	$ (3,204)	10.00%
1940	Tools, Shop & Garage Equipment	$ 242,672	$ (74,066)	$ (22,882)	10.00%
1945	Measurement & Testing Equipment	$ 63,987	$ (11,901)	$ (5,916)	10.00%
1950	Power Operated Equipment	$ -	$ -	$ -	0.00%
1955	Communications Equipment	$ 226,916	$ (126,412)	$ (16,874)	10.00%
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	0.00%
1960	Miscellaneous Equipment	$ -	$ -	$ -	0.00%
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	0.00%
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	0.00%
1980	System Supervisor Equipment	$ -	$ -	$ -	0.00%
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	0.00%
1990	Other Tangible Property	$ -	$ -	$ -	0.00%
1995	Contributions & Grants	$(12,003,010)	$ 377,155	$ 288,452	4.00%
2440	Deferred Revenue	$ -	$ -	$ -	0.00%
	Total	**$ 51,669,129**	**$ (16,049,092)**	**$ (2,306,964)**	

2

3

4

Figure 34 – 2012 Actual – CGAAP – Gross Asset & Depreciation Summary

USoA	Description	Gross Assets	Accumulated Amortization	Depreciation Expense	Depreciation Rate
1611	Computer Software (Formally known as Account 1925)	$ 1,186,475	$ (694,893)	$ (76,486)	20.00%
1612	Land Rights (Formally known as Account 1906)	$ 115,165	$ (7,066)	$ (2,407)	2.00%
1805	Land	$ 47,899	$ -	$ -	0.00%
1808	Buildings	$ -	$ -	$ -	0.00%
1810	Leasehold Improvements	$ -	$ -	$ -	0.00%
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	0.00%
1820	Distribution Station Equipment <50 kV	$ 114,073	$ (27,269)	$ (4,344)	4.00%
1825	Storage Battery Equipment	$ -	$ -	$ -	0.00%
1830	Poles, Towers & Fixtures	$ 6,463,571	$ (837,320)	$ (205,289)	4.00%
1835	Overhead Conductors & Devices	$ 6,414,747	$ (2,691,103)	$ (252,579)	4.00%
1840	Underground Conduit	$ 10,656,520	$ (2,060,617)	$ (313,087)	4.00%
1845	Underground Conductors & Devices	$ 11,570,868	$ (4,047,205)	$ (448,094)	4.00%
1850	Line Transformers	$ 15,077,416	$ (4,368,021)	$ (592,640)	4.00%
1855	Services (Overhead & Underground)	$ 8,376,599	$ (2,253,471)	$ (322,721)	4.00%
1860	Meters	$ 5,160,299	$ (1,109,760)	$ (202,596)	4.00%
1860	Meters (Smart Meters)	$ -	$ -	$ -	0.00%
1905	Land	$ 190,119	$ -	$ -	0.00%
1908	Buildings & Fixtures	$ 2,394,956	$ (299,898)	$ (79,682)	4.00%
1910	Leasehold Improvements	$ -	$ -	$ -	0.00%
1915	Office Furniture & Equipment (10 years)	$ 180,243	$ (89,836)	$ (16,141)	10.00%
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	0.00%
1920	Computer Equipment - Hardware	$ 306,043	$ (120,562)	$ (50,831)	20.00%
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	0.00%
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	0.00%
1930	Transportation Equipment	$ 1,282,473	$ (53,357)	$ (185,945)	12.50%
1935	Stores Equipment	$ 37,075	$ (16,087)	$ (3,572)	10.00%
1940	Tools, Shop & Garage Equipment	$ 329,469	$ (96,948)	$ (28,086)	10.00%
1945	Measurement & Testing Equipment	$ 63,987	$ (17,817)	$ (6,399)	10.00%
1950	Power Operated Equipment	$ -	$ -	$ -	0.00%
1955	Communications Equipment	$ 276,532	$ (143,286)	$ (20,766)	10.00%
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	0.00%
1960	Miscellaneous Equipment	$ -	$ -	$ -	0.00%
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	0.00%
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	0.00%
1980	System Supervisor Equipment	$ -	$ -	$ -	0.00%
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	0.00%
1990	Other Tangible Property	$ -	$ -	$ -	0.00%
1995	Contributions & Grants	$(12,872,863)	$ 665,607	$ 344,643	4.00%
2440	Deferred Revenue		$ -	$ -	0.00%
	Total	**$ 57,371,668**	**$ (18,268,909)**	**$ (2,467,021)**	

Figure 35 – 2013 Actual – RCGAAP – Gross Asset & Depreciation

USoA	Description	Gross Assets	Accumulated Amortization	Depreciation Expense	Depreciation Rate
1611	Computer Software (Formally known as Account 1925)	$ 1,252,529	$ (771,379)	$ (342,040)	20.00%
1612	Land Rights (Formally known as Account 1906)	$ 175,427	$ (9,473)	$ (2,930)	2.00%
1805	Land	$ 47,899	$ -	$ -	0.00%
1808	Buildings	$ -	$ -	$ -	0.00%
1810	Leasehold Improvements	$ -	$ -	$ -	0.00%
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	0.00%
1820	Distribution Station Equipment <50 kV	$ 115,505	$ (31,612)	$ (4,002)	4.00%
1825	Storage Battery Equipment	$ -	$ -	$ -	0.00%
1830	Poles, Towers & Fixtures	$ 6,852,565	$ (1,042,609)	$ (148,490)	2.00%
1835	Overhead Conductors & Devices	$ 6,909,277	$ (2,943,682)	$ (95,859)	2.00%
1840	Underground Conduit	$ 11,489,326	$ (2,373,704)	$ (199,739)	2.50%
1845	Underground Conductors & Devices	$ 12,495,775	$ (4,495,300)	$ (229,618)	3.33%
1850	Line Transformers	$ 16,432,674	$ (4,960,661)	$ (326,072)	2.50%
1855	Services (Overhead & Underground)	$ 9,221,942	$ (2,576,192)	$ (144,526)	2.00%
1860	Meters	$ 5,319,772	$ (1,312,355)	$ (198,723)	4.00%
1860	Meters (Smart Meters)	$ -	$ -	$ -	0.00%
1905	Land	$ 190,119	$ -	$ -	0.00%
1908	Buildings & Fixtures	$ 2,422,357	$ (379,580)	$ (42,858)	2.00%
1910	Leasehold Improvements	$ -	$ -	$ -	0.00%
1915	Office Furniture & Equipment (10 years)	$ 188,609	$ (105,977)	$ (16,755)	10.00%
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	0.00%
1920	Computer Equipment - Hardware	$ 324,149	$ (171,393)	$ (141,384)	20.00%
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	0.00%
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	0.00%
1930	Transportation Equipment	$ 1,553,552	$ (128,316)	$ (157,920)	10.00%
1935	Stores Equipment	$ 37,075	$ (19,659)	$ (3,670)	10.00%
1940	Tools, Shop & Garage Equipment	$ 383,628	$ (125,034)	$ (58,184)	10.00%
1945	Measurement & Testing Equipment	$ 63,987	$ (24,216)	$ (11,669)	10.00%
1950	Power Operated Equipment	$ -	$ -	$ -	0.00%
1955	Communications Equipment	$ 281,480	$ (164,051)	$ (59,435)	10.00%
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	0.00%
1960	Miscellaneous Equipment	$ -	$ -	$ -	0.00%
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	0.00%
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	0.00%
1980	System Supervisor Equipment	$ -	$ -	$ -	0.00%
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	0.00%
1990	Other Tangible Property	$ -	$ -	$ -	0.00%
1995	Contributions & Grants	$(15,064,761)	$ 1,010,250	$ 278,492	2.50%
2440	Deferred Revenue	$ -	$ -	$ -	0.00%
	Total	**$ 60,692,887**	**$ (20,624,944)**	**$ (1,905,383)**	

Figure 36 – 2014 Actual – MIFRS – Gross Asset & Depreciation Summary

USoA	Description	Gross Assets	Accumulated Amortization	Depreciation Expense	Depreciation Rate
1611	Computer Software (Formally known as Account 1925)	$ 1,327,398	$ (1,113,418)	$ (75,831)	20.00%
1612	Land Rights (Formally known as Account 1906)	$ 190,498	$ (12,403)	$ (3,679)	2.00%
1805	Land	$ 47,899	$ -	$ -	0.00%
1808	Buildings	$ -	$ -	$ -	0.00%
1810	Leasehold Improvements	$ -	$ -	$ -	0.00%
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	0.00%
1820	Distribution Station Equipment <50 kV	$ 115,505	$ (35,614)	$ (3,599)	4.00%
1825	Storage Battery Equipment	$ -	$ -	$ -	0.00%
1830	Poles, Towers & Fixtures	$ 7,343,189	$ (1,191,099)	$ (129,121)	2.00%
1835	Overhead Conductors & Devices	$ 7,340,765	$ (3,039,541)	$ (73,359)	2.00%
1840	Underground Conduit	$ 12,740,042	$ (2,573,444)	$ (122,833)	2.50%
1845	Underground Conductors & Devices	$ 13,335,773	$ (4,724,918)	$ (365,105)	3.33%
1850	Line Transformers	$ 17,747,645	$ (5,286,733)	$ (353,494)	2.50%
1855	Services (Overhead & Underground)	$ 10,266,869	$ (2,720,718)	$ (166,800)	2.00%
1860	Meters	$ 5,652,387	$ (1,511,079)	$ (202,705)	4.00%
1860	Meters (Smart Meters)	$ -	$ -	$ -	0.00%
1905	Land	$ 190,119	$ -	$ -	0.00%
1908	Buildings & Fixtures	$ 2,422,357	$ (422,438)	$ (27,100)	2.00%
1910	Leasehold Improvements	$ -	$ -	$ -	0.00%
1915	Office Furniture & Equipment (10 years)	$ 190,108	$ (122,732)	$ (17,979)	10.00%
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	0.00%
1920	Computer Equipment - Hardware	$ 367,497	$ (312,778)	$ (4,346)	20.00%
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	0.00%
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	0.00%
1930	Transportation Equipment	$ 1,842,598	$ (150,182)	$ (146,305)	10.00%
1935	Stores Equipment	$ 37,075	$ (23,329)	$ (2,673)	10.00%
1940	Tools, Shop & Garage Equipment	$ 461,960	$ (183,218)	$ (63,233)	10.00%
1945	Measurement & Testing Equipment	$ 63,987	$ (35,885)	$ (11,235)	10.00%
1950	Power Operated Equipment	$ -	$ -	$ -	0.00%
1955	Communications Equipment	$ 281,480	$ (223,486)	$ (43,937)	10.00%
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	0.00%
1960	Miscellaneous Equipment	$ -	$ -	$ -	0.00%
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	0.00%
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	0.00%
1980	System Supervisor Equipment	$ -	$ -	$ -	0.00%
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	0.00%
1990	Other Tangible Property	$ -	$ -	$ -	0.00%
1995	Contributions & Grants	$(16,186,932)	$ 1,288,742	$ 247,371	2.50%
2440	Deferred Revenue	$ -	$ -	$ -	0.00%
	Total	**$ 65,778,217**	**$ (22,394,273)**	**$ (1,565,964)**	

Figure 37 – 2015 Actual – MIFRS – Gross Asset & Depreciation Summary

USoA	Description	Gross Assets	Accumulated Amortization	Depreciation Expense	Depreciation Rate
1611	Computer Software (Formally known as Account 1925)	$ 1,344,441	$ (1,189,249)	$ (75,579)	20.00%
1612	Land Rights (Formally known as Account 1906)	$ 205,159	$ (16,082)	$ (3,983)	2.00%
1805	Land	$ 47,899	$ -	$ -	0.00%
1808	Buildings	$ -	$ -	$ -	0.00%
1810	Leasehold Improvements	$ -	$ -	$ -	0.00%
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	0.00%
1820	Distribution Station Equipment <50 kV	$ -	$ -	$ -	4.00%
1825	Storage Battery Equipment	$ -	$ -	$ -	0.00%
1830	Poles, Towers & Fixtures	$ 8,277,989	$ (1,320,220)	$ (133,666)	2.00%
1835	Overhead Conductors & Devices	$ 8,330,924	$ (3,112,900)	$ (73,557)	2.00%
1840	Underground Conduit	$ 13,019,342	$ (2,696,277)	$ (226,513)	2.50%
1845	Underground Conductors & Devices	$ 13,920,280	$ (5,075,833)	$ (287,646)	3.33%
1850	Line Transformers	$ 18,562,128	$ (5,640,180)	$ (287,574)	2.50%
1855	Services (Overhead & Underground)	$ 11,329,169	$ (2,887,518)	$ (158,272)	2.00%
1860	Meters	$ 4,484,564	$ (1,713,784)	$ (1,488,521)	4.00%
1860	Meters (Smart Meters)	$ 3,835,084	$ -	$ -	0.00%
1905	Land	$ 190,119	$ -	$ -	0.00%
1908	Buildings & Fixtures	$ 2,471,271	$ (449,538)	$ (41,157)	2.00%
1910	Leasehold Improvements	$ -	$ -	$ -	0.00%
1915	Office Furniture & Equipment (10 years)	$ 196,088	$ (140,712)	$ (8,342)	10.00%
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	0.00%
1920	Computer Equipment - Hardware	$ 371,372	$ (317,124)	$ (35,385)	20.00%
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	0.00%
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	0.00%
1930	Transportation Equipment	$ 2,244,755	$ (296,487)	$ (189,589)	10.00%
1935	Stores Equipment	$ 37,092	$ (26,002)	$ (2,198)	10.00%
1940	Tools, Shop & Garage Equipment	$ 518,499	$ (246,451)	$ (42,042)	10.00%
1945	Measurement & Testing Equipment	$ 63,987	$ (47,120)	$ (6,269)	10.00%
1950	Power Operated Equipment	$ -	$ -	$ -	0.00%
1955	Communications Equipment	$ 294,423	$ (267,423)	$ (29,553)	10.00%
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	0.00%
1960	Miscellaneous Equipment	$ -	$ -	$ -	0.00%
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	0.00%
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	0.00%
1980	System Supervisor Equipment	$ -	$ -	$ -	0.00%
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	0.00%
1990	Other Tangible Property	$ -	$ -	$ -	0.00%
1995	Contributions & Grants	$(17,635,115)	$ 1,536,113	$ 552,530	2.50%
2440	Deferred Revenue	$ -	$ -	$ -	0.00%
	Total	**$ 72,109,471**	**$ (23,906,787)**	**$ (2,537,316)**	

Figure 38 – 2016 Actual – MIFRS – Gross Asset & Depreciation Summary

USoA	Description	Gross Assets	Accumulated Amortization	Depreciation Expense	Depreciation Rate
1611	Computer Software (Formally known as Account 1925)	$ 1,349,658	$ (1,057,277)	$ (63,196)	20.00%
1612	Land Rights (Formally known as Account 1906)	$ 207,803	$ (20,013)	$ (4,166)	2.00%
1805	Land	$ 35,899	$ -	$ -	0.00%
1808	Buildings	$ -	$ -	$ -	0.00%
1810	Leasehold Improvements	$ -	$ -	$ -	0.00%
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	0.00%
1820	Distribution Station Equipment <50 kV	$ -	$ -	$ -	4.00%
1825	Storage Battery Equipment	$ -	$ -	$ -	0.00%
1830	Poles, Towers & Fixtures	$ 8,897,418	$ (1,371,068)	$ (148,824)	2.00%
1835	Overhead Conductors & Devices	$ 9,205,503	$ (3,194,505)	$ (89,922)	2.00%
1840	Underground Conduit	$ 13,230,112	$ (2,869,571)	$ (232,711)	2.50%
1845	Underground Conductors & Devices	$ 14,457,773	$ (5,384,238)	$ (293,497)	3.33%
1850	Line Transformers	$ 19,300,481	$ (5,906,704)	$ (334,035)	2.50%
1855	Services (Overhead & Underground)	$ 12,154,283	$ (3,066,599)	$ (178,610)	2.00%
1860	Meters	$ 9,412,656	$ (3,288,200)	$ (374,594)	4.00%
1860	Meters (Smart Meters)	$ -	$ -	$ -	0.00%
1905	Land	$ 190,119	$ -	$ -	0.00%
1908	Buildings & Fixtures	$ 2,513,740	$ (478,209)	$ (42,169)	2.00%
1910	Leasehold Improvements	$ -	$ -	$ -	0.00%
1915	Office Furniture & Equipment (10 years)	$ 216,760	$ (153,607)	$ (9,697)	10.00%
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	0.00%
1920	Computer Equipment - Hardware	$ 488,701	$ (302,807)	$ (11,815)	20.00%
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	0.00%
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	0.00%
1930	Transportation Equipment	$ 2,381,417	$ (513,230)	$ (213,884)	10.00%
1935	Stores Equipment	$ 47,367	$ (18,079)	$ (2,701)	10.00%
1940	Tools, Shop & Garage Equipment	$ 564,329	$ (234,710)	$ (46,828)	10.00%
1945	Measurement & Testing Equipment	$ 70,247	$ (42,048)	$ (6,599)	10.00%
1950	Power Operated Equipment	$ -	$ -	$ -	0.00%
1955	Communications Equipment	$ 294,423	$ (245,382)	$ (29,874)	10.00%
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	0.00%
1960	Miscellaneous Equipment	$ -	$ -	$ -	0.00%
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	0.00%
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	0.00%
1980	System Supervisor Equipment	$ -	$ -	$ -	0.00%
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	0.00%
1990	Other Tangible Property	$ -	$ -	$ -	0.00%
1995	Contributions & Grants	$(18,566,136)	$ 2,088,643	$ 589,771	2.50%
2440	Deferred Revenue	$ -	$ -	$ -	0.00%
	Total	**$ 76,452,554**	**$ (26,057,604)**	**$ (1,493,351)**	

Figure 39 – 2017 Bridge – MIFRS – Gross Asset & Depreciation Summary

USoA	Description	Gross Assets	Accumulated Amortization	Depreciation Expense	Depreciation Rate
1611	Computer Software (Formally known as Account 1925)	$ 1,604,158	$ (1,120,473)	$ (81,624)	20.00%
1612	Land Rights (Formally known as Account 1906)	$ 249,995	$ (24,179)	$ (4,604)	2.00%
1805	Land	$ 35,899	$ -	$ -	0.00%
1808	Buildings	$ -	$ -	$ -	0.00%
1810	Leasehold Improvements	$ -	$ -	$ -	0.00%
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	0.00%
1820	Distribution Station Equipment <50 kV	$ -	$ -	$ -	4.00%
1825	Storage Battery Equipment	$ -	$ -	$ -	0.00%
1830	Poles, Towers & Fixtures	$ 9,829,756	$ (1,519,892)	$ (163,794)	2.00%
1835	Overhead Conductors & Devices	$ 9,747,151	$ (3,284,427)	$ (104,679)	2.00%
1840	Underground Conduit	$ 13,964,522	$ (3,102,282)	$ (243,945)	2.50%
1845	Underground Conductors & Devices	$ 15,245,984	$ (5,677,735)	$ (314,089)	3.33%
1850	Line Transformers	$ 20,326,051	$ (6,240,739)	$ (322,980)	2.50%
1855	Services (Overhead & Underground)	$ 12,976,997	$ (3,245,209)	$ (197,036)	2.00%
1860	Meters	$ 9,679,588	$ (3,662,794)	$ (384,378)	4.00%
1860	Meters (Smart Meters)	$ -	$ -	$ -	0.00%
1905	Land	$ 190,119	$ -	$ -	0.00%
1908	Buildings & Fixtures	$ 2,800,540	$ (520,378)	$ (45,350)	2.00%
1910	Leasehold Improvements	$ -	$ -	$ -	0.00%
1915	Office Furniture & Equipment (10 years)	$ 226,760	$ (163,304)	$ (11,209)	10.00%
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	0.00%
1920	Computer Equipment - Hardware	$ 844,851	$ (314,622)	$ (73,917)	20.00%
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	0.00%
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	0.00%
1930	Transportation Equipment	$ 2,868,417	$ (727,114)	$ (211,990)	10.00%
1935	Stores Equipment	$ 97,367	$ (20,780)	$ (5,708)	10.00%
1940	Tools, Shop & Garage Equipment	$ 624,329	$ (281,538)	$ (52,011)	10.00%
1945	Measurement & Testing Equipment	$ 70,247	$ (48,647)	$ (6,895)	10.00%
1950	Power Operated Equipment	$ -	$ -	$ -	0.00%
1955	Communications Equipment	$ 294,423	$ (275,256)	$ (15,040)	10.00%
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	0.00%
1960	Miscellaneous Equipment	$ -	$ -	$ -	0.00%
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	0.00%
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	0.00%
1980	System Supervisor Equipment	$ -	$ -	$ -	0.00%
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	0.00%
1990	Other Tangible Property	$ -	$ -	$ -	0.00%
1995	Contributions & Grants	$(19,790,893)	$ 2,678,414	$ 367,800	2.50%
2440	Deferred Revenue	$ -	$ -	$ -	0.00%
	Total	**$ 81,886,262**	**$ (27,550,955)**	**$ (1,871,449)**	

Figure 40 – 2018 Test – MIFRS – Gross Asset & Depreciation Summary

USoA	Description	Gross Assets	Accumulated Amortization	Depreciation Expense	Depreciation Rate
1611	Computer Software (Formally known as Account 1925)	$ 1,719,158	$ (1,202,097)	$ (103,175)	20.00%
1612	Land Rights (Formally known as Account 1906)	$ 298,936	$ (28,783)	$ (5,515)	2.00%
1805	Land	$ 35,899	$ -	$ -	0.00%
1808	Buildings	$ -	$ -	$ -	0.00%
1810	Leasehold Improvements	$ -	$ -	$ -	0.00%
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	0.00%
1820	Distribution Station Equipment <50 kV	$ -	$ -	$ -	4.00%
1825	Storage Battery Equipment	$ -	$ -	$ -	0.00%
1830	Poles, Towers & Fixtures	$ 10,262,670	$ (1,683,686)	$ (177,447)	2.00%
1835	Overhead Conductors & Devices	$ 10,586,627	$ (3,389,106)	$ (118,491)	2.00%
1840	Underground Conduit	$ 14,829,081	$ (3,346,227)	$ (263,932)	2.50%
1845	Underground Conductors & Devices	$ 16,099,450	$ (5,991,824)	$ (341,450)	3.33%
1850	Line Transformers	$ 21,366,845	$ (6,563,719)	$ (348,809)	2.50%
1855	Services (Overhead & Underground)	$ 13,777,367	$ (3,442,245)	$ (213,267)	2.00%
1860	Meters	$ 9,945,259	$ (4,047,172)	$ (402,131)	4.00%
1860	Meters (Smart Meters)	$ -	$ -	$ -	0.00%
1905	Land	$ 190,119	$ -	$ -	0.00%
1908	Buildings & Fixtures	$ 3,170,540	$ (565,728)	$ (51,918)	2.00%
1910	Leasehold Improvements	$ -	$ -	$ -	0.00%
1915	Office Furniture & Equipment (10 years)	$ 236,760	$ (174,513)	$ (11,445)	10.00%
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	0.00%
1920	Computer Equipment - Hardware	$ 1,006,660	$ (388,539)	$ (121,790)	20.00%
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	0.00%
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	0.00%
1930	Transportation Equipment	$ 3,138,417	$ (939,104)	$ (273,932)	10.00%
1935	Stores Equipment	$ 147,367	$ (26,488)	$ (10,101)	10.00%
1940	Tools, Shop & Garage Equipment	$ 684,329	$ (333,549)	$ (49,066)	10.00%
1945	Measurement & Testing Equipment	$ 70,247	$ (55,542)	$ (5,458)	10.00%
1950	Power Operated Equipment	$ -	$ -	$ -	0.00%
1955	Communications Equipment	$ 294,423	$ (290,296)	$ (13,332)	10.00%
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	0.00%
1960	Miscellaneous Equipment	$ -	$ -	$ -	0.00%
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	0.00%
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	0.00%
1980	System Supervisor Equipment	$ -	$ -	$ -	0.00%
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	0.00%
1990	Other Tangible Property	$ -	$ -	$ -	0.00%
1995	Contributions & Grants	$(21,015,650)	$ 3,046,214	$ 398,418	2.50%
2440	Deferred Revenue	$ -	$ -	$ -	0.00%
	Total	**$ 86,844,505**	**$ (29,422,404)**	**$ (2,112,841)**	

4.11.2 Asset Retirement Obligations

EPLC does not have any material Asset Retirement Obligations ("AROs") to report as part of this Application. Further, EPLC confirms that it does not have any associated depreciation or accretion expense related to AROs.

4.11.3 Depreciation Practices – Useful Lives & Componentization

This section outlines EPLC's proposed changes to useful life changes since its previous Cost of Service Application.

In conjunction with the Kinetrics Report, EPLC staff completed a comprehensive review of its PP&E componentization to determine a reasonable level of componentization for its historical assets which included all historical costs and material components. As a result, EPLC adjusted its service lives within the ranges suggested within the Kinetrics Report and completed an assessment on the impact of remaining service life of its assets in order to calculate depreciation in 2013 looking forward. The resulting changes resulted in a material impact to EPLC's depreciation expense and a resulting material refund to EPLC electricity customers. The amount of this refund is recorded in Account 1576 and further outlined in Exhibit 9 of this Application.

Since EPLC transitioned to IFRS on January 1st, 2015, EPLC can no longer capitalize customer contributions as part of its net assets. As a result, EPLC will classify contributions as a deferred revenue liability and amortize the costs to revenue over the life of the asset for which the contribution relates to.

EPLC confirms that no additional depreciation expense policy change have been made since January 1st, 2013.

Additional information regarding EPLC's conversion to IFRS can be found in EPLC's Capitalization Policy included in Exhibit 2 of this Application.

Figure 41 below outlines the changes to asset useful lives, consistent with Board Appendix 2-BB and the Kinetrics Report. A copy of Board Appendix 2-BB is also included as Attachment 4-L of this Exhibit. EPLC does not have proposed changes that are outside of the suggested range contained within the Kinetrics Report and confirms that significant parts or components of each item of PP&E are being depreciated separately.

Figure 41 – Service Life Comparison

Parent*	#	Asset Details: Category| Component | Type			Useful Life: MIN UL	TUL	MAX UL	USoA Account Number	USoA Account Description	Current: Years	Current: Rate	Proposed: Years	Proposed: Rate	Outside Range of: Below Min TUL	Outside Range of: Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers and Fixtures	25	4%	50	2%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	2	Fully Dressed Concrete Poles	Overall		50	60	80	1830	Poles, Towers and Fixtures	25	4%	50	2%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	3	Fully Dressed Steel Poles	Overall		60	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	4	OH Line Switch			30	45	55								
	5	OH Line Switch Motor			15	25	25								
	6	OH Line Switch RTU			15	20	20								
	7	OH Integral Switches			35	45	60								
	8	OH Conductors			50	60	75	1835	Overhead Conductors and Devices	25	4%	50	2%	No	No
	9	OH Transformers & Voltage Regulators			30	40	60	1850	Line Transformers	25	4%	40	3%	No	No
	10	OH Shunt Capacitor Banks			25	30	40								
	11	Reclosers			25	40	55								
TS & MS	12	Power Transformers	Overall		30	45	60								
			Bushing		10	20	30								
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55								
	14	Station Grounding Transformer			30	40	40								
	15	Station DC System	Overall		10	20	30								
			Battery Bank		10	15	15								
			Charger		20	20	30								
	16	Station Metal Clad Switchgear	Overall		30	40	60								
			Removable Breaker		25	40	60								
	17	Station Independent Breakers			35	45	65								
	18	Station Switch			30	50	60								
	19	Electromechanical Relays			25	35	50								
	20	Solid State Relays			10	30	45								
	21	Digital & Numeric Relays			15	20	20								
	22	Rigid Busbars			30	55	60								
	23	Steel Structure			35	50	90								
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75								
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25								
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30								
	27	Primary Non-TR XLPE Cables in Duct			20	25	30								
	30	Secondary PILC Cables			70	75	80								
	31	Secondary Cables Direct Buried			25	35	40	1845	Underground Conductors and Devices	25	4%	30	3%	No	No
	32	Secondary Cables in Duct			35	40	60								
	33	Network Tranformers	Overall		20	35	50								
			Protector		20	35	40								
	34	Pad-Mounted Transformers			25	40	45	1850	Line Transformers	25	4%	40	3%	No	No
	35	Submersible/Vault Transformers			25	35	45								
	36	UG Foundation			35	55	70								
	37	UG Vaults	Overall		40	60	80								
			Roof		20	30	45								
	38	UG Vault Switches			20	35	50								
	39	Pad-Mounted Switchgear			20	30	45								
	40	Ducts			30	50	85	1840	Underground Conduit	25	4%	40	3%	No	No
	41	Concrete Encased Duct Banks			35	55	80								
	42	Cable Chambers			50	60	80								
S	43	Remote SCADA			15	20	30								

#	Asset Details: Category| Component | Type		Useful Life Range		USoA Account Number	USoA Account Description	Current Years	Current Rate	Proposed Years	Proposed Rate	Outside Range of Min, Max TUL? Below Min Range	Outside Range of Min, Max TUL? Above Max Range
1	Office Equipment		5	15	1915	Office Furniture and Equipment	10	10%	10	10%	No	No
2	Vehicles	Trucks & Buckets	5	15	1930	Transportation Equipment	8	13%	10	10%	No	No
		Trailers	5	20	1930	Transportation Equipment	5	20%	7	14%	No	No
		Vans	5	10	1930	Transportation Equipment	5	20%	7	14%	No	No
3	Administrative Buildings		50	75	1908	Buildings and Fixtures	25	4%	50	2%	No	No
4	Leasehold Improvements		Lease dependent									
5	Station Buildings	Station Buildings	50	75								
		Parking	25	30								
		Fence	25	60								
		Roof	20	30								
6	Computer Equipment	Hardware	3	5	1920	Computer Equipment - Hardware	5	20%	5	20%	No	No
		Software	2	5	1611	Computer Software	5	20%	5	20%	No	No
7	Equipment	Power Operated	5	10								
		Stores	5	10	1935	Stores Equipment	10	10%	10	10%	No	No
		Tools, Shop, Garage Equipment	5	10	1940	Tools, Shop and Garage Equipment	10	10%	10	10%	No	No
		Measurement & Testing Equipment	5	10	1945	Power Measurement & Test Equip	10	10%	10	10%	No	No
8	Communication	Towers	60	70								
		Wireless	2	10	1955	Communication Equipment	10	10%	10	10%	No	No
9	Residential Energy Meters		25	35								
10	Industrial/Commercial Energy Meters		25	35	1860	Meters	25	4%	25	4%	No	No
11	Wholesale Energy Meters		15	30	1860	Meters	25	4%	25	4%	No	No
12	Current & Potential Transformer (CT & PT)		35	50								
13	Smart Meters		5	15	1860	Meters	25	4%	15	7%	No	No
14	Repeaters - Smart Metering		10	15								
15	Data Collectors - Smart Metering		15	20								

4.11.4 Depreciation Expense

Consistent with Board Appendix 2-C, EPLC completed the following depreciation and amortization expense tables included as Figures 42-48 below. As specified in the Filing Requirements, EPLC completed 2-C for the following years and accounting standards:

- Figure 42 - 2013 CGAAP;
- Figure 43 - 2013 RCGAAP;
- Figure 44 - 2014 RCGAAP;
- Figure 45 - 2015 MIFRS
- Figure 46 - 2016 MIFRS
- Figure 47 - 2017 MIFRS;
- Figure 48 - 2018 MIFRS;

Variances identified in the tables below are the result of EPLC's historical treatment of contributed capital. Since the formation of EPLC and the amalgamation of its four municipal PUCs in 2000 and until 2008, EPLC allocated contributed capital among distribution assets for the purpose of depreciation calculation. This practice ended in 2009 and asset acquired after 2005 began to be depreciated based on their original capitalized values with a separate depreciation entry recorded to contributed capital. Assets acquired prior to 2005 continued to be depreciated with contributed capital allocations. All other variances are immaterial.

Figure 42 – Depreciation and Amortization Expense – 2013 CGAAP

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d - e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 415,096		$ 415,096			$ -	$ 66,055	2.67	37.45%	5	20.00%	$ 155,467	$ -	$ 6,605	$ 162,072	$ 84,022	-$ 78,050
1612	Land Rights (Formally known as Account 1906)	$ 105,692		$ 105,692			$ -	$ 60,262	46.50	2.15%	50	2.00%	$ 2,273	$ -	$ 603	$ 2,876	$ 2,902	$ 27
1805	Land	$ 47,899		$ 47,899			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 82,461		$ 82,461			$ -	$ 1,572	21.00	4.76%	25	4.00%	$ 3,927	$ -	$ 31	$ 3,958	$ 4,594	$ 636
1825	Storage Battery Equipment	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 5,420,962		$ 5,420,962			$ -	$ 427,090	20.08	4.98%	25	4.00%	$ 269,968	$ -	$ 8,542	$ 278,510	$ 219,433	-$ 59,077
1835	Overhead Conductors & Devices	$ 3,471,065		$ 3,471,065			$ -	$ 542,962	17.00	5.88%	25	4.00%	$ 204,180	$ -	$ 10,859	$ 215,040	$ 276,494	$ 61,454
1840	Underground Conduit	$ 8,282,816		$ 8,282,816			$ -	$ 914,367	19.08	5.24%	25	4.00%	$ 434,110	$ -	$ 18,287	$ 452,397	$ 346,792	-$ 105,606
1845	Underground Conductors & Devices	$ 7,075,569		$ 7,075,569			$ -	$ 1,015,489	18.00	5.56%	25	4.00%	$ 393,087	$ -	$ 20,310	$ 413,397	$ 480,111	$ 66,714
1850	Line Transformers	$ 10,116,755		$ 10,116,755			$ -	$ 1,487,986	20.00	5.00%	25	4.00%	$ 505,838	$ -	$ 29,760	$ 535,597	$ 635,746	$ 100,148
1855	Services (Overhead)	$ 1,066,258		$ 1,066,258			$ -	$ 307,890	18.00	5.56%	25	4.00%	$ 59,237	$ -	$ 6,158	$ 65,394	$ 60,875	-$ 4,520
1855	Services (Underground)	$ 4,734,149		$ 4,734,149			$ -	$ 620,242	19.08		25		$ 248,121	$ -	$ 12,405	$ 260,526	$ 291,278	$ 30,752
1860	Meters	$ 3,293,757		$ 3,293,757			$ -	$ 156,556	19.00	5.26%	25	4.00%	$ 173,356	$ -	$ 3,131	$ 176,487	$ 274,103	$ 97,616
1860	Meters (Smart Meters)	$ 554,186		$ 554,186			$ -	$ 37,316	24.50	4.08%	25	4.00%	$ 22,620	$ -	$ 746	$ 23,366	$ 31,148	$ 7,782
1905	Land	$ 190,119		$ 190,119			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 2,015,376		$ 2,015,376			$ -	$ 27,401	22.00	4.55%	25	4.00%	$ 91,608	$ -	$ 548	$ 92,156	$ 94,562	$ 2,406
1910	Leasehold Improvements	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 74,266		$ 74,266			$ -	$ 8,365	5.00	20.00%	5	20.00%	$ 14,853	$ -	$ 837	$ 15,690	$ 17,562	$ 1,872
1915	Office Furniture & Equipment (5 years)	$ -		$ -			$ -			0.00%	10	10.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 134,650		$ 134,650			$ -	$ 18,106	3.50	28.57%	5	20.00%	$ 38,471	$ -	$ 1,811	$ 40,282	$ 50,350	$ 10,068
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,043,171		$ 1,043,171			$ -	$ 382,064	8.80	11.36%	8	12.50%	$ 118,542	$ -	$ 23,879	$ 142,421	$ 273,213	$ 130,792
1935	Stores Equipment	$ 17,416		$ 17,416			$ -		7.85	12.74%	10	10.00%	$ 2,219	$ -	$ -	$ 2,219	$ 3,708	$ 1,489
1940	Tools, Shop & Garage Equipment	$ 204,435		$ 204,435			$ -	$ 54,159	7.33	13.64%	10	10.00%	$ 27,890	$ -	$ 2,708	$ 30,598	$ 33,574	$ 2,976
1945	Measurement & Testing Equipment	$ 39,772		$ 39,772			$ -		6.25	16.00%	10	10.00%	$ 6,363	$ -	$ -	$ 6,363	$ 6,399	$ 35
1950	Power Operated Equipment	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ 112,481		$ 112,481			$ -	$ 4,947	6.12	16.34%	10	10.00%	$ 18,379	$ -	$ 247	$ 18,627	$ 21,372	$ 2,745
1955	Communication Equipment (Smart Meters)	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls Customer Premises	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1985	Miscellaneous Fixed Assets	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 11,862,613		-$ 11,862,613			$ -	-$ 2,191,898	20.00	5.00%	25	4.00%	-$ 593,131	$ -	-$ 43,838	-$ 636,969	-$ 360,377	$ 276,592
	Total	$ 36,635,738	$ -	$ 36,635,738	$ -	$ -	$ -	$ 3,940,933					$ 2,197,378	$ -	$ 103,629	$ 2,301,007	$ 2,847,858	$ 546,850

Figure 43 – Depreciation and Amortization Expense – 2013 RCGAAP

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d - e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 415,096		$ 415,096			$ -	$ 66,055	2.67	37.45%	5.00	20.00%	$ 155,467	$ -	$ 6,605	$ 162,072	$ 342,040	$ 179,967
1612	Land Rights (Formally known as Account 1906)	$ 105,692		$ 105,692			$ -	$ 60,262	44.00	2.27%	50.00	2.00%	$ 2,402	$ -	$ 603	$ 3,005	$ 2,930	-$ 75
1805	Land	$ 47,899		$ 47,899			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 82,461		$ 82,461			$ -	$ 1,432	21.80	4.59%	25.00	4.00%	$ 3,783	$ -	$ 29	$ 3,811	$ 4,002	$ 191
1825	Storage Battery Equipment	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 5,420,962		$ 5,420,962			$ -	$ 388,994	45.50	2.20%	50.00	2.00%	$ 119,142	$ -	$ 3,890	$ 123,032	$ 148,490	$ 25,458
1835	Overhead Conductors & Devices	$ 3,471,065		$ 3,471,065			$ -	$ 494,530	44.00	2.27%	50.00	2.00%	$ 78,888	$ -	$ 4,945	$ 83,833	$ 95,859	$ 12,026
1840	Underground Conduit	$ 8,282,816		$ 8,282,816			$ -	$ 832,806	34.00	2.94%	40.00	2.50%	$ 243,612	$ -	$ 10,410	$ 254,022	$ 199,739	-$ 54,283
1845	Underground Conductors & Devices	$ 7,075,569		$ 7,075,569			$ -	$ 924,907	24.00	4.17%	30.00	3.33%	$ 294,815	$ -	$ 15,415	$ 310,230	$ 229,618	-$ 80,612
1850	Line Transformers	$ 10,116,755		$ 10,116,755			$ -	$ 1,355,258	34.00	2.94%	40.00	2.50%	$ 297,552	$ -	$ 16,941	$ 314,492	$ 326,072	$ 11,579
1855	Services (Overhead)	$ 1,066,258		$ 1,066,258			$ -	$ 279,903	44.00	2.27%	50.00	2.00%	$ 24,233	$ -	$ 2,799	$ 27,032	$ 28,434	$ 1,402
1855	Services (Underground)	$ 4,734,149		$ 4,734,149			$ -	$ 565,440	34.00	2.94%	40.00	2.50%	$ 139,240	$ -	$ 7,068	$ 146,308	$ 116,093	-$ 30,215
1860	Meters	$ 3,293,757		$ 3,293,757			$ -	$ 150,060	20.00	5.00%	25.00	4.00%	$ 164,688	$ -	$ 3,001	$ 167,689	$ 167,575	-$ 114
1860	Meters (Smart Meters)	$ 554,186		$ 554,186			$ -	$ 24,347	14.50	6.90%	15.00	6.67%	$ 38,220	$ -	$ 812	$ 39,031	$ 31,148	-$ 7,883
1905	Land	$ 190,119		$ 190,119			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 2,015,376		$ 2,015,376			$ -	$ 27,401	47.50	2.11%	50.00	2.00%	$ 42,429	$ -	$ 274	$ 42,703	$ 42,858	$ 155
1910	Leasehold Improvements	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 74,266		$ 74,266			$ -	$ 8,365	6.60	15.15%	10.00	10.00%	$ 11,252	$ -	$ 418	$ 11,671	$ 16,755	$ 5,085
1915	Office Furniture & Equipment (5 years)	$ -		$ -			$ -			0.00%	10.00	10.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 134,650		$ 134,650			$ -	$ 18,106	2.50	40.00%	5.00	20.00%	$ 53,860	$ -	$ 1,811	$ 55,670	$ 141,384	$ 85,714
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,043,171		$ 1,043,171			$ -	$ 382,064	13.00	7.69%	10.00	10.00%	$ 80,244	$ -	$ 19,103	$ 99,347	$ 157,920	$ 58,573
1935	Stores Equipment	$ 17,416		$ 17,416			$ -		8.00	12.50%	10.00	10.00%	$ 2,177	$ -	$ -	$ 2,177	$ 3,670	$ 1,493
1940	Tools, Shop & Garage Equipment	$ 204,435		$ 204,435			$ -	$ 54,159	7.60	13.16%	10.00	10.00%	$ 26,899	$ -	$ 2,708	$ 29,607	$ 58,184	$ 28,577
1945	Measurement & Testing Equipment	$ 39,772		$ 39,772			$ -			0.00%	10.00	10.00%	$ -	$ -	$ -	$ -	$ 11,669	$ 11,669
1950	Power Operated Equipment	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment	$ 112,481		$ 112,481			$ -	$ 4,947	5.00	20.00%	10.00	10.00%	$ 22,496	$ -	$ 247	$ 22,744	$ 59,435	$ 36,691
1955	Communication Equipment (Smart Meters)	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls Customer Premises	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1985	Miscellaneous Fixed Assets	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 11,862,613		-$ 11,862,613			$ -	-$ 2,191,898	33.50	2.99%	40.00	2.50%	-$ 354,108	$ -	-$ 27,399	-$ 381,507	-$ 278,492	$ 103,015
	Total	$ 36,635,738	$ -	$ 36,635,738	$ -	$ -	$ -	$ 3,447,138					$ 1,447,291	$ -	$ 69,680	$ 1,516,971	$ 1,905,383	$ 388,412

Figure 44 – Depreciation and Amortization Expense – 2014 RCGAAP

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 415,096	$ 155,466.71	$ 259,629	$ 66,055		$ 66,055	$ 74,868	2.67	37.45%	5.00	20.00%	$ 97,239	$ 13,211	$ 7,487	$ 117,937	$ 75,831	-$ 42,106
1612	Land Rights (Formally known as Account 1906)	$ 105,692	$ 2,402.08	$ 103,290	$ 60,262		$ 60,262	$ 15,071	43.00	2.33%	50.00	2.00%	$ 2,402	$ 1,205	$ 151	$ 3,758	$ 3,679	-$ 79
1805	Land	$ 47,899	$ -	$ 47,899	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 82,461	$ 3,782.59	$ 78,678	$ 1,432		$ 1,432		20.80	4.81%	25.00	4.00%	$ 3,783	$ 57	$ -	$ 3,840	$ 3,599	-$ 240
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 5,420,962	$ 119,142.02	$ 5,301,820	$ 388,994		$ 388,994	$ 490,624	44.50	2.25%	50.00	2.00%	$ 119,142	$ 7,780	$ 4,906	$ 131,828	$ 129,121	-$ 2,707
1835	Overhead Conductors & Devices	$ 3,471,065	$ 78,887.84	$ 3,392,177	$ 494,530		$ 494,530	$ 431,488	43.00	2.33%	50.00	2.00%	$ 78,888	$ 9,891	$ 4,315	$ 93,093	$ 73,359	-$ 19,734
1840	Underground Conduit	$ 8,282,816	$ 243,612.24	$ 8,039,204	$ 832,806		$ 832,806	$ 1,250,716	33.00	3.03%	40.00	2.50%	$ 243,612	$ 20,820	$ 15,634	$ 280,066	$ 122,833	-$ 157,234
1845	Underground Conductors & Devices	$ 7,075,569	$ 294,815.36	$ 6,780,753	$ 924,907		$ 924,907	$ 839,997	23.00	4.35%	30.00	3.33%	$ 294,815	$ 30,830	$ 14,000	$ 339,646	$ 365,105	$ 25,460
1850	Line Transformers	$ 10,116,755	$ 297,551.62	$ 9,819,203	$ 1,355,258		$ 1,355,258	$ 1,287,293	33.00	3.03%	40.00	2.50%	$ 297,552	$ 33,881	$ 16,091	$ 347,524	$ 353,494	$ 5,970
1855	Services (Overhead & Underground)	$ 1,066,258	$ 24,233.15	$ 1,042,025	$ 279,903		$ 279,903	$ 274,859	43.00	2.33%	50.00	2.00%	$ 24,233	$ 5,598	$ 2,749	$ 32,580	$ 34,973	$ 2,393
1855	Services (Underground)	$ 4,734,149	$ 139,239.68	$ 4,594,909	$ 565,440		$ 565,440	$ 770,067	33.00	3.03%	40.00	2.50%	$ 139,240	$ 14,136	$ 9,626	$ 163,002	$ 131,827	-$ 31,175
1860	Meters	$ 3,293,757	$ 164,687.86	$ 3,129,069	$ 150,060		$ 150,060	$ 68,368	19.00	5.26%	25.00	4.00%	$ 164,688	$ 6,002	$ 1,367	$ 172,058	$ 178,821	$ 6,763
1860	Meters (Smart Meters)	$ 554,186	$ 38,219.73	$ 515,966	$ 24,347		$ 24,347	$ 26,539	13.50	7.41%	15.00	6.67%	$ 38,220	$ 1,623	$ 885	$ 40,728	$ 23,884	-$ 16,844
1905	Land	$ 190,119	$ -	$ 190,119	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 2,015,376	$ 42,428.97	$ 1,972,947	$ 27,401		$ 27,401		46.50	2.15%	50.00	2.00%	$ 42,429	$ 548	$ -	$ 42,977	$ 27,100	-$ 15,877
1910	Leasehold Improvements	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 74,266	$ 11,252.46	$ 63,014	$ 8,365		$ 8,365	$ 1,499	5.60	17.86%	10.00	10.00%	$ 11,252	$ 837	$ 75	$ 12,164	$ 17,979	$ 5,816
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -		$ -			0.00%	10.00	10.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 134,650	$ 53,859.81	$ 80,790	$ 18,106		$ 18,106	$ 43,348	1.50	66.67%	5.00	20.00%	$ 53,860	$ 3,621	$ 4,335	$ 61,816	$ 4,346	-$ 57,470
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,043,171	$ 80,243.92	$ 962,927	$ 382,064		$ 382,064	$ 425,100	12.00	8.33%	10.00	10.00%	$ 80,244	$ 38,206	$ 21,255	$ 139,705	$ 146,305	$ 6,599
1935	Stores Equipment	$ 17,416	$ 2,177.04	$ 15,239	$ -		$ -		7.00	14.29%	10.00	10.00%	$ 2,177	$ -	$ -	$ 2,177	$ 2,673	$ 496
1940	Tools, Shop & Garage Equipment	$ 204,435	$ 26,899.30	$ 177,535	$ 54,159		$ 54,159	$ 78,333	6.60	15.15%	10.00	10.00%	$ 26,899	$ 5,416	$ 3,917	$ 36,232	$ 63,233	$ 27,002
1945	Measurement & Testing Equipment	$ 39,772	$ -	$ 39,772	$ -		$ -			0.00%	10.00	10.00%	$ -	$ -	$ -	$ -	$ 11,235	$ 11,235
1950	Power Operated Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ 112,481	$ 22,496.19	$ 89,985	$ 4,947		$ 4,947		4.00	25.00%	10.00	10.00%	$ 22,496	$ 495	$ -	$ 22,991	$ 43,937	$ 20,946
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 11,862,613	-$ 354,107.85	-$ 11,508,505	-$ 2,191,898		-$ 2,191,898	-$ 1,122,171	32.50	3.08%	40.00	2.50%	-$ 354,108	-$ 54,797	-$ 14,027	-$ 422,932	-$ 247,371	$ 175,561
	Total	$ 36,635,738	$ 1,447,291	$ 35,188,447	$ 3,447,138	$ -	$ 3,447,138	$ 4,955,998					$ 1,389,063	$ 139,361	$ 92,764	$ 1,621,189	$ 1,565,965	-$ 55,224

Figure 45 – Depreciation and Amortization Expense – 2015 MIFRS

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d-e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 415,096	$ 252,706	$ 162,390	$ 140,923		$ 140,923	$ 17,043	2.50	40.00%	5.00	20.00%	$ 64,956	$ 28,185	$ 1,704	$ 94,845	$ 75,579	-$ 19,266
1612	Land Rights (Formally known as Account 1906)	$ 105,692	$ 4,804	$ 100,887	$ 75,333		$ 75,333	$ 14,661	42.00	2.38%	50.00	2.00%	$ 2,402	$ 1,507	$ 147	$ 4,055	$ 3,983	-$ 72
1805	Land	$ 47,899	$ -	$ 47,899	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 82,461	$ 7,565	$ 74,895	$ 1,432	$ 1,432	-$ 0		19.80	5.05%	25.00	4.00%	$ 3,783	-$ 0	$ -	$ 3,783	$ -	-$ 3,783
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 5,420,962	$ 238,284	$ 5,182,678	$ 879,618		$ 879,618	$ 934,800	43.50	2.30%	50.00	2.00%	$ 119,142	$ 17,592	$ 9,348	$ 146,082	$ 133,666	-$ 12,416
1835	Overhead Conductors & Devices	$ 3,471,065	$ 157,776	$ 3,313,289	$ 926,017		$ 926,017	$ 990,160	42.00	2.38%	50.00	2.00%	$ 78,888	$ 18,520	$ 9,902	$ 107,310	$ 73,557	-$ 33,753
1840	Underground Conduit	$ 8,282,816	$ 487,224	$ 7,795,592	$ 2,083,521		$ 2,083,521	$ 279,301	32.00	3.13%	40.00	2.50%	$ 243,612	$ 52,088	$ 3,491	$ 299,192	$ 226,513	-$ 72,679
1845	Underground Conductors & Devices	$ 7,075,569	$ 575,441	$ 6,500,128	$ 1,764,904		$ 1,764,904	$ 584,507	22.00	4.55%	30.00	3.33%	$ 295,460	$ 58,830	$ 9,742	$ 364,032	$ 287,646	-$ 76,386
1850	Line Transformers	$ 10,116,755	$ 595,103	$ 9,521,652	$ 2,642,551		$ 2,642,551	$ 923,100	32.00	3.13%	40.00	2.50%	$ 297,552	$ 66,064	$ 11,539	$ 375,154	$ 287,574	-$ 87,580
1855	Services (Overhead)	$ 1,066,258	$ 48,466	$ 1,017,792	$ 554,762		$ 554,762	$ 197,869	42.00	2.38%	50.00	2.00%	$ 24,233	$ 11,095	$ 1,979	$ 37,307	$ 28,760	-$ 8,547
1855	Services (Underground)	$ 4,734,149	$ 278,479	$ 4,455,670	$ 1,335,508		$ 1,335,508	$ 864,431	32.00	3.13%	40.00	2.50%	$ 139,240	$ 33,388	$ 10,805	$ 183,433	$ 129,512	-$ 53,921
1860	Meters	$ 3,293,757	$ 329,376	$ 2,964,381	$ 218,427		$ 218,427	$ 241,104	18.00	5.56%	25.00	4.00%	$ 164,688	$ 8,737	$ 4,822	$ 178,247	$ 139,296	-$ 38,951
1860	Meters (Smart Meters)	$ 554,186	$ 76,439	$ 477,747	$ 50,886		$ 50,886	$ 3,196,304	12.50	8.00%	15.00	6.67%	$ 38,220	$ 3,392	$ 106,543	$ 148,156	$ 244,350	$ 96,194
1905	Land	$ 190,119	$ -	$ 190,119	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 2,015,376	$ 84,858	$ 1,930,518	$ 27,401		$ 27,401	$ 48,914	45.50	2.20%	50.00	2.00%	$ 42,429	$ 548	$ 489	$ 43,466	$ 41,157	-$ 2,309
1910	Leasehold Improvements	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 74,266	$ 22,505	$ 51,761	$ 9,864		$ 9,864	$ 5,980	4.60	21.74%	10.00	10.00%	$ 11,252	$ 986	$ 299	$ 12,538	$ 8,342	-$ 4,196
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -		$ -			0.00%	10.00	10.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 134,650	$ 107,720	$ 26,930	$ 61,454		$ 61,454	$ 3,875	0.50	200.00%	5.00	20.00%	$ 53,860	$ 12,291	$ 388	$ 66,538	$ 35,385	-$ 31,153
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,043,171	$ 160,488	$ 882,683	$ 807,164		$ 807,164	$ 402,157	11.00	9.09%	10.00	10.00%	$ 80,244	$ 80,716	$ 20,108	$ 181,068	$ 189,589	$ 8,521
1935	Stores Equipment	$ 17,416	$ 4,354	$ 13,062	$ -		$ -	$ 17	6.00	16.67%	10.00	10.00%	$ 2,177	$ -	$ 1	$ 2,178	$ 2,198	$ 20
1940	Tools, Shop & Garage Equipment	$ 204,435	$ 53,799	$ 150,636	$ 132,492		$ 132,492	$ 56,539	5.60	17.86%	10.00	10.00%	$ 26,899	$ 13,249	$ 2,827	$ 42,975	$ 42,042	-$ 933
1945	Measurement & Testing Equipment	$ 39,772	$ -	$ 39,772	$ -		$ -			0.00%	10.00	10.00%	$ -	$ -	$ -	$ -	$ 6,269	$ 6,269
1950	Power Operated Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ 112,481	$ 44,992	$ 67,489	$ 4,947		$ 4,947	$ 12,943	3.00	33.33%	10.00	10.00%	$ 22,496	$ 495	$ 647	$ 23,638	$ 29,553	$ 5,915
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 11,862,613	-$ 708,216	-$ 11,154,397	-$ 3,314,069		-$ 3,314,069	-$ 1,448,183	31.50	3.17%	40.00	2.50%	-$ 354,108	-$ 82,852	-$ 18,102	-$ 455,062	-$ 552,530	-$ 97,468
	Total	$ 36,635,738	$ 2,822,164	$ 33,813,573	$ 8,403,136	$ 1,432	$ 8,401,704	$ 7,325,523					$ 1,357,425	$ 324,832	$ 176,678	$ 1,858,935	$ 1,432,441	-$ 426,495

Figure 46 – Depreciation and Amortization Expense – 2016 MIFRS

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1)[1]	Less Fully Depreciated[7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change[2]	Less Fully Depreciated[8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change[3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change[4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions[5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance[6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 415,096	$ 317,662	$ 97,434	$ 157,966		$ 157,966	$ 5,217	2.50	40.00%	5.00	20.00%	$ 38,974	$ 31,593	$ 522	$ 71,088	$ 63,196	-$ 7,892
1612	Land Rights (Formally known as Account 1906)	$ 105,692	$ 7,206	$ 98,485	$ 89,994		$ 89,994	$ 2,644	41.00	2.44%	50.00	2.00%	$ 2,402	$ 1,800	$ 26	$ 4,228	$ 4,114	-$ 114
1805	Land	$ 47,899	$ -	$ 47,899	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 82,461	$ 11,348	$ 71,113	-$ 0		-$ 0		18.80	5.32%	25.00	4.00%	$ 3,783	-$ 0	$ -	$ 3,783		-$ 3,783
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 5,420,962	$ 357,426	$ 5,063,536	$ 1,814,418		$ 1,814,418	$ 598,652	42.50	2.35%	50.00	2.00%	$ 119,142	$ 36,288	$ 5,987	$ 161,417	$ 148,824	-$ 12,593
1835	Overhead Conductors & Devices	$ 3,471,065	$ 236,664	$ 3,234,402	$ 1,916,177		$ 1,916,177	$ 956,400	41.00	2.44%	50.00	2.00%	$ 78,888	$ 38,324	$ 9,564	$ 126,775	$ 89,922	-$ 36,853
1840	Underground Conduit	$ 8,282,816	$ 730,837	$ 7,551,979	$ 2,362,822		$ 2,362,822	$ 213,140	31.00	3.23%	40.00	2.50%	$ 243,612	$ 59,071	$ 2,664	$ 305,347	$ 232,711	-$ 72,636
1845	Underground Conductors & Devices	$ 7,075,569	$ 870,901	$ 6,204,668	$ 2,349,411		$ 2,349,411	$ 577,705	21.00	4.76%	30.00	3.33%	$ 295,460	$ 78,314	$ 9,628	$ 383,402	$ 293,497	-$ 89,905
1850	Line Transformers	$ 10,116,755	$ 892,655	$ 9,224,100	$ 3,565,651		$ 3,565,651	$ 774,929	31.00	3.23%	40.00	2.50%	$ 297,552	$ 89,141	$ 9,687	$ 396,380	$ 334,035	-$ 62,345
1855	Services (Overhead)	$ 1,066,258	$ 72,699	$ 993,559	$ 752,631		$ 752,631	$ 227,956	41.00	2.44%	50.00	2.00%	$ 24,233	$ 15,053	$ 2,280	$ 41,565	$ 22,691	-$ 18,874
1855	Services (Underground)	$ 4,734,149	$ 417,719	$ 4,316,430	$ 2,199,939		$ 2,199,939	$ 665,323	31.00	3.23%	40.00	2.50%	$ 139,240	$ 54,998	$ 8,317	$ 202,555	$ 155,919	-$ 46,636
1860	Meters	$ 3,293,757	$ 494,064	$ 2,799,694	$ 459,531		$ 459,531	$ 411,948	17.00	5.88%	25.00	4.00%	$ 164,688	$ 18,381	$ 8,239	$ 191,308	$ 96,476	-$ 94,832
1860	Meters (Smart Meters)	$ 554,186	$ 114,659	$ 439,527	$ 3,247,190		$ 3,247,190	$ 66,961	11.50	8.70%	15.00	6.67%	$ 38,220	$ 216,479	$ 2,232	$ 256,931	$ 278,118	$ 21,187
1905	Land	$ 190,119	$ -	$ 190,119	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 2,015,376	$ 127,287	$ 1,888,089	$ 76,315		$ 76,315	$ 42,469	44.50	2.25%	50.00	2.00%	$ 42,429	$ 1,526	$ 425	$ 44,380	$ 42,169	-$ 2,211
1910	Leasehold Improvements	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 74,266	$ 33,757	$ 40,509	$ 15,844		$ 15,844	$ 20,672	3.60	27.78%	10.00	10.00%	$ 11,252	$ 1,584	$ 1,034	$ 13,870	$ 9,697	-$ 4,173
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -		$ -			0.00%	10.00	10.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 134,650	$ 161,579	-$ 26,930	$ 65,329		$ 65,329	$ 117,329		0.00%	5.00	20.00%	$ -	$ 13,066	$ 11,733	$ 24,799	$ 11,815	-$ 12,984
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,043,171	$ 240,732	$ 802,439	$ 1,209,321		$ 1,209,321	$ 136,662	10.00	10.00%	10.00	10.00%	$ 80,244	$ 120,932	$ 6,833	$ 208,009	$ 213,884	$ 5,875
1935	Stores Equipment	$ 17,416	$ 6,531	$ 10,885	$ 17		$ 17	$ 10,275	5.00	20.00%	10.00	10.00%	$ 2,177	$ 2	$ 514	$ 2,692	$ 2,701	$ 9
1940	Tools, Shop & Garage Equipment	$ 204,435	$ 80,698	$ 123,737	$ 189,031		$ 189,031	$ 45,830	4.60	21.74%	10.00	10.00%	$ 26,899	$ 18,903	$ 2,292	$ 48,094	$ 46,828	-$ 1,266
1945	Measurement & Testing Equipment	$ 39,772	$ -	$ 39,772	$ -		$ -	$ 6,260		0.00%	10.00	10.00%	$ -	$ -	$ 313	$ 313	$ 6,599	$ 6,286
1950	Power Operated Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ 112,481	$ 67,489	$ 44,992	$ 17,890		$ 17,890		2.00	50.00%	10.00	10.00%	$ 22,496	$ 1,789	$ -	$ 24,285	$ 29,874	$ 5,589
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 11,862,613	-$ 1,062,324	-$ 10,800,289	-$ 4,762,252		-$ 4,762,252	-$ 931,021	30.50	3.28%	40.00	2.50%	-$ 354,108	-$ 119,056	-$ 11,638	-$ 484,802	-$ 589,771	-$ 104,969
	Total	$ 36,635,738	$ 4,179,589	$ 32,456,148	$ 15,727,226	$ -	$ 15,727,226	$ 3,949,352					$ 1,277,583	$ 678,188	$ 70,650	$ 2,026,421	$ 1,493,299	-$ 533,122

Figure 47 – Depreciation and Amortization Expense – 2017 MIFRS

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 415,096	$ 356,636	$ 58,460	$ 163,183		$ 163,183	$ 254,500	1.00	100.00%	5.00	20.00%	$ 58,460	$ 32,637	$ 25,450	$ 116,547	$ 81,624	-$ 34,923
1612	Land Rights (Formally known as Account 1906)	$ 105,692	$ 9,608	$ 96,083	$ 92,638		$ 92,638	$ 42,192	40.00	2.50%	50.00	2.00%	$ 2,402	$ 1,853	$ 422	$ 4,677	$ 4,604	-$ 73
1805	Land	$ 47,899	$ -	$ 47,899	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 82,461	$ 15,130	$ 67,330	-$ 0		-$ 0		17.80	5.62%	25.00	4.00%	$ 3,783	-$ 0	$ -	$ 3,783		-$ 3,783
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 5,420,962	$ 476,568	$ 4,944,394	$ 2,413,070		$ 2,413,070	$ 932,338	41.50	2.41%	50.00	2.00%	$ 119,142	$ 48,261	$ 9,323	$ 176,727	$ 163,794	-$ 12,933
1835	Overhead Conductors & Devices	$ 3,471,065	$ 315,551	$ 3,155,514	$ 2,872,577		$ 2,872,577	$ 541,648	40.00	2.50%	50.00	2.00%	$ 78,888	$ 57,452	$ 5,416	$ 141,756	$ 104,679	-$ 37,077
1840	Underground Conduit	$ 8,282,816	$ 974,449	$ 7,308,367	$ 2,575,962		$ 2,575,962	$ 734,410	30.00	3.33%	40.00	2.50%	$ 243,612	$ 64,399	$ 9,180	$ 317,191	$ 243,945	-$ 73,246
1845	Underground Conductors & Devices	$ 7,075,569	$ 1,166,361	$ 5,909,207	$ 2,927,116		$ 2,927,116	$ 788,211	20.00	5.00%	30.00	3.33%	$ 295,460	$ 97,571	$ 13,137	$ 406,168	$ 314,089	-$ 92,079
1850	Line Transformers	$ 10,116,755	$ 1,190,206	$ 8,926,549	$ 4,340,580		$ 4,340,580	$ 1,025,570	30.00	3.33%	40.00	2.50%	$ 297,552	$ 108,514	$ 12,820	$ 418,886	$ 322,980	-$ 95,906
1855	Services (Overhead & Underground)	$ 1,066,258	$ 96,933	$ 969,326	$ 980,588		$ 980,588	$ 205,679	40.00	2.50%	50.00	2.00%	$ 24,233	$ 19,612	$ 2,057	$ 45,902	$ 22,691	-$ 23,211
1855	Services (Underground)	$ 4,734,149	$ 556,959	$ 4,177,190	$ 2,865,262		$ 2,865,262	$ 617,036	30.00	3.33%	40.00	2.50%	$ 139,240	$ 71,632	$ 7,713	$ 218,584	$ 174,345	-$ 44,239
1860	Meters	$ 3,293,757	$ 658,751	$ 2,635,006	$ 871,479		$ 871,479	$ 266,932	16.00	6.25%	25.00	4.00%	$ 164,688	$ 34,859	$ 5,339	$ 204,886	$ 106,260	-$ 98,626
1860	Meters (Smart Meters)	$ 554,186	$ 152,879	$ 401,307	$ 3,314,151		$ 3,314,151		10.50	9.52%	15.00	6.67%	$ 38,220	$ 220,943	$ -	$ 259,163	$ 278,118	$ 18,955
1905	Land	$ 190,119	$ -	$ 190,119	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -	$ 45,350	$ 45,350
1908	Buildings & Fixtures	$ 2,015,376	$ 169,716	$ 1,845,660	$ 118,784		$ 118,784	$ 286,800	43.50	2.30%	50.00	2.00%	$ 42,429	$ 2,376	$ 2,868	$ 47,673		-$ 47,673
1910	Leasehold Improvements	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -	$ 11,209	$ 11,209
1915	Office Furniture & Equipment (10 years)	$ 74,266	$ 45,010	$ 29,256	$ 36,516		$ 36,516	$ 10,000	2.60	38.46%	10.00	10.00%	$ 11,252	$ 3,652	$ 500	$ 15,404		-$ 15,404
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -		$ -			0.00%	10.00	10.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 134,650	$ 161,579	-$ 26,930	$ 182,658		$ 182,658	$ 356,150		0.00%	5.00	20.00%	$ -	$ 36,532	$ 35,615	$ 72,147	$ 73,917	$ 1,770
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,043,171	$ 320,976	$ 722,195	$ 1,345,983		$ 1,345,983	$ 487,000	9.00	11.11%	10.00	10.00%	$ 80,244	$ 134,598	$ 24,350	$ 239,192	$ 211,990	-$ 27,202
1935	Stores Equipment	$ 17,416	$ 8,708	$ 8,708	$ 10,292		$ 10,292	$ 50,000	4.00	25.00%	10.00	10.00%	$ 2,177	$ 1,029	$ 2,500	$ 5,706	$ 5,708	$ 2
1940	Tools, Shop & Garage Equipment	$ 204,435	$ 107,597	$ 96,837	$ 234,861		$ 234,861	$ 60,000	3.60	27.78%	10.00	10.00%	$ 26,899	$ 23,486	$ 3,000	$ 53,385	$ 52,011	-$ 1,374
1945	Measurement & Testing Equipment	$ 39,772	$ -	$ 39,772	$ 6,260		$ 6,260			0.00%	10.00	10.00%	$ -	$ 626	$ -	$ 626	$ 6,895	$ 6,269
1950	Power Operated Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ 112,481	$ 89,985	$ 22,496	$ 17,890		$ 17,890		1.00	100.00%	10.00	10.00%	$ 22,496	$ 1,789	$ -	$ 24,285	$ 15,040	-$ 9,245
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 11,862,613	-$ 1,416,431	-$ 10,446,182	-$ 5,693,273		-$ 5,693,273	-$ 1,224,757	29.50	3.39%	40.00	2.50%	-$ 354,108	-$ 142,332	-$ 15,309	-$ 511,749	-$ 367,800	$ 143,949
	Total	**$ 36,635,738**	**$ 5,457,172**	**$ 31,178,566**	**$ 19,676,578**	**$ -**	**$ 19,676,578**	**$ 5,433,708**					**$ 1,297,070**	**$ 819,488**	**$ 144,380**	**$ 2,260,938**	**$ 1,871,449**	**-$ 389,489**

Figure 48 – Depreciation and Amortization Expense – 2018 MIFRS

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 415,096	$ 415,096	$ -	$ 417,683		$ 417,683	$ 115,000		0.00%	5.00	20.00%	$ -	$ 83,537	$ 11,500	$ 95,037	$ 103,175	$ 8,138
1612	Land Rights (Formally known as Account 1906)	$ 105,692	$ 12,010	$ 93,681	$ 134,830		$ 134,830	$ 48,941	39.00	2.56%	50.00	2.00%	$ 2,402	$ 2,697	$ 489	$ 5,588	$ 5,515	-$ 73
1805	Land	$ 47,899	$ -	$ 47,899	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 82,461	$ 18,913	$ 63,548	-$ 0		-$ 0		16.80	5.95%	25.00	4.00%	$ 3,783	-$ 0	$ -	$ 3,783		-$ 3,783
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 5,420,962	$ 595,710	$ 4,825,252	$ 3,345,408		$ 3,345,408	$ 432,914	40.50	2.47%	50.00	2.00%	$ 119,142	$ 66,908	$ 4,329	$ 190,379	$ 177,447	-$ 12,932
1835	Overhead Conductors & Devices	$ 3,471,065	$ 394,439	$ 3,076,626	$ 3,414,225		$ 3,414,225	$ 839,476	39.00	2.56%	50.00	2.00%	$ 78,888	$ 68,285	$ 8,395	$ 155,567	$ 118,491	-$ 37,076
1840	Underground Conduit	$ 8,282,816	$ 1,218,061	$ 7,064,755	$ 3,310,372		$ 3,310,372	$ 864,559	29.00	3.45%	40.00	2.50%	$ 243,612	$ 82,759	$ 10,807	$ 337,179	$ 263,932	-$ 73,247
1845	Underground Conductors & Devices	$ 7,075,569	$ 1,461,822	$ 5,613,747	$ 3,715,327		$ 3,715,327	$ 853,466	19.00	5.26%	30.00	3.33%	$ 295,460	$ 123,844	$ 14,224	$ 433,529	$ 341,450	-$ 92,079
1850	Line Transformers	$ 10,116,755	$ 1,487,758	$ 8,628,997	$ 5,366,150		$ 5,366,150	$ 1,040,794	29.00	3.45%	40.00	2.50%	$ 297,552	$ 134,154	$ 13,010	$ 444,715	$ 348,809	-$ 95,906
1855	Services (Overhead)	$ 1,066,258	$ 121,166	$ 945,093	$ 1,186,266		$ 1,186,266	$ 200,093	39.00	2.56%	50.00	2.00%	$ 24,233	$ 23,725	$ 2,001	$ 49,959	$ 22,691	-$ 27,268
1855	Services (Underground)	$ 4,734,149	$ 696,198	$ 4,037,951	$ 3,482,298		$ 3,482,298	$ 600,278	29.00	3.45%	40.00	2.50%	$ 139,240	$ 87,057	$ 7,503	$ 233,801	$ 190,576	-$ 43,225
1860	Meters	$ 3,293,757	$ 823,439	$ 2,470,318	$ 1,138,411		$ 1,138,411	$ 265,671	15.00	6.67%	25.00	4.00%	$ 164,688	$ 45,536	$ 5,313	$ 215,538	$ 124,013	-$ 91,524
1860	Meters (Smart Meters)	$ 554,186	$ 191,099	$ 363,087	$ 3,314,151		$ 3,314,151		9.50	10.53%	15.00	6.67%	$ 38,220	$ 220,943	$ -	$ 259,163	$ 278,118	$ 18,955
1905	Land	$ 190,119	$ -	$ 190,119	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 2,015,376	$ 212,145	$ 1,803,231	$ 405,584		$ 405,584	$ 370,000	42.50	2.35%	50.00	2.00%	$ 42,429	$ 8,112	$ 3,700	$ 54,241	$ 51,918	-$ 2,323
1910	Leasehold Improvements	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 74,266	$ 56,262	$ 18,004	$ 46,516		$ 46,516	$ 10,000	1.60	62.50%	10.00	10.00%	$ 11,252	$ 4,652	$ 500	$ 16,404	$ 11,445	-$ 4,959
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -		$ -			0.00%	10.00	10.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 134,650	$ 161,579	-$ 26,930	$ 538,808		$ 538,808	$ 161,809		0.00%	5.00	20.00%	$ -	$ 107,762	$ 16,181	$ 123,942	$ 121,790	-$ 2,152
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,043,171	$ 401,220	$ 641,951	$ 1,832,983		$ 1,832,983	$ 270,000	8.00	12.50%	10.00	10.00%	$ 80,244	$ 183,298	$ 13,500	$ 277,042	$ 273,932	-$ 3,110
1935	Stores Equipment	$ 17,416	$ 10,885	$ 6,531	$ 60,292		$ 60,292	$ 50,000	3.00	33.33%	10.00	10.00%	$ 2,177	$ 6,029	$ 2,500	$ 10,706	$ 10,101	-$ 605
1940	Tools, Shop & Garage Equipment	$ 204,435	$ 134,497	$ 69,938	$ 294,861		$ 294,861	$ 60,000	2.60	38.46%	10.00	10.00%	$ 26,899	$ 29,486	$ 3,000	$ 59,385	$ 49,066	-$ 10,319
1945	Measurement & Testing Equipment	$ 39,772	$ -	$ 39,772	$ 6,260		$ 6,260			0.00%	10.00	10.00%	$ -	$ 626	$ -	$ 626	$ 5,458	$ 4,832
1950	Power Operated Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ 112,481	$ 112,481	$ -	$ 17,890		$ 17,890		-	0.00%	10.00	10.00%	$ -	$ 1,789	$ -	$ 1,789	$ 13,332	$ 11,543
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 11,862,613	-$ 1,770,539	-$ 10,092,074	-$ 6,918,030		-$ 6,918,030	-$ 1,224,757	28.50	3.51%	40.00	2.50%	-$ 354,108	-$ 172,951	-$ 15,309	-$ 542,368	-$ 398,418	$ 143,950
	Total	$ 36,635,738	$ 6,754,242	$ 29,881,496	$ 25,110,286	$ -	$ 25,110,286	$ 4,958,243					$ 1,216,113	$ 1,108,248	$ 101,644	$ 2,426,005	$ 2,112,841	-$ 313,164

4.12 PILs & Property Tax

4.12.1 PILs

As per Section 93 of the Electricity Act, the Income Tax Act (Canada) and the Corporations Tax Act (Ontario), EPLC is subject to Payments In Lieu (“PILs”). A copy of EPLC’s 2016 Federal & Provincial Income Tax Returns are included as Attachment 4-N of this Exhibit.

EPLC confirms that the 2016 audited financial statements filed with this Application are the same 2016 audited financial statements filed with its Federal & Provincial Income Tax Returns.

EPLC has calculated PILs of $227,249 using the Board’s Test Year Income Tax/PILs Workform. EPLC’s Test Year Income Tax/PILs Workform is included as Attachment 4-O.

EPLC determined the estimated 2018 Test Year PILs by applying the 2017 tax rates against EPLC’s projected Taxable Income for 2018 Test Year.

Utility Income Before Taxes

EPLC calculated 2018 Test Year Utility Income Before Taxes by subtracting 2018 expected revenue and 2018 expected expenses. The resulting 2018 Utility Income Before Taxes has been calculated as $2,104,644. Further information relating to this calculation can be found in Exhibit 6, Section 6.6.

Tax Adjustments

For the purpose of this Application, EPLC has included Tax Adjustments to account for significant temporary differences and reserves. The differences include adjustments for the difference between accounting depreciation and Capital Cost Allowance (“CCA”) for tax purposes as well as the opening and closing differences for financial statement reserves. Figure 49 below outlines EPLC’s calculation for Taxable Income for the 2018 Test Year.

Figure 49 – 2018 Test Year Taxable Income

Taxable Income - Test Year

	T2 S1 line #	Working Paper Reference	Test Year Taxable Income
Net Income Before Taxes		A.	2,104,644
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets 2-4 ADJUSTED ACCOUNTING DATA P489	104		2,391,096
Amortization of intangible assets 2-4 ADJUSTED ACCOUNTING DATA P490	106		108,587
Non-deductible meals and entertainment expense	121		1,900
Non-deductible penalties	293		5,974
Amortization of deferred charge	294		175,472
Post employment benefits paid	295		220,000
Total Additions			**2,903,029**
Deductions:			
Capital cost allowance from Schedule 8	403	T8	4,221,702
Post-employment benefits	394		155,676
Total Deductions		calculated	**4,377,378**
NET INCOME FOR TAX PURPOSES		calculated	**630,295**
REGULATORY TAXABLE INCOME		calculated	**630,295**

Expected 2018 Tax Rates

For the purpose of this Application, EPLC estimated a combined income tax rate of 26.5% for the 2018 Test Year.

Calculation of Tax Credits

For the purpose of this Application, EPLC does not currently estimate the realization of any Income Tax Credits.

Tax Calculation

Please see Figure 50 below which details EPLC's Tax Calculation for the 2018 Test Year.

Figure 50 – 2018 Test Year Tax Calculation

PILs Tax Provision - Test Year

								Wires Only	
Regulatory Taxable Income							T1	$ 630,295	A
	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate					
Ontario (Max 11.5%)	11.5%	11.5%	$ 72,484	11.5%	B				
Federal (Max 15%)	15.0%	15.0%	$ 94,544	15.0%	C				
Combined effective tax rate (Max 26.5%)								26.50%	D = B + C
Total Income Taxes								**$ 167,028**	**E = A * D**
Investment Tax Credits								$ -	F
Miscellaneous Tax Credits								$ -	G
Total Tax Credits								**$ -**	**H = F + G**
Corporate PILs/Income Tax Provision for Test Year								**$ 167,028**	**I = E - H**
Corporate PILs/Income Tax Provision Gross Up [1]						73.50%	**J = 1-D**	**$ 60,221**	**K = I/J-I**
Income Tax (grossed-up)								**$ 227,249**	**L = K + I**

Note:

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

Capital Cost Allowance

Figures 51 & 52 below demonstrate EPLC's Capital Cost Allowance continuity schedules for the Bridge and Test Years respectively.

Figure 51 – 2017 Bridge Year CCA Continuity Schedule

Schedule 8 CCA - Bridge Year

Class	Class Description	Working Paper Reference	UCC Regulated Historical Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA		UCC End of Bridge Year
1	Distribution System - post 1987	H8	$19,327,199.00	$ 328,992		$19,656,191	$ 164,496	$19,491,695	4%	$ 779,668		$18,876,523
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	H8				$ -	$ -	$ -	6%	$ -		$ -
2	Distribution System - pre 1988	H8				$ -	$ -	$ -	6%	$ -		$ -
8	General Office/Stores Equip	H8	$ 204,133.00	$ 120,000		$ 324,133	$ 60,000	$ 264,133	20%	$ 52,827		$ 271,306
10	Computer Hardware/ Vehicles	H8	$ 821,871.00	$ 487,000		$ 1,308,871	$ 243,500	$ 1,065,371	30%	$ 319,611		$ 989,260
10.1	Certain Automobiles	H8				$ -	$ -	$ -	30%	$ -		$ -
12	Computer Software	H8	$ 106,000.00	$ 254,500		$ 360,500	$ 127,250	$ 233,250	100%	$ 233,250		$ 127,250
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	H8	$ 171,662.00			$ 171,662	$ -	$ 171,662	8%	$ 13,733		$ 157,929
47	Distribution System - post February 2005	H8	$27,791,309.00	$5,111,823		$32,903,132	$2,555,912	$30,347,221	8%	$2,427,778		$30,475,354
50	Data Network Infrastructure Equipment - post Mar 2007	H8	$ 94,693.00	$ 356,150		$ 450,843	$ 178,075	$ 272,768	55%	$ 150,022		$ 300,821
52	Computer Hardware and system software	H8				$ -	$ -	$ -	100%	$ -		$ -
95	CWIP	H8	$ 229,628.00			$ 229,628	$ -	$ 229,628	0%	$ -		$ 229,628
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)1	H10	$ 84,044.10			$ 84,044	$ -	$ 84,044	7%	$ 5,883		$ 78,161
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)1		$ -			$ -	$ -	$ -	5%	$ -		$ -
	TOTAL		$ 48,830,539	$6,658,465	$ -	$55,489,004	$3,329,233	$52,159,772		$3,982,772	B1	$51,506,232

Figure 52 – 2018 Test Year CCA Continuity Schedule

Schedule 8 CCA - Test Year

Class	Class Description	Working Paper Reference	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA		UCC End of Test Year
1	Distribution System - post 1987	B8	$ 18,876,523	418,941		$19,295,464	$ 209,471	$19,085,994	4%	$ 763,440		$18,532,024
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	B8	$ -			$ -	$ -	$ -	6%	$ -		$ -
2	Distribution System - pre 1988	B8	$ -			$ -	$ -	$ -	6%	$ -		$ -
8	General Office/Stores Equip	B8	$ 271,306	120,000		$ 391,306	$ 60,000	$ 331,306	20%	$ 66,261		$ 325,045
10	Computer Hardware/ Vehicles	B8	$ 989,260	270,000		$ 1,259,260	$ 135,000	$ 1,124,260	30%	$ 337,278		$ 921,982
10.1	Certain Automobiles	B8	$ -			$ -	$ -	$ -	30%	$ -		$ -
12	Computer Software	B8	$ 127,250	115,000		$ 242,250	$ 57,500	$ 184,750	100%	$ 184,750		$ 57,500
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	B8	$ 157,929			$ 157,929	$ -	$ 157,929	8%	$ 12,634		$ 145,295
47	Distribution System - post February 2005	B8	$ 30,475,354	5,097,250		$35,572,604	$2,548,625	$33,023,979	8%	$2,641,918		$32,930,686
50	Data Network Infrastructure Equipment - post Mar 2007	B8	$ 300,821	161,809		$ 462,630	$ 80,905	$ 381,725	55%	$ 209,949		$ 252,681
52	Computer Hardware and system software	B8	$ -			$ -	$ -	$ -	100%	$ -		$ -
95	CWIP	B8	$ 229,628			$ 229,628	$ -	$ 229,628	0%	$ -		$ 229,628
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)1	B8	$ 78,161			$ 78,161	$ -	$ 78,161	7%	$ 5,471		$ 72,690
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)1	B8	$ -			$ -	$ -	$ -	5%	$ -		$ -
	TOTAL		$ 51,506,232	$6,183,000	$ -	$57,689,232	$3,091,500	$54,597,732		$4,221,702	T1	$53,467,531

4.12.2 Property Tax

EPLC pays property tax for its service station and offices located at 2730 Highway #3, Oldcastle, Ontario as well as a few smaller parcels of land that EPLC owns throughout its distribution territory. Figure 53 below outlines EPLC's historical Property Tax spend.

Figure 53 – Historical Property Tax Spend

2010 BAP	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
$ 85,824	$ 68,136	$ 43,471	$ 43,122	$ 45,301	$ 44,568	$ 41,843	$ 41,042	$ 42,639	$ 42,554

4.13 Non-Recoverable & Disallowed Expenses

Aside from excluded non-regulated revenues and expenses, EPLC does not have any non-recoverable or disallowed expenses that are deductible for general tax purposes but would be included in 2018 distribution rates.

4.14 Integrity Checks

EPLC confirms the following integrity checks have been completed for the purpose of this Application:

- The depreciation and amortization added back in this Application's PILs Model agree with the numbers disclosed in Exhibit 2 of this Application;

- The capital additions and deductions in the UCC/CCA Schedule 8 agree with the Exhibit 2 of this Application for historical, Bridge and Test Years;

- The opening 2017 Bridge Year UCC at January 1st agrees with the closing December 31st historical year UCC as shown in EPLC's most recent federal T2 tax return (2016);

- The CCA deductions in this Application's PILs Model for historical, Bridge and Test Years agree with the numbers in the UCC schedules for the same years filed in this Application;

- EPLC does not have any tax loss carry-forwards;

- EPLC's accounting OPEB amounts added back on Schedule 1 agree with the OM&A analysis for compensation;

- The income tax rate used to calculate the tax expense is consistent with EPLC's actual tax facts and evidenced filed in this Application;

4.15 Conservation & Demand Management

4.15.1 Overview

The Ministry of Energy & Infrastructure issued a Directive to the Board on March 31st, 2011 requiring all distributors in Ontario to achieve Conservation & Demand Management targets as a condition of license. Further, on April 26th, 2012, the Board issued *"Guidelines for Electricity Distributor Conservation & Demand Management"* and later *"Conservation and Demand Management Requirement Guidelines for Electricity Distributors"* (EB-2014-0278) on December 19th, 2014, updated on August 11th, 2016.

In order for lost revenues associated with conservation & demand management activities to not act as a disincentive for distributors, the Board included a mechanism (Lost Revenue Adjustment Mechanism "LRAM") to capture the difference between actual verified conservation & demand management results with a distributors load forecast in the Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA").

In this section, EPLC is proposing to dispose of a total balance of $513,500 for the period of 2013 to 2016.

4.15.2 LRAM Claim For Pre-2011 Activities

As part of EB-2013-0128, EPLC applied for and received Board approval for recovery of lost revenue for 2011 and 2012. Pre-2011 activities were also addressed as part of EB-2013-0128. As such, EPLC is not seeking any recovery for activities prior to 2012.

4.15.3 LRAMVA Claim

As part of this Application, EPLC is seeking approval for recovery of lost revenue from conservation & demand management activities for years 2013, 2014 and 2015, consistent with verified results received from the Independent Electricity System Operator and included as Attachment 4-P of this Exhibit. In order to calculate the proposed claim, EPLC utilized the Board's *Lost Revenue Adjustment Mechanism Variance Account Work Form Version 1.0 (2017)*, included as Attachment 4-Q of this Exhibit. Figure 54 below summarizes EPLC's proposed LRAMVA claim for years 2013 through 2015.

Figure 54 – 2013-2015 LRAMVA Claim

Rate Class	LRAMVA Balance
Residential	$ 259,295
General Service Less Than 50 kW	$ 167,801
General Service 50 to 4,999 kW	$ 77,559
Unmetered Scattered Load	$ -
Sentinel Lighting	$ -
Street Lighting	$ 8,845
Embedded Distributor	$ -
Total	**$ 513,500**

4.15.4 Disposition of LRAM & LRAMVA Accounts

Consistent with section 9.7.3 of Exhibit 9, EPLC requests recovery of the proposed $513,500 via volumetric rate riders beginning May 1st, 2018 for recovery over one year. For more information on the rate rider, please refer to Exhibit 9 of this Application.

Attachment 4-A

Summary of Recoverable OM&A Expenses

File Number:	EB-2017-0039
Exhibit:	4
Attachment:	4-A
Page:	1 of 1
Date:	August 28th, 2017

Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Operations	$ 1,111,126	$ 767,608	$ 1,003,987	$ 1,190,375	$ 1,207,057	$ 1,545,489	$ 1,332,350	$ 1,337,677	$ 1,221,419	$ 1,518,208
Maintenance	$ 1,517,732	$ 1,496,651	$ 1,614,034	$ 2,013,059	$ 1,515,425	$ 1,448,980	$ 1,808,438	$ 1,833,650	$ 1,572,404	$ 1,548,463
SubTotal	**$ 2,628,858**	**$ 2,264,259**	**$ 2,618,021**	**$ 3,203,433**	**$ 2,722,482**	**$ 2,994,470**	**$ 3,140,788**	**$ 3,171,328**	**$ 2,793,823**	**$ 3,066,671**
%Change (year over year)			15.6%	22.4%	-15.0%	10.0%	4.9%	1.0%	-11.9%	9.8%
%Change (Test Year vs Last Rebasing Year - Actual)										35.4%
Billing and Collecting	$ 1,480,565	$ 1,305,098	$ 1,131,257	$ 1,174,568	$ 1,329,771	$ 1,158,128	$ 1,229,676	$ 1,348,249	$ 1,499,880	$ 1,550,150
Community Relations	$ 22,500	$ 16,957	$ 11,394	$ 8,539	$ 8,451	$ 10,016	$ 12,013	$ 6,482	$ 23,442	$ 23,396
Administrative and General	$ 2,068,443	$ 1,894,041	$ 1,786,257	$ 1,806,757	$ 1,966,590	$ 2,541,606	$ 2,381,742	$ 2,455,564	$ 2,950,224	$ 3,070,058
SubTotal	**$ 3,571,508**	**$ 3,216,096**	**$ 2,928,908**	**$ 2,989,863**	**$ 3,304,813**	**$ 3,709,749**	**$ 3,623,431**	**$ 3,810,295**	**$ 4,473,546**	**$ 4,643,604**
%Change (year over year)			-8.9%	2.1%	10.5%	12.3%	-2.3%	5.2%	17.4%	3.8%
%Change (Test Year vs Last Rebasing Year - Actual)										44.4%
Total	**$ 6,200,366**	**$ 5,480,354**	**$ 5,546,929**	**$ 6,193,296**	**$ 6,027,295**	**$ 6,704,219**	**$ 6,764,218**	**$ 6,981,623**	**$ 7,267,369**	**$ 7,710,275**
%Change (year over year)			1.2%	11.7%	-2.7%	11.2%	0.9%	3.2%	4.1%	6.1%

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Operations	$ 1,111,126	$ 767,608	$ 1,003,987	$ 1,190,375	$ 1,207,057	$ 1,545,489	$ 1,332,350	$ 1,337,677	$ 1,221,419	$ 1,518,208
Maintenance	$ 1,517,732	$ 1,496,651	$ 1,614,034	$ 2,013,059	$ 1,515,425	$ 1,448,980	$ 1,808,438	$ 1,833,650	$ 1,572,404	$ 1,548,463
Billing and Collecting	$ 1,480,565	$ 1,305,098	$ 1,131,257	$ 1,174,568	$ 1,329,771	$ 1,158,128	$ 1,229,676	$ 1,348,249	$ 1,499,880	$ 1,550,150
Community Relations	$ 22,500	$ 16,957	$ 11,394	$ 8,539	$ 8,451	$ 10,016	$ 12,013	$ 6,482	$ 23,442	$ 23,396
Administrative and General	$ 2,068,443	$ 1,894,041	$ 1,786,257	$ 1,806,757	$ 1,966,590	$ 2,541,606	$ 2,381,742	$ 2,455,564	$ 2,950,224	$ 3,070,058
Total	**$ 6,200,366**	**$ 5,480,354**	**$ 5,546,929**	**$ 6,193,296**	**$ 6,027,295**	**$ 6,704,219**	**$ 6,764,218**	**$ 6,981,623**	**$ 7,267,369**	**$ 7,710,275**
%Change (year over year)			1.2%	11.7%	-2.7%	11.2%	0.9%	3.2%	4.1%	6.1%

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	Variance 2010 Board-approved – 2010 Actuals	2011 Actuals	Variance 2011 Actuals vs. 2010 Actuals	2012 Actuals	Variance 2012 Actuals vs. 2011 Actuals	2013 Actuals	Variance 2013 Actuals vs. 2012 Actuals	2014 Actuals	Variance 2014 Actuals vs. 2013 Actuals	2015 Actuals	Variance 2015 Actuals vs. 2014 Actuals	2016 Actuals	Variance 2016 Actuals vs. 2015 Actuals	2017 Bridge Year	Variance 2017 Bridge vs. 2016 Actuals	2018 Test Year	Variance 2018 Test vs. 2017 Bridge
Operations	$ 1,111,126	$ 767,608	$ 343,518	$ 1,003,987	$ 236,379	$ 1,190,375	$ 186,387	$ 1,207,057	$ 16,682	$ 1,545,489	$ 338,432	$ 1,332,350	-$ 213,140	$ 1,337,677	$ 5,328	$ 1,221,419	-$ 116,258	$ 1,518,208	$ 296,789
Maintenance	$ 1,517,732	$ 1,496,651	$ 21,081	$ 1,614,034	$ 117,384	$ 2,013,059	$ 399,024	$ 1,515,425	-$ 497,633	$ 1,448,980	-$ 66,445	$ 1,808,438	$ 359,457	$ 1,833,650	$ 25,212	$ 1,572,404	-$ 261,246	$ 1,548,463	-$ 23,941
Billing and Collecting	$ 1,480,565	$ 1,305,098	$ 175,467	$ 1,131,257	-$ 173,841	$ 1,174,568	$ 43,311	$ 1,329,771	$ 155,203	$ 1,158,128	-$ 171,643	$ 1,229,676	$ 71,548	$ 1,348,249	$ 118,573	$ 1,499,880	$ 151,631	$ 1,550,150	$ 50,270
Community Relations	$ 22,500	$ 16,957	$ 5,543	$ 11,394	-$ 5,564	$ 8,539	-$ 2,855	$ 8,451	-$ 88	$ 10,016	$ 1,564	$ 12,013	$ 1,997	$ 6,482	-$ 5,530	$ 23,442	$ 16,959	$ 23,396	-$ 46
Administrative and General	$ 2,068,443	$ 1,894,041	$ 174,402	$ 1,786,257	-$ 107,784	$ 1,806,757	$ 20,500	$ 1,966,590	$ 159,834	$ 2,541,606	$ 575,015	$ 2,381,742	-$ 159,864	$ 2,455,564	$ 73,822	$ 2,950,224	$ 494,660	$ 3,070,058	$ 119,834
Total OM&A Expenses	$ 6,200,366	$ 5,480,354	$ 720,012	$ 5,546,929	$ 66,575	$ 6,193,296	$ 646,367	$ 6,027,295	-$ 166,002	$ 6,704,219	$ 676,924	$ 6,764,218	$ 59,999	$ 6,981,623	$ 217,405	$ 7,267,369	$ 285,746	$ 7,710,275	$ 442,906
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)																			
Total Recoverable OM&A Expenses	$ 6,200,366	$ 5,480,354	$ 720,012	$ 5,546,929	$ 66,575	$ 6,193,296	$ 646,367	$ 6,027,295	-$ 166,002	$ 6,704,219	$ 676,924	$ 6,764,218	$ 59,999	$ 6,981,623	$ 217,405	$ 7,267,369	$ 285,746	$ 7,710,275	$ 442,906
Variance from previous year				$ 66,575		$ 646,367		-$ 166,002		$ 676,924		$ 59,999		$ 217,405		$ 285,746		$ 442,906	
Percent change (year over year)				1%		12%		-3%		11%		1%		3%		4%		6%	
Percent Change: Test year vs. Most Current Actual														10.44%					
Simple average of % variance for all years														40.69%					4%
Compound Annual Growth Rate for all years																			7.1%
Compound Growth Rate (2016 Actuals vs. 2010 Actuals)														8.40%					

Note:

1 If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.

2 Recoverable OM&A that is included on these tables should be identical to the recoverable OM&A that is shown for the corresponding periods on Appendix 2-JB.

Attachment 4-B

Recoverable OM&A Cost Driver Table

File Number:	EB-2017-0039
Exhibit:	4
Attachment:	4-B
Page:	1 of 1
Date:	August 28th, 2017

Appendix 2-JB
Recoverable OM&A Cost Driver Table[1, 3]

OM&A	Last Rebasing Year (2010 Actuals)	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance[2]	$ 6,200,366	$ 5,546,929	$ 6,193,296	$ 6,027,295	$ 6,704,219	$ 6,764,218	$ 6,981,623	$ 7,267,369
Operations								
Reduction in Load Dispatching	-$ 104,082	$ 645	-$ 6,206	$ 5,797	$ 2,487	$ 6,016	$ 28,804	$ 51,959
Metering	-$ 77,388	$ 223,114	$ 105,856	$ 182,221	-$ 370,601	-$ 7,348	$ 8,953	-$ 5,348
Customer Premises	-$ 26,103	$ 41,179	$ 2,023	$ 121,874	$ 141,961	-$ 108,519	-$ 65,567	$ 29,964
Changes in Supervision	$ 45,064	$ 56,897	-$ 14,704	$ 30,810	-$ 99,134	-$ 1,159	-$ 9,037	-$ 1,084
Control Room								$ 186,000
Other Immaterial/Misc. Operational	-$ 181,008	-$ 135,448	-$ 70,286	-$ 2,269	$ 112,148	$ 116,339	-$ 79,411	-$ 150,702
Subtotal - Operations	**-$ 343,518**	**$ 186,387**	**$ 16,682**	**$ 338,432**	**-$ 213,140**	**$ 5,328**	**-$ 116,258**	**$ 296,789**
Maintenance								
Changes in Supervision	$ 9,649	$ 97,609	-$ 83,366	$ 2,176	$ 356,113	-$ 366,006	$ 22,609	$ 9,813
O/H Right of Way - Conversion	-$ 75,120	$ 392,541	-$ 154,244	$ 31,584	-$ 22,812	$ 146,708	-$ 175,692	$ 49,303
Other Immaterial/Misc. Maintenance	$ 44,390	-$ 91,125	-$ 260,024	-$ 100,205	$ 26,157	$ 244,511	-$ 108,164	-$ 83,056
Subtotal - Maintenance	**-$ 21,081**	**$ 399,024**	**-$ 497,633**	**-$ 66,445**	**$ 359,457**	**$ 25,212**	**-$ 261,246**	**-$ 23,941**
Billing & Collecting								
Customer Billing	-$ 192,846	$ 38,451	$ 151,623	-$ 118,082	-$ 24,488	$ 138,637	$ 203,832	$ 36,004
Collecting	$ 3,344	$ 100,555	$ 33,225	$ 45,194	-$ 13,614	$ 52,485	$ 72,978	$ 7,987
Changes in Supervision	$ 24,651	-$ 95,226	$ 13,288	$ 11,196	$ 3,568	$ 4,575	$ 13,832	$ 3,627
Meter Reading	$ 43,481	-$ 61,144	$ 1,724	-$ 52,098	$ 51,382	-$ 59,854	-$ 121,092	-$ 221
Changes in Bad Debt Expense	-$ 52,589	$ 67,625	-$ 35,575	-$ 57,537	$ 54,207	-$ 39,837	$ 9,352	-$ 312
Other Immaterial/Misc. B&C	-$ 1,509	-$ 6,951	-$ 9,082	-$ 315	$ 494	$ 22,566	-$ 27,270	$ 3,184
Subtotal - Billing & Collecting	**-$ 175,467**	**$ 43,311**	**$ 155,203**	**-$ 171,643**	**$ 71,548**	**$ 118,573**	**$ 151,631**	**$ 50,270**
Community Relations								
Other Immaterial/Misc. Community Rela	-$ 5,543	-$ 2,855	-$ 88	$ 1,564	$ 1,997	-$ 5,530	$ 16,959	-$ 46
Subtotal - Community Relations	**-$ 5,543**	**-$ 2,855**	**-$ 88**	**$ 1,564**	**$ 1,997**	**-$ 5,530**	**$ 16,959**	**-$ 46**
Admin & General								
Change in Salaries & General Expenses	-$ 100,670	-$ 153,124	$ 313,788	$ 345,104	-$ 65,931	$ 20,243	-$ 55,274	$ 82,142
Change in Employee Pensions & Benefi	$ 46,599	$ 185,372	$ 7	$ 173,332	-$ 9,459	$ 11,582	$ 31,046	-$ 457
Regulatory Re-alignment							$ 236,958	$ 31,623
Outside Services/Cybersecurity			$ 67,342		-$ 63,317		$ 231,463	$ 8,141
Other Immaterial/Misc. Admin & Genera	-$ 120,332	-$ 11,748	-$ 153,961	$ 56,579	-$ 84,474	$ 41,997	$ 50,468	-$ 1,615
Subtotal - Admin & General	**-$ 174,402**	**$ 20,500**	**$ 159,834**	**$ 575,015**	**-$ 159,864**	**$ 73,822**	**$ 494,660**	**$ 119,834**
Closing Balance[2]	$ 5,480,354	$ 6,193,296	$ 6,027,295	$ 6,704,219	$ 6,764,218	$ 6,981,623	$ 7,267,369	$ 7,710,275

Notes:

1 For each year, a detailed explanation for each cost driver and associated amount is requied in Exhibit 4.
2 Opening Balance for "Last Rebasing Year" (cell B15) should be equal to the Board-Approved amount. For purposes of assessing incremental cost drivers, the closing balance for each year becomes the opening balance for the next year.
3 If it has been more than four years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than four years ago, a minimum of three years of actual information is required.

<u>Attachment 4-C</u>

Recoverable OM&A Per Customer &
Per FTE

File Number:	EB-2017-0039
Exhibit:	4
Tab:	4-C
Page:	1 of 1
Date:	August 28th, 2017

Appendix 2-L
Recoverable OM&A Cost per Customer and per FTE [1]

	Last Rebasing Year - 2010- Board Approved	Last Rebasing Year - 2010- Actual	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
OM&A Costs										
O&M	$ 2,628,858	$ 2,264,259	$ 2,618,021	$ 3,203,433	$ 2,722,482	$ 2,994,470	$ 3,140,788	$ 3,171,328	$ 2,793,823	$ 3,066,671
Admin Expenses	$ 3,571,508	$ 3,216,096	$ 2,928,908	$ 2,989,863	$ 3,304,813	$ 3,709,749	$ 3,623,431	$ 3,810,295	$ 4,473,546	$ 4,643,604
Total Recoverable OM&A from Appendix 2-JB [5]	**$ 6,200,366**	**$ 5,480,354**	**$ 5,546,929**	**$ 6,193,296**	**$ 6,027,295**	**$ 6,704,219**	**$ 6,764,218**	**$ 6,981,623**	**$ 7,267,369**	**$ 7,710,275**
Number of Customers [2,4]	30,940	31,200	31,314	31,249	31,521	31,742	31,985	32,346	32,550	32,736
Number of FTEs [3,4]	57.4	53	44	44	44	48	44	44	46	46
Customers/FTEs	**539.02**	**588.68**	**711.68**	**710.20**	**716.39**	**661.29**	**726.93**	**735.14**	**707.61**	**711.65**
OM&A cost per customer										
O&M per customer	$ 84.97	$ 72.57	$ 83.61	$ 102.51	$ 86.37	$ 94.34	$ 98.20	$ 98.04	$ 85.83	$ 93.68
Admin per customer	$ 115.43	$ 103.08	$ 93.53	$ 95.68	$ 104.84	$ 116.87	$ 113.29	$ 117.80	$ 137.44	$ 141.85
Total OM&A per customer	$ 200.40	$ 175.65	$ 177.14	$ 198.19	$ 191.22	$ 211.21	$ 211.48	$ 215.84	$ 223.27	$ 235.53
OM&A cost per FTE										
O&M per FTE	$ 45,798.92	$ 42,721.86	$ 59,500.49	$ 72,805.30	$ 61,874.59	$ 62,384.79	$ 71,381.54	$ 72,075.63	$ 60,735.29	$ 66,666.76
Admin per FTE	$ 62,221.39	$ 60,681.05	$ 66,566.08	$ 67,951.44	$ 75,109.38	$ 77,286.44	$ 82,350.69	$ 86,597.61	$ 97,251.00	$ 100,947.91
Total OM&A per FTE	$ 108,020.31	$ 103,402.91	$ 126,066.57	$ 140,756.74	$ 136,983.97	$ 139,671.23	$ 153,732.23	$ 158,673.25	$ 157,986.29	$ 167,614.67

Notes:

1 If it has been more than four years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than four years ago, a minimum of three years of actual information is required.

2 The method of calculating the number of customers must be identified. Should correspond with data provided in Appendix 2-IB.

3 The method of calculating the number of FTEs must be identified. See also Appendix 2-K.

4 The number of customers and the number of FTEs should correspond to mid-year or average of January 1 and December 31 figures.

5 For the test year, the applicant should take into account the system O&M (line 22 of Appendix 2-AB) in developing its forecasted OM&A.

Attachment 4-D

OM&A Programs Table

File Number:	EB-2017-0039
Exhibit:	4
Tab:	4-D
Page:	1 of 1
Date:	August 28th, 2017

Appendix 2-JC
OM&A Programs Table

Programs	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year	Variance (Test Year vs. 2016 Actuals)	Variance (Test Year vs. Last Rebasing Year (2010 Board-
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**		
Administration												
General Building Expenses	241,203	191,801	384,048	454,397	282,679	284,692	287,490	316,821	338,503	342,304	25,483	101,101
Insurance	30,500	23,911	24,658	16,320	16,984	27,449	21,206	18,944	34,630	34,562	15,619	4,062
Office Supplies	269,633	333,799	368,589	371,682	396,385	402,033	443,140	402,558	448,399	478,697	76,140	209,064
Audit, Legal and Consulting	82,600	101,643	104,384	47,788	115,130	118,220	54,903	64,135	295,597	303,738	239,603	221,138
Regulatory Affairs	162,462	126,894	168,067	168,224	130,878	108,565	146,535	124,953	361,911	393,533	268,580	231,071
Administration & HR Expenses	1,282,045	1,115,992	736,511	748,345	1,024,535	1,587,220	1,415,040	1,514,727	1,457,756	1,500,403	-14,324	218,358
Donations/LEAP Funding	0	0	0	0	0	13,427	13,427	13,427	13,427	16,820	3,394	16,820
Sub-Total	2,068,443	1,894,041	1,786,257	1,806,757	1,966,590	2,541,606	2,381,742	2,455,564	2,950,224	3,070,058	614,494	1,001,615
Community Relations												
Community Relations	22,500	16,957	11,394	8,539	8,451	10,016	12,013	6,482	23,442	23,396	16,914	896
Sub-Total	22,500	16,957	11,394	8,539	8,451	10,016	12,013	6,482	23,442	23,396	16,914	896
Customer Service												
Bad Debt	187,500	134,911	161,595	229,220	193,645	136,108	190,315	150,478	159,830	159,518	9,040	-27,982
Customer Service & Billings	1,212,670	1,087,957	1,041,611	923,692	1,090,327	931,342	961,804	1,045,162	1,141,734	1,181,144	135,981	-31,526
Customer Collections	80,395	82,230	-71,948	21,656	45,799	90,677	77,557	152,609	198,317	209,488	56,880	129,093
Sub-Total	1,480,565	1,305,098	1,131,257	1,174,568	1,329,771	1,158,128	1,229,676	1,348,249	1,499,880	1,550,150	201,901	69,585
Maintenance												
Emergency Response	273,360	344,695	363,959	330,898	253,549	231,804	286,063	274,797	263,708	259,741	-15,056	-13,619
Field Service Maintenance	106,726	68,103	43,253	30,382	73,450	72,038	51,518	185,984	127,766	57,433	-128,551	-49,293
Meter Maintenance	139,601	85,225	78,060	95,844	17,387	2,848	90,081	0	574	568	568	-139,033
Overhead/Underground Maintenance	507,669	640,148	675,925	614,525	470,877	430,493	531,260	510,337	489,744	482,377	-27,961	-25,292
Vegetation Control	356,024	271,632	372,500	812,584	625,237	660,465	792,620	778,165	609,254	666,029	-112,136	310,006
Transformer & Substation Maintenanc	134,352	86,847	80,338	128,825	74,925	51,332	56,896	84,367	81,358	82,315	-2,053	-52,037
Sub-Total	1,517,732	1,496,651	1,614,034	2,013,059	1,515,425	1,448,980	1,808,438	1,833,650	1,572,404	1,548,463	-285,187	30,731
Operations												
Cable Locates	356,155	330,052	288,282	329,461	331,484	453,358	595,318	486,799	421,232	451,196	-35,603	95,041
General Customer Inquiries & Misc.	184,215	185,796	370,563	236,541	164,099	127,149	127,633	196,927	229,406	224,633	27,706	40,418
Meter Operations	135,439	58,051	79,937	303,051	408,908	591,129	220,528	213,180	222,133	216,785	3,605	81,346
Station Operations	78,499	17,932	16,130	26,197	25,806	95,716	42,106	0	0	0	0	-78,499
Operations Management	160,174	101,155	127,767	185,309	164,399	201,005	104,358	109,215	128,982	365,857	256,642	205,683
Overhead Operations	42,013	14,605	29,826	48,042	38,702	26,559	132,482	167,408	124,519	114,893	-52,515	72,880
Transformer Operations	122,523	40,324	82,151	49,935	46,145	39,021	63,883	52,888	43,444	86,805	33,917	-35,718
Underground Operations	32,108	19,692	9,330	11,838	27,514	11,552	46,040	111,261	51,703	58,040	-53,221	25,932
Sub-Total	1,111,126	767,608	1,003,987	1,190,375	1,207,057	1,545,489	1,332,350	1,337,677	1,221,419	1,518,208	180,530	407,082
Miscellaneous											0	0
Total	**6,200,366**	**5,480,354**	**5,546,929**	**6,193,296**	**6,027,295**	**6,704,219**	**6,764,218**	**6,981,623**	**7,267,369**	**7,710,275**	**728,652**	**1,509,909**

Notes:

1 Please provide a breakdown of the major components of each OM&A Program undertaken in each year. Please ensure that all Programs below the materiality threshold are included in the miscellaneous line. Add more Programs as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the OM&A budget in the miscellaneous category

Attachment 4-E

EPLC Employee Handbook – Management/Non-Union

The MEARIE Group
Employee Benefit Program

Employee Benefit Booklet

Essex Power Corp.
Management

Prepared: August 2015

Notice of Disclaimer

This handbook has been prepared to help you better understand the coverage provided under your employee benefit program. This handbook is not an agreement and it does not create nor confer any contractual or other rights.

The terms and conditions governing your benefit plans are set out in the official contracts between the insurers, your employer and MEARIE Management Inc.

Every effort has been made to ensure that the information in this handbook is accurate. However, if any question should arise, a decision will be made by reference to the official plan contracts and texts.

This handbook has been designed to help you understand and get the most out of your benefits. It gives you most of the information you will generally require regarding your benefits. Separate sections for each benefit plan allow you quick access to the benefit information you want when you want it.

Please keep this handbook in a safe place. If changes are made to your benefits, replacement pages will be provided to you for insertion in this handbook.

*Your life and disability plans are insured through **Desjardins Insurance**, while your accident plan is insured through **AIG Insurance Company of Canada**.*

Any questions you have about your benefit program should be referred to your Plan Administrator.

General Information

Enrolling In The Benefit Program

Who Can Enroll

If you are an active permanent full-time employee under the age of 65 and working at least 20 hours per week, you are first eligible to enroll in the benefit program on the date your employment commences.

Your spouse is also eligible for coverage under the optional spouse life insurance plan, should you decide to apply.

Spouse

- the person who you are legally married to, or
- a person who continuously resides with you in a role like that of a marriage partner.

Dependent Children

Dependent children include your natural or legally adopted children, or step-children who:

- are unmarried,
- are not employed on a full-time basis,
- are not eligible for insurance as an employee under this plan or any other group plan, and
- are under 21 years of age, or, if in full-time attendance at an accredited school, college or university, are under 25 years of age.

A child insured under this plan, who is incapacitated due to a mental or physical handicap on the date he reaches the age when he would otherwise no longer be eligible for coverage, will continue to be an eligible dependent subject to written proof of the dependent's condition. A child is considered incapacitated if he is incapable of engaging in any substantially gainful activity and is dependent on you for support, maintenance and care, due to a mental or physical handicap.

A stepchild must be living with you to be an eligible dependent.

When Coverage Starts

Coverage for you and your spouse commences on the date you first become eligible to enroll. If you are not actively at work on the date your coverage would normally begin, your coverage will not start until you return to active full-time work.

General Information

When Coverage Terminates

Coverage for you and your dependents will end on:

- the date your employment ends,
- the date you or your spouse cease to qualify for coverage based on the plan's eligibility requirements,
- the date you enter an armed service on full-time duty,
- the date your employer receives a written request from you to terminate the insurance, where permitted,
- the date you fail to make any required premium contribution,
- the date you attain age 65 (applies to all coverage expect Basic Life and Basic AD&D which terminate at age 71),
- the date your spouse attains age 65 (applies to spousal life insurance),
- the date you retire, or
- the date the group plan is cancelled.

If you are not actively at work due to **Maternity or Parental Leave of Absence**, coverage may be continued for the period of leave to which you are entitled by legislation provided premiums continue to be paid on your behalf. If you do not intend to continue your coverage during this period, where permitted by law, you must inform your employer in writing on or before the date your leave begins. In this case, coverage for you and your dependents will not be reinstated until you return to active full-time work.

Coverage for you and your spouse will cease on the date you are not actively at work due to **lay-off, leave of absence (other than maternity or parental leave), strike or lock-out**.

If you are not actively at work due to **illness or injury**:

- your life, accident and disability coverage will continue in accordance with the "Waiver of Premium" provisions described in the applicable sections of this handbook.

Long Term Disability

Your long term disability plan has been developed to protect you against the financial impact of lost income, if a lengthy illness or injury keeps you from coming to work.

How The Plan Works

Benefits are payable under the long term disability plan after you have been totally and continuously disabled for a period of **6 months** or have used all the sick days to which you are entitled under your sick leave plan, whichever occurs later.

Benefits Provided

If you are totally disabled you will receive a monthly income benefit equal to **66.7% of your regular monthly earnings, to a maximum of $7,000* per month**.

**Evidence of insurability, satisfactory to the insurer, is required for amounts in excess of $4,000.*

> *To qualify for long term disability benefits you must be "totally disabled". During the first 24 months that you receive long term disability, this means that you are unable to do the essential duties of your normal job and are not otherwise employed. After this 24-month period, you will continue to qualify for long term disability benefits only if you are unable to work at any job for which you are reasonably suited by virtue of your education, training and experience.*

Any benefits you receive from the long term disability plan are taxable if your employer contributes, in whole or in part, towards the cost of providing the plan.

Benefits from the long term disability plan will stop if you:

- recover,
- attain age 65,
- are unable to provide written proof of your disability,
- are no longer under a physician's care,
- fail to undergo an examination by an independent doctor of the Insurance Company's choice, or
- in the event of your death.

Long Term Disability

Coordination With Other Disability Benefits

Long term disability benefits are reduced by the amount of income you receive or are entitled to receive as a result of the same disability from:

- Workers' Compensation or similar legislation (excluding any future cost of living adjustments),
- the Canada or Quebec Pension Plan (excluding any future cost of living adjustments or dependent benefits payable to you),
- any other federal, provincial or municipal government plan, excluding any disability benefits available to you through the Ontario Municipal Employees' Retirement System, but not filed on your behalf, and
- any other group insurance plan, or any retirement or pension plan of the employer, excluding any disability benefits available to you through the Ontario Municipal Employees' Retirement System.

The benefit you receive will be further reduced, if necessary, so that the total disability income you receive from this plan and any other source (other than income from a private source) does not exceed 85% of your pre-disability net earnings (if benefits are non-taxable) or gross earnings (if benefits are taxable).

Rehabilitation Benefit

The rehabilitation benefit is designed to help you through an adjustment period of up to 24 months while working part-time, in a reduced capacity or involved in a retraining program approved by the Insurance Company.

While you are participating in an approved rehabilitation program, your long term disability benefit will not be discontinued. However, your monthly long term disability benefit will be reduced by 50% of the compensation you receive from rehabilitative employment.

Long Term Disability

When Disability Recurs

If you recover from total disability, only to become disabled again, the second period of disability will be treated as a continuation of the first unless the second disability is unrelated to the first, or is separated from the first by more than six months.

Waiver of Premium

Premium payments are waived during any period in which you receive benefits from this plan. Long term disability benefits will continue in accordance with the terms of the policy regardless of whether or not this plan remains in effect or your other benefit coverages are subsequently terminated, provided your disability begins while your coverage under this plan is in force.

How To Claim Long Term Disability Benefits

Claim forms are available from your Plan Administrator. Early filing of claims is recommended. Forms should be completed and returned to your Plan Administrator after you have been disabled at least 30 days and do not expect to return to work before the *Elimination Period* expires. Long term disability claims must be submitted no later than 90 days after the date you are eligible for benefits to begin.

Long Term Disability

What's Not Covered

Your long term disability plan does not cover:

- intentionally self-inflicted injury or illness,
- disability resulting from war, or act of war, or while engaged in the armed services,
- any period of disability during which you are not under the regular care and attendance of a legally qualified physician,
- any period of disability which commences while you are not insured under this plan,
- participation in a criminal act, or
- disability, loss or expense which commences or occurs during any period of statutory maternity or parental leave of absence except to the extent:
    1. the continuance of insurance coverage during such period of statutory maternity or parental leave of absence is required by legislation or by written agreement between you and your employer; and
    2. you do not receive or are not entitled to receive any payment, benefit, indemnity or other amount from any source, including any policy, plan or fund provided by any employer, insurer or government (including basic and supplementary unemployment insurance maternity/parental leave benefits).

Basic Life Insurance

Your basic life insurance plan pays a benefit to your beneficiary in the event of your death.

How The Plan Works

If you should die, your basic life insurance plan will pay a benefit to your appointed beneficiary, regardless of the cause of death.

You may name anyone you choose to receive benefits payable under the plan in the event of your death. However, if you name a minor, a trustee must also be appointed. You may change your beneficiary designation at any time, subject to the laws governing such changes, by contacting your Plan Administrator.

Benefits Provided

Your basic life insurance coverage is equal to **two times your annual earnings to a maximum of $200,000**. (Amounts that are not an event multiple of $1,000 are rounded up to the nearest $1,000). Your coverage will reduce by 50% on your 65th birthday.

Waiver of Premium

If you become totally disabled while insured and before your 65th birthday or earlier retirement, your life insurance coverage under the Basic Life plan will be continued without further payment of premiums. Your coverage will continue until you are no longer disabled, retire or reach age 65, whichever occurs first.

Proof that you are totally disabled must be submitted to Desjardins within 12 months from the onset of the disability, and periodically as requested by Desjardins thereafter.

Totally Disabled means that you are prevented from performing any work for compensation or profit or from following any gainful occupation. (However, if you are insured for Long Term Disability benefits by Desjardins under this same master policy, the definition of total disability used to determine your eligibility for disability benefits, as described in this booklet, shall also apply when assessing your life insurance waiver of premium benefit.)

Basic Life Insurance

Conversion Privilege

Your basic life insurance coverage ceases on the date your employment terminates. However, if you are under age 65, you may apply to convert your insurance to an individual policy — *without* having to provide medical evidence. You must make written application for the individual policy to Desjardins Insurance accompanied by payment of the first premium within 31 days of the date your supplementary life insurance terminates. The amount of the individual policy will not exceed the lesser of $200,000 ($400,000 for employees residing in Quebec[1]) or the total amount of your life insurance in force under all life insurance plans provided under this policy immediately prior to the termination of your coverage. If you should die during the 31-day conversion period, a death benefit will be paid, regardless of whether or not application for conversion has been made.

[1]For a Quebec plan Member to convert, his or her convertible amount must be at least $10,000 or 25 percent of group coverage (whichever is greater).

How To Claim Death Benefits

Your Plan Administrator will furnish all the required claim forms to your beneficiary in the event of your death. Claims for death benefits must be submitted no later than 12 months after the date of death.

Supplementary Life Insurance

The Supplementary life insurance plan enables you to purchase additional coverage for yourself and/or your spouse. In the event of your death, the plan pays a benefit to your beneficiary. The benefit is payable to you in the event of the death of your covered spouse.

How The Plan Works

The purchase of supplementary life insurance is completely voluntary; you decide whether or not to participate.

If you should die while insured your supplementary life insurance plan will pay a benefit to the last nominated beneficiary as filed. In the absence of a beneficiary nomination, payment will be made to your estate.

You may name anyone you choose to receive benefits payable under the plan in the event of your death. However, if you name a minor, a trustee must also be appointed. You may change your beneficiary designation at any time, subject to the laws governing such changes, by contacting your Plan Administrator.

If your spouse is insured for life insurance coverage under the spouse's optional life plan, benefits are payable to *you* in the event of the death of your covered spouse.

Benefits Available

Supplementary life insurance coverage is available in **multiples of $10,000, to a maximum of $250,000**. All coverage is subject to medical evidence — proof that you are insurable, satisfactory to the insurer.

Supplementary Life Insurance

Cost of Supplementary Life Insurance

Your cost, paid through payroll deduction, depends on your gender, your age and on whether or not you smoke. (You are considered a “non-smoker” if you have not smoked for the last 12 months). Monthly costs are provided in the table below.

Employee’s Attained Age (as at January 1st)	Male		Female	
	Smoker Monthly Rate (per $1,000)	Non-Smoker Monthly Rate (per $1,000)	Smoker Monthly Rate (per $1,000)	Non-Smoker Monthly Rate (per $1,000)
Under 35	$0.044	$0.022	$0.022	$0.020
35 - 39	$0.060	$0.039	$0.033	$0.028
40 - 44	$0.163	$0.080	$0.099	$0.062
45 - 49	$0.285	$0.142	$0.169	$0.098
50 - 54	$0.445	$0.231	$0.240	$0.151
55 - 59	$0.757	$0.383	$0.395	$0.231
60 - 64	$0.890	$0.480	$0.480	$0.300

Note: *Monthly costs shown above reflect those in effect as of January 1st, 2015.*
The monthly cost schedule is subject to change by the insurer; your employer will notify you prior to any changes taking effect.
Monthly costs shown above are subject to applicable taxes.

Supplementary Life Insurance

Waiver of Premium

If you become totally disabled while insured and before your 65th birthday or earlier retirement, your life insurance coverage under the Supplementary Life plan will be continued without further payment of premiums. Your coverage will continue until you are no longer disabled, retire or reach age 65, whichever occurs first.

Proof that you are totally disabled must be submitted to Desjardins Insurance within 12 months from the onset of the disability, and periodically as requested by Desjardins Insurance thereafter.

Totally Disabled means that you are prevented from performing any work for compensation or profit or from following any gainful occupation. (However, if you are insured for Long Term Disability benefits by Desjardins Insurance under this same master policy, the definition of total disability used to determine your eligibility for disability benefits, as described in this booklet, shall also apply when assessing your life insurance waiver of premium benefit).

Conversion Privilege

Your supplementary life insurance coverage ceases on the date your employment terminates. However, if you are under age 65, you may apply to convert your insurance to an individual policy — *without* having to provide medical evidence. You must make written application for the individual policy to Desjardins Insurance accompanied by payment of the first premium within 31 days of the date your supplementary life insurance terminates. The amount of the individual policy will not exceed the lesser of $200,000 ($400,000 for employees residing in Quebec[1]) or the total amount of your life insurance in force under all life insurance plans provided under this policy immediately prior to the termination of your coverage. If you should die during the 31-day conversion period, a death benefit will be paid, regardless of whether or not application for conversion has been made.

[1]For a Quebec plan Member to convert, his or her convertible amount must be at least $10,000 or 25 percent of group coverage (whichever is greater).

Supplementary Life Insurance

How To Claim Death Benefits

Your Plan Administrator will furnish all the required claim forms to your beneficiary in the event of your death. In the event of the death of your covered spouse, the required claim forms will be furnished to you. Claims for death benefits must be submitted no later than 12 months after the date of death.

What's Not Covered

No amount will be paid for that part of your Supplementary Life Insurance benefit or spouse's optional life benefit that has been in force for less than 2 years, if loss of life results directly or indirectly, while sane or insane, from suicide, attempted suicide or purposely self-inflicted injury. However, Desjardins Insurance will refund all applicable premiums paid.

For **spouse's optional life insurance,** the rates vary based on your spouse's age, gender and smoking status, and are adjusted according to your spouse's age on the 1st of January each year, with any required adjustment taking effect at that time. Monthly costs are provided in the chart below.

Spouse's Attained Age (as at January 1st)	Male		Female	
	Smoker Monthly Rate (per $1,000)	Non-Smoker Monthly Rate (per $1,000)	Smoker Monthly Rate (per $1,000)	Non-Smoker Monthly Rate (per $1,000)
Under 30	$0.042	$0.032	$0.042	$0.026
30 - 39	$0.069	$0.035	$0.054	$0.032
40 - 49	$0.187	$0.094	$0.113	$0.069
50 - 59	$0.615	$0.307	$0.312	$0.187
60 – 64	$1.200	$0.599	$0.653	$0.390

Note: *Monthly costs shown above reflect those in effect as of January 1st, 2015.*
The monthly cost schedule is subject to change by the insurer; your employer will notify you prior to any changes taking effect.
Monthly costs shown above are subject to applicable taxes.

Supplementary Life Insurance

Conversion Privilege

Your **spouse's** life insurance coverage ceases on the date your employment terminates. You may, however, apply to convert your spouse's insurance, on or before your spouse's 65th birthday, to an individual policy — *without* having to provide medical evidence. You must make written application for the individual policy to Desjardins accompanied by payment of the first premium within 31 days of the date your employment ends. If your spouse should die during the 31-day conversion period, a death benefit equal to the amount of insurance eligible for conversion will be paid, regardless of whether application for conversion has been made.

Dependent Life Insurance

The dependent life insurance plan provides
life insurance coverage for your spouse and/or children.

How The Plan Works

Dependent life insurance benefits are payable to *you* in the event of the death of your covered spouse or dependent child.

Benefits Provided

Under the dependent life insurance plan, your **spouse is covered for $8,000**, while **each dependent child is covered for $4,000**.

Benefits for a dependent child commence on the 15th day after birth.

Waiver of Premium

If you become totally disabled for at least 6 consecutive months before your 65th birthday, your dependent life insurance coverage will be continued without further payment of premiums. Your coverage will continue until you are no longer disabled, retire or reach age 65, whichever occurs first. Proof that you are totally disabled must be submitted to the Insurance Company within 12 months from the onset of the disability, and periodically as requested by the Insurance Company thereafter.

Premium payments are waived during any period in which you are totally disabled and premiums are being waived for your basic life insurance coverage. Premiums will be waived until age 65, recovery or death, whichever occurs first, provided this plan remains in force.

The life waiver benefit will continue in accordance with the terms of the policy regardless of whether or not the plan remains in effect or your other benefit coverages are subsequently terminated, provided your disability begins while your coverage under this plan is in force.

Dependent Life Insurance

Conversion Privilege

Your dependent life insurance coverage ceases on the date your employment terminates. Your spouse may, however, apply to convert his or her insurance to an individual policy — *without* having to provide medical evidence. Your spouse must apply to convert within 31 days of the date your employment ends. If your spouse should die during the 31-day conversion period, a death benefit will be paid, regardless of whether or not application for conversion has been made. A dependent child's insurance may *not* be converted.

How To Claim Death Benefits

Your Plan Administrator will furnish all the required claim forms in the event of the death of your covered spouse or dependent child. Claims for death benefits must be submitted no later than 12 months after the date of death.

Basic Accident Insurance

Your basic accidental death and dismemberment plan provides coverage in the event of accidental death or serious injury.

How The Plan Works

Your basic accidental death and dismemberment insurance covers you 24 hours a day, 7 days a week, anywhere in the world. Benefits from this plan are paid in addition to any life or disability insurance that you receive.

In the event of your accidental death, your accident insurance plan will pay a benefit to your appointed beneficiary. Benefits for all other covered accidental losses are payable to *you*.

You may name anyone you choose to receive benefits payable under the plan in the event of your accidental death. However, if you name a minor, a trustee must also be appointed. You may change your beneficiary designation at any time, subject to the laws governing such changes, by contacting your Plan Administrator.

Benefits Provided

Your basic accidental death and dismemberment insurance coverage is equal to **one and a half times your annual earnings, to a maximum of $200,000**. (Amounts that are not an even multiple of $1,000 are rounded up to the nearest $1,000). Your coverage will reduce by 50% on your 65th birthday.

If you have an accident which results in a serious injury or death within 365 days of the accident, benefits will be paid according to the chart on the following page.

Basic Accident Insurance

If An Accident Results In:	Amount Payable
Quadriplegia (total paralysis of both arms and legs)	2 X insured amount
Paraplegia (total paralysis of both legs)	2 X insured amount
Hemiplegia (total paralysis of the arm and leg on one side of the body)	2 X insured amount
Loss of life	whole amount
Loss of both hands, both feet or both eyes	whole amount
Loss of use of both arms or both hands	whole amount
Loss of one hand and one foot	whole amount
Loss of one hand and one eye or one foot and one eye	whole amount
Loss of speech and hearing in both ears	whole amount
Loss of use of both feet	whole amount
Loss of one arm or one leg	3/4 of insured amount
Loss of use of one arm or one leg	3/4 of insured amount
Loss of one hand, one foot or one eye	2/3 of insured amount
Loss of use of one hand or one foot	2/3 of insured amount
Loss of speech or hearing in both ears	2/3 of insured amount
Loss of thumb and index finger or at least 4 fingers of one hand	1/3 of insured amount
Loss of hearing in one ear	1/3 of insured amount
Loss of all toes of one foot	1/4 of insured amount

Only one of the amounts payable (the largest applicable) is paid for injuries to the same limb caused by any one accident.

The maximum payable for all losses suffered by one covered person in any one accident will not exceed the following:

1. with the exception of quadriplegia, paraplegia and hemiplegia, the whole amount for which he or she is insured,
2. with respect to quadriplegia, paraplegia and hemiplegia, 200% of the amount for which he or she is insured, or 100% if Loss of Life occurs within 90 days after the date of the accident.

Basic Accident Insurance

Exposure & Disappearance

Benefits will also be paid for:

- losses caused by exposure to the elements, resulting from an accident within 365 days of the accident, and
- disappearance due to travel accidents (if a covered person's body is not found within 365 days of an accident in which their vehicle sinks or disappears, and there is no evidence that they survived, the benefit for loss of life is payable).

Repatriation Benefit

The plan will pay for the preparation and transportation of the deceased for burial:

- up to $10,000 if death occurs more than 50 km from the deceased's home, or
- up to $10,000 if death occurs outside of Canada.

Rehabilitation Benefit

The plan provides reimbursement of up to $10,000 for expenses incurred for special training received within 2 years of the accident required in order for you to engage in a new occupation, if you are unable to perform your normal occupation as a result of an accidental loss. Payment will not be made for ordinary living, travelling or clothing expenses.

Occupational Training Benefit

In the event of your accidental death, the plan provides reimbursement of up to $10,000 for expenses incurred for training that qualifies your widowed spouse for a job for which he or she would not have otherwise engaged in, but for your death.

Basic Accident Insurance

Family Transportation Benefit

In the event you are on a trip covered by this plan, and are confined as an inpatient in a hospital because of injuries which result in a loss payable under the Loss Schedule and require the personal attendance of a member of your immediate family as recommended by the attending physician, the plan will pay up to $10,000 for the expense incurred by the member for transportation by the most direct route by a licensed common carrier to be in attendance with you.

"Member of the immediate family" means the spouse or common law spouse, parent, grandparent, children over age 18, brother or sister of the insured person.

Education Benefit

In the event of your accidental death, the plan provides a benefit of up to $5,000 (or 5% of your insured amount, whichever is less) to your dependent child, provided the child was enrolled on a full-time basis in an institution of higher learning beyond the 12th grade level at the time of your death, or was enrolled in the 12th grade level and subsequently enrolls as a full-time student in an institution of higher learning within 365 days of your death.

The maximum benefit is in combination with the Education Benefit maximum provided under any other policy issued by the insurer, and is payable annually for a maximum of four (4) consecutive annual payments, provided the child continues to be enrolled in the institute of higher learning. Payment will not be made for expenses incurred prior to the date of your death, nor for room, board or other ordinary living, travelling or clothing expenses.

If, at the time of your accidental death, you have no dependent child(ren) eligible for either the Education Benefit or the Day Care Benefit, the insurer will pay $1,500 to your designated beneficiary.

Basic Accident Insurance

Day-Care Benefit

In the event of your accidental death, the plan provides a benefit of up to $5,000 (or 5% of your insured amount, whichever is less) for reasonable and necessary expenses actually incurred for day-care, provided the child is enrolled in a day-care centre at the time of your death, or will subsequently enroll in a day-care centre within 365 days of your death.

The maximum benefit is in combination with the Day-Care Benefit maximum provided under any other policy issued by the insurer, for not more than four (4) consecutive years with respect to any one dependent child, provided the child continues to be enrolled in a day-care centre. Payment will not be made for expenses incurred prior to the date of your death, nor for room, board or other ordinary living, travelling or clothing expenses.

"Day-Care centre" means a facility which is operated according to law, including laws and regulations applicable to day-care facilities, and which provides care and supervision for children in a group setting on a regular basis. Day-Care centre shall neither include a hospital, the child's home, care provided during school hours while a child is attending grades one (1) through twelve (12) nor any other day-care facility which does not charge a fee for services rendered. **"Dependent child"** means a person who is either a natural child, step-child or legally adopted child of the insured employee, who is residing in his or her household, is under thirteen (13) years of age and dependent upon the insured employee for maintenance and support.

Private Automobile Seat Belt Coverage

In the event you sustain an injury which results in a loss payable under the Loss Schedule, an additional amount equal to 10% of the amount payable will be paid if, at the time of the accident, you were driving or riding in a vehicle and wearing a properly fastened seat belt.

The driver of the vehicle must hold a current and valid driver's license of a rating authorizing him or her to operate such vehicle, and neither be intoxicated nor under the influence of drugs, unless such drugs are taken as prescribed by a physician, at the time of the accident.

Basic Accident Insurance

Home Alteration & Vehicle Modification Benefit

In the event you receive a payment under the Loss Schedule and subsequently require (due to the same cause for which payment was made under the Loss Schedule) the use of a wheelchair to be ambulatory, this benefit will pay up to $10,000, upon presentation of proof of payment, for:

- the one-time cost of alterations to your residence to make it wheelchair accessible and habitable, and/or
- the one-time cost of modifications necessary to a motor vehicle, owned by you, to make the vehicle accessible or driveable for you.

Benefit payments will not be paid unless:

1. home alterations are made by a person or persons experienced in such alterations and recommended by a recognized organization, providing support and assistance to wheelchair users; and
2. vehicle modifications are carried out by a person or persons with experience in such matters and modifications are approved by the Provincial vehicle licensing authorities.

Waiver of Premium

Premium payments are waived during any period in which you are totally disabled and premiums are being waived for your basic life insurance coverage. Premiums will be waived until age 65, recovery or death, whichever occurs first, provided this plan remains in force.

Conversion Privilege

Your basic accidental death and dismemberment insurance coverage ceases on the date your employment terminates. You may, however, apply to convert your insurance to an individual policy provided this plan is still in force — *without* having to provide medical evidence. You must apply to convert prior to age 70 and within 31 days of the date your employment ends. If you should die accidentally or suffer a covered accidental loss during the 31-day conversion period, a benefit will be paid in accordance with the Loss Schedule, regardless of whether or not application for conversion has been made.

Basic Accident Insurance

How To Claim Accident Benefits

Your Plan Administrator will furnish all the required claim forms to you or your beneficiary in the event of a covered accidental loss or death, respectively. Claims for accident benefits must be submitted no later than 12 months after the accident occurs.

What's Not Covered

Your basic accidental death and dismemberment insurance plan does not cover losses caused by or resulting from:

- suicide or attempted suicide,
- intentionally self-inflicted injury,
- any act of war, declared or undeclared,
- full-time active service in the armed forces of any country,
- injuries suffered while travelling in an aircraft owned or leased by your employer, or a subsidiary, affiliate or associate company of your employer,
- death or bodily injuries suffered while a pilot or crew member of an aircraft, or
- death or bodily injuries suffered while a passenger in an aircraft that is not properly licensed, or operated by a person not holding a current and valid pilot's license.

Note: *Benefits provided under the Repatriation Benefit; Rehabilitation Benefit; Occupational Training Benefit; Family Transportation Benefit; and Home Alteration and Vehicle Modification Benefit are payable under only one of the policies issued to your employer by the insurer.*

3700 Steeles Avenue West, Suite 1100
Vaughan, Ontario L4L 8K8
905.265.5300
1.800.668.9979
www.mearie.ca
Fax: 905.265.5301 Email: mearie@mearie.ca

Attachment 4-F

EPLC Employee Handbook – Non-Management/Union

The MEARIE Group
Employee Benefit Program

Employee Benefit Booklet

Essex Power Corp.
Union

Prepared: October 2015

Notice of Disclaimer

This handbook has been prepared to help you better understand the coverage provided under your employee benefit program. This handbook is not an agreement and it does not create nor confer any contractual or other rights.

The terms and conditions governing your benefit plans are set out in the official contracts between the insurers, your employer and MEARIE Management Inc.

Every effort has been made to ensure that the information in this handbook is accurate. However, if any question should arise, a decision will be made by reference to the official plan contracts and texts.

This handbook has been designed to help you understand and get the most out of your benefits. It gives you most of the information you will generally require regarding your benefits. Separate sections for each benefit plan allow you quick access to the benefit information you want when you want it.

Please keep this handbook in a safe place. If changes are made to your benefits, replacement pages will be provided to you for insertion in this handbook.

Your life and disability plans are insured through ***Desjardins Insurance****, while your accident plan is insured through* ***AIG Insurance Company of Canada****.*

Any questions you have about your benefit program should be referred to your Plan Administrator.

General Information

Enrolling In The Benefit Program

Who Can Enroll

If you are an active permanent full-time employee under the age of 65 and working at least 20 hours per week, you are first eligible to enroll in the benefit program on the date you complete 80 days of continuous service with your employer.

Your spouse is also eligible for coverage under the optional spouse life insurance plan, should you decide to apply.

Spouse

- the person who you are legally married to, or
- a person who continuously resides with you in a role like that of a marriage partner.

Dependent Children

Dependent children include your natural or legally adopted children, or step-children who:

- are unmarried,
- are not employed on a full-time basis,
- are not eligible for insurance as an employee under this plan or any other group plan, and
- are under 21 years of age, or, if in full-time attendance at an accredited school, college or university, are under 25 years of age.

A child insured under this plan, who is incapacitated due to a mental or physical handicap on the date he reaches the age when he would otherwise no longer be eligible for coverage, will continue to be an eligible dependent subject to written proof of the dependent's condition. A child is considered incapacitated if he is incapable of engaging in any substantially gainful activity and is dependent on you for support, maintenance and care, due to a mental or physical handicap.

A stepchild must be living with you to be an eligible dependent.

When Coverage Starts

Coverage for you and your spouse commences on the date you first become eligible to enroll. If you are not actively at work on the date your coverage would normally begin, your coverage will not start until you return to active full-time work.

General Information

When Coverage Terminates

Coverage for you and your dependents will end on:

- the date your employment ends,
- the date you or your spouse cease to qualify for coverage based on the plan's eligibility requirements,
- the date you enter an armed service on full-time duty,
- the date your employer receives a written request from you to terminate the insurance, where permitted,
- the date you fail to make any required premium contribution,
- the date you attain age 65 (applies to all coverage expect Basic Life and Basic AD&D which terminate at age 71),
- the date your spouse attains age 65 (applies to spousal life insurance),
- the date you retire, or
- the date the group plan is cancelled.

If you are not actively at work due to **Maternity or Parental Leave of Absence**, coverage may be continued for the period of leave to which you are entitled by legislation provided premiums continue to be paid on your behalf. If you do not intend to continue your coverage during this period, where permitted by law, you must inform your employer in writing on or before the date your leave begins. In this case, coverage for you and your dependents will not be reinstated until you return to active full-time work.

Coverage for you and your spouse will cease on the date you are not actively at work due to **lay-off, leave of absence (other than maternity or parental leave), strike or lock-out**.

If you are not actively at work due to **illness or injury**:

- your life, accident and disability coverage will continue in accordance with the "Waiver of Premium" provisions described in the applicable sections of this handbook.

Short Term Disability

Your short term disability plan provides you with a weekly income if you are unable to work due to non-occupational injury or illness.

How The Plan Works

Benefits are payable under the short term disability plan if, due to non-occupational injury or illness, you are unable to perform the duties of your normal job.

Benefits are payable from the **1st** day of disability if the disability is due to an accident, or from the **15th** day of disability if the disability is due to illness. However, if an employee is admitted to a hospital overnight as an in-patient, benefits will commence on the first day of hospitalization if the disability is due to either an accident or due to illness.

A hospital is a facility that is licensed to provide active, convalescent or chronic care treatment for sick or injured patients. It does not include nursing homes, homes for the aged, rest homes or any other facility that provides similar care.

Benefits will be paid for up to **26 weeks**.

Benefits Provided

The short term disability plan provides a weekly benefit equal to **66.67% of your weekly earnings, to a maximum of $550**.

To receive benefits, you must be under the regular and continuing care of a physician. Satisfactory proof of your condition and medical attendance must be provided to the Insurance Company.

Any benefits you receive from the short term disability plan are taxable if your employer contributes, in whole or in part, towards the cost of providing the plan.

Short Term Disability

Coordination With Other Disability Benefits

Short term disability benefits are reduced by the amount of income you receive or are entitled to receive as a result of the same disability from any salary continuation arrangement or plan, the Canada Pension Plan, Quebec Pension Plan, or any other federal, provincial, municipal or foreign government plan, excluding any benefits payable with respect to your dependents. However, the benefit will not be offset unless it exceeds 100% of pre-disability income.

When Disability Recurs

If you recover and are able to return to work, only to become unable to work again, the second period of absence will be treated as a continuation of the first unless the medical reason for the second period is unrelated to the first, or is separated from the first by more than 2 weeks.

How To Claim Short Term Disability Benefits

Claim forms are available from your Plan Administrator. Forms should be completed and returned to your Plan Administrator promptly, if you are unable to report for work. Short term disability claims must be submitted no later than 31 days from the date your disability begins.

Short Term Disability

What's Not Covered

Your short term disability plan does not cover:

- any period of disability during which you are not under the regular care and attendance of a legally qualified physician (a legally qualified physician is a medical doctor - a general practitioner (GP) or a specialist - neurologist; orthopaedic surgeon; psychiatrist; etc. A chiropractor is not a medical doctor.),
- any accidental injury arising out of or in the course of employment, or disease covered by Workers' Compensation or similar legislation,
- intentionally self-inflicted injury or illness,
- disability resulting from war, or act of war, or while engaged in the armed services,
- participation in a criminal act, or
- any of the following:
    1. any disability, loss or expense that commences or occurs during your leave of absence except to the extent that the continuation of such insurance coverage during any period of statutory maternity or parental leave of absence is required either by any relevant federal or provincial law (whether statutory, regulatory or otherwise) or by any written agreement between your Utility and you; and
    2. any disability, loss or expense for which you are entitled to receive any basic and supplementary unemployment insurance, maternity/parental leave benefits.

Long Term Disability

Your long term disability plan has been developed to protect you against the financial impact of lost income, if a lengthy illness or injury keeps you from coming to work.

How The Plan Works

Benefits are payable under the long term disability plan after you have been totally and continuously disabled for a period of **6 months** or have used all the sick days to which you are entitled under your sick leave plan, whichever occurs later.

Benefits Provided

If you are totally disabled you will receive a monthly income benefit equal to **75% of your regular monthly earnings, to a maximum of $3,500 per month**.

> *To qualify for long term disability benefits you must be "totally disabled". During the first 24 months that you receive long term disability, this means that you are unable to do the essential duties of your normal job and are not otherwise employed. After this 24-month period, you will continue to qualify for long term disability benefits only if you are unable to work at any job for which you are reasonably suited by virtue of your education, training and experience.*

Any benefits you receive from the long term disability plan are taxable if your employer contributes, in whole or in part, towards the cost of providing the plan.

Benefits from the long term disability plan will stop if you:

- recover,
- attain age 65,
- are unable to provide written proof of your disability,
- are no longer under a physician's care,
- fail to undergo an examination by an independent doctor of the Insurance Company's choice, or
- in the event of your death.

Long Term Disability

Coordination With Other Disability Benefits

Long term disability benefits are reduced by the amount of income you receive or are entitled to receive as a result of the same disability from:

- Workers' Compensation or similar legislation (excluding any future cost of living adjustments),
- the Canada or Quebec Pension Plan (excluding any future cost of living adjustments or dependent benefits payable to you),
- any other federal, provincial or municipal government plan, excluding any disability benefits available to you through the Ontario Municipal Employees' Retirement System, but not filed on your behalf, and
- any other group insurance plan, or any retirement or pension plan of the employer, excluding any disability benefits available to you through the Ontario Municipal Employees' Retirement System.

The benefit you receive will be further reduced, if necessary, so that the total disability income you receive from this plan and any other source (other than income from a private source) does not exceed 85% of your pre-disability net earnings (if benefits are non-taxable) or gross earnings (if benefits are taxable).

Rehabilitation Benefit

The rehabilitation benefit is designed to help you through an adjustment period of up to 24 months while working part-time, in a reduced capacity or involved in a retraining program approved by the Insurance Company.

While you are participating in an approved rehabilitation program, your long term disability benefit will not be discontinued. However, your monthly long term disability benefit will be reduced by 50% of the compensation you receive from rehabilitative employment.

Long Term Disability

When Disability Recurs

If you recover from total disability, only to become disabled again, the second period of disability will be treated as a continuation of the first unless the second disability is unrelated to the first, or is separated from the first by more than six months.

Waiver of Premium

Premium payments are waived during any period in which you receive benefits from this plan. Long term disability benefits will continue in accordance with the terms of the policy regardless of whether or not this plan remains in effect or your other benefit coverages are subsequently terminated, provided your disability begins while your coverage under this plan is in force.

How To Claim Long Term Disability Benefits

Claim forms are available from your Plan Administrator. Early filing of claims is recommended. Forms should be completed and returned to your Plan Administrator after you have been disabled at least 30 days and do not expect to return to work before the *Elimination Period* expires. Long term disability claims must be submitted no later than 90 days after the date you are eligible for benefits to begin.

Long Term Disability

What’s Not Covered

Your long term disability plan does not cover:

- intentionally self-inflicted injury or illness,
- disability resulting from war, or act of war, or while engaged in the armed services,
- any period of disability during which you are not under the regular care and attendance of a legally qualified physician (a legally qualified physician is a medical doctor – a general practitioner (GP) or a specialist – neurologist; orthopaedic surgeon; psychiatrist; etc. A chiropractor is not a medical doctor.),
- any period of disability which commences while you are not insured under this plan,
- participation in a criminal act, or
- disability, loss or expense which commences or occurs during any period of statutory maternity or parental leave of absence except to the extent:
    1. the continuance of insurance coverage during such period of statutory maternity or parental leave of absence is required by legislation or by written agreement between you and your employer; and
    2. you do not receive or are not entitled to receive any payment, benefit, indemnity or other amount from any source, including any policy, plan or fund provided by any employer, insurer or government (including basic and supplementary unemployment insurance maternity/parental leave benefits).

Basic Life Insurance

Your basic life insurance plan pays a benefit
to your beneficiary in the event of your death.

How The Plan Works

If you should die, your basic life insurance plan will pay a benefit to your appointed beneficiary, regardless of the cause of death.

You may name anyone you choose to receive benefits payable under the plan in the event of your death. However, if you name a minor, a trustee must also be appointed. You may change your beneficiary designation at any time, subject to the laws governing such changes, by contacting your Plan Administrator.

Benefits Provided

Your basic life insurance coverage is equal to **one and a half times your annual earnings to a maximum of $125,000**. (Amounts that are not an event multiple of $1,000 are rounded up to the nearest $1,000). Your coverage will reduce by 50% on your 65th birthday.

Waiver of Premium

If you become totally disabled while insured and before your 65th birthday or earlier retirement, your life insurance coverage under the Basic Life plan will be continued without further payment of premiums. Your coverage will continue until you are no longer disabled, retire or reach age 65, whichever occurs first.

Proof that you are totally disabled must be submitted to Desjardins Insurance within 12 months from the onset of the disability, and periodically as requested by Desjardins Insurance thereafter.

Totally Disabled means that you are prevented from performing any work for compensation or profit or from following any gainful occupation. (However, if you are insured for Long Term Disability benefits by Desjardins Insurance under this same master policy, the definition of total disability used to determine your eligibility for disability benefits, as described in this booklet, shall also apply when assessing your life insurance waiver of premium benefit).

Basic Life Insurance

Conversion Privilege

Your basic life insurance coverage ceases on the date your employment terminates. However, if you are under age 65, you may apply to convert your insurance to an individual policy — *without* having to provide medical evidence. You must make written application for the individual policy to Desjardins Insurance accompanied by payment of the first premium within 31 days of the date your basic life insurance terminates. The amount of the individual policy will not exceed the lesser of $200,000 ($400,000 for employees residing in Quebec[1]) or the total amount of your life insurance in force under all life insurance plans provided under this policy immediately prior to the termination of your coverage. If you should die during the 31-day conversion period, a death benefit will be paid, regardless of whether or not application for conversion has been made.

[1]For a Quebec plan Member to convert, his or her convertible amount must be at least $10,000 or 25 percent of group coverage (whichever is greater).

How To Claim Death Benefits

Your Plan Administrator will furnish all the required claim forms to your beneficiary in the event of your death. Claims for death benefits must be submitted no later than 12 months after the date of death.

Supplementary Life Insurance

The Supplementary life insurance plan enables you to purchase additional coverage for yourself and/or your spouse. In the event of your death, the plan pays a benefit to your beneficiary. The benefit is payable to you in the event of the death of your covered spouse.

How The Plan Works

The purchase of supplementary life insurance is completely voluntary; you decide whether or not to participate.

If you should die while insured your supplementary life insurance plan will pay a benefit to the last nominated beneficiary as filed. In the absence of a beneficiary nomination, payment will be made to your estate.

You may name anyone you choose to receive benefits payable under the plan in the event of your death. However, if you name a minor, a trustee must also be appointed. You may change your beneficiary designation at any time, subject to the laws governing such changes, by contacting your Plan Administrator.

If your spouse is insured for life insurance coverage under the spouse's optional life plan, benefits are payable to *you* in the event of the death of your covered spouse.

Benefits Available

Supplementary life insurance coverage is available in **multiples of $10,000, to a maximum of $250,000**. All coverage is subject to medical evidence — proof that you are insurable, satisfactory to the insurer.

Supplementary Life Insurance

Cost of Supplementary Life Insurance

Your cost, paid through payroll deduction, depends on your gender, your age and on whether or not you smoke. (You are considered a "non-smoker" if you have not smoked for the last 12 months). Monthly costs are provided in the table below.

Employee's Attained Age (as at January 1st)	Male		Female	
	Smoker Monthly Rate (per $1,000)	Non-Smoker Monthly Rate (per $1,000)	Smoker Monthly Rate (per $1,000)	Non-Smoker Monthly Rate (per $1,000)
Under 35	$0.044	$0.022	$0.022	$0.020
35 - 39	$0.060	$0.039	$0.033	$0.028
40 - 44	$0.163	$0.080	$0.099	$0.062
45 - 49	$0.285	$0.142	$0.169	$0.098
50 - 54	$0.445	$0.231	$0.240	$0.151
55 - 59	$0.757	$0.383	$0.395	$0.231
60 - 64	$0.890	$0.480	$0.480	$0.300

Note: *Monthly costs shown above reflect those in effect as of January 1st, 2015.*
The monthly cost schedule is subject to change by the insurer; your employer will notify you prior to any changes taking effect.
Monthly costs shown above are subject to applicable taxes.

Supplementary Life Insurance

Waiver of Premium

If you become totally disabled while insured and before your 65th birthday or earlier retirement, your life insurance coverage under the Supplementary Life plan will be continued without further payment of premiums. Your coverage will continue until you are no longer disabled, retire or reach age 65, whichever occurs first.

Proof that you are totally disabled must be submitted to Desjardins Insurance within 12 months from the onset of the disability, and periodically as requested by Desjardins Insurance thereafter.

Totally Disabled means that you are prevented from performing any work for compensation or profit or from following any gainful occupation. (However, if you are insured for Long Term Disability benefits by Desjardins Insurance under this same master policy, the definition of total disability used to determine your eligibility for disability benefits, as described in this booklet, shall also apply when assessing your life insurance waiver of premium benefit).

Conversion Privilege

Your supplementary life insurance coverage ceases on the date your employment terminates. However, if you are under age 65, you may apply to convert your insurance to an individual policy — *without* having to provide medical evidence. You must make written application for the individual policy to Desjardins Insurance accompanied by payment of the first premium within 31 days of the date your supplementary life insurance terminates. The amount of the individual policy will not exceed the lesser of \$200,000 (\$400,000 for employees residing in Quebec[1]) or the total amount of your life insurance in force under all life insurance plans provided under this policy immediately prior to the termination of your coverage. If you should die during the 31-day conversion period, a death benefit will be paid, regardless of whether or not application for conversion has been made.

[1]For a Quebec plan Member to convert, his or her convertible amount must be at least \$10,000 or 25 percent of group coverage (whichever is greater).

Supplementary Life Insurance

How To Claim Death Benefits

Your Plan Administrator will furnish all the required claim forms to your beneficiary in the event of your death. In the event of the death of your covered spouse, the required claim forms will be furnished to you. Claims for death benefits must be submitted no later than 12 months after the date of death.

What's Not Covered

No amount will be paid for that part of your Supplementary Life Insurance benefit or spouse's optional life benefit that has been in force for less than 2 years, if loss of life results directly or indirectly, while sane or insane, from suicide, attempted suicide or purposely self-inflicted injury. However, Desjardins Insurance will refund all applicable premiums paid.

For **spouse's optional life insurance,** the rates vary based on your spouse's age, gender and smoking status, and are adjusted according to your spouse's age on the 1st of January each year, with any required adjustment taking effect at that time. Monthly costs are provided in the chart below.

Spouse's Attained Age (as at January 1st)	Male		Female	
	Smoker Monthly Rate (per $1,000)	Non-Smoker Monthly Rate (per $1,000)	Smoker Monthly Rate (per $1,000)	Non-Smoker Monthly Rate (per $1,000)
Under 30	$0.042	$0.032	$0.042	$0.026
30 - 39	$0.069	$0.035	$0.054	$0.032
40 - 49	$0.187	$0.094	$0.113	$0.069
50 - 59	$0.615	$0.307	$0.312	$0.187
60 – 64	$1.200	$0.599	$0.653	$0.390

Note: *Monthly costs shown above reflect those in effect as of January 1st, 2015.*
The monthly cost schedule is subject to change by the insurer; your employer will notify you prior to any changes taking effect.
Monthly costs shown above are subject to applicable taxes.

Supplementary Life Insurance

Conversion Privilege

Your **spouse's** life insurance coverage ceases on the date your employment terminates. You may, however, apply to convert your spouse's insurance, on or before your spouse's 65th birthday, to an individual policy — *without* having to provide medical evidence. You must make written application for the individual policy to Desjardins accompanied by payment of the first premium within 31 days of the date your employment ends. If your spouse should die during the 31-day conversion period, a death benefit equal to the amount of insurance eligible for conversion will be paid, regardless of whether application for conversion has been made.

Dependent Life Insurance

The dependent life insurance plan provides
life insurance coverage for your spouse and/or children.

How The Plan Works

Dependent life insurance benefits are payable to *you* in the event of the death of your covered spouse or dependent child.

Benefits Provided

Under the dependent life insurance plan, your **spouse is covered for $8,000**, while **each dependent child is covered for $4,000**.

Benefits for a dependent child commence on the 15th day after birth.

Waiver of Premium

If you become totally disabled for at least 6 consecutive months before your 65th birthday, your dependent life insurance coverage will be continued without further payment of premiums. Your coverage will continue until you are no longer disabled, retire or reach age 65, whichever occurs first. Proof that you are totally disabled must be submitted to the Insurance Company within 12 months from the onset of the disability, and periodically as requested by the Insurance Company thereafter.

Premium payments are waived during any period in which you are totally disabled and premiums are being waived for your basic life insurance coverage. Premiums will be waived until age 65, recovery or death, whichever occurs first, provided this plan remains in force.

The life waiver benefit will continue in accordance with the terms of the policy regardless of whether or not the plan remains in effect or your other benefit coverages are subsequently terminated, provided your disability begins while your coverage under this plan is in force.

Dependent Life Insurance

Conversion Privilege

Your dependent life insurance coverage ceases on the date your employment terminates. Your spouse may, however, apply to convert his or her insurance to an individual policy — *without* having to provide medical evidence. Your spouse must apply to convert within 31 days of the date your employment ends. If your spouse should die during the 31-day conversion period, a death benefit will be paid, regardless of whether or not application for conversion has been made. A dependent child's insurance may *not* be converted.

How To Claim Death Benefits

Your Plan Administrator will furnish all the required claim forms in the event of the death of your covered spouse or dependent child. Claims for death benefits must be submitted no later than 12 months after the date of death.

Basic Accident Insurance

Your basic accidental death and dismemberment plan provides coverage in the event of accidental death or serious injury.

How The Plan Works

Your basic accidental death and dismemberment insurance covers you 24 hours a day, 7 days a week, anywhere in the world. Benefits from this plan are paid in addition to any life or disability insurance that you receive.

In the event of your accidental death, your accident insurance plan will pay a benefit to your appointed beneficiary. Benefits for all other covered accidental losses are payable to *you*.

You may name anyone you choose to receive benefits payable under the plan in the event of your accidental death. However, if you name a minor, a trustee must also be appointed. You may change your beneficiary designation at any time, subject to the laws governing such changes, by contacting your Plan Administrator.

Benefits Provided

Your basic accidental death and dismemberment insurance coverage is equal to **one and a half times your annual earnings, to a maximum of $125,000**. (Amounts that are not an even multiple of $1,000 are rounded up to the nearest $1,000). Your coverage will reduce by 50% on your 65th birthday.

If you have an accident which results in a serious injury or death within 365 days of the accident, benefits will be paid according to the chart on the following page.

Basic Accident Insurance

If An Accident Results In:	Amount Payable
Quadriplegia (total paralysis of both arms and legs)	2 X insured amount
Paraplegia (total paralysis of both legs)	2 X insured amount
Hemiplegia (total paralysis of the arm and leg on one side of the body)	2 X insured amount
Loss of life	whole amount
Loss of both hands, both feet or both eyes	whole amount
Loss of use of both arms or both hands	whole amount
Loss of one hand and one foot	whole amount
Loss of one hand and one eye or one foot and one eye	whole amount
Loss of speech and hearing in both ears	whole amount
Loss of use of both feet	whole amount
Loss of one arm or one leg	3/4 of insured amount
Loss of use of one arm or one leg	3/4 of insured amount
Loss of one hand, one foot or one eye	2/3 of insured amount
Loss of use of one hand or one foot	2/3 of insured amount
Loss of speech or hearing in both ears	2/3 of insured amount
Loss of thumb and index finger or at least 4 fingers of one hand	1/3 of insured amount
Loss of hearing in one ear	1/3 of insured amount
Loss of all toes of one foot	1/4 of insured amount

Only one of the amounts payable (the largest applicable) is paid for injuries to the same limb caused by any one accident.

The maximum payable for all losses suffered by one covered person in any one accident will not exceed the following:

1. with the exception of quadriplegia, paraplegia and hemiplegia, the whole amount for which he or she is insured,
2. with respect to quadriplegia, paraplegia and hemiplegia, 200% of the amount for which he or she is insured, or 100% if Loss of Life occurs within 90 days after the date of the accident.

Basic Accident Insurance

Exposure & Disappearance

Benefits will also be paid for:

- losses caused by exposure to the elements, resulting from an accident within 365 days of the accident, and
- disappearance due to travel accidents (if a covered person's body is not found within 365 days of an accident in which their vehicle sinks or disappears, and there is no evidence that they survived, the benefit for loss of life is payable).

Repatriation Benefit

The plan will pay for the preparation and transportation of the deceased for burial:

- up to $10,000 if death occurs more than 50 km from the deceased's home, or
- up to $10,000 if death occurs outside of Canada.

Rehabilitation Benefit

The plan provides reimbursement of up to $10,000 for expenses incurred for special training received within 2 years of the accident required in order for you to engage in a new occupation, if you are unable to perform your normal occupation as a result of an accidental loss. Payment will not be made for ordinary living, travelling or clothing expenses.

Occupational Training Benefit

In the event of your accidental death, the plan provides reimbursement of up to $10,000 for expenses incurred for training that qualifies your widowed spouse for a job for which he or she would not have otherwise engaged in, but for your death.

Basic Accident Insurance

Family Transportation Benefit

In the event you are on a trip covered by this plan, and are confined as an inpatient in a hospital because of injuries which result in a loss payable under the Loss Schedule and require the personal attendance of a member of your immediate family as recommended by the attending physician, the plan will pay up to $10,000 for the expense incurred by the member for transportation by the most direct route by a licensed common carrier to be in attendance with you.

"Member of the immediate family" means the spouse or common law spouse, parent, grandparent, children over age 18, brother or sister of the insured person.

Education Benefit

In the event of your accidental death, the plan provides a benefit of up to $5,000 (or 5% of your insured amount, whichever is less) to your dependent child, provided the child was enrolled on a full-time basis in an institution of higher learning beyond the 12th grade level at the time of your death, or was enrolled in the 12th grade level and subsequently enrolls as a full-time student in an institution of higher learning within 365 days of your death.

The maximum benefit is in combination with the Education Benefit maximum provided under any other policy issued by the insurer, and is payable annually for a maximum of four (4) consecutive annual payments, provided the child continues to be enrolled in the institute of higher learning. Payment will not be made for expenses incurred prior to the date of your death, nor for room, board or other ordinary living, travelling or clothing expenses.

If, at the time of your accidental death, you have no dependent child(ren) eligible for either the Education Benefit or the Day Care Benefit, the insurer will pay $1,500 to your designated beneficiary.

Basic Accident Insurance

Day-Care Benefit

In the event of your accidental death, the plan provides a benefit of up to $5,000 (or 5% of your insured amount, whichever is less) for reasonable and necessary expenses actually incurred for day-care, provided the child is enrolled in a day-care centre at the time of your death, or will subsequently enroll in a day-care centre within 365 days of your death.

The maximum benefit is in combination with the Day-Care Benefit maximum provided under any other policy issued by the insurer, for not more than four (4) consecutive years with respect to any one dependent child, provided the child continues to be enrolled in a day-care centre. Payment will not be made for expenses incurred prior to the date of your death, nor for room, board or other ordinary living, travelling or clothing expenses.

"Day-Care centre" means a facility which is operated according to law, including laws and regulations applicable to day-care facilities, and which provides care and supervision for children in a group setting on a regular basis. Day-Care centre shall neither include a hospital, the child's home, care provided during school hours while a child is attending grades one (1) through twelve (12) nor any other day-care facility which does not charge a fee for services rendered. **"Dependent child"** means a person who is either a natural child, step-child or legally adopted child of the insured employee, who is residing in his or her household, is under thirteen (13) years of age and dependent upon the insured employee for maintenance and support.

Private Automobile Seat Belt Coverage

In the event you sustain an injury which results in a loss payable under the Loss Schedule, an additional amount equal to 10% of the amount payable will be paid if, at the time of the accident, you were driving or riding in a vehicle and wearing a properly fastened seat belt.

The driver of the vehicle must hold a current and valid driver's license of a rating authorizing him or her to operate such vehicle, and neither be intoxicated nor under the influence of drugs, unless such drugs are taken as prescribed by a physician, at the time of the accident.

Basic Accident Insurance

Home Alteration & Vehicle Modification Benefit

In the event you receive a payment under the Loss Schedule and subsequently require (due to the same cause for which payment was made under the Loss Schedule) the use of a wheelchair to be ambulatory, this benefit will pay up to $10,000, upon presentation of proof of payment, for:

- the one-time cost of alterations to your residence to make it wheelchair accessible and habitable, and/or
- the one-time cost of modifications necessary to a motor vehicle, owned by you, to make the vehicle accessible or driveable for you.

Benefit payments will not be paid unless:

1. home alterations are made by a person or persons experienced in such alterations and recommended by a recognized organization, providing support and assistance to wheelchair users; and
2. vehicle modifications are carried out by a person or persons with experience in such matters and modifications are approved by the Provincial vehicle licensing authorities.

Waiver of Premium

Premium payments are waived during any period in which you are totally disabled and premiums are being waived for your basic life insurance coverage. Premiums will be waived until age 65, recovery or death, whichever occurs first, provided this plan remains in force.

Conversion Privilege

Your basic accidental death and dismemberment insurance coverage ceases on the date your employment terminates. You may, however, apply to convert your insurance to an individual policy provided this plan is still in force — *without* having to provide medical evidence. You must apply to convert prior to age 70 and within 31 days of the date your employment ends. If you should die accidentally or suffer a covered accidental loss during the 31-day conversion period, a benefit will be paid in accordance with the Loss Schedule, regardless of whether or not application for conversion has been made.

Basic Accident Insurance

How To Claim Accident Benefits

Your Plan Administrator will furnish all the required claim forms to you or your beneficiary in the event of a covered accidental loss or death, respectively. Claims for accident benefits must be submitted no later than 12 months after the accident occurs.

What's Not Covered

Your basic accidental death and dismemberment insurance plan does not cover losses caused by or resulting from:

- suicide or attempted suicide,
- intentionally self-inflicted injury,
- any act of war, declared or undeclared,
- full-time active service in the armed forces of any country,
- injuries suffered while travelling in an aircraft owned or leased by your employer, or a subsidiary, affiliate or associate company of your employer,
- death or bodily injuries suffered while a pilot or crew member of an aircraft, or
- death or bodily injuries suffered while a passenger in an aircraft that is not properly licensed, or operated by a person not holding a current and valid pilot's license.

Note: *Benefits provided under the Repatriation Benefit; Rehabilitation Benefit; Occupational Training Benefit; Family Transportation Benefit; and Home Alteration and Vehicle Modification Benefit are payable under only one of the policies issued to your employer by the insurer.*

The MEARIE Group
3700 Steeles Avenue West, Suite 1100
Vaughan, Ontario L4L 8K8
905.265.5300
1.800.668.9979
www.mearie.ca
Fax: 905.265.5301 Email: mearie@mearie.ca

Attachment 4-G

Employee Costs

File Number:	EB-2017-0039
Exhibit:	4
Attachment:	4-G
Page:	1 of 1
Date:	August 28th, 2017

Appendix 2-K
Employee Costs

	Last Rebasing Year - 2010- Board Approved	Last Rebasing Year - 2010- Actual	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Number of Employees (FTEs including Part-Time)[1]										
Management (including executive)	12	15	15	12	12	13	12	10	11	11
Non-Management (union and non-union)	45	38	29	32	32	35	32	34	35	35
Total	57	53	44	44	44	48	44	44	46	46
Total Salary and Wages including ovetime and incentive pay										
Management (including executive)	$ 1,020,892	$ 1,235,240	$ 1,151,468	$ 1,067,030	$ 1,067,391	$ 1,110,844	$ 1,052,468	$ 969,389	$ 1,127,378	$ 1,149,926
Non-Management (union and non-union)	$ 3,086,722	$ 2,582,457	$ 1,916,942	$ 2,385,412	$ 2,382,334	$ 2,645,925	$ 2,721,429	$ 2,883,015	$ 2,838,207	$ 2,894,971
Total	$ 4,107,614	$ 3,817,697	$ 3,068,410	$ 3,452,442	$ 3,449,725	$ 3,756,769	$ 3,773,897	$ 3,852,404	$ 3,965,585	$ 4,044,897
Total Benefits (Current + Accrued) [2]										
Management (including executive)	$ 210,560	$ 251,109	$ 294,304	$ 241,866	$ 237,232	$ 233,455	$ 223,354	$ 217,211	$ 266,096	$ 213,995
Non-Management (union and non-union)	$ 630,555	$ 524,981	$ 489,952	$ 540,707	$ 529,482	$ 556,068	$ 577,539	$ 645,996	$ 669,904	$ 683,005
Total	$ 841,115	$ 776,090	$ 784,256	$ 782,573	$ 766,714	$ 789,523	$ 800,893	$ 863,207	$ 936,000	$ 897,000
Total Compensation (Salary, Wages, & Benefits)										
Management (including executive)	$ 1,231,452	$ 1,486,349	$ 1,445,772	$ 1,308,896	$ 1,304,623	$ 1,344,299	$ 1,275,822	$ 1,186,600	$ 1,393,474	$ 1,363,920
Non-Management (union and non-union)	$ 3,717,277	$ 3,107,438	$ 2,406,894	$ 2,926,119	$ 2,911,816	$ 3,201,993	$ 3,298,968	$ 3,529,011	$ 3,508,111	$ 3,577,977
Total	$ 4,948,729	$ 4,593,787	$ 3,852,666	$ 4,235,015	$ 4,216,439	$ 4,546,292	$ 4,574,790	$ 4,715,611	$ 4,901,585	$ 4,941,897

Note:

[1] If an applicant wishes to use headcount, it must also file the same schedule on an FTE basis.

[2] Current employee benefits, plus Pension and Other Post-Employment Benefits costs, as recorded for recovery in distribution rates. Should be consistent with OPEBs costs as documented in Appendix 2-KA.

Attachment 4-H

EPLC Post-Employment Benefits
Actuary Report

K-W ACTUARIAL SERVICES INC.

102 – 515 Riverbend Drive | Phone: (519) 579-1255
Kitchener, ON N2K 3S3 | Fax: (519) 579-5010

January 16, 2015

Richard Dimmel, CMA **sent by email only**
General Manager
Essex Powerlines Corporation
2730 Highway #3
Oldcastle, ON N0R 1L0

Dear Richard:

Re: Post-Employment Benefits Accounting

Further to your request, we have completed a full valuation of the plan(s) and disclosure requirements for the fiscal period ending December 31, 2014 for Essex Power Corporation, Essex Powerlines Corporation, and Essex Energy Corporation. Obligations were previously determined as at December 31, 2011 and were reported for fiscal year 2011, with projections for fiscal years 2012 through 2014.

We have been informed that accounting under IFRS 19(R) is to be adopted effective January 1, 2015. Further, it is assumed that the plan sponsor has chosen to recognize gains and losses through adjustments to Other Comprehensive Income.

Data

Current monthly premium rates were provided by the plan sponsor as shown in the following table.

	Health		**Dental**	
Division	**Single**	**Family**	**Single**	**Family**
Grandfathered Amherstburg	152.99	325.34	33.30	105.31
Grandfathered Leamington		323.72		105.31
Grandfathered LaSalle		325.34		105.31
Union Retirees	191.37	289.41	64.65	123.73
Management Retirees	191.37	327.70	64.65	144.27

Individual employee and retiree data was provided for all covered individuals. The following table summarizes the data provided by the plan sponsor.

	Active Employees	Retired Employees
Essex Power Corporation		
Number	9	1
Average Age	45.1	65.3
Average Years of Service	11.5	
Essex Powerlines Corporation		
Number	40	21
Average Age	46.8	64.2
Average Years of Service	14.6	
Essex Energy Corporation		
Number	10	0
Average Age	34.7	
Average Years of Service	5.3	

Insurance Plan

The following table summarizes the plan provisions:

Retiring Allowance	Retirement with OMERS pension and with age plus service totaling 80 points. Payment is $600 per year of completed OMERS service. Available only if hired prior to June 2003.	
Other Benefits	**Payable To Age 65**	**Payable From Age 65 to Age 70**
Eligibility	Retirement from OMERS with age plus service totaling 80 points.	Date of hire prior to June 2003.
Drugs	$5.00 prescription fee; no over the counter drugs	N/A
	100% employer paid (excludes over the counter)	80% employer paid to $20,000/year
Extended Health	Employer pay all - no deductible	$25/$50 employee co-pay
	Physiotherapy to $500/year	Physiotherapy to $300/year
	Psychologist, $35/visit to $350/year	N/A
	Chiropractor to $400/year ($10 co-pay first 15 visits)	Chiropractor to $300/year
	Osteopath/Chiropodist/Podiatrist to $400/year	Chiropodist/Podiatrist to $300/year
	Speech Therapist to $200/year	N/A
	Massage Therapy, $7/visit to 12/year	N/A
	Private Hospital, $1,000 lifetime maximum	N/A
	Semi Private Hospital	Semi Private Hospital, 15 day maximum
	Audio company self-funded - $300 maximum for 3 years	N/A
	Vision to $300/24 months	Vision to $200/24 months

	Out of Province, 180 days to $1 Million/year	N/A
	Employee Assistance Plan	N/A
Dental	No deductible ($3,500 maximum)	N/A
	100% Basic	90% Basic to $1,000 annual maximum
	100% Endodontics/periodontics	N/A
	50% Crowns/bridges/caps	N/A
	50% Dentures	N/A
	50% Orthodontics, maximum $2,500	N/A
Spousal Benefits	Continues to surviving spouse and eligible dependents.	Continues to surviving spouse and eligible dependents.

Grandfathered Groups (for employees who retired prior to June, 2003):

Amherstburg	**Life insurance** at 50% of final annual earnings, reducing by 2.5% per year to an ultimate level of 25% of final earnings. Benefit is provided for life. Only two retirees remain with this benefit.
	Health and Dental coverage is for the retiree and his/her spouse's lifetime.
Leamington	**Health and Dental** coverage ends at age 65.
	Life insurance at 50% of final annual earnings, reducing by 2.5% per year to an ultimate level of 25% of final earnings. Benefit is provided for life. Only one retiree remains with this benefit.
LaSalle	**Health and Dental** coverage is for the retiree and his/her spouse's lifetime. Two retirees remain with these benefits.

Attestation

I am pleased to provide the following:

a. This report provides a summary of the valuation.
b. The assumptions outlined below provide methods and principles applied in their establishment.
c. The data summarized above was provided by the plan sponsor and have been relied upon for purposes of the valuation. Rigorous tests were not carried out on the data provided, with the exception of comparing current data to previous valuation data.
d. This report has been completed prior to the fiscal year end date. We are not aware of any events subsequent to the fiscal year end that would impact on the valuation results.
e. Canadian GAAP (Part V) accounting policies have been used through 2014. IFRS(R) is adopted effective January 1, 2015; 2014 results are provided on both bases.
f. We are not aware of any significant events that occurred during the reporting period.
g. We confirm the following:
   (i) We have been appointed by the management of Essex Powerlines Corporation to carry out the valuation. I am aware that your auditor intends to use my work for audit evidence.
   (ii) In our valuation we have been objective and are free from material financial interest in the outcome of the valuation.

(iii) I am a fully qualified Fellow of the CIA in good professional standing and possess the requisite competency to perform the valuation.
(iv) The valuation has been performed with due care.
(v) There have been no restrictions imposed on me regarding what may be communicated to your auditor.
(vi) I agree to preserve the confidentiality of any information provided by the auditor.
(vii) The benefit plan is a defined benefit plan as defined in CPA Canada Handbook.
(viii) I have confirmed with the plan sponsor that:
1. The valuation includes all employee future benefit plans required to be included in the valuation.
2. The plan's provisions are up to date as at the date of the report.
3. The plan sponsor will advise us of changes to the plan's provisions and events that could have a material effect on the valuation.

(ix) The valuation has been performed in accordance with the standards of the CIA.
(x) The amounts derived from the valuation are in accordance with the framework as described above.
(xi) In performing the valuation we have used a discount rate determined in accordance with the framework and best estimate assumptions developed by management following discussions with us. It is our opinion that the assumptions are appropriate for the valuation and disclosure.

The significant actuarial assumptions used in the calculations are as follows:

- The date of all calculations is December 31, 2014.
- A discount rate of 5.00% was used to establish liabilities at December 31, 2013 and for extrapolation during 2014. A rate of 4.00% was chosen for use as at December 31, 2014 and subsequent extrapolations; this is the single discount rate, rounded to the nearest 0.25%, that duplicates the plan's obligations determined using the Fiera Capital/CIA yield curve as at November 28, 2014 (the latest date for which the curve is available).
- No assets have or are expected to be accumulated for the plan.
- A salary growth rate is not incorporated as no benefits are related to earnings.
- Mortality is on the basis of the CPM 2014 Mortality Table (Composite) projected on a generational basis using Improvement Scale CPM-B1D2014; no size band adjustments are included. The previous valuation used the 1994 UP Mortality Table projected to 2015.
- Termination of employment is based on the Ontario Light Scale.

- The following table shows rates of mortality and employee termination at certain ages:

	Mortality Rate		Projection Scale		Termination
Age	**Male**	**Female**	**Male**	**Female**	**Rate**
20	0.000820	0.000180	0.00890	0.00960	0.100
25	0.001080	0.000240	0.00790	0.00570	0.100
30	0.001200	0.000300	0.01300	0.00610	0.056
35	0.001200	0.000420	0.01630	0.00850	0.032
40	0.001360	0.000610	0.01420	0.00970	0.022
45	0.001900	0.000860	0.00730	0.00610	0.017
50	0.002660	0.001290	-0.00020	0.00290	0.012
55	0.004030	0.002070	0.00140	0.00310	
60	0.006280	0.003500	0.00550	0.00490	
65	0.008440	0.005620	0.00810	0.00690	
70	0.012820	0.008860	0.00990	0.00690	
75	0.021830	0.014690	0.01420	0.00820	
80	0.039810	0.027290	0.01950	0.01160	
85	0.075710	0.053520	0.01540	0.01450	
90	0.140410	0.102800	0.00890	0.00910	
95	0.248080	0.189020	0.00110	0.00120	

- Retirement at age 57 (current age plus 1 if currently age 57 or more) is presumed. For certain management employees the plan sponsor has estimated a future retirement year based on knowledge of the employee.
- Health care trend rates of 8% in the first year after the valuation, reducing linearly to 4.5% over 6 years has been used.
- Dental care trend rates of 4.5% per year are assumed.
- Expenses related to the payout of life insurance benefits are presumed to be 10% of the amount of insurance paid.
- The value of projected benefits is prorated over the attribution period to determine the amount of expense to charge to various periods. The accrued obligation represents the present value of benefits assigned to periods prior to the valuation date.
- Amortizations are made using a straight-line method over the average of the expected average future service period of active employees.
- The attribution method is based on prorating benefits over each employee's period of service to the attainment of age 55 or the attainment of age plus service totaling 80 if later.
- The valuation allowance is zero.

- The Expected Average Remaining Service Lifetime (EARSL) has been calculated as shown in the attached disclosure tables.

Calculations

On the basis of the assumptions and methods noted above, I have determined the present value of benefit obligations related to service through 2014. The attached tables show the calculated obligation amounts at the December 31, 2014 fiscal end date, as well as projections for fiscal years 2015 through 2017. The projections will remain reasonable for reporting purposes provided the above assumptions remain reasonable (notably the discount rate). Separate tables are provided for Essex Power Corporation, Essex Powerlines Corporation, and Essex Energy Corporation.

The net gain over the three year valuation period ending December 2014 totals $1,141,000. The main factors influencing this gain were as follows:

- The previous valuation established lifetime benefits for some employees and retirees not who were in fact entitled to benefits to age 65 or 70, thereby overstating the liabilities. Liabilities should have been stated as $759,000 lower than presented in the previous report.
- Experience gains of $746,000 resulted from experience differing from those established in the last valuation.
- A loss of $300,000 resulted from the reduction in the discount rate from 5% to 4%.
- A loss of $64,000 resulted from the change in the mortality assumption used to predict future deaths.

Please feel free to contact me should you require additional information or clarification of any of the information provided here.

Sincerely,

W.M. (Bill) Loucks, FCIA

Att.

Appendix A: Essex Powerlines Corporation	**CICA**	**IFRS**	**Projected**	**Projected**	**Projected**
Fiscal Year	**2014**	**2014**	**2015**	**2016**	**2017**
Discount rate at start of period	5.00%	5.00%	4.00%	4.00%	4.00%
Discount rate at end of period	4.00%	4.00%	4.00%	4.00%	4.00%
Interest rate on assets	N/A	N/A	N/A	N/A	N/A
CPI increase assumption	2.00%	2.00%	2.00%	2.00%	2.00%
Termination rates	Ont. Light	Ont. Light	Ont. Light	Ont. Light	Ont. Light
Mortality table	CPM proj.	CPM proj.	CPM proj.	CPM proj.	CPM proj.
Retirement Age	57	57	57	57	57
Health Care Initial Trend Rate	6.50%	6.50%	6.00%	5.50%	5.00%
Ultimate Trend Rate	4.50%	4.50%	4.50%	4.50%	4.50%
Dental Care Initial Trend Rate	4.50%	4.50%	4.50%	4.50%	4.50%
Ultimate Trend Rate	4.50%	4.50%	4.50%	4.50%	4.50%
EARSL Period	8.9	8.9	8.9	8.9	8.9
Reconcile Obligation					
Obligation at start of year	3,600,716	3,600,716	2,562,809	2,667,598	2,688,420
Plan amendments in year	0	0	0	0	0
Employer current service cost	75,977	75,977	87,516	91,017	94,658
Member contributions	0	0	0	0	0
Benefit payments	(124,452)	(124,452)	(87,000)	(177,000)	(119,000)
Interest on obligation	180,723	180,723	104,273	106,805	108,943
Obligation at end of year	3,732,964	3,732,964	2,667,598	2,688,420	2,773,021
Actual obligations at end of year	2,562,809	2,562,809	2,667,598	2,688,420	2,773,021
(Gain)/Loss recognized at end of year	(1,170,155)	(1,170,155)	0	0	0
Reconcile Plan Funds					
Asset at start of period	0	0	0	0	0
Employer contributions	124,452	124,452	87,000	177,000	119,000
Benefit payments	(124,452)	(124,452)	(87,000)	(177,000)	(119,000)
Fund earnings	0	0	0	0	0
Asset at end of period	0	0	0	0	0

Appendix A: Essex Powerlines Corporation	**CICA**	**IFRS**	**Projected**	**Projected**	**Projected**
Fiscal Year	**2014**	**2014**	**2015**	**2016**	**2017**
Expense					
Current service cost	75,977	75,977	87,516	91,017	94,658
Interest on obligation	180,723	180,723	104,273	106,805	108,943
Interest on assets	0	0	0	0	0
Amortize transition amount	0	0	0	0	0
Amortize plan improvements	(26,424)	0	0	0	0
Amortize gains and losses	(29,028)	0	0	0	0
Expense	201,248	256,700	191,789	197,822	203,601
Transition obligation (asset)					
Transition amount at start of period	0	0	0	0	0
Amortization during period	0	0	0	0	0
Transition amount at end of period	0	0	0	0	0
Prior service costs					
Unamortized prior costs at start 2003	0	0	0	0	0
Unamortized prior costs at start 2005	26,427	26,427	0	0	0
Total	26,427	26,427	0	0	0
Amortization during period 2003	0	0	0	0	0
Amortization during period 2005	(26,424)	0	0	0	0
Total	(26,424)	0	0	0	0
Unamortized prior costs at end 2003	0	0	0	0	0
Unamortized prior costs at end 2005	3	26,427	0	0	0
Total	3	26,427	0	0	0
Transfer to Balance Sheet on Conversion		26,427			
Actuarial (gains) & losses					
Unamortized amount at start	(258,346)	(258,346)	0	0	0
(Gain) or Loss in period	(1,170,155)	(1,170,155)	0	0	0
Transfer to Balance Sheet on Conversion		1,428,501			
Amortization during period	(29,028)	0	0	0	0
Unamortized amount at end	(1,399,473)	0	0	0	0

Appendix A: Essex Powerlines Corporation **Fiscal Year**	**CICA** **2014**	**IFRS** **2014**	**Projected** **2015**	**Projected** **2016**	**Projected** **2017**
Accrued benefit asset (liability)					
Amount at start of period	(3,885,489)	(3,885,489)	(2,562,809)	(2,667,598)	(2,688,420)
Expense in period	(201,248)	(256,700)	(191,789)	(197,822)	(203,601)
Transfer to Balance Sheet on Conversion		1,454,928			
Employer contribution	124,452	124,452	87,000	177,000	119,000
Amount at end of period	(3,962,285)	(2,562,809)	(2,667,598)	(2,688,420)	(2,773,021)
Reconcile funded status					
Benefit obligation at end of period	2,562,809	2,562,809	2,667,598	2,688,420	2,773,021
Asset value at end of period	0	0	0	0	0
Funded status - surplus (deficit)	(2,562,809)	(2,562,809)	(2,667,598)	(2,688,420)	(2,773,021)
Unamortized transition obligation (asset)	0	0	0	0	0
Unamortized prior service costs	(3)	0	0	0	0
Unamortized (gains) & losses	(1,399,473)	0	0	0	0
Accrued benefit asset (liability)	(3,962,285)	(2,562,809)	(2,667,598)	(2,688,420)	(2,773,021)
Estimated benefit costs					
First year following fiscal year	87,000	87,000	177,000	119,000	180,000
Second year following fiscal year	177,000	177,000	119,000	180,000	154,000
Third year following fiscal year	119,000	119,000	180,000	154,000	161,000
Fourth year following fiscal year	180,000	180,000	154,000	161,000	207,000
Fifth-10th years following fiscal year	999,000	999,000	1,058,000	1,148,000	1,161,000
Sensitivity Testing					
Liability change resulting from:					
1% increase in trend rate	252,000	252,000	262,000	264,000	272,000
1% decrease in trend rate	(219,000)	(219,000)	(228,000)	(230,000)	(237,000)

Appendix B: Essex Power Corporation	**CICA**	**IFRS**	**Projected**	**Projected**	**Projected**
Fiscal Year	**2014**	**2014**	**2015**	**2016**	**2017**
Discount rate at start of period	5.00%	5.00%	4.00%	4.00%	4.00%
Discount rate at end of period	4.00%	4.00%	4.00%	4.00%	4.00%
Interest rate on assets	N/A	N/A	N/A	N/A	N/A
CPI increase assumption	2.00%	2.00%	2.00%	2.00%	2.00%
Termination rates	Ont. Light	Ont. Light	Ont. Light	Ont. Light	Ont. Light
Mortality table	CPM proj.	CPM proj.	CPM proj.	CPM proj.	CPM proj.
Retirement Age	57	57	57	57	57
Health Care Initial Trend Rate	6.50%	6.50%	6.00%	5.50%	5.00%
Ultimate Trend Rate	4.50%	4.50%	4.50%	4.50%	4.50%
Dental Care Initial Trend Rate	4.50%	4.50%	4.50%	4.50%	4.50%
Ultimate Trend Rate	4.50%	4.50%	4.50%	4.50%	4.50%
EARSL Period	10.3	10.3	10.3	10.3	10.3
Reconcile Obligation					
Obligation at start of year	367,892	367,892	324,776	362,120	395,934
Plan amendments in year	0	0	0	0	0
Employer current service cost	23,125	23,125	26,359	27,413	28,510
Member contributions	0	0	0	0	0
Benefit payments	(5,518)	(5,518)	(3,000)	(9,000)	(25,000)
Interest on obligation	19,413	19,413	13,985	15,401	16,478
Obligation at end of year	404,912	404,912	362,120	395,934	415,922
Actual obligations at end of year	324,776	324,776	362,120	395,934	415,922
(Gain)/Loss recognized at end of year	(80,136)	(80,136)	0	0	0
Reconcile Plan Funds					
Asset at start of period	0	0	0	0	0
Employer contributions	5,518	5,518	3,000	9,000	25,000
Benefit payments	(5,518)	(5,518)	(3,000)	(9,000)	(25,000)
Fund earnings	0	0	0	0	0
Asset at end of period	0	0	0	0	0

Appendix B: Essex Power Corporation	**CICA**	**IFRS**	**Projected**	**Projected**	**Projected**
Fiscal Year	**2014**	**2014**	**2015**	**2016**	**2017**
Expense					
Current service cost	23,125	23,125	26,359	27,413	28,510
Interest on obligation	19,413	19,413	13,985	15,401	16,478
Interest on assets	0	0	0	0	0
Amortize transition amount	0	0	0	0	0
Amortize plan improvements	(6,642)	0	0	0	0
Amortize gains and losses	(3,707)	0	0	0	0
Expense	32,189	42,538	40,344	42,814	44,988
Transition obligation (asset)					
Transition amount at start of period	0	0	0	0	0
Amortization during period	0	0	0	0	0
Transition amount at end of period	0	0	0	0	0
Prior service costs					
Unamortized prior costs at start 2003	0	0	0	0	0
Unamortized prior costs at start 2005	6,642	6,642	0	0	0
Total	6,642	6,642	0	0	0
Amortization during period 2003	0	0	0	0	0
Amortization during period 2005	(6,642)	0	0	0	0
Total	(6,642)	0	0	0	0
Unamortized prior costs at end 2003	0	0	0	0	0
Unamortized prior costs at end 2005	0	6,642	0	0	0
Total	0	6,642	0	0	0
Transfer to Balance Sheet on Conversion		6,642			
Actuarial (gains) & losses					
Unamortized amount at start	(38,185)	(38,185)	0	0	0
(Gain) or Loss in period	(80,136)	(80,136)	0	0	0
Transfer to Balance Sheet on Conversion		118,321			
Amortization during period	(3,707)	0	0	0	0
Unamortized amount at end	(114,614)	0	0	0	0

Appendix B: Essex Power Corporation Fiscal Year	CICA 2014	IFRS 2014	Projected 2015	Projected 2016	Projected 2017
Accrued benefit asset (liability)					
Amount at start of period	(412,719)	(412,719)	(324,776)	(362,120)	(395,934)
Expense in period	(32,189)	(42,538)	(40,344)	(42,814)	(44,988)
Transfer to Balance Sheet on Conversion		124,963			
Employer contribution	5,518	5,518	3,000	9,000	25,000
Amount at end of period	(439,390)	(324,776)	(362,120)	(395,934)	(415,922)
Reconcile funded status					
Benefit obligation at end of period	324,776	324,776	362,120	395,934	415,922
Asset value at end of period	0	0	0	0	0
Funded status - surplus (deficit)	(324,776)	(324,776)	(362,120)	(395,934)	(415,922)
Unamortized transition obligation (asset)	0	0	0	0	0
Unamortized prior service costs	0	0	0	0	0
Unamortized (gains) & losses	(114,614)	0	0	0	0
Accrued benefit asset (liability)	(439,390)	(324,776)	(362,120)	(395,934)	(415,922)
Estimated benefit costs					
First year following fiscal year	3,000	3,000	9,000	25,000	16,000
Second year following fiscal year	9,000	9,000	25,000	16,000	17,000
Third year following fiscal year	25,000	25,000	16,000	17,000	14,000
Fourth year following fiscal year	16,000	16,000	17,000	14,000	8,000
Fifth-10th years following fiscal year	83,000	83,000	82,000	85,000	118,000
Sensitivity Testing					
Liability change resulting from:					
1% increase in trend rate	17,000	17,000	19,000	21,000	22,000
1% decrease in trend rate	(14,000)	(14,000)	(16,000)	(17,000)	(18,000)

Appendix C: Essex Energy Corporation	**CICA**	**IFRS**	**Projected**	**Projected**	**Projected**
Fiscal Year	**2014**	**2014**	**2015**	**2016**	**2017**
Discount rate at start of period	5.00%	5.00%	4.00%	4.00%	4.00%
Discount rate at end of period	4.00%	4.00%	4.00%	4.00%	4.00%
Interest rate on assets	N/A	N/A	N/A	N/A	N/A
CPI increase assumption	2.00%	2.00%	2.00%	2.00%	2.00%
Termination rates	Ont. Light	Ont. Light	Ont. Light	Ont. Light	Ont. Light
Mortality table	CPM prom.	CPM prom.	CPM prom.	CPM prom.	CPM prom.
Retirement Age	57	57	57	57	57
Health Care Initial Trend Rate	6.50%	6.50%	8.00%	7.50%	7.00%
Ultimate Trend Rate	4.50%	4.50%	4.50%	4.50%	4.50%
Dental Care Initial Trend Rate	4.50%	4.50%	4.50%	4.50%	4.50%
Ultimate Trend Rate	4.50%	4.50%	4.50%	4.50%	4.50%
EARSL Period	15.5	15.5	15.5	15.5	15.5
Reconcile Obligation					
Obligation at start of year	33,199	33,199	70,071	84,006	92,946
Plan amendments in year	0	0	0	0	0
Employer current service cost	10,763	10,763	13,646	14,192	14,760
Member contributions	0	0	0	0	0
Benefit payments	0	0	(3,000)	(9,000)	(25,000)
Interest on obligation	2,198	2,198	3,289	3,748	3,808
Obligation at end of year	46,160	46,160	84,006	92,946	86,514
Actual obligations at end of year	70,071	70,071	84,006	92,946	86,514
(Gain)/Loss recognized at end of year	23,911	23,911	0	0	0
Reconcile Plan Funds					
Asset at start of period	0	0	0	0	0
Employer contributions	0	0	3,000	9,000	25,000
Benefit payments	0	0	(3,000)	(9,000)	(25,000)
Fund earnings	0	0	0	0	0
Asset at end of period	0	0	0	0	0

Appendix C: Essex Energy Corporation	CICA	IFRS	Projected	Projected	Projected
Fiscal Year	**2014**	**2014**	**2015**	**2016**	**2017**
Expense					
Current service cost	10,763	10,763	13,646	14,192	14,760
Interest on obligation	2,198	2,198	3,289	3,748	3,808
Interest on assets	0	0	0	0	0
Amortize transition amount	0	0	0	0	0
Amortize plan improvements	0	0	0	0	0
Amortize gains and losses	0	0	0	0	0
Expense	12,961	12,961	16,935	17,940	18,568
Transition obligation (asset)					
Transition amount at start of period	0	0	0	0	0
Amortization during period	0	0	0	0	0
Transition amount at end of period	0	0	0	0	0
Prior service costs					
Unamortized prior costs at start 2003	0	0	0	0	0
Unamortized prior costs at start 2005	0	0	0	0	0
Total	0	0	0	0	0
Amortization during period 2003	0	0	0	0	0
Amortization during period 2005	0	0	0	0	0
Total	0	0	0	0	0
Unamortized prior costs at end 2003	0	0	0	0	0
Unamortized prior costs at end 2005	0	0	0	0	0
Total	0	0	0	0	0
Transfer to Balance Sheet on Conversion		0			
Actuarial (gains) & losses					
Unamortized amount at start	0	0	0	0	0
(Gain) or Loss in period	23,911	23,911	0	0	0
Transfer to Balance Sheet on Conversion		(23,911)			
Amortization during period	0	0	0	0	0
Unamortized amount at end	23,911	0	0	0	0

Appendix C: Essex Energy Corporation Fiscal Year	CICA 2014	IFRS 2014	Projected 2015	Projected 2016	Projected 2017
Accrued benefit asset (liability)					
Amount at start of period	(33,199)	(33,199)	(70,071)	(84,006)	(92,946)
Expense in period	(12,961)	(12,961)	(16,935)	(17,940)	(18,568)
Transfer to Balance Sheet on Conversion		(23,911)			
Employer contribution	0	0	3,000	9,000	25,000
Amount at end of period	(46,160)	(70,071)	(84,006)	(92,946)	(86,514)
Reconcile funded status					
Benefit obligation at end of period	70,071	70,071	84,006	92,946	86,514
Asset value at end of period	0	0	0	0	0
Funded status - surplus (deficit)	(70,071)	(70,071)	(84,006)	(92,946)	(86,514)
Unamortized transition obligation (asset)	0	0	0	0	0
Unamortized prior service costs	0	0	0	0	0
Unamortized (gains) & losses	23,911	0	0	0	0
Accrued benefit asset (liability)	(46,160)	(70,071)	(84,006)	(92,946)	(86,514)
Estimated benefit costs					
First year following fiscal year	3,000	3,000	9,000	25,000	16,000
Second year following fiscal year	9,000	9,000	25,000	16,000	17,000
Third year following fiscal year	25,000	25,000	16,000	17,000	14,000
Fourth year following fiscal year	16,000	16,000	17,000	14,000	8,000
Fifth-10th years following fiscal year	83,000	83,000	82,000	85,000	118,000
Sensitivity Testing					
Liability change resulting from:					
1% increase in trend rate	43,000	43,000	52,000	58,000	54,000
1% decrease in trend rate	(36,000)	(36,000)	(43,000)	(48,000)	(45,000)

MONDELIS
ACTUARIAL

April 15, 2016

Gilbert Iovino, CPA, CMA **sent by email only**
Corporate Controller
Essex Power Corporation
2730 Highway #3
Oldcastle, ON N0R 1L0

Dear Gilbert:

Re: Post-Employment Benefits Accounting

Further to your request, we have completed an extrapolation of the plan(s) and disclosure requirements for the fiscal period ending December 31, 2015 for Essex Power Corporation and Essex Powerlines Corporation. A full valuation was performed at December 31, 2014 and results from that valuation, including demographic updates were extrapolated to December 31, 2015, with projections for fiscal years 2016 through 2017.

Please note that results are also shown for Essex Energy Corporation in Appendix C. These results are shown for management purposes only. The Essex Energy employees and retirees DO NOT not receive post-employment benefits. The results were requested by management to show the actuarial impact if Essex Energy did provide post-employment benefits.

Accounting under IFRS 19(R) was adopted effective January 1, 2015. Further, it is assumed that the plan sponsor has chosen to recognize gains and losses through adjustments to Other Comprehensive Income.

PREMIUMS

Monthly premium rates were provided by the plan sponsor for the December 31, 2014 valuation and are shown in the following table. These rates are pre-tax.

	Health		Dental	
Division	**Single**	**Family**	**Single**	**Family**
Grandfathered Amherstburg	152.99	325.34	33.30	105.31
Grandfathered Leamington		323.72		105.31
Grandfathered LaSalle		325.34		105.31
Union Retirees	191.37	289.41	64.65	123.73
Management Retirees	191.37	327.70	64.65	144.27

Premium rates at December 31, 2015 were provided by the plan sponsor. These rates are illustrated below. No adjustment was made to the obligations at December 31, 2015 for the change in premium rates. At the next full valuation, the rates then in effect will be utilized, and any gains or losses due to premium experience will be recognized.

	Health		Dental	
Division	**Single**	**Family**	**Single**	**Family**
Grandfathered Amherstburg	146.10	325.34	34.00	105.31
Grandfathered Leamington		306.24		107.58
Grandfathered LaSalle		307.86		107.58
Union Retirees	179.27	271.71	66.04	126.40
Management Retirees	n/a	307.64	n/a	147.37

DATA

Individual employee and retiree data was provided for all covered individuals. The following table summarizes the data provided by the plan sponsor for the December 31, 2014 valuation.

	Active Employees	Retired Employees
Essex Power Corporation		
Number	9	1
Average Age	45.1	65.3
Average Years of Service	11.5	
Essex Powerlines Corporation		
Number	40	21
Average Age	46.8	64.2
Average Years of Service	14.6	
Essex Energy Corporation		
Number	10	0
Average Age	34.7	
Average Years of Service	5.3	

Note that a summary of data for Essex Energy is provided for information purposes only. Essex Energy employees and retirees do not receive post-employment benefits.

The table below shows total member counts at the December 31, 2014 valuation and at the current review.

	Valuation Dec 31 2014	Current Review
Active	59	56
Retired	22	25
Total	81	81

INSURANCE PLAN

The following table summarizes the plan provisions:

Retiring Allowance	Retirement with OMERS pension and with age plus service totaling 80 points. Payment is $600 per year of completed OMERS service. Available only if hired prior to June 2003.	
Other Benefits Eligibility	**Payable To Age 65** Retirement from OMERS with age plus service totaling 80 points.	**Payable From Age 65 to Age 70** Date of hire prior to June 2003.
Drugs	$5.00 prescription fee; no over the counter drugs	N/A
	100% employer paid (excludes over the counter)	80% employer paid to $20,000/year
Extended Health	Employer pay all - no deductible	$25/$50 employee co-pay
	Physiotherapy to $500/year	Physiotherapy to $300/year
	Psychologist, $35/visit to $350/year; ($500/year management)	N/A
	Chiropractor to $400/year ($10 co-pay first 15 visits); ($500/year management)	Chiropractor to $300/year
	Osteopath/Chiropodist/Podiatrist to $400/year; ($500/year management)	Chiropodist/Podiatrist to $300/year
	Speech Therapist to $200/year; ($500/year management)	N/A
	Massage Therapy, $250/year ($25 co-pay); ($500/year management)	N/A
	Private Hospital, $1,000 lifetime maximum	N/A
	Semi Private Hospital	Semi Private Hospital, 15 day maximum
	Audio company self-funded - $300 maximum for 3 years	N/A
	Vision $350/24 months and one eye exam/24 months	Vision to $200/24 months
	Out of Province, 180 days to $1 Million/year	N/A
	Employee Assistance Plan	N/A

Other Benefits	Payable To Age 65	Payable From Age 65 to Age 70
Dental	No deductible ($3,500 maximum)	N/A
	100% Basic	90% Basic to $1,000 annual maximum
	100% Endodontics/periodontics	N/A
	50% Crowns/bridges/caps	N/A
	50% Dentures	N/A
	50% Orthodontics, maximum $2,500	N/A
Spousal Benefits	Continues to surviving spouse and eligible dependents	Continues to surviving spouse and eligible dependents

Grandfathered Groups (for employees who retired prior to June, 2003):

Amherstburg	**Life insurance** at 50% of final annual earnings, reducing by 2.5% per year to an ultimate level of 25% of final earnings. Benefit is provided for life. Only two retirees remain with this benefit. **Health and Dental** coverage is for the retiree and his/her spouse's lifetime.
Leamington	**Health and Dental** coverage is for the retiree and his/her spouse's lifetime. **Life insurance** at 50% of final annual earnings, reducing by 2.5% per year to an ultimate level of 25% of final earnings. Benefit is provided for life. One retiree remains with this benefit.
LaSalle	**Health and Dental** coverage is for the retiree and his/her spouse's lifetime. Three retirees remain with these benefits.

Data Updates

At the December 31, 2014 valuation, the retiree in the Leamington grandfathered group benefits were assumed to have ceased at 65. The data has since been updated to reflect the post-retirement benefits continuing for life.

Also at the December 31, 2014 valuation it was assumed that two LasSalle retired members were entitled to the grandfathered benefits noted above. The data has been updated at December 31, 2015 to reflect three members in this group.

These changes have been reflected in the obligations at December 31, 2015.

ATTESTATION

I am pleased to provide the following:

a. This report provides a summary of the extrapolation.

b. The assumptions outlined below provide methods and principles applied in their establishment.

c. The data summarized above was provided by the plan sponsor and have been relied upon for purposes of the extrapolation. Rigorous tests were not carried out on the data provided, with the exception of comparing current data to previous valuation data.

d. This report has been completed prior to the fiscal year end date. We are not aware of any events subsequent to the fiscal year end that would impact on the extrapolation results.

e. Canadian GAAP (Part V) accounting policies have been used through 2014. IFRS is adopted effective January 1, 2015; 2014 results are provided on both basis.

f. We are not aware of any significant events that occurred during the reporting period.

g. We confirm the following:

   (i) We have been appointed by the management of Essex Power Corporation to carry out the valuation. I am aware that your auditor intends to use my work for audit evidence.

   (ii) In our valuation we have been objective and are free from material financial interest in the outcome of the valuation.

   (iii) I am a fully qualified Fellow of the CIA in good professional standing and possess the requisite competency to perform the valuation.

   (iv) The valuation has been performed with due care.

   (v) There have been no restrictions imposed on me regarding what may be communicated to your auditor.

   (vi) I agree to preserve the confidentiality of any information provided by the auditor.

   (vii) The benefit plan is a defined benefit plan as defined in CPA Canada Handbook.

   (viii) I have confirmed with the plan sponsor that:

      1. The extrapolation includes all employee future benefit plans required to be included in the valuation.
      2. The plan's provisions are up to date as at the date of the report.
      3. The plan sponsor will advise us of changes to the plan's provisions and events that could have a material effect on the valuation.

   (ix) The extrapolation has been performed in accordance with the standards of the CIA.

   (x) The amounts derived from the extrapolation are in accordance with the framework as described above.

   (xi) In performing the extrapolation we have used a discount rate determined in accordance with the framework and best estimate assumptions developed by management following discussions with us. It is our opinion that the assumptions are appropriate for the valuation and disclosure.

The significant actuarial assumptions used in the calculations are as follows:

- The date of all calculations is December 31, 2015.
- A discount rate of 4.00% was chosen for use as at December 31, 2014 and to establish liabilities for extrapolation during 2015. A rate of 3.75% is used at December 31, 2015 and subsequent extrapolations; this is the single discount rate, rounded to the nearest 0.25%, that closely matches the plan's obligations determined using the Fiera Capital/CIA yield curve as at December 31, 2015.
- No assets have or are expected to be accumulated for the plan.
- A salary growth rate is not incorporated as no benefits are related to earnings.
- Mortality is on the basis of the CPM 2014 Mortality Table (Composite) projected on a generational basis using Improvement Scale CPM-B1D2014
- Termination of employment is based on the Ontario Light Scale.
- The following table shows rates of mortality and employee termination at certain ages:

	Mortality Rate		**Projection Scale**		**Termination**
Age	**Male**	**Female**	**Male**	**Female**	**Rate**
20	0.000820	0.000180	0.00890	0.00960	0.100
25	0.001080	0.000240	0.00790	0.00570	0.100
30	0.001200	0.000300	0.01300	0.00610	0.056
35	0.001200	0.000420	0.01630	0.00850	0.032
40	0.001360	0.000610	0.01420	0.00970	0.022
45	0.001900	0.000860	0.00730	0.00610	0.017
50	0.002660	0.001290	-0.00020	0.00290	0.012
55	0.004030	0.002070	0.00140	0.00310	
60	0.006280	0.003500	0.00550	0.00490	
65	0.008440	0.005620	0.00810	0.00690	
70	0.012820	0.008860	0.00990	0.00690	
75	0.021830	0.014690	0.01420	0.00820	
80	0.039810	0.027290	0.01950	0.01160	
85	0.075710	0.053520	0.01540	0.01450	
90	0.140410	0.102800	0.00890	0.00910	
95	0.248080	0.189020	0.00110	0.00120	

- Retirement at age 57 (current age plus 1 if currently age 57 or more) is presumed. For certain management employees the plan sponsor has estimated a future retirement year based on knowledge of the employee.

- Health care trend rates of 8% in the first year after the valuation, reducing linearly to 4.5% over 6 years has been used.
- Dental care trend rates of 4.5% per year are assumed.
- Expenses related to the payout of life insurance benefits are presumed to be 10% of the amount of insurance paid.
- The value of projected benefits is prorated over the attribution period to determine the amount of expense to charge to various periods. The accrued obligation represents the present value of benefits assigned to periods prior to the valuation date.
- Amortizations are made using a straight-line method over the average of the expected average future service period of active employees.
- The attribution method is based on prorating benefits over each employee's period of service to the attainment of age 55 or the attainment of age plus service totaling 80 if later.
- The valuation allowance is zero.
- The Expected Average Remaining Service Lifetime (EARSL) has been calculated as shown in the attached disclosure tables.

CALCULATIONS

On the basis of the assumptions and methods noted above, we have determined the present value of benefit obligations related to service through 2015. The attached tables show the calculated obligation amounts at the December 31, 2014 fiscal end date and at the December 31, 2015 fiscal end date, as well as projections for fiscal years 2016 and 2017. The projections will remain reasonable for reporting purposes provided the above assumptions remain reasonable (notably the discount rate and data). Separate tables are provided for Essex Power Corporation, Essex Powerlines Corporation, and Essex Energy Corporation.

Please contact me should you require additional information or clarification of any of the information provided here.

Sincerely,

Kathryn T. Licata, FSA, FCIA, MAAA
Direct (519) 804-2895

ACCOUNTING SCHEDULE

APPENDIX A: ESSEX POWERLINES CORPORATION	CICA	IFRS	IFRS	Projected	Projected
Fiscal Year	**2014**	**2014**	**2015**	**2016**	**2017**
Discount rate at start of period	5.00%	5.00%	4.00%	3.75%	3.75%
Discount rate at end of period	4.00%	4.00%	3.75%	3.75%	3.75%
Interest rate on assets	n/a	n/a	n/a	n/a	n/a
CPI increase assumption	2.00%	2.00%	2.00%	2.00%	2.00%
Termination rates	Ont. Light	Ont. Light	Ont. Light	Ont. Light	Ont. Light
Mortality table	CPM	CPM	CPM	CPM	CPM
Retirement Age	57	57	57	57	57
Health Care Initial Trend Rate	8.00%	8.00%	7.50%	7.00%	6.50%
Ultimate Trend Rate	4.50%	4.50%	4.50%	4.50%	4.50%
Dental Care Initial Trend Rate	4.50%	4.50%	4.50%	4.50%	4.50%
Ultimate Trend Rate	4.50%	4.50%	4.50%	4.50%	4.50%
EARSL Period	8.9	8.9	8.9	8.9	8.9
Reconcile Obligation					
Obligation at start of year	3,600,716	3,600,716	2,562,809	2,914,823	2,930,194
Plan amendments in year	0	0	0	0	0
Employer current service cost	75,977	75,977	87,516	94,063	97,590
Member contributions	0	0	0	0	0
Benefit payments	(124,452)	(124,452)	(164,631)	(188,000)	(130,000)
Interest on obligation	180,723	180,723	102,720	109,308	111,104
Obligation at end of year	3,732,964	3,732,964	2,588,414	2,930,194	3,008,888
Actual obligations at end of year	2,562,809	2,562,809	2,914,823	2,930,194	3,008,888
(Gain)/Loss recognized at end of year	(1,170,155)	(1,170,155)	326,409	0	0

APPENDIX A: ESSEX POWERLINES CORPORATION	CICA	IFRS	IFRS	Projected	Projected
Fiscal Year	**2014**	**2014**	**2015**	**2016**	**2017**
Reconcile Plan Funds					
Asset at start of period	0	0	0	0	0
Employer contributions	124,452	124,452	164,631	188,000	130,000
Benefit payments	(124,452)	(124,452)	(164,631)	(188,000)	(130,000)
Fund earnings	0	0	0	0	0
Asset at end of period	0	0	0	0	0
Expense					
Current service cost	75,977	75,977	87,516	94,063	97,590
Interest on obligation	180,723	180,723	102,720	109,308	111,104
Interest on assets	0	0	0	0	0
Amortize transition amount	0	0	0	0	0
Amortize plan improvements	(26,424)	0	0	0	0
Amortize gains and losses	(29,028)	0	0	0	0
Expense	201,248	256,700	190,236	203,371	208,694
Transition obligation (asset)					
Transition amount at start of period	0	0	0	0	0
Amortization during period	0	0	0	0	0
Transition amount at end of period	0	0	0	0	0

APPENDIX A: ESSEX POWERLINES CORPORATION	CICA	IFRS	IFRS	Projected	Projected
Fiscal Year	**2014**	**2014**	**2015**	**2016**	**2017**
Prior service costs					
Unamortized prior costs at start 2003	0	0	0	0	0
Unamortized prior costs at start 2005	26,427	26,427	0	0	0
Total	26,427	26,427	0	0	0
Amortization during period 2003	0	0	0	0	0
Amortization during period 2005	(26,424)	0	0	0	0
Total	(26,424)	0	0	0	0
Unamortized prior costs at end 2003	0	0	0	0	0
Unamortized prior costs at end 2005	3	26,427	0	0	0
Total	3	26,427	0	0	0
Transfer to Balance Sheet on Conversion		26,427			
Actuarial (gains) & losses					
Unamortized amount at start	(258,346)	(258,346)	0	0	0
(Gain) or Loss in period	(1,170,155)	(1,170,155)	326,409	0	0
Transfer to Balance Sheet on Conversion		1,428,501			
Amortization during period	(29,028)	0	326,409	0	0
Unamortized amount at end	(1,399,473)	0	0	0	0
Accrued benefit asset (liability)					
Amount at start of period	(3,885,489)	(3,885,489)	(2,562,809)	(2,914,823)	(2,930,194)
Expense in period	(201,248)	(256,700)	(190,236)	(203,371)	(208,694)
Transfer to Balance Sheet on Conversion		1,454,928			
Recognize Gains/(Losses)			(326,409)	0	0
Employer contribution	124,452	124,452	164,631	188,000	130,000
Amount at end of period	(3,962,285)	(2,562,809)	(2,914,823)	(2,930,194)	(3,008,888)

APPENDIX A: ESSEX POWERLINES CORPORATION	CICA	IFRS	IFRS	Projected	Projected
Fiscal Year	**2014**	**2014**	**2015**	**2016**	**2017**
Reconcile funded status					
Benefit obligation at end of period	2,562,809	2,562,809	2,914,823	2,930,194	3,008,888
Asset value at end of period	0	0	0	0	0
Funded status - surplus (deficit)	(2,562,809)	(2,562,809)	(2,914,823)	(2,930,194)	(3,008,888)
Unamortized transition obligation (asset)	0	0	0	0	0
Unamortized prior service costs	(3)	0	0	0	0
Unamortized (gains) & losses	(1,399,473)	0	0	0	0
Accrued benefit asset (liability)	(3,962,285)	(2,562,809)	(2,914,823)	(2,930,194)	(3,008,888)
Estimated benefit costs					
First year following fiscal year			188,000	130,000	192,000
Second year following fiscal year			130,000	192,000	166,000
Third year following fiscal year			192,000	166,000	175,000
Fourth year following fiscal year			166,000	175,000	221,000
Fifth-10th years following fiscal year			1,130,000	1,222,000	1,237,000
Sensitivity Testing					
Liability change resulting from:					
1% increase in trend rate			287,000	289,000	297,000
1% decrease in trend rate			(249,000)	(250,000)	(257,000)
Liability change resulting from:					
1% increase in discount rate			(281,000)	(282,000)	(290,000)
1% decrease in discount rate			329,000	331,000	340,000
Gain and Loss					
Discount rate			74,276		
Demographic changes			252,133		
Total (Gain)/Loss			326,409		

APPENDIX B ESSEX POWER CORPORATION	CICA	IFRS	IFRS	Projected	Projected
Fiscal Year	**2014**	**2014**	**2015**	**2016**	**2017**
Discount rate at start of period	5.00%	5.00%	4.00%	3.75%	3.75%
Discount rate at end of period	4.00%	4.00%	3.75%	3.75%	3.75%
Interest rate on assets	n/a	n/a	n/a	n/a	n/a
CPI increase assumption	2.00%	2.00%	2.00%	2.00%	2.00%
Termination rates	Ont. Light	Ont. Light	Ont. Light	Ont. Light	Ont. Light
Mortality table	CPM	CPM	CPM	CPM	CPM
Retirement Age	57	57	57	57	57
Health Care Initial Trend Rate	8.00%	8.00%	7.50%	7.00%	6.50%
Ultimate Trend Rate	4.50%	4.50%	4.50%	4.50%	4.50%
Dental Care Initial Trend Rate	4.50%	4.50%	4.50%	4.50%	4.50%
Ultimate Trend Rate	4.50%	4.50%	4.50%	4.50%	4.50%
EARSL Period	10.3	10.3	10.3	10.3	10.3
Reconcile Obligation					
Obligation at start of year	367,892	367,892	324,776	373,666	407,834
Plan amendments in year	0	0	0	0	0
Employer current service cost	23,125	23,125	26,359	28,264	29,323
Member contributions	0	0	0	0	0
Benefit payments	(5,518)	(5,518)	(3,072)	(9,000)	(25,000)
Interest on obligation	19,413	19,413	13,984	14,904	15,925
Obligation at end of year	404,912	404,912	362,047	407,834	428,082
Actual obligations at end of year	324,776	324,776	373,666	407,834	428,082
(Gain)/Loss recognized at end of year	(80,136)	(80,136)	11,619	0	0

APPENDIX B ESSEX POWER CORPORATION	CICA	IFRS	IFRS	Projected	Projected
Fiscal Year	**2014**	**2014**	**2015**	**2016**	**2017**
Reconcile Plan Funds					
Asset at start of period	0	0	0	0	0
Employer contributions	5,518	5,518	3,072	9,000	25,000
Benefit payments	(5,518)	(5,518)	(3,072)	(9,000)	(25,000)
Fund earnings	0	0	0	0	0
Asset at end of period	0	0	0	0	0
Expense					
Current service cost	23,125	23,125	26,359	28,264	29,323
Interest on obligation	19,413	19,413	13,984	14,904	15,925
Interest on assets	0	0	0	0	0
Amortize transition amount	0	0	0	0	0
Amortize plan improvements	(6,642)	0	0	0	0
Amortize gains and losses	(3,707)	0	0	0	0
Expense	32,189	42,538	40,343	43,168	45,248
Transition obligation (asset)					
Transition amount at start of period	0	0	0	0	0
Amortization during period	0	0	0	0	0
Transition amount at end of period	0	0	0	0	0

APPENDIX B ESSEX POWER CORPORATION **Fiscal Year**	**CICA 2014**	**IFRS 2014**	**IFRS 2015**	**Projected 2016**	**Projected 2017**
Prior service costs					
Unamortized prior costs at start 2003	0	0	0	0	0
Unamortized prior costs at start 2005	6,642	6,642	0	0	0
Total	6,642	6,642	0	0	0
Amortization during period 2003	0	0	0	0	0
Amortization during period 2005	(6,642)	0	0	0	0
Total	(6,642)	0	0	0	0
Unamortized prior costs at end 2003	0	0	0	0	0
Unamortized prior costs at end 2005	0	6,642	0	0	0
Total	0	6,642	0	0	0
Transfer to Balance Sheet on Conversion		6,642			
Actuarial (gains) & losses					
Unamortized amount at start	(38,185)	(38,185)	0	0	0
(Gain) or Loss in period	(80,136)	(80,136)	11,619	0	0
Transfer to Balance Sheet on Conversion		118,321			
Amortization during period	(3,707)	0	11,619	0	0
Unamortized amount at end	(114,614)	0	0	0	0
Accrued benefit asset (liability)					
Amount at start of period	(412,719)	(412,719)	(324,776)	(373,666)	(407,834)
Expense in period	(32,189)	(42,538)	(40,343)	(43,168)	(45,248)
Transfer to Balance Sheet on Conversion		124,963			
Recognize Gains/(Losses)			(11,619)	0	0
Employer contribution	5,518	5,518	3,072	9,000	25,000
Amount at end of period	(439,390)	(324,776)	(373,666)	(407,834)	(428,082)

APPENDIX B ESSEX POWER CORPORATION Fiscal Year	CICA 2014	IFRS 2014	IFRS 2015	Projected 2016	Projected 2017
Reconcile funded status					
Benefit obligation at end of period	324,776	324,776	373,666	407,834	428,082
Asset value at end of period	0	0	0	0	0
Funded status - surplus (deficit)	(324,776)	(324,776)	(373,666)	(407,834)	(428,082)
Unamortized transition obligation (asset)	0	0	0	0	0
Unamortized prior service costs	0	0	0	0	0
Unamortized (gains) & losses	(114,614)	0	0	0	0
Accrued benefit asset (liability)	(439,390)	(324,776)	(373,666)	(407,834)	(428,082)
Estimated benefit costs					
First year following fiscal year			9,000	25,000	16,000
Second year following fiscal year			25,000	16,000	17,000
Third year following fiscal year			16,000	17,000	14,000
Fourth year following fiscal year			17,000	14,000	8,000
Fifth-10th years following fiscal year			82,000	85,000	118,000
Sensitivity Testing					
Liability change resulting from:					
1% increase in trend rate			49,000	53,000	56,000
1% decrease in trend rate			(41,000)	(45,000)	(47,000)
Liability change resulting from:					
1% increase in discount rate			(46,000)	(50,000)	(52,000)
1% decrease in discount rate			55,000	60,000	63,000
Gain and Loss					
Discount rate			11,619		
Demographic changes			0		
Total (Gain)/Loss			11,619		

APPENDIX C: ESSEX ENERGY CORPORATION
PROVIDED FOR MANAGEMENT PURPOSES ONLY

	CICA	IFRS	IFRS	Projected	Projected
Fiscal Year	**2014**	**2014**	**2015**	**2016**	**2017**
Discount rate at start of period	5.00%	5.00%	4.00%	3.75%	3.75%
Discount rate at end of period	4.00%	4.00%	3.75%	3.75%	3.75%
Interest rate on assets	n/a	n/a	n/a	n/a	n/a
CPI increase assumption	2.00%	2.00%	2.00%	2.00%	2.00%
Termination rates	Ont. Light	Ont. Light	Ont. Light	Ont. Light	Ont. Light
Mortality table	CPM	CPM	CPM	CPM	CPM
Retirement Age	57	57	57	57	57
Health Care Initial Trend Rate	8.00%	8.00%	7.50%	7.00%	6.50%
Ultimate Trend Rate	4.50%	4.50%	4.50%	4.50%	4.50%
Dental Care Initial Trend Rate	4.50%	4.50%	4.50%	4.50%	4.50%
Ultimate Trend Rate	4.50%	4.50%	4.50%	4.50%	4.50%
EARSL Period	15.5	15.5	15.5	15.5	15.5
Reconcile Obligation					
Obligation at start of year	33,199	33,199	70,071	91,932	110,925
Plan amendments in year	0	0	0	0	0
Employer current service cost	10,763	10,763	13,646	14,984	15,545
Member contributions	0	0	0	0	0
Benefit payments	0	0	0	0	0
Interest on obligation	2,198	2,198	3,349	4,009	4,743
Obligation at end of year	46,160	46,160	87,066	110,925	131,213
Actual obligations at end of year	70,071	70,071	91,932	110,925	131,213
(Gain)/Loss recognized at end of year	23,911	23,911	4,866	0	0

APPENDIX C: ESSEX ENERGY CORPORATION
PROVIDED FOR MANAGEMENT PURPOSES ONLY

	CICA	IFRS	IFRS	Projected	Projected
Fiscal Year	**2014**	**2014**	**2015**	**2016**	**2017**
Reconcile Plan Funds					
Asset at start of period	0	0	0	0	0
Employer contributions	0	0	0	0	0
Benefit payments	0	0	0	0	0
Fund earnings	0	0	0	0	0
Asset at end of period	0	0	0	0	0
Expense					
Current service cost	10,763	10,763	13,646	14,984	15,545
Interest on obligation	2,198	2,198	3,349	4,009	4,743
Interest on assets	0	0	0	0	0
Amortize transition amount	0	0	0	0	0
Amortize plan improvements	0	0	0	0	0
Amortize gains and losses	0	0	0	0	0
Expense	12,961	12,961	16,995	18,993	20,288
Transition obligation (asset)					
Transition amount at start of period	0	0	0	0	0
Amortization during period	0	0	0	0	0
Transition amount at end of period	0	0	0	0	0

APPENDIX C: ESSEX ENERGY CORPORATION
PROVIDED FOR MANAGEMENT PURPOSES ONLY

Fiscal Year	**CICA 2014**	**IFRS 2014**	**IFRS 2015**	**Projected 2016**	**Projected 2017**
Prior service costs					
Unamortized prior costs at start 2003	0	0	0	0	0
Unamortized prior costs at start 2005	0	0	0	0	0
Total	0	0	0	0	0
Amortization during period 2003	0	0	0	0	0
Amortization during period 2005	0	0	0	0	0
Total	0	0	0	0	0
Unamortized prior costs at end 2003	0	0	0	0	0
Unamortized prior costs at end 2005	0	0	0	0	0
Total	0	0	0	0	0
Transfer to Balance Sheet on Conversion		0			
Actuarial (gains) & losses					
Unamortized amount at start	0	0	0	0	0
(Gain) or Loss in period	23,911	23,911	4,866	0	0
Transfer to Balance Sheet on Conversion		(23,911)			
Amortization during period	0	0	4,866	0	0
Unamortized amount at end	23,911	0	0	0	0
Accrued benefit asset (liability)					
Amount at start of period	(33,199)	(33,199)	(70,071)	(91,932)	(110,925)
Expense in period	(12,961)	(12,961)	(16,995)	(18,993)	(20,288)
Transfer to Balance Sheet on Conversion		(23,911)			
Recognize Gains/(Losses)			(4,866)	0	0
Employer contribution	0	0	0	0	0
Amount at end of period	(46,160)	(70,071)	(91,932)	(110,925)	(131,213)

APPENDIX C: ESSEX ENERGY CORPORATION
PROVIDED FOR MANAGEMENT PURPOSES ONLY

Fiscal Year	CICA 2014	IFRS 2014	IFRS 2015	Projected 2016	Projected 2017
Reconcile funded status					
Benefit obligation at end of period	70,071	70,071	91,932	110,925	131,213
Asset value at end of period	0	0	0	0	0
Funded status - surplus (deficit)	(70,071)	(70,071)	(91,932)	(110,925)	(131,213)
Unamortized transition obligation (asset)	0	0	0	0	0
Unamortized prior service costs	0	0	0	0	0
Unamortized (gains) & losses	23,911	0	0	0	0
Accrued benefit asset (liability)	(46,160)	(70,071)	(91,932)	(110,925)	(131,213)
Estimated benefit costs					
First year following fiscal year			0	0	0
Second year following fiscal year			0	0	0
Third year following fiscal year			0	0	0
Fourth year following fiscal year			0	0	0
Fifth-10th years following fiscal year			0	0	1,000
Sensitivity Testing					
Liability change resulting from:					
1% increase in trend rate			22,000	27,000	32,000
1% decrease in trend rate			(18,000)	(22,000)	(26,000)
Liability change resulting from:					
1% increase in discount rate			(18,000)	(22,000)	(26,000)
1% decrease in discount rate			24,000	29,000	34,000
Gain and Loss					
Discount rate			4,866		
Demographic changes			0		
Total (Gain)/Loss			4,866		

Attachment 4-I

Shared Services & Corporate Cost Allocation

Appendix 2-N
Shared Services and Corporate Cost Allocation [1]

Year: 2010 Actual

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
EPLC	Municipalities of Tecumseh, Amherstburg, Leamington, LaSalle	Water billing & collection	Flat monthly service charge	$ 772,334	
EEC	EPLC	Engineering support service	Fully allocated cost		$ 67,734
EEC	EPLC	CDM services	Fully allocated cost		$ 340,824
EEC	EPLC	IT development services	Hourly Rate		$ 33,750
EPS	EPLC	Streetlight maintenance	Fully allocated cost		
EPC	EPLC	HR services, IT services, Procurement service and Executive Services	Fully allocated cost		$ 1,256,205
UC	EPLC	Wholesale settlement services and interval meter reading and communication			$ 6,541

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$

Note:

1 **This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The required information includes:**

· ***Type of Service:***

Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.

· ***Pricing Methodology:***

Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.

· ***% Allocation:***

The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.

Year: 2011 Actual

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
EPLC	Municipalities of Tecumseh, Amherstburg, Leamington, LaSalle	Water billing & collection	Flat monthly service charge	$ 895,442	
EEC	EPLC	Engineering support service	Fully allocated cost		$ 157,951
EEC	EPLC	CDM services	Fully allocated cost		$ 519,841
EEC	EPLC	IT development services	Hourly Rate		$ 26,303
EPS	EPLC	Streetlight maintenance	Fully allocated cost		$ 1,229
EPC	EPLC	HR services, IT services, Procurement service and Executive Services	Fully allocated cost		$ 1,181,342
UC	EPLC	Wholesale settlement services and interval meter reading and communication			$ 255,865

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
eg: parent company	*eg: regulated entity*				

File Number:	EB-2017-0039
Exhibit:	4
Attachment:	4-I
Page:	3 of 9
Date:	August 27th, 2017

Year: 2012 Actual

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
EPLC	Municipalities of Tecumseh, Amherstburg, Leamington, LaSalle	Water billing & collection	Flat monthly service charge	$ 848,242	
EEC	EPLC	Engineering support service	Fully allocated cost		$ 281,005
EEC	EPLC	CDM services	Fully allocated cost		$ 429,535
EEC	EPLC	IT development services	Hourly Rate		$ 44,797
EPS	EPLC	Streetlight maintenance	Fully allocated cost		$ 10,410
EPC	EPLC	HR services, IT services, Procurement service and Executive Services	Fully allocated cost		$ 1,000,134
UC	EPLC	Wholesale settlement services and interval meter reading and communication			$ 242,403

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
eg: parent company	*eg: regulated entity*				

Year: 2013 Actual

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
EPLC	Municipalities of Tecumseh, Amherstburg, Leamington, LaSalle	Water billing & collection	Flat monthly service charge	$ 929,921	
EEC	EPLC	Engineering support service	Fully allocated cost		$ 315,299
EEC	EPLC	CDM services	Fully allocated cost		$ 835,318
EEC	EPLC	IT development services	Hourly Rate		$ 38,458
EPS	EPLC	Streetlight maintenance	Fully allocated cost		$ 97,556
EPC	EPLC	HR services, IT services, Procurement service and Executive Services	Fully allocated cost		$ 1,036,741
UC	EPLC	Wholesale settlement services and interval meter reading and communication			$ 254,677

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
eg: parent company	*eg: regulated entity*				

File Number:	EB-2017-0039
Exhibit:	4
Attachment:	4-I
Page:	5 of 9
Date:	August 27th, 2017

Year: 2014 Actual

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
EPLC	Municipalities of Tecumseh, Amherstburg, Leamington, LaSalle	Water billing & collection	Flat monthly service charge	$ 947,980	
EEC	EPLC	Engineering support service	Fully allocated cost		$ 195,214
EEC	EPLC	CDM services	Fully allocated cost		$ 628,122
EEC	EPLC	IT development services	Hourly Rate		$ 311,894
EPS	EPLC	Streetlight maintenance	Fully allocated cost		$ 94,257
EPC	EPLC	HR services, IT services, Procurement service and Executive Services	Fully allocated cost		$ 1,145,205
UC	EPLC	Wholesale settlement services and interval meter reading and communication			$ 272,267

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
eg: parent company	*eg: regulated entity*				

Year: 2015 Actual

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
EPLC	Municipalities of Tecumseh, Amherstburg, Leamington, LaSalle	Water billing & collection	Flat monthly service charge	$ 948,337	
EEC	EPLC	Engineering support service	Fully allocated cost		$ 281,927
EEC	EPLC	CDM services	Fully allocated cost		$ 970,799
EEC	EPLC	IT development services	Hourly Rate		$ 132,986
EPS	EPLC	Streetlight maintenance	Fully allocated cost		$ 34,975
EPC	EPLC	HR services, IT services, Procurement service and Executive Services	Fully allocated cost		$ 1,132,261
UC	EPLC	Wholesale settlement services and interval meter reading and communication			$ 371,231

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
eg: parent company	*eg: regulated entity*				

Year: 2016 Actual

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
EPLC	Municipalities of Tecumseh, Amherstburg, Leamington, LaSalle	Water billing & collection	Flat monthly service charge	$ 941,723	
EEC	EPLC	Engineering support service	Fully allocated cost		$ 249,758
EEC	EPLC	CDM services	Fully allocated cost		$ 639,590
EEC	EPLC	IT development services	Hourly Rate		$ 129,814
EPS	EPLC	Streetlight maintenance	Fully allocated cost		$ 71,497
EPC	EPLC	HR services, IT services, Procurement service and Executive Services	Fully allocated cost		$ 1,012,571
UC	EPLC	Wholesale settlement services and interval meter reading and communication			$ 343,123

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
eg: parent company	*eg: regulated entity*				

Year: 2017 Bridge Year

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
EPLC	Municipalities of Tecumseh, Amherstburg, Leamington	Water billing & collection	Flat monthly service charge	$ 765,456	
EEC	EPLC	Engineering support service	Fully allocated cost		$ 90,817
EEC	EPLC	CDM services	Fully allocated cost		$ 914,911
EEC	EPLC	IT development services	Hourly Rate		$ 32,489
EPS	EPLC	Streetlight maintenance	Fully allocated cost		$ 71,497
EPC	EPLC	HR services, IT services, Procurement service and Executive Services	Fully allocated cost		$ 873,740
UC	EPLC	Wholesale settlement services and interval meter reading and communication			$ 343,123

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
eg: parent company	*eg: regulated entity*				

File Number:	EB-2017-0039
Exhibit:	4
Attachment:	4-I
Page:	9 of 9
Date:	August 27th, 2017

Year: 2018 Test Year

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
EPLC	Municipalities of Tecumseh, Amherstburg, Leamington	Water billing & collection	Flat monthly service charge	$ 765,456	
EEC	EPLC	Engineering support service	Fully allocated cost		$ 90,817
EEC	EPLC	CDM services	Fully allocated cost		$ 914,911
EEC	EPLC	IT development services	Hourly Rate		$ 32,489
EPS	EPLC	Streetlight maintenance	Fully allocated cost		$ 71,497
EPC	EPLC	HR services, IT services, Procurement service and Executive Services	Fully allocated cost		$ 873,740
UC	EPLC	Wholesale settlement services and interval meter reading and communication			$ 343,123

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
eg: parent company	*eg: regulated entity*				

Attachment 4-J

EPLC Purchasing Policy

Purchasing & Tender Policy	
Approved by:	**Approval date:**
Reference No.:	**Revision date:**

Policy Statement

It is the policy of Essex Power Corporation to acquire needed goods and services in such a manner as to obtain maximum value for each dollar disbursed, subject to the terms and conditions set forth by the company. Essex Power Corporation is committed to a fair and open competitive tendering policy for all interested, qualified suppliers. This objective will be achieved by the use of informal and formal tender documentation and appropriate authorization as outlined in the Purchasing Policy. The policy also provides employees with guidelines to receive competitive pricing and best overall value in a manner that meets the company objectives.

Policy Details

Essex Power Corporation's Tendering Policy is based on the following fundamental principles:

- open and effective competition
- best overall value for money disbursed (best overall value for money takes into account both price and non price factors and the need to ensure benefits are commensurate with costs)
- enhancing, where reasonably possible, the capabilities of local business and industry
- environmental protection

Purchasing Thresholds with Respect to the Purchasing/Tendering Process

1.0 Essex Power Corporation's policy on purchasing (Tendering) is based on the following thresholds:

1.1 $0 but less than $100

- No purchase order form or quoting process is required; petty cash or company credit cards may be used to purchase items. Supervisor is to sign the credit card statements to authorize the transactions.

1.2 $100 to less than $1,000

- No purchase order form or quoting process is required; Supervisor is to verbally approve before purchasing and sign the supplier invoice to authorize the transaction or if on a credit card the Supervisor is to sign the credit card statements to authorize the transactions.

1.3 $1,001 but less than $10,000
- Purchase order form completed and valid quoting process (at least 2 quotes) is required; Manager authorization required

1.4 $10,001 and above
- Purchase order form completed and valid quoting process (at least 3 quotes) is required; EPC President or designate

All non budgeted purchases require the authorization of the President of EPC or his designate.

Other policy conditions

1 Multiple, similar small purchases/requisitions, to circumvent Purchase value limits, do not meet the intent of this policy, will not be processed and as such should be refrained from occurring.

2 Quotations required – quotes are required when if and possible from not less than 2 appropriate suppliers; it is understood however, that best price sources are established on an annual basis and hence subsequent purchases of the same item are made without competitive quotes; however, from time to time one of, or out of the ordinary item purchases will occur, and therefore competitive quotes are required.

3 Order quantities should equal semi-annual or annual needs (once determined), if applicable, thereby eliminating the need for frequent orders of the same items, and lessening administration time, where carrying cost is not an issue and if storage space is negatively impacted.

4 Planning and lead times are a key part of the purchasing process and must be considered at all times.

5 Requisition/purchase order forms should be forwarded by the originating department.

6 A standard Request for Quote (RFQ) form is required where appropriate as above, with a covering letter when necessary. (EPL) The RFQ must provide the specific product information, quantity, unit price, freight charges and conditions, discounts, payment terms, deliver dates (if applicable) to be evaluated as part of the selection process.

7 Annual Quotes which "lock in" the detailed purchase arrangements for items to be delivered throughout the subsequent year, should be obtained whenever possible thereby reducing the need for frequent quotes for the same item.

8 Based on larger quantity orders, split delivery dates will be required to locations as designated.

9 Where the minimum required quotations cannot be obtained, documentation should be included to detail reasons why and provide appropriate authorization.

Contracts for Services

There are occasions when contracts for purchasing services are entered into for a duration that exceeds one year. In no circumstance should these contracts exceed 3 years. Contracts are required to be subject to the tendering/quotation process before being renewed to the same vendor. Any exception to this policy requires the approval of the President of EPC.

Other Guidelines

Obsolete and/or surplus assets, or assets with no demonstrated value, that are not donated or sold, will be disposed of in the garbage in accordance with pertinent regulations.

<u>Key Points to Remember</u>

- ✓ Disposal of assets will occur when assets become obsolete and/or surplus.
- ✓ Disposal of assets will be managed to ensure sound business and accounting practices and fairness.
- ✓ The purchaser is accountable to pay for the asset in advance of removing it from Essex Power in a timely manner, and with liability for safe removal.

Attachment 4-K

Regulatory Cost Schedule

File Number:	EB-2017-0039
Exhibit:	4
Attachment:	4-K
Page:	1 of 1
Date:	August 28th, 2017

Appendix 2-M
Regulatory Cost Schedule

	Regulatory Cost Category	**USoA Account**	**USoA Account Balance**	**Ongoing or One-time Cost?** [2]	**Last Rebasing Year (2010 Board Approved)**	**Most Current Actuals Year 2016**	**2017 Bridge Year**	**Annual % Change**	**2018 Test Year**	**Annual % Change**
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 59,962	$ 119,310	$ 121,696	2.00%	$ 124,130	2.00%
2	OEB Section 30 Costs (Applicant-originated)									
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going		$ 5,643	$ 5,646	0.05%	$ 5,646	0.00%
4	Expert Witness costs for regulatory matters									
5	Legal costs for regulatory matters	5655		One-Time					$ 50,000	
6	Consultants' costs for regulatory matters	5655		One-Time			$ 140,812		$ 17,370	-87.66%
7	Operating expenses associated with staff resources allocated to regulatory matters	5610		On-Going	$ 50,000	$ 116,250	$ 195,688	68.33%	$ 217,000	10.89%
8	Operating expenses associated with other resources allocated to regulatory matters [1]									
9	Other regulatory agency fees or assessments									
10	Any other costs for regulatory matters (please define)	5655		One-Time						
11	Intervenor costs	5655		One-Time	$ 52,500				$ 35,000	
12	Sub-total - Ongoing Costs [3]		$ -		$ 162,462	$ 241,203	$ 323,030	33.92%	$ 346,776	7.35%
13	Sub-total - One-time Costs [4]		$ -		$ -	$ -	$ 140,812		$ 102,370	-27.30%
14	Total		$ -		$ 162,462	$ 241,203	$ 463,842	92.30%	$ 449,146	-3.17%
									-$ 95,000	remove one-time
									$ 39,386.23	Add: annualized
									$ 393,532.33	Total regulatory

Please fill out the following table for all one-time costs related to this cost of service application to be amortized over the test year plus the IRM period.

		Historical Year(s)	**2017 Bridge Year**	**2018 Test Year**		
4	Expert Witness costs					
5	Legal costs			$ 50,000.00		
6	Consultants' costs		$ 101,931.17	$ 10,000.00		
7	Incremental operating expenses associated with staff resources allocated to this application.					
8	Incremental operating expenses associated with other resources allocated to this application. [1]				Total Application Cost	
11	Intervenor costs			$ 35,000	$ 196,931.17	
		$ -	$ 101,931.17	$ 95,000.00	$ 39,386.23	Annualized cost to be recovered

Notes:

[1] Please identify the resources involved.
[2] Where a category's costs include both one-time and ongoing costs, the applicant should prove a separate breakdown between one-time and ongoing costs.
[3] Sum of all ongoing costs identified in rows 1 to 11 inclusive.
[4] Sum of all one-time costs identified in rows 1 to 11 inclusive.

Attachment 4-L

Service Life Comparison

Appendix 2-BB
Service Life Comparison
Table F-1 from Kinetrics Report[1]

Parent*	#	Asset Details: Category| Component | Type			Useful Life: MIN UL	TUL	MAX UL	USoA Account Number	USoA Account Description	Current: Years	Current: Rate	Proposed: Years	Proposed: Rate	Outside Range of Min, Max TUL?: Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers and Fixtures	25	4%	50	2%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	2	Fully Dressed Concrete Poles	Overall		50	60	80	1830	Poles, Towers and Fixtures	25	4%	50	2%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	3	Fully Dressed Steel Poles	Overall		60	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	4	OH Line Switch			30	45	55								
	5	OH Line Switch Motor			15	25	25								
	6	OH Line Switch RTU			15	20	20								
	7	OH Integral Switches			35	45	60								
	8	OH Conductors			50	60	75	1835	Overhead Conductors and Devices	25	4%	50	2%	No	No
	9	OH Transformers & Voltage Regulators			30	40	60	1850	Line Transformers	25	4%	40	3%	No	No
	10	OH Shunt Capacitor Banks			25	30	40								
	11	Reclosers			25	40	55								
TS & MS	12	Power Transformers	Overall		30	45	60								
			Bushing		10	20	30								
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55								
	14	Station Grounding Transformer			30	40	40								
	15	Station DC System	Overall		10	20	30								
			Battery Bank		10	15	15								
			Charger		20	20	30								
	16	Station Metal Clad Switchgear	Overall		30	40	60								
			Removable Breaker		25	40	60								
	17	Station Independent Breakers			35	45	65								
	18	Station Switch			30	50	60								
	19	Electromechanical Relays			25	35	50								
	20	Solid State Relays			10	30	45								
	21	Digital & Numeric Relays			15	20	20								
	22	Rigid Busbars			30	55	60								
	23	Steel Structure			35	50	90								
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75								
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25								
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30								
	27	Primary Non-TR XLPE Cables in Duct			20	25	30								
	30	Secondary PILC Cables			70	75	80								
	31	Secondary Cables Direct Buried			25	35	40	1845	Underground Conductors and Devices	25	4%	30	3%	No	No
	32	Secondary Cables in Duct			35	40	60								
	33	Network Tranformers	Overall		20	35	50								
			Protector		20	35	40								
	34	Pad-Mounted Transformers			25	40	45	1850	Line Transformers	25	4%	40	3%	No	No
	35	Submersible/Vault Transformers			25	35	45								
	36	UG Foundation			35	55	70								
	37	UG Vaults	Overall		40	60	80								
			Roof		20	30	45								
	38	UG Vault Switches			20	35	50								
	39	Pad-Mounted Switchgear			20	30	45								
	40	Ducts			30	50	85	1840	Underground Conduit	25	4%	40	3%	No	No
	41	Concrete Encased Duct Banks			35	55	80								
	42	Cable Chambers			50	60	80								
S	43	Remote SCADA			15	20	30								

Table F-2 from Kinetrics Report[1]

#	Asset Details: Category| Component | Type		Useful Life Range		USoA Account Number	USoA Account Description	Current: Years	Current: Rate	Proposed: Years	Proposed: Rate	Outside Range of Min, Max TUL?: Below Min Range	Above Max Range
1	Office Equipment		5	15	1915	Office Furniture and Equipment	10	10%	10	10%	No	No
2	Vehicles	Trucks & Buckets	5	15	1930	Transportation Equipment	8	13%	10	10%	No	No
		Trailers	5	20	1930	Transportation Equipment	5	20%	7	14%	No	No
		Vans	5	10	1930	Transportation Equipment	5	20%	7	14%	No	No
3	Administrative Buildings		50	75	1908	Buildings and Fixtures	25	4%	50	2%	No	No
4	Leasehold Improvements		Lease dependent									
5	Station Buildings	Station Buildings	50	75								
		Parking	25	30								
		Fence	25	60								
		Roof	20	30								
6	Computer Equipment	Hardware	3	5	1920	Computer Equipment - Hardware	5	20%	5	20%	No	No
		Software	2	5	1611	Computer Software	5	20%	5	20%	No	No
7	Equipment	Power Operated	5	10								
		Stores	5	10	1935	Stores Equipment	10	10%	10	10%	No	No
		Tools, Shop, Garage Equipment	5	10	1940	Tools, Shop and Garage Equipment	10	10%	10	10%	No	No
		Measurement & Testing Equipment	5	10	1945	Power Measurement & Test Equip	10	10%	10	10%	No	No
8	Communication	Towers	60	70								
		Wireless	2	10	1955	Communication Equipment	10	10%	10	10%	No	No
9	Residential Energy Meters		25	35								
10	Industrial/Commercial Energy Meters		25	35	1860	Meters	25	4%	25	4%	No	No
11	Wholesale Energy Meters		15	30	1860	Meters	25	4%	25	4%	No	No
12	Current & Potential Transformer (CT & PT)		35	50								
13	Smart Meters		5	15	1860	Meters	25	4%	15	7%	No	No
14	Repeaters - Smart Metering		10	15								
15	Data Collectors - Smart Metering		15	20								

*** TS & MS = Transformer and Municipal Stations UG = Underground Systems S = Monitoring and Control Systems**

Note 1: Tables F-1 and F-2 above are to be used as a reference in order to complete columns J, K, L and N.
See pages 17-19 of Kinetrics Report

Attachment 4-M

Depreciation & Amortization Expense

File Number:	EB-2017-0039
Exhibit:	4
Tab:	4-M
Page:	1 of 7
Date:	August 28th, 2017

Appendix 2-C
Depreciation and Amortization Expense

This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012. ☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013. ☑	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2013	CGAAP
Already rebased with depreciation policy changes in a prior rate application ☐	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 415,096		$ 415,096			$ -	$ 66,055	2.67	37.45%	5	20.00%	$ 155,467	$ -	$ 6,605	$ 162,072	$ 84,022	-$ 78,050
1612	Land Rights (Formally known as Account 1906)	$ 105,692		$ 105,692			$ -	$ 60,262	46.50	2.15%	50	2.00%	$ 2,273	$ -	$ 603	$ 2,876	$ 2,902	$ 27
1805	Land	$ 47,899		$ 47,899			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 82,461		$ 82,461			$ -	$ 1,572	21.00	4.76%	25	4.00%	$ 3,927	$ -	$ 31	$ 3,958	$ 4,594	$ 636
1825	Storage Battery Equipment	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 5,420,962		$ 5,420,962			$ -	$ 427,090	20.08	4.98%	25	4.00%	$ 269,968	$ -	$ 8,542	$ 278,510	$ 219,433	-$ 59,077
1835	Overhead Conductors & Devices	$ 3,471,065		$ 3,471,065			$ -	$ 542,962	17.00	5.88%	25	4.00%	$ 204,180	$ -	$ 10,859	$ 215,040	$ 276,494	$ 61,454
1840	Underground Conduit	$ 8,282,816		$ 8,282,816			$ -	$ 914,367	19.08	5.24%	25	4.00%	$ 434,110	$ -	$ 18,287	$ 452,397	$ 346,792	-$ 105,606
1845	Underground Conductors & Devices	$ 7,075,569		$ 7,075,569			$ -	$ 1,015,489	18.00	5.56%	25	4.00%	$ 393,087	$ -	$ 20,310	$ 413,397	$ 480,111	$ 66,714
1850	Line Transformers	$ 10,116,755		$ 10,116,755			$ -	$ 1,487,986	20.00	5.00%	25	4.00%	$ 505,838	$ -	$ 29,760	$ 535,597	$ 635,746	$ 100,148
1855	Services (Overhead)	$ 1,066,258		$ 1,066,258			$ -	$ 307,890	18.00	5.56%	25	4.00%	$ 59,237	$ -	$ 6,158	$ 65,394	$ 60,875	-$ 4,520
1855	Services (Underground)	$ 4,734,149		$ 4,734,149			$ -	$ 620,242	19.08		25		$ 248,121	$ -	$ 12,405	$ 260,526	$ 291,278	$ 30,752
1860	Meters	$ 3,293,757		$ 3,293,757			$ -	$ 156,556	19.00	5.26%	25	4.00%	$ 173,356	$ -	$ 3,131	$ 176,487	$ 274,103	$ 97,616
1860	Meters (Smart Meters)	$ 554,186		$ 554,186			$ -	$ 37,316	24.50	4.08%	25	4.00%	$ 22,620	$ -	$ 746	$ 23,366	$ 31,148	$ 7,782
1905	Land	$ 190,119		$ 190,119			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 2,015,376		$ 2,015,376			$ -	$ 27,401	22.00	4.55%	25	4.00%	$ 91,608	$ -	$ 548	$ 92,156	$ 94,562	$ 2,406
1910	Leasehold Improvements	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 74,266		$ 74,266			$ -	$ 8,365	5.00	20.00%	5	20.00%	$ 14,853	$ -	$ 837	$ 15,690	$ 17,562	$ 1,872
1915	Office Furniture & Equipment (5 years)	$ -		$ -			$ -			0.00%	10	10.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 134,650		$ 134,650			$ -	$ 18,106	3.50	28.57%	5	20.00%	$ 38,471	$ -	$ 1,811	$ 40,282	$ 50,350	$ 10,068
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,043,171		$ 1,043,171			$ -	$ 382,064	8.80	11.36%	8	12.50%	$ 118,542	$ -	$ 23,879	$ 142,421	$ 273,213	$ 130,792
1935	Stores Equipment	$ 17,416		$ 17,416			$ -		7.85	12.74%	10	10.00%	$ 2,219	$ -	$ -	$ 2,219	$ 3,708	$ 1,489
1940	Tools, Shop & Garage Equipment	$ 204,435		$ 204,435			$ -	$ 54,159	7.33	13.64%	10	10.00%	$ 27,890	$ -	$ 2,708	$ 30,598	$ 33,574	$ 2,976
1945	Measurement & Testing Equipment	$ 39,772		$ 39,772			$ -		6.25	16.00%	10	10.00%	$ 6,363	$ -	$ -	$ 6,363	$ 6,399	$ 35
1950	Power Operated Equipment	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ 112,481		$ 112,481			$ -	$ 4,947	6.12	16.34%	10	10.00%	$ 18,379	$ -	$ 247	$ 18,627	$ 21,372	$ 2,745
1955	Communication Equipment (Smart Meters)	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls Customer Premises	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1985	Miscellaneous Fixed Assets	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 11,862,613		-$ 11,862,613			$ -	-$ 2,191,898	20.00	5.00%	25	4.00%	-$ 593,131	$ -	-$ 43,838	-$ 636,969	-$ 360,377	$ 276,592
	Total	**$ 36,635,738**	**$ -**	**$ 36,635,738**	**$ -**	**$ -**	**$ -**	**$ 3,940,933**					**$ 2,197,378**	**$ -**	**$ 103,629**	**$ 2,301,007**	**$ 2,847,858**	**$ 546,850**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the prior year's additions.

3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B

File Number:	EB-2017-0039
Exhibit:	4
Tab:	4-M
Page:	2 of 7
Date:	August 28th, 2017

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012. ☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013. ☑	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2013	Revised CGAAP
Already rebased with depreciation policy changes in a prior rate application ☐	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		

		Book Values							Service Lives				Depreciation Expense					
Account	**Description**	**Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]**	**Less Fully Depreciated [7]**	**Net Amount of Existing Assets Before Policy Change to be Depreciated**	**Opening Gross Book Value of Assets Acquired After Policy Change [2]**	**Less Fully Depreciated [8]**	**Net Amount of Assets Acquired After Policy Change to be Depreciated**	**Current Year Additions**	**Average Remaining Life of Assets Existing Before Policy Change [3]**	**Depreciation Rate Assets Acquired After Policy Change**	**Life of Assets Acquired After Policy Change [4]**	**Depreciation Rate on New Additions**	**Depreciation Expense on Assets Existing Before Policy Change**	**Depreciation Expense on Assets Acquired After Policy Change**	**Depreciation Expense on Current Year Additions [5]**	**Total Current Year Depreciation Expense**	**Depreciation Expense per Appendix 2-BA Fixed Assets, Column J**	**Variance [6]**
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 415,096		$ 415,096			$ -	$ 66,055	2.67	37.45%	5.00	20.00%	$ 155,467	$ -	$ 6,605	$ 162,072	$ 342,040	$ 179,967
1612	Land Rights (Formally known as Account 1906)	$ 105,692		$ 105,692			$ -	$ 60,262	44.00	2.27%	50.00	2.00%	$ 2,402	$ -	$ 603	$ 3,005	$ 2,930	-$ 75
1805	Land	$ 47,899		$ 47,899			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 82,461		$ 82,461			$ -	$ 1,432	21.80	4.59%	25.00	4.00%	$ 3,783	$ -	$ 29	$ 3,811	$ 4,002	$ 191
1825	Storage Battery Equipment	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 5,420,962		$ 5,420,962			$ -	$ 388,994	45.50	2.20%	50.00	2.00%	$ 119,142	$ -	$ 3,890	$ 123,032	$ 148,490	$ 25,458
1835	Overhead Conductors & Devices	$ 3,471,065		$ 3,471,065			$ -	$ 494,530	44.00	2.27%	50.00	2.00%	$ 78,888	$ -	$ 4,945	$ 83,833	$ 95,859	$ 12,026
1840	Underground Conduit	$ 8,282,816		$ 8,282,816			$ -	$ 832,806	34.00	2.94%	40.00	2.50%	$ 243,612	$ -	$ 10,410	$ 254,022	$ 199,739	-$ 54,283
1845	Underground Conductors & Devices	$ 7,075,569		$ 7,075,569			$ -	$ 924,907	24.00	4.17%	30.00	3.33%	$ 294,815	$ -	$ 15,415	$ 310,230	$ 229,618	-$ 80,612
1850	Line Transformers	$ 10,116,755		$ 10,116,755			$ -	$ 1,355,258	34.00	2.94%	40.00	2.50%	$ 297,552	$ -	$ 16,941	$ 314,492	$ 326,072	$ 11,579
1855	Services (Overhead)	$ 1,066,258		$ 1,066,258			$ -	$ 279,903	44.00	2.27%	50.00	2.00%	$ 24,233	$ -	$ 2,799	$ 27,032	$ 28,434	$ 1,402
1855	Services (Underground)	$ 4,734,149		$ 4,734,149			$ -	$ 565,440	34.00	2.94%	40.00	2.50%	$ 139,240	$ -	$ 7,068	$ 146,308	$ 116,093	-$ 30,215
1860	Meters	$ 3,293,757		$ 3,293,757			$ -	$ 150,060	20.00	5.00%	25.00	4.00%	$ 164,688	$ -	$ 3,001	$ 167,689	$ 167,575	-$ 114
1860	Meters (Smart Meters)	$ 554,186		$ 554,186			$ -	$ 24,347	14.50	6.90%	15.00	6.67%	$ 38,220	$ -	$ 812	$ 39,031	$ 31,148	-$ 7,883
1905	Land	$ 190,119		$ 190,119			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 2,015,376		$ 2,015,376			$ -	$ 27,401	47.50	2.11%	50.00	2.00%	$ 42,429	$ -	$ 274	$ 42,703	$ 42,858	$ 155
1910	Leasehold Improvements	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 74,266		$ 74,266			$ -	$ 8,365	6.60	15.15%	10.00	10.00%	$ 11,252	$ -	$ 418	$ 11,671	$ 16,755	$ 5,085
1915	Office Furniture & Equipment (5 years)	$ -		$ -			$ -			0.00%	10.00	10.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 134,650		$ 134,650			$ -	$ 18,106	2.50	40.00%	5.00	20.00%	$ 53,860	$ -	$ 1,811	$ 55,670	$ 141,384	$ 85,714
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,043,171		$ 1,043,171			$ -	$ 382,064	13.00	7.69%	10.00	10.00%	$ 80,244	$ -	$ 19,103	$ 99,347	$ 157,920	$ 58,573
1935	Stores Equipment	$ 17,416		$ 17,416			$ -		8.00	12.50%	10.00	10.00%	$ 2,177	$ -	$ -	$ 2,177	$ 3,670	$ 1,493
1940	Tools, Shop & Garage Equipment	$ 204,435		$ 204,435			$ -	$ 54,159	7.60	13.16%	10.00	10.00%	$ 26,899	$ -	$ 2,708	$ 29,607	$ 58,184	$ 28,577
1945	Measurement & Testing Equipment	$ 39,772		$ 39,772			$ -			0.00%	10.00	10.00%	$ -	$ -	$ -	$ -	$ 11,669	$ 11,669
1950	Power Operated Equipment	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment	$ 112,481		$ 112,481			$ -	$ 4,947	5.00	20.00%	10.00	10.00%	$ 22,496	$ -	$ 247	$ 22,744	$ 59,435	$ 36,691
1955	Communication Equipment (Smart Meters)	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls Customer Premises	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1985	Miscellaneous Fixed Assets	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ -		$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 11,862,613		-$ 11,862,613			$ -	-$ 2,191,898	33.50	2.99%	40.00	2.50%	-$ 354,108	$ -	-$ 27,399	-$ 381,507	-$ 278,492	$ 103,015
	Total	**$ 36,635,738**	**$ -**	**$ 36,635,738**	**$ -**	**$ -**	**$ -**	**$ 3,447,138**					**$ 1,447,291**	**$ -**	**$ 69,680**	**$ 1,516,971**	**$ 1,905,383**	**$ 388,412**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the prior year's additions.

3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

File Number:	EB-2017-0039
Exhibit:	4
Tab:	4-M
Page:	3 of 7
Date:	August 28th, 2017

This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012. ☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013. ☑	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2014	Revised CGAAP
Already rebased with depreciation policy changes in a prior rate application ☐	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 415,096	$ 155,466.71	$ 259,629	$ 66,055		$ 66,055	$ 74,868	2.67	37.45%	5.00	20.00%	$ 97,239	$ 13,211	$ 7,487	$ 117,937	$ 75,831	-$ 42,106
1612	Land Rights (Formally known as Account 1906)	$ 105,692	$ 2,402.08	$ 103,290	$ 60,262		$ 60,262	$ 15,071	43.00	2.33%	50.00	2.00%	$ 2,402	$ 1,205	$ 151	$ 3,758	$ 3,679	-$ 79
1805	Land	$ 47,899	$ -	$ 47,899	$ -		$ -	$ -		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 82,461	$ 3,782.59	$ 78,678	$ 1,432		$ 1,432		20.80	4.81%	25.00	4.00%	$ 3,783	$ 57	$ -	$ 3,840	$ 3,599	-$ 240
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 5,420,962	$ 119,142.02	$ 5,301,820	$ 388,994		$ 388,994	$ 490,624	44.50	2.25%	50.00	2.00%	$ 119,142	$ 7,780	$ 4,906	$ 131,828	$ 129,121	-$ 2,707
1835	Overhead Conductors & Devices	$ 3,471,065	$ 78,887.84	$ 3,392,177	$ 494,530		$ 494,530	$ 431,488	43.00	2.33%	50.00	2.00%	$ 78,888	$ 9,891	$ 4,315	$ 93,093	$ 73,359	-$ 19,734
1840	Underground Conduit	$ 8,282,816	$ 243,612.24	$ 8,039,204	$ 832,806		$ 832,806	$ 1,250,716	33.00	3.03%	40.00	2.50%	$ 243,612	$ 20,820	$ 15,634	$ 280,066	$ 122,833	-$ 157,234
1845	Underground Conductors & Devices	$ 7,075,569	$ 294,815.36	$ 6,780,753	$ 924,907		$ 924,907	$ 839,997	23.00	4.35%	30.00	3.33%	$ 294,815	$ 30,830	$ 14,000	$ 339,646	$ 365,105	$ 25,460
1850	Line Transformers	$ 10,116,755	$ 297,551.62	$ 9,819,203	$ 1,355,258		$ 1,355,258	$ 1,287,293	33.00	3.03%	40.00	2.50%	$ 297,552	$ 33,881	$ 16,091	$ 347,524	$ 353,494	$ 5,970
1855	Services (Overhead & Underground)	$ 1,066,258	$ 24,233.15	$ 1,042,025	$ 279,903		$ 279,903	$ 274,859	43.00	2.33%	50.00	2.00%	$ 24,233	$ 5,598	$ 2,749	$ 32,580	$ 34,973	$ 2,393
1855	Services (Underground)	$ 4,734,149	$ 139,239.68	$ 4,594,909	$ 565,440		$ 565,440	$ 770,067	33.00	3.03%	40.00	2.50%	$ 139,240	$ 14,136	$ 9,626	$ 163,002	$ 131,827	-$ 31,175
1860	Meters	$ 3,293,757	$ 164,687.86	$ 3,129,069	$ 150,060		$ 150,060	$ 68,368	19.00	5.26%	25.00	4.00%	$ 164,688	$ 6,002	$ 1,367	$ 172,058	$ 178,821	$ 6,763
1860	Meters (Smart Meters)	$ 554,186	$ 38,219.73	$ 515,966	$ 24,347		$ 24,347	$ 26,539	13.50	7.41%	15.00	6.67%	$ 38,220	$ 1,623	$ 885	$ 40,728	$ 23,884	-$ 16,844
1905	Land	$ 190,119	$ -	$ 190,119	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 2,015,376	$ 42,428.97	$ 1,972,947	$ 27,401		$ 27,401		46.50	2.15%	50.00	2.00%	$ 42,429	$ 548	$ -	$ 42,977	$ 27,100	-$ 15,877
1910	Leasehold Improvements	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 74,266	$ 11,252.46	$ 63,014	$ 8,365		$ 8,365	$ 1,499	5.60	17.86%	10.00	10.00%	$ 11,252	$ 837	$ 75	$ 12,164	$ 17,979	$ 5,816
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -		$ -			0.00%	10.00	10.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 134,650	$ 53,859.81	$ 80,790	$ 18,106		$ 18,106	$ 43,348	1.50	66.67%	5.00	20.00%	$ 53,860	$ 3,621	$ 4,335	$ 61,816	$ 4,346	-$ 57,470
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,043,171	$ 80,243.92	$ 962,927	$ 382,064		$ 382,064	$ 425,100	12.00	8.33%	10.00	10.00%	$ 80,244	$ 38,206	$ 21,255	$ 139,705	$ 146,305	$ 6,599
1935	Stores Equipment	$ 17,416	$ 2,177.04	$ 15,239	$ -		$ -		7.00	14.29%	10.00	10.00%	$ 2,177	$ -	$ -	$ 2,177	$ 2,673	$ 496
1940	Tools, Shop & Garage Equipment	$ 204,435	$ 26,899.30	$ 177,535	$ 54,159		$ 54,159	$ 78,333	6.60	15.15%	10.00	10.00%	$ 26,899	$ 5,416	$ 3,917	$ 36,232	$ 63,233	$ 27,002
1945	Measurement & Testing Equipment	$ 39,772	$ -	$ 39,772	$ -		$ -			0.00%	10.00	10.00%	$ -	$ -	$ -	$ -	$ 11,235	$ 11,235
1950	Power Operated Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ 112,481	$ 22,496.19	$ 89,985	$ 4,947		$ 4,947		4.00	25.00%	10.00	10.00%	$ 22,496	$ 495	$ -	$ 22,991	$ 43,937	$ 20,946
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 11,862,613	-$ 354,107.85	-$ 11,508,505	-$ 2,191,898		-$ 2,191,898	-$ 1,122,171	32.50	3.08%	40.00	2.50%	-$ 354,108	-$ 54,797	-$ 14,027	-$ 422,932	-$ 247,371	$ 175,561
	Total	**$ 36,635,738**	**$ 1,447,291**	**$ 35,188,447**	**$ 3,447,138**	**$ -**	**$ 3,447,138**	**$ 4,955,998**					**$ 1,389,063**	**$ 139,361**	**$ 92,764**	**$ 1,621,189**	**$ 1,565,965**	**-$ 55,224**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the prior year's additions.

3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B

File Number:	EB-2017-0039
Exhibit:	4
Tab:	4-M
Page:	4 of 7
Date:	August 28th, 2017

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012. ☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013. ☑	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2015	MIFRS
Already rebased with depreciation policy changes in a prior rate application ☐	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 415,096	$ 252,706	$ 162,390	$ 140,923		$ 140,923	$ 17,043	2.50	40.00%	5.00	20.00%	$ 64,956	$ 28,185	$ 1,704	$ 94,845	$ 75,579	-$ 19,266
1612	Land Rights (Formally known as Account 1906)	$ 105,692	$ 4,804	$ 100,887	$ 75,333		$ 75,333	$ 14,661	42.00	2.38%	50.00	2.00%	$ 2,402	$ 1,507	$ 147	$ 4,055	$ 3,983	-$ 72
1805	Land	$ 47,899	$ -	$ 47,899	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 82,461	$ 7,565	$ 74,895	$ 1,432	$ 1,432	-$ 0		19.80	5.05%	25.00	4.00%	$ 3,783	-$ 0	$ -	$ 3,783	$ -	-$ 3,783
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 5,420,962	$ 238,284	$ 5,182,678	$ 879,618		$ 879,618	$ 934,800	43.50	2.30%	50.00	2.00%	$ 119,142	$ 17,592	$ 9,348	$ 146,082	$ 133,666	-$ 12,416
1835	Overhead Conductors & Devices	$ 3,471,065	$ 157,776	$ 3,313,289	$ 926,017		$ 926,017	$ 990,160	42.00	2.38%	50.00	2.00%	$ 78,888	$ 18,520	$ 9,902	$ 107,310	$ 73,557	-$ 33,753
1840	Underground Conduit	$ 8,282,816	$ 487,224	$ 7,795,592	$ 2,083,521		$ 2,083,521	$ 279,301	32.00	3.13%	40.00	2.50%	$ 243,612	$ 52,088	$ 3,491	$ 299,192	$ 226,513	-$ 72,679
1845	Underground Conductors & Devices	$ 7,075,569	$ 575,441	$ 6,500,128	$ 1,764,904		$ 1,764,904	$ 584,507	22.00	4.55%	30.00	3.33%	$ 295,460	$ 58,830	$ 9,742	$ 364,032	$ 287,646	-$ 76,386
1850	Line Transformers	$ 10,116,755	$ 595,103	$ 9,521,652	$ 2,642,551		$ 2,642,551	$ 923,100	32.00	3.13%	40.00	2.50%	$ 297,552	$ 66,064	$ 11,539	$ 375,154	$ 287,574	-$ 87,580
1855	Services (Overhead)	$ 1,066,258	$ 48,466	$ 1,017,792	$ 554,762		$ 554,762	$ 197,869	42.00	2.38%	50.00	2.00%	$ 24,233	$ 11,095	$ 1,979	$ 37,307	$ 28,760	-$ 8,547
1855	Services (Underground)	$ 4,734,149	$ 278,479	$ 4,455,670	$ 1,335,508		$ 1,335,508	$ 864,431	32.00	3.13%	40.00	2.50%	$ 139,240	$ 33,388	$ 10,805	$ 183,433	$ 129,512	-$ 53,921
1860	Meters	$ 3,293,757	$ 329,376	$ 2,964,381	$ 218,427		$ 218,427	$ 241,104	18.00	5.56%	25.00	4.00%	$ 164,688	$ 8,737	$ 4,822	$ 178,247	$ 139,296	-$ 38,951
1860	Meters (Smart Meters)	$ 554,186	$ 76,439	$ 477,747	$ 50,886		$ 50,886	$ 3,196,304	12.50	8.00%	15.00	6.67%	$ 38,220	$ 3,392	$ 106,543	$ 148,156	$ 244,350	$ 96,194
1905	Land	$ 190,119	$ -	$ 190,119	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 2,015,376	$ 84,858	$ 1,930,518	$ 27,401		$ 27,401	$ 48,914	45.50	2.20%	50.00	2.00%	$ 42,429	$ 548	$ 489	$ 43,466	$ 41,157	-$ 2,309
1910	Leasehold Improvements	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 74,266	$ 22,505	$ 51,761	$ 9,864		$ 9,864	$ 5,980	4.60	21.74%	10.00	10.00%	$ 11,252	$ 986	$ 299	$ 12,538	$ 8,342	-$ 4,196
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -		$ -			0.00%	10.00	10.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 134,650	$ 107,720	$ 26,930	$ 61,454		$ 61,454	$ 3,875	0.50	200.00%	5.00	20.00%	$ 53,860	$ 12,291	$ 388	$ 66,538	$ 35,385	-$ 31,153
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,043,171	$ 160,488	$ 882,683	$ 807,164		$ 807,164	$ 402,157	11.00	9.09%	10.00	10.00%	$ 80,244	$ 80,716	$ 20,108	$ 181,068	$ 189,589	$ 8,521
1935	Stores Equipment	$ 17,416	$ 4,354	$ 13,062	$ -		$ -	$ 17	6.00	16.67%	10.00	10.00%	$ 2,177	$ -	$ 1	$ 2,178	$ 2,198	$ 20
1940	Tools, Shop & Garage Equipment	$ 204,435	$ 53,799	$ 150,636	$ 132,492		$ 132,492	$ 56,539	5.60	17.86%	10.00	10.00%	$ 26,899	$ 13,249	$ 2,827	$ 42,975	$ 42,042	-$ 933
1945	Measurement & Testing Equipment	$ 39,772	$ -	$ 39,772	$ -		$ -			0.00%	10.00	10.00%	$ -	$ -	$ -	$ -	$ 6,269	$ 6,269
1950	Power Operated Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ 112,481	$ 44,992	$ 67,489	$ 4,947		$ 4,947	$ 12,943	3.00	33.33%	10.00	10.00%	$ 22,496	$ 495	$ 647	$ 23,638	$ 29,553	$ 5,915
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 11,862,613	-$ 708,216	-$ 11,154,397	-$ 3,314,069		-$ 3,314,069	-$ 1,448,183	31.50	3.17%	40.00	2.50%	-$ 354,108	-$ 82,852	-$ 18,102	-$ 455,062	-$ 552,530	-$ 97,468
	Total	**$ 36,635,738**	**$ 2,822,164**	**$ 33,813,573**	**$ 8,403,136**	**$ 1,432**	**$ 8,401,704**	**$ 7,325,523**					**$ 1,357,425**	**$ 324,832**	**$ 176,678**	**$ 1,858,935**	**$ 1,432,441**	**-$ 426,495**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the prior year's additions.

3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B

File Number:	EB-2017-0039
Exhibit:	4
Tab:	4-M
Page:	5 of 7
Date:	August 28th, 2017

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012. ☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013. ☑	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2016	MIFRS
Already rebased with depreciation policy changes in a prior rate application ☐	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 415,096	$ 317,662	$ 97,434	$ 157,966		$ 157,966	$ 5,217	2.50	40.00%	5.00	20.00%	$ 38,974	$ 31,593	$ 522	$ 71,088	$ 63,196	-$ 7,892
1612	Land Rights (Formally known as Account 1906)	$ 105,692	$ 7,206	$ 98,485	$ 89,994		$ 89,994	$ 2,644	41.00	2.44%	50.00	2.00%	$ 2,402	$ 1,800	$ 26	$ 4,228	$ 4,114	-$ 114
1805	Land	$ 47,899	$ -	$ 47,899	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 82,461	$ 11,348	$ 71,113	-$ 0		-$ 0		18.80	5.32%	25.00	4.00%	$ 3,783	-$ 0	$ -	$ 3,783		-$ 3,783
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 5,420,962	$ 357,426	$ 5,063,536	$ 1,814,418		$ 1,814,418	$ 598,652	42.50	2.35%	50.00	2.00%	$ 119,142	$ 36,288	$ 5,987	$ 161,417	$ 148,824	-$ 12,593
1835	Overhead Conductors & Devices	$ 3,471,065	$ 236,664	$ 3,234,402	$ 1,916,177		$ 1,916,177	$ 956,400	41.00	2.44%	50.00	2.00%	$ 78,888	$ 38,324	$ 9,564	$ 126,775	$ 89,922	-$ 36,853
1840	Underground Conduit	$ 8,282,816	$ 730,837	$ 7,551,979	$ 2,362,822		$ 2,362,822	$ 213,140	31.00	3.23%	40.00	2.50%	$ 243,612	$ 59,071	$ 2,664	$ 305,347	$ 232,711	-$ 72,636
1845	Underground Conductors & Devices	$ 7,075,569	$ 870,901	$ 6,204,668	$ 2,349,411		$ 2,349,411	$ 577,705	21.00	4.76%	30.00	3.33%	$ 295,460	$ 78,314	$ 9,628	$ 383,402	$ 293,497	-$ 89,905
1850	Line Transformers	$ 10,116,755	$ 892,655	$ 9,224,100	$ 3,565,651		$ 3,565,651	$ 774,929	31.00	3.23%	40.00	2.50%	$ 297,552	$ 89,141	$ 9,687	$ 396,380	$ 334,035	-$ 62,345
1855	Services (Overhead)	$ 1,066,258	$ 72,699	$ 993,559	$ 752,631		$ 752,631	$ 227,956	41.00	2.44%	50.00	2.00%	$ 24,233	$ 15,053	$ 2,280	$ 41,565	$ 22,691	-$ 18,874
1855	Services (Underground)	$ 4,734,149	$ 417,719	$ 4,316,430	$ 2,199,939		$ 2,199,939	$ 665,323	31.00	3.23%	40.00	2.50%	$ 139,240	$ 54,998	$ 8,317	$ 202,555	$ 155,919	-$ 46,636
1860	Meters	$ 3,293,757	$ 494,064	$ 2,799,694	$ 459,531		$ 459,531	$ 411,948	17.00	5.88%	25.00	4.00%	$ 164,688	$ 18,381	$ 8,239	$ 191,308	$ 96,476	-$ 94,832
1860	Meters (Smart Meters)	$ 554,186	$ 114,659	$ 439,527	$ 3,247,190		$ 3,247,190	$ 66,961	11.50	8.70%	15.00	6.67%	$ 38,220	$ 216,479	$ 2,232	$ 256,931	$ 278,118	$ 21,187
1905	Land	$ 190,119	$ -	$ 190,119	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 2,015,376	$ 127,287	$ 1,888,089	$ 76,315		$ 76,315	$ 42,469	44.50	2.25%	50.00	2.00%	$ 42,429	$ 1,526	$ 425	$ 44,380	$ 42,169	-$ 2,211
1910	Leasehold Improvements	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 74,266	$ 33,757	$ 40,509	$ 15,844		$ 15,844	$ 20,672	3.60	27.78%	10.00	10.00%	$ 11,252	$ 1,584	$ 1,034	$ 13,870	$ 9,697	-$ 4,173
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -		$ -			0.00%	10.00	10.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 134,650	$ 161,579	-$ 26,930	$ 65,329		$ 65,329	$ 117,329		0.00%	5.00	20.00%	$ -	$ 13,066	$ 11,733	$ 24,799	$ 11,815	-$ 12,984
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,043,171	$ 240,732	$ 802,439	$ 1,209,321		$ 1,209,321	$ 136,662	10.00	10.00%	10.00	10.00%	$ 80,244	$ 120,932	$ 6,833	$ 208,009	$ 213,884	$ 5,875
1935	Stores Equipment	$ 17,416	$ 6,531	$ 10,885	$ 17		$ 17	$ 10,275	5.00	20.00%	10.00	10.00%	$ 2,177	$ 2	$ 514	$ 2,692	$ 2,701	$ 9
1940	Tools, Shop & Garage Equipment	$ 204,435	$ 80,698	$ 123,737	$ 189,031		$ 189,031	$ 45,830	4.60	21.74%	10.00	10.00%	$ 26,899	$ 18,903	$ 2,292	$ 48,094	$ 46,828	-$ 1,266
1945	Measurement & Testing Equipment	$ 39,772	$ -	$ 39,772	$ -		$ -	$ 6,260		0.00%	10.00	10.00%	$ -	$ -	$ 313	$ 313	$ 6,599	$ 6,286
1950	Power Operated Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ 112,481	$ 67,489	$ 44,992	$ 17,890		$ 17,890		2.00	50.00%	10.00	10.00%	$ 22,496	$ 1,789	$ -	$ 24,285	$ 29,874	$ 5,589
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 11,862,613	-$ 1,062,324	-$ 10,800,289	-$ 4,762,252		-$ 4,762,252	-$ 931,021	30.50	3.28%	40.00	2.50%	-$ 354,108	-$ 119,056	-$ 11,638	-$ 484,802	-$ 589,771	-$ 104,969
	Total	**$ 36,635,738**	**$ 4,179,589**	**$ 32,456,148**	**$ 15,727,226**	**$ -**	**$ 15,727,226**	**$ 3,949,352**					**$ 1,277,583**	**$ 678,188**	**$ 70,650**	**$ 2,026,421**	**$ 1,493,299**	**-$ 533,122**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the prior year's additions.

3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B

File Number:	EB-2017-0039
Exhibit:	4
Tab:	4-M
Page:	6 of 7
Date:	August 28th, 2017

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012. ☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013. ☑	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2017	MIFRS
Already rebased with depreciation policy changes in a prior rate application ☐	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 415,096	$ 356,636	$ 58,460	$ 163,183		$ 163,183	$ 254,500	1.00	100.00%	5.00	20.00%	$ 58,460	$ 32,637	$ 25,450	$ 116,547	$ 81,624	-$ 34,923
1612	Land Rights (Formally known as Account 1906)	$ 105,692	$ 9,608	$ 96,083	$ 92,638		$ 92,638	$ 42,192	40.00	2.50%	50.00	2.00%	$ 2,402	$ 1,853	$ 422	$ 4,677	$ 4,604	-$ 73
1805	Land	$ 47,899	$ -	$ 47,899	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 82,461	$ 15,130	$ 67,330	-$ 0		-$ 0		17.80	5.62%	25.00	4.00%	$ 3,783	-$ 0	$ -	$ 3,783		-$ 3,783
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 5,420,962	$ 476,568	$ 4,944,394	$ 2,413,070		$ 2,413,070	$ 932,338	41.50	2.41%	50.00	2.00%	$ 119,142	$ 48,261	$ 9,323	$ 176,727	$ 163,794	-$ 12,933
1835	Overhead Conductors & Devices	$ 3,471,065	$ 315,551	$ 3,155,514	$ 2,872,577		$ 2,872,577	$ 541,648	40.00	2.50%	50.00	2.00%	$ 78,888	$ 57,452	$ 5,416	$ 141,756	$ 104,679	-$ 37,077
1840	Underground Conduit	$ 8,282,816	$ 974,449	$ 7,308,367	$ 2,575,962		$ 2,575,962	$ 734,410	30.00	3.33%	40.00	2.50%	$ 243,612	$ 64,399	$ 9,180	$ 317,191	$ 243,945	-$ 73,246
1845	Underground Conductors & Devices	$ 7,075,569	$ 1,166,361	$ 5,909,207	$ 2,927,116		$ 2,927,116	$ 788,211	20.00	5.00%	30.00	3.33%	$ 295,460	$ 97,571	$ 13,137	$ 406,168	$ 314,089	-$ 92,079
1850	Line Transformers	$ 10,116,755	$ 1,190,206	$ 8,926,549	$ 4,340,580		$ 4,340,580	$ 1,025,570	30.00	3.33%	40.00	2.50%	$ 297,552	$ 108,514	$ 12,820	$ 418,886	$ 322,980	-$ 95,906
1855	Services (Overhead & Underground)	$ 1,066,258	$ 96,933	$ 969,326	$ 980,588		$ 980,588	$ 205,679	40.00	2.50%	50.00	2.00%	$ 24,233	$ 19,612	$ 2,057	$ 45,902	$ 22,691	-$ 23,211
1855	Services (Underground)	$ 4,734,149	$ 556,959	$ 4,177,190	$ 2,865,262		$ 2,865,262	$ 617,036	30.00	3.33%	40.00	2.50%	$ 139,240	$ 71,632	$ 7,713	$ 218,584	$ 174,345	-$ 44,239
1860	Meters	$ 3,293,757	$ 658,751	$ 2,635,006	$ 871,479		$ 871,479	$ 266,932	16.00	6.25%	25.00	4.00%	$ 164,688	$ 34,859	$ 5,339	$ 204,886	$ 106,260	-$ 98,626
1860	Meters (Smart Meters)	$ 554,186	$ 152,879	$ 401,307	$ 3,314,151		$ 3,314,151		10.50	9.52%	15.00	6.67%	$ 38,220	$ 220,943	$ -	$ 259,163	$ 278,118	$ 18,955
1905	Land	$ 190,119	$ -	$ 190,119	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -	$ 45,350	$ 45,350
1908	Buildings & Fixtures	$ 2,015,376	$ 169,716	$ 1,845,660	$ 118,784		$ 118,784	$ 286,800	43.50	2.30%	50.00	2.00%	$ 42,429	$ 2,376	$ 2,868	$ 47,673		-$ 47,673
1910	Leasehold Improvements	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -	$ 11,209	$ 11,209
1915	Office Furniture & Equipment (10 years)	$ 74,266	$ 45,010	$ 29,256	$ 36,516		$ 36,516	$ 10,000	2.60	38.46%	10.00	10.00%	$ 11,252	$ 3,652	$ 500	$ 15,404		-$ 15,404
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -		$ -			0.00%	10.00	10.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 134,650	$ 161,579	-$ 26,930	$ 182,658		$ 182,658	$ 356,150		0.00%	5.00	20.00%	$ -	$ 36,532	$ 35,615	$ 72,147	$ 73,917	$ 1,770
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,043,171	$ 320,976	$ 722,195	$ 1,345,983		$ 1,345,983	$ 487,000	9.00	11.11%	10.00	10.00%	$ 80,244	$ 134,598	$ 24,350	$ 239,192	$ 211,990	-$ 27,202
1935	Stores Equipment	$ 17,416	$ 8,708	$ 8,708	$ 10,292		$ 10,292	$ 50,000	4.00	25.00%	10.00	10.00%	$ 2,177	$ 1,029	$ 2,500	$ 5,706	$ 5,708	$ 2
1940	Tools, Shop & Garage Equipment	$ 204,435	$ 107,597	$ 96,837	$ 234,861		$ 234,861	$ 60,000	3.60	27.78%	10.00	10.00%	$ 26,899	$ 23,486	$ 3,000	$ 53,385	$ 52,011	-$ 1,374
1945	Measurement & Testing Equipment	$ 39,772	$ -	$ 39,772	$ 6,260		$ 6,260			0.00%	10.00	10.00%	$ -	$ 626	$ -	$ 626	$ 6,895	$ 6,269
1950	Power Operated Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ 112,481	$ 89,985	$ 22,496	$ 17,890		$ 17,890		1.00	100.00%	10.00	10.00%	$ 22,496	$ 1,789	$ -	$ 24,285	$ 15,040	-$ 9,245
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 11,862,613	-$ 1,416,431	-$ 10,446,182	-$ 5,693,273		-$ 5,693,273	-$ 1,224,757	29.50	3.39%	40.00	2.50%	-$ 354,108	-$ 142,332	-$ 15,309	-$ 511,749	-$ 367,800	$ 143,949
	Total	**$ 36,635,738**	**$ 5,457,172**	**$ 31,178,566**	**$ 19,676,578**	**$ -**	**$ 19,676,578**	**$ 5,433,708**					**$ 1,297,070**	**$ 819,488**	**$ 144,380**	**$ 2,260,938**	**$ 1,871,449**	**-$ 389,489**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the prior year's additions.

3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

This appendix is to be completed in conjunction with the accounting instructions in Appendix 2-B

File Number:	EB-2017-0039
Exhibit:	4
Tab:	4-M
Page:	7 of 7
Date:	August 28th, 2017

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012. ☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		
Rebasing for the first time with depreciation policy changes made in 2013. ☑	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).	2018	MIFRS
Already rebased with depreciation policy changes in a prior rate application ☐	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2014 to 2018 is to be completed under MIFRS (2014 if changes to MIFRS are material).		

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 415,096	$ 415,096	$ -	$ 417,683		$ 417,683	$ 115,000		0.00%	5.00	20.00%	$ -	$ 83,537	$ 11,500	$ 95,037	$ 103,175	$ 8,138
1612	Land Rights (Formally known as Account 1906)	$ 105,692	$ 12,010	$ 93,681	$ 134,830		$ 134,830	$ 48,941	39.00	2.56%	50.00	2.00%	$ 2,402	$ 2,697	$ 489	$ 5,588	$ 5,515	-$ 73
1805	Land	$ 47,899	$ -	$ 47,899	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 82,461	$ 18,913	$ 63,548	-$ 0		-$ 0		16.80	5.95%	25.00	4.00%	$ 3,783	-$ 0	$ -	$ 3,783		-$ 3,783
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 5,420,962	$ 595,710	$ 4,825,252	$ 3,345,408		$ 3,345,408	$ 432,914	40.50	2.47%	50.00	2.00%	$ 119,142	$ 66,908	$ 4,329	$ 190,379	$ 177,447	-$ 12,932
1835	Overhead Conductors & Devices	$ 3,471,065	$ 394,439	$ 3,076,626	$ 3,414,225		$ 3,414,225	$ 839,476	39.00	2.56%	50.00	2.00%	$ 78,888	$ 68,285	$ 8,395	$ 155,567	$ 118,491	-$ 37,076
1840	Underground Conduit	$ 8,282,816	$ 1,218,061	$ 7,064,755	$ 3,310,372		$ 3,310,372	$ 864,559	29.00	3.45%	40.00	2.50%	$ 243,612	$ 82,759	$ 10,807	$ 337,179	$ 263,932	-$ 73,247
1845	Underground Conductors & Devices	$ 7,075,569	$ 1,461,822	$ 5,613,747	$ 3,715,327		$ 3,715,327	$ 853,466	19.00	5.26%	30.00	3.33%	$ 295,460	$ 123,844	$ 14,224	$ 433,529	$ 341,450	-$ 92,079
1850	Line Transformers	$ 10,116,755	$ 1,487,758	$ 8,628,997	$ 5,366,150		$ 5,366,150	$ 1,040,794	29.00	3.45%	40.00	2.50%	$ 297,552	$ 134,154	$ 13,010	$ 444,715	$ 348,809	-$ 95,906
1855	Services (Overhead)	$ 1,066,258	$ 121,166	$ 945,093	$ 1,186,266		$ 1,186,266	$ 200,093	39.00	2.56%	50.00	2.00%	$ 24,233	$ 23,725	$ 2,001	$ 49,959	$ 22,691	-$ 27,268
1855	Services (Underground)	$ 4,734,149	$ 696,198	$ 4,037,951	$ 3,482,298		$ 3,482,298	$ 600,278	29.00	3.45%	40.00	2.50%	$ 139,240	$ 87,057	$ 7,503	$ 233,801	$ 190,576	-$ 43,225
1860	Meters	$ 3,293,757	$ 823,439	$ 2,470,318	$ 1,138,411		$ 1,138,411	$ 265,671	15.00	6.67%	25.00	4.00%	$ 164,688	$ 45,536	$ 5,313	$ 215,538	$ 124,013	-$ 91,524
1860	Meters (Smart Meters)	$ 554,186	$ 191,099	$ 363,087	$ 3,314,151		$ 3,314,151		9.50	10.53%	15.00	6.67%	$ 38,220	$ 220,943	$ -	$ 259,163	$ 278,118	$ 18,955
1905	Land	$ 190,119	$ -	$ 190,119	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 2,015,376	$ 212,145	$ 1,803,231	$ 405,584		$ 405,584	$ 370,000	42.50	2.35%	50.00	2.00%	$ 42,429	$ 8,112	$ 3,700	$ 54,241	$ 51,918	-$ 2,323
1910	Leasehold Improvements	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 74,266	$ 56,262	$ 18,004	$ 46,516		$ 46,516	$ 10,000	1.60	62.50%	10.00	10.00%	$ 11,252	$ 4,652	$ 500	$ 16,404	$ 11,445	-$ 4,959
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -		$ -			0.00%	10.00	10.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 134,650	$ 161,579	-$ 26,930	$ 538,808		$ 538,808	$ 161,809		0.00%	5.00	20.00%	$ -	$ 107,762	$ 16,181	$ 123,942	$ 121,790	-$ 2,152
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,043,171	$ 401,220	$ 641,951	$ 1,832,983		$ 1,832,983	$ 270,000	8.00	12.50%	10.00	10.00%	$ 80,244	$ 183,298	$ 13,500	$ 277,042	$ 273,932	-$ 3,110
1935	Stores Equipment	$ 17,416	$ 10,885	$ 6,531	$ 60,292		$ 60,292	$ 50,000	3.00	33.33%	10.00	10.00%	$ 2,177	$ 6,029	$ 2,500	$ 10,706	$ 10,101	-$ 605
1940	Tools, Shop & Garage Equipment	$ 204,435	$ 134,497	$ 69,938	$ 294,861		$ 294,861	$ 60,000	2.60	38.46%	10.00	10.00%	$ 26,899	$ 29,486	$ 3,000	$ 59,385	$ 49,066	-$ 10,319
1945	Measurement & Testing Equipment	$ 39,772	$ -	$ 39,772	$ 6,260		$ 6,260			0.00%	10.00	10.00%	$ -	$ 626	$ -	$ 626	$ 5,458	$ 4,832
1950	Power Operated Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ 112,481	$ 112,481	$ -	$ 17,890		$ 17,890		-	0.00%	10.00	10.00%	$ -	$ 1,789	$ -	$ 1,789	$ 13,332	$ 11,543
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 11,862,613	-$ 1,770,539	-$ 10,092,074	-$ 6,918,030		-$ 6,918,030	-$ 1,224,757	28.50	3.51%	40.00	2.50%	-$ 354,108	-$ 172,951	-$ 15,309	-$ 542,368	-$ 398,418	$ 143,950
	Total	**$ 36,635,738**	**$ 6,754,242**	**$ 29,881,496**	**$ 25,110,286**	**$ -**	**$ 25,110,286**	**$ 4,958,243**					**$ 1,216,113**	**$ 1,108,248**	**$ 101,644**	**$ 2,426,005**	**$ 2,112,841**	**-$ 313,164**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utilities change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the gross book value of the prior year plus the prior year's additions.

3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column a (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column d (excel column f) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

Attachment 4-N

EPLC Federal & Provincial Income Tax Returns – December 31st, 2016

pwc

Private and Confidential
July 6, 2017

Joe Barile
Essex Powerlines Corporation
2730 Highway 3
Oldcastle ON N0R 1L0

Dear Mr. Barile:

We have prepared tax returns and filing documents for Essex Powerlines Corporation ("you" or "the Company") in respect of the year ended December 31, 2016.

We have prepared these tax returns and forms on the Company's behalf from information made available to us. We did not audit or otherwise verify the information provided. Therefore, we can assume no responsibility for errors in filings that result from missing information or incorrect information that has been provided to us.

In preparing these returns and forms, we have relied on the relevant provisions of the Income Tax Act (Canada) (the "Act") and Regulations in force as at the date of this letter, applicable proposed amendments to the Act publicly announced by the Minister of Finance and our understanding of the administrative practices of Canada Revenue Agency ("CRA"), as well as judicial decisions as they relate to these provisions.

The responsibility for filing "true, correct and complete" tax returns and forms on or before the statutory due dates rests under law with you. All tax returns and forms should be carefully reviewed and, where appropriate, information in the tax returns and forms should be checked against the Company's own accounting and other records.

After this review, each return and form (together with any prescribed forms listed on the attached **"Filing Instructions"**) should be signed by an authorized officer of the Company to attest that he or she has examined the return and found it to be complete and correct.

PricewaterhouseCoopers LLP
245 Ouellette Avenue, Suite 300, Windsor, Ontario, Canada N9A 7J4
T: +1 519 985 8900, F: +1 519 258 5457, www.pwc.com/ca

The tax returns and forms should be sent on time to ensure their receipt by the appropriate government departments indicated on the **Filing Instructions**. Filing the tax returns and forms by the required due dates avoids late-filing penalties and also helps to ensure that any income tax elections made with the tax returns and forms will be accepted by the government.

Tax Returns and Filing Documents

The tax returns and forms we have prepared for the Company include:

Federal T2 Corporation Income Tax Return x2 (1 copy to e-file with CRA and 1 copy to file with Ontario Ministry of Finance)
Federal T2 Corporation Income Tax Return (for your records)

Any tax owing should be received by the appropriate government departments by the dates indicated in the **Filing Instructions** to avoid incurring interest charges.

E-filing of corporate income tax returns (For CRA Filing Only)

Corporations with annual gross revenue exceeding $1 million are required to file their corporate income tax returns via the internet ("E-filing").

E-filing cannot be used to change certain basic information, such as the corporation's name, head office or mailing address. Corporations subject to mandatory E-filing should register these changes with Canada Revenue Agency ("CRA") before E-filing their returns. E-filing also cannot be used to file certain information returns (e.g., Form T106 and Form T1134). These returns must be filed separately.

The CRA will continue to process paper tax returns filed, but penalties will apply if the returns must be E-filed. The penalties per return are $1,000.

Corporations Information Act Annual Return for Ontario Corporations

Corporations incorporated, continued or amalgamated in Ontario must report any changes to the corporate information (e.g., director/officer information) recorded on the Ontario Ministry of Government Services ("MGS") public record under the Corporations Information Act. Changes to the corporate information can either be reported on Schedule 546 of the tax returns **or** Form 1 (Ontario Corporation Initial Return/Notice of Change), which is filed separately from the tax returns within 15 days after a change takes place in the information previously provided.

We have indicated that there has been no change in the corporate directors and officers on Schedule 546 since the last time the MGS was notified. If this is not correct, please let us know.

Notices of Assessment and Reassessment

To ensure our files are current and to obtain notification of any discrepancies between amounts assessed and amounts filed, please forward copies of all Notices of Assessment or Re-assessment upon receipt to Jocelyne G. Lavoie.

2017 instalments (For Ontario Ministry of Finance Only)

A computer printout of instalment payments for the year ending December 31, 2017 is attached. The schedules of estimated instalment payments are based on the Company's prior year income taxes. The Company should revise its tax instalment payments if taxable income for the year is estimated to be significantly less than that of the prior year. We will be pleased to assist you in this regard.

* * * * *

Please call me at 519 985 8930 or Jocelyne G. Lavoie at 519 640 7960, if you have any questions.

Yours very truly,

PricewaterhouseCoopers LLP

Giancarlo Dimaio, CPA, CA
Partner

Encl.

Filing instructions

Essex Powerlines Corporation
Taxation year-end: December 31, 2016

Canada Revenue Agency (CRA) Return

Filing due date: June 30, 2016

Payment:
• No payment is required.

Mail to:
• Return has been e-filed.

Signatures required:
• Part 3 of T183. Signature previously obtained for purposes of PwC releasing the return electronically.

Ontario Ministry of Finance P.I.L.T. Return

Filing due date: June 30, 2016

Overpayment:
• We have requested that $41,729 be transferred to the next taxation year.

Mail to:
• PwC has mailed PILT return on your behalf.

Signatures required:
• Page 2 of T2 Bar Code Return.

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2017-12-31

Business number 87006 6529 RC0001

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Canada Revenue Agency. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. Payment may be made by cheque or money order payable to the Receiver General either at an authorized financial institution or filed with **the appropriate remittance voucher at the following address:**

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date	Monthly tax instalments	Refund transferred to instalments	Instalments paid	Cumulative difference	Instalments payable
2017-01-31	43,456	41,729			1,727
2017-02-28	43,456				43,456
2017-03-31	43,456				43,456
2017-04-30	43,456				43,456
2017-05-31	43,456				43,456
2017-06-30	43,456				43,456
2017-07-31	43,456				43,456
2017-08-31	43,456				43,456
2017-09-30	43,456				43,456
2017-10-31	43,456				43,456
2017-11-30	43,456				43,456
2017-12-31	43,445				43,445
Totals	521,461	41,729			479,732

200

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

055 Do not use this area

…form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in …bec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act* and *Income Tax Regulations*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see cra.gc.ca or Guide T4012, *T2 Corporation - Income Tax Guide*.

Identification

Business number (BN) 001 87006 6529 RC0001

Corporation's name
002 Essex Powerlines Corporation

Address of head office
Has this address changed since the last time we were notified? 010 1 Yes [ ] 2 No [X]
If yes, complete lines 011 to 018.
011 2730 Highway 3
012
City: 015 Oldcastle
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal or ZIP code: 018 N0R 1L0

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? 020 1 Yes [ ] 2 No [X]
If yes, complete lines 021 to 028.
021 c/o
022 2730 Highway 3
023
City: 025 Oldcastle
Province, territory, or state: 026 ON
Country (other than Canada): 027
Postal or ZIP code: 028 N0R 1L0

Location of books and records (if different from head office address)
Has this address changed since the last time we were notified? 030 1 Yes [ ] 2 No [X]
If yes, complete lines 031 to 038.
031 2730 Highway 3
032
City: 035 Oldcastle
Province, territory, or state: 036 ON
Country (other than Canada): 037
Postal or ZIP code: 038 N0R 1L0

040 **Type of corporation at the end of the tax year** (tick one)
- [X] 1 Canadian-controlled private corporation (CCPC)
- [ ] 2 Other private corporation
- [ ] 3 Public corporation
- [ ] 4 Corporation controlled by a public corporation
- [ ] 5 Other corporation (specify)

If the type of corporation changed during the tax year, provide the effective date of the change 043 Year Month Day

To which tax year does this return apply?
Tax year start: 060 Year Month Day 2016-01-01
Tax year-end: 061 Year Month Day 2016-12-31

Has there been an acquisition of control resulting in the application of subsection 249(4) since the tax year start on line 060? 063 1 Yes [ ] 2 No [X]

If yes, provide the date control was acquired 065 Year Month Day

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? 070 1 Yes [ ] 2 No [X]
Amalgamation? 071 1 Yes [ ] 2 No [X]
If yes, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? 072 1 Yes [ ] 2 No [X]
If yes, complete and attach Schedule 24.

Is this the final tax year before amalgamation? 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada? 080 1 Yes [X] 2 No [ ]
If no, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? 082 1 Yes [ ] 2 No [X]
If yes, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
- [ ] 1 Exempt under paragraph 149(1)(e) or (l)
- [ ] 2 Exempt under paragraph 149(1)(j)
- [ ] 3 Exempt under paragraph 149(1)(t)
- [ ] 4 Exempt under other paragraphs of section 149

Do not use this area
095 096 898

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

Question	Line	Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164	X	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the *Income Tax Regulations*?	170		29
Did the corporation have a total amount over $1 million of reportable transactions with non-arm's length non-residents?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Does the corporation earn income from one or more Internet webpages or websites?	180		88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206	X	6
i) Is the corporation claiming the small business deduction and reporting a) income or loss from property (other than dividends deductible on line 320 of the T2 return), b) income from a partnership, c) income from a foreign business, d) income from a personal services business, e) income referred to in clause 125(1)(a)(i)(C) or 125(1)(a)(i)(B), or f) business limit assigned under subsection 125(3.2); or ii) does the corporation have aggregate investment income at line 440?	207	X	7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments (continued)

		Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	271		T1134
Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

		1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	X	
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? 913910 Other Local, Municipal and Regional Public Administration

Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	LDC - BILL & COLLECT	285	100.000 %
286		287	%
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 Year Month Day

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes ☐ 2 No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.		300	1,932,721	A
Deduct:				
Charitable donations from Schedule 2	311			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal		►		B
Subtotal (amount A minus amount B) (if negative, enter "0")			1,932,721	C
Section 110.5 additions or subparagraph 115(1)(a)(vii) additions		355		D
Taxable income (amount C plus amount D)		360	1,932,721	
Income exempt under paragraph 149(1)(t)		370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)			1,932,721	Z
Taxable income for the year from a personal services business**				Z.1

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 9.

** For a taxation year that ends after 2015.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	400	1,880,792	A
Taxable income from line 360 on page 3, **minus** 100/28 3.57143 of the amount on line 632* on page 8, **minus** 4 times the amount on line 636** on page 8, and **minus** any amount that, because of federal law, is exempt from Part I tax	405	1,932,721	B
Business limit (see notes 1 and 2 below)	410	500,000	C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year **divided** by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x 415 *** 83,437 D / 11,250 = 3,708,311 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0")	425		F
Business limit the CCPC assigns under subsection 125(3.2) (from line 515 below)			G
Amount F **minus** amount G	427		H

Small business deduction

Amount A, B, C, or H, whichever is the least ______ x Number of days in the tax year before January 1, 2016 ______ / Number of days in the tax year 366 x 17 % = ______ 1

Amount A, B, C, or H, whichever is the least ______ x Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366 x 17.5 % = ______ 2

Total of amounts 1 and 2 (enter amount I on line J on page 8) 430 ______ I

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year minus** $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year minus** $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

Specified corporate income and assignment under subsection 125(3.2)

Applicable to tax years that begin after March 21, 2016

Except that, if the tax year of your corporation started before **and** ends on or after March 22, 2016 and in the tax year of a CCPC, you can make an assignment of business limit to that other CCPC if its tax year started after March 21, 2016.

	J1 Name of corporation receiving the income and assigned amount	J Business number of the corporation receiving the assigned amount 490	K Income paid under clause 125(1)(a)(i)(B) to the corporation identified in column J [3] 500	L Business limit assigned to corporation identified in column J [4] 505
1.				
			Total 510	Total 515

Notes:

3. This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts each of which is income from an active business of the corporation for the year from the provision of services or property to a private corporation (directly or indirectly, in any manner whatever) if
   (A) at any time in the year, the corporation (or one of its shareholders) or a person who does not deal at arm's length with the corporation (or one of its shareholders) holds a direct or indirect interest in the private corporation, and
   (B) it is not the case that all or substantially all of the corporation's income for the year from an active business is from the provision of services or property to
   (I) persons (other than the private corporation) with which the corporation deals at arm's length, or
   (II) partnerships with which the corporation deals at arm's length, other than a partnership in which a person that does not deal at arm's length with the corporation holds a direct or indirect interest.

The amount of the business limit you assign to a CCPC cannot be greater than the amount determined by the formula A – B, where A is the amount of income referred to in column K in respect of that CCPC and B is the portion of the amount described in A that is deductible by you in respect of the amount of income referred to in clauses 125(1)(a)(i)(A) or (B) for the year. The amount on line 515 cannot be greater than the amount on line 425.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from page 3 (line 360 or amount Z, whichever applies)				1,932,721	A
Lesser of amounts B9 and H9 from Part 9 of Schedule 27			B		
Amount K13 from Part 13 of Schedule 27			C		
Personal services business income	432		D		
Amount used to calculate the credit union deduction (amount F from Schedule 17)			E		
Amount from line 400, 405, 410, or 427 on page 4, whichever is the least			F		
Aggregate investment income from line 440 on page 6*		51,929	G		
Subtotal (add amounts B to G)		51,929	▶	51,929	H
Amount A **minus** amount H (if negative, enter "0")				1,880,792	I
General tax reduction for Canadian-controlled private corporations – Amount I **multiplied** by	13 %			244,503	J

Enter amount J on line 638 on page 8.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)					K
Lesser of amounts B9 and H9 from Part 9 of Schedule 27			L		
Amount K13 from Part 13 of Schedule 27			M		
Personal services business income	434		N		
Amount used to calculate the credit union deduction (amount F from Schedule 17)			O		
Subtotal (add amounts L to O)			▶		P
Amount K **minus** amount P (if negative, enter "0")					Q
General tax reduction – Amount Q **multiplied** by	13 %				R

Enter amount R on line 639 on page 8.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7	440	51,929	A
Amount A 51,929 × (Number of days in the tax year before January 1, 2016 / Number of days in the tax year 366) × 26 2/3 % =			1
Amount A 51,929 × (Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366) × 30 2/3 % =		15,925	2
Subtotal (amount 1 **plus** amount 2)		15,925 ► 15,925	B
Foreign investment income from Schedule 7	445		C
Amount C × (Number of days in the tax year before January 1, 2016 / Number of days in the tax year 366) × 9 1/3 % =			3
Amount C × (Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366) × 8 % =			4
Subtotal (amount 3 **plus** amount 4)			D
Foreign non-business income tax credit from line 632 on page 8 **minus** amount D (if negative, enter "0")			E
Amount B **minus** amount E (if negative, enter "0")		15,925	F
Foreign non-business income tax credit from line 632 on page 8			G
(Number of days in the tax year before January 1, 2016 / Number of days in the tax year 366) × 35 =			5
(Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366) × 38 2/3 =		38.66667	6
Subtotal (amount 5 **plus** amount 6)		38.6667	H
Amount G × 100 / H (100 / 38.6667) =			I
Taxable income from line 360 on page 3		1,932,721	J
Deduct:			
Amount from line 400, 405, 410, or 427 on page 4, whichever is the least			K
Amount I			L
Foreign business income tax credit from line 636 on page 8 × 4 =			M
Subtotal (total of amounts K to M) ►			N
Subtotal (amount J **minus** amount N)		1,932,721	O
Amount O 1,932,721 × (Number of days in the tax year before January 1, 2016 / Number of days in the tax year 366) × 26 2/3 % =			7
Amount O 1,932,721 × (Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366) × 30 2/3 % =		592,701	8
Subtotal (amount 7 **plus** amount 8)		592,701 ► 592,701	P
Part I tax payable **minus** investment tax credit refund (line 700 **minus** line 780 from page 9)		302,198	Q
Refundable portion of Part I tax – Amount F, P, or Q, whichever is the least	450	15,925	R

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	460			
Deduct:				
Dividend refund for the previous tax year	465			
			►	A
Add:				
Refundable portion of Part I tax from line 450 on page 6		15,925 B		
Total Part IV tax payable from Schedule 3		C		
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480			
Subtotal (add amounts B, C, and line 480)		15,925	►	15,925 D
Refundable dividend tax on hand at the end of the tax year – Amount A plus amount D	485			15,925

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 3 of Schedule 3		1,046,176 E		
Amount E 1,046,176 x (Number of days in the tax year before January 1, 2016 / Number of days in the tax year 366) x 33 1/3 % =		1		
Amount E 1,046,176 x (Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366) x 38 1/3 % =		401,034 2		
Subtotal (amount 1 plus amount 2)		401,034	►	401,034 F
Refundable dividend tax on hand at the end of the tax year from line 485 above				15,925 G
Dividend refund – Amount F or G, whichever is less				15,925 H

Enter amount H on line 784 on page 9.

Part I tax

Base amount Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) multiplied by 38 % . . . 550 734,434 A

Additional tax on personal services business income (section 123.5)

Taxable income from a personal services business 555 ______ x Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366 x 5 % = 560 ______ B

Recapture of investment tax credit from Schedule 31 . . . . . 602 ______ C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income (if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6 . . . . . 51,929 D

Taxable income from line 360 on page 3 . . . . . 1,932,721 E

Deduct:

Amount from line 400, 405, 410, or 427 on page 4, whichever is the least . . . . . ______ F

Net amount (amount E **minus** amount F) 1,932,721 ▶ 1,932,721 G

Amount D or G, whichever is less 51,929 x Number of days in the tax year before January 1, 2016 ______ / Number of days in the tax year 366 x 6 2 / 3 % = ______ 1

Amount D or G, whichever is less 51,929 x Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366 x 10 2 / 3 % = 5,539 2

Refundable tax on CCPC's investment income (amount 1 **plus** amount 2) . . . . . 604 5,539 ▶ 5,539 H

Subtotal (**add** amounts A, B, C, and H) 739,973 I

Deduct:

Small business deduction from line 430 on page 4				J
Federal tax abatement	608	193,272		
Manufacturing and processing profits deduction from Schedule 27	616			
Investment corporation deduction	620			
Taxed capital gains 624 ______				
Additional deduction – credit unions from Schedule 17	628			
Federal foreign non-business income tax credit from Schedule 21	632			
Federal foreign business income tax credit from Schedule 21	636			
General tax reduction for CCPCs from amount J on page 5	638	244,503		
General tax reduction from amount R on page 5	639			
Federal logging tax credit from Schedule 21	640			
Eligible Canadian bank deduction under section 125.21	641			
Federal qualifying environmental trust tax credit	648			
Investment tax credit from Schedule 31	652			
Subtotal		437,775 ▶	437,775	K

Part I tax payable – Amount I **minus** amount K . . . . . 302,198 L

Enter amount L on line 700 on page 9.

Privacy statement

Summary of tax and credits

Federal tax

Part I tax payable from amount L on page 8	700	302,198
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		302,198

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	219,263
Total tax payable	770	521,461 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from amount H on page 7	784	15,925	
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld 801			
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	547,265	
Total credits	890	563,190	563,190 B

Refund code 894 2 Overpayment 41,729

Balance (amount A minus amount B) -41,729

If the result is positive, you have a **balance unpaid**.
If the result is negative, you have an **overpayment**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid ______

For information on how to make your payment, go to cra.gc.ca/payments.

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 ______ Branch number

914 ______ Institution number 918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number 920 A4259

Certification

I, 950 Barile (Last name) 951 Joe (First name) 954 General Manager (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 ______ Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 (519) 737-9811 Telephone number

Is the contact person the same as the authorized signing officer? If no, complete the information below 957 1 Yes ☒ 2 No ☐

958 Maxim Picco (Name of other authorized person) 959 (519) 737-9811 (Telephone number)

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering 1 for English or 2 for French.
Indiquez votre langue de correspondance en inscrivant 1 pour anglais ou 2 pour français. 990 1

Schedule of Instalment Remittances

ne of corporation contact

elephone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
		547,265
	Total amount of instalments claimed (carry the result to line 840 of the T2 Return)	547,265 A
	Total instalments credited to the taxation year per T9	547,265 B

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2016-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	15,637,000	15,954,000
	Total tangible capital assets	2008	+	60,199,000	55,856,000
	Total accumulated amortization of tangible capital assets	2009	–	6,013,000	3,943,000
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	40,987,000	44,382,000
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	110,810,000	112,249,000
	Liabilities				
	Total current liabilities	3139	+	23,359,000	19,663,000
	Total long-term liabilities	3450	+	61,723,000	68,918,000
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	85,082,000	88,581,000
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	25,728,000	23,668,000
	Total liabilities and shareholder equity	3640	=	110,810,000	112,249,000
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	8,832,000	6,772,000

* Generic item

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2016-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	85,289,000	72,903,654
	Cost of sales	8518	–	74,762,000	61,784,731
	Gross profit/loss	8519	=	10,527,000	11,118,923
	Cost of sales	8518	+	74,762,000	61,784,731
	Total operating expenses	9367	+	11,452,000	11,221,538
	Total expenses (mandatory field)	9368	=	86,214,000	73,006,269
	Total revenue (mandatory field)	8299	+	89,668,000	75,879,677
	Total expenses (mandatory field)	9368	–	86,214,000	73,006,269
	Net non-farming income	9369	=	3,454,000	2,873,408
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	3,454,000	2,873,408
	Total other comprehensive income	9998	=		
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	170,000	442,000
	Future (deferred) income tax provision	9995	–	699,000	-590,705
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	2,585,000	3,022,113

Canada Revenue Agency | Agence du revenu du Canada

Schedule 141

Notes Checklist

Corporation's name	Business number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2016-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? ..... 095 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? ..... 097 1 Yes [ ] 2 No [X]

Note

If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: 198

Completed an auditor's report ..... 1 [X]

Completed a review engagement report ..... 2 [ ]

Conducted a compilation engagement ..... 3 [ ]

Part 3 – Reservations

If you selected option 1 or 2 under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? ..... 099 1 Yes [ ] 2 No [X]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: 110

Prepared the tax return (financial statements prepared by client) ..... 1 [ ]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) ..... 2 [ ]

Were notes to the financial statements prepared? ..... 101 1 Yes [X] 2 No [ ]

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? ..... 104 1 Yes [ ] 2 No [X]

Is re-evaluation of asset information mentioned in the notes? ..... 105 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? ..... 106 1 Yes [X] 2 No [ ]

Is information regarding commitments mentioned in the notes? ..... 107 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? ..... 108 1 Yes [ ] 2 No [X]

Part 4 – Other information (continued)

Impairment and fair value changes

'any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a ;ult of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . . 200 1 Yes [ ] 2 No [X]

If yes, enter the amount recognized:

		In net income Increase (decrease)		In OCI Increase (decrease)
Property, plant, and equipment	210		211	
Intangible assets	215		216	
Investment property	220			
Biological assets	225			
Financial instruments	230		231	
Other	235		236	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . . 250 1 Yes [ ] 2 No [X]

Did the corporation apply hedge accounting during the tax year? . . . . . . 255 1 Yes [ ] 2 No [X]

Did the corporation discontinue hedge accounting during the tax year? . . . . . . 260 1 Yes [ ] 2 No [X]

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . . 265 1 Yes [X] 2 No [ ]

If yes, you have to maintain a separate reconciliation.

T2 BAR CODE RETURN

Name: Essex Powerlines Corporation

BN: 87006 6529 RC 0001

Tax Year Start: 2016-01-01

Tax Year End: 2016-12-31

Notes to the Finacial Statements will be forwarded separately.

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2016-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125			2,585,000 A
Add:			
Provision for income taxes – current	101	170,000	
Provision for income taxes – deferred	102	699,000	
Amortization of tangible assets	104	2,182,000	
Amortization of intangible assets	106	67,000	
Taxable capital gains from Schedule 6	113	51,929	
Non-deductible meals and entertainment expenses	121	1,815	
Subtotal of additions		3,171,744 ▶	3,171,744

Other additions:

Miscellaneous other additions:

	1 Description 605	2 Amount 295
1	Inducement under 12(1)(x) ITA	5,974
2	See attached	724,000
3	Amort of deferred charge	175,472
	Total of column 2	905,446

Total of column 2 ▶	296	905,446	
Subtotal of other additions	199	905,446 ▶	905,446
Total additions	500	4,077,190 ▶	4,077,190 B
Amount A plus amount B			6,662,190 C
Deduct:			
Gain on disposal of assets per financial statements	401	37,263	
Capital cost allowance from Schedule 8	403	3,792,844	
Cumulative eligible capital deduction from Schedule 10	405	6,326	
Subtotal of deductions		3,836,433 ▶	3,836,433

Other deductions:

Miscellaneous other deductions:

	1 Description 705	2 Amount 395
1	See attachment	775,000
2	Mark to Market adjustment	118,036
	Total of column 2	893,036

Total of column 2 ▶	396	893,036	
Subtotal of other deductions	499	893,036 ▶	893,036
Total deductions	510	4,729,469 ▶	4,729,469 D
Net income (loss) for income tax purposes (amount C minus amount D)			1,932,721 E

Enter amount E on line 300 of the T2 return.

Attached Schedule with Total

ne 395 – Amount

Title Line 395 – Amount

Description	Operator (Note)	Amount	
Post-employement benefits - benefits paid		112,000	00
Decrease of deferred tax liability booked to regulatory account	+	663,000	00
	+		
	Total	775,000	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

e 295 – Amount

Title Line 295 – Amount

Description	Operator (Note)	Amount
Post-employement benefits - costs		203,000 00
PY regulatory adjustments booked to retained earnings	+	521,000 00
	+	
	Total	724,000 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Inducement

form is used to calculate inducements that a corporation must add to its income under paragraph 12(1)(x) of the ITA. If an amount reduces the capital cost property, this amount will be indicated in Part "Tax credits whose amount should reduce the capital cost of property."

If you want to transfer an amount to Schedule 1 and include it in the corporation's income for tax purposes, select the corresponding check box in column A. You can also select the option **Select this check box to add all the amounts to income calculated in Schedule 1** to transfer all the amounts to Schedule 1. In either case, the column A check box will be selected for that amount and it will therefore be updated to Schedule 1.

Tax credits whose amount should be added to income

Select this check box to add all the amounts to income calculated in Schedule 1. ☐

Ontario

A		
X	Portion of the Ontario research and development tax credit that relates to the prescribed proxy amount (PPA) and portion of the Ontario investment tax credit that relates to contributions made to SR&ED farming organizations	
X	Ontario co-operative education tax credit	5,974
☐	Ontario apprenticeship training tax credit	
☐	Ontario computer animation and special effects tax credit* * Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario film and television tax credit* * Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario production services tax credit* * Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario interactive digital media tax credit* * Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario sound recording tax credit* * Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario book publishing tax credit	
X	Portion of the Ontario innovation tax credit that relates to the prescribed proxy amount (PPA) and portion of the Ontario investment tax credit that relates to contributions made to SR&ED farming organizations	
☐	Ontario business-research institute tax credit	
☐	Ontario community food program donation tax credit for farmers	

Tax credits whose amount should reduce the capital cost of property

Canada Revenue Agency / Agence du revenu du Canada

Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculations

Schedule 3

Corporation's name	Business number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2016-12-31

- Corporations must use this schedule to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a),(a.1), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- All legislative references are to the federal *Income Tax Act*.
- The calculations in this schedule apply only to private or subject corporations.
- A recipient corporation is **connected** with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- If you need more space, continue on a separate schedule.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- Column A1 – Enter "X" if dividends received from a foreign source.
- Column F1 – Enter the amount of dividends received reported in column 240 that are eligible.
- Column F2 – Enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

- Do **not** include dividends received from foreign non-affiliates.
- Complete columns B, C, D, H and I **only** if the payer corporation is **connected.**

Important instructions to follow if the payer corporation is connected

- If your corporation's tax year-end is different than that of the **connected** payer corporation, dividends could have been received from more than one tax year of the payer corporation. If so, **use a separate line** to provide the information according to each tax year of the payer corporation.
- When completing column J and K use the **special calculations provided in the notes.**

A Name of payer corporation (from which the corporation received the dividend) 200	A1	B Enter 1 if payer corporation is **connected** 205	C Business Number of connected corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD 220	E Non-taxable dividends under section 83 230

Total of column E (enter amount on line 402 of Schedule 1) | |

F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (a.1),(b), or (d)[note 1] 240	F1 Eligible dividends (included in column F)	F2	G Dividends included in column F that was received before 2016 241	H Total taxable dividends paid by connected payer corporation (for tax year in column D) 250	I Dividend refund of the connected payer corporation (for tax year in column D)[note 2] 260	J Part IV tax before deductions. Dividends (from column G) received before 2016 multiplied by 33 1/3%[note 3] 270	K Part IV tax before deductions. Dividends received after 2015 (column F minus column G) multiplied by 38 1/3%[note 4] 275
Total of column F (include this amount on line 320 of the T2 Return)						Total of column J (enter amount on line a in Part 2)	Total of column K (enter amount on line b in Part 2)

1 If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270 or column 275 as applicable according to the date received. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

2 If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

3 For dividends received **before** 2016 from **connected** corporations, Part IV tax on dividends is equal to: column G **multiplied** by column I **divided** by column H.

4 For dividends received **after** 2015 from **connected** corporations, Part IV tax on dividends is equal to: column I **divided** by column H **multiplied** by the result of column F **minus** column G.

Part 2 – Calculation of Part IV tax payable

Part IV tax on dividends received **before** 2016, before deductions (total of column J in part 1) ...... ______ a

Part IV tax on dividends received **after** 2015, before deductions (total of column K in part 1) ...... ______ b

Part IV tax before deductions (amount a **plus** amount b) ...... ______ ▶ ______ L

Deduct:

Part IV.I tax payable on dividends subject to Part IV tax (from line 360 of Schedule 43) ...... 320 ______

Subtotal (amount L **minus** line 320) ______ M

Deduct:

Current-year non-capital loss claimed to reduce Part IV tax ...... 330 ______ c

Non-capital losses from previous years claimed to reduce Part IV tax ...... 335 ______ d

Current-year farm loss claimed to reduce Part IV tax ...... 340 ______ e

Farm losses from previous years claimed to reduce Part IV tax ...... 345 ______ f

Total losses applied against Part IV tax (total of amounts c to f) ______ g

If your tax year begins after December 31, 2015:

Amount g **multiplied** by 38 1 / 3 % ...... ______ h

If your tax year begins before January 1, 2016:

Amount b or M whichever is less

______ ÷ 38 1 / 3 % ... = ______ 1

Amount 1 or g, whichever is less ...... ______ 2

Amount g **minus** amount 2 ...... ______ 3

Amount 2 ______ x 38 1 / 3 % = ______ i

Amount 3 ______ x 33 1 / 3 % = ______ j

Subtotal (amount i **plus** amount j) ______ k

Amount h or amount k, whichever applies depending on your tax year start date ...... ______ N

Part IV tax payable (amount M **minus** amount N, if negative enter "0") ...... 360 ______
(enter amount on line 712 of the T2 return)

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information according to each tax year of the recipient corporation.

	O Name of connected recipient corporation 400	P Business Number 410	Q Tax year-end of connected recipient corporation in which the dividends in column R were received YYYY/MM/DD 420	R Taxable dividends paid to connected corporations 430	R1 Eligible dividends (included in column R)
1	Essex Power Corporation	86953 5435 RC0001	2016-12-31	1,046,176	

Total of column R 1,046,176

Total taxable dividends paid in the tax year to other than connected corporations . . . . . 450 ______

Eligible dividends (included in line 450) . . . . . 450a ______

Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column R **plus** line 450) 460 1,046,176

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above) 1,046,176

Other dividends paid in the tax year (total of 510 to 540) . . . . . ______

Total dividends paid in the tax year 500 1,046,176

Deduct:

Dividends paid out of capital dividend account . . . . . 510 ______

Capital gains dividends . . . . . 520 ______

Dividends paid on shares described in subsection 129(1.2) . . . . . 530 ______

Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year . . . . . 540 ______

Subtotal (total of lines 510 to 540) ______ ► ______ S

Total taxable dividends paid in the tax year that qualify for a dividend refund (Line 500 **minus** amount S) 1,046,176 T

T2SCH3 E (16)

Canadä

Canada Revenue Agency / Agence du revenu du Canada

Schedule 5

Tax Calculation Supplementary – Corporations

Corporation's name	Business Number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2016-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- All legislative references mentioned in this schedule are from the *Income Tax Regulations*.
- For more information, see the *T2 Corporation – Income Tax Guide*.
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ______ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year.*		B Total salaries and wages paid in jurisdiction	C (B x taxable income) / G	D Gross revenue	E (D x taxable income) / H	F Allocation of taxable income (C + E) x 1/2** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes	103		143		
Newfoundland and Labrador Offshore	004 1 Yes	104		144		
Prince Edward Island	005 1 Yes	105		145		
Nova Scotia	007 1 Yes	107		147		
Nova Scotia Offshore	008 1 Yes	108		148		
New Brunswick	009 1 Yes	109		149		
Quebec	011 1 Yes	111		151		
Ontario	013 1 Yes	113		153		
Manitoba	015 1 Yes	115		155		
Saskatchewan	017 1 Yes	117		157		
Alberta	019 1 Yes	119		159		
British Columbia	021 1 Yes	121		161		
Yukon	023 1 Yes	123		163		
Northwest Territories	025 1 Yes	125		165		
Nunavut	026 1 Yes	126		166		
Outside Canada	027 1 Yes	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in subsection 400(2).

** For corporations other than those described under section 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.
3. If the corporation is a member of a partnership and the partnership had a permanent establishment in a jurisdiction, select the jurisdiction in Column A and include your proportionate share of the partnership's salaries and wages and gross revenue in columns B and D, respectively.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
1,932,721		1,932,721	222,263

	Line	Amount		Amount	
Ontario basic income tax (from Schedule 500)	270	222,263			
Deduct: Ontario small business deduction (from Schedule 500)	402				
Subtotal		222,263	►	222,263	A6
Add:					
Ontario additional tax re Crown royalties (from Schedule 504)	274				
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal			►		B6
Subtotal (amount A6 **plus** amount B6)				222,263	C6
Deduct:					
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario political contributions tax credit (from Schedule 525)	415				
Subtotal			►		D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")				222,263	E6
Deduct: Ontario research and development tax credit (from Schedule 508)	416				
Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount E6 **minus** amount on line 416) (if negative, enter "0")				222,263	F6
Deduct:					
Ontario corporate minimum tax credit (from Schedule 510)	418				
Ontario community food program donation tax credit for farmers (from Schedule 2)	420				
Ontario corporate income tax payable (amount F6 **minus** amounts on line 418 and line 420) (if negative, enter "0")				222,263	G6
Add:					
Ontario corporate minimum tax (from Schedule 510)	278				
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Subtotal			►		H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)				222,263	I6
Deduct:					
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452	3,000			
Ontario apprenticeship training tax credit (from Schedule 552)	454				
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario sound recording tax credit (from Schedule 562)	464				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Subtotal		3,000	►	3,000	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.	290			219,263	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

provincial and territorial tax payable or refundable credits	255	219,263

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 6

Summary of Dispositions of Capital Property

Corporation's name	Business number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2016-12-31

- Use this schedule if your corporation disposed of (actual or deemed) capital property or claimed an allowable business investment loss (ABIL), or both, in the tax year.
- Also use this schedule to make a designation under paragraph 111(4)(e) of the *Income Tax Act* if control of the corporation has been acquired by a person or a group of persons.
- For more information, see the section called "Schedule 6, Summary of Dispositions of Capital Property" in Guide T4012, *T2 Corporation – Income Tax Guide.*

Designation under paragraph 111(4)(e) of the Income Tax Act

Are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e)? . . . . . . 050 1 Yes ☐ 2 No ☒

If yes, attach a statement specifying which properties such a designation applies to.

Part 1 – Shares

1 Number of shares 100	2 Name of corporation in which the shares are held 105	3 Class of shares 106	4 Date of Acquisition YYYY/MM/DD 110	5 Proceeds of disposition 120	6 Adjusted cost base 130	7 Outlays and expenses from disposition 140	8 Gain (or loss) (column 5 minus columns 6 and 7) 150	Foreign source
			Totals					

Total adjustment under subsection 112(3) of the Act to all losses identified in Part 1 . . . . 160 ________

Actual gain or loss from the disposition of shares (total of column 8 plus line 160) . . . . ________ A

Part 2 – Real estate (Do not include losses on depreciable property)

	1 Municipal address of real estate 1 = Address 1 2 = Address 2 3 = City 4 = Province, Country, Postal Code and Zip Code or Foreign Postal Code 200	2 Date of Acquisition YYYY/MM/DD 210	3 Proceeds of disposition 220	4 Adjusted cost base 230	5 Outlays and expenses from disposition 240	6 Gain (or loss) (column 3 minus columns 4 and 5) 250	Foreign source	
1	Georgia Street land		94,000		7,357	86,643		
2	Sunnyside Street land		67,000	12,000	37,785	17,215		
		Totals	161,000	12,000	45,142	103,858		B

Part 3 – Bonds

1 Face value of bonds 300	2 Maturity date YYYY/MM/DD 305	3 Name of bond issuer 307	4 Date of Acquisition YYYY/MM/DD 310	5 Proceeds of disposition 320	6 Adjusted cost base 330	7 Outlays and expenses from disposition 340	8 Gain (or loss) (column 5 minus columns 6 and 7) 350	Foreign source
			Totals					C

Part 4 – Other properties (Do not include losses on depreciable property)

1 Description of other property 400	2 Date of Acquisition YYYY/MM/DD 410	3 Proceeds of disposition 420	4 Adjusted cost base 430	5 Outlays and expenses from disposition 440	6 Gain (or loss) (column 3 minus columns 4 and 5) 450	Foreign source
	Totals					D

Note
Other property includes capital debts established as bad debts, as well as amounts that arise from foreign currency transactions.

Part 5 – Personal-use property (Do not include listed personal property)

1 Description of personal-use property 500	2 Date of Acquisition YYYY/MM/DD 510	3 Proceeds of disposition 520	4 Adjusted cost base 530	5 Outlays and expenses from disposition 540	6 Gain only (column 3 minus columns 4 and 5; if negative, enter "0") 550	Foreign source
	Totals					E

Note
You cannot deduct losses on dispositions of personal-use property (other than listed personal property) from your income.

Part 6 – Listed personal property

1 Description of listed personal property 600	2 Date of Acquisition YYYY/MM/DD 610	3 Proceeds of disposition 620	4 Adjusted cost base 630	5 Outlays and expenses from disposition 640	6 Gain (or loss) (column 3 minus columns 4 and 5) 650	Foreign source
	Totals					

Deduct: Unapplied listed personal property losses from other years (amount from line 530 of Schedule 4, *Corporation Loss Continuity and Application*) . . . . . 655 ________

Net gains (or losses) from the disposition of listed personal property (total of column 6 minus line 655) . . . . . ________ F

Note
Net listed personal property losses can only be applied against listed personal property gains.

Part 7 – Property qualifying for and resulting in an allowable business investment loss

1 Name of small business corporation 900	2 Shares, enter 1; debt, enter 2 905	3 Date of Acquisition YYYY/MM/DD 910	4 Proceeds of disposition 920	5 Adjusted cost base 930	6 Outlays and expenses from disposition 940	7 Loss only (column 4 minus columns 5 and 6) 950	Foreign source
		Totals					

Allowable business investment losses (ABILs) . . . . . Total of Column 7 ________ x 50.0000 % = ________ G

Enter amount G on line 406 of Schedule 1, *Net Income (Loss) for Income Tax Purposes.*

Note
Properties listed in Part 7 should not be included in any other parts of this schedule.

Part 8 – Capital gains or losses

Total of amounts A to F (do not include amount F if it is a loss) . . . . . 103,858 H

`d:

Foreign source

Capital gains dividend received in the year . . . . . 875 ______ I ☐

Capital gains reserve opening balance (from Part 1 of Schedule 13, *Continuity of Reserves*, enter the amount from line 8, *Balance at the beginning of the year* **plus** the amount from line 9, *Transfer on an amalgamation or the wind–up of a subsidiary*) . . . . . 880 ______ J

Subtotal (total of amounts H to J) 103,858 K

Deduct: Capital gains reserve closing balance (from Schedule 13) . . . . . 885 ______ L

Capital gains or losses, excluding ABILs (amount K **minus** amount L) . . . . . 890 103,858 M

Part 9 – Taxable capital gains and total capital losses

Capital gains or losses, excluding ABILs (amount from line 890 in Part 8) . . . . . 103,858 N

Deduct the following amounts included in amount N, that are subject to the zero inclusion rate:

Note

When a taxpayer is entitled to an advantage in respect of a donation, the zero inclusion rate is restricted to only part of the taxpayer's capital gain on disposition of the property. See section 38.2 of the Act for more information.

Gain on the donation to a qualified donee of a share, debt obligation, or right listed on a designated stock exchange and other securities under subparagraphs 38(a.1)(i) and (iii) of the Act . . . . . 895 ______ a — Foreign source ☐

Gain on the donation to a qualified donee of ecologically sensitive land under paragraph 38(a.2) of the Act* . . . . . 896 ______ b — Foreign source ☐

Exempt portion of the gain on the donation of securities arising from the exchange of a partnership interest under paragraph 38(*a.3*) . . . . . ______ b-2 — Foreign source ☐

Subtotal (amount a **plus** amount b **plus** b-2) ______ ▶ ______ O

Subtotal (amount N **minus** amount O) 103,858 P

Add:

Deemed capital gain from the donation of property included in a flow-through share class of property to a qualified donee under subsection 40(12) of the Act:

Exemption threshold at time of disposition . . . . . 897 ______ c

The total of all capital gains from the disposition of the actual property . . . . . 898 ______ d

Foreign source

Amount c or amount d, whichever is less ______ Q ☐

Taxable capital gains under section 34.2 of the Act (line 275 of Schedule 73, *Income Inclusion Summary for Corporations that are Members of Partnerships*) . . . . . ______ x 2 = 899 ______ R

Subtotal (total of amounts P to R) 103,858 S

Deduct:

Allowable capital losses under section 34.2 of the Act (line 285 of Schedule 73, *Income Inclusion Summary for Corporations that are Members of Partnerships*) . . . . . ______ x 2 = 901 ______ T

Total capital gains or losses (amount S **minus** amount T) 103,858 U

Taxable capital gains or total capital losses

Total capital losses (amount U, if amount U is negative; if amount U is positive, enter "0") . . . . . ______ V

Enter amount V on line 210 of Schedule 4.

Taxable capital gains (if amount U is positive, enter amount U 103,858 multiplied by 50.0000 %;
if amount U is negative, enter "0") . . . . . 51,929 W

Enter amount W on line 113 of Schedule 1.

* Do not include gains on donations of ecologically sensitive land to a private foundation.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 7

Aggregate Investment Income and Active Business Income

Corporation's name	Business number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2016-12-31

- Use this schedule if you are a Canadian-controlled private corporation (CCPC) to calculate:
  - your aggregate investment income and foreign investment income, as defined in subsection 129(4), to determine the refundable portion of Part I tax;
  - your **specified partnership income**, if you are a member or **designated member** of one or more partnerships as defined under subsection 125(7); and
  - your income from an active business carried on in Canada eligible for the small business deduction including any **specified corporate income** as defined in subsection 125(7).
- Use this schedule if another CCPC is making an assignment of business limit under subsection 125(3.2) to you.
- Use this schedule if you are a member of a partnership to **assign specified partnership business limit** to a **designated member** under subsection 125(8).
  Note: If you are a corporation that is not a CCPC, **only** complete Table 1 (columns A1, B1, C1, G1, H1 and J1) and Table 3 to make this assignment.
- All legislative references are to the *Income Tax Act*.
- For more information, see **Small Business Deduction** and **Refundable Portion of Part I Tax** in Guide T4012, *T2 Corporation – Income Tax Guide*.
- All notes with regards to this form can be found at the bottom of the form.

Part 1 – Aggregate investment income

Aggregate investment income is all **world** source income.

Eligible portion of taxable capital gains for the year			002	51,929
Eligible portion of allowable capital losses for the year (including allowable business investment losses)	012			
Net capital losses of previous years claimed on line 332 on the T2 return	022			
Subtotal (line 012 **plus** line 022)		▶		A
Line 002 **minus** amount A (if negative, enter "0")				51,929 B
Total income from property (include income from a specified investment business carried on in Canada other than income from a source outside Canada)	032			
Exempt income	042			
Amounts received from AgriInvest Fund No. 2 that were included in computing the corporation's income for the year	052			
Taxable dividends deductible (total of column F on Schedule 3 **minus** related expenses)	062			
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)	072			
Subtotal (**add** lines 042, 052, 062 and 072)	▶	C		
Subtotal (line 032 **minus** amount C)		▶		D
Amount B **plus** amount D				51,929 E
Total losses from property (include losses from a specified investment business carried on in Canada other than a loss from a source outside Canada)			082	
Amount E **minus** line 082 (if negative, enter "0") (enter on line 440 of the T2 return)			092	51,929

Part 2A – Canadian investment income calculation

Eligible portion of taxable capital gains for the year before taking into account the capital gains reserve (federal) of Schedule 13	51,929	1.1			
...erve's eligible portion (addition/deduction)		1.2			
Taxable capital gains under section 34.2 (line 275 on Schedule 73)		1.3			
Eligible portion of taxable capital gains for the year after taking into account the capital gains reserve from Schedule 13 and the taxable capital gains under section 34.2 (**add** amounts 1.1, 1.2, and 1.3)	51,929	▶		51,929	1a
Eligible portion of allowable capital losses for the year (including allowable business investment losses)		2.1			
Net capital losses of previous years claimed on line 332 on the T2 return		2.2			
Allowable capital losses under section 34.2 (line 285 of Schedule 73)		2.3			
Add amounts 2.1, 2.2 and 2.3		▶			2a
			Amount 1a **minus** amount 2a (if negative, enter "0")	51,929	3a
Taxable dividends		4.1			
Rental property income (under regulation 1100(11))		4.2			
Other property income		4.3			
Property income under section 34.2 (line 280 of Schedule 73)		4.4			
Total property income from **Canadian** sources (**add** amounts 4.1, 4.2, 4.3 and 4.4)		▶			4a
Exempt income		5.1			
Amounts received from AgriInvest Fund No. 2 that were included in computing the corporation's income for the year		5.2			
Taxable dividends deductible (total of column F on Schedule 3 **minus** related expenses)		5.3			
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)		5.4			
Add amounts 5.1, 5.2, 5.3 and 5.4		▶			5a
			Amount 4a **minus** amount 5a		6a
			Amount 3a **plus** amount 6a	51,929	7a
Rental property losses (under regulation 1100(11))		8.1			
Dividend losses		8.2			
Other property losses		8.3			
Property losses under section 34.2 (line 280 of Schedule 73)		8.4			
Total property losses from **Canadian** sources (**add** amounts 8.1, 8.2, 8.3 and 8.4)		▶			8a
			Amount 7a **minus** amount 8a (if negative, enter "0")	51,929	9a

Part 2 – Foreign investment income

Foreign investment income is all income from sources **outside Canada**.

Eligible portion of taxable capital gains for the year before taking into account the capital gains reserve (federal) of Schedule 13				a1	
Reserve's eligible portion (addition/deduction)				a2	
Taxable capital gains under section 34.2 (line 275 of Schedule 73)*				a3	
Eligible portion of taxable capital gains for the year after taking into account the capital gains reserve (federal) of Schedule 13 and taxable capital gains under section 34.2 (add amounts a1, a2, and a3)				▶ 001	
Allowable capital losses for the year				b1	
Allowable capital losses under section 34.2 (line 285 of Schedule 73)*				b2	
Eligible portion of allowable capital losses for the year (including allowable business investment losses) (**Add** amounts b1 and b2)				▶ 009	
Subtotal (line 001 **minus** line 009) (if negative, enter "0")					F
Taxable dividends		c1			
Rental property income (under regulation 1100(11))		c2			
Other property income		c3			
Property income under section 34.2 (line 280 of Schedule 73)*		c4			
Total income from property from a source **outside Canada** (net of related expenses) (**add** amounts c1, c2, c3 and c4)		▶ 019			
Exempt income	029				
Taxable dividends deductible (total of column F on Schedule 3 **minus** related expenses)	049				
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)	059				
Subtotal (**add** lines 029, 049, and 059)		▶	G		
Subtotal (line 019 **minus** amount G)				▶	H
Amount F **plus** amount H					I
Rental property losses (under regulation 1100(11))				d1	
Dividend losses				d2	
Other property losses				d3	
Property losses under section 34.2 (line 280 of Schedule 73)*				d4	
Total losses from property from a source **outside Canada** (**add** amounts d1, d2, d3 and d4)				▶ 069	
Amount I **minus** line 069 (if negative, enter "0") (enter on line 445 of the T2 return)				079	

* When an amount is entered on these lines, the amounts calculated for the taxable capital gains or allowable capital losses on lines 1.3 and 2.3 as well as property income or losses on lines 4.4 and 8.4 in Part 2A, "Canadian investment income calculation" are automatically updated. For more details, press F1 to consult the Help.

Net taxable dividends	Canadian	Foreign	Total
Taxable dividends deducted per schedule 3			
Less: Expenses related to such dividends			
Total expenses			
Net taxable dividends			

Part 3 – Specified partnership income

Table 1 – Specified partnership income

	A	A1	1A
	Is the corporation a designated member of the partnership?	Partnership name 200	Partnership's account number
1	Yes [ ] No [X]		

	B1	C1	D1	1D	2D	E1	F1
	Total income (loss) of partnership from an active business 300	Corporation's share of amount in column B1 310	Income of the corporation from providing (directly or indirectly) services or property to the partnership note 1 311	Adjustments under section 34.2 note 2	Expenses the corporation incurred to earn partnership income	Adjustments (column 1D **minus** column 2D) 315	Corporation's income (loss) in respect of the partnership note 3 (add columns C1, D1 and E1) 320
1							
							Total 350

	G1	H1	I1	J1	K1	L1	M1
	Number of days in the partnership's fiscal period 325	Prorated business limit notes 3 and 4 (column C1 ÷ column B1) × [$ 500 000 × (column G1 ÷ 365)] (if column C1 is negative, enter "0") 330	Specified partnership business limit **assigned to you** (from H2 in Table 2) notes 1, 5 and 7 335	Specified partnership business limit **assigned by you** from F3 in Table 3) notes 1, 6 and 8 336	Specified partnership business limit amount (column H1 **plus** column I1 **minus** column J1)	Column F1 **minus** column K1 (if negative, enter "0")	Lesser of columns F1 and K1 (if column F1 is negative, enter "0") notes 5 340
1							
						Total 385	360

Corporation's losses for the year from an active business carried on in Canada (other than as a member of a partnership) – enter as a positive amount . . . . 370 ______

Specified partnership loss of the corporation for the year – enter as a positive amount (total of all negative amounts in column F1) . . . . 380 ______

Subtotal (line 370 **plus** line 380) ______ J

Amount at line 385 or amount J, whichever is less . . . . 390 ______

Specified partnership income (line 360 **plus** line 390) . . . . 400 ______
(enter at amount N in Part 4)

Part 3 – Specified partnership income (continued)

Tables 2 and 3 are used to make an assignment of **specified partnership business limit** under subsection 125(8). A person that is a member of a partnership can make an assignment of **specified partnership business limit** under subsection 125(8) to a **designated member** for any tax year that **starts after** March 21, 2016. Also, that person can make an assignment for its tax year that **starts before** March 22, 2016 and **ends after** March 21, 2016 if the tax year of the **designated member starts after** March 21, 2016.

If you are a designated member and **receiving** specified partnership business limit from a person that is a member of the partnership, complete Table 2.

If you are a member of the partnership and **assigning** specified partnership business limit to a designated member, complete Table 3.

Table 2 – A member is assigning to you specified partnership business limit under subsection 125(8)

A2	2A	B2
Partnership name 405	Partnership's account number	Name of the member 406

C2	D2	E2	F2	G2	H2
Business number of the member (if applicable) 410	Social insurance number of the member (if applicable) 411	Trust account number of the member (if applicable) 412	Tax year start of the member (yyyymmdd) 415	Tax year-end of the member (yyyymmdd) 416	Specified partnership business limit assigned to you by the member note 9 420

Table 3 – You are assigning to a designated member (CCPC) specified partnership business limit under subsection 125(8)

A3	3A	B3
Partnership name 425	Partnership's account number	Name of the designated member 426

C3	D3	E3	F3
Business number of the designated member 430	Tax year start of the designated member 435	Tax year-end of the designated member (yyyymmdd) 436	Specified partnership business limit assigned by you to the designated member note 10 440

Part 4 – Partnership income not eligible for the small business deduction

Corporation's income from active businesses carried on in Canada as a member or designated member of a partnership (after deducting related expenses) – from line 350 in Part 3 (if the net amount is negative, enter "0" on line 450)		K
Specified partnership loss (from line 380 in Part 3)		L
Subtotal (amount K **plus** amount L)		M
Specified partnership income (from line 400 in Part 3)		N
Partnership income not eligible for the small business deduction (amount M **minus** amount N) (enter at amount V in Part 5)	450	

Part 5 – Income from active business carried on in Canada

Net income for income tax purposes from line 300 of the T2 return		1,932,721	O		
Allowable business investment loss from line 406 of Schedule 1			P		
Subtotal (amount O **plus** amount P)		1,932,721	▶	1,932,721	Q
Foreign business income after deducting related expenses note 11	500				
Taxable capital gains from line 113 of Schedule 1		51,929	R		
Net property income (line 032 note 12 **minus** the total of lines 042, 052 and 082 in Part 1) note 11			S		
Personal services business income and other income after deducting related expenses note 11	520				
Subtotal (**add** line 500, amount R, amount S and line 520)		51,929	▶	51,929	T
Net amount (amount Q **minus** amount T)				1,880,792	U
Partnership income not eligible for the small business deduction (line 450 in Part 4)			V		
Partnership income allocated to your corporation under subsection 96(1.1)	530				
Income referred to in clause 125(1)(a)(i)(C)	540				
Income referred to in clause 125(1)(a)(i)(B) (from line 615 in Part 6)			W		
Subtotal (**add** amount V, line 530, line 540 and amount W)			▶		X
Specified corporate income (from line 625 in Part 6)					Y
Income from active business carried on in Canada (amount U **minus** amount X **plus** amount Y) (enter amount Z on line 400 of the T2 return – if negative, enter "0")				1,880,792	Z

Part 6 – Specified corporate income and assignment under subsection 125(3.2)

Applies to tax years that begin after March 21, 2016.

A CCPC can also make an assignment of business limit to you for its tax year that **starts before** March 22, 2016, and **ends after** March 21, 2016, if your **tax year starts** after March 21, 2016.

	1AA Name of the corporation	AA Business number of the corporation 600	BB Income described under clause 125(1)(a)(i)(B) received from the corporation identified in column AA note 13 610	CC Business limit assigned from the corporation identified in column AA note 14 620
1				
			Total 615	Total 625

Notes

Note 1 Applies to tax years that **begin after** March 21, 2016. For tax years beginning before March 22, 2016 leave blank.

Note 2 Do **not** include expenses that were deducted in computing the income of the corporation in column D1.

In general, amounts included under subsections 34.2(2) and 34.2(3) or claimed under subsection 34.2(4) are deemed to have the **same character** and be in the **same proportions** as the partnership income they relate to. Amounts claimed under subsection 34.2(11) and included under subsection 34.2(12) are deemed to have the **same character** and **be in the same proportions** as the qualifying transitional income. For example, if a corporation receives $100,000 of partnership income for the partnership's fiscal period ending in its tax year, and that income is made up of $40,000 of active business income, $30,000 of income from property, and $30,000 as a taxable capital gain, the corporation's adjusted stub period accrual (ASPA) in respect of the partnership would be 40% active business income, 30% property income, and 30% taxable capital gains. Add or deduct only the portion of the following amounts that are characterized as **active business income** in accordance with subsection 34.2(5):

Add:

- the ASPA under subsection 34.2(2) (column 4 of Schedule 73)
- the income inclusion for a new corporate member of a partnership under subsection 34.2(3) (column 6 of Schedule 73)
- the previous-year transitional reserve under subsection 34.2(12) (column 12 of Schedule 73)

Deduct:

- the previous-year ASPA under subsection 34.2(4) (column 5 of Schedule 73)
- the previous-year income inclusion for a new corporate member of a partnership under subsection 34.2(4) (column 7 of Schedule 73)
- the current-year transitional reserve under subsection 34.2(11) (column 11 of Schedule 73)

Note 3 When a partnership carries on more than one business, one of which generates income and another of which realizes a loss, the loss is **not** netted against the partnership's income when calculating the prorated business limit (column H1). Enter on line 380 the total of all losses from column F1.

Note 4 For tax years that begin after March 21, 2016, **if** you are a **designated member** of the partnership, enter "0".

Note 5 For tax years that begin after March 21, 2016, you must enter "0" **if** the partnership provides services or property to either:

(A) a private corporation (directly or indirectly in any manner whatever) in the year, if:

- you (or one of your shareholders) or a person that does **not** deal at arm's length with you (or one of your shareholders) holds a direct or indirect interest in the private corporation, and
- it is not the case that all or substantially all of the partnership's income for the year from an active business is from providing services or property to
  - persons (other than the private corporation) that deal at arm's length with the partnership and each person that holds a direct or indirect interest in the partnership, or
  - partnerships with which the partnership deals at arm's length, other than a partnership in which a person that does **not** deal at arm's length with you holds a direct or indirect interest, or

(B) a particular partnership (directly or indirectly in any manner whatever) in the year, if:

- you (or one of your shareholders) do **not** deal at arm's length with the particular partnership or a person that holds a direct or indirect interest in the particular partnership, and
- it is not the case that all or substantially all of the partnership's income for the year from an active business is from providing services or property to
  - persons that deal at arm's length with the partnership and each person that holds a direct or indirect interest in the partnership, or
  - partnerships (other than the particular partnership) with which the partnership deals at arm's length, other than a partnership in which a person that does **not** deal at arm's length with you holds a direct or indirect interest.

Note 6 A person that is a member of a partnership can make an assignment of **specified partnership business limit** under subsection 125(8) to a **designated member** for any tax year that **starts after** March 21, 2016. Also, that person can make an assignment for its tax year that **starts before** March 22, 2016 **and ends after** March 21, 2016 if the tax year of the **designated member starts after** March 21, 2016.

Note 7 If you are a **designated member** receiving an assignment of **specified partnership business limit**, complete Table 2 to determine the amounts to enter in Table 1 column I1.

Note 8 If you are a corporation that is a **member** of the partnership and you are assigning **specified partnership business limit**, complete Table 3 to determine the amounts to enter in Table 1 column J1.

Note 9 Add the amounts in column H2 that are for the same partnership and enter it in Table 1 column I1, in the row of the applicable partnership.

Note 10 Add the amounts in column F3 that are for the same partnership and enter it in Table 1 column J1, in the row of the applicable partnership. This amount **cannot** be higher than the amount of prorated business limit you would otherwise be entitled to in Table 1 column H1 for that partnership.

Note 11 If negative, enter amount in brackets, and **add** instead of subtracting.

Note 12 Net of related expenses.

Note 13 This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts, each of which is your income from an active business for the year from providing services or property to a private corporation (directly or indirectly, in any manner whatever) if

(A) at any time in the year, you (or one of your shareholders) or a person that does **not** deal at arm's length with you (or one of your shareholders) holds a direct or indirect interest in the private corporation, and

(B) it is not the case that all or substantially all of your income for the year from an active business is from providing services or property to

(I) persons (other than the private corporation) with which you deal at arm's length, or

(II) partnerships with which you deal at arm's length, other than a partnership in which a person that does **not** deal at arm's length with you holds a direct or indirect interest.

Do **not** include income from an associated corporation if the conditions described in subsection 125(10) are met.

Note 14 The amount of business limit that a CCPC can assign to you cannot be greater than the amount in column BB that is from providing services or property **directly** to that CCPC. If there is an amount included in column BB that is deductible by that CCPC in respect of the amount of its income referred to in clause 125(1)(a)(i)(A) or (B) for its tax year, you need to deduct it from column BB for the purpose of determining the amount that can be assigned to you.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business Number	Tax year end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2016-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under *Regulation* 1101(5q)? 101 1 Yes ☐ 2 No ☒

	1 Class number (See Note)	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8)	3 Cost of acquisitions during the year (new property must be available for use)*	4 Adjustments and transfers**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)***	7 Reduced undepreciated capital cost	8 CCA rate % ****	9 Recapture of capital cost allowance***** (line 107 of Schedule 1)	10 Terminal loss (line 404 of Schedule 1)	11 Capital cost allowance (for declining balance method, column 7 multiplied by column 8, or a lower amount) (line 403 of Schedule 1) ******	12 Undepreciated capital cost at the end of the year (column 6 plus column 7 minus column 11)
	200		201	203	205	207	211		212	213	215	217	220
1.	1	1908 Buildings	20,089,145	42,469		0	21,235	20,110,379	4	0	0	804,415	19,327,199
2.	10	1930-1935-1940-1945	942,140	199,027		8,000	95,514	1,037,653	30	0	0	311,296	821,871
3.	8	1915 Office Furniture & Equipme	231,910	20,672		0	10,336	242,246	20	0	0	48,449	204,133
4.	17	1955-1956 Communication Equip	186,589			0		186,589	8	0	0	14,927	171,662
5.	47	18xx Distribution Plant	25,813,455	4,158,468	334,547	10,863	2,073,803	28,221,804	8	0	0	2,257,744	28,037,863
6.	50	1920 Computer Equipment	21,399	117,329		0	58,665	80,063	55	0	0	44,035	94,693
7.	43.2	2075 Solar Photovoltaic Equipme	602,279			0		602,279	50	0	0	301,140	301,139
8.	12	1611 Computer Software	8,522	4,632		0	2,316	10,838	100	0	0	10,838	2,316
9.	95	2055 CIP	564,175		-334,547	0		229,628	0	0	0		229,628
		Totals	48,459,614	4,542,597		18,863	2,261,869	50,721,479				3,792,844	49,190,504

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see *Regulation* 1100(2) and (2.2).

** Enter in column 4, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost.
Items that **increase** the undepreciated capital cost include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that **reduce** the undepreciated capital cost include government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the *T2 Corporation Income Tax Guide* for other examples of adjustments and transfers to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments and transfers from column 4. For information on the exceptions to the 50% rule, as well as how to calculate the amounts to enter in column 6 in those cases, see Interpretation Bulletin IT-285, *Capital Cost Allowance - General Comments.*

**** Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** For every entry in column 9, the "Recapture of capital cost allowance" there must be a corresponding entry in column 5, "Proceeds of dispositions during the year". The recapture and terminal loss rules do not apply to passenger vehicles in Class 10.1.

****** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (14)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2016-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	Essex Energy Corporation		87007 1123 RC0001	3					
2.	Essex Power Services Corporation		86612 1635 RC0001	3					
3.	Essex Power Corporation		86953 5435 RC0001	1					
4.	Utilismart Corporation		86443 9450 RC0001	3					
5.	Wattsworth Analysis Inc.		87746 8108 RC0001	3					
6.	Enerconnect Inc.		87367 1499 RC0001	3					
7.	Enermajica Ontario Inc.		88660 6409 RC0001	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

SCHEDULE 10

Canada Revenue Agency / Agence du revenu du Canada

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2016-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") ... 200 — 88,387 A

Add: Cost of eligible capital property acquired during the taxation year ... 222 — 2,644

Other adjustments ... 226 —

Subtotal (line 222 plus line 226) 2,644 x 3 / 4 = 1,983 B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 ... 228 — x 1 / 2 = C

amount B minus amount C (if negative, enter "0") 1,983 ▶ 1,983 D

Amount transferred on amalgamation or wind-up of subsidiary ... 224 — E

Subtotal (add amounts A, D, and E) 230 — 90,370 F

Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year ... 242 — G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) ... 244 — H

Other adjustments ... 246 — I

(add amounts G,H, and I) — x 3 / 4 = 248 — J

Cumulative eligible capital balance (amount F minus amount J) ... 90,370 K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business 249 —

amount K 90,370

less amount from line 249 —

Current year deduction ... 90,370 x 7.00 % = 250 — 6,326 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 6,326 ▶ 6,326 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") ... 300 — 84,044 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)					N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988		400	1		
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)		401	2		
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402	3			
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408	4			
Line 3 minus line 4 (if negative, enter "0")		▶	5		
Total of lines 1, 2 and 5			6		
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400		7			
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000		8			
Subtotal (line 7 plus line 8)	409	▶	9		
Line 6 minus line 9 (if negative, enter "0")			▶		O
Line N minus line O (if negative, enter "0")					P
	Line 5		x 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")					R
	Amount R		x 2 / 3 =		S
Amount N or amount O, whichever is less					T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)				410	

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 14

MISCELLANEOUS PAYMENTS TO RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2016-12-31

- This schedule must be completed by all corporations who made the following payments to residents of Canada: royalties for which the corporation has not filed a T5 slip; research and development fees; management fees; technical assistance fees; and similar payments.
- Please enter the name and address of the recipient and the amount of the payment in the applicable column. If several payments of the same type (i.e., management fees) were made to the same person, enter the total amount paid. If similar types of payments have been made, but do not fit into any of the categories, enter these amounts in the column entitled "Similar payments".

	Name of recipient 100	Address of recipient 200	Royalties 300	Research and development fees 400	Management fees 500	Technical assistance fees 600	Similar payments 700
1	Essex Power Corporation	2730 Highway 3 Oldcastle ON CA N0R 1L0			1,085,000		

T2 SCH 14 (99)

Canada

Canada Revenue Agency / Agence du revenu du Canada

Schedule 23

Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Business Limit

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* not to be associated for purposes of the small business deduction.

Column 2: Provide the business number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code from the list below that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A.

Ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . 025 Year Month Day

Enter the calendar year to which the agreement applies . . . . . 050 Year 2016

Is this an amended agreement for the above calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . 075 1 Yes [ ] 2 No [X]

	1 Names of associated corporations 100	2 Business number of associated corporations 200	3 Association code 300	4 Business limit for the year before the allocation $	5 Percentage of the business limit % 350	6 Business limit allocated* $ 400
1	Essex Powerlines Corporation	87006 6529 RC0001	1	500,000	100.0000	500,000
2	Essex Energy Corporation	87007 1123 RC0001	1	500,000		
3	Essex Power Services Corporation	86612 1635 RC0001	1	500,000		
4	Essex Power Corporation	86953 5435 RC0001	1	500,000		
5	Utilismart Corporation	86443 9450 RC0001	1	500,000		
6	Wattsworth Analysis Inc.	87746 8108 RC0001	1	500,000		
7	Enerconnect Inc.	87367 1499 RC0001	1	500,000		
8	Enermajica Ontario Inc.	88660 6409 RC0001	1	500,000		
				Total	100.0000	500,000 A

Business limit reduction under subsection 125(5.1) of the Act

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "large corporation amount" at line 415 of the T2 return. The amount at line 415 is determined using the formula 0.225% x (D – $10,000,000). Details of this formula and variable D are in subsection 125(5.1) of the Act.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules for business limit

Special rules apply under subsection 125(5) if a CCPC has more than one tax year ending in the same calendar year and it is associated in more than one of those tax years with another CCPC that has a tax year ending in that calendar year. The business limit for the second or later tax year will be equal to the business limit determined for the first tax year ending in the calendar year or the business limit determined for the second or later tax year ending in the same calendar year, whichever is less.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2016-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a **financial** institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 *Corporation Income Tax Return* no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada.**

Part 1 – Capital

Add the following year-end amounts:

	Line	Amount		Total
Reserves that have not been deducted in calculating income for the year under Part I	101			
Capital stock (or members' contributions if incorporated without share capital)	103	15,773,000		
Retained earnings	104	8,832,000		
Contributed surplus	105			
Any other surpluses	106	374,000		
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108			
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109			
Any dividends declared but not paid by the corporation before the end of the year	110	1,046,000		
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111			
The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below)	112			
Subtotal (**add** lines 101 to 112)		26,025,000	▶	26,025,000 A

Note:

Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if
  a) those lines applied to partnerships in the same manner that they apply to corporations, and
  b) those amounts were computed without reference to amounts owing by the partnership
    (i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or
    (ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.

B is the partnership's deferred unrealized foreign exchange losses at the end of the period,

C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and

D is the partnership's income or loss for the period.

Part 1 – Capital (continued)

Subtotal A (from page 1)			26,025,000 A
Deduct the following amounts:			
Deferred tax debit balance at the end of the year	121		
Any deficit deducted in calculating its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122		
To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year.	123		
Deferred unrealized foreign exchange losses at the end of the year	124		
Subtotal (add lines 121 to 124)		►	B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")		190	26,025,000

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend payable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(d)), or another partnership described in paragraph 181.2(4)(d.1)	406	
An interest in a partnership (see note 2 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	

Notes:

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation. Refer to subsection 181.2(6) for special rules that may apply.

Part 3 – Taxable capital

Capital for the year (line 190)		26,025,000 C
Deduct: Investment allowance for the year (line 490)		D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	26,025,000

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500)	26,025,000	x	Taxable income earned in Canada **610** / Taxable income	1,932,721 / 1,932,721	= **Taxable capital employed in Canada** **690**	26,025,000

Notes: 1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **701** ______

Deduct the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada . . . . **711** ______

Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **712** ______

Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) . . . . **713** ______

Total deductions (add lines 711, 712, and 713) ______ ► ______ E

Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0") . . . . **790** ______

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (amount from line 690) . . . . ______ F

Deduct: . . . . 10,000,000 G

Excess (amount F **minus** amount G) (if negative, enter "0") ______ H

Calculation for purposes of the small business deduction (amount H x 0.225%) . . . . ______ I

Enter this amount at line 415 of the T2 return.

Attached Schedule with Total

rt 1 – All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations

Title Part 1 – All indebtedness of the corporation represented by bonds, debentu

Description	Operator (Note)	Amount
Long term debt		
Current portion long term debt	+	
	+	
	Total	

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

rt 1 – All loans and advances to the corporation

Title Part 1 – All loans and advances to the corporation

Description	Operator (Note)	Amount
Due to affiliates		
Shareholder loan	+	
	+	
	Total	

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

rt 1 – Reserves that have not been deducted in calculating income for the year under Part I

Title Part 1 – Reserves that have not been deducted in computing income for th

Description	Operator (Note)	Amount
Employee future benefits	+	
Interest rate swap	+	
	+	
	+	
	+	
	Total	

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2016-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)	Provide only one number per shareholder: Business Number (If a corporation is not registered, enter "NR")	Social insurance number	Trust number	Percentage common shares	Percentage preferred shares
	100	200	300	350	400	500
1	ESSEX POWER CORPORATION	86953 5435 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada Revenue Agency / Agence du revenu du Canada

Schedule 53

General Rate Income Pool (GRIP) Calculation

Corporation's name	Business number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2016-12-31

On: 2016-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- All legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsection 89(1) defines the terms **eligible dividend, excessive eligible dividend designation, general rate income pool,** and **low rate income pool.**

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? ☒ Yes ☐ No

If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC ☐ Yes ☒ No

If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation ☐ Yes ☒ No

If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.

7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? ☐ Yes ☐ No

If the answer to question 7 is yes, complete Part 4.

8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? ☐ Yes ☐ No

If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Has the corporation wound-up a subsidiary in the preceding taxation year? ☐ Yes ☒ No

If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.

10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? ☐ Yes ☐ No

If the answer to question 10 is yes, complete Part 4.

11. Was the subsidiary a CCPC or a DIC during its last taxation year? ☐ Yes ☐ No

If the answer to question 11 is yes, complete Part 3.

Part 1 – General rate income pool (GRIP)

GRIP at the end of the previous tax year			100	11,666,483 A
Taxable income for the year (DICs enter "0") *		110	1,932,721 B	
Income for the credit union deduction * (amount E in Part 3 of Schedule 17)	120			
Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less *	130			
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income *	140	51,929		
Subtotal (add lines 120, 130, and 140)		51,929 ►	51,929 C	
Income taxable at the general corporate rate (amount B minus amount C) (if negative enter "0")		150	1,880,792	
After-tax income (line 150 multiplied by 0.72 (the general rate factor for the tax year))			190	1,354,170 D
Eligible dividends received in the tax year		200		
Dividends deductible under section 113 received in the tax year		210		
Subtotal (line 200 plus line 210)			►	E
Becoming a CCPC (amount W5 in Part 4)		220		
Post-amalgamation (total of amounts E4 in Part 3 and amounts W5 in Part 4)		230		
Post-wind-up (total of amounts E4 in Part 3 and amounts W5 in Part 4)		240		
Subtotal (add lines 220, 230, and 240)		290	►	F
Subtotal (add amounts A, D, E, and F)				13,020,653 G
Eligible dividends paid in the previous tax year		300		
Excessive eligible dividend designations made in the previous tax year		310		
(If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.)				
Subtotal (line 300 minus line 310)			►	H
GRIP before adjustment for specified future tax consequences (amount G minus amount H) (amount can be negative)			490	13,020,653
Total GRIP adjustment for specified future tax consequences to previous tax years (amount N3 in Part 2)			560	
GRIP at the end of the tax year (line 490 **minus** line 560)			590	13,020,653

Enter this amount on line 160 of Schedule 55.

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2015-12-31

Taxable income before specified future tax consequences from the current tax year		1,710,337 A1	
Enter the following amounts before specified future tax consequences from the current tax year:			
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	B1		
Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less	C1		
Aggregate investment income (line 440 of the T2 return)	D1		
Subtotal (add amounts B1, C1, and D1)	►	E1	
Subtotal (amount A1 minus amount E1) (if negative, enter "0")		1,710,337 ►	1,710,337 F1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences . . . . ____ G1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ____ H1

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less . . . . ____ I1

Aggregate investment income (line 440 of the T2 return) . . . . ____ J1

Subtotal (add amounts H1, I1, and J1) ____ ► ____ K1

Subtotal (amount G1 **minus** amount K1) (if negative, enter "0") ____ ► ____ L1

Subtotal (amount F1 **minus** amount L1) (if negative, enter "0") ____ M1

GRIP adjustment for specified future tax consequences to the first previous tax year
(amount M1 **multiplied** by 0.72) . . . . 500 ____

Second previous tax year 2014-12-31

Taxable income before specified future tax consequences from the current tax year . . . . ____ A2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ____ B2

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less . . . . ____ C2

Aggregate investment income (line 440 of the T2 return) . . . . ____ D2

Subtotal (add amounts B2, C2, and D2) ____ ► ____ E2

Subtotal (amount A2 **minus** amount E2) (if negative, enter "0") ____ ► ____ F2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences . . . . ____ G2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ____ H2

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less . . . . ____ I2

Aggregate investment income (line 440 of the T2 return) . . . . ____ J2

Subtotal (add amounts H2, I2, and J2) ____ ► ____ K2

Subtotal (amount G2 **minus** amount K2) (if negative, enter "0") ____ ► ____ L2

Subtotal (amount F2 **minus** amount L2) (if negative, enter "0") ____ M2

GRIP adjustment for specified future tax consequences to the second previous tax year
(amount M2 **multiplied** by 0.72) . . . . 520 ____

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2013-12-31

Taxable income before specified future tax consequences from the current tax year . . . . ________ A3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ________ B3

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less . . . . ________ C3

Aggregate investment income (line 440 of the T2 return) . . . . ________ D3

Subtotal (**add** amounts B3, C3, and D3) ________ ► ________ E3

Subtotal (amount A3 **minus** amount E3) (if negative, enter "0") ________ ► ________ F3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ________ G3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ________ H3

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less . . . . ________ I3

Aggregate investment income (line 440 of the T2 return) . . . . ________ J3

Subtotal (**add** amounts H3, I3, and J3) ________ ► ________ K3

Subtotal (amount G3 **minus** amount K3) (if negative, enter "0") ________ ► ________ L3

Subtotal (amount F3 **minus** amount L3) (if negative, enter "0") ________ M3

GRIP adjustment for specified future tax consequences to the third previous tax year
(amount M3 **multiplied by** 0.72) . . . . 540 ________

Total GRIP adjustment for specified future tax consequences to previous tax years:
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . ________ N3

Enter amount N3 on line 560 in part 1.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . ________ A4

Eligible dividends paid by the corporation in its last tax year . . . . ________ B4

Excessive eligible dividend designations made by the corporation in its last tax year . . . . ________ C4

Subtotal (amount B4 **minus** amount C4) ________ ► ________ D4

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)
(amount A4 **minus** amount D4) . . . . ________ E4

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the E4 amounts. Enter this total amount on:

– line 230 for post-amalgamation; or
– line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

J. 1 Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . ☐ Post wind-up . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year . . . . ________ A5

The corporation's money on hand immediately before the end of its previous/last tax year . . . . ________ B5

Total of subsection 111(1) losses that would have been deductible in calculating the corporation's taxable income for the previous/last tax year if the corporation had had unlimited income from each business carried on and each property held and had realized an unlimited amount of capital gains for the previous/last tax year:

Non-capital losses . . . . ________ C5
Net capital losses . . . . ________ D5
Farm losses . . . . ________ E5
Restricted farm losses . . . . ________ F5
Limited partnership losses . . . . ________ G5

Subtotal (add amounts C5 to G5) ________ ► ________ H5

Total of all amounts deducted under subsection 111(1) in calculating the corporation's taxable income for the previous/last tax year:

Non-capital losses . . . . ________ I5
Net capital losses . . . . ________ J5
Farm losses . . . . ________ K5
Restricted farm losses . . . . ________ L5
Limited partnership losses . . . . ________ M5

Subtotal (**add** amounts I5 to M5) ________ ► ________ N5

Unused and unexpired losses at the end of the corporation's previous/last tax year (amount H5 **minus** amount N5) ________ ► ________ O5

Subtotal (**add** amounts A5, B5, and O5) ________ P5

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year . . . . ________ Q5

Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year . . . . ________ R5

All the corporation's reserves deducted in its previous/last tax year . . . . ________ S5

The corporation's capital dividend account immediately before the end of its previous/last tax year . . . . ________ T5

The corporation's low rate income pool immediately before the end of its previous/last tax year . . . . ________ U5

Subtotal (add amounts Q5 to U5) ________ ► ________ V5

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (amount P5 **minus** amount V5) (if negative, enter "0") . . . . ________ W5

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the W5 amounts. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 55

Part III.1 Tax on Excessive Eligible Dividend Designations

Corporation's name	Business number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2016-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

	Line	Amount	Line	Amount	
Taxable dividends paid in the tax year **not included** in Schedule 3					
Taxable dividends paid in the tax year **included** in Schedule 3		1,046,176			
Total taxable dividends paid in the tax year	100	1,046,176			
Total eligible dividends paid in the tax year			150		A
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")			160	13,020,653	B
Excessive eligible dividend designation (line 150 **minus** line 160)					C
Deduct:					
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *			180		D
Subtotal (amount C **minus** amount D)					E
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount E **multiplied** by 20 %)			190		F

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

	Line	Amount	Line	Amount	
Taxable dividends paid in the tax year **not included** in Schedule 3					
Taxable dividends paid in the tax year **included** in Schedule 3					
Total taxable dividends paid in the tax year	200				
Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54)					G
Deduct:					
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *			280		H
Subtotal (amount G **minus** amount H)					I
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount I **multiplied** by 20 %)			290		J

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days after the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends.**

Canada Revenue Agency / Agence du revenu du Canada

Schedule 500

Ontario Corporation Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2016-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only. You do not have to file it with your *T2 Corporation Income Tax Return*.

Part 1 – Ontario basic rate of tax for the year

Ontario basic rate of tax for the year . . . . 11.5 % A

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . 1,932,721 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A from Part 1) . . . . 222,263 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit in addition to Ontario basic income tax, or has Ontario corporate minimum tax or Ontario special additional tax on life insurance corporations payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the **T2 return**)	1,880,792	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)	1,932,721	2
Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return)	500,000	3

Ontario business limit reduction:

Amount from line 3 . . . 500,000 a

Deduct:

Amount from line E of the T2 return 3,708,311 × (Number of days in the tax year after May 1, 2014 366 / Number of days in the tax year 366) = 3,708,311 b

Reduced Ontario business limit (amount a **minus** amount b) (if negative, enter "0") ______ c

Business limit the CCPC assigns under subsection 125(3.2) ITA ______ d

Amount c **minus** amount d ______ ► ______ 4

Enter the least of amounts **1**, 2, 3, and 4 . . . ______ D

Ontario domestic factor (ODF): Ontario taxable income * / Taxable income earned in all provinces and territories ** = 1,932,721.00 / 1,932,721 = 1.00000 E

Amount D × ODF (line E) ______ e

Ontario taxable income (amount B from Part 2) 1,932,721 f

Reduced Ontario business limit (lesser of amount e and amount f) (if negative, enter "0") . . . ______ F

OSBD rate for the year . . . 7 % G

Ontario small business deduction: amount F **multiplied** by rate G . . . ______ H

Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Ontario adjusted small business income (lesser of amount D and amount f from Part 3) . . . ______ I

Enter amount I on line K in Part 5 of this schedule or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 5 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17		J		
Deduct:				
Ontario adjusted small business income (amount I from Part 4)		K		
Subtotal (amount J minus amount K) (if negative, enter "0")		L		
Amount L **multiplied** by rate G from Part 3				M
Ontario domestic factor (line E from Part 3)			1.00000	N
Ontario credit union tax reduction (amount M **multiplied** by ODF from line N)				O

Enter amount O on line 410 of Schedule 5.

Canada Revenue Agency | Agence du revenu du Canada

Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2016-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	110,810,000
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	47,000,000
Total assets (total of lines 112 to 116)		157,810,000
Total revenue of the corporation for the tax year **	142	89,668,000
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	18,000,000
Total revenue (total of lines 142 to 146)		107,668,000

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

Description	Line	Amount	Line	Amount	
Net income/loss per financial statements *			210	2,585,000	
Add (to the extent reflected in income/loss):					
vision for current income taxes/cost of current income taxes	220	170,000			
Provision for deferred income taxes (debits)/cost of future income taxes	222	699,000			
Equity losses from corporations	224				
Financial statement loss from partnerships and joint ventures	226				
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230				
Other additions (see note below):					
Share of adjusted net income of partnerships and joint ventures **	228				
Total patronage dividends received, not already included in net income/loss	232				
281	282				
283	284				
Subtotal		869,000	▶	869,000	A
Deduct (to the extent reflected in income/loss):					
Provision for recovery of current income taxes/benefit of current income taxes	320				
Provision for deferred income taxes (credits)/benefit of future income taxes	322				
Equity income from corporations	324				
Financial statement income from partnerships and joint ventures	326				
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330				
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332				
Gain on donation of listed security or ecological gift	340				
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342				
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344				
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346				
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348				
er deductions (see note below):					
are of adjusted net loss of partnerships and joint ventures **	328				
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334				
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336				
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338				
381	382				
383	384				
385	386				
387	388				
389	390				
Subtotal			▶		B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	3,454,000	

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

- exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
- include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

*** Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)	515	3,454,000	
Deduct:			
CMT loss available (amount R from Part 7)			
Minus: Adjustment for an acquisition of control *	518		
Adjusted CMT loss available			C
Net income subject to CMT calculation (if negative, enter "0")	520	3,454,000	

Amount from line 520 3,454,000 × (Number of days in the tax year before July 1, 2010 / Number of days in the tax year 366) × 4 % = ______ 1

Amount from line 520 3,454,000 × (Number of days in the tax year after June 30, 2010 366 / Number of days in the tax year 366) × 2.7 % = 93,258 2

Subtotal (amount 1 plus amount 2) 93,258 3

Gross CMT: amount on line 3 above x OAF **	540	93,258	
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		93,258	D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		222,263	
Net CMT payable (if negative, enter "0")			E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

**** Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** ______ = ______

Ontario allocation factor 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *			G
Deduct:			
CMT credit expired *	600		
CMT credit carryforward at the beginning of the current tax year * (see note below)		620	
Add:			
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)		650	
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)			H
Deduct:			
CMT credit deducted in the current tax year (amount P from Part 5)			I
Subtotal (amount H **minus** amount I)			J
Add:			
Net CMT payable (amount E from Part 3)			
SAT payable (amount O from Part 6 of Schedule 512)			
Subtotal			K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)		670	L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)			M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)	222,263	1	
For a corporation that is not a life insurance corporation:			
CMT after foreign tax credit deduction (amount D from Part 3)	93,258	2	
For a life insurance corporation:			
Gross CMT (line 540 from Part 3)		3	
Gross SAT (line 460 from Part 6 of Schedule 512)		4	
The **greater** of amounts 3 and 4		5	
Deduct: line 2 or line 5, whichever applies:	93,258	6	
Subtotal (if negative, enter "0")	129,005		129,005 N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)	222,263		
Deduct:			
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)	3,000		
Subtotal (if negative, enter "0")	219,263		219,263 O
CMT credit deducted in the current tax year (least of amounts M, N, and O)			P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * .... ______ Q

Deduct:

CMT loss expired * .... 700 ______

CMT loss carryforward at the beginning of the tax year * (see note below) .... ______ ▶ 720 ______

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) .... 750 ______

CMT loss available (line 720 **plus** line 750) .... ______ R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) .... ______

Subtotal (if negative, enter "0") ______ S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) .... 760 ______

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) .... 770 ______ T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2016-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	Essex Energy Corporation	87007 1123 RC0001	0	0
2	Essex Power Services Corporation	86612 1635 RC0001	0	0
3	Essex Power Corporation	86953 5435 RC0001	47,000,000	18,000,000
4	Utilismart Corporation	86443 9450 RC0001	0	0
5	Wattsworth Analysis Inc.	87746 8108 RC0001	0	0
6	Enerconnect Inc.	87367 1499 RC0001	0	0
7	Enermajica Ontario Inc.	88660 6409 RC0001	0	0
		Total	450 47,000,000	550 18,000,000

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax.*
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter "NR" if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

* **Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

** **Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2016-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
Essex Powerlines Corporation

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	110 Date of incorporation or amalgamation, whichever is the most recent — Year Month Day	120 Ontario Corporation No.
Ontario	2000-04-18	1413911

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

0 Care of (if applicable)

210 Street number	220 Street name/Rural route/Lot and Concession number	230 Suite number
2730	Highway 3	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	260 Province/state	270 Country	280 Postal/zip code
Oldcastle	ON	CA	N0R 1L0

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 [1] If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 Barile — Last name

451 Joe — First name

454 ______ — Middle name(s)

460 [1] Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

ote: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 ☐ Please enter one of the following numbers in this box:

1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)		
520 Street number	530 Street name/Rural route/Lot and Concession number	540 Suite number
550 Additional address information if applicable (line 530 must be completed first)		

560 Municipality (e.g., city, town)	570 Province/state	580 Country	590 Postal/zip code

Part 6 – Language of preference

600 ☐ Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2016-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information	120 Telephone number including area code
Maxim Picco	(519) 737-9811

Is the claim filed for a CETC earned through a partnership?* . . . . . 150 1 Yes [ ] 2 No [X]

If you answered yes to the question at line 150, what is the name of the partnership? . . . . . 160 ____

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . 170 ____ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . 200 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . 210 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year* 300 601,000

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\% - \left[5\% \times \left(\frac{\text{amount on line 300} \quad \text{minus } \$ \; 400{,}000}{\$ \; 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . . 310 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\% - \left[5\% \times \left(\frac{\text{amount on line 300} \quad \text{minus } \$ \; 400{,}000}{\$ \; 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . . 312 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
1.	Univeristy of Windsor	BAS-Electrical Engineering
2.		

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
1.	Jacob Weninger	2016-05-01	2016-08-31
2.			

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.		10.000 %	12,229	25.000 %		17
2.		10.000 %		25.000 %		

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	3,057	3,000	3,000		3,000
2.					

Ontario co-operative education tax credit (total of amounts in column K) 500 3,000 L

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ______ x percentage on line 170 in Part 1 ______ % = ... ______ M

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009,
and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received.
Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

Attached Schedule with Total

EDCFF.UnusedTtwcff30

Title Tax return – Other – Amount

Explanatory note

Amortization of land easements included in T2S1 add back of amortization expense

Description	Operator (Note)	Amount
Construction in progress - additions		
Change in Inventory included in capital assets	+	
Change in amortization Land Easements (per GIFI)	+	
	Total	

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attachment 4-O

Test Year Income Tax/PILs Work Form

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Version **1.00**

Utility Name	Essex Powerlines Corporation
Assigned EB Number	EB-2017-0039
Name and Title	Kristopher Taylor, Director of Corporate Strategy
Phone Number	519-946-2000
Email Address	ktaylor@essexpower.ca
Date	August 28th, 2017
Last COS Re-based Year	**2010**

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

Instructions

Purpose
The purpose of this workbook is to calculate the estimated Payment in Lieu of Taxes (PILs) for the Test Year. The calculation of PILs for the Test Year is on tab T0 and is based on the inputs on the other tabs.

Tab S Summary is a summary of the amounts to be transferred to the Data Input Sheet of the Revenue Requirement Workform.

Tab S1 Integrity Checks must be completed after the completion of the PILS calculation in this workbook.

Methodology
To calculate the PILs for the Test Year:

1) input the balances from the income tax return of the Historical Year in tabs H1 to H13.
2) input the balances for the Bridge Year and the Test Year.
Inputs should include:
- non-deductible expenses (Schedule 1 - B1 and T1)
- loss carryforward (Schedule 4 - B4 and T4)
- capital cost allowance (Schedule 8 - B8 and T8)
- non-deductible reserves (Schedule 13 - B13 and T13)

3) make any other adjustments and inputs required so that the PILs amount calculated for the Test Year on tab T0 is reasonable.

Other Notes
Tabs H1 to H13 relate to the Historical Year.
Tabs B1 to B13 relate to the Bridge Year.
Tabs T1 to T13 relate to the Test Year.

The amounts on tabs H1 to H13 should agree to the tax return filed with the Canada Revenue Agency. Any CRA audit adjustments or corrections should also be reflected.

It is assumed the net income before tax for the Test Year is equal to the Return on Equity. Return on Equity is calculated on tab A.

On tab "A. Data Input Sheet", input the "Rate Base" amount and "Return on Rate Base" amounts.

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

No inputs required on this worksheet.

Inputs on Service Revenue Requirement Worksheet

The Service Revenue Requirement is in the 'Revenue Requirement Workform' - Tab 3.

Item	Working Paper Reference	
Adjustments required to arrive at taxable income	as below	**-1,474,349**
Test Year - Payments in Lieu of Taxes (PILs)	T0	**167,028**
Test Year - Grossed-up PILs	T0	**227,249**
Effective Federal Tax Rate	T0	**15.0%**
Effective Ontario Tax Rate	T0	**11.5%**

Calculation of Adjustments required to arrive at Taxable Income			
Regulatory Income (before income taxes)	T1	2,104,644	
Taxable Income	T1	630,295	
Difference	calculated	-1,474,349	as above

Income Tax/PILs Workform for 2018 Filers

Integrity Checks

The applicant must ensure the following integrity checks have been completed and confirm this is the case in the table below, or provide an explanation if this is not the case:

	Item	Utility Confirmation (Y/N)	Notes
1	The depreciation and amortization added back in the application's PILs model agree with the numbers disclosed in the rate base section of the application	Yes	
2	The capital additions and deductions in the UCC/ CCA Schedule 8 agree with the rate base section for historical, bridge and test years	Yes	
3	Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31 historical year UCC that agrees with the opening (January 1) bridge year UCC. If the amounts do not agree, then the applicant must provide a reconciliation with explanations. Distributors must segregate non- distribution tax amounts on Schedule 8.	Yes	
4	The CCA deductions in the application's PILs tax model for historical, bridge and test years (as applicable) agree with the numbers in the UCC schedules for the same years filed in the application	Yes	
5	Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application	Yes	
6	A discussion is included in the application as to when the loss carry-forwards, if any, will be fully utilized	Yes	
7	CCA is maximized even if there are tax loss carry-forwards	Yes	
8	Accounting OPEB and pension amounts added back on Schedule 1 to reconcile accounting income to net income for tax purposes, must agree with the OM&A analysis for compensation. The amounts deducted must be reasonable when compared with the notes in the audited financial statements, FSCO reports, and the actuarial valuations.	Yes	
9	The income tax rate used to calculate the tax expense must be consistent with the utility's actual tax facts and evidence filed in the application.	Yes	

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

			Test Year	Bridge Year
Rate Base		S	**$ 59,927,210**	**$ 57,027,989**

Return on Ratebase

Deemed ShortTerm Debt %	4.00%	T	$ 2,397,088	*W = S * T*
Deemed Long Term Debt %	56.00%	U	$ 33,559,238	*X = S * U*
Deemed Equity %	40.00%	V	$ 23,970,884	*Y = S * V*
Short Term Interest Rate	1.76%	Z	$ 42,189	*AC = W * Z*
Long Term Interest	3.72%	AA	$ 1,248,404	*AD = X * AA*
Return on Equity (Regulatory Income)	8.78%	AB	**$ 2,104,644**	*AE = Y * AB* T1
Return on Rate Base			**$ 3,395,236**	*AF = AC + AD + AE*

Questions that must be answered

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

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Tax Rates Federal & Provincial As of May 16, 2016	Effective January 1, 2013	Effective January 1, 2014	Effective January 1, 2015	Effective January 1, 2016	Effective January 1, 2017	Effective January 1, 2018
Federal income tax						
General corporate rate	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
Rate reduction	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%
Federal Income Tax	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Ontario income tax	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%
Combined federal and Ontario	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Federal & Ontario Small Business						
Federal small business threshold	500,000	500,000	500,000	500,000	500,000	500,000
Ontario Small Business Threshold	500,000	500,000	500,000	500,000	500,000	500,000
Federal small business rate	11.00%	11.00%	11.00%	10.50%	10.50%	10.50%
Ontario small business rate	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%

Notes

1. The Ontario Energy Board's proxy for taxable capital is rate base.
2. Regarding the small business deduction, if applicable,
   a. If taxable capital exceeds $15 million, the small business rate will not be applicable.
   b. If taxable capital is below $10 million, the small business rate would be applicable.
   c. If taxable capital is between $10 million and $15 million, the appropriate small business rate will be calculated.

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

PILs Tax Provision - Historical Year

Note: Input the actual information from the tax returns for the historical year.

				Wires Only	
Regulatory Taxable Income			H1	$ 1,932,721	**A**
Combined Tax Rate and PILs	Ontario Tax Rate (Maximum 11.5%)	11.50%	**B**		
	Federal tax rate (Maximum 15%)	15.00%	**C**		
	Combined tax rate (Maximum 26.5%)			26.50%	**D = B+C**
Total Income Taxes				**$ 512,171**	**E = A * D**
Investment Tax Credits				$ -	**F**
Miscellaneous Tax Credits				$ 3,000	**G**
Total Tax Credits				**$ 3,000**	**H = F + G**
Corporate PILs/Income Tax Provision for Historical Year				**$ 509,171**	**I = E - H**

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Adjusted Taxable Income - Historical Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	A	3,454,000		3,454,000
Additions:				
Interest and penalties on taxes	103			0
Amortization of tangible assets	104	2,182,000		2,182,000
Amortization of intangible assets	106	67,000		67,000
Recapture of capital cost allowance from Schedule 8	107			0
Gain on sale of eligible capital property from Schedule 10	108			0
Income or loss for tax purposes- joint ventures or partnerships	109			0
Loss in equity of subsidiaries and affiliates	110			0
Loss on disposal of assets	111			0
Charitable donations	112			0
Taxable Capital Gains	113	51,929		51,929
Political Donations	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118			0
Capitalized interest	119			0
Non-deductible club dues and fees	120			0
Non-deductible meals and entertainment expense	121	1,815		1,815
Non-deductible automobile expenses	122			0
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125			0
Reserves from financial statements- balance at end of year	126			0
Soft costs on construction and renovation of buildings	127			0
Book loss on joint ventures or partnerships	205			0
Capital items expensed	206			0
Debt issue expense	208			0
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other Additions				
Interest Expensed on Capital Leases	290			0
Realized Income from Deferred Credit Accounts	291			0
Pensions	292			0
Non-deductible penalties	293			0
	294			0
Inducement under 12(1), regulatory adjustments, amort of deferred charge	295	905,446		905,446
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))				0
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))				0
Prior Year Investment Tax Credits received				0
				0

				0
				0
				0
				0
				0
				0
				0
				0
				0
Total Additions		**3,208,190**	**0**	**3,208,190**
Deductions:				
Gain on disposal of assets per financial statements	401	37,263		37,263
Dividends not taxable under section 83	402			0
Capital cost allowance from Schedule 8	403	3,792,844		3,792,844
Terminal loss from Schedule 8	404			0
Cumulative eligible capital deduction from Schedule 10	405	6,326		6,326
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411			0
Tax reserves claimed in current year	413			0
Reserves from financial statements - balance at beginning of year	414			0
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390			0
Capital Lease Payments	391			0
Non-taxable imputed interest income on deferral and variance accounts	392			0
	393			0
Post-employment benefits, decrease of deferred tax liability, market to market adjustment	394	893,036		893,036
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received				0
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve				0
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)				0
				0
				0
				0
				0
				0
				0
				0
Total Deductions		**4,729,469**	**0**	**4,729,469**
Net Income for Tax Purposes		**1,932,721**	**0**	**1,932,721**
Charitable donations from Schedule 2	311			0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320			0
Non-capital losses of preceding taxation years from Schedule 4	331			0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332			0
Limited partnership losses of preceding taxation years from Schedule 4	335			0
TAXABLE INCOME		**1,932,721**	**0**	**1,932,721**

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Schedule 7-1 Loss Carry Forward - Historical

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical			0	B4

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical			0	B4

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historical per tax returns	Less: Non-Distribution Portion	UCC Regulated Historical Year
1	Distribution System - post 1987	###########		############
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election			$ -
2	Distribution System - pre 1988			$ -
8	General Office/Stores Equip	$ 204,133.00		$ 204,133.00
10	Computer Hardware/ Vehicles	$ 821,871.00		$ 821,871.00
10.1	Certain Automobiles			$ -
12	Computer Software	$ 106,000.00		$ 106,000.00
13_1	Lease # 1			$ -
13_2	Lease #2			$ -
13_3	Lease # 3			$ -
13_4	Lease # 4			$ -
14	Franchise			$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 171,662.00		$ 171,662.00
42	Fibre Optic Cable			$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment			$ -
43.2	Certain Clean Energy Generation Equipment	$ 301,139.00	$ 301,139.00	$ -
45	Computers & Systems Software acq'd post Mar 22/04			$ -
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			$ -
47	Distribution System - post February 2005	###########		############
50	Data Network Infrastructure Equipment - post Mar 2007	$ 94,693.00		$ 94,693.00
52	Computer Hardware and system software			$ -
95	CWIP	$ 229,628.00		$ 229,628.00
				$ -
				$ -
				$ -
				$ -
				$ -
				$ -
				$ -
				$ -
				$ -
				0
	SUB-TOTAL - UCC	49,047,634	301,139	48,746,495

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filer

Schedule 10 CEC - Historical Year

Cumulative Eligible Capital				**88,387**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	2,644			
Other Adjustments	0			
Subtotal	2,644	**x 3/4 =**	1,983	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			1,983	**1,983**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**90,370**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**90,370**
Current Year Deduction		**90,370**	**x 7% =**	**6,326**
Cumulative Eligible Capital - Closing Balance				**$ 84,044.10**

Ontario Energy Board

Income Tax/PILs Workform for 20

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital Gains Reserves ss.40(1)			0
Tax Reserves Not Deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)			0
Reserve for goods and services not delivered ss. 20(1)(m)			0
Reserve for unpaid amounts ss. 20(1)(n)			0
Debt & Share Issue Expenses ss. 20(1)(e)			0
Other tax reserves			0
			0
			0
			0
			0
			0
Total	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)			
General Reserve for Inventory Obsolescence (non-specific)			0
General reserve for bad debts			0
Accrued Employee Future Benefits:			0
- Medical and Life Insurance			0
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost			0
- Other Post-Employment Benefits			0
Provision for Environmental Costs			0
Restructuring Costs			0
Accrued Contingent Litigation Costs			0
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other			0
			0
			0
Total	**0**	**0**	**0**

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

PILS Tax Provision - Bridge Year

							Reference	Wires Only	
Regulatory Taxable Income							B1	$ 1,003,045	**A**
	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate					
Ontario (Max 11.5%)	11.5%	11.5%	$ 115,350	11.5%	**B**				
Federal (Max 15%)	15.0%	15.0%	$ 150,457	15.0%	**C**				
Combined effective tax rate (Max 26.5%)								26.50%	**D = B + C**
Total Income Taxes								**$ 265,807**	**E = A * D**
Investment Tax Credits									**F**
Miscellaneous Tax Credits								$ 3,000	**G**
Total Tax Credits								**$ 3,000**	**H = F + G**
Corporate PILs/Income Tax Provision for Bridge Year								**$ 262,807**	**I = E - H**

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Working Paper Reference	Total for Regulated Utility
Income before PILs/Taxes	A		2,468,571
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets	104		2,153,646
Amortization of intangible assets	106		86,716
Recapture of capital cost allowance from Schedule 8	107		
Gain on sale of eligible capital property from Schedule 10	108		
Income or loss for tax purposes- joint ventures or partnerships	109		
Loss in equity of subsidiaries and affiliates	110		
Loss on disposal of assets	111		
Charitable donations	112		
Taxable Capital Gains	113		
Political Donations	114		
Deferred and prepaid expenses	116		
Scientific research expenditures deducted on financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120		
Non-deductible meals and entertainment expense	121		1,900
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves deducted in prior year	125	B13	0
Reserves from financial statements- balance at end of year	126	B13	0
Soft costs on construction and renovation of buildings	127		
Book loss on joint ventures or partnerships	205		
Capital items expensed	206		
Debt issue expense	208		
Development expenses claimed in current year	212		
Financing fees deducted in books	216		
Gain on settlement of debt	220		
Non-deductible advertising	226		
Non-deductible interest	227		
Non-deductible legal and accounting fees	228		
Recapture of SR&ED expenditures	231		
Share issue expense	235		
Write down of capital property	236		
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Adjusted Taxable Income - Bridge Year

Other Additions			
Interest Expensed on Capital Leases	290		
Realized Income from Deferred Credit Accounts	291		
Pensions	292		
Non-deductible penalties	293		5,974
	294		175,472
Future benefits paid	295		208,694
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received			
Total Additions			**2,632,402**
Deductions:			
Gain on disposal of assets per financial statements	401		
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403	B8	3,982,772
Terminal loss from Schedule 8	404		
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves claimed in current year	413	B13	0
Reserves from financial statements - balance at beginning of year	414	B13	0
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions: (Please explain in detail the nature of the item)			

Income Tax/PILs Workform for 2018 Filers

Adjusted Taxable Income - Bridge Year

Interest capitalized for accounting deducted for tax	390		
Capital Lease Payments	391		
Non-taxable imputed interest income on deferral and variance accounts	392		
	393		
Post-employment benefits - cost	394		115,156
ARO Payments - Deductible for Tax when Paid			
ITA 13(7.4) Election - Capital Contributions Received			
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			
Principal portion of lease payments			
Lease Inducement Book Amortization credit to income			
Financing fees for tax ITA 20(1)(e) and (e.1)			
Total Deductions		calculated	**4,097,928**
Net Income for Tax Purposes		calculated	**1,003,045**
Charitable donations from Schedule 2	311		
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320		
Non-capital losses of preceding taxation years from Schedule 4	331	B4	0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	B4	0
Limited partnership losses of preceding taxation years from Schedule 4	335		
TAXABLE INCOME		calculated	**1,003,045**

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Corporation Loss Continuity and Application

Schedule 4 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction		**Total**	
Actual Historical	H4	0	
Amount to be used in Bridge Year	B1	0	
Loss Carry Forward Generated in Bridge Year (if any)	B1	0	
Other Adjustments			
Balance available for use post Bridge Year	calculated	0	T4

Net Capital Loss Carry Forward Deduction		**Total**	
Actual Historical	H4	0	
Amount to be used in Bridge Year			
Loss Carry Forward Generated in Bridge Year (if any)	B1		
Other Adjustments			
Balance available for use post Bridge Year	calculated	0	T4

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Schedule 8 CCA - Bridge Year

Class	Class Description	Working Paper Reference	UCC Regulated Historical Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}
1	Distribution System - post 1987	H8	$ 19,327,199.00	$ 328,992		$ 19,656,191	$ 164,496
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	H8				$ -	$ -
2	Distribution System - pre 1988	H8				$ -	$ -
8	General Office/Stores Equip	H8	$ 204,133.00	$ 120,000		$ 324,133	$ 60,000
10	Computer Hardware/ Vehicles	H8	$ 821,871.00	$ 487,000		$ 1,308,871	$ 243,500
10.1	Certain Automobiles	H8				$ -	$ -
12	Computer Software	H8	$ 106,000.00	$ 254,500		$ 360,500	$ 127,250
13 1	Lease # 1	H8				$ -	$ -
13 2	Lease #2	H8				$ -	$ -
13 3	Lease # 3	H8				$ -	$ -
13 4	Lease # 4	H8				$ -	$ -
14	Franchise	H8				$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	H8	$ 171,662.00			$ 171,662	$ -
42	Fibre Optic Cable	H8				$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	H8				$ -	$ -
43.2	Certain Clean Energy Generation Equipment	H8	$ -			$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	H8				$ -	$ -
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	H8				$ -	$ -
47	Distribution System - post February 2005	H8	$ 27,791,309.00	$ 5,111,823		$ 32,903,132	$ 2,555,912
50	Data Network Infrastructure Equipment - post Mar 2007	H8	$ 94,693.00	$ 356,150		$ 450,843	$ 178,075
52	Computer Hardware and system software	H8				$ -	$ -
95	CWIP	H8	$ 229,628.00			$ 229,628	$ -
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)[1]	H10	$ 84,044.10			$ 84,044	$ -
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)[1]		$ -			$ -	$ -
						$ -	$ -
						$ -	$ -
						$ -	$ -
						$ -	$ -
						$ -	$ -
						$ -	$ -
						$ -	$ -
						$ -	$ -
	TOTAL		$ 48,830,539	$ 6,658,465	$ -	$ 55,489,004	$ 3,329,233

Reduced UCC	Rate %	Bridge Year CCA		UCC End of Bridge Year
$ 19,491,695	4%	$ 779,668		$ 18,876,523
$ -	6%	$ -		$ -
$ -	6%	$ -		$ -
$ 264,133	20%	$ 52,827		$ 271,306
$ 1,065,371	30%	$ 319,611		$ 989,260
$ -	30%	$ -		$ -
$ 233,250	100%	$ 233,250		$ 127,250
$ -		$ -		$ -
$ -		$ -		$ -
$ -		$ -		$ -
$ -		$ -		$ -
$ -		$ -		$ -
$ 171,662	8%	$ 13,733		$ 157,929
$ -	12%	$ -		$ -
$ -	30%	$ -		$ -
$ -	50%	$ -		$ -
$ -	45%	$ -		$ -
$ -	30%	$ -		$ -
$ 30,347,221	8%	$ 2,427,778		$ 30,475,354
$ 272,768	55%	$ 150,022		$ 300,821
$ -	100%	$ -		$ -
$ 229,628	0%	$ -		$ 229,628
$ 84,044	7%	$ 5,883		$ 78,161
$ -	5%	$ -		$ -
$ -		$ -		$ -
$ -		$ -		$ -
$ -		$ -		$ -
$ -		$ -		$ -
$ -		$ -		$ -
$ -		$ -		$ -
$ -		$ -		$ -
$ -		$ -		$ -
$ 52,159,772		**$ 3,982,772**	B1	**$ 51,506,232**

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

						Bridge Year Adjustments				
Description	**Reference**	**Historical Utility Only**	**Eliminate Amounts Not Relevant for Bridge Year**	**Adjusted Utility Balance**		**Additions**	**Disposals**	**Balance for Bridge Year**		**Change During the Year**
Capital Gains Reserves ss.40(1)	H13	0		0				0	T13	0
Tax Reserves Not Deducted for accounting purposes										
Reserve for doubtful accounts ss. 20(1)(l)	H13	0		0				0	T13	0
Reserve for goods and services not delivered ss. 20(1)(m)	H13	0		0				0	T13	0
Reserve for unpaid amounts ss. 20(1)(n)	H13	0		0				0	T13	0
Debt & Share Issue Expenses ss. 20(1)(e)	H13	0		0				0	T13	0
Other tax reserves	H13	0		0				0	T13	0
		0		0				0		0
		0		0				0		0
Total		**0**	**0**	**0**	B1	**0**	**0**	**0**	B1	**0**
Financial Statement Reserves (not deductible for Tax Purposes)										
General Reserve for Inventory Obsolescence (non-specific)	H13	0		0				0	T13	0
General reserve for bad debts	H13	0		0				0	T13	0
Accrued Employee Future Benefits:	H13	0		0				0	T13	0
- Medical and Life Insurance	H13	0		0				0	T13	0
-Short & Long-term Disability	H13	0		0				0	T13	0
-Accmulated Sick Leave	H13	0		0				0	T13	0
- Termination Cost	H13	0		0				0	T13	0
- Other Post-Employment Benefits	H13	0		0				0	T13	0
Provision for Environmental Costs	H13	0		0				0	T13	0
Restructuring Costs	H13	0		0				0	T13	0
Accrued Contingent Litigation Costs	H13	0		0				0	T13	0
Accrued Self-Insurance Costs	H13	0		0				0	T13	0
Other Contingent Liabilities	H13	0		0				0	T13	0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	H13	0		0				0	T13	0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	H13	0		0				0	T13	0
Other	H13	0		0				0	T13	0
		0		0				0		0
		0		0				0		0
Total		**0**	**0**	**0**	B1	**0**	**0**	**0**	B1	**0**

Disallowed Expenses
0
0

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

PILs Tax Provision - Test Year

								Wires Only	
Regulatory Taxable Income							T1	$ 630,295	**A**
	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate					
Ontario (Max 11.5%)	11.5%	11.5%	$ 72,484	11.5%	**B**				
Federal (Max 15%)	15.0%	15.0%	$ 94,544	15.0%	**C**				
Combined effective tax rate (Max 26.5%)								26.50%	**D = B + C**
Total Income Taxes								**$ 167,028**	**E = A * D**
Investment Tax Credits								$ -	**F**
Miscellaneous Tax Credits								$ -	**G**
Total Tax Credits								**$ -**	**H = F + G**
Corporate PILs/Income Tax Provision for Test Year								**$ 167,028**	**I = E - H** S. Su
Corporate PILs/Income Tax Provision Gross Up [1]						73.50%	**J = 1-D**	**$ 60,221**	**K = I/J-I**
Income Tax (grossed-up)								**$ 227,249**	**L = K + I** S. Su

Note:

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

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Taxable Income - Test Year

	T2 S1 line #	Working Paper Reference	Test Year Taxable Income
Net Income Before Taxes		A.	2,104,644
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104		2,391,096
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106		108,587
Recapture of capital cost allowance from Schedule 8	107		
Gain on sale of eligible capital property from Schedule 10	108		
Income or loss for tax purposes- joint ventures or partnerships	109		
Loss in equity of subsidiaries and affiliates	110		
Loss on disposal of assets	111		
Charitable donations	112		
Taxable Capital Gains	113		
Political Donations	114		
Deferred and prepaid expenses	116		
Scientific research expenditures deducted on financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120		
Non-deductible meals and entertainment expense	121		1,900
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves beginning of year	125	T13	0
Reserves from financial statements- balance at end of year	126	T13	0
Soft costs on construction and renovation of buildings	127		
Book loss on joint ventures or partnerships	205		
Capital items expensed	206		
Debt issue expense	208		
Development expenses claimed in current year	212		
Financing fees deducted in books	216		
Gain on settlement of debt	220		
Non-deductible advertising	226		
Non-deductible interest	227		
Non-deductible legal and accounting fees	228		
Recapture of SR&ED expenditures	231		
Share issue expense	235		
Write down of capital property	236		
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		
Other Additions: (please explain in detail the nature of the item)			
Interest Expensed on Capital Leases	290		
Realized Income from Deferred Credit Accounts	291		
Pensions	292		
Non-deductible penalties	293		5,974
Amortization of deferred charge	294		175,472
Post employment benefits paid	295		220,000
	296		
	297		
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received			

Total Additions			**2,903,029**
Deductions:			
Gain on disposal of assets per financial statements	401		
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403	T8	4,221,702
Terminal loss from Schedule 8	404		
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves end of year	413	T13	0
Reserves from financial statements - balance at beginning of year	414	T13	0
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions: (Please explain in detail the nature of the item)			
Interest capitalized for accounting deducted for tax	390		
Capital Lease Payments	391		
Non-taxable imputed interest income on deferral and variance accounts	392		
	393		
Post-employment benefits	394		155,676
	395		
	396		
	397		
ARO Payments - Deductible for Tax when Paid			
ITA 13(7.4) Election - Capital Contributions Received			
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			
Principal portion of lease payments			
Lease Inducement Book Amortization credit to income			
Financing fees for tax ITA 20(1)(e) and (e.1)			
Total Deductions		calculated	**4,377,378**
NET INCOME FOR TAX PURPOSES		calculated	**630,295**
Charitable donations	311		
Taxable dividends received under section 112 or 113	320		
Non-capital losses of preceding taxation years from Schedule 7-1	331	T4	0
Net-capital losses of preceding taxation years (Please show calculation)	332	T4	0
Limited partnership losses of preceding taxation years from Schedule 4	335		
REGULATORY TAXABLE INCOME		calculated	**630,295**

T0

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Schedule 7-1 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Working Paper Reference	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year Carried Forward	B4	0		0
Amount to be used in Test Year and Price Cap Years	T1	0		0
Number of years loss until next cost of service (i.e. years the loss is to be spread over)				
Amount to be used in Test Year	calculated	0		0
Loss Carry Forward Generated in Test Year (if any)	T1	0		0
Other Adjustments				0
Balance available for use in Future Years	calculated	0		0

Net Capital Loss Carry Forward Deduction		Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year Carried Forward	B4	0		0
Amount to be used in Test Year and Price Cap Years				0
Number of years loss until next cost of service (i.e. years the loss is to be spread over)				
Amount to be used in Test Year	T1	0		0
Loss Carry Forward Generated in Test Year (if any)				0
Other Adjustments				0
Balance available for use in Future Years		0		0

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Schedule 8 CCA - Test Year

Class	Class Description	Working Paper Reference	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA		UCC End of Test Year
1	Distribution System - post 1987	B8	$ 18,876,523	418,941		$ 19,295,464	$ 209,471	$ 19,085,994	4%	$ 763,440		$ 18,532,024
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	B8	$ -			$ -	$ -	$ -	6%	$ -		$ -
2	Distribution System - pre 1988	B8	$ -			$ -	$ -	$ -	6%	$ -		$ -
8	General Office/Stores Equip	B8	$ 271,306	120,000		$ 391,306	$ 60,000	$ 331,306	20%	$ 66,261		$ 325,045
10	Computer Hardware/ Vehicles	B8	$ 989,260	270,000		$ 1,259,260	$ 135,000	$ 1,124,260	30%	$ 337,278		$ 921,982
10.1	Certain Automobiles	B8	$ -			$ -	$ -	$ -	30%	$ -		$ -
12	Computer Software	B8	$ 127,250	115,000		$ 242,250	$ 57,500	$ 184,750	100%	$ 184,750		$ 57,500
13 1	Lease # 1	B8	$ -			$ -	$ -	$ -		$ -		$ -
13 2	Lease #2	B8	$ -			$ -	$ -	$ -		$ -		$ -
13 3	Lease # 3	B8	$ -			$ -	$ -	$ -		$ -		$ -
13 4	Lease # 4	B8	$ -			$ -	$ -	$ -		$ -		$ -
14	Franchise	B8	$ -			$ -	$ -	$ -		$ -		$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than E	B8	$ 157,929			$ 157,929	$ -	$ 157,929	8%	$ 12,634		$ 145,295
42	Fibre Optic Cable	B8	$ -			$ -	$ -	$ -	12%	$ -		$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	B8	$ -			$ -	$ -	$ -	30%	$ -		$ -
43.2	Certain Clean Energy Generation Equipment	B8	$ -			$ -	$ -	$ -	50%	$ -		$ -
45	Computers & Systems Software acq'd post Mar 22/04	B8	$ -			$ -	$ -	$ -	45%	$ -		$ -
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	B8	$ -			$ -	$ -	$ -	30%	$ -		$ -
47	Distribution System - post February 2005	B8	$ 30,475,354	5,097,250		$ 35,572,604	$ 2,548,625	$ 33,023,979	8%	$ 2,641,918		$ 32,930,686
50	Data Network Infrastructure Equipment - post Mar 2007	B8	$ 300,821	161,809		$ 462,630	$ 80,905	$ 381,725	55%	$ 209,949		$ 252,681
52	Computer Hardware and system software	B8	$ -			$ -	$ -	$ -	100%	$ -		$ -
95	CWIP	B8	$ 229,628			$ 229,628	$ -	$ 229,628	0%	$ -		$ 229,628
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)1	B8	$ 78,161			$ 78,161	$ -	$ 78,161	7%	$ 5,471		$ 72,690
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)1	B8	$ -			$ -	$ -	$ -	5%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
	TOTAL		$ 51,506,232	$ 6,183,000	$ -	$ 57,689,232	$ 3,091,500	$ 54,597,732		$ 4,221,702	T1	$ 53,467,531

1. New CCA class 14.1 effective January 1, 2017. The class includes property that was eligible capital property immediately before January 1, 2017. For tax years that end prior to 2027, transitional rules apply to class 14.1 that were acquired before January 1, 2017

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

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

Attachment 4-P

EPLC Details of Historical LRAM & LRAMVA Claims

Elenchus
34 King Street East
Suite 600
Toronto, ON
M5C 2X8

September 25, 2013

Michelle Soucie
Operations & Regulatory Accounting Analyst
Essex Powerlines Corporation
2730 Highway 3
Oldcastle, ON N0R 1L0

Re: 2011 and 2012 LRAMVA

Dear Michelle;

Elenchus is pleased to attach the 2011 and 2012 LRAMVA Report For Essex Powerlines Corporation for inclusion in your 2014 IRM Rate Application.

Elenchus concludes that Essex Powerlines Corporation's electricity rates should be adjusted to reflect an LRAMVA claim of $109,212.

Thank you for allowing Elenchus to be of service. Please contact me should you have any questions about this report.

Yours Truly,

Martin Benum
Senior Advisor

Elenchus

Essex Powerlines Corporation 2011 and 2012 LRAMVA

Date Prepared: September 25, 2013

Elenchus

34 King Street East

Suite 600

Toronto, ON

M5C 2X8

elenchus

Tab 1 of 3

Report

Table of Contents

Executive Review

On April 26, 2012 the Ontario Energy Board ("OEB" or "the Board") issued Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003) which permit Essex Powerlines Corporation to make application for recovery of lost revenue that results from the successful operation of CDM initiatives within its boundaries.

The Guidelines delineate two distinct processes for recovery of lost revenues:

- Lost Revenue Adjustment Mechanism ("LRAM") accommodates the recovery of lost revenues resulting from CDM initiatives for the period from 2005 to the end of 2010 either through approved distribution rate funding by way of the third instalment of the incremental market adjusted revenue requirement ("MAAR") or through contracts with the OPA. The manner in which distributors were instructed to determine the LRAM amount was set out in the Board's Guidelines for Electricity Distributor Conservation and Demand Management, dated March 28, 2008 (EB-2008-0037) (the "2008 CDM Guidelines").

- Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") accommodates the recovery of lost revenues resulting from CDM initiatives for the period 2011-2014. The manner in which distributors were instructed to determine the LRAMVA amount is set out in the Board's Guidelines for Electricity Distributor Conservation and Demand Management, dated April 26, 2012 (EB-2012-0003) (the "2012 CDM Guidelines").

Essex Powerlines Corporation's ("EPLC") 2012 IRM Application EB-2011-0166 concluded EPLC's claims to LRAM for 2006 to 2009 programs with persistence to 2009. EPLC filed a 2010 COS of Service Application for which the Board denied LRAM claim for 2010 programs and 2010 persistence for 2006 to 2009 programs in the 2012 IRM Application. EPLC did not file for an LRAMVA claim in its 2013 IRM Application EB-2012-0123.

EPLC's CDM activities consist of programs initiated by the Ontario Power Authority (OPA) only. By way of this report EPLC is entitled to claim in its 2014 IRM application 2011 OPA CDM program activities, 2012 persistence of OPA CDM program activities from 2011 programs , and 2012 OPA CDM program activities. In addition EPLC may claim adjustments for previous years (2011) verified results in 2012.

Elenchus concludes that Essex Powerlines Corporation's electricity rates should be adjusted to reflect an LRAM claim of $109,212.

Introduction

The LRAM and LRAMVA are designed to ensure that Local Distribution Companies ("LDC") "remain whole" despite the lower consumption levels that are, by design, the result of successful conservation and demand management initiatives. There should not be a disincentive for LDC's to encourage energy efficiency and energy conservation efforts. Therefore, an LDC is compensated for these lost revenues.

Essex Powerlines Corporation's ("EPLC") 2012 IRM Application EB-2011-0166 concluded EPLC's claims to LRAM for 2006 to 2009 programs with persistence to 2009. EPLC filed a 2010 COS of Service Application for which the Board denied LRAM claim for 2010 programs and 2010 persistence for 2006 to 2009 programs in the 2012 IRM Application. EPLC did not file for an LRAMVA claim in its 2013 IRM Application EB-2012-0123.

EPLC's CDM activities consist of programs initiated by the Ontario Power Authority (OPA) only. This reviews claim is for 2011 OPA CDM program activities, 2012 persistence of OPA CDM program activities from 2011 programs, and 2012 OPA CDM program activities. In addition EPLC may claim adjustments for previous years (2011) verified results in 2012. The LRAMVA claim is based on the 2012 Guidelines for OPA programs initiated in 2011 and 2012. EPLC does not have any Board Approved programs.

The LRAMVA calculations are based on the sum of the electricity savings over the period of the claim, which are then valued at the appropriate distribution rate depending on the timing (year) of the savings and to which rate class they belonged.

The savings themselves are the product of an energy program evaluation process, often referred to as Evaluation, Measurement and Verification (EM&V). Fortunately, in the case of this claim, all savings estimates are for OPA programs and are provided by the OPA.

These savings estimates include persistence—the installation of energy conservation measures whose savings that last past the initial year that they are installed. A four-year program that installed 10 widgets per year with a savings of 1,000 kWh each would result in the following savings profile if the widgets lasted 4 or more years (which is common):

Example Savings Profile Showing Effect of Persistence

Year	In-Year Savings (kWh)	Cumulative Savings (kWh)
1	10,000	10,000

2	20,000	30,000
3	30,000	60,000
4	40,000	100,000

Savings from CDM programs typically follow a pattern similar to the one illustrated in the table above. Energy program evaluations determine the energy and demand savings estimates to a reasonable degree of accuracy and also determine the persistence including patterns, or effective useful life (EUL) of new measures being installed and the remaining useful life (RUL) of measures being replaced. It is assumed that the tables provided to each LDC by the OPA contain accurate interpretations and transcriptions of the results from those evaluations (available on the OPA Website).

There are "gross" savings and "net" savings for energy efficiency programs. OPA documentation details the differences between these two, and both are provided to LDC's by the OPA, but for the purposes of this LRAM claim only "net" savings are utilized. Net savings are determined to be those savings that would not have occurred unless the energy efficiency program was running. They are not natural conservation or savings that someone could claim would have occurred anyway. They do not include savings from "free riders."

Some energy efficiency programs are operated at a province-wide scale. These include some behavioural-based programs and some residential/consumer-orientated initiatives like discount coupons. In certain of these cases, savings are apportioned to LDC's by the OPA rather than an attempt made to track individual transactions (which is sometimes impossible).

The 2011 and 2012 program savings claimed by EPLC are the net energy and demand savings that can be attributed to the programs and initiatives that operated in EPLC's territory during the 2011 and 2012 period as apportioned to Essex Powerlines Corporation by the OPA according to its established formulae.

Assumptions

This report for EPLC was created with the following assumptions that are often peculiar to the 2011 - 2012 periods:

- “Consumer Program” classified as the Residential rate class
- “Business Program” classified as General Service <50 kW rate class
- “Industrial Program” classified as General Service >50 kW rate class
- “Home Assistance Program” classified as the Residential rate class
- “Pre-2011 Programs completed in 2011” classified as General Service >50 kW rate class
- “Industrial” and “Pre-2011 Programs” kWh savings were omitted because they are not assignable as a volumetric charge
- “Consumer” “Business” and “Home Assistance Program” kW savings were omitted because they are not assignable as a volumetric charge

For purposes of monetary estimation kWh savings are multiplied by the 2011 and 2012 volumetric distribution rates of the Residential and General Service <50 kW rate classes. kW savings are multiplied by the 2011 and 2012 volumetric distribution rates of the General Service 50 to 2,999 kW rate class. Please reference Appendix 2 and Appendix 3 for EPLC’s 2011 and 2012 schedule of rates and charges for the claim rate classes.

Energy (kWh) savings are assumed to be annual values. Peak Demand (kW) savings have been extended by the number of months (either 5 months for Demand Response programs or 12 months for all other programs).

Persistence of programs are assumed to be one year only for Demand Response programs or continuing into future years for all other programs.

2011 and 2012 LRAMVA Recommendation

Elenchus has concluded that Essex Powerlines Corporation can justifiably claim $109,212 in LRAMVA including carrying cost to April 30, 2014, allocated by rate class as shown in the Table 1 below. Please reference Attachment 1 for the complete calculation.

2011 and 2012 LRAMVA

Customer Class	Amount	Interest *	Total
Residential	$ 31,899	$ 960	$ 32,859
General Service Less Than 50 kW	$ 28,266	$ 806	$ 29,071
General Service Greater Than 50 kW	$ 45,854	$ 1,428	$ 47,283
Total	**$ 106,019**	**$ 3,194**	**$ 109,212**

* Carrying Costs to April 30, 2014

Table 1 2012 LRAMVA

Elenchus has calculated the following rate rider for disposition of the 2011 and 2012 LRAMVA claim as shown in the Table 2 below. This is based on a one year recovery. Billing determinants have been applied based on EPLC's 2010 Cost of Service load forecast.

2011 and 2012 LRAMVA Rate Rider Calculation

Effective: May 1, 2014 to April 30, 2015

Rate Class	Total	Billing Determinant		Rate Rider
Residential	$ 32,859	271,379,498	kWh	$ 0.0001
General Service Less Than 50 kW	$ 29,071	72,012,960	kWh	$ 0.0004
General Service Greater Than 50 kW	$ 47,283	467,092	kW	$ 0.1012
Total	**$ 109,212**			

Table 2 2012 LRAMVA Rate Rider

LRAMVA Declaration

EPLC may apply for the disposition of the balance in the 2011 and 2012 LRAMVA as part of it 2014 IRM application if EPLC's deems the amount to be significant. Elenchus would confirm this.

In support of its application for lost revenues, and specifically the actual results used in the determination of the LRAMVA balance to be disposed, EPLC must file the following:

- A statement indicating that the EPLC has used the most recent input assumptions available at the time of the program evaluation when calculating its lost revenue amount. Elenchus would confirm this.

- A statement indicating that the distributor has relied on the most recent and appropriate final CDM evaluation report from the OPA in support of its lost revenue calculation and a copy of this report. Elenchus would confirm using the OPA Annual CDM Report 2012 - Final Verified Results attached as Appendix 1 of this report.

- Separate tables for each rate class showing the lost revenue amounts requested by the year they are associated with and the year the lost revenues took place. Elenchus would confirm this as attached in Attachment 1to this report.

- Lost revenue calculations, determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board approved variable distribution charge appropriate to the class. Elenchus would confirm this as attached in Attachment 1 to this report.

- A statement, and if applicable a table, that indicates if carrying charges are being requested on the lost revenue amount. Elenchus would confirm this as attached in Attachment 1 to this report.
- Elenchus confirms EPLC is not including any claims for Board-approved programs.

Work Sited and Referenced

1. Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003) Issued: April 26, 2012
2. OPA 2012 Annual CDM Report – Final Verified Results on provincial conservation results to Local Distribution Company service territories – issued August 30, 2013
    - Please reference Appendix 1 attached to this report.

Tab 2 of 3

2011 and 2012 LRAMVA Calculation

Attachment 1 of 1

2011 and 2012 LRAMVA Calculation

Input Table One
2011 Programs in 2011
(Net kWh)

Amount	2011
RES	
2011	
Consumer Program	
Appliance Exchange	3,231
Appliance Retirement	48,406
Bi-Annual Retailer Event	192,162
Conservation Instant Coupon Booklet	121,822
HVAC Incentives	463,694
Consumer Program Total	829,315
2011 Total	**829,315**
RES Total	**829,315**
GSLT50	
2011	
Business Program	
Demand Response 3*	7,344
Direct Install Lighting	139,935
Retrofit	337,744
Business Program Total	485,023
2011 Total	**485,023**
GSLT50 Total	**485,023**

Input Table Two
2011 Persistence in 2012 and 2012 Programs
(Net kWh)

Amount	2012
RES	
2011	
Consumer Program	
Appliance Exchange	3,231
Appliance Retirement	48,406
Bi-Annual Retailer Event	192,162
Bi-Annual Retailer Event - previous year adjustment	14,277
Conservation Instant Coupon Booklet	121,822
Conservation Instant Coupon Booklet - previous year adjustment	1,802
HVAC Incentives	463,694
HVAC Incentives - previous year adjustment	-70,103
Consumer Program Total	775,291
2011 Total	**775,291**
2012	
Consumer Program	
Appliance Exchange	4,153
Appliance Retirement	16,070
Bi-Annual Retailer Event	175,123
Conservation Instant Coupon Booklet	9,143
HVAC Incentives	249,324
Consumer Program Total	453,813
Home Assistance Program	
Home Assistance Program	88,006
Home Assistance Program Total	88,006
2012 Total	**541,819**
RES Total	**1,317,110**
GSLT50	
2011	
Business Program	
Direct Install Lighting	139,935
Retrofit	337,744
Business Program Total	477,679
2011 Total	**477,679**
2012	
Business Program	
Demand Response 3*	2,742
Direct Install Lighting	23,662
Energy Audit	25,176
Retrofit	1,594,397
Business Program Total	1,645,977
2012 Total	**1,645,977**
GSLT50 Total	**2,123,656**

Input Table Three
2011 Programs in 2011
(Net kW)

	2011 Report Amount	Months	Annual Amount
GSGT50			
2011			
Industrial Program			
Demand Response 3*	1,749	5	8,745
Retrofit	93	12	1,116
Industrial Program Total	1,842		9,861
Pre-2011 Programs completed in 2011			
Electricity Retrofit Incentive Program	10	12	120
Pre-2011 Programs completed in 2011 Total	10	12	120
2011 Total	**1,852**		**9,981**
GSGT50 Total	**1,852**		**9,981**

Input Table Four
2011 Persistence in 2012 and 2012 Programs
(Net kW)

	2012 Report Amount	Months	Annual Amount
GSGT50			
2011			
Industrial Program			
Retrofit	93	12	1,116
Industrial Program Total	93		1,116
Pre-2011 Programs completed in 2011			
Electricity Retrofit Incentive Program	10	12	120
Pre-2011 Programs completed in 2011 Total	10		120
2011 Total	**103**		**1,236**
2012			
Industrial Program			
Demand Response 3*	1,811	5	9,055
Industrial Program Total	1,811		9,055
Pre-2011 Programs completed in 2011			
High Performance New Construction	1	12	12
Pre-2011 Programs completed in 2011 Total	1	12	12
2012 Total	**1,812**		**9,067**
GSGT50 Total	**1,915**		**10,303**

Output Table One

2011 and 2012 LRAMVA

2011 Programs in 2011

	Net kWh	2011 Rate	Amount		RES	GSLT 50	GSGT50
RES	829,315	0.0148	$ 12,274		$ 12,274		
GSLT 50	485,023	0.0088	$ 4,268			$ 4,268	
			$ 16,542				
	Net kW	**2011 Rate**	**Amount**				
GSGT50	9,981	2.4899	$ 24,851.69				$ 24,852
			2012 LRAMVA	**$ 41,394**	$ 12,274	$ 4,268	$ 24,852

2011 Persistence in 2012 and 2012 Programs

	Net kWh	2012 Rate	Amount		RES	GSLT 50	GSGT50
RES	1,317,110	0.0149	$ 19,625		$ 19,625		
GSLT 50	2,123,656	0.0113	$ 23,997			$ 23,997	
			$ 43,622				
	Net kW	**2012 Rate**	**Amount**				
GSGT50	10,303	2.0385	$ 21,002.67				$ 21,003
			2012 LRAMVA	**$ 64,625**	$ 19,625	$ 23,997	$ 21,003
			Total	**$ 106,019**	**$ 31,899**	**$ 28,266**	**$ 45,854**

Output Table Two
Calculated Carrying Costs to April 30, 2014

				LRAM LRAMVA			Allocated Carrying Costs		
Month	OEB Prescribed Annual Rate	Days in Month	Monthly Interest Rate	Residential	GS LT 50	GS GT 50	Residential	GS LT 50	GS GT 50
Jan-2011	1.47%	31	0.12%	$ 1,023	$ 356	$ 2,071	$ 1.28	$ 0.44	$ 2.59
Feb-2011	1.47%	28	0.11%	$ 2,046	$ 711	$ 4,142	$ 2.31	$ 0.80	$ 4.67
Mar-2011	1.47%	31	0.12%	$ 3,068	$ 1,067	$ 6,213	$ 3.83	$ 1.33	$ 7.76
Apr-2011	1.47%	30	0.12%	$ 4,091	$ 1,423	$ 8,284	$ 4.94	$ 1.72	$ 10.01
May-2011	1.47%	31	0.12%	$ 5,114	$ 1,778	$ 10,355	$ 6.38	$ 2.22	$ 12.93
Jun-2011	1.47%	30	0.12%	$ 6,137	$ 2,134	$ 12,426	$ 7.41	$ 2.58	$ 15.01
Jul-2011	1.47%	31	0.12%	$ 7,160	$ 2,490	$ 14,497	$ 8.94	$ 3.11	$ 18.10
Aug-2011	1.47%	31	0.12%	$ 8,183	$ 2,845	$ 16,568	$ 10.22	$ 3.55	$ 20.68
Sep-2011	1.47%	30	0.12%	$ 9,205	$ 3,201	$ 18,639	$ 11.12	$ 3.87	$ 22.52
Oct-2011	1.47%	31	0.12%	$ 10,228	$ 3,557	$ 20,710	$ 12.77	$ 4.44	$ 25.86
Nov-2011	1.47%	30	0.12%	$ 11,251	$ 3,913	$ 22,781	$ 13.59	$ 4.73	$ 27.52
Dec-2011	1.47%	31	0.12%	$ 12,274	$ 4,268	$ 24,852	$ 15.32	$ 5.33	$ 31.03
Jan-2012	1.47%	31	0.12%	$ 13,909	$ 6,268	$ 26,602	$ 17.37	$ 7.83	$ 33.21
Feb-2012	1.47%	29	0.12%	$ 15,545	$ 8,268	$ 28,352	$ 18.16	$ 9.66	$ 33.11
Mar-2012	1.47%	31	0.12%	$ 17,180	$ 10,268	$ 30,102	$ 21.45	$ 12.82	$ 37.58
Apr-2012	1.47%	30	0.12%	$ 18,816	$ 12,267	$ 31,853	$ 22.73	$ 14.82	$ 38.48
May-2012	1.47%	31	0.12%	$ 20,451	$ 14,267	$ 33,603	$ 25.53	$ 17.81	$ 41.95
Jun-2012	1.47%	30	0.12%	$ 22,086	$ 16,267	$ 35,353	$ 26.69	$ 19.65	$ 42.71
Jul-2012	1.47%	31	0.12%	$ 23,722	$ 18,267	$ 37,103	$ 29.62	$ 22.81	$ 46.32
Aug-2012	1.47%	31	0.12%	$ 25,357	$ 20,266	$ 38,853	$ 31.66	$ 25.30	$ 48.51
Sep-2012	1.47%	30	0.12%	$ 26,993	$ 22,266	$ 40,604	$ 32.61	$ 26.90	$ 49.06
Oct-2012	1.47%	31	0.12%	$ 28,628	$ 24,266	$ 42,354	$ 35.74	$ 30.30	$ 52.88
Nov-2012	1.47%	30	0.12%	$ 30,263	$ 26,266	$ 44,104	$ 36.56	$ 31.73	$ 53.29
Dec-2012	1.47%	31	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 39.83	$ 35.29	$ 57.25
Jan-2013	1.47%	31	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 39.72	$ 35.19	$ 57.09
Feb-2013	1.47%	28	0.11%	$ 31,899	$ 28,266	$ 45,854	$ 35.87	$ 31.79	$ 51.57
Mar-2013	1.47%	31	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 39.72	$ 35.19	$ 57.09
Apr-2013	1.47%	30	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 38.44	$ 34.06	$ 55.25
May-2013	1.47%	31	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 39.72	$ 35.19	$ 57.09
Jun-2013	1.47%	30	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 38.44	$ 34.06	$ 55.25
Jul-2013	1.47%	31	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 39.72	$ 35.19	$ 57.09
Aug-2013	1.47%	31	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 39.72	$ 35.19	$ 57.09
Sep-2013	1.47%	30	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 38.44	$ 34.06	$ 55.25
Oct-2013	1.47%	31	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 39.72	$ 35.19	$ 57.09
Nov-2013	1.47%	30	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 38.44	$ 34.06	$ 55.25
Dec-2013	1.47%	31	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 39.72	$ 35.19	$ 57.09
Jan-2014	1.47%	31	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 39.83	$ 35.29	$ 57.25
Feb-2014	1.47%	28	0.11%	$ 31,899	$ 28,266	$ 45,854	$ 35.97	$ 31.87	$ 51.71
Mar-2014	1.47%	31	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 39.83	$ 35.29	$ 57.25
Apr-2014	1.47%	30	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 38.54	$ 34.15	$ 55.40
							$ 959.74	$ 805.89	$ 1,428.19

Output Table Three
2011 and 2012 LRAMVA

Customer Class	Amount	Interest *	Total
Residential	$ 31,899	$ 960	$ 32,859
General Service Less Than 50 kW	$ 28,266	$ 806	$ 29,071
General Service Greater Than 50 kW	$ 45,854	$ 1,428	$ 47,283
Total	**$ 106,019**	**$ 3,194**	**$ 109,212**

* Carrying Costs to April 30, 2014

2011 and 2012 LRAMVA Rate Rider Calculation

Effective: May 1, 2014 to April 30, 2015

Rate Class	Total	Billing Determinant		Rate Rider
Residential	$ 32,859	271,379,498	kWh	$ 0.0001
General Service Less Than 50 kW	$ 29,071	72,012,960	kWh	$ 0.0004
General Service Greater Than 50 kW	$ 47,283	467,092	kW	$ 0.1012
Total	**$ 109,212**			

Tab 3 of 3

Appendices

Appendix 1 of 3

Appendix 1 - OPA Final Verified 2012 Annual CDM Report

Message from the Vice President:

The OPA is pleased to provide you with the enclosed Final 2012 Results Report. We have seen a 39% increase in energy savings for our new province-wide 2011-2014 suite of saveONenergy initiatives. Overall progress to targets is moving up with 29% of demand and 65% of energy savings achieved. Many LDCs, both large and small, continue to stay on track to meet or exceed their OEB targets. Conservation programs continue to be a valuable and cost effective resource for customers across the province, over the past two years the program cost to consumers remains within 3 cents per kWh.

Further to programmatic savings, capability building efforts launched in 2011 are yielding healthy enabled savings through Embedded Energy Managers and Audit initiative projects. The strong momentum continues in 2013.

We remain committed to ensuring LDCs are successful in meeting their objectives and our collective efforts to date have improved the current program suite by offering more local program opportunities, implementing a new expedited change management process, and enhancing incentives to make it easier for customers to participate in programs. We invite you to continue to provide your feedback to us and to celebrate our successes as we move forward.

The format of this report was developed in collaboration with the OPA-LDC Reporting and Evaluation Working Group and is designed to help populate LDC annual report templates that will be submitted to the OEB in late September. All results are now considered final for 2012. Any additional 2012 program activity not captured will be reported in the Final 2013 Results Report.

Please continue to monitor saveONenergy E-blasts for any further updates and should you have any other questions or comments please contact LDC.Support@powerauthority.on.ca.

We appreciate your ongoing collaboration and cooperation throughout the reporting and evaluation process. We look forward to another successful year.

Sincerely,

Andrew Pride

Table of Contents

OPA-Contracted Province-Wide CDM Programs FINAL 2012 Results

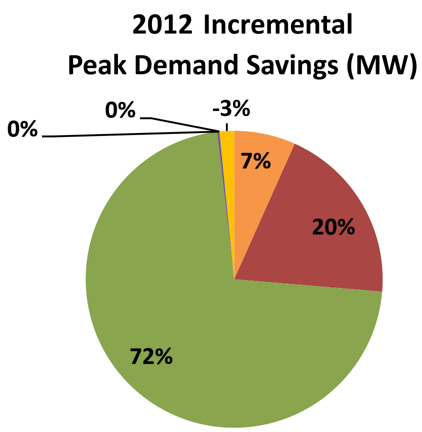
LDC: Essex Powerlines Corporation

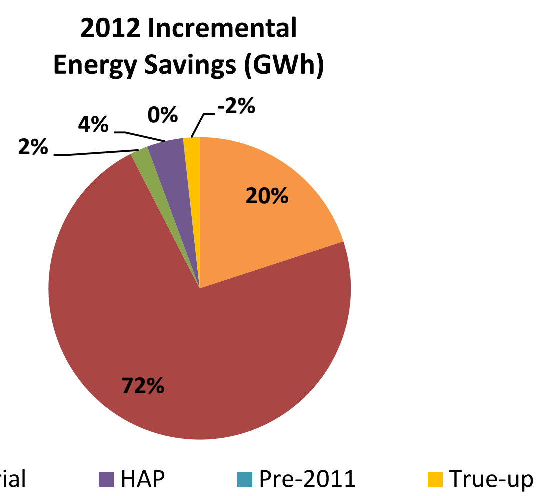
FINAL 2012 Progress to Targets	2012 Incremental	Program-to-Date Progress to Target (Scenario 1)	Scenario 1: % of Target Achieved	Scenario 2: % of Target Achieved
Net Annual Peak Demand Savings (MW)	2.4	0.9	**12.8%**	**40.6%**
Net Energy Savings (GWh)	2.2	14.6	**67.9%**	**68.4%**

Scenario 1 = Assumes that demand resource resources have a persistence of 1 year

Scenario 2 = Assumes that demand response resources remain in your territory until 2014

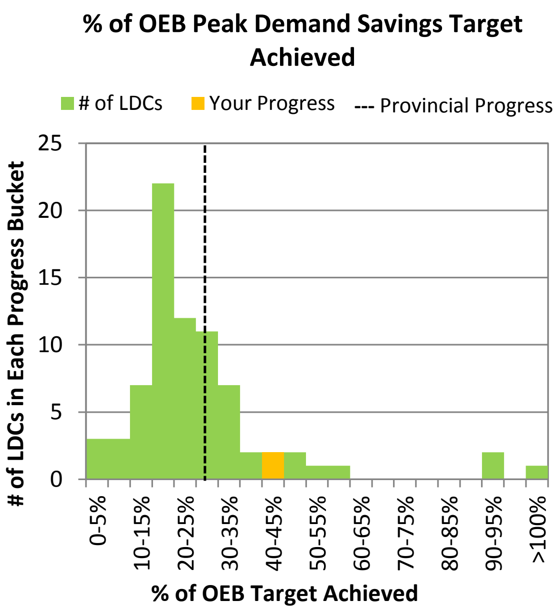
Achievement by Sector





Comparison: Your Achievement vs. LDC Community Achievement (Progress to Target)

The following graphs assume that demand response resources remain in your territory until 2014 (aligns with Scenario 2)



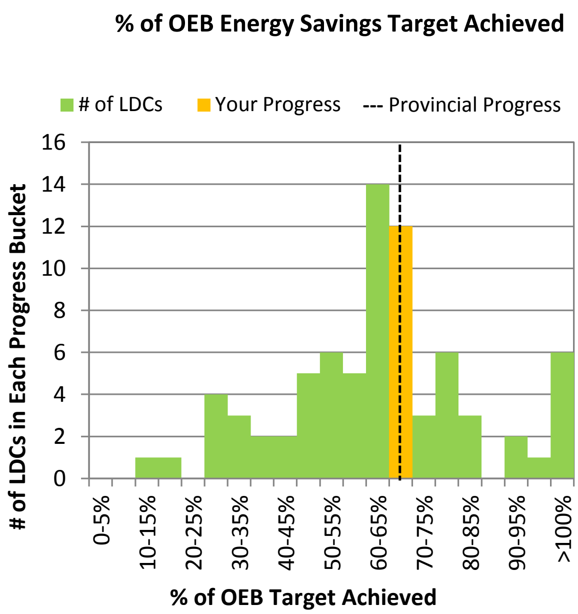


Table 1: **Essex Powerlines Corporation** Initiative and Program Level Savings by Year (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	118	40			7	2			48,406	16,070			9	241,633
Appliance Exchange	Appliances	29	17			3	2			3,231	4,153			3	23,584
HVAC Incentives	Equipment	1,016	743			264	153			463,694	249,324			417	2,602,748
Conservation Instant Coupon Booklet	Items	3,256	202			8	2			121,822	9,143			9	514,715
Bi-Annual Retailer Event	Items	5,691	6,937			11	10			192,162	175,123			21	1,294,015
Retailer Co-op	Items	0	0			0	0			0	0			0	0
Residential Demand Response (switch/pstat)	Devices	85	0			48	0			0	0			0	0
Residential Demand Response (IHD)	Devices	0	0			0				0					
Residential New Construction	Homes	0	0			0	0			0	0			0	0
Consumer Program Total						**340**	**169**			**829,315**	**453,813**			**459**	**4,676,694**
Business Program															
Retrofit	Projects	10	27			56	295			337,744	1,594,397			343	6,111,172
Direct Install Lighting	Projects	40	7			52	7			139,935	23,662			43	578,708
Building Commissioning	Buildings	0	0			0	0			0	0			0	0
New Construction	Buildings	0	0			0	0			0	0			0	0
Energy Audit	Audits	0	1			0	5			0	25,176			5	75,529
Small Commercial Demand Response	Devices	0	0			0	0			0	0			0	0
Small Commercial Demand Response (IHD)	Devices	0	0			0				0				0	0
Demand Response 3	Facilities	3	3			188	189			7,344	2,742			0	10,086
Business Program Total						**296**	**495**			**485,023**	**1,645,977**			**391**	**6,775,495**
Industrial Program															
Process & System Upgrades	Projects	0	0			0	0			0	0			0	0
Monitoring & Targeting	Projects	0	0			0	0			0	0			0	0
Energy Manager	Projects	0	0			0	0			0	0			0	0
Retrofit	Projects	4				93				688,860				93	2,755,441
Demand Response 3	Facilities	4	4			1,749	1,811			102,648	43,656			0	146,305
Industrial Program Total						**1,841**	**1,811**			**791,509**	**43,656**			**93**	**2,901,745**
Home Assistance Program															
Home Assistance Program	Homes	0	149			0	6			0	88,006			6	264,017
Home Assistance Program Total						**0**	**6**			**0**	**88,006**			**6**	**264,017**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	7	0			10	0			56,015	0			10	224,061
High Performance New Construction	Projects	0	0			0	1			1,239	716			1	7,102
Toronto Comprehensive	Projects	0	0			0	0			0	0			0	0
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0			0	0			0	0
LDC Custom Programs	Projects	0	0			0	0			0	0			0	0
Pre-2011 Programs completed in 2011 Total						**10**	**1**			**57,254**	**716**			**11**	**231,163**
Other															
Program Enabled Savings	Projects	0	0			0	0			0	0			0	0
Time-of-Use Savings	Homes														
Other Total							**0**				**0**			**0**	**0**
Adjustments to Previous Year's Verified Results							**-39**				**-54,023**			**-39**	**-216,093**
Energy Efficiency Total						**503**	**482**			**2,053,107**	**2,185,769**			**959**	**14,692,723**
Demand Response Total (Scenario 1)						**1,984**	**2,000**			**109,992**	**46,398**			**0**	**156,391**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**2,487**	**2,443**			**2,163,100**	**2,178,144**			**920**	**14,633,021**
													Full OEB Target:	**7,190**	**21,540,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**12.8%**	**67.9%**

Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Due to the limited timeframe of data, which didn't include the summer months, 2012 IHD results have been deemed inconclusive. The IHD line item on the 2012 annual report will be left blank. Once a full year of data is available (2013 evaluation), and the savings are quantified, 2012 results will be updated to reflect the quantified savings.

Table 2: Adjustments to **Essex Powerlines Corporation** Verified Results due to Errors or Omissions (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	0				0				0				0	0
Appliance Exchange	Appliances	0				0				0				0	0
HVAC Incentives	Equipment	-160				-40				-70,103				-40	-280,411
Conservation Instant Coupon Booklet	Items	54				0				1,802				0	7,210
Bi-Annual Retailer Event	Items	535				1				14,277				1	57,108
Retailer Co-op	Items	0				0				0				0	0
Residential Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Residential Demand Response (IHD)	Devices	0				0				0				0	0
Residential New Construction	Homes	0				0				0				0	0
Consumer Program Total						**-39**				**-54,023**				**-39**	**-216,093**
Business Program															
Retrofit	Projects	0				0				0				0	0
Direct Install Lighting	Projects	0				0				0				0	0
Building Commissioning	Buildings	0				0				0				0	0
New Construction	Buildings	0				0				0				0	0
Energy Audit	Audits	0				0				0				0	0
Small Commercial Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Small Commercial Demand Response (IHD)	Devices	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Business Program Total						**0**				**0**				**0**	**0**
Industrial Program															
Process & System Upgrades	Projects	0				0				0				0	0
Monitoring & Targeting	Projects	0				0				0				0	0
Energy Manager	Projects	0				0				0				0	0
Retrofit	Projects	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Industrial Program Total						**0**				**0**				**0**	**0**
Home Assistance Program															
Home Assistance Program	Homes	0				0				0				0	0
Home Assistance Program Total						**0**				**0**				**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	0				0				0				0	0
High Performance New Construction	Projects	0				0				0				0	0
Toronto Comprehensive	Projects	0				0				0				0	0
Multifamily Energy Efficiency Rebates	Projects	0				0				0				0	0
LDC Custom Programs	Projects	0				0				0				0	0
Pre-2011 Programs completed in 2011 Total						**0**				**0**				**0**	**0**
Other															
Program Enabled Savings	Projects	0				0				0				0	0
Time-of-Use Savings	Homes														
Other Total						**0**				**0**				**0**	**0**
Adjustments to Previous Year's Verified Results						**-39**				**-54,023**				**-39**	**-216,093**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Table 3: Essex Powerlines Corporation Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement		1.00				0.47				1.00				0.47		
Appliance Exchange		1.00				0.52				1.00				0.52		
HVAC Incentives		1.00				0.50				1.00				0.49		
Conservation Instant Coupon Booklet		1.00				1.00				1.00				1.05		
Bi-Annual Retailer Event		1.00				0.91				1.00				0.92		
Retailer Co-op		n/a				n/a				n/a				n/a		
Residential Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Residential Demand Response (IHD)		n/a				n/a				n/a				n/a		
Residential New Construction		n/a				n/a				n/a				n/a		
Business Program																
Retrofit		1.00				0.79				1.22				0.80		
Direct Install Lighting		0.68				0.94				0.85				0.94		
Building Commissioning		n/a				n/a				n/a				n/a		
New Construction		n/a				n/a				n/a				n/a		
Energy Audit		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (IHD)		n/a				n/a				n/a				n/a		
Demand Response 3*		n/a				n/a				n/a				n/a		
Industrial Program																
Process & System Upgrades		n/a				n/a				n/a				n/a		
Monitoring & Targeting		n/a				n/a				n/a				n/a		
Energy Manager		n/a				n/a				n/a				n/a		
Retrofit																
Demand Response 3*		n/a				n/a				n/a				n/a		
Home Assistance Program																
Home Assistance Program		0.40				1.00				0.44				1.00		
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program		n/a				n/a				n/a				n/a		
High Performance New Construction		1.00				0.50				1.00				0.50		
Toronto Comprehensive		n/a				n/a				n/a				n/a		
Multifamily Energy Efficiency Rebates		n/a				n/a				n/a				n/a		
LDC Custom Programs		n/a				n/a				n/a				n/a		
Other																
Program Enabled Savings		n/a				n/a				n/a				n/a		
Time-of-Use Savings		n/a				n/a				n/a				n/a		

Progress Towards CDM Targets

Results are attributed to target using current OPA reporting policies. Energy efficiency resources persist for the duration of the effective useful life. Any upcoming code changes are taken into account. Demand response resources persist for 1 year. Please see methodology tab for more detailed information.

Table 4: Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	2.5	0.5	0.5	0.5
2012 - Verified		2.4	0.4	0.4
2013				
2014				
Verified Net Annual Peak Demand Savings Persisting in 2014:				**0.9**
Essex Powerlines Corporation 2014 Annual CDM Capacity Target				**7.2**
Verified Portion of Peak Demand Savings Target Achieved in 2014(%):				**12.8%**

Table 5: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	2.2	2.1	2.1	2.0	8.3
2012 - Verified		2.2	2.1	2.1	6.4
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					**14.6**
Essex Powerlines Corporation 2011-2014 Annual CDM Energy Target					**21.5**
Verified Portion of Cumulative Energy Target Achieved (%):					**67.9%**

*2011 energy adjustments included in cumulative energy savings.

Table 6: Province-Wide Initiatives and Program Level Savings by Year

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	56,110	34,146			3,299	2,011			23,005,812	13,424,518			5,171	132,176,857
Appliance Exchange	Appliances	3,688	3,836			371	556			450,187	974,621			689	4,512,525
HVAC Incentives	Equipment	111,587	85,221			32,037	19,060			59,437,670	32,841,283			51,097	336,274,530
Conservation Instant Coupon Booklet	Items	559,462	30,891			1,344	230			21,211,537	1,398,202			1,575	89,040,754
Bi-Annual Retailer Event	Items	870,332	1,060,901			1,681	1,480			29,387,468	26,781,674			3,161	197,894,897
Retailer Co-op	Items	152	0			0	0			2,652	0			0	10,607
Residential Demand Response (switch/pstat)*	Devices	19,550	98,388			10,947	49,038			24,870	359,408			0	384,279
Residential Demand Response (IHD)	Devices	0	49,689			0				0					
Residential New Construction	Homes	7	19			0	2			743	17,152			2	54,430
Consumer Program Total						**49,681**	**72,377**			**133,520,941**	**75,796,859**			**61,696**	**760,348,879**
Business Program															
Retrofit	Projects	2,516	5,605			24,467	61,147			136,002,258	314,922,468			84,018	1,480,647,459
Direct Install Lighting	Projects	20,297	18,494			23,724	15,284			61,076,701	57,345,798			31,181	391,072,869
Building Commissioning	Buildings	0	0			0	0			0	0			0	0
New Construction	Buildings	10	69			123	764			411,717	1,814,721			888	7,091,031
Energy Audit	Audits	103	280			0	1,450			0	7,049,351			1,450	21,148,054
Small Commercial Demand Response	Devices	132	294			84	187			157	1,068			0	1,224
Small Commercial Demand Response (IHD)	Devices	0	0			0				0				0	0
Demand Response 3*	Facilities	145	151			16,218	19,389			633,421	281,823			0	915,244
Business Program Total						**64,617**	**98,221**			**198,124,253**	**381,415,230**			**117,535**	**1,900,875,881**
Industrial Program															
Process & System Upgrades	Projects	0	0			0	0			0	0			0	0
Monitoring & Targeting	Projects	0	0			0	0			0	0			0	0
Energy Manager	Projects	0	39			0	1,086			0	7,372,108			1,086	22,116,324
Retrofit	Projects	433				4,615				28,866,840				4,613	115,462,282
Demand Response 3*	Facilities	124	185			52,484	74,056			3,080,737	1,784,712			0	4,865,449
Industrial Program Total						**57,098**	**75,141**			**31,947,577**	**9,156,820**			**5,699**	**142,444,054**
Home Assistance Program															
Home Assistance Program	Homes	46	5,033			2	566			39,283	5,442,232			569	16,483,831
Home Assistance Program Total						**2**	**566**			**39,283**	**5,442,232**			**569**	**16,483,831**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	2,016	0			21,662	0			121,138,219	0			21,662	484,552,876
High Performance New Construction	Projects	145	69			5,098	3,251			26,185,591	11,901,944			8,349	140,448,197
Toronto Comprehensive	Projects	577	0			15,805	0			86,964,886	0			15,805	347,859,545
Multifamily Energy Efficiency Rebates	Projects	110	0			1,981	0			7,595,683	0			1,981	30,382,733
LDC Custom Programs	Projects	8	0			399	0			1,367,170	0			399	5,468,679
Pre-2011 Programs completed in 2011 Total						**44,945**	**3,251**			**243,251,550**	**11,901,944**			**48,195**	**1,008,712,030**
Other															
Program Enabled Savings	Projects	0	16			0	2,304			0	1,188,362			2,304	3,565,086
Time-of-Use Savings	Homes														
Other Total							**2,304**				**1,188,362**			**2,304**	**3,565,086**
Adjustments to Previous Year's Verified Results							**1,406**				**18,689,081**			**1,156**	**73,918,598**
Energy Efficiency Total						**136,610**	**109,191**			**603,144,419**	**482,474,435**			**235,998**	**3,826,263,564**
Demand Response Total (Scenario 1)						**79,733**	**142,670**			**3,739,185**	**2,427,011**			**0**	**6,166,196**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**216,343**	**253,267**			**606,883,604**	**503,590,526**			**237,154**	**3,906,348,358**
													Full OEB Target:	**1,330,000**	**6,000,000,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**17.8%**	**65.1%**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Due to the limited timeframe of data, which didn't include the summer months, 2012 IHD results have been deemed inconclusive. The IHD line item on the 2012 annual report will be left blank. Once a full year of data is available (2013 evaluation), and the savings are quantified, 2012 results will be updated to reflect the quantified savings.

Table 7: Adjustments to **Province-Wide** Verified Results due to Errors & Omissions (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	0				0				0				0	0
Appliance Exchange	Appliances	0				0				0				0	0
HVAC Incentives	Equipment	-18,866				-5,278				-9,721,817				-5,278	-38,887,267
Conservation Instant Coupon Booklet	Items	8,216				16				275,655				16	1,102,621
Bi-Annual Retailer Event	Items	81,817				108				2,183,391				108	8,733,563
Retailer Co-op	Items	0				0				0				0	0
Residential Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Residential Demand Response (IHD)	Devices	0				0				0				0	0
Residential New Construction	Homes	19				1				13,767				1	55,069
Consumer Program Total						**-5,153**				**-7,249,004**				**-5,153**	**-28,996,015**
Business Program															
Retrofit	Projects	303				3,204				16,216,165				3,083	64,398,674
Direct Install Lighting	Projects	444				501				1,250,388				372	4,624,945
Building Commissioning	Buildings	0				0				0				0	0
New Construction	Buildings	12				828				3,520,620				828	14,082,482
Energy Audit	Audits	93				481				2,341,392				481	9,365,567
Small Commercial Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Small Commercial Demand Response (IHD)	Devices	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Business Program Total						**5,014**				**23,328,565**				**4,764**	**92,471,668**
Industrial Program															
Process & System Upgrades	Projects	0				0				0				0	0
Monitoring & Targeting	Projects	0				0				0				0	0
Energy Manager	Projects	0				0				0				0	0
Retrofit	Projects	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Industrial Program Total						**0**				**0**				**0**	**0**
Home Assistance Program															
Home Assistance Program	Homes	0				0				0				0	0
Home Assistance Program Total						**0**				**0**				**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	12				138				545,536				138	2,182,145
High Performance New Construction	Projects	34				1,407				2,065,200				1,407	8,260,800
Toronto Comprehensive	Projects	0				0				0				0	0
Multifamily Energy Efficiency Rebates	Projects	0				0				0				0	0
LDC Custom Programs	Projects	0				0				0				0	0
Pre-2011 Programs completed in 2011 Total						**1,545**				**2,610,736**				**1,545**	**10,442,945**
Other															
Program Enabled Savings	Projects	0				0				0				0	0
Time-of-Use Savings	Homes														
Other Total						**0**				**0**				**0**	**0**
Adjustments to Previous Year's Verified Results						**1,406**				**18,690,297**				**1,156**	**73,918,598**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Table 8: Province-Wide Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement		1.00				0.46				1.00				0.47		
Appliance Exchange		1.00				0.52				1.00				0.52		
HVAC Incentives		1.00				0.50				1.00				0.49		
Conservation Instant Coupon Booklet		1.00				1.00				1.00				1.05		
Bi-Annual Retailer Event		1.00				0.91				1.00				0.92		
Retailer Co-op		n/a				n/a				n/a				n/a		
Residential Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Residential Demand Response (IHD)		n/a				n/a				n/a				n/a		
Residential New Construction		3.65				0.49				7.17				0.49		
Business Program																
Retrofit		0.93				0.75				1.05				0.76		
Direct Install Lighting		0.69				0.94				0.85				0.94		
Building Commissioning		n/a				n/a				n/a				n/a		
New Construction		0.98				0.49				0.99				0.49		
Energy Audit		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (IHD)		n/a				n/a				n/a				n/a		
Demand Response 3*		n/a				n/a				n/a				n/a		
Industrial Program																
Process & System Upgrades		n/a				n/a				n/a				n/a		
Monitoring & Targeting		n/a				n/a				n/a				n/a		
Energy Manager		1.16				0.90				1.16				0.90		
Retrofit																
Demand Response 3*		n/a				n/a				n/a				n/a		
Home Assistance Program																
Home Assistance Program		0.32				1.00				0.99				1.00		
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program		n/a				n/a				n/a				n/a		
High Performance New Construction		1.00				0.50				1.00				0.50		
Toronto Comprehensive		n/a				n/a				n/a				n/a		
Multifamily Energy Efficiency Rebates		n/a				n/a				n/a				n/a		
LDC Custom Programs		n/a				n/a				n/a				n/a		
Other																
Program Enabled Savings		1.06				1.00				2.26				1.00		
Time-of-Use Savings		n/a				n/a				n/a				n/a		

Summary - Provincial Progress

Table 9: Province-Wide Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011	216.3	136.6	135.8	129.0
2012		253.3	109.8	108.2
2013				
2014				
Verified Net Annual Peak Demand Savings in 2014:				**237.2**
2014 Annual CDM Capacity Target				**1,330**
Verified Peak Demand Savings Target Achieved - 2011 (%):				**17.8%**

Table 10: Province-Wide Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011	606.9	603.0	601.0	582.3	2,393
2012		503.6	498.4	492.6	1,513
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					**3,906**
2011-2014 Cumulative CDM Energy Target:					**6,000**
Verified Portion of Energy Target Achieved - 2011 (%):					**65.1%**

*2011 energy adjustments included in cumulative energy savings.

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS	
Prescriptive Measures and Projects	**Gross Savings =** Activity * Per Unit Assumption **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
Engineered and Custom Projects	**Gross Savings =** Reported Savings * Realization Rate **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
Demand Response	**Peak Demand: Gross Savings = Net Savings =** contracted MW at contributor level * Provincial contracted to ex ante ratio **Energy: Gross Savings = Net Savings =** provincial ex post energy savings * LDC proportion of total provincial contracted MW All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)
Adjustments to Previous Year's Verified Results	All errors and omissions from the prior years Final Annual Results report will be adjusted within this report. Any errors and ommissions with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the cumulative effect of energy savings.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program			
Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection	Savings are considered to begin in the year the appliance is picked up.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year that the exchange event occurred	
HVAC Incentives	Results directly attributed to LDC based on customer postal code	Savings are considered to begin in the year that the installation occurred	

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the coupon was redeemed.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the event occurs.	
Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any “snapback” in energy consumption experienced after the event. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program			
Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
	Additional Note: project counts were derived by filtering out "Application Status" = "Post-Project Submission - Payment denied by LDC" and only including projects with an "Actual Project Completion Date" in 2012 and pulling both the "Application Name" field followed by the "Building Address 1" field from the Post Stage Retrofit Report and finally performing a count of the Building Addresses.		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011 or 2012.	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the actual project completion date.	
Energy Audit	Projects are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year of the audit date.	**Peak demand and energy savings** are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program			
Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated, no completed projects in 2011 or 2012.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011 or 2012.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
Energy Manager	Results are directly attributed to LDC based on LDC identified in the application; No completed projects in 2011 or 2012.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Home Assistance Program			

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	**Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Pre-2011 Programs completed in 2011			
Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation		
EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation		

ERII Sector (C&I vs. Industrial Mapping)	
Building Type	**Sector**
Agribusiness - Cattle Farm	C&I
Agribusiness - Dairy Farm	C&I
Agribusiness - Greenhouse	C&I
Agribusiness - Other	C&I
Agribusiness - Other,Mixed-Use - Office/Retail	C&I
Agribusiness - Other,Office,Retail,Warehouse	C&I
Agribusiness - Other,Office,Warehouse	C&I
Agribusiness - Poultry	C&I
Agribusiness - Poultry,Hospitality - Motel	C&I
Agribusiness - Swine	C&I
Convenience Store	C&I
Education - College / Trade School	C&I
Education - College / Trade School,Multi-Residential - Condominium	C&I
Education - College / Trade School,Multi-Residential - Rental Apartment	C&I
Education - College / Trade School,Retail	C&I
Education - Primary School	C&I
Education - Primary School,Education - Secondary School	C&I
Education - Primary School,Multi-Residential - Rental Apartment	C&I
Education - Primary School,Not-for-Profit	C&I
Education - Secondary School	C&I
Education - University	C&I
Education - University,Office	C&I
Hospital/Healthcare - Clinic	C&I
Hospital/Healthcare - Clinic,Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Clinic,Industrial	C&I
Hospital/Healthcare - Clinic,Retail	C&I
Hospital/Healthcare - Long-term Care	C&I
Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail,Office	C&I
Hospitality - Hotel	C&I
Hospitality - Hotel,Restaurant - Dining	C&I
Hospitality - Motel	C&I
Industrial	Industrial
Mixed-Use - Office/Retail	C&I
Mixed-Use - Office/Retail,Industrial	Industrial
Mixed-Use - Office/Retail,Mixed-Use - Other	C&I
Mixed-Use - Office/Retail,Mixed-Use - Other,Not-for-Profit,Warehouse	C&I
Mixed-Use - Office/Retail,Mixed-Use - Residential/Retail	C&I
Mixed-Use - Office/Retail,Office,Restaurant - Dining,Restaurant - Quick Serve,Retail,Warehouse	C&I

Mixed-Use - Office/Retail,Office,Warehouse	C&I
Mixed-Use - Office/Retail,Retail	C&I
Mixed-Use - Office/Retail,Warehouse	C&I
Mixed-Use - Office/Retail,Warehouse,Industrial	Industrial
Mixed-Use - Other	C&I
Mixed-Use - Other,Industrial	Industrial
Mixed-Use - Other,Not-for-Profit,Office	C&I
Mixed-Use - Other,Office	C&I
Mixed-Use - Other,Other: Please specify	C&I
Mixed-Use - Other,Retail,Warehouse	C&I
Mixed-Use - Other,Warehouse	C&I
Mixed-Use - Residential/Retail	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Condominium	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Rental Apartment	C&I
Mixed-Use - Residential/Retail,Retail	C&I
Multi-Residential - Condominium	C&I
Multi-Residential - Condominium,Multi-Residential - Rental Apartment	C&I
Multi-Residential - Condominium,Other: Please specify	C&I
Multi-Residential - Rental Apartment	C&I
Multi-Residential - Rental Apartment,Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Warehouse	C&I
Multi-Residential - Social Housing Provider	C&I
Multi-Residential - Social Housing Provider,Industrial	C&I
Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Not-for-Profit	C&I
Not-for-Profit,Office	C&I
Not-for-Profit,Other: Please specify	C&I
Not-for-Profit,Warehouse	C&I
Office	C&I
Office,Industrial	Industrial
Office,Other: Please specify	C&I
Office,Other: Please specify,Warehouse	C&I
Office,Restaurant - Dining	C&I
Office,Restaurant - Dining,Industrial	Industrial
Office,Retail	C&I
Office,Retail,Industrial	C&I
Office,Retail,Warehouse	C&I
Office,Warehouse	C&I
Office,Warehouse,Industrial	Industrial
Other: Please specify	C&I
Other: Please specify,Industrial	Industrial
Other: Please specify,Retail	C&I
Other: Please specify,Warehouse	C&I
Restaurant - Dining	C&I
Restaurant - Dining,Retail	C&I

Restaurant - Quick Serve	C&I
Restaurant - Quick Serve,Retail	C&I
Retail	C&I
Retail,Industrial	Industrial
Retail,Warehouse	C&I
Warehouse	C&I
Warehouse,Industrial	Industrial

Consumer Program Allocation Methodology

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Local Distribution Company	Allocation
Algoma Power Inc.	0.2%
Atikokan Hydro Inc.	0.0%
Attawapiskat Power Corporation	0.0%
Bluewater Power Distribution Corporation	0.6%
Brant County Power Inc.	0.2%
Brantford Power Inc.	0.7%
Burlington Hydro Inc.	1.4%
Cambridge and North Dumfries Hydro Inc.	1.0%
Canadian Niagara Power Inc.	0.5%
Centre Wellington Hydro Ltd.	0.1%
Chapleau Public Utilities Corporation	0.0%
COLLUS Power Corporation	0.3%
Cooperative Hydro Embrun Inc.	0.0%
E.L.K. Energy Inc.	0.2%
Enersource Hydro Mississauga Inc.	3.9%
ENTEGRUS	0.6%
ENWIN Utilities Ltd.	1.6%
Erie Thames Powerlines Corporation	0.4%
Espanola Regional Hydro Distribution Corporation	0.1%
Essex Powerlines Corporation	0.7%
Festival Hydro Inc.	0.3%
Fort Albany Power Corporation	0.0%
Fort Frances Power Corporation	0.1%
Greater Sudbury Hydro Inc.	1.0%
Grimsby Power Inc.	0.2%
Guelph Hydro Electric Systems Inc.	0.9%
Haldimand County Hydro Inc.	0.4%
Halton Hills Hydro Inc.	0.5%
Hearst Power Distribution Company Limited	0.1%
Horizon Utilities Corporation	4.0%
Hydro 2000 Inc.	0.0%
Hydro Hawkesbury Inc.	0.1%
Hydro One Brampton Networks Inc.	2.8%
Hydro One Networks Inc.	30.0%

Hydro Ottawa Limited	5.6%
Innisfil Hydro Distribution Systems Limited	0.4%
Kashechewan Power Corporation	0.0%
Kenora Hydro Electric Corporation Ltd.	0.1%
Kingston Hydro Corporation	0.5%
Kitchener-Wilmot Hydro Inc.	1.6%
Lakefront Utilities Inc.	0.2%
Lakeland Power Distribution Ltd.	0.2%
London Hydro Inc.	2.7%
Middlesex Power Distribution Corporation	0.1%
Midland Power Utility Corporation	0.1%
Milton Hydro Distribution Inc.	0.6%
Newmarket - Tay Power Distribution Ltd.	0.7%
Niagara Peninsula Energy Inc.	1.0%
Niagara-on-the-Lake Hydro Inc.	0.2%
Norfolk Power Distribution Inc.	0.3%
North Bay Hydro Distribution Limited	0.5%
Northern Ontario Wires Inc.	0.1%
Oakville Hydro Electricity Distribution Inc.	1.5%
Orangeville Hydro Limited	0.2%
Orillia Power Distribution Corporation	0.3%
Oshawa PUC Networks Inc.	1.2%
Ottawa River Power Corporation	0.2%
Parry Sound Power Corporation	0.1%
Peterborough Distribution Incorporated	0.7%
PowerStream Inc.	6.6%
PUC Distribution Inc.	0.9%
Renfrew Hydro Inc.	0.1%
Rideau St. Lawrence Distribution Inc.	0.1%
Sioux Lookout Hydro Inc.	0.1%
St. Thomas Energy Inc.	0.3%
Thunder Bay Hydro Electricity Distribution Inc.	0.9%
Tillsonburg Hydro Inc.	0.1%
Toronto Hydro-Electric System Limited	12.8%
Veridian Connections Inc.	2.4%
Wasaga Distribution Inc.	0.2%
Waterloo North Hydro Inc.	1.0%
Welland Hydro-Electric System Corp.	0.4%
Wellington North Power Inc.	0.1%
West Coast Huron Energy Inc.	0.1%
Westario Power Inc.	0.5%
Whitby Hydro Electric Corporation	0.9%
Woodstock Hydro Services Inc.	0.3%

Reporting Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity in a given year and resource savings persisting from previous years).

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).

Free-ridership: the percentage of participants who would have implemented the program measure or practice in the absence of the program.

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start' (please see table 5).

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net-to-Gross Ratio: The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

Program: a group of initiatives that target a particular market sector (i.e. Consumer, Industrial).

Realization Rate: A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.

Settlement Account: the grouping of demand response facilities (contributors) into one contractual agreement

Spillover: Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

Appendix 2 of 3

Appendix 2 - 2011 Schedule of Rates and Charges

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0082

RESIDENTIAL SERVICE CLASSIFICATION

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

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	12.57
Smart Meter Funding Adder – effective until April 30, 2012	$	1.96
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.17
Distribution Volumetric Rate	$/kWh	0.0148
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	(0.0003)
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	(0.0008)
Rate Rider for Tax Change – effective until April 30, 2012	$/kWh	(0.0001)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0065
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0049

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0082

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	25.89
Smart Meter Funding Adder – effective until April 30, 2012	$	1.96
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.19
Distribution Volumetric Rate	$/kWh	0.0088
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	(0.0003)
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	(0.0006)
Rate Rider for Tax Change – effective until April 30, 2012	$/kWh	(0.0001)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0047

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0082

GENERAL SERVICE 50 to 2,999 kW SERVICE CLASSIFICATION

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 3,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	262.15
Smart Meter Funding Adder – effective until April 30, 2012	$	1.96
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	5.69
Distribution Volumetric Rate	$/kW	2.4899
Low Voltage Service Rate	$/kW	0.3506
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	(0.1219)
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.2431)
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(0.0188)
Retail Transmission Rate – Network Service Rate	$/kW	2.3273
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.8648
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.8670
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.0667

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0082

GENERAL SERVICE 3,000 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 3,000 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	1,734.31
Smart Meter Funding Adder – effective until April 30, 2012	$	1.96
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	37.85
Distribution Volumetric Rate	$/kW	1.6082
Low Voltage Service Rate	$/kW	0.4094
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	(0.6753)
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(1.0514)
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(0.0178)
Retail Transmission Rate – Network Service Rate	$/kW	2.8670
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0667

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0082

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/ documentation with regard to electrical consumption of the proposed unmetered load. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	8.93
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.28
Distribution Volumetric Rate	$/kWh	0.0279
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	(0.0003)
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	(0.0007)
Rate Rider for Tax Change – effective until April 30, 2012	$/kWh	(0.0002)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0047

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0082

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	2.43
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.03
Distribution Volumetric Rate	$/kW	6.9763
Low Voltage Service Rate	$/kW	0.2816
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	(0.1061)
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.2610)
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(0.0545)
Retail Transmission Rate – Network Service Rate	$/kW	1.7918
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4215

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0082

STREET LIGHTING SERVICE CLASSIFICATION

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

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	2.20
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.02
Distribution Volumetric Rate	$/kW	5.9608
Low Voltage Service Rate	$/kW	0.2798
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	(0.0940)
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.1344)
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(0.0465)
Retail Transmission Rate – Network Service Rate	$/kW	1.7668
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4125

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0082

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

ALLOWANCES

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

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0082

SPECIFIC SERVICE CHARGES

APPLICATION

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

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

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

Customer Administration		
Arrears Certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income tax Letter	$	15.00
Account history	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge - no disconnection – after regular hours	$	165.00
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charge - At meter - After Regular Hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service install & remove – underground – no transformer	$	300.00
Temporary service install & remove – overhead – with transformer	$	1000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0082

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

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

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

LOSS FACTORS

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

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0602
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0496
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Appendix 3 of 3

Appendix 3 - 2012 Schedule of Rates and Charges

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0166

RESIDENTIAL SERVICE CLASSIFICATION

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

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	12.68
Distribution Volumetric Rate	$/kWh	0.0149
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	(0.0008)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	0.0023
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	(0.0003)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	(0.0126)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kWh	0.0009
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kWh	(0.0002)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0069
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0046

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Original Issuance Date: April 30, 2012
Corrected Issuance Date: May 3, 2012

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0166

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	33.19
Distribution Volumetric Rate	$/kWh	0.0113
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	(0.0006)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	0.0025
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	(0.0003)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kWh	(0.0126)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kWh	0.0002
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kWh	(0.0001)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0061
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0044

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Original Issuance Date: April 30, 2012
Corrected Issuance Date: May 3, 2012

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0166

GENERAL SERVICE 50 to 2,999 kW SERVICE CLASSIFICATION

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 3,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	214.62
Distribution Volumetric Rate	$/kW	2.0385
Low Voltage Service Rate	$/kW	0.3506
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.2431)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	1.0218
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	(0.1219)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kW	(5.3132)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kW	0.0349
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kW	(0.0283)
Retail Transmission Rate – Network Service Rate	$/kW	2.4752
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7517
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	3.0491
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.9423

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0166

GENERAL SERVICE 3,000 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 3,000 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	1,408.58
Distribution Volumetric Rate	$/kW	1.3062
Low Voltage Service Rate	$/kW	0.4094
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(1.0514)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	4.7135
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	(0.6753)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kW	(23.9176)
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kW	(0.0266)
Retail Transmission Rate – Network Service Rate	$/kW	3.0491
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9423

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Original Issuance Date: April 30, 2012
Corrected Issuance Date: May 3, 2012

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0166

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/ documentation with regard to electrical consumption of the proposed unmetered load. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	9.01
Distribution Volumetric Rate	$/kWh	0.0281
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	(0.0007)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	0.0021
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	(0.0003)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	(0.0126)
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kWh	(0.0003)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0061
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0044

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0166

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	2.74
Distribution Volumetric Rate	$/kW	7.868
Low Voltage Service Rate	$/kW	0.2816
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.2610)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	0.8496
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	(0.1061)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kW	(4.5914)
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kW	(0.0820)
Retail Transmission Rate – Network Service Rate	$/kW	1.9056
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3353

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0166

STREET LIGHTING SERVICE CLASSIFICATION

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

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	2.67
Distribution Volumetric Rate	$/kW	7.2326
Low Voltage Service Rate	$/kW	0.2798
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.1344)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	0.781
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	(0.0940)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kW	(4.1576)
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kW	(0.0699)
Retail Transmission Rate – Network Service Rate	$/kW	1.8790
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3268

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0166

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

ALLOWANCES

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

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0166

SPECIFIC SERVICE CHARGES

APPLICATION

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

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

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

Customer Administration		
Arrears Certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income tax Letter	$	15.00
Account history	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge - no disconnection – after regular hours	$	165.00
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charge - At meter - After Regular Hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service install & remove – underground – no transformer	$	300.00
Temporary service install & remove – overhead – with transformer	$	1000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

Original Issuance Date: April 30, 2012
Corrected Issuance Date: May 3, 2012

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0166

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

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

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

LOSS FACTORS

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

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0602
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0496

Attachment 4-Q

Lost Revenue Adjustment Mechanism
Work Form

Ontario Energy Board

Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) Work Form

Version 2.0 (2017)

Generic LRAMVA Work Forms

Worksheet Name	Description
1. LRAMVA Summary	**Tables 1-a and 1-b** provide a summary of the LRAMVA balances and carrying charges associated with the LRAMVA disposition. The balances are populated from entries into other tabs throughout this work form.
1-a. Summary of Changes	**Tables A-1 and A-2** include a template for LDCs to summarize changes to the LRAMVA work form.
2. LRAMVA Threshold	**Tables 2-a, 2-b and 2-c** include the LRAMVA thresholds and allocations by rate class.
3. Distribution Rates	**Tables 3-a and 3-b** include the distribution rates that are used to calculate lost revenues.
3-a. Rate Class Allocations	A blank spreadsheet is provided to allow LDCs to populate distributor specific rate class percentages to allocate actual CDM savings to different customer classes.
4. 2011-2014 LRAM	**Tables 4-a, 4-b, 4-c and 4-d** include the template 2011-2014 LRAMVA work forms.
5. 2015-2020 LRAM	**Tables 5-a, 5-b, 5-c and 5-d** include the template 2015-2020 LRAMVA work forms.
6. Carrying Charges	**Table 6-b** includes the variance on carrying charges related to the LRAMVA disposition.
7. Persistence Report	A blank spreadsheet is provided to allow LDCs to populate with CDM savings persistence data provided by the IESO.
8. Streetlighting	A blank spreadsheet is provided to allow LDCs to populate data on streetlighting projects whose savings were not provided by the IESO in the CDM Final Results Report (i.e., streetlighting projects).

Ontario Energy Board

LRAMVA Work Form:
Instructions

Version 2.0 (2017)

Tab	Instructions
LRAMVA Checklist/Schematic Tab	The LRAMVA work form was created in a generic manner for use by all LDCs. There are some elements that are not applicable at this time (i.e., 2017, 2018, 2019 and 2020 related components) but have been included in an effort to avoid major updates in the future. Distributors should follow the checklist, which is referenced in this tab of the work form and listed below: o Highlight changes to this work form made by the LDC, if any, and provide rationale for the change in Tab 1-a. o Include any necessary assumptions the LDC has to make in its LRAMVA work form in the "Notes" section of the work form. o Provide documentation on the LRAMVA threshold by providing the reference and source material from the LDC's cost of service proceeding where its most recent load forecast was approved. o Include a copy of initiative-level persistence savings information that was verified by the IESO. Persistence information is available upon request from the IESO. o Apply the IESO verified savings adjustments to the year it relates to. For example, savings adjustments to 2015 programs will be provided to LDCs with the 2016 Final Results Report. The 2015 savings adjustments should be included in the 2015 verified savings portion of the work form. o Provide documentation or data substantiating savings from projects that were not provided in the IESO's verified results reports, inserted in Tab 8 (i.e., streetlighting projects), as applicable. o Provide documentation or analysis on how rate class allocations were determined by customer class and program each year, inserted in Tab 3-a.
Tab 1. LRAMVA Summary	Distributors are required to report any past approved LRAMVA amounts along with the current LRAMVA amount requested for approval. There are separate tables indicating new lost revenues and carrying charges amounts by year and the totals for rate rider calculations.
Tab 1-a. Summary of Changes	Distributors should list all significant changes and changes in assumptions in the generic work form affecting the LRAMVA.
Tab 2. LRAMVA Threshold	Distributors should use the tables to display the LRAMVA threshold amounts as approved at a rate class level. This should be taken from the LDC's most recently approved cost of service application.
Tab 3. Distribution Rates	Distributors should complete the tables with rate class specific distribution rates and adjustments as applicable.
Tab 3-a. Rate Class Allocations	A tab is provided to allow LDCs to include documentation or analysis on how rate class allocations for actual CDM savings were determined by customer class and program each year. The rate class allocations would support the LRAMVA rate class allocation figures used in Tabs 4 and 5.
Tabs 4 and 5 (2011-2020)	Distributors should complete the lost revenue calculation for 2011-2014 program years and 2015-2020 program years, as applicable, by undertaking the following: o Input or manually link the savings, adjustments and program savings persistence data from Tab 7 (Persistence Report) to Tabs 4 and 5. As noted earlier, persistence data is available upon request from the IESO. o Ensure that the IESO verified savings adjustments apply to the program year it relates to. For example, savings adjustments related to 2012 programs that were reported by the IESO in 2013 should be included in the 2012 program savings table. o Confirm the monthly multipliers applied to demand savings. If a different monthly multiplier is used than what was confirmed in the LRAMVA Report, provide rationale in Tab 1-a and highlight the new monthly multiplier that has been used. o Input the rate class allocations by program and year to allocate actual savings to customers. If a different allocation is proposed for adjustments, LDCs must provide the supporting rationale in Tab 1-a and highlight the change. o Provide assumptions about the year(s) in which persistence is captured in the load forecast via the "Notes" section of each table and adjust what is included in the LRAMVA totals, as appropriate.
Tab 6. Carrying Charges	Distributors are requested to calculate carrying charges based on the methodology provided in the work form. This includes updating Table 6 as new prescribed interest rates for deferral and variance accounts become available and entering any collected interest amounts into the "Amounts Cleared" row to calculate outstanding variances on carrying charges.
Tab 7. Persistence Report	Persistence savings report(s) provided by the IESO should be included for the relevant years in the LRAMVA work form. Tab 7 has been created consistently with the IESO's persistence report.
Tab 8. Streetlighting	A tab is provided to ensure LDCs include documentation or data to support projects whose program savings were not provided by the IESO (i.e., streetlighting projects).

Ontario Energy Board

LRAMVA Work Form: Checklist and Schematic

Version 2.0 (2017)

General Note on the LRAMVA Model

The LRAMVA work form has been created in a generic manner that should allow for use by all LDCs. There are some elements that are not applicable at this time (i.e., 2017, 2018, 2019 and 2020 related components). These have been included (but hidden in the work form) in an effort to avoid major updates in the future. This LRAMVA work form consolidates information that LDCs are already required to file with the OEB. The model has been created to provide LDCs with a consistent format to display CDM impacts, the forecast savings component and, ultimately, any variance between actual CDM savings and forecast CDM savings. The majority of the information required in the LRAMVA work form will be provided to LDCs from the IESO as part of the Final CDM Results each year. Please contact the IESO for any reports that may be required to complete this LRAMVA work form.

The LRAMVA work form is unlocked to enable LDCs to tailor it to their own unique circumstances.

LRAMVA ($) = (Actual Net CDM Savings - Forecast CDM Savings) x Distribution Volumetric Rate + Carrying Charges from LRAMVA balance

Legend Drop Down List (Blue)

Important Checklist

o Highlight changes to this work form made by the LDC, if any, and provide rationale for the change in Tab 1-a

o Include any necessary assumptions the LDC has to make in its LRAMVA work form in the "Notes" section of the work form

o Provide documentation on the LRAMVA threshold by providing the reference and source material from the LDC's cost of service proceeding where its most recent load forecast was approved

o Include a copy of initiative-level persistence savings information that was verified by the IESO in Tab 7. Persistence information is available upon request from the IESO

o Apply the IESO verified savings adjustments to the year it relates to.

o Provide documentation or data substantiating savings from projects that were not provided in the IESO's verified results reports, inserted in Tab 8 (i.e., streetlighting projects), as applicable

o Provide documentation or analysis on how rate class allocations were determined by customer class and program each year, inserted in Tab 3-a

Work Form Calculations	Source of Calculation	Inputs (Tables to Complete)	Source of Data Inputs	Outputs of Data (Auto-Populated)
Actual Incremental CDM Savings by Initiative	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns D & O)	IESO Verified Persistence Results Reports included in Tab 7 (Columns L to BT).	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AL)
+/- IESO Verified Savings Adjustments	Tab "4. 2011-2014 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns D-M & Columns O-X)	IESO Verified Persistence Results Reports included in Tab 7 (Columns L to BT).	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AL)
+ Initiative Level Savings Persistence	Tab "4. 2011-2014 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns E-M & Columns P-X)	IESO Verified Persistence Results Reports included in Tab 7 (Columns L to BT).	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AL)
x Allocation % to Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AJ)	Determined by the LDC	
Actual Lost Revenues (kWh and kW) by Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"			
- Forecast Lost Revenues (kWh and kW) by Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"	Tab "2. LRAMVA Threshold" Tables 2-a, 2-b and 2-c		
x Distribution Rate by Rate Class	Tab "3. Distribution Rates"	Table 3	LDC's Approved Tariff Sheets	
LRAMVA ($) by Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"			Tables 1-a and 1-b
+ Carrying Charges ($) by Rate Class	Tabs "1. LRAMVA Summary" and "6. Carrying Charges"	Table 6		Table 6-a
Total LRAMVA ($) by Rate Class	Tab "1. LRAMVA Summary"			

Ontario Energy Board

LRAMVA Work Form:
Summary Tab

Version 2.0 (2017)

Legend	
	User Inputs (Green)
	Auto Populated Cells (White)
	Instructions (Grey)

LDC Name Essex Powerlines Corporation

Application Details

Please fill in the requested information: a) the amounts approved in the previous LRAMVA application, b) details on the current application, and c) documentation of changes if applicable.

A. Previous LRAMVA Application

Previous LRAMVA Application (EB#)	EB-2013-0128
Application of Previous LRAMVA Claim	20XX COS/IRM Application
Period of LRAMVA Claimed in Previous Application	2011-2012
Amount of LRAMVA Claimed in Previous Application	$ 109,213.00

B. Current LRAMVA Application

Current LRAMVA Application (EB#)		EB-2017-0039
Application of Current LRAMVA Claim		2018 COS Application
Period of New LRAMVA in this Application		2013-2015
Actual Lost Revenues ($)	A	$ 504,108
Forecast Lost Revenues ($)	B	$ -
Carrying Charges ($)	C	$ 9,392
LRAMVA ($) for Account 1568	A-B+C	$ 513,500

C. Documentation of Changes

Original Amount	
Amount for Final Disposition	

Table 1-a. LRAMVA Totals by Rate Class

Please input the customer rate classes applicable to the LDC and associated billing units (kWh or kW) in Table 1-a below. This will update all tables throughout the workform.

The LRAMVA total by rate class in Table 1-a should be used to inform the determination of rate riders in the Deferral and Variance Account Work Form or IRM Rate Generator Model. Please also ensure that the principal amounts in column E of Table 1-a capture the appropriate years and amounts for the LRAMVA claim.

NOTE: If the LDC has more than 14 customer classes in which CDM savings was allocated, LDCs must contact OEB staff to make adjustments to the workform.

Customer Class	Billing Unit	Principal ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	kWh	$254,685	$4,610	$259,295
General Service <50 kW	kWh	$164,634	$3,166	$167,801
General Service 50 - 2,999 kW	kW	$75,989	$1,571	$77,559
General Service 3,000 - 4,999 kW	kW	$0	$0	$0
Sentinel Lighting	kW	$0	$0	$0
Street Lighting	kW	$8,801	$44	$8,845
Unmetered Scattered Load	kWh	$0	$0	$0
		$0	$0	$0
		$0	$0	$0
		$0	$0	$0
		$0	$0	$0
		$0	$0	$0
		$0	$0	$0
		$0	$0	$0
Total		**$504,108**	**$9,392**	**$513,500**

Table 1-b. Annual LRAMVA Breakdown by Year and Rate Class

In column C of Table 1-b below, please insert a 'check mark' to indicate the years in which LRAMVA has been claimed. If you inserted a check-mark for a particular year, please delete the amounts associated with the actual and forecast lost revenues for all rate classes for that year, up to and including the total. Any LRAMVA from a prior year that has already been claimed cannot be included in the current LRAMVA disposition, with the exception of the case noted below.

If LDCs are seeking to claim true-up amounts that were previously approved by the OEB, please note that the "Amount Cleared" rows are applicable to the LDC and should be filled out. This may relate to claiming the difference in LRAM approved before the May 19, 2016 Peak Demand Consultation, and the lost revenues that would have been incurred after that consultation, as approved by the OEB. If this is the case, reference to the decision must be noted in the rate application. If this is not the case, LDCs are requested to leave those rows blank.

Depending on the period of LRAMVA to be claimed, LDCs are expected to adjust the totals for carrying charges in row 82 of Table 1-b and the years included in the LRAMVA balance in row 83, as appropriate.

Description	LRAMVA Previously Claimed	Residential	General Service <50 kW	General Service 50 - 2,999 kW	General Service 3,000 - 4,999 kW	Sentinel Lighting	Street Lighting	Unmetered Scattered Load								Total
		kWh	kWh	kW	kW	kW	kW	kWh	0	0	0	0	0	0	0	
2011 Actuals	☑															
2011 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																$0.00
2012 Actuals	☑															
2012 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																$0.00
2013 Actuals	☐	$31,829.63	$24,211.25	$13,058.28	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$69,099.16
2013 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2014 Actuals	☐	$52,439.93	$34,282.44	$17,078.31	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$103,800.68
2014 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2015 Actuals	☐	$70,727.82	$48,780.34	$22,910.74	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$142,418.91
2015 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2016 Actuals		$99,687.23	$57,360.15	$22,941.22	$0.00	$0.00	$8,800.75	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$188,789.35
2016 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
Amount Cleared																
Carrying Charges		$4,610.18	$3,166.44	$1,570.84	$0.00	$0.00	$44.37	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$9,391.83
Total LRAMVA Balance		**$259,295**	**$167,801**	**$77,559**	**$0**	**$0**	**$8,845**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$513,500**

Note: LDC to make note of assumptions included above, if any

Ontario Energy Board

LRAMVA Work Form:
Summary of Changes

Version 2.0 (2017)

Legend	
	User Inputs (Green)
	Drop Down List (Blue)
	Instructions (Grey)

Table A-1. Changes to Generic Assumptions in LRAMVA Work Form

Please document any changes in assumptions made to the generic inputs of the LRAMVA work form. This may include, but are not limited to, the use of different monthly multipliers to claim demand savings from energy efficiency programs; use of different rate allocations between current year savings and prior year savings adjustments; inclusion of additional adjustments affecting distribution rates; use of a different LRAMVA threshold; etc. All important changes should be highlighted in the work form as well.

No.	Tab	Cell Reference	Description	Rationale
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
etc.				

Table A-2. Updates to LRAMVA Disposition

Please document any changes related to interrogatories or questions during the application process that affect the LRAMVA amount.

No.	Tab	Cell Reference	Description	Rationale
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
etc.				

Ontario Energy Board

LRAMVA Work Form:
Forecast Lost Revenues

Version 2.0 (2017)

Legend

- User Inputs (Green)
- Drop Down List (Blue)
- Auto Populated Cells (White)
- Instructions (Grey)

Table 2-a. LRAMVA Threshold

Please provide the LRAMVA threshold approved in the cost of service (COS) application, which is used as the comparator against actual savings in the period of the LRAMVA claim. The LRAMVA threshold should generally be consistent with the annualized savings targets developed from Appendix 2-I. If a manual update is required to reflect a different allocation of forecast savings that was approved by the OEB, please note the changes and provide rationale for the change in Tab 1-a.

	Total	Residential	General Service <50 kW	General Service 50 - 2,999 kW	General Service 3,000 - 4,999 kW	Sentinel Lighting	Street Lighting	Unmetered Scattered Load							
		kWh	kWh	kW	kW	kW	kW	kWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0
kWh	0														
kW	0														
Summary		0	0	0	0	0	0	0	0	0	0	0	0	0	0

Basis of Threshold

Source of Threshold: 20XX Settlement Agreement, p. X

Table 2-b. LRAMVA Threshold

Please provide the LRAMVA threshold approved in the last COS application, which is used as the comparator against actual savings in the period of the LRAMVA claim. The LRAMVA threshold should generally be consistent with the annualized savings targets developed from Appendix 2-I. If a manual update is required to reflect a different allocation of forecast savings that was approved by the OEB, please note the changes and provide rationale for the change in Tab 1-a.

	Total	Residential	General Service <50 kW	General Service 50 - 2,999 kW	General Service 3,000 - 4,999 kW	Sentinel Lighting	Street Lighting	Unmetered Scattered Load							
		kWh	kWh	kW	kW	kW	kW	kWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0
kWh	0														
kW	0														
Summary		0	0	0	0	0	0	0	0	0	0	0	0	0	0

Basis of Threshold

Source of Threshold: 20XX Settlement Agreement, p. X

Table 2-c. Inputs for LRAMVA Thresholds

Please complete Table 2-c below by selecting the appropriate LRAMVA threshold year in column C. The LRAMVA threshold values in Table 2-c will auto-populate from Tables 2-a and 2-b depending on the year selected. If there was no LRAMVA threshold established for a particular year, please select the "blank" option. The LRAMVA threshold values in Table 2-c will be auto-populated in Tabs 4 and 5 of this work form.

Year	LRAMVA Threshold	Residential	General Service <50 kW	General Service 50 - 2,999 kW	General Service 3,000 - 4,999 kW	Sentinel Lighting	Street Lighting	Unmetered Scattered Load							
		kWh	kWh	kW	kW	kW	kW	kWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2011		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2012		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2013		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2014		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2015		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016		0	0	0	0	0	0	0	0	0	0	0	0	0	0

Note: LDC to make note of assumptions included above, if any

Ontario Energy Board

LRAMVA Work Form: Distribution Rates

Version 2.0 (2017)

Table 3. Inputs for Distribution Rates and Adjustments by Rate Class

Please complete Table 3 with the rate class specific distribution rates that pertain to the years of the LRAMVA disposition. Any adjustments that affect distribution rates can be incorporated in the calculation by expanding the "plus" button at the left hand bar. Table 3 will convert the distribution rates to a calendar year rate (January to December) based on the number of months entered in row 16 of each rate year starting from January to the start of the LDC's rate year. Please enter 0 in row 16, if the rate year begins on January 1. If there are additional adjustments (i.e., rows) added to Table 3, please adjust the formulas in Table 3-a accordingly.

	Billing Unit	EB-2009-0143	EB-2010-0082	EB-2011-0166	EB-2012-0123	EB-2013-0128	EB-2014-0072	EB-2015-0005	EB-2016-0069	**EB-2017-XXXX**	**EB-2018-XXXX**	**EB-2019-XXXX**	**EB-2020-XXXX**
Rate Year		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Period 1 (# months)		***4***	***4***	***4***	***4***	***4***	***4***	***4***	***4***				
Period 2 (# months)		***8***	***8***	***8***	***8***	***8***	***8***	***8***	***8***	***12***	***12***	***12***	***12***
Residential	kWh	$ 0.0148	$ 0.0148	$ 0.0149	$ 0.0150	$ 0.0152	$ 0.0152	$ 0.0116	$ 0.0078				
Adjusted rate		$ 0.0148	$ 0.0148	$ 0.0149	$ 0.0150	$ 0.0152	$ 0.0152	$ 0.0116	$ 0.0078	$ -	$ -	$ -	
Calendar year equivalent			**$ 0.0148**	**$ 0.0149**	**$ 0.0150**	**$ 0.0151**	**$ 0.0152**	**$ 0.0128**	**$ 0.0091**	**$ -**	**$ -**	**$ -**	
General Service <50 kW	kWh	$ 0.0070	$ 0.0088	$ 0.0113	$ 0.0114	$ 0.0116	$ 0.0116	$ 0.0118	$ 0.0120				
Adjusted rate		$ 0.0070	$ 0.0088	$ 0.0113	$ 0.0114	$ 0.0116	$ 0.0116	$ 0.0118	$ 0.0120	$ -	$ -	$ -	
Calendar year equivalent			**$ 0.0082**	**$ 0.0105**	**$ 0.0114**	**$ 0.0115**	**$ 0.0116**	**$ 0.0117**	**$ 0.0119**	**$ -**	**$ -**	**$ -**	
General Service 50 - 2,999 kW	kW	$ 2.8494	$ 2.4899	$ 2.0385	$ 2.0981	$ 2.1306	$ 2.1306	$ 2.1721	$ 2.2101				
Adjusted rate		$ 2.8494	$ 2.4899	$ 2.0385	$ 2.0981	$ 2.1306	$ 2.1306	$ 2.1721	$ 2.2101	$ -	$ -	$ -	
Calendar year equivalent			**$ 2.6097**	**$ 2.1890**	**$ 2.0782**	**$ 2.1198**	**$ 2.1306**	**$ 2.1583**	**$ 2.1974**	**$ -**	**$ -**	**$ -**	
General Service 3,000 - 4,999 kW	kW	$ 1.8485	$ 1.6082	$ 1.3062	$ 1.3457	$ 1.3666	$ 1.3666	$ 1.3932	$ 1.4176				
Adjusted rate		$ 1.8485	$ 1.6082	$ 1.3062	$ 1.3457	$ 1.3666	$ 1.3666	$ 1.3932	$ 1.4176	$ -	$ -	$ -	
Calendar year equivalent			**$ 1.6883**	**$ 1.4069**	**$ 1.3325**	**$ 1.3596**	**$ 1.3666**	**$ 1.3843**	**$ 1.4095**	**$ -**	**$ -**	**$ -**	
Sentinel Lighting	kW	$ 5.8683	$ 6.9763	$ 7.8680	$ 9.2956	$ 9.4397	$ 9.4397	$ 9.6238	$ 9.7922				
Adjusted rate		$ 5.8683	$ 6.9763	$ 7.8680	$ 9.2956	$ 9.4397	$ 9.4397	$ 9.6238	$ 9.7922	$ -	$ -	$ -	
Calendar year equivalent			**$ 6.6070**	**$ 7.5708**	**$ 8.8197**	**$ 9.3917**	**$ 9.4397**	**$ 9.5624**	**$ 9.7361**	**$ -**	**$ -**	**$ -**	
Street Lighting	kW	$ 4.7426	$ 5.9608	$ 7.2326	$ 8.4872	$ 8.6188	$ 8.6188	$ 8.7869	$ 8.9407				
Adjusted rate		$ 4.7426	$ 5.9608	$ 7.2326	$ 8.4872	$ 8.6188	$ 8.6188	$ 8.7869	$ 8.9407	$ -	$ -	$ -	
Calendar year equivalent			**$ 5.5547**	**$ 6.8087**	**$ 8.0690**	**$ 8.5749**	**$ 8.6188**	**$ 8.7309**	**$ 8.8894**	**$ -**	**$ -**	**$ -**	
Unmetered Scattered Load	kWh	$ 0.0278	$ 0.0279	$ 0.0281	$ 0.0282	$ 0.0286	$ 0.0286	$ 0.0292	$ 0.0297				
Adjusted rate		$ 0.0278	$ 0.0279	$ 0.0281	$ 0.0282	$ 0.0286	$ 0.0286	$ 0.0292	$ 0.0297	$ -	$ -	$ -	
Calendar year equivalent			**$ 0.0279**	**$ 0.0280**	**$ 0.0282**	**$ 0.0285**	**$ 0.0286**	**$ 0.0290**	**$ 0.0295**	**$ -**	**$ -**	**$ -**	
0	0												
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0												
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0												
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0												
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0												
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0												
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0												
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	

Note: LDC to make note of adjustments made to Table 3 to accommodate the LDC's specific circumstances

Table 3-a. Distribution Rates by Rate Class

Table 3-a below autopopulates the average distribution rates from Table 3. Please ensure that the distribution rates relevant to the years of the LRAMVA disposition are used. As such, please clear the rates related to the year(s) that are not part of the LRAMVA claim. The distribution rates that remain in Table 3-a will be used in Tabs 4 and 5 of the work form to calculate actual and forecast lost revenues. If there are additional adjustments (i.e., rows) added to Table 3, please adjust the formulas from Table 3-a, as well as the distribution rate links in Tabs 4 and 5.

Year	Residential	General Service <50 kW	General Service 50 - 2,999 kW	General Service 3,000 - 4,999 kW	Sentinel Lighting	Street Lighting	Unmetered Scattered Load							
	kWh	kWh	kW	kW	kW	kW	kWh	0	0	0	0	0	0	0
2011	$0.0148	$0.0082	$2.6097	$1.6883	$6.6070	$5.5547	$0.0279	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2012	$0.0149	$0.0105	$2.1890	$1.4069	$7.5708	$6.8087	$0.0280	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2013	$0.0150	$0.0114	$2.0782	$1.3325	$8.8197	$8.0690	$0.0282	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2014	$0.0151	$0.0115	$2.1198	$1.3596	$9.3917	$8.5749	$0.0285	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2015	$0.0152	$0.0116	$2.1306	$1.3666	$9.4397	$8.6188	$0.0286	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2016	$0.0128	$0.0117	$2.1583	$1.3843	$9.5624	$8.7309	$0.0290	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

Note: LDC to make note of the years removed from this table, whose distribution rates are not part of the LRAMVA disposition

Ontario Energy Board

LRAMVA Work Form:
Determination of Rate Class Allocations

Version 2.0 (2017)

Instructions

LDCs must clearly show how it has allocated actual CDM savings to applicable rate classes, including supporting documentation and rationale for its proposal. This should be shown by customer class and program each year.

Program	Allocation	Rationale
Appliance Retirement	100% Residential	Only residential customers are eligible for this program
Appliance Exchange	100% Residential	Only residential customers are eligible for this program
HVAC Incentives	100% Residential	Only residential customers are eligible for this program
Conservation Instant Coupor	100% Residential	Only residential customers are eligible for this program
Bi-Annual Retailer Event	100% Residential	Only residential customers are eligible for this program
Residential New Constructio	100% Residential	Only residential customers are eligible for this program
Retrofit	50% GS<50, 50% GS>50	This program is open to both GS<50 and GS>50 customers. EPLC has had significant uptake from both customer classes. EPLC is therefore proposing a 50/50 split of verified savings.
Direct Install Lighting	100% GS<50	Only GS<50 customers are eligible for this program
Energy Manager	100% GS>50	EPLC only had one Energy Manager and it was a GS>50 customer
Home Assistance Program	100% Residential	Only residential customers are eligible for this program
High Performance New Cons	100% GS>50	EPLC has reviewed and only GS>50 customers have applied for this program for the time period under review
Time of Use Savings	100% Residential	Only residential customers are eligible for this program
Coupon Initiative	100% Residential	Only residential customers are eligible for this program
Bi-Annual Retailer Event Initi	100% Residential	Only residential customers are eligible for this program
Appliance Retirement Initiati	100% Residential	Only residential customers are eligible for this program
HVAC Incentives Initiative	100% Residential	Only residential customers are eligible for this program
Residential New Constructio	100% Residential	Only residential customers are eligible for this program
Energy Audit Initiative	25% GS<50, 75% GS>50	This program is open to both GS<50 and GS>50 customers. EPLC has reviewed its prior applications and uptake has been predominantly GS>50. EPLC is therefore proposing a 75/25 split of verified savings.
Efficiency: Equipment Repla	50% GS<50, 50% GS>50	This program is open to both GS<50 and GS>50 customers. EPLC has had significant uptake from both customer classes. EPLC is therefore proposing a 50/50 split of verified savings.
Direct Install Lighting and W	100% GS<50	Only GS<50 customers are eligible for this program
Process and Systems Upgrad	100% GS>50	EPLC has reviewed and only GS>50 customers have applied for this program for the time period under review
Program Enabled Savings	100% GS>50	EPLC had one major Program Enabled Savings which related to the Parkway project which was entirely GS>50
Save on Energy Coupon Prog	100% Residential	Only residential customers are eligible for this program
Save on Energy Heating and	100% Residential	Only residential customers are eligible for this program
Save on Energy Retrofit Prog	50% GS<50, 50% GS>50	This program is open to both GS<50 and GS>50 customers. EPLC has had significant uptake from both customer classes. EPLC is therefore proposing a 50/50 split of verified savings.

Ontario Energy Board

LRAMVA Work Form:
2011 - 2014 Lost Revenues Work Form

Version 2.0 (2017)

Legend

- User Inputs (Green)
- Auto Populated Cells (White)
- Instructions (Grey)

Instructions

1. LDCs can apply for disposition of LRAMVA amounts at any time, but at a minimum, must do so as part of a cost of service (COS) application. The following LRAMVA work forms apply to LDCs that need to recover lost revenues from the 2011-2014 period. Please input or manually link the savings, adjustments and program savings persistence data in these tables from the LDC's Persistence Reports provided by the IESO (in Tab 7). As noted earlier, persistence data is available upon request from the IESO. Please also be advised that the same rate classes (of up to 14) are carried over from the Summary Tab 1.

2. Please ensure that the IESO verified savings adjustments apply back to the program year it relates to. For example, savings adjustments related to 2012 programs that were reported by the IESO in 2013 should be included in the 2012 program savings table. In order for persisting savings to be claimed in future years, past year's initiative level savings results need to be filled out in the tables below. If the IESO adjustments were made available to the LDC after the LRAMVA was approved, the persistence of those savings adjustments in the future can be claimed as approved LRAMVA amounts are considered to be final.

3. The work forms below include the monthly multipliers for most programs in order to claim demand savings from energy efficiency programs, consistent with the monthly multipliers indicated in the OEB's updated LRAM policy related to peak demand savings in EB-2016-0182. Demand Response (DR3) savings should generally not be included with the LRAMVA calculation, unless suported by empirical evidence. LDCs are requested to confirm the monthly multipliers for all programs each year as placeholder values are provided. If a different monthly multiplier is used, please include rationale in Tab 1-a and highlight the new multiplier that has been used.

4. LDC are requested to input the applicable rate class allocation percentages to allocate actual savings to the rate classes. The generic template currently includes the same allocation percentage for program savings and its savings adjustments. If a different allocation is proposed for savings adjustments, LDCs must provide supporting rationale in Tab 1-a and highlight the change.

5. The persistence of future savings is expected to be included in the distributor's load forecast after re-basing. LDCs are requested to delete the applicable savings persistence rows (auto-calculated after the LRAMVA totals for the year) if future year's persistence of savings is already captured in the updated load forecast. Please also provide assumptions about the years in which persistence is captured in the load forecast calculation in the "Notes" section below each table.

Tables

Table 4-a. 2011 Lost Revenues Work Form

Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA														
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Residential	General Service <50 kW	General Service 50 - 2,999 kW	General Service 3,000 - 4,999 kW	Sentinel Lighting	Street Lighting	Unmetered Scattered Load								Total
Consumer Program																							kWh	kWh	kW	kW	kW	kW	kWh	0	0	0	0	0	0	0	
1 Appliance Retirement	Verified	48,406	48,406	48,406	48,203	37,742	0	0	0	0	0		7	7	7	7	5	0	0	0	0	0	100.00%														100%
Adjustment to 2011 savings	True-up																						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2 Appliance Exchange	Verified	3,231	3,231	3,231	1,432	0	0	0	0	0	0		3	3	3	1	0	0	0	0	0	0	100.00%														100%
Adjustment to 2011 savings	True-up																						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3 HVAC Incentives	Verified	463,694	463,694	463,694	463,694	463,694	463,694	463,694	463,694	463,694	463,694		264	264	264	264	264	264	264	264	264	264	100.00%														100%
Adjustment to 2011 savings	True-up	-70,103	-70,103	-70,103	-70,103	-70,103	-70,103	-70,103	-70,103	-70,103	-70,103		-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4 Conservation Instant Coupon Booklet	Verified	121,822	121,822	121,822	121,822	112,064	101,404	79,289	78,776	99,193	37,912		8	8	8	8	7	7	6	6	7	4	100.00%														100%
Adjustment to 2011 savings	True-up	1,802	1,802	1,802	1,802	1,802	1,647	1,010	1,009	1,009	357		0	0	0	0	0	0	0	0	0	0	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5 Bi-Annual Retailer Event	Verified	192,162	192,162	192,162	192,162	175,622	157,552	118,784	118,351	152,960	49,084		11	11	11	11	10	9	8	8	9	4	100.00%														100%
Adjustment to 2011 savings	True-up	14,277	14,277	14,277	14,277	14,277	12,974	7,004	7,003	7,003	1,545		1	1	1	1	1	1	0	0	0	0	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
6 Retailer Co-op	Verified																						100.00%														100%
Adjustment to 2011 savings	True-up																						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7 Residential Demand Response	Verified	0	0	0	0	0	0	0	0	0	0		48	0	0	0	0	0	0	0	0	0	100.00%														100%
Adjustment to 2011 savings	True-up																						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8 Residential Demand Response (IHD)	Verified																						100.00%														100%
Adjustment to 2011 savings	True-up																						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9 Residential New Construction	Verified																						100.00%														100%
Adjustment to 2011 savings	True-up																						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Business Program																																					
10 Retrofit	Verified	337,744	337,744	337,744	337,744	337,744	337,744	337,744	337,744	317,302	317,302	12	56	56	56	56	56	56	56	56	52	52		50.00%	50.00%												100%
Adjustment to 2011 savings	True-up											12											0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
11 Direct Install Lighting	Verified	139,935	139,935	139,935	87,918	87,918	84,499	17,966	17,966	17,966	17,966	12	52	52	52	36	36	35	7	7	7	7		100.00%													100%
Adjustment to 2011 savings	True-up											12											0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12 Building Commissioning	Verified											3																									0%
Adjustment to 2011 savings	True-up											3											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13 New Construction	Verified											12																									0%
Adjustment to 2011 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
14 Energy Audit	Verified											12																									0%
Adjustment to 2011 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
15 Small Commercial Demand Response	Verified																																				0%
Adjustment to 2011 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16 Small Commercial Demand Response (IHD)	Verified																																				0%
Adjustment to 2011 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
17 Demand Response 3	Verified	7,344	0	0	0	0	0	0	0	0	0		188	0	0	0	0	0	0	0	0	0															0%
Adjustment to 2011 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Industrial Program																																					
18 Process & System Upgrades	Verified											12																									0%
Adjustment to 2011 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19 Monitoring & Targeting	Verified											12																									0%
Adjustment to 2011 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20 Energy Manager	Verified											12																									0%
Adjustment to 2011 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
21 Retrofit	Verified	688,860	688,860	688,860	688,860	688,860	688,860	688,860	688,860	688,860	688,860	12	93	93	93	93	93	93	93	93	93	93		50.00%	50.00%												100%
Adjustment to 2011 savings	True-up											12											0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22 Demand Response 3	Verified	102,648	0	0	0	0	0	0	0	0	0		1,749	0	0	0	0	0	0	0	0	0															0%
Adjustment to 2011 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Home Assistance Program																																					
23 Home Assistance Program	Verified																						100.00%														100%
Adjustment to 2011 savings	True-up																						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Aboriginal Program																																					
24 Home Assistance Program	Verified																																				0%
Adjustment to 2011 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
25 Direct Install Lighting	Verified											0																									0%
Adjustment to 2011 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Pre-2011 Programs completed in 2011																																					
26 Electricity Retrofit Incentive Program	Verified	56,015	56,015	56,015	56,015	56,015	56,015	56,015	56,015	56,015	56,015	12	10	10	10	10	10	10	10	10	10	10			100.00%												100%

	Adjustment to 2011 savings	True-up											12										
27	High Performance New Construction	Verified	1,239	1,239	1,239	1,239	1,239	1,239	1,239	1,239	1,239	1,239	12	0	0	0	0	0	0	0	0	0	0
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0
28	Toronto Comprehensive	Verified											0										
	Adjustment to 2011 savings	True-up											0										
29	Multifamily Energy Efficiency Rebates	Verified											0										
	Adjustment to 2011 savings	True-up											0										
30	LDC Custom Programs	Verified											0										
	Adjustment to 2011 savings	True-up											0										
	Other																						
31	Program Enabled Savings	Verified											0										
	Adjustment to 2011 savings	True-up											0										
32	Time of Use Savings	Verified											0										
	Adjustment to 2011 savings	True-up											0										
33	LDC Pilots	Verified											0										
	Adjustment to 2011 savings	True-up											0										
	Actual CDM Savings in 2011		**2,109,076**											**2,448**									
	Forecast CDM Savings in 2011																						

	Adjustment to 2011 savings	True-up	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
27	High Performance New Construction	Verified			100.00%												100%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Toronto Comprehensive	Verified															0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29	Multifamily Energy Efficiency Rebates	Verified															0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	LDC Custom Programs	Verified															0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other																
31	Program Enabled Savings	Verified															0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Time of Use Savings	Verified															0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
33	LDC Pilots	Verified															0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2011		**775,291**	**653,237**	**1,007**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Forecast CDM Savings in 2011		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Distribution Rate in 2011		$0.01480	$0.00820	$2.60970	$1.68830	$6.60700	$5.55470	$0.02790	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
	Lost Revenue in 2011 from 2011 programs		**$11,474.31**	**$5,356.54**	**$2,627.68**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$19,458.53**
	Forecast Lost Revenues in 2011		**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2011																**$19,458.53**
	2011 Savings Persisting in 2012		775,291	653,237	1,007	0	0	0	0	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2013		775,291	653,237	1,007	0	0	0	0	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2014		773,289	601,220	1,007	0	0	0	0	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2015		735,098	601,220	1,007	0	0	0	0	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2016		667,168	597,801	1,007	0	0	0	0	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2017		599,679	531,268	1,007	0	0	0	0	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2018		598,730	531,268	1,007	0	0	0	0	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2019		653,757	521,047	985	0	0	0	0	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2020		482,489	521,047	985	0	0	0	0	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

Table 4-b. 2012 Lost Revenues Work Form

Return to top

	Program	Results Status	Net Energy Savings (kWh) 2012	Net Energy Savings Persistence (kWh) 2013	2014	2015	2016	2017	2018	2019	2020	2021	Monthly Multiplier	Net Demand Savings (kW) 2012	Net Peak Demand Savings Persistence (kW) 2013	2014	2015	2016	2017	2018	2019	2020	2021
	Consumer Program																						
1	Appliance Retirement	Verified	16,070	16,070	16,070	15,968	9,621	0	0	0	0	0		2	2	2	2	1	0	0	0	0	0
	Adjustment to 2012 savings	True-up																					
2	Appliance Exchange	Verified	4,153	4,153	4,153	4,065	0	0	0	0	0	0		2	2	2	2	0	0	0	0	0	0
	Adjustment to 2012 savings	True-up																					
3	HVAC Incentives	Verified	249,324	249,324	249,324	249,324	249,324	249,324	249,324	249,324	249,324	249,324		153	153	153	153	153	153	153	153	153	153
	Adjustment to 2012 savings	True-up	5,382	5,382	5,382	5,382	5,382	5,382	5,382	5,382	5,382	5,382		3	3	3	3	3	3	3	3	3	3
4	Conservation Instant Coupon Booklet	Verified	9,143	9,143	9,143	9,143	9,005	9,005	4,241	4,217	4,217	4,217		2	2	2	2	2	2	1	1	1	1
	Adjustment to 2012 savings	True-up																					
5	Bi-Annual Retailer Event	Verified	175,123	175,123	175,123	175,123	157,424	128,008	87,315	87,133	87,133	44,257		10	10	10	10	9	7	6	6	6	4
	Adjustment to 2012 savings	True-up																					
6	Retailer Co-op	Verified																					
	Adjustment to 2012 savings	True-up																					
7	Residential Demand Response	Verified																					
	Adjustment to 2012 savings	True-up																					
8	Residential Demand Response (IHD)	Verified																					
	Adjustment to 2012 savings	True-up																					
9	Residential New Construction	Verified																					
	Adjustment to 2012 savings	True-up																					
	Business Program																						
10	Retrofit	Verified	1,594,397	1,594,397	1,571,403	1,507,205	1,507,205	1,481,206	#######	#######	#######	#######	12	295	295	288	268	268	260	260	260	246	243
	Adjustment to 2012 savings	True-up	21,859	21,859	21,859	21,859	21,859	21,859	21,370	21,370	21,370	18,448	12	4	4	4	4	4	4	3	3	3	3
11	Direct Install Lighting	Verified	23,662	23,662	23,662	12,337	12,337	1,329	1,329	1,329	1,329	1,329	12	7	7	7	4	4	0	0	0	0	0
	Adjustment to 2012 savings	True-up											12										
12	Building Commissioning	Verified											3										
	Adjustment to 2012 savings	True-up											3										
13	New Construction	Verified											12										
	Adjustment to 2012 savings	True-up											12										
14	Energy Audit	Verified	25,176	25,176	25,176	25,176	0	0	0	0	0	0	12	5	5	5	5	0	0	0	0	0	0
	Adjustment to 2012 savings	True-up											12										
15	Small Commercial Demand Response	Verified																					
	Adjustment to 2012 savings	True-up																					
16	Small Commercial Demand Response (IHD)	Verified																					
	Adjustment to 2012 savings	True-up																					
17	Demand Response 3	Verified	2,742	0	0	0	0	0	0	0	0	0		189	0	0	0	0	0	0	0	0	0
	Adjustment to 2012 savings	True-up																					
	Industrial Program																						
18	Process & System Upgrades	Verified											12										
	Adjustment to 2012 savings	True-up											12										
19	Monitoring & Targeting	Verified											12										
	Adjustment to 2012 savings	True-up											12										
20	Energy Manager	Verified											12										
	Adjustment to 2012 savings	True-up											12										
21	Retrofit	Verified											12										
	Adjustment to 2012 savings	True-up											12										
22	Demand Response 3	Verified	43,656	0	0	0	0	0	0	0	0	0		1,811	0	0	0	0	0	0	0	0	0
	Adjustment to 2012 savings	True-up																					
	Home Assistance Program																						
23	Home Assistance Program	Verified	88,006	88,006	88,006	88,006	87,804	87,804	73,261	73,039	19,227	19,032		6	6	6	6	6	6	5	5	2	2
	Adjustment to 2012 savings	True-up																					
	Aboriginal Program																						
24	Home Assistance Program	Verified																					
	Adjustment to 2012 savings	True-up																					
25	Direct Install Lighting	Verified											0										
	Adjustment to 2012 savings	True-up											0										
	Pre-2011 Programs completed in 2011																						
26	Electricity Retrofit Incentive Program	Verified											12										
	Adjustment to 2012 savings	True-up											12										

	Program	Results Status	Rate Allocations for LRAMVA: Residential	General Service <50 kW	General Service 50 - 2,999 kW	General Service 3,000 - 4,999 kW	Sentinel Lighting	Street Lighting	Unmetered Scattered Load								Total
			kWh	kWh	kW	kW	kW	kW	kWh	0	0	0	0	0	0	0	
	Consumer Program																
1	Appliance Retirement	Verified	100.00%														100%
	Adjustment to 2012 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Appliance Exchange	Verified	100.00%														100%
	Adjustment to 2012 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	HVAC Incentives	Verified	100.00%														100%
	Adjustment to 2012 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	Conservation Instant Coupon Booklet	Verified	100.00%														100%
	Adjustment to 2012 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Bi-Annual Retailer Event	Verified	100.00%														100%
	Adjustment to 2012 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
6	Retailer Co-op	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Residential Demand Response	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Residential Demand Response (IHD)	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	Residential New Construction	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Business Program																
10	Retrofit	Verified		50%	50%												100%
	Adjustment to 2012 savings	True-up	0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
11	Direct Install Lighting	Verified		100%													100%
	Adjustment to 2012 savings	True-up	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Building Commissioning	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	New Construction	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
14	Energy Audit	Verified		25.00%	75.00%												100%
	Adjustment to 2012 savings	True-up	0.00%	25.00%	75.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
15	Small Commercial Demand Response	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Small Commercial Demand Response (IHD)	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
17	Demand Response 3	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program																
18	Process & System Upgrades	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Monitoring & Targeting	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Energy Manager	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
21	Retrofit	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Demand Response 3	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Home Assistance Program																
23	Home Assistance Program	Verified	100%														100%
	Adjustment to 2012 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Aboriginal Program																
24	Home Assistance Program	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
25	Direct Install Lighting	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Pre-2011 Programs completed in 2011																
26	Electricity Retrofit Incentive Program	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

27	High Performance New Construction	Verified	716	716	716	716	716	716	716	716	716	716	12	1	1	1	1	1	1	1	1	1	1
	Adjustment to 2012 savings	True-up											12										
28	Toronto Comprehensive	Verified											0										
	Adjustment to 2012 savings	True-up											0										
29	Multifamily Energy Efficiency Rebates	Verified											0										
	Adjustment to 2012 savings	True-up											0										
30	LDC Custom Programs	Verified											0										
	Adjustment to 2012 savings	True-up											0										
	Other																						
31	Program Enabled Savings	Verified											0										
	Adjustment to 2012 savings	True-up											0										
32	Time of Use Savings	Verified											0										
	Adjustment to 2012 savings	True-up											0										
33	LDC Pilots	Verified											0										
	Adjustment to 2012 savings	True-up											0										
	Actual CDM Savings in 2012		**2,259,408**											**2,489**									
	Forecast CDM Savings in 2012																						

27	High Performance New Construction	Verified			100.00%												100%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Toronto Comprehensive	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29	Multifamily Energy Efficiency Rebates	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	LDC Custom Programs	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other																
31	Program Enabled Savings	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Time of Use Savings	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
33	LDC Pilots	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2012		**547,200**	**838,084**	**1,847**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Forecast CDM Savings in 2012		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Distribution Rate in 2012		$0.01490	$0.01050	$2.18900	$1.40690	$7.57080	$6.80870	$0.02800	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
	Lost Revenue in 2012 from 2011 programs		$11,551.84	$6,858.99	$2,204.08	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$20,614.91
	Lost Revenue in 2012 from 2012 programs		$8,153.28	$8,799.88	$4,043.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$20,996.17
	Total Lost Revenues in 2012		**$19,705.12**	**$15,658.87**	**$6,247.09**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$41,611.08**
	Forecast Lost Revenues in 2012		**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2012																**$41,611.08**
	2012 Savings Persisting in 2013		547,200	838,084	1,847	0	0	0	0	0	0	0	0	0	0	0	
	2012 Savings Persisting in 2014		547,200	826,587	1,805	0	0	0	0	0	0	0	0	0	0	0	
	2012 Savings Persisting in 2015		547,009	783,163	1,686	0	0	0	0	0	0	0	0	0	0	0	
	2012 Savings Persisting in 2016		518,560	776,869	1,640	0	0	0	0	0	0	0	0	0	0	0	
	2012 Savings Persisting in 2017		479,523	752,862	1,592	0	0	0	0	0	0	0	0	0	0	0	
	2012 Savings Persisting in 2018		419,522	752,010	1,590	0	0	0	0	0	0	0	0	0	0	0	
	2012 Savings Persisting in 2019		419,095	752,010	1,590	0	0	0	0	0	0	0	0	0	0	0	
	2012 Savings Persisting in 2020		365,283	718,312	1,503	0	0	0	0	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

Table 4-c. 2013 Lost Revenues Work Form

Return to top

	Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)								
			2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	Consumer Program																						
1	Appliance Retirement	Verified	8,577	8,577	8,577	8,577	6,215	0	0	0	0	0		1	1	1	1	1	0	0	0	0	0
	Adjustment to 2013 savings	True-up																					
2	Appliance Exchange	Verified	11,453	11,453	11,453	11,453	0	0	0	0	0	0		6	6	6	6	0	0	0	0	0	0
	Adjustment to 2013 savings	True-up																					
3	HVAC Incentives	Verified	263,999	263,999	263,999	263,999	263,999	263,999	263,999	263,999	263,999	263,999		164	164	164	164	164	164	164	164	164	164
	Adjustment to 2013 savings	True-up	6,870	6,870	6,870	6,870	6,870	6,870	6,870	6,870	6,870	6,870		4	4	4	4	4	4	4	4	4	4
4	Conservation Instant Coupon Booklet	Verified	50,399	50,399	48,457	41,053	41,053	41,053	41,053	41,019	29,828	29,828		3	3	3	3	3	3	3	3	2	2
	Adjustment to 2013 savings	True-up	154	154	147	127	127	127	127	127	106	106		0	0	0	0	0	0	0	0	0	0
5	Bi-Annual Retailer Event	Verified	112,337	112,337	105,569	82,469	82,469	82,469	82,469	82,372	69,270	69,270		8	8	7	6	6	6	6	6	5	5
	Adjustment to 2013 savings	True-up																					
6	Retailer Co-op	Verified																					
	Adjustment to 2013 savings	True-up																					
7	Residential Demand Response	Verified																					
	Adjustment to 2013 savings	True-up																					
8	Residential Demand Response (IHD)	Verified																					
	Adjustment to 2013 savings	True-up																					
9	Residential New Construction	Verified																					
	Adjustment to 2013 savings	True-up																					
	Business Program																						
10	Retrofit	Verified	965,814	943,411	925,102	873,829	827,192	822,875	822,875	821,914	807,225	775,756	12	231	224	218	201	186	186	186	186	181	176
	Adjustment to 2013 savings	True-up	114,260	110,928	101,941	93,127	90,940	90,525	90,525	90,525	90,525	87,502	12	26	25	23	20	20	19	19	19	19	19
11	Direct Install Lighting	Verified	43,954	43,954	43,803	42,981	7,727	7,727	7,727	7,727	7,727	7,727	12	14	14	14	14	2	2	2	2	2	2
	Adjustment to 2013 savings	True-up											12										
12	Building Commissioning	Verified											3										
	Adjustment to 2013 savings	True-up											3										
13	New Construction	Verified											12										
	Adjustment to 2013 savings	True-up											12										
14	Energy Audit	Verified	193,803	193,803	193,803	193,803	0	0	0	0	0	0	12	35	35	35	0	0	0	0	0	0	0
	Adjustment to 2013 savings	True-up	129	129	129	129	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0
15	Small Commercial Demand Response	Verified																					
	Adjustment to 2013 savings	True-up																					
16	Small Commercial Demand Response (IHD)	Verified																					
	Adjustment to 2013 savings	True-up																					
17	Demand Response 3	Verified	2,555	0	0	0	0	0	0	0	0	0		191	0	0	0	0	0	0	0	0	0
	Adjustment to 2013 savings	True-up																					
	Industrial Program																						
18	Process & System Upgrades	Verified											12										
	Adjustment to 2013 savings	True-up											12										
19	Monitoring & Targeting	Verified											12										
	Adjustment to 2013 savings	True-up											12										
20	Energy Manager	Verified	150,984	144,990	144,990	144,990	0	0	0	0	0	0	12	92	36	36	36	0	0	0	0	0	0
	Adjustment to 2013 savings	True-up	16,482	22,476	22,476	22,476	167,466	166,282	166,282	166,282	166,282	166,282	12	38	35	35	35	71	71	71	71	71	71
21	Retrofit	Verified											12										
	Adjustment to 2013 savings	True-up											12										
22	Demand Response 3	Verified	96,815	0	0	0	0	0	0	0	0	0		2,182	0	0	0	0	0	0	0	0	0
	Adjustment to 2013 savings	True-up																					
	Home Assistance Program																						
23	Home Assistance Program	Verified	345,695	336,739	326,572	294,525	278,852	267,255	243,042	241,974	109,974	107,635		33	32	32	30	29	29	27	27	20	18
	Adjustment to 2013 savings	True-up																					
	Aboriginal Program																						
24	Home Assistance Program	Verified																					
	Adjustment to 2013 savings	True-up																					
25	Direct Install Lighting	Verified											0										
	Adjustment to 2013 savings	True-up											0										
	Pre-2011 Programs completed in 2011																						
26	Electricity Retrofit Incentive Program	Verified											12										
	Adjustment to 2013 savings	True-up											12										
27	High Performance New Construction	Verified											12										
	Adjustment to 2013 savings	True-up											12										

	Program	Results Status	Rate Allocations for LRAMVA: Residential	General Service <50 kW	General Service 50 - 2,999 kW	General Service 3,000 - 4,999 kW	Sentinel Lighting	Street Lighting	Unmetered Scattered Load								Total
	Consumer Program		kWh	kWh	kW	kW	kW	kW	kWh	0	0	0	0	0	0	0	
1	Appliance Retirement	Verified	100.00%														100%
	Adjustment to 2013 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Appliance Exchange	Verified	100.00%														100%
	Adjustment to 2013 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	HVAC Incentives	Verified	100.00%														100%
	Adjustment to 2013 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	Conservation Instant Coupon Booklet	Verified	100.00%														100%
	Adjustment to 2013 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Bi-Annual Retailer Event	Verified	100.00%														100%
	Adjustment to 2013 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
6	Retailer Co-op	Verified															0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Residential Demand Response	Verified	100.00%														100%
	Adjustment to 2013 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Residential Demand Response (IHD)	Verified															0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	Residential New Construction	Verified															0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Business Program																
10	Retrofit	Verified		50%	50%												100%
	Adjustment to 2013 savings	True-up	0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
11	Direct Install Lighting	Verified		100%													100%
	Adjustment to 2013 savings	True-up	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Building Commissioning	Verified															0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	New Construction	Verified															0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
14	Energy Audit	Verified		25.00%	75%												100%
	Adjustment to 2013 savings	True-up	0.00%	25.00%	75.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
15	Small Commercial Demand Response	Verified															0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Small Commercial Demand Response (IHD)	Verified															0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
17	Demand Response 3	Verified															0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program																
18	Process & System Upgrades	Verified															0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Monitoring & Targeting	Verified															0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Energy Manager	Verified			100.00%												100%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
21	Retrofit	Verified															0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Demand Response 3	Verified															0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Home Assistance Program																
23	Home Assistance Program	Verified	100%														100%
	Adjustment to 2013 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Aboriginal Program																
24	Home Assistance Program	Verified															0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
25	Direct Install Lighting	Verified															0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Pre-2011 Programs completed in 2011																
26	Electricity Retrofit Incentive Program	Verified															0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
27	High Performance New Construction	Verified															0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

28	Toronto Comprehensive	Verified		0																0%
	Adjustment to 2013 savings	True-up		0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29	Multifamily Energy Efficiency Rebates	Verified		0																0%
	Adjustment to 2013 savings	True-up		0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	LDC Custom Programs	Verified		0																0%
	Adjustment to 2013 savings	True-up		0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other																			
31	Program Enabled Savings	Verified		0																0%
	Adjustment to 2013 savings	True-up		0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Time of Use Savings	Verified		0																0%
	Adjustment to 2013 savings	True-up		0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
33	LDC Pilots	Verified		0																0%
	Adjustment to 2013 savings	True-up		0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2013		**2,384,279**		**3,030**	**799,484**	**632,473**	**3,430**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Forecast CDM Savings in 2013					**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Distribution Rate in 2013					$0.01500	$0.01140	$2.07820	$1.33250	$8.81970	$8.06900	$0.02820	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
	Lost Revenue in 2013 from 2011 programs					$11,629.37	$7,446.90	$2,092.52	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$21,168.78
	Lost Revenue in 2013 from 2012 programs					$8,208.00	$9,554.16	$3,838.37	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$21,600.53
	Lost Revenue in 2013 from 2013 programs					$11,992.26	$7,210.19	$7,127.40	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$26,329.86
	Total Lost Revenues in 2013					**$31,829.63**	**$24,211.25**	**$13,058.28**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$69,099.16**
	Forecast Lost Revenues in 2013					**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2013																			**$69,099.16**
	2013 Savings Persisting in 2014					790,528	619,606	2,662	0	0	0	0	0	0	0	0	0	0	0	
	2013 Savings Persisting in 2015					771,643	605,807	2,612	0	0	0	0	0	0	0	0	0	0	0	
	2013 Savings Persisting in 2016					709,073	574,942	2,180	0	0	0	0	0	0	0	0	0	0	0	
	2013 Savings Persisting in 2017					679,586	466,793	2,087	0	0	0	0	0	0	0	0	0	0	0	
	2013 Savings Persisting in 2018					661,773	464,427	2,082	0	0	0	0	0	0	0	0	0	0	0	
	2013 Savings Persisting in 2019					637,560	464,427	2,082	0	0	0	0	0	0	0	0	0	0	0	
	2013 Savings Persisting in 2020					636,360	463,946	2,082	0	0	0	0	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

Table 4-d. 2014 Lost Revenues Work Form

Return to Top

	Program	Results Status	Net Energy Savings (kWh) 2014	Net Energy Savings Persistence (kWh) 2015	2016	2017	2018	2019	2020	2021	2022	2023	Monthly Multiplier
	Consumer Program												
1	Appliance Retirement	Verified	11,926	11,926	11,926	11,926	7,374	0	0	0	0	0	
	Adjustment to 2014 savings	True-up											
2	Appliance Exchange	Verified	12,561	12,561	12,561	12,561	0	0	0	0	0	0	
	Adjustment to 2014 savings	True-up											
3	HVAC Incentives	Verified	340,235	340,235	340,235	340,235	340,235	340,235	340,235	340,235	340,235	340,235	
	Adjustment to 2014 savings	True-up											
4	Conservation Instant Coupon Booklet	Verified	184,680	171,930	165,775	165,775	165,775	165,775	165,775	165,453	165,453	141,537	
	Adjustment to 2014 savings	True-up											
5	Bi-Annual Retailer Event	Verified	803,649	697,157	641,659	641,659	641,659	641,659	641,659	641,381	641,381	596,520	
	Adjustment to 2014 savings	True-up											
6	Retailer Co-op	Verified											
	Adjustment to 2014 savings	True-up											
7	Residential Demand Response	Verified	0	0	0	0	0	0	0	0	0	0	
	Adjustment to 2014 savings	True-up											
8	Residential Demand Response (IHD)	Verified											
	Adjustment to 2014 savings	True-up											
9	Residential New Construction	Verified	5,938	5,938	5,938	5,938	5,938	5,938	5,938	5,938	5,938	5,938	
	Adjustment to 2014 savings	True-up											
	Business Program												
10	Retrofit	Verified	1,785,969	1,763,532	1,763,532	1,759,981	1,759,981	1,759,981	#######	#######	#######	#######	12
	Adjustment to 2014 savings	True-up											12
11	Direct Install Lighting	Verified	40,685	40,685	39,701	15,613	15,613	15,613	15,613	15,613	15,613	15,613	12
	Adjustment to 2014 savings	True-up											12
12	Building Commissioning	Verified											3
	Adjustment to 2014 savings	True-up											3
13	New Construction	Verified											12
	Adjustment to 2014 savings	True-up											12
14	Energy Audit	Verified											12
	Adjustment to 2014 savings	True-up											12
15	Small Commercial Demand Response	Verified	0	0	0	0	0	0	0	0	0	0	
	Adjustment to 2014 savings	True-up											
16	Small Commercial Demand Response (IHD)	Verified											
	Adjustment to 2014 savings	True-up											
17	Demand Response 3	Verified	0	0	0	0	0	0	0	0	0	0	
	Adjustment to 2014 savings	True-up											
	Industrial Program												
18	Process & System Upgrades	Verified											12
	Adjustment to 2014 savings	True-up											12
19	Monitoring & Targeting	Verified											12
	Adjustment to 2014 savings	True-up											12
20	Energy Manager	Verified	81,552	81,552	81,552	81,552	81,552	81,552	81,552	81,552	81,552	81,552	12
	Adjustment to 2014 savings	True-up											12
21	Retrofit	Verified											12
	Adjustment to 2014 savings	True-up											12
22	Demand Response 3	Verified	0	0	0	0	0	0	0	0	0	0	
	Adjustment to 2014 savings	True-up											
	Home Assistance Program												
23	Home Assistance Program	Verified	2,839	2,712	2,443	2,305	2,218	2,218	1,886	1,886	707	707	
	Adjustment to 2014 savings	True-up											
	Aboriginal Program												
24	Home Assistance Program	Verified											
	Adjustment to 2014 savings	True-up											
25	Direct Install Lighting	Verified											0
	Adjustment to 2014 savings	True-up											0
	Pre-2011 Programs completed in 2011												
26	Electricity Retrofit Incentive Program	Verified											12
	Adjustment to 2014 savings	True-up											12
27	High Performance New Construction	Verified	321,000	321,000	321,000	321,000	321,000	321,000	321,000	321,000	321,000	321,000	12
	Adjustment to 2014 savings	True-up											12
28	Toronto Comprehensive	Verified											0

	Program	Net Demand Savings (kW) 2014	Net Peak Demand Savings Persistence (kW) 2015	2016	2017	2018	2019	2020	2021	2022	2023
	Consumer Program										
1	Appliance Retirement	2	2	2	2	1	0	0	0	0	0
	Adjustment to 2014 savings										
2	Appliance Exchange	7	7	7	7	0	0	0	0	0	0
	Adjustment to 2014 savings										
3	HVAC Incentives	187	187	187	187	187	187	187	187	187	187
	Adjustment to 2014 savings										
4	Conservation Instant Coupon Booklet	14	13	13	13	13	13	13	13	13	11
	Adjustment to 2014 savings										
5	Bi-Annual Retailer Event	53	46	42	42	42	42	42	42	42	40
	Adjustment to 2014 savings										
6	Retailer Co-op										
	Adjustment to 2014 savings										
7	Residential Demand Response	118	0	0	0	0	0	0	0	0	0
	Adjustment to 2014 savings										
8	Residential Demand Response (IHD)										
	Adjustment to 2014 savings										
9	Residential New Construction	0	0	0	0	0	0	0	0	0	0
	Adjustment to 2014 savings										
	Business Program										
10	Retrofit	267	260	260	259	259	259	254	254	244	222
	Adjustment to 2014 savings										
11	Direct Install Lighting	12	12	11	4	4	4	4	4	4	4
	Adjustment to 2014 savings										
12	Building Commissioning										
	Adjustment to 2014 savings										
13	New Construction										
	Adjustment to 2014 savings										
14	Energy Audit										
	Adjustment to 2014 savings										
15	Small Commercial Demand Response	4	0	0	0	0	0	0	0	0	0
	Adjustment to 2014 savings										
16	Small Commercial Demand Response (IHD)										
	Adjustment to 2014 savings										
17	Demand Response 3	149	0	0	0	0	0	0	0	0	0
	Adjustment to 2014 savings										
	Industrial Program										
18	Process & System Upgrades										
	Adjustment to 2014 savings										
19	Monitoring & Targeting										
	Adjustment to 2014 savings										
20	Energy Manager	19	19	19	19	19	19	19	19	19	19
	Adjustment to 2014 savings										
21	Retrofit										
	Adjustment to 2014 savings										
22	Demand Response 3	106	0	0	0	0	0	0	0	0	0
	Adjustment to 2014 savings										
	Home Assistance Program										
23	Home Assistance Program	0	0	0	0	0	0	0	0	0	0
	Adjustment to 2014 savings										
	Aboriginal Program										
24	Home Assistance Program										
	Adjustment to 2014 savings										
25	Direct Install Lighting										
	Adjustment to 2014 savings										
	Pre-2011 Programs completed in 2011										
26	Electricity Retrofit Incentive Program										
	Adjustment to 2014 savings										
27	High Performance New Construction	63	63	63	63	63	63	63	63	63	63
	Adjustment to 2014 savings										
28	Toronto Comprehensive										

	Program	Rate Allocations for LRAMVA: Residential	General Service <50 kW	General Service 50 - 2,999 kW	General Service 3,000 - 4,999 kW	Sentinel Lighting	Street Lighting	Unmetered Scattered Load								Total
	Consumer Program	kWh	kWh	kW	kW	kW	kW	kWh	0	0	0	0	0	0	0	
1	Appliance Retirement	100%														100%
	Adjustment to 2014 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Appliance Exchange	100%														100%
	Adjustment to 2014 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	HVAC Incentives	100%														100%
	Adjustment to 2014 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	Conservation Instant Coupon Booklet	100%														100%
	Adjustment to 2014 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Bi-Annual Retailer Event	100%														100%
	Adjustment to 2014 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
6	Retailer Co-op															0%
	Adjustment to 2014 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Residential Demand Response															0%
	Adjustment to 2014 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Residential Demand Response (IHD)															0%
	Adjustment to 2014 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	Residential New Construction	100.00%														100%
	Adjustment to 2014 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Business Program															
10	Retrofit		50%	50%												100%
	Adjustment to 2014 savings	0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
11	Direct Install Lighting		100%													100%
	Adjustment to 2014 savings	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Building Commissioning															0%
	Adjustment to 2014 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	New Construction															0%
	Adjustment to 2014 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
14	Energy Audit															0%
	Adjustment to 2014 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
15	Small Commercial Demand Response															0%
	Adjustment to 2014 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Small Commercial Demand Response (IHD)															0%
	Adjustment to 2014 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
17	Demand Response 3															0%
	Adjustment to 2014 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program															
18	Process & System Upgrades															0%
	Adjustment to 2014 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Monitoring & Targeting															0%
	Adjustment to 2014 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Energy Manager			100.00%												100%
	Adjustment to 2014 savings	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
21	Retrofit															0%
	Adjustment to 2014 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Demand Response 3															0%
	Adjustment to 2014 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Home Assistance Program															
23	Home Assistance Program	100%														100%
	Adjustment to 2014 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Aboriginal Program															
24	Home Assistance Program															0%
	Adjustment to 2014 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
25	Direct Install Lighting															0%
	Adjustment to 2014 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Pre-2011 Programs completed in 2011															
26	Electricity Retrofit Incentive Program															0%
	Adjustment to 2014 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
27	High Performance New Construction			100.00%												100%
	Adjustment to 2014 savings	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Toronto Comprehensive															0%

Adjustment to 2014 savings	True-up											0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29 Multifamily Energy Efficiency Rebates	Verified											0																								0%
Adjustment to 2014 savings	True-up											0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30 LDC Custom Programs	Verified											0																								0%
Adjustment to 2014 savings	True-up											0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Other																																				
31 Program Enabled Savings	Verified											0																								0%
Adjustment to 2014 savings	True-up											0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32 Time of Use Savings	Verified	0	0	0	0	0	0	0	0	0	0	0	296	0	0	0	0	0	0	0	0	0	100.00%														100%
Adjustment to 2014 savings	True-up											0										100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
33 LDC Pilots	Verified											0																								0%
Adjustment to 2014 savings	True-up											0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Actual CDM Savings in 2014		**3,591,032**											**1,297**									**1,361,826**	**933,669**	**2,583**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Forecast CDM Savings in 2014																						**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Distribution Rate in 2014																						$0.01510	$0.01150	$2.11980	$1.35960	$9.39170	$8.57490	$0.02850	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
Lost Revenue in 2014 from 2011 programs																						$11,676.67	$6,914.02	$2,134.40	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$20,725.09
Lost Revenue in 2014 from 2012 programs																						$8,262.72	$9,505.75	$3,825.39	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$21,593.86
Lost Revenue in 2014 from 2013 programs																						$11,936.97	$7,125.47	$5,643.89	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$24,706.33
Lost Revenue in 2014 from 2014 programs																						$20,563.57	$10,737.20	$5,474.63	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$36,775.40
Total Lost Revenues in 2014																						**$52,439.93**	**$34,282.44**	**$17,078.31**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$103,800.68**
Forecast Lost Revenues in 2014																						**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2014																																				**$103,800.68**
2014 Savings Persisting in 2015																						1,242,458	922,451	2,544	0	0	0	0	0	0	0	0	0	0	0	
2014 Savings Persisting in 2016																						1,180,535	921,467	2,544	0	0	0	0	0	0	0	0	0	0	0	
2014 Savings Persisting in 2017																						1,180,398	895,603	2,538	0	0	0	0	0	0	0	0	0	0	0	
2014 Savings Persisting in 2018																						1,163,198	895,603	2,538	0	0	0	0	0	0	0	0	0	0	0	
2014 Savings Persisting in 2019																						1,155,823	895,603	2,538	0	0	0	0	0	0	0	0	0	0	0	
2014 Savings Persisting in 2020																						1,155,492	876,160	2,508	0	0	0	0	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

Ontario Energy Board

LRAMVA Work Form:
2015 - 2020 Lost Revenues Work Form

Version 2.0 (2017)

Legend

- User Inputs (Green)
- Auto Populated Cells (White)
- Instructions (Grey)

Instructions

1. LDCs can apply for disposition of LRAMVA amounts at any time, but at a minimum, must do so as part of a cost of service (COS) application. The following LRAMVA work forms apply to LDCs that need to recover lost revenues from the 2015-2020 period. Please input or manually link the savings, adjustments and program savings persistence data in these tables from the LDC's Persistence Reports provided by the IESO (in Tab 7). As noted earlier, persistence data is available upon request from the IESO. Please also be advised that the same rate classes (of up to 14) are carried over from the Summary Tab 1.

2. Please ensure that the IESO verified savings adjustments apply back to the program year it relates to. For example, savings adjustments related to 2016 programs that were reported by the IESO in 2017 should be included in the 2016 program savings table. In order for persisting savings to be claimed in future years, past year's initiative level savings results need to be filled out in the tables below. If the IESO adjustments were made available to the LDC after the LRAMVA was approved, the persistence of those savings adjustments in the future can be claimed as approved LRAMVA amounts are considered to be final.

3. The work forms below include the monthly multipliers for most programs in order to claim demand savings from energy efficiency programs, consistent with the monthly multipliers indicated in the OEB's updated LRAM policy related to peak demand savings in EB-2016-0182. Demand Response (DR3) savings should generally not be included with the LRAMVA calculation, unless suported by empirical evidence. LDCs are requested to confirm the monthly multipliers for all programs each year as placeholder values are provided. If a different monthly multiplier is used, please include rationale in Tab 1-a and highlight the new multiplier that has been used.

4. LDC are requested to input the applicable rate class allocation percentages to allocate actual savings to the rate classes. The generic template currently includes the same allocation percentage for program savings and its savings adjustments. If a different allocation is proposed for savings adjustments, LDCs must provide supporting rationale in Tab 1-a and highlight the change.

5. The persistence of future savings is expected to be included in the distributor's load forecast after re-basing. LDCs are requested to delete the applicable savings persistence rows (auto-calculated after the LRAMVA totals for the year) if future year's persistence of savings is already captured in the updated load forecast. Please also provide assumptions about the years in which persistence is captured in the load forecast calculation in the "Notes" section below each table.

Tables

Table 5-a. 2015 Lost Revenues Work Form

#	Program	Results Status	Net Energy Savings (kWh) 2015	Net Energy Savings Persistence (kWh) 2016	2017	2018	2019	2020	2021	2022	2023	2024	Monthly Multiplier	Net Demand Savings (kW) 2015	Net Peak Demand Savings Persistence (kW) 2016	2017	2018	2019	2020	2021	2022	2023	2024
	Legacy Framework																						
	Residential Program																						
1	Coupon Initiative	Verified	163,745	162,271	162,271	162,271	162,271	162,271	162,271	162,236	162,236	162,236		11	10	10	10	10	10	10	10	10	10
	Adjustment to 2015 savings	True-up																					
2	Bi-Annual Retailer Event Initiative	Verified	238,330	230,426	230,426	230,426	230,426	230,426	230,426	230,418	230,418	230,418		18	17	17	17	17	17	17	17	17	17
	Adjustment to 2015 savings	True-up																					
3	Appliance Retirement Initiative	Verified	9,159	9,159	9,159	9,159	6,105	0	0	0	0	0		1	1	1	1	1	0	0	0	0	0
	Adjustment to 2015 savings	True-up																					
4	HVAC Incentives Initaitive	Verified	314,522	314,522	314,522	314,522	314,522	314,522	314,522	314,522	314,522	314,522		168	168	168	168	168	168	168	168	168	168
	Adjustment to 2015 savings	True-up																					
5	Residential New Construction and Major	Verified	15,578	15,578	15,578	15,578	15,578	15,578	15,578	15,578	15,578	15,578		6	6	6	6	6	6	6	6	6	6
	Adjustment to 2015 savings	True-up																					
	Commercial & Institutional Program																						
6	Energy Audit Initiative	Verified	214,071	214,071	214,071	214,071	0	0	0	0	0	0	12	46	46	46	46	0	0	0	0	0	0
	Adjustment to 2015 savings	True-up											12										
7	Efficiency: Equipment Replacement Incentive Initiative	Verified	2,298,106	2,298,106	2,294,054	2,294,054	2,294,054	2,294,054	2,214,936	2,214,936	2,198,068	1,934,063	12	376	376	375	375	375	375	363	363	359	320
	Adjustment to 2015 savings	True-up											12										
8	Direct Install Lighting and Water Heating Initiative	Verified	14,098	10,671	10,460	10,460	10,460	10,460	10,460	10,460	10,460	10,460	12	3	2	2	2	2	2	2	2	2	2
	Adjustment to 2015 savings	True-up											12										
9	New Construction and Major Renovation Initiative	Verified	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0
	Adjustment to 2015 savings	True-up											12										
10	Existing Building Commissioning Incentive Initiative	Verified	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0
	Adjustment to 2015 savings	True-up											3										
	Industrial Program																						
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative	Verified	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0
	Adjustment to 2015 savings	True-up											12										
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	Verified	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0
	Adjustment to 2015 savings	True-up											12										
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified	28,463	28,463	28,463	28,463	28,463	28,463	28,463	26,738	26,738	26,738	12	19	19	19	19	19	19	19	19	19	19
	Adjustment to 2015 savings	True-up											12										
	Low Income Program																						
14	Low Income Initiative	Verified	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0
	Adjustment to 2015 savings	True-up											12										
	Other																						
15	Aboriginal Conservation Program	Verified	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Adjustment to 2015 savings	True-up											0										
16	Program Enabled Savings	Verified	8,746,466	8,746,466	8,746,466	8,746,466	8,746,466	866	866	866	866	866	0	977	977	977	977	977	0	0	0	0	0
	Adjustment to 2015 savings	True-up											0										
	Conservation Fund Pilots																						
17	Conservation Fund Pilot - EnerNOC	Verified	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Adjustment to 2015 savings	True-up											0										
18	Loblaws Pilot	Verified	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Adjustment to 2015 savings	True-up											0										
19	Conservation Fund Pilot - SEG	Verified	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Adjustment to 2015 savings	True-up											0										
20	Social Benchmarking Pilot	Verified											0										
	Adjustment to 2015 savings	True-up											0										
	Conservation First Framework																						

#	Program	Rate Allocations for LRAMVA: Residential	General Service <50 kW	General Service 50 - 2,999 kW	General Service 3,000 - 4,999 kW	Sentinel Lighting	Street Lighting	Unmetered Scattered Load								Total
	Legacy Framework	kWh	kWh	kW	kW	kW	kW	kWh	0	0	0	0	0	0	0	
	Residential Program															
1	Coupon Initiative	100.00%														100%
	Adjustment to 2015 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Bi-Annual Retailer Event Initiative	100.00%														100%
	Adjustment to 2015 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	Appliance Retirement Initiative	100.00%														100%
	Adjustment to 2015 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	HVAC Incentives Initaitive	100.00%														100%
	Adjustment to 2015 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Residential New Construction and Major	100.00%														100%
	Adjustment to 2015 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Commercial & Institutional Program															
6	Energy Audit Initiative		25.00%	75.00%												100%
	Adjustment to 2015 savings	0.00%	25.00%	75.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Efficiency: Equipment Replacement Incentive Initiative		50%	50%												100%
	Adjustment to 2015 savings	0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Direct Install Lighting and Water Heating Initiative		100%													100%
	Adjustment to 2015 savings	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	New Construction and Major Renovation Initiative															0%
	Adjustment to 2015 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
10	Existing Building Commissioning Incentive Initiative															0%
	Adjustment to 2015 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program															
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative															0%
	Adjustment to 2015 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative			100.00%												100%
	Adjustment to 2015 savings	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative			100.00%												100%
	Adjustment to 2015 savings	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Low Income Program															
14	Low Income Initiative															0%
	Adjustment to 2015 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other															
15	Aboriginal Conservation Program															0%
	Adjustment to 2015 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Program Enabled Savings			100.00%												100%
	Adjustment to 2015 savings	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Conservation Fund Pilots															
17	Conservation Fund Pilot - EnerNOC															0%
	Adjustment to 2015 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
18	Loblaws Pilot															0%
	Adjustment to 2015 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Conservation Fund Pilot - SEG															0%
	Adjustment to 2015 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Social Benchmarking Pilot															0%
	Adjustment to 2015 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Conservation First Framework															

	Residential Province-Wide Programs																																					
21	Save on Energy Coupon Program	Verified	535,138	530,818	530,818	530,818	530,818	530,818	530,818	530,481	530,481	530,481		34	34	34	34	34	34	34	34	31	31	100%														100%
	Adjustment to 2015 savings	True-up																						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Save on Energy Heating and Cooling Program	Verified	80,466	80,466	80,466	80,466	80,466	80,466	80,466	80,466	80,466	80,466		42	42	42	42	42	42	42	42	42	42	100%														100%
	Adjustment to 2015 savings	True-up																						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
23	Save on Energy New Construction Program	Verified																																				0%
	Adjustment to 2015 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
24	Save on Energy Home Assistance Program	Verified	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0															0%
	Adjustment to 2015 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Non-Residential Province-Wide Programs																																					
25	Save on Energy Audit Funding Program	Verified	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0															0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
26	Save on Energy Retrofit Program	Verified	151,786	151,786	151,786	151,786	151,786	151,786	151,663	151,663	151,663	151,262	12	1	1	1	1	1	1	1	0	0	0		50%	50%												100%
	Adjustment to 2015 savings	True-up											12											0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
27	Save on Energy Small Business Lighting Program	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Save on Energy High Performance New Construction Program	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29	Save on Energy Existing Building Commissioning Program	Verified											3																									0%
	Adjustment to 2015 savings	True-up											3											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	Save on Energy Process & Systems Upgrades Program	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
31	Save on Energy Monitoring & Targeting Program	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Save on Energy Energy Manager Program	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Local & Regional Programs																																					
33	Business Refrigeration Local Program	Verified											0																									0%
	Adjustment to 2015 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
34	First Nation Conservation Local Program	Verified											0																									0%
	Adjustment to 2015 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
35	Social Benchmarking Local Program	Verified	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0															0%
	Adjustment to 2015 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Pilot Programs																																					
36	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - Conservation Fund	Verified											0																									0%
	Adjustment to 2015 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
37	EnWin Utilities Ltd. - Building Optimization Pilot	Verified											0																									0%
	Adjustment to 2015 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
38	EnWin Utilities Ltd. - Re-Invest Pilot	Verified											0																									0%
	Adjustment to 2015 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
39	Horizon Utilities Corporation - ECM Furnace Motor Pilot	Verified											0																									0%
	Adjustment to 2015 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
40	Horizon Utilities Corporation - Social Benchmarking Pilot	Verified											0																									0%
	Adjustment to 2015 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
41	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pilot	Verified											0																									0%
	Adjustment to 2015 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
42	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot	Verified																																				0%
	Adjustment to 2015 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
43	Kitchener-Wilmot Hydro Inc. - Pilot - DCKV	Verified											0																									0%
	Adjustment to 2015 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
44	Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agricultural Sector	Verified											0																									0%
	Adjustment to 2015 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
45	Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic	Verified											0																									0%
	Adjustment to 2015 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
46	Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls	Verified											0																									0%
	Adjustment to 2015 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
47	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)	Verified											0																									0%
	Adjustment to 2015 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
48	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)	Verified											0																									0%
	Adjustment to 2015 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
49	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)	Verified											0																									0%
	Adjustment to 2015 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2015		**12,809,928**											**1,702**										**1,356,938**	**1,292,562**	**2,904**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Forecast CDM Savings in 2015																							**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Distribution Rate in 2015																							$0.01520	$0.01160	$2.13060	$1.36660	$9.43970	$8.61880	$0.02860	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
	Lost Revenue in 2015 from 2011 programs																							$11,173.50	$6,974.15	$2,145.28	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$20,292.92
	Lost Revenue in 2015 from 2012 programs																							$8,314.54	$9,084.69	$3,592.84	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$20,992.07
	Lost Revenue in 2015 from 2013 programs																							$11,728.98	$7,027.37	$5,564.63	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$24,320.97
	Lost Revenue in 2015 from 2014 programs																							$18,885.35	$10,700.43	$5,420.73	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$35,006.51
	Lost Revenue in 2015 from 2015 programs																							$20,625.46	$14,993.72	$6,187.26	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$41,806.44
	Total Lost Revenues in 2015																							**$70,727.82**	**$48,780.34**	**$22,910.74**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$142,418.91**
	Forecast Lost Revenues in 2015																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2015																																					**$142,418.91**
	2015 Savings Persisting in 2016																							1,343,240	1,289,135	2,904	0	0	0	0	0	0	0	0	0	0	0	
	2015 Savings Persisting in 2017																							1,343,240	1,286,898	2,898	0	0	0	0	0	0	0	0	0	0	0	

	2015 Savings	Residential	General Service <50 kW	General Service 50 - 2,999 kW	General Service 3,000 - 4,999 kW	Sentinel Lighting	Street Lighting	Unmetered Scattered Load							
	2015 Savings Persisting in 2018	1,343,240	1,286,898	2,898	0	0	0	0	0	0	0	0	0	0	0
	2015 Savings Persisting in 2019	1,340,186	1,233,380	2,484	0	0	0	0	0	0	0	0	0	0	0
	2015 Savings Persisting in 2020	1,334,081	1,233,380	2,484	0	0	0	0	0	0	0	0	0	0	0

Note: LDC to make note of key assumptions included above

Table 5-b. 2016 Lost Revenues Work Form Return to top

#	Program	Results Status	Net Energy Savings (kWh) 2016	Net Energy Savings Persistence (kWh) 2017	2018	2019	2020	2021	2022	2023	2024	2025	Monthly Multiplier	Net Demand Savings (kW) 2016	Net Peak Demand Savings Persistence (kW) 2017	2018	2019	2020	2021	2022	2023	2024	2025
	Legacy Framework																						
	Residential Program																						
1	Coupon Initiative	Verified	2,561,702	2,561,702	2,561,702	2,561,702	2,561,702	2,561,702	2,561,702	2,561,315	2,561,315	2,549,878		166	166	166	166	166	166	166	166	166	166
	Adjustment to 2016 savings	True-up																					
2	Bi-Annual Retailer Event Initiative	Verified																					
	Adjustment to 2016 savings	True-up																					
3	Appliance Retirement Initiative	Verified																					
	Adjustment to 2016 savings	True-up																					
4	HVAC Incentives Initaitive	Verified	709,482	709,482	709,482	709,482	709,482	709,482	709,482	709,482	709,482	709,482		210	210	210	210	210	210	210	210	210	210
	Adjustment to 2016 savings	True-up																					
5	Residential New Construction and Major Renovation Initiative	Verified	9,213	9,213	9,213	9,213	9,213	9,213	9,213	9,213	9,213	9,213		3	3	3	3	3	3	3	3	3	3
	Adjustment to 2016 savings	True-up																					
	Commercial & Institutional Program																						
6	Energy Audit Initiative	Verified	13,143	13,143	13,143	13,143	13,143	13,143	13,143	13,143	13,143	13,143	12	2	2	2	2	2	2	2	2	2	2
	Adjustment to 2016 savings	True-up											12										
7	Efficiency: Equipment Replacement Incentive Initiative	Verified	3,695,390	3,676,386	3,676,386	3,676,386	3,676,386	3,675,209	3,675,209	3,675,209	3,674,505	3,674,505	12	140	137	137	137	137	136	136	136	136	136
	Adjustment to 2016 savings	True-up											12										
8	Direct Install Lighting and Water Heating Initiative	Verified											12										
	Adjustment to 2016 savings	True-up											12										
9	New Construction and Major Renovation Initiative	Verified											12										
	Adjustment to 2016 savings	True-up											12										
10	Existing Building Commissioning Incentive Initiative	Verified											3										
	Adjustment to 2016 savings	True-up											3										
	Industrial Program																						
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative	Verified											12										
	Adjustment to 2016 savings	True-up											12										
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	Verified											12										
	Adjustment to 2016 savings	True-up											12										
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified											12										
	Adjustment to 2016 savings	True-up											12										
	Low Income Program																						
14	Low Income Initiative	Verified	89,092	89,092	89,092	89,092	89,092	89,092	89,092	89,092	89,092	78,459	12	11	11	11	11	11	11	11	11	10
	Adjustment to 2016 savings	True-up											12										
	Other																						
15	Aboriginal Conservation Program	Verified											0										
	Adjustment to 2016 savings	True-up											0										
16	Program Enabled Savings	Verified											0										
	Adjustment to 2016 savings	True-up											0										
	Conservation Fund Pilots																						
17	Conservation Fund Pilot - EnerNOC	Verified											0										
	Adjustment to 2016 savings	True-up											0										
18	Loblaws Pilot	Verified											0										
	Adjustment to 2016 savings	True-up											0										
19	Conservation Fund Pilot - SEG	Verified											0										
	Adjustment to 2016 savings	True-up											0										
20	Social Benchmarking Pliot	Verified											0										
	Adjustment to 2016 savings	True-up											0										
	Conservation First Framework																						
	Residential Province-Wide Programs																						
21	Save on Energy Coupon Program	Verified																					
	Adjustment to 2016 savings	True-up																					
22	Save on Energy Heating and Cooling Program	Verified																					
	Adjustment to 2016 savings	True-up																					
23	Save on Energy New Construction Program	Verified																					
	Adjustment to 2016 savings	True-up																					
24	Save on Energy Home Assistance Program	Verified																					
	Adjustment to 2016 savings	True-up																					
	Non-Residential Province-Wide Programs																						
25	Save on Energy Audit Funding Program	Verified											12										
	Adjustment to 2016 savings	True-up											12										
26	Save on Energy Retrofit Program	Verified											12										
	Adjustment to 2016 savings	True-up											12										
27	Save on Energy Small Business Lighting Program	Verified											12										
	Adjustment to 2016 savings	True-up											12										
28	Save on Energy High Performance New Construction Program	Verified											12										
	Adjustment to 2016 savings	True-up											12										
29	Save on Energy Existing Building Commissioning Program	Verified											3										
	Adjustment to 2016 savings	True-up											3										
30	Save on Energy Process & Systems Upgrades Program	Verified											12										
	Adjustment to 2016 savings	True-up											12										
31	Save on Energy Monitoring & Targeting Program	Verified											12										

#	Program	Results Status	Rate Allocations for LRAMVA: Residential	General Service <50 kW	General Service 50 - 2,999 kW	General Service 3,000 - 4,999 kW	Sentinel Lighting	Street Lighting	Unmetered Scattered Load								Total
	Legacy Framework		kWh	kWh	kW	kW	kW	kW	kWh	0	0	0	0	0	0	0	
	Residential Program																
1	Coupon Initiative	Verified	100.00%														100%
	Adjustment to 2016 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Bi-Annual Retailer Event Initiative	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	Appliance Retirement Initiative	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	HVAC Incentives Initaitive	Verified	100.00%														100%
	Adjustment to 2016 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Residential New Construction and Major Renovation Initiative	Verified	100.00%														100%
	Adjustment to 2016 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Commercial & Institutional Program																
6	Energy Audit Initiative	Verified		25.00%	75.00%												100%
	Adjustment to 2016 savings	True-up	0.00%	25.00%	75.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Efficiency: Equipment Replacement Incentive Initiative	Verified		20.00%	20.00%			60.00%									100%
	Adjustment to 2016 savings	True-up	0.00%	20.00%	20.00%	0.00%	0.00%	60.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Direct Install Lighting and Water Heating Initiative	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	New Construction and Major Renovation Initiative	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
10	Existing Building Commissioning Incentive Initiative	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program																
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Low Income Program																
14	Low Income Initiative	Verified	100.00%														100%
	Adjustment to 2016 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other																
15	Aboriginal Conservation Program	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Program Enabled Savings	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Conservation Fund Pilots																
17	Conservation Fund Pilot - EnerNOC	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
18	Loblaws Pilot	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Conservation Fund Pilot - SEG	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Social Benchmarking Pliot	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Conservation First Framework																
	Residential Province-Wide Programs																
21	Save on Energy Coupon Program	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Save on Energy Heating and Cooling Program	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
23	Save on Energy New Construction Program	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
24	Save on Energy Home Assistance Program	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Non-Residential Province-Wide Programs																
25	Save on Energy Audit Funding Program	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
26	Save on Energy Retrofit Program	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
27	Save on Energy Small Business Lighting Program	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Save on Energy High Performance New Construction Program	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29	Save on Energy Existing Building Commissioning Program	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	Save on Energy Process & Systems Upgrades Program	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
31	Save on Energy Monitoring & Targeting Program	Verified															0%

	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Save on Energy Energy Manager Program	Verified											12																									0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Local & Regional Programs																																					
33	Business Refrigeration Local Program	Verified											0																									0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
34	First Nation Conservation Local Program	Verified											0																									0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
35	Social Benchmarking Local Program	Verified											0																									0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Pilot Programs																																					
36	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - Conservation Fund	Verified											0																									0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
37	EnWin Utilities Ltd. - Building Optimization Pilot	Verified											0																									0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
38	EnWin Utilities Ltd. - Re-Invest Pilot	Verified											0																									0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
39	Horizon Utilities Corporation - ECM Furnace Motor Pilot	Verified											0																									0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
40	Horizon Utilities Corporation - Social Benchmarking Pilot	Verified											0																									0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
41	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pilot	Verified											0																									0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
42	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot	Verified																																					0%
	Adjustment to 2016 savings	True-up																							0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
43	Kitchener-Wilmot Hydro Inc. - Pilot - DCKV	Verified											0																									0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
44	Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agricultural Sector	Verified											0																									0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
45	Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic	Verified											0																									0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
46	Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls	Verified											0																									0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
47	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)	Verified											0																									0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
48	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)	Verified											0																									0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
49	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)	Verified											0																									0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2016		7,078,022											532										**3,369,489**	**742,364**	**354**	**0**	**0**	**1,008**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Forecast CDM Savings in 2016																							**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Distribution Rate in 2016																							$0.01280	$0.01170	$2.15830	$1.38430	$9.56240	$8.73090	$0.02900	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
	Lost Revenue in 2016 from 2011 programs																							$8,539.75	$6,994.27	$2,173.17	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$17,707.20
	Lost Revenue in 2016 from 2012 programs																							$6,637.56	$9,089.36	$3,538.99	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$19,265.91
	Lost Revenue in 2016 from 2013 programs																							$9,076.13	$6,726.82	$4,706.12	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$20,509.07
	Lost Revenue in 2016 from 2014 programs																							$15,110.85	$10,781.17	$5,491.20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$31,383.22
	Lost Revenue in 2016 from 2015 programs																							$17,193.47	$15,082.88	$6,267.70	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$38,544.05
	Lost Revenue in 2016 from 2016 programs																							$43,129.46	$8,685.66	$764.04	$0.00	$0.00	$8,800.75	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$61,379.90
	Total Lost Revenues in 2016																							**$99,687.23**	**$57,360.15**	**$22,941.22**	**$0.00**	**$0.00**	**$8,800.75**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$188,789.35**
	Forecast Lost Revenues in 2016																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2016																																					**$188,789.35**
	2016 Savings Persisting in 2017																							3,369,489	738,563	347	0	0	986	0	0	0	0	0	0	0	0	
	2016 Savings Persisting in 2018																							3,369,489	738,563	347	0	0	986	0	0	0	0	0	0	0	0	
	2016 Savings Persisting in 2019																							3,369,489	738,563	347	0	0	986	0	0	0	0	0	0	0	0	
	2016 Savings Persisting in 2020																							3,369,489	738,563	347	0	0	986	0	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

Table 5-c. 2017 Lost Revenues Work Form Return to top

Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA														
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Residential	General Service <50 kW	General Service 50 - 2,999 kW	General Service 3,000 - 4,999 kW	Sentinel Lighting	Street Lighting	Unmetered Scattered Load								Total
Legacy Framework																							kWh	kWh	kW	kW	kW	kW	kWh	0	0	0	0	0	0	0	
Actual CDM Savings in 2017		0											0										**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Forecast CDM Savings in 2017																							**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Distribution Rate in 2017																							$0.00910	$0.01190	$2.19740	$1.40950	$9.73610	$8.88940	$0.02950	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
Lost Revenue in 2017 from 2011 programs																							$5,457.08	$6,322.09	$2,212.54	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$13,991.70
Lost Revenue in 2017 from 2012 programs																							$4,363.66	$8,959.05	$3,498.62	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$16,821.33
Lost Revenue in 2017 from 2013 programs																							$6,184.23	$5,554.83	$4,585.04	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$16,324.10
Lost Revenue in 2017 from 2014 programs																							$10,741.62	$10,657.68	$5,577.24	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$26,976.54
Lost Revenue in 2017 from 2015 programs																							$12,223.48	$15,314.08	$6,368.07	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$33,905.63
Lost Revenue in 2017 from 2016 programs																							$30,662.35	$8,788.90	$762.06	$0.00	$0.00	$8,768.50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$48,981.81
Lost Revenue in 2017 from 2017 programs																							$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2017																							**$69,632.42**	**$55,596.63**	**$23,003.56**	**$0.00**	**$0.00**	**$8,768.50**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$157,001.12**
Forecast Lost Revenues in 2017																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2017																																					**$157,001.12**
2017 Savings Persisting in 2018																							0	0	0	0	0	0	0	0	0	0	0	0	0	0	
2017 Savings Persisting in 2019																							0	0	0	0	0	0	0	0	0	0	0	0	0	0	
2017 Savings Persisting in 2020																							0	0	0	0	0	0	0	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

Table 5-d. 2018 Lost Revenues Work Form Return to top

	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)		Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)	Rate Allocations for LRAMVA

Program	Results Status	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Monthly Multiplier	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Legacy Framework																						
Actual CDM Savings in 2018		0											0									
Forecast CDM Savings in 2018																						

Program	Residential	General Service <50 kW	General Service 50 - 2,999 kW	General Service 3,000 - 4,999 kW	Sentinel Lighting	Street Lighting	Unmetered Scattered Load								Total
Legacy Framework	kWh	kWh	kW	kW	kW	kW	kWh	0	0	0	0	0	0	0	
Actual CDM Savings in 2018	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Forecast CDM Savings in 2018	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Distribution Rate in 2018	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
Lost Revenue in 2018 from 2011 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2012 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2013 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2014 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2015 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2016 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2017 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2018 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2018	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2018	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2018															**$0.00**
2018 Savings Persisting in 2019	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
2018 Savings Persisting in 2020	0	0	0	0	0	0	0	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

Table 5-e. 2019 Lost Revenues Work Form Return to top

Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)								
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Legacy Framework																						
Actual CDM Savings in 2019		0											0									
Forecast CDM Savings in 2019																						

Program	Rate Allocations for LRAMVA														
	Residential	General Service <50 kW	General Service 50 - 2,999 kW	General Service 3,000 - 4,999 kW	Sentinel Lighting	Street Lighting	Unmetered Scattered Load								Total
Legacy Framework	kWh	kWh	kW	kW	kW	kW	kWh	0	0	0	0	0	0	0	
Actual CDM Savings in 2019	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Forecast CDM Savings in 2019	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Distribution Rate in 2019	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
Lost Revenue in 2019 from 2011 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2012 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2013 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2014 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2015 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2016 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2017 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2018 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2019 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2019	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2019	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2019															**$0.00**
2019 Savings Persisting in 2020	0	0	0	0	0	0	0	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

Table 5-f. 2020 Lost Revenues Work Form Return to top

Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)								
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Legacy Framework																						
Actual CDM Savings in 2020		0											0									
Forecast CDM Savings in 2020																						

Program	Rate Allocations for LRAMVA														
	Residential	General Service <50 kW	General Service 50 - 2,999 kW	General Service 3,000 - 4,999 kW	Sentinel Lighting	Street Lighting	Unmetered Scattered Load								Total
Legacy Framework	kWh	kWh	kW	kW	kW	kW	kWh	0	0	0	0	0	0	0	
Actual CDM Savings in 2020	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Forecast CDM Savings in 2020	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Distribution Rate in 2020	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
Lost Revenue in 2020 from 2011 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2012 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2013 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2014 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2015 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2016 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2017 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2018 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2019 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2020 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2020	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2020	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2020															**$0.00**

Note: LDC to make note of key assumptions included above

Return to top

Ontario Energy Board

LRAMVA Work Form:
Carrying Charges by Rate Class

Version 2.0 (2017)

Legend

User Inputs (Green)
Auto Populated Cells (White)
Instructions (Grey)

Instructions

1. Please update Table 6 as new approved prescribed interest rates for deferral and variance accounts become available. Monthly interest rates are used to calculate the variance on the carrying charges for LRAMVA. Starting from column I, the principal will auto-populate as monthly variances in Table 6-a, and are multiplied by the interest rate from column H to determine the monthly variances on carrying charges for each rate class by year.

2. The annual carrying charges totals in Table 6-a below pertain to the amount that was originally collected in interest from forecasted CDM savings and what should have been collected based on actual CDM savings. As the amounts calculated in Table 6-a are cumulative, LDCs are requested to enter any collected interest amounts into the "Amounts Cleared" row in order to clear the balance and calculate outstanding variances on carrying charges.

Table 6. Prescribed Interest Rates

Quarter	Approved Deferral & Variance Accounts
2011 Q1	1.47%
2011 Q2	1.47%
2011 Q3	1.47%
2011 Q4	1.47%
2012 Q1	1.47%
2012 Q2	1.47%
2012 Q3	1.47%
2012 Q4	1.47%
2013 Q1	1.47%
2013 Q2	1.47%
2013 Q3	1.47%
2013 Q4	1.47%
2014 Q1	1.47%
2014 Q2	1.47%
2014 Q3	1.47%
2014 Q4	1.47%
2015 Q1	1.47%
2015 Q2	1.10%
2015 Q3	1.10%
2015 Q4	1.10%
2016 Q1	1.10%
2016 Q2	1.10%
2016 Q3	1.10%
2016 Q4	1.10%
2017 Q1	1.10%
2017 Q2	1.10%
2017 Q3	1.10%
2017 Q4	1.10%
2018 Q1	
2018 Q2	
2018 Q3	
2018 Q4	
2019 Q1	
2019 Q2	
2019 Q3	
2019 Q4	
2020 Q1	
2020 Q2	
2020 Q3	
2020 Q4	

Check OEB website

Table 6-a. Calculation of Carrying Costs by Rate Class

Go to Tab 1: Summary

Month	Period	Quarter	Monthly Rate	Residential	General Service <50 kW	General Service 50 - 2,999 kW	General Service 3,000 - 4,999 kW	Sentinel Lighting	Street Lighting	Unmetered Scattered Load								Total
Jan-11	2011	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-11	2011	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-11	2011	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-11	2011	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-11	2011	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-11	2011	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-11	2011	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-11	2011	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-11	2011	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-11	2011	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-11	2011	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-11	2011	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2011				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2012				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-12	2011-2012	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-12	2011-2012	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-12	2011-2012	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-12	2011-2012	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-12	2011-2012	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-12	2011-2012	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-12	2011-2012	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-12	2011-2012	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-12	2011-2012	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-12	2011-2012	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-12	2011-2012	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-12	2011-2012	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2012				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2013				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-13	2011-2013	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-13	2011-2013	Q1	0.12%	$3.25	$2.47	$1.33	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.05
Mar-13	2011-2013	Q1	0.12%	$6.50	$4.94	$2.67	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$14.11
Apr-13	2011-2013	Q2	0.12%	$9.75	$7.41	$4.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$21.16
May-13	2011-2013	Q2	0.12%	$13.00	$9.89	$5.33	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$28.22
Jun-13	2011-2013	Q2	0.12%	$16.25	$12.36	$6.67	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$35.27
Jul-13	2011-2013	Q3	0.12%	$19.50	$14.83	$8.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$42.32
Aug-13	2011-2013	Q3	0.12%	$22.74	$17.30	$9.33	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$49.38
Sep-13	2011-2013	Q3	0.12%	$25.99	$19.77	$10.66	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$56.43
Oct-13	2011-2013	Q4	0.12%	$29.24	$22.24	$12.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$63.48
Nov-13	2011-2013	Q4	0.12%	$32.49	$24.72	$13.33	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$70.54
Dec-13	2011-2013	Q4	0.12%	$35.74	$27.19	$14.66	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$77.59
Total for 2013				**$214.45**	**$163.12**	**$87.98**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$465.56**
Amount Cleared																		
Opening Balance for 2014				**$214.45**	**$163.12**	**$87.98**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$465.56**
Jan-14	2011-2014	Q1	0.12%	$38.99	$29.66	$16.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$84.65
Feb-14	2011-2014	Q1	0.12%	$44.34	$33.16	$17.74	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$95.24
Mar-14	2011-2014	Q1	0.12%	$49.70	$36.66	$19.48	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$105.84
Apr-14	2011-2014	Q2	0.12%	$55.05	$40.16	$21.23	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$116.44
May-14	2011-2014	Q2	0.12%	$60.40	$43.66	$22.97	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$127.03
Jun-14	2011-2014	Q2	0.12%	$65.76	$47.16	$24.71	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$137.63
Jul-14	2011-2014	Q3	0.12%	$71.11	$50.66	$26.46	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$148.22
Aug-14	2011-2014	Q3	0.12%	$76.46	$54.16	$28.20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$158.82
Sep-14	2011-2014	Q3	0.12%	$81.82	$57.66	$29.94	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$169.42
Oct-14	2011-2014	Q4	0.12%	$87.17	$61.16	$31.69	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$180.01
Nov-14	2011-2014	Q4	0.12%	$92.52	$64.66	$33.43	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$190.61
Dec-14	2011-2014	Q4	0.12%	$97.88	$68.16	$35.17	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$201.21
Total for 2014				**$1,035.66**	**$750.01**	**$395.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$2,180.67**
Amount Cleared																		
Opening Balance for 2015				**$1,035.66**	**$750.01**	**$395.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$2,180.67**
Jan-15	2011-2015	Q1	0.12%	$103.23	$71.65	$36.92	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$211.80
Feb-15	2011-2015	Q1	0.12%	$110.45	$76.63	$39.26	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$226.34
Mar-15	2011-2015	Q1	0.12%	$117.67	$81.61	$41.59	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$240.88
Apr-15	2011-2015	Q2	0.09%	$93.46	$64.80	$32.88	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$191.13
May-15	2011-2015	Q2	0.09%	$98.86	$68.52	$34.63	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$202.01
Jun-15	2011-2015	Q2	0.09%	$104.26	$72.25	$36.38	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$212.89
Jul-15	2011-2015	Q3	0.09%	$109.66	$75.98	$38.13	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$223.77
Aug-15	2011-2015	Q3	0.09%	$115.07	$79.70	$39.88	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$234.65
Sep-15	2011-2015	Q3	0.09%	$120.47	$83.43	$41.63	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$245.53
Oct-15	2011-2015	Q4	0.09%	$125.87	$87.16	$43.38	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$256.40
Nov-15	2011-2015	Q4	0.09%	$131.28	$90.88	$45.13	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$267.28
Dec-15	2011-2015	Q4	0.09%	$136.68	$94.61	$46.88	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$278.16
Total for 2015				**$2,402.61**	**$1,697.24**	**$871.66**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$4,971.51**
Amount Cleared																		
Opening Balance for 2016				**$2,402.61**	**$1,697.24**	**$871.66**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$4,971.51**
Jan-16	2011-2016	Q1	0.09%	$142.08	$98.33	$48.63	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$289.04
Feb-16	2011-2016	Q1	0.09%	$149.70	$102.72	$50.38	$0.00	$0.00	$0.67	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$303.46
Mar-16	2011-2016	Q1	0.09%	$157.31	$107.10	$52.13	$0.00	$0.00	$1.34	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$317.89
Apr-16	2011-2016	Q2	0.09%	$164.93	$111.48	$53.88	$0.00	$0.00	$2.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$332.31
May-16	2011-2016	Q2	0.09%	$172.54	$115.86	$55.64	$0.00	$0.00	$2.69	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$346.73
Jun-16	2011-2016	Q2	0.09%	$180.16	$120.24	$57.39	$0.00	$0.00	$3.36	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$361.15
Jul-16	2011-2016	Q3	0.09%	$187.77	$124.62	$59.14	$0.00	$0.00	$4.03	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$375.57
Aug-16	2011-2016	Q3	0.09%	$195.39	$129.01	$60.89	$0.00	$0.00	$4.71	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$389.99
Sep-16	2011-2016	Q3	0.09%	$203.00	$133.39	$62.65	$0.00	$0.00	$5.38	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$404.41
Oct-16	2011-2016	Q4	0.09%	$210.62	$137.77	$64.40	$0.00	$0.00	$6.05	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$418.83
Nov-16	2011-2016	Q4	0.09%	$218.23	$142.15	$66.15	$0.00	$0.00	$6.72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$433.26
Dec-16	2011-2016	Q4	0.09%	$225.85	$146.53	$67.90	$0.00	$0.00	$7.40	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$447.68
Total for 2016				**$4,610.18**	**$3,166.44**	**$1,570.84**	**$0.00**	**$0.00**	**$44.37**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$9,391.83**
Amount Cleared																		

Ontario Energy Board

Supporting D
LDC Persistence Savi

Legend

User Inputs (Green)
Drop Down List (Blue)
Instructions (Grey)

Instructions
(Steps)

1. Columns B to H of this tab have been structured in a way to match the formatting of the persistence report provided by the IESO. Please copy and paste the program information by initiat

2. Please identify the source of the report via the dropdown list in Column I.

3. To faciliate the identification of adjustments that may be available in a prospective year's results report, it will be easier to sort all the savings by implementation year (Column H). This car

4. Please identify what the savings value represents (i.e., current year savings for the year or an adjustment to a prior year) via the dropdown list in Column J. Current year savings would be

5. Please manually input or link the applicable savings and adjustments (Columns L to BT) for all applicable initiatives in Tabs 4 and 5 of this work form.

NOTE: The Net Verified Peak Demand Savings table and Net Verified Energy Savings table below are in the reverse order to the accompanying tables in Tab 4 and Tab 5. The ta

Table 7. 2011-2020 Verified Program Results and Persistence into Future Years

Step:	*#1*					*#3*	*#2*
Portfolio	**Program**	**Initiative**	**LDC**	**Sector**	**Conservation Resource Type**	**(Implementation) Year**	**Identify Source of Report**
Non-LDC	Business	peaksaverPLUS	Essex Powerlines Corporation	Commercial & Institutional	DR	2009	2013 Results Persistence
Non-LDC	Consumer	peaksaverPLUS	Essex Powerlines Corporation	Residential	DR	2009	2013 Results Persistence
non-Tier 1	Business	Commercial Demand Response	Essex Powerlines Corporation	Commercial	DR	2009	2014 Results Persistence
non-Tier 1	Consumer	Residential Demand Response	Essex Powerlines Corporation	Residential	DR	2009	2014 Results Persistence
Tier 1	Consumer	Residential Demand Response	Essex Powerlines Corporation	Residential	DR	2009	2014 Results Persistence
Non-LDC	Consumer	peaksaverPLUS	Essex Powerlines Corporation	Residential	DR	2010	2013 Results Persistence
non-Tier 1	Consumer	Residential Demand Response	Essex Powerlines Corporation	Residential	DR	2010	2014 Results Persistence
Tier 1	Consumer	Residential Demand Response	Essex Powerlines Corporation	Residential	DR	2010	2014 Results Persistence
Tier 1	Consumer	Appliance Exchange	Essex Powerlines Corporation	Residential	EE	2011	2011 Results Persistence
Tier 1	Consumer	Appliance Retirement	Essex Powerlines Corporation	Residential	EE	2011	2011 Results Persistence
Tier 1	Consumer	Bi-Annual Retailer Event	Essex Powerlines Corporation	Residential	EE	2011	2011 Results Persistence
Tier 1	Consumer	Conservation Instant Coupon Booklet	Essex Powerlines Corporation	Residential	EE	2011	2011 Results Persistence
Tier 1	Industrial	Demand Response 3	Essex Powerlines Corporation	Industrial	DR	2011	2011 Results Persistence
Tier 1	Business	Demand Response 3 (part of the Industrial program schedule)	Essex Powerlines Corporation	Commercial & Institutional	DR	2011	2011 Results Persistence
Tier 1	Business	Direct Install Lighting	Essex Powerlines Corporation	Commercial & Institutional	EE	2011	2011 Results Persistence
Tier 1	Pre-2011 Prog	Electricity Retrofit Incentive Program	Essex Powerlines Corporation	Commercial & Institutional	EE	2011	2011 Results Persistence
Tier 1	Pre-2011 Prog	High Performance New Construction	Essex Powerlines Corporation	Commercial & Institutional	EE	2011	2011 Results Persistence
Tier 1	Consumer	HVAC Incentives	Essex Powerlines Corporation	Residential	EE	2011	2011 Results Persistence
Tier 1	Consumer	Residential Demand Response	Essex Powerlines Corporation	Residential	DR	2011	2011 Results Persistence
Tier 1	Consumer	Retailer Co-op	Essex Powerlines Corporation	Residential	EE	2011	2011 Results Persistence
Tier 1	Business	Retrofit	Essex Powerlines Corporation	Commercial & Institutional	EE	2011	2011 Results Persistence
Tier 1	Industrial	Retrofit	Essex Powerlines Corporation	Industrial	EE	2011	2011 Results Persistence
Tier 1 - 2011 Adjustment	Consumer	Bi-Annual Retailer Event	Essex Powerlines Corporation	Residential	EE	2011	2012 Results Persistence
Tier 1 - 2011 Adjustment	Consumer	Conservation Instant Coupon Booklet	Essex Powerlines Corporation	Residential	EE	2011	2012 Results Persistence
Tier 1 - 2011 Adjustment	Pre-2011 Prog	High Performance New Construction	Essex Powerlines Corporation	C&I	EE	2011	2012 Results Persistence
Tier 1 - 2011 Adjustment	Consumer	HVAC Incentives	Essex Powerlines Corporation	Residential	EE	2011	2012 Results Persistence
LDC	Consumer	peaksaverPLUS	Essex Powerlines Corporation	Residential	DR	2011	2013 Results Persistence
Tier 1	Consumer	Residential Demand Response	Essex Powerlines Corporation	Residential	DR	2011	2014 Results Persistence

ocumentation:
ngs Results from IESO

Version 2.0 (2017)

:ive in Columns B to H and the corresponding demand and energy savings data by initiative in Columns L to BT of this work form.

ı be done by clicking on the filter button at cell H25 (highlighted in orange). Before you sort values, please ensure that all table columns have filters.

: identified with an implementation year that matches the year of the persistence report. A savings adjustment would be identified with a prior year implementation in the future year's results report.

bles below match those provided by the IESO.

#4 Identify Status of Savings	#1 Net Verified Annual Peak Demand Savings at the End-User Level (kW)																					
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Adjustment	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Adjustment	0	0	55	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Adjustment	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Adjustment	0	0	0	23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Adjustment	0	0	0	23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Adjustment	0	0	146	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Adjustment	0	0	0	64	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Adjustment	0	0	0	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Current year savings	3	3	3	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Current year savings	7	7	7	7	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Current year savings	11	11	11	11	10	9	8	8	9	4	1	1	1	1	1	0	0	0	0	0	0	0
Current year savings	8	8	8	8	7	7	6	6	7	4	0	0	0	0	0	0	0	0	0	0	0	0
Current year savings	1,749	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Current year savings	188	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Current year savings	52	52	52	36	36	35	7	7	7	7	6	6	0	0	0	0	0	0	0	0	0	0
Current year savings	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0	0	0	0	0
Current year savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Current year savings	264	264	264	264	264	264	264	264	264	264	264	264	264	264	264	264	264	264	196	0	0	0
Current year savings	48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Current year savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Current year savings	56	56	56	56	56	56	56	56	52	52	52	52	17	0	0	0	0	0	0	0	0	0
Current year savings	93	93	93	93	93	93	93	93	93	93	93	93	0	0	0	0	0	0	0	0	0	0
Adjustment	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Adjustment	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-29	0	0	0
Adjustment	0	0	39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Adjustment	0	0	0	33	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

#1

Net Verified Annual Energy Savings at the End-User Level (kWh)

2033	2034	2035	2036	2037	2038	2039	2040	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	94	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	257	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	3,231	3,231	3,231	1,432	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	48,406	48,406	48,406	48,203	37,742	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	192,162	192,162	192,162	192,162	175,622	157,552	118,784	118,351	152,960	49,084	17,673	15,557
0	0	0	0	0	0	0	0	121,822	121,822	121,822	121,822	112,064	101,404	79,289	78,776	99,193	37,912	12,245	9,980
0	0	0	0	0	0	0	0	102,648	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	7,344	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	139,935	139,935	139,935	87,918	87,918	84,499	17,966	17,966	17,966	17,966	16,329	16,329
0	0	0	0	0	0	0	0	56,015	56,015	56,015	56,015	56,015	56,015	56,015	56,015	56,015	56,015	56,015	56,015
0	0	0	0	0	0	0	0	1,239	1,239	1,239	1,239	1,239	1,239	1,239	1,239	1,239	1,239	1,239	1,239
0	0	0	0	0	0	0	0	463,694	463,694	463,694	463,694	463,694	463,694	463,694	463,694	463,694	463,694	463,694	463,694
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	337,744	337,744	337,744	337,744	337,744	337,744	337,744	337,744	317,302	317,302	317,302	317,302
0	0	0	0	0	0	0	0	688,860	688,860	688,860	688,860	688,860	688,860	688,860	688,860	688,860	688,860	688,860	688,860
0	0	0	0	0	0	0	0	14,277	14,277	14,277	14,277	14,277	12,974	7,004	7,003	7,003	1,545	1,298	1,192
0	0	0	0	0	0	0	0	1,802	1,802	1,802	1,802	1,802	1,647	1,010	1,009	1,009	357	161	117
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	-70,103	-70,103	-70,103	-70,103	-70,103	-70,103	-70,103	-70,103	-70,103	-70,103	-70,103	-70,103
0	0	0	0	0	0	0	0	0	0	67	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15,557	11,490	11,490	10,440	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9,980	9,222	9,222	8,963	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
56,015	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1,239	1,239	1,239	1,239	1,239	1,239	1,239	1,239	1,239	1,239	1,239	1,239	1,239	1,239	0	0	0	0
463,694	463,694	463,694	463,694	463,694	463,694	402,761	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
102,183	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85,379	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1,192	989	989	988	0	0	0	0	0	0	0	0	0	0	0	0	0	0
117	105	105	104	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
-70,103	-70,103	-70,103	-70,103	-70,103	-70,103	-60,297	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Ontario Energy Board

LRAMVA Work Form: Documentation for Streetlighting Projects

Version 2.0 (2017)

Instructions

Please provide documentation and/or data to substantiate program savings that were not provided in the IESO's verified results reports (i.e., streetlighting projects).

EPLC had two significant streetlighting retrofits in 2016. EPLC calculated that these two streetlighting retrofits account for approximately 60% of ERII savings in 2016. As a result, EPLC allocated 60% of ERII savings to the Streetlighting rate class.

Exhibit 5:

Cost of Capital

Table of Contents

List of Attachments

5.1 Capital Structure

This section is intended to summarize EPLC's methodology and cost of financing capital requirements for the 2018 Test Year.

For clarity, EPLC followed the Report of the Board on the *Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084, December 11th, 2009*), the OEB's *Review of Existing Methodology of the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084, January 14th, 2016)* and the OEB's letter titled *Cost of Capital Parameter Updates for 2017 Cost of Service and Custom Incentive Rate-setting Applications (October 27th, 2016)*.

EPLC acknowledges and understands that these rates are subject to change at such time that the 2018 Cost of Capital parameters are issued by the OEB.

For the purpose of this Application, EPLC has completed its application with a deemed capital structure of 56% Long Term Debt, 4% Short Term Debt and 40% Equity in accordance with the OEB issued documentation listed above. No significant changes to this structure are expected in the foreseeable future.

In summary, EPLC is requesting the following for the 2018 Test Year: a deemed interest expense of $1,230,186 and a deemed return on equity of $2,104,644 for a total regulated rate of return on capital of $3,334,829.

5.2 Cost of Capital

5.2.1 Cost of Long Term Debt

For the purpose of this Application, EPLC has utilized its actual Long-Term Debt Rate of 3.54% which is lower than the Board prescribed deemed rate of 3.72% issued by the Board October 27th, 2017. A summary of EPLC's Debt Instruments are included as Attachments 5-A, 5B and 5-C of this Exhibit. Attachment 5-C is consistent with Board Appendix 2-OB.

EPLC acknowledges and understands that these rates are subject to change at such time that the 2018 Cost of Capital parameters are issued by the OEB.

5.2.2 Cost of Short Term Debt

For the purpose of this Application, EPLC has utilized and is requesting the Deemed Short-Term Debt Rate of 1.76% issued by the OEB October 27th, 2017.

EPLC acknowledges and understands that these rates are subject to change at such time that the 2018 Cost of Capital parameters are issued by the OEB.

5.2.3 Return on Equity

For the purpose of this Application, EPLC has utilized and is requesting the Return on Equity Rate of 8.78% issued by the OEB October 27th, 2017.

EPLC acknowledges and understands that these rates are subject to change at such time that the 2018 Cost of Capital parameters are issued by the OEB.

5.2.4 Profit or Loss on Redemption of Debt and/or Preferred Shares

EPLC has not redeemed any debt and does not have any preferred shares therefore this filing requirement is not applicable.

5.2.5 Notional Debt

EPLC's deemed and actual long-term debts are relatively close. For 2018, EPLC is currently estimating its average long-term debt balance at $25,114,828. EPLC's deemed long-term debt is $35,957,227 which results in notional debt of $10,842,399. EPLC understands the notional debt should attract the weighted average cost of actual long-term debt.

5.2.6 Weighted Average Cost of Capital

Figure 1 below demonstrates EPLC's previously OEB Approved capital structure consistent with the OEB Appendix 2-OA. Further, Figure 2 below demonstrates EPLC's proposed capital structure for the 2018 Test Year. OEB Appendix 2-OA for 2010 and 2018 are affixed as Attachment 5-E. For the 2018 Test Year, EPLC is requesting a Weighted Average Cost of Capital of 5.56% on a proposed Rate Base of $59,927,210 resulting in a Return on Rate Base of $3,334,829. Further detail is available in Exhibit 2 of this Application.

Figure 1 – OEB Approved Capital Structure – 2010 COS

Appendix 2-OA
Capital Structure and Cost of Capital

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

Year: 2010 Board Approved

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$23,027,039	5.40%	$1,244,473
2	Short-term Debt	4.00%	(1)	$1,644,789	2.07%	$34,047
3	**Total Debt**	60.0%		$24,671,828	5.18%	$1,278,520
	Equity					
4	Common Equity	40.00%		$16,447,885	9.85%	$1,620,117
5	Preferred Shares	0.00%		$ -	0.00%	$ -
6	**Total Equity**	40.0%		$16,447,885	9.85%	$1,620,117
7	**Total**	100.0%		$41,119,713	7.05%	$2,898,637

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

Figure 2 – Proposed Capital Structure – 2018 Test Year

Year: 2018 Test Year

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$33,559,238	3.54%	$1,187,997
2	Short-term Debt	4.00%	(1)	$2,397,088	1.76%	$42,189
3	**Total Debt**	60.0%		$35,956,326	3.42%	$1,230,186
	Equity					
4	Common Equity	40.00%		$23,970,884	8.78%	$2,104,644
5	Preferred Shares			$ -	0.00%	$ -
6	**Total Equity**	40.0%		$23,970,884	8.78%	$2,104,644
7	**Total**	100.0%		$59,927,210	5.56%	$3,334,829

5.3 Not for Profit Corporations

EPLC is a for profit corporation therefore this filing requirement is not applicable.

Attachment 5-A

Municipality of Leamington – Note Payable 1

LONG TERM FINANCING AGREEMENT

THIS AGREEMENT made this 20th day of December, 2012

BETWEEN:

THE CORPORATION OF THE MUNICIPALITY OF LEAMINGTON

(hereinafter referred to as **"The Municipality"**)

OF THE FIRST PART

and

ESSEX POWERLINES CORPORATION

(hereinafter referred to as **"EPL"**)

OF THE SECOND PART

WHEREAS EPL is duly incorporated pursuant to Section 142, Schedule A of the Electricity Act, 1998;

AND WHEREAS The Municipality is duly incorporated pursuant to The Ministry of Municipal Affairs and Housing Order;

AND WHEREAS The Municipality presently holds a loan from EPL pursuant to an agreement that expires on December 31, 2012,

AND WHEREAS The Municipality is a shareholder of EPL and operate as separate corporate entities, notwithstanding the provisions of this Agreement and other agreements that the parties may enter into from time to time;

AND WHEREAS the parties shall consult as frequently as may be desirable to ensure declarations and intentions are known;

NOW THEREFORE IN CONSIDERATION the parties have agreed that The Municipality will continue to hold a loan for the sum of 2,150,296 dollars of lawful money of Canada (hereinafter referred to as the original loan principal, the receipt and sufficiency of which is hereby expressly acknowledged), the Parties covenant and agree, with each other, as follows;

1. Prior Agreements

All other agreements regarding the matters contained in this agreement, whether oral or written, are terminated.

2. Term

The term of this Agreement shall be from January 1, 2013 to and including December 31, 2017 and year by year thereafter until there is no outstanding loan principal unless EPL gives notification in writing not less than one year to The Municipality that EPL wishes to end the agreement at which time EPL will pay the remaining loan principal and interest prior to the end of the Agreement.

3. Repayment Schedule

3.01 EPL shall pay The Municipality annually not more than twenty percent (20%) of the original loan principal in the first year of this agreement and not more than twenty percent (20%) thereafter subject to article 3.03 and 3.04.

3.02 The Municipality may defer the payment in any year to a subsequent year and EPL shall pay The Municipality the deferred payment or payments in addition to the current year's annual payment subject to article 3.03 and 3.04.

3.03 The Municipality shall notify EPL by March 1 or the 1st business day thereafter in the year that payment is due The Municipality's intention to receive payment as per article 3.01 and 3.02.

3.04 EPL shall notify The Municipality by July 1 or the 1st business day thereafter EPL's intention to make payment or partial payment as per article 3.01 and 3.02 by October 1 or the 1st business day thereafter in the year that payment is due.

3.05 The Municipality may request payment and EPL will make payment of the entire outstanding loan principal by notifying EPL by March 1 that The Municipality wishes payment to be made by March 1 of the following year conditional on EPL's ability to make distributions according to the "Unanimous Shareholders Agreement" which classifies this agreement as a "Second Tier Loan".

4. Interest

Interest means the rate paid for use of the outstanding loan principal calculated at 4% per annum of the loan principal calculated annually and payable to The Municipality by the 20th business day following the calendar year end.

5. Arbitration

5.01 The parties agree to consult with each other and to negotiate in good faith to resolve any differences or disputes which either party may have relating to the interpretation, application or implementation of this agreement, or any dispute which may arise over any costs, fees or other costs incurred and failing agreement the parties agree to resolve their disputes by arbitration as provided in Article 5.02.

5.02 Arbitration of a dispute shall be commenced by written notice by a party requesting arbitration to the other, which notice shall identify the issue or issues it wishes to submit to arbitration. Within thirty (30) days of the date of the notice, the Parties shall agree upon a single arbitrator and failing agreement then each party shall appoint an arbitrator and the two appointees shall within 45 days of the date of the notice of arbitration appoint a third person who shall act as Chair of the arbitration panel, and failing agreement the Chair shall be appointed by a judge of the Superior Court of Ontario pursuant to the provisions of the Arbitration's Act, RSO 1991 c.A.17.

5.03 The commencement of the arbitration and all rules of procedure for the arbitration shall be by agreement of the Parties, or failing agreement, as determined by the arbitrator or Chair of the arbitrator panel. The provisions of the Arbitration's Act, RSO 1991 c.A.17, as amended or any successor legislation shall apply to the arbitration.

5.04 All decisions of the arbitrator or arbitrators, as the case may be, shall be made in writing and shall be delivered to all Parties within ten (10) days from the conclusion of the arbitration. All decisions shall be final and binding upon the Parties, their respective successors and assigns, and shall not be subject to appeal.

5.05 Each Party shall pay its own costs incurred in respect of the arbitration including the payment of its appointee to the arbitration panel, and in the case of a three person panel the parties agree to share the fees of the Chair and other related costs equally.

6. Notices

All notices required to be given to either of the Parties under this Agreement shall be in writing and shall be delivered by prepaid unregistered post or hand delivery to the following:

a) to the Municipal Clerk at: 111 Erie Street North, Leamington, Ontario, N8H 2Z9

b) to the General Manager, EPL at: 360 Fairview Avenue West Suite 318, Essex, Ontario, N8M 3G4

or to such other address or individual as may be designated by written notice to the other Party. Any notice given by personal delivery shall be deemed to have been given on the day of actual delivery hereof and if sent by prepaid post, on the third day after mailing.

7. Amendments

Amendments to this Agreement shall be in writing and executed by the Parties duly authorized signing officers.

8. Headings

The headings in this Agreement are for purposes of reference only and shall not be read or construed so as to abridge or modify the meaning of any provision in the main text of this Agreement.

9. Governing Law

This Agreement shall be construed in accordance with the laws of the Province of Ontario.

10. Successors

10.01 This Agreement shall ensure to the benefit of and be binding upon the Parties and their successors and assigns, respectively.

10.02 The Parties explicitly acknowledge and agree that the term of this Agreement shall remain in full force and effect and be binding upon new business corporations incorporated under the Business Corporations Act to whom assets and liabilities will be transferred.

10.03 For the purposes of this Agreement, whenever the term The Municipality or EPL is used, the term shall be deemed to include all successor business corporations incorporated to whom assets and liabilities are transferred.

11. Regulatory Changes

The Parties acknowledge that substantial changes to legislation and regulations and government policies are likely to occur during the term of this Agreement which are likely to affect the nature of the relationship between them, and as consequence the parties hereby agree to consult and negotiate in good faith any amendments to this Agreement which may be necessitated by changes in the regulatory environment, and failing agreement to submit their differences to arbitration as provided in Article 5.

IN WITNESS WHEREOF the Parties have duly executed this Agreement on the date first above written:

The Municipality of Leamington

Per:

Mayor – John Paterson

Clerk – Brian R. Sweet

Essex Powerlines Corporation

Per:

Chair WAYNE HURST

General Manager RICHARD DIMMER

<u>Attachment 5-B</u>

Town of Tecumseh – Note Payable 2

The Corporation of the

917 Lesperance Road
Tecumseh, ON
N8N 1W9

Phone (519) 735-2184
Fax (519) 735-6712
www.tecumseh.ca

Town of Tecumseh
Staff Services/Clerk

December 18, 2012

ESSEX POWERLINES CORPORATION
2730 Highway 3
Oldcastle, ON N0R1L0
Attn: Richard Dimmel, Vice President of Finance

Dear Mr. Dimmel:

Re: Long Term Financing Agreement, 2013 - 2017

The Municipal Council of the Town of Tecumseh, at their regular meeting held Tuesday, December 11, 2012, gave consideration to entering into a Long Term Financing Agreement with Essex Powerlines Corporation.

At the meeting Council passed the following resolution (RCM-436/12):

> "***THAT*** *By-law No. 2012-96,* being a by-law to authorize the execution of a Long Term Financing Agreement between The Corporation of the Town of Tecumseh and Essex Powerlines be given third and final reading...
>
> *Carried"*

Enclosed for your records is one original fully executed Long Term Financing Agreement as between The Corporation of the Town of Tecumseh and Essex Powerlines Corporation.

Yours very truly,
TOWN OF TECUMSEH

Laura Moy

Laura Moy, A.M.C.T.
Director Staff Services / Clerk

LM/sk
Cc: Luc Gagnon, Director Financial Services / Treasurer

LONG TERM FINANCING AGREEMENT

THIS AGREEMENT made this 28th day of November, 2012

BETWEEN:

THE CORPORATION OF THE TOWN OF TECUMSEH (hereinafter referred to as **"The Town"**)

OF THE FIRST PART

and

ESSEX POWERLINES CORPORATION (hereinafter referred to as **"EPL"**)

OF THE SECOND PART

WHEREAS EPL is duly incorporated pursuant to Section 142, Schedule A of the Electricity Act, 1998;

AND WHEREAS The Town is duly incorporated pursuant to The Ministry of Municipal Affairs and Housing Order;

AND WHEREAS the parties have agreed that The Town holds a promissory note dated June 1, 2000;

AND WHEREAS The Town is a shareholder of EPL and operate as separate corporate entities, notwithstanding the provisions of this Agreement and other agreements that the parties may enter into from time to time;

AND WHEREAS the parties shall consult as frequently as may be desirable to ensure declarations and intentions are known;

NOW THEREFORE IN CONSIDERATION the parties have agreed that The Town will hold a loan for the sum of $1,544,408 dollars of lawful money of Canada (hereinafter referred to as the original loan principal, the receipt and sufficiency of which is hereby expressly acknowledged), the Parties covenant and agree, with each other, as follows;

1. **Prior Agreements**

All other agreements regarding the matters contained in this agreement, whether oral or written are terminated.

2. **Term**

The term of this Agreement shall be from January 1, 2013 to and including December 31, 2017 and year by year thereafter until there is no outstanding loan principal unless EPL gives notification, of not less than one year, in writing to The Town that EPL wishes to end the agreement at which time EPL will pay the remaining loan principal and interest prior to the end of the Agreement.

3. **Repayment Schedule**

3.01 EPL shall pay The Town annually not more than twenty percent (20%) of the original loan principal in the first year of this agreement and not more than twenty percent (20%) thereafter subject to article 3.03 and 3.04.

3.02 The Town may defer the payment in any year to a subsequent year and EPL shall pay The Town the deferred payment or payments in addition to the current year's annual payment subject to article 3.03 and 3.04.

3.03 The Town shall notify EPL, by March 1 or the 1st business day thereafter in the year that payment is due, of The Town's intention to receive payment as per article 3.01 and 3.02.

3.04 EPL shall notify The Town by July 1 or the 1st business day thereafter EPL's intention to make payment or partial payment as per article 3.01 and 3.02 by October 1 or the 1st business day thereafter in the year that payment is due.

3.05 The Town may request payment, and EPL will make payment, of the entire outstanding loan principal by notifying EPL by March 1 that The Town wishes payment to be made by March 1 of the following year conditional on EPL's ability to make distributions according to the "Unanimous Shareholders Agreement" which classifies this agreement as a "Second Tier Loan".

4. **Interest**

Interest means the rate paid for use of the outstanding loan principal calculated at 4.00% per annum of the loan principal calculated annually and payable to The Town by the 20th business day following the calendar year end.

5. **Arbitration**

5.01 The parties agree to consult with each other and to negotiate in good faith to resolve any differences or disputes which either party may have relating to the interpretation, application or implementation of this agreement, or any dispute which may arise over any costs, fees or other costs incurred and failing agreement the parties agree to resolve their disputes by arbitration as provided in Article 5.02.

5.02 Arbitration of a dispute shall be commenced by written notice by a party requesting arbitration to the other, which notice shall identify the issue or issues it wishes to submit to arbitration. Within thirty (30) days of the date of the notice, the Parties shall agree upon a single arbitrator and failing agreement then each party shall appoint an arbitrator and the two appointees shall within 45 days of the date of the notice of arbitration appoint a third person who shall act as Chair of the arbitration panel, and failing agreement the Chair shall be appointed by a judge of the Superior Court of Ontario pursuant to the provisions of the Arbitration's Act, RSO 1991 c.A.17.

5.03 The commencement of the arbitration and all rules of procedure for the arbitration shall be by agreement of the Parties, or failing agreement, as determined by the arbitrator or Chair of the arbitrator panel. The provisions of the Arbitration's Act, RSO 1991 c.A.17, as amended or any successor legislation shall apply to the arbitration.

5.04 All decisions of the arbitrator or arbitrators, as the case may be, shall be made in writing and shall be delivered to all Parties within ten (10) days from the conclusion of the arbitration. All decisions shall be final and binding upon the Parties, their respective successors and assigns, and shall not be subject to appeal.

5.05 Each Party shall pay its own costs incurred in respect of the arbitration including the payment of its appointee to the arbitration panel, and in the case of a three person panel the parties agree to share the fees of the Chair and other related costs equally.

6. Notices

All notices required to be given to either of the Parties under this Agreement shall be in writing and shall be delivered by prepaid unregistered post or hand delivery to the following:

a) to the Chief Administrative Officer at: 917 Lesperance Road, Tecumseh, Ontario, N8N 1W9

b) to the General Manager, EPL at: 2730 Highway 3,Oldcastle, Ontario, N0R 1L0

or to such other address or individual as may be designated by written notice to the other Party. Any notice given by personal delivery shall be deemed to have been given on the day of actual delivery hereof and if sent by prepaid post, on the third day after mailing.

7. Amendments

Amendments to this Agreement shall be in writing and executed by the Parties duly authorized signing officers.

8. Headings

The headings in this Agreement are for purposes of reference only and shall not be read or construed so as to abridge or modify the meaning of any provision in the main text of this Agreement.

9. Governing Law

This Agreement shall be construed in accordance with the laws of the Province of Ontario.

10. Successors

10.01 This Agreement shall ensure to the benefit of and be binding upon the Parties and their successors and assigns, respectively.

10.02 The Parties explicitly acknowledge and agree that the term of this Agreement shall remain in full force and effect and be binding upon new business corporations incorporated under the Business Corporations Act to whom assets and liabilities will be transferred.

10.03 For the purposes of this Agreement, whenever the term The Town or EPL is used, the term shall be deemed to include all successor business corporations incorporated to whom assets and liabilities are transferred.

11. Regulatory Changes

The Parties acknowledge that substantial changes to legislation and regulations and government policies are likely to occur during the term of this Agreement which are likely to affect the nature of the relationship between them, and as consequence the parties hereby agree to consult and negotiate in good faith any amendments to this Agreement which may be necessitated by changes in the regulatory environment, and failing agreement to submit their differences to arbitration as provided in Article 5.

IN WITNESS WHEREOF the Parties have duly executed this Agreement on the date first above written:

The Corporation of the Town of Tecumseh

Per:

Gary McNamara, Mayor

Laura Moy, Clerk

Essex Powerlines Corporation

Per:

Chair

General Manager

Attachment 5-C

Debt Instruments

Appendix 2-OB
Debt Instruments

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

Year 2010

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Municipal Loan	Town of Tecumseh	Affiliated	Fixed Rate	1-Jan-08	5	$ 2,150,296	6.00%	$ 129,017.76	
2	Municipal Loan	Municipality of Leamington	Affiliated	Fixed Rate	1-Jan-08	5	$ 1,544,408	6.00%	$ 92,664.48	
3	TD 20 yr amort loan 19	TD Bank	Third-Party	Fixed Rate	9-Nov-09	10	$ 5,804,859	4.99%	$ 289,662.46	
4	TD 10 yr amort loan 40	TD Bank	Third-Party	Fixed Rate	9-Nov-09	10	$ 5,471,546	4.48%	$ 245,125.26	
5	TD BA and Interest Swap	TD Bank	Third-Party	Fixed Rate	4-Nov-08	10	$ 3,300,000	5.03%	$ 165,990.00	
6	Mortgage Payable	Woodslee Credit Union	Third-Party	Fixed Rate	15-Sep-03	15	$ 656,713	5.90%	$ 38,746.07	
7	TD BA and Interest Swap	TD Bank	Third-Party	Fixed Rate	2-Jun-03	10	$ 3,000,000	6.55%	$ 196,500.00	
Total							$ 21,927,822	5.28%	$1,157,706.03	

Year 2011

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Municipal Loan	Town of Tecumseh	Affiliated	Fixed Rate	1-Jan-08	5	$ 2,150,296	6.00%	$ 129,017.76	
2	Municipal Loan	Municipality of Leamington	Affiliated	Fixed Rate	1-Jan-08	5	$ 1,544,408	6.00%	$ 92,664.48	
3	TD 20 yr amort loan 19	TD Bank	Third-Party	Fixed Rate	9-Nov-09	10	$ 5,615,471	4.99%	$ 280,212.00	
4	TD 10 yr amort loan 40	TD Bank	Third-Party	Fixed Rate	9-Nov-09	10	$ 4,960,783	4.48%	$ 222,243.08	
5	TD BA and Interest Swap	TD Bank	Third-Party	Fixed Rate	4-Nov-08	10	$ 3,300,000	5.03%	$ 165,990.00	
6	Mortgage Payable	Woodslee Credit Union	Third-Party	Fixed Rate	15-Sep-03	15	$ 587,647	5.90%	$ 34,671.17	
7	TD BA and Interest Swap	TD Bank	Third-Party	Fixed Rate	2-Jun-03	10	$ 3,000,000	6.55%	$ 196,500.00	
Total							$ 21,158,605	5.30%	$1,121,298.49	

Year 2012

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Municipal Loan	Town of Tecumseh	Affiliated	Fixed Rate	1-Jan-08	5	$ 2,150,296	4.00%	$ 86,011.84	
2	Municipal Loan	Municipality of Leamington	Affiliated	Fixed Rate	1-Jan-08	5	$ 1,544,408	4.00%	$ 61,776.32	
3	TD 20 yr amort loan 19	TD Bank	Third-Party	Fixed Rate	9-Nov-09	10	$ 5,417,206	4.99%	$ 270,318.58	
4	TD 10 yr amort loan 40	TD Bank	Third-Party	Fixed Rate	9-Nov-09	10	$ 4,427,283	4.48%	$ 198,342.28	
5	TD BA and Interest Swap	TD Bank	Third-Party	Fixed Rate	4-Nov-08	10	$ 3,300,000	5.44%	$ 179,520.00	
6	Mortgage Payable	Woodslee Credit Union	Third-Party	Fixed Rate	15-Sep-03	15	$ 514,543	5.90%	$ 30,358.04	
7	TD BA and Interest Swap	TD Bank	Third-Party	Fixed Rate	2-Jun-03	10	$ 3,000,000	6.55%	$ 196,500.00	
8	TD 20 year amort loan 28	TD Bank	Third-Party	Fixed Rate	1-Dec-12	5	$ 2,000,000	3.00%	$ 4,931.51	
Total							$ 22,353,736	4.60%	$1,027,758.56	

Year 2013

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Municipal Loan	Town of Tecumseh	Affiliated	Fixed Rate	1-Jan-13	5	$ 2,150,296	4.00%	$ 86,011.84	
2	Municipal Loan	Municipality of Leamington	Affiliated	Fixed Rate	1-Jan-13	5	$ 1,544,408	4.00%	$ 61,776.32	
3	TD 20 yr amort loan 19	TD Bank	Third-Party	Fixed Rate	9-Nov-09	10	$ 5,202,845	4.99%	$ 259,621.97	
4	TD 10 yr amort loan 40	TD Bank	Third-Party	Fixed Rate	9-Nov-09	10	$ 3,868,766	4.48%	$ 173,320.72	
5	TD BA and Interest Swap	TD Bank	Third-Party	Fixed Rate	4-Nov-08	10	$ 3,300,000	5.44%	$ 179,520.00	
6	TD 20 year amort loan 28	TD Bank	Third-Party	Variable Rate	1-Dec-12	5	$ 1,900,000	3.00%	$ 57,000.00	
Total							$ 17,966,315	4.55%	$ 817,250.84	

Year 2014

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Municipal Loan	Town of Tecumseh	Affiliated	Fixed Rate	1-Jan-13	5	$ 2,150,296	4.00%	$ 86,011.84	
2	Municipal Loan	Municipality of Leamington	Affiliated	Fixed Rate	1-Jan-13	5	$ 1,544,408	4.00%	$ 61,776.32	
3	TD 20 yr amort loan 19	TD Bank	Third-Party	Fixed Rate	9-Nov-09	10	$ 4,988,343	4.99%	$ 248,918.32	
4	TD 10 yr amort loan 40	TD Bank	Third-Party	Fixed Rate	9-Nov-09	10	$ 3,284,958	4.48%	$ 147,166.12	
5	TD BA and Interest Swap	TD Bank	Third-Party	Fixed Rate	4-Nov-08	10	$ 3,300,000	5.03%	$ 165,990.00	
6	TD 20 year amort loan 28	TD Bank	Third-Party	Fixed Rate	24-Nov-14	5	$ 1,800,000	2.47%	$ 44,460.00	
7	TD 20 year amort loan 29	TD Bank	Third-Party	Fixed Rate	19-Dec-14	10	$ 2,000,000	2.47%	$ 1,624.11	
Total							$ 19,068,005	3.96%	$ 755,946.70	

File Number:	EB-2017-0039
Exhibit:	5
Tab:	5-C
Page:	2 of 2
Date:	August 28th, 2017

Year 2015

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Municipal Loan	Town of Tecumseh	Affiliated	Fixed Rate	1-Jan-13	5	$ 2,150,296	4.00%	$ 86,011.84	
2	Municipal Loan	Municipality of Leamington	Affiliated	Fixed Rate	1-Jan-13	5	$ 1,544,408	4.00%	$ 61,776.32	
3	TD 20 yr amort loan 19	TD Bank	Third-Party	Fixed Rate	9-Nov-09	10	$ 4,757,000	4.99%	$ 237,374.30	
4	TD 10 yr amort loan 40	TD Bank	Third-Party	Fixed Rate	9-Nov-09	10	$ 2,674,000	4.48%	$ 119,795.20	
5	TD BA and Interest Swap	TD Bank	Third-Party	Fixed Rate	4-Nov-08	10	$ 3,300,000	5.03%	$ 165,990.00	
6	TD 20 year amort loan 28	TD Bank	Third-Party	Fixed Rate	24-Nov-14	5	$ 1,704,000	2.47%	$ 42,088.80	
7	TD 20 year amort loan 29	TD Bank	Third-Party	Fixed Rate	19-Dec-14	5	$ 1,902,000	2.47%	$ 46,979.40	
8	TD 10 year amort loan 27	TD Bank	Third-Party	Fixed Rate	26-Oct-15	5	$ 2,980,000	2.42%	$ 13,040.15	
Total							$ 21,011,704	3.68%	$ 773,056.01	

Year 2016

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Municipal Loan	Town of Tecumseh	Affiliated	Fixed Rate	1-Jan-13	5	$ 2,150,296	4.00%	$ 86,011.84	
2	Municipal Loan	Municipality of Leamington	Affiliated	Fixed Rate	1-Jan-13	5	$ 1,544,408	4.00%	$ 61,776.32	
3	TD 20 yr amort loan 19	TD Bank	Third-Party	Fixed Rate	9-Nov-09	10	$ 4,515,000	4.99%	$ 225,298.50	
4	TD 10 yr amort loan 40	TD Bank	Third-Party	Fixed Rate	9-Nov-09	10	$ 2,036,000	4.48%	$ 91,212.80	
5	TD BA and Interest Swap	TD Bank	Third-Party	Fixed Rate	4-Nov-08	10	$ 3,300,000	5.03%	$ 165,990.00	
6	TD 20 year amort loan 28	TD Bank	Third-Party	Fixed Rate	24-Nov-15	5	$ 1,622,000	2.47%	$ 40,063.40	
7	TD 20 year amort loan 29	TD Bank	Third-Party	Fixed Rate	19-Dec-15	5	$ 1,822,000	2.47%	$ 45,003.40	
8	TD 10 year amort loan 27	TD Bank	Third-Party	Fixed Rate	26-Oct-15	5	$ 2,862,000	2.42%	$ 69,260.40	
9	TD 20 year amort loan 31	TD Bank	Third-Party	Fixed Rate	2-Dec-16	5	$ 1,000,000	2.19%	$ 1,740.00	
Total							$ 20,851,704	3.77%	$ 786,356.66	

Year 2017

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Municipal Loan	Town of Tecumseh	Affiliated	Fixed Rate	1-Jan-13	5	$ 2,150,296	4.00%	$ 86,011.84	
2	Municipal Loan	Municipality of Leamington	Affiliated	Fixed Rate	1-Jan-13	5	$ 1,544,408	4.00%	$ 61,776.32	
3	TD 20 yr amort loan 19	TD Bank	Third-Party	Fixed Rate	9-Nov-09	10	$ 4,515,000	4.99%	$ 225,298.50	
4	TD 10 yr amort loan 40	TD Bank	Third-Party	Fixed Rate	9-Nov-09	10	$ 2,036,000	4.48%	$ 91,212.80	
5	TD BA and Interest Swap	TD Bank	Third-Party	Fixed Rate	4-Nov-08	10	$ 3,300,000	5.03%	$ 165,990.00	
6	TD 20 year amort loan 28	TD Bank	Third-Party	Fixed Rate	24-Nov-15	5	$ 1,622,000	2.47%	$ 40,063.40	
7	TD 20 year amort loan 29	TD Bank	Third-Party	Fixed Rate	19-Dec-15	5	$ 1,822,000	2.47%	$ 45,003.40	
8	TD 10 year amort loan 27	TD Bank	Third-Party	Fixed Rate	26-Oct-15	5	$ 2,862,000	2.42%	$ 69,260.40	
9	TD 20 year amort loan 31	TD Bank	Third-Party	Fixed Rate	2-Dec-16	5	$ 1,000,000	2.19%	$ 21,900.00	
10	New Loan 2017 $5.15 M	TBD	Third-Party	Fixed Rate	1-Jul-17	10	$ 5,150,000	2.91%	$ 75,600.31	
Total							$ 26,001,704	3.39%	$ 882,116.97	

Year 2018

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Municipal Loan	Town of Tecumseh	Affiliated	Fixed Rate	1-Jan-13	5	$ 2,150,296	3.72%	$ 79,991.01	Expected rate reduction. Currently under negotiation.
2	Municipal Loan	Municipality of Leamington	Affiliated	Fixed Rate	1-Jan-13	5	$ 1,544,408	3.72%	$ 57,451.98	Expected rate reduction. Currently under negotiation.
3	TD 20 yr amort loan 19	TD Bank	Third-Party	Fixed Rate	9-Nov-09	10	$ 4,127,000	4.99%	$ 205,937.30	
4	TD 10 yr amort loan 40	TD Bank	Third-Party	Fixed Rate	9-Nov-09	10	$ 1,019,000	4.48%	$ 45,651.20	
5	TD BA and Interest Swap	TD Bank	Third-Party	Fixed Rate	4-Nov-08	10	$ 2,784,658	5.03%	$ 140,068.27	
6	TD 20 year amort loan 28	TD Bank	Third-Party	Fixed Rate	24-Nov-14	5	$ 1,494,000	2.47%	$ 36,901.80	
7	TD 20 year amort loan 29	TD Bank	Third-Party	Fixed Rate	19-Dec-14	5	$ 1,699,000	2.47%	$ 41,965.30	
8	TD 10 year amort loan 27	TD Bank	Third-Party	Fixed Rate	26-Oct-15	5	$ 2,679,000	2.42%	$ 64,831.80	
9	TD 20 year amort loan 31	TD Bank	Third-Party	Fixed Rate	2-Dec-16	5	$ 939,000	2.19%	$ 20,564.10	
10	New Loan replace BA swap $3.3 M	TBD	Third-Party	Fixed Rate	4-Nov-18	10	$ 522,795	2.91%	$ 15,223.78	
11	New Loan 2017 $5.15 M	TBD	Third-Party	Fixed Rate	1-Jul-17	10	$ 4,957,000	2.91%	$ 144,347.84	
12	New Loan 2018 $2.40 M	TBD	Third-Party	Fixed Rate	1-Jul-18	10	$ 1,198,672	2.91%	$ 34,905.32	
Total							$ 25,114,828	3.54%	$ 887,839.70	

Notes

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

<u>Attachment 5-D</u>

Capital Structure

Appendix 2-OA
Capital Structure and Cost of Capital

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

Year: 2010 BAP

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt					
1	Long-term Debt	56.00%		$23,027,040	5.40%	$1,243,460
2	Short-term Debt	4.00%	(1)	$1,644,789	2.07%	$34,047
3	**Total Debt**	60.0%		$24,671,828	5.18%	$1,277,507
	Equity					
4	Common Equity	40.00%		$16,447,886	9.85%	$1,620,117
5	Preferred Shares			$ -	0.00%	$ -
6	**Total Equity**	40.0%		$16,447,886	9.85%	$1,620,117
7	**Total**	100.0%		$41,119,714	7.05%	$2,897,624

Notes

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

File Number:	EB-2017-0039
Exhibit:	5
Attachment	5-D
Page:	2 of 2
Date:	August 28th, 2017

Year: 2018 Test Year

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$33,559,238	3.54%	$1,187,997
2	Short-term Debt	4.00%	(1)	$2,397,088	1.76%	$42,189
3	**Total Debt**	60.0%		$35,956,326	3.42%	$1,230,186
	Equity					
4	Common Equity	40.00%		$23,970,884	8.78%	$2,104,644
5	Preferred Shares			$ -	0.00%	$ -
6	**Total Equity**	40.0%		$23,970,884	8.78%	$2,104,644
7	**Total**	100.0%		$59,927,210	5.56%	$3,334,829

Notes

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

Exhibit 6:

Revenue Requirement

Table of Contents

List of Attachments

6-A. Revenue Requirement Work Form

6.1 Overview

This section is intended to outline and support EPLC's request for an overall increase in its Revenue Requirement. The following items are included in this Exhibit:

- Determination of Net Utility Income;
- Statement of Rate Base;
- Actual Utility Return on Rate Base;
- Indicated Rate of Return;
- Requested Rate of Return;
- Gross Deficiency in Revenue;

EPLC has determined that the Revenue Deficiency for the 2018 Test Year is $280,095.

The methodology at which EPLC used to arrive at the calculated Revenue Deficiency is described herein. EPLC completed the Revenue Requirement Work Form Version 7.02 ("RRWF Model") provided by the Board on July 14th, 2017. The RRWF Model is provided in this Application as Attachment 6-A to this Exhibit.

As per the Board's Filing Requirements, the calculation of gross Revenue Sufficiency/Deficiency must isolate the delivery Sufficiency/Deficiency from any energy Sufficiency/Deficiency. As a result, EPLC's calculation does not include any recovery of deferral/variance accounts or any other electricity charge (ie Transmission Charges, Wholesale Market Service Charges, Commodity Charges, etc). These charges are considered elsewhere in this Application.

6.2 Calculation of Revenue Requirement

EPLC has calculated the proposed Revenue Requirement with the following drivers:

- Operations, Maintenance & Administration ("OM&A") Expenses;
- Property Taxes;
- Depreciation/Amortization Expense;
- PILs;
- Deemed Interest Expense;
- Return on Equity;

A significant portion of EPLC's Revenue Requirement is recovered through electricity distribution charges with Other Revenue from Board Approved services charges such as Late Payment Charges and other various Distribution services. This Other Revenue is treated as an offset to EPLC's Service Revenue Requirement and is further described in Exhibit 3 of this Application.

EPLC completed the Revenue Requirement Work Form Version 7.02 ("RRWF Model") provided by the Board on July 14th, 2017. The RRWF Model is provided in this Application as Attachment 6-A to this Exhibit. EPLC has ensured that values entered into the RRWF Model are consistent with other Exhibits in this Application.

6.3 Determination of Net Utility Income

As per Tab 5 of the RRWF Model, EPLC proposes a 2018 Test Year Net Income of $2,147,181. Figure 1 below outlines EPLC's calculation.

Figure 1 – EPLC Proposed 2018 Test Year Net Income

Description	Amount
Operating Revenues:	
Distribution Revenue	$ 12,471,074
Other Revenue	$ 691,821
Total Revenue	**$ 13,162,895**
Operating Expenses:	
OM&A Expenses	$ 7,710,275
Depreciation/Amortization	$ 1,848,004
Deemed Interest Expense	$ 1,230,186
Total Cost & Expenses	**$ 10,788,465**
Net Income before Income Taxes	$ 2,374,430
Income Taxes (Grossed-Up)	$ 227,249
Utility Net Income	**$ 2,147,181**

6.4 Statement of Rate Base

As per Tab 4 of the RRWF Model, EPLC proposes a 2018 Test Year Rate Base of $59,927,210. Figure 2 below outlines EPLC's calculation.

Figure 2 – EPLC Proposed 2018 Test Year Rate Base

Description	Amount
Opening Net Fixed Assets	$ 84,365,384
Closing Net Fixed Assets	$ (30,144,082)
Average Net Fixed Assets	$ 54,221,302
Working Capital Allowance	$ 5,705,908
Total Rate Base	**$ 59,927,210**

6.5 Actual Utility Return on Rate Base

A comparison of EPLC's 2018 Test Year Actual Return on Rate Base and Expected Return on Rate Base is shown below as Figure 3 for both Current Approved Rates and Proposed Rates.

Figure 3 – EPLC's Return on Rate Base

Description	At Current Approved Rates	At Proposed Rates
Actual Return on Rate Base		
Rate Base	$59,927,210	$59,927,210
Interest Expense	$ 1,230,186	$ 1,230,186
Net Income	$ 1,824,549	$ 2,104,643
Total Actual Return on Rate Base	$ 3,054,735	$ 3,334,829
Weighted Average Cost of Capital	5.10%	5.56%
Required Return on Rate Base		
Rate Base	$59,927,210	$59,927,210
Return Rates:		
Return on Debt	3.59%	3.59%
Return on Equity	8.78%	8.78%
Deemed Interest Expense	$ 1,230,186	$ 1,230,186
Return on Equity	$ 2,104,644	$ 2,104,644
Total Required Return on Rate Base	$ 3,334,829	$ 3,334,829
Expected Return on Rate Base	**5.10%**	**5.56%**

6.5.1 Indicated Rate of Return

As per Figure 4 below, EPLC has calculated its Indicated Rate of Return of 5.10% at Currently Approved Rates and 5.56% at Proposed Rates.

6.5.2 Requested Rate of Return

As per Figure 3 above, EPLC has calculated and proposes a Requested Rate of Return of 5.56% ($3,334,829).

Where distribution rates remained unchanged, EPLC's Return on Rate Base would be 5.10% ($3,054,735).

6.6 Revenue Deficiency

As per Figure 4 below and consistent with the RRWF Model, EPLC has calculated a Revenue Deficiency of $280,095 and a Gross Revenue Deficiency of $381,081.

Figure 4 – EPLC's 2018 Test Year Revenue Deficiency

Description	At Current Approved Rates	At Proposed Rates
Revenue Deficiency from Below		$ 381,081
Distribution Revenue	$ 12,190,979	$ 12,089,993
Other Operating Revenue Offsets	$ 691,821	$ 691,821
Required Return on Rate Base	**$ 12,882,800**	**$ 13,162,895**
Operating Expenses	$ 9,600,817	$ 9,600,817
Deemed Interest Expense	$ 1,230,186	$ 1,230,186
Total Cost & Expenses	**$ 10,831,003**	**$ 10,831,003**
Utility Income Before Income Taxes	$ 2,051,797	$ 2,331,892
Tax Adjustments to Accounting	$ (1,205,576)	$ (1,205,576)
Taxable Income	**$ 846,221**	**$ 1,126,316**
Income Tax Rate	26.50%	26.50%
Income Tax on Taxable Income	$ 224,249	$ 298,474
Income Tax Credits	$ 3,000	$ 3,000
Utility Net Income	**$ 1,824,549**	**$ 2,104,193**
Utility Rate Base	$ 59,927,210	$ 59,927,210
Deemed Equity Portion of Rate Base	$ 23,970,884	$ 23,970,884
Income/(Equity Portion of Rate Base)	7.61%	8.78%
Target Return - Equity on Rate Base	8.78%	8.78%
Deficiency/Sufficiency in Return on Equity	**-1.17%**	**0.00%**
Indicated Rate of Return	5.08%	5.56%
Requested Rate of Return on Rate Base	5.56%	5.56%
Deficiency/Sufficiency in Rate of Return	**-0.49%**	**0.00%**
Target Return on Equity	$ 2,104,644	$ 2,104,644
Revenue Deficiency/(Sufficiency)	**$ 280,095**	**$ -**
Gross Revenue Deficiency/(Sufficiency)	**$ 381,081**	**$ -**

6.7 Cost Drivers on Revenue Deficiency

As per Figure 5 below and consistent with the RRWF Model, EPLC has calculated the contributors towards its Revenue Deficiency of $280,095. Column A represents EPLC's 2010 Board Approved amounts. Column B lists the estimated proportionate contributions by cost type based on the Required Return on Rate Base shown in Figure 4 above. Column C represents the 2017 proposed components and Column D represents the variance between Columns C and B respectively.

Figure 5 – Revenue Deficiency by Revenue Requirement Component

Description	2010 Board Approved Rates	At Current Approved Rates	At Proposed Rates	Variance (Deficiency)
	A	B	C	D = C - B
Revenue Requirement:				
OM&A	$ 6,254,188	$ 6,726,671	$ 7,710,275	$ 983,604
Depreciation	$ 2,247,501	$ 2,417,292	$ 1,848,004	$ (569,288)
Property Tax	$ 32,001	$ 34,419	$ 42,538	$ 8,119
Income Tax	$ 545,581	$ 586,798	$ 227,249	$ (359,549)
Return on Rate Base	$ 2,898,637	$ 3,117,620	$ 3,334,829	$ 217,209
Total	**$ 11,977,909**	**$ 12,882,800**	**$ 13,162,895**	**$ 280,095**
Rate Base				
Rate Base	$ 41,119,713		$ 59,927,210	$ 18,807,497

There are two (2) primary drivers for EPLC's Revenue Deficiency of $280,095 for the 2018 Test Year:

- The first contributor is an OM&A increase of approximately $983,604. Details relating to EPLC's OM&A increases are summarized in Exhibit 4 of this Application;

- The second contributor is an increase in Return on Rate Base which is driven by a Rate Base increase of $18.8M between 2010 and the 2018 Test Year. Further detail related to the $18.8M increase in rate base is summarized in Exhibit 2 of this Application.

<u>Attachment 6-A</u>

Revenue Requirement Work Form

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Version 7.02

Utility Name	Essex Powerlines Corporation
Service Territory	*Amherstburg, Lasalle, Leamington, Tecumseh*
Assigned EB Number	EB-2017-0039
Name and Title	Kristopher Taylor, Director of Corporate Strategy
Phone Number	519-946-2000 x219
Email Address	ktaylor@essexpower.ca

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

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Notes:

(1) Pale green cells represent inputs

(2) Pale green boxes at the bottom of each page are for additional notes

(3) Pale yellow cells represent drop-down lists

(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Data Input [1]

		Initial Application	[2]		[6]	Per Board Decision	
1	**Rate Base**						
	Gross Fixed Assets (average)	$84,365,384		$ 84,365,384		$84,365,384	
	Accumulated Depreciation (average)	($30,144,082)	[5]	($30,144,082)		($30,144,082)	
	Allowance for Working Capital:						
	Controllable Expenses	$7,752,813		$ 7,752,813		$7,752,813	
	Cost of Power	$68,325,958		$ 68,325,958		$68,325,958	
	Working Capital Rate (%)	7.50%	[9]		[9]		[9]
2	**Utility Income**						
	Operating Revenues:						
	Distribution Revenue at Current Rates	$12,190,979					
	Distribution Revenue at Proposed Rates	$12,471,074					
	Other Revenue:						
	Specific Service Charges	$166,480					
	Late Payment Charges	$260,400					
	Other Distribution Revenue	$225,155					
	Other Income and Deductions	$39,786					
	Total Revenue Offsets	$691,821	[7]				
	Operating Expenses:						
	OM+A Expenses	$7,710,275		$ 7,710,275		$7,710,275	
	Depreciation/Amortization	$1,848,004		$ 1,848,004		$1,848,004	
	Property taxes	$42,538		$ 42,538		$42,538	
	Other expenses	$ -		0		$0	
3	**Taxes/PILs**						
	Taxable Income:						
	Adjustments required to arrive at taxable income	($1,205,576)	[3]				
	Utility Income Taxes and Rates:						
	Income taxes (not grossed up)	$167,028					
	Income taxes (grossed up)	$227,249					
	Federal tax (%)	15.00%					
	Provincial tax (%)	11.50%					
	Income Tax Credits	$3,000					
4	**Capitalization/Cost of Capital**						
	Capital Structure:						
	Long-term debt Capitalization Ratio (%)	56.0%					
	Short-term debt Capitalization Ratio (%)	4.0%	[8]		[8]		[8]
	Common Equity Capitalization Ratio (%)	40.0%					
	Prefered Shares Capitalization Ratio (%)	0.0%					
		100.0%					
	Cost of Capital						
	Long-term debt Cost Rate (%)	3.54%					
	Short-term debt Cost Rate (%)	1.76%					
	Common Equity Cost Rate (%)	8.78%					
	Prefered Shares Cost Rate (%)	0.00%					

Notes:

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

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

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

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

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

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

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

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

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

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application				Per Board Decision
1	Gross Fixed Assets (average)	(2)	$84,365,384	$ -	$84,365,384	$ -	$84,365,384
2	Accumulated Depreciation (average)	(2)	($30,144,082)	$ -	($30,144,082)	$ -	($30,144,082)
3	Net Fixed Assets (average)	(2)	$54,221,302	$ -	$54,221,302	$ -	$54,221,302
4	Allowance for Working Capital	(1)	$5,705,908	($5,705,908)	$ -	$ -	$ -
5	**Total Rate Base**		$59,927,210	($5,705,908)	$54,221,302	$ -	$54,221,302

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

Line No.	Particulars		Initial Application				Per Board Decision
6	Controllable Expenses		$7,752,813	$ -	$7,752,813	$ -	$7,752,813
7	Cost of Power		$68,325,958	$ -	$68,325,958	$ -	$68,325,958
8	Working Capital Base		$76,078,771	$ -	$76,078,771	$ -	$76,078,771
9	Working Capital Rate %	(1)	7.50%	-7.50%	0.00%	0.00%	0.00%
10	Working Capital Allowance		$5,705,908	($5,705,908)	$ -	$ -	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2018 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Utility Income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$12,471,074	($12,471,074)	$ -	$ -	$ -
2	Other Revenue	(1)	$691,821	($691,821)	$ -	$ -	$ -
3	Total Operating Revenues		$13,162,895	($13,162,895)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$7,710,275	$ -	$7,710,275	$ -	$7,710,275
5	Depreciation/Amortization		$1,848,004	$ -	$1,848,004	$ -	$1,848,004
6	Property taxes		$42,538	$ -	$42,538	$ -	$42,538
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -	$ -	$ -	$ -
9	Subtotal (lines 4 to 8)		$9,600,817	$ -	$9,600,817	$ -	$9,600,817
10	Deemed Interest Expense		$1,230,186	($1,230,186)	$ -	$ -	$ -
11	Total Expenses (lines 9 to 10)		$10,831,003	($1,230,186)	$9,600,817	$ -	$9,600,817
12	**Utility income before income taxes**		$2,331,892	($11,932,709)	($9,600,817)	$ -	($9,600,817)
13	Income taxes (grossed-up)		$227,249	$ -	$227,249	$ -	$227,249
14	**Utility net income**		$2,104,643	($11,932,709)	($9,828,066)	$ -	($9,828,066)

Notes

Other Revenues / Revenue Offsets

Note	Particulars					
(1)	Specific Service Charges	$166,480		$ -		$ -
	Late Payment Charges	$260,400		$ -		$ -
	Other Distribution Revenue	$225,155		$ -		$ -
	Other Income and Deductions	$39,786		$ -		$ -
	Total Revenue Offsets	$691,821	$ -	$ -	$ -	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$2,104,644	$ -	$ -
2	Adjustments required to arrive at taxable utility income	($1,205,576)	$ -	$ -
3	Taxable income	$899,068	$ -	$ -
	Calculation of Utility income Taxes			
4	Income taxes	$167,028	$167,028	$167,028
6	Total taxes	$167,028	$167,028	$167,028
7	Gross-up of Income Taxes	$60,221	$60,221	$60,221
8	Grossed-up Income Taxes	$227,249	$227,249	$227,249
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$227,249	$227,249	$227,249
10	Other tax Credits	$3,000	$3,000	$3,000
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$33,559,238	3.54%	$1,187,997
2	Short-term Debt	4.00%	$2,397,088	1.76%	$42,189
3	**Total Debt**	60.00%	$35,956,326	3.42%	$1,230,186
	Equity				
4	Common Equity	40.00%	$23,970,884	8.78%	$2,104,644
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$23,970,884	8.78%	$2,104,644
7	**Total**	100.00%	$59,927,210	5.56%	$3,334,829

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$ -
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
4	Common Equity	0.00%	$ -	0.00%	$ -
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	$ -
7	**Total**	0.00%	$54,221,302	0.00%	$ -

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	0.00%	$ -	3.54%	$ -
9	Short-term Debt	0.00%	$ -	1.76%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	8.78%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$54,221,302	0.00%	$ -

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	At Current Approved Rates	At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$381,081		($3,020,744)		$13,062,336
2	Distribution Revenue	$12,190,979	$12,089,993	$12,190,979	$15,491,818	$ -	($13,062,336)
3	Other Operating Revenue Offsets - net	$691,821	$691,821	$ -	$ -	$ -	$ -
4	**Total Revenue**	$12,882,800	$13,162,895	$12,190,979	$12,471,074	$ -	$ -
5	Operating Expenses	$9,600,817	$9,600,817	$9,600,817	$9,600,817	$9,600,817	$9,600,817
6	Deemed Interest Expense	$1,230,186	$1,230,186	$ -	$ -	$ -	$ -
8	**Total Cost and Expenses**	$10,831,003	$10,831,003	$9,600,817	$9,600,817	$9,600,817	$9,600,817
9	**Utility Income Before Income Taxes**	$2,051,797	$2,331,892	$2,590,162	$2,870,257	($9,600,817)	($9,600,817)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($1,205,576)	($1,205,576)	($1,205,576)	($1,205,576)	$ -	$ -
11	**Taxable Income**	$846,221	$1,126,316	$1,384,586	$1,664,681	($9,600,817)	($9,600,817)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$224,249	$298,474	$366,915	$441,140	$ -	$ -
14	**Income Tax Credits**	$3,000	$3,000	$3,000	$3,000	$ -	$ -
15	**Utility Net Income**	$1,824,549	$2,104,643	$2,220,247	($9,828,066)	($9,600,817)	($9,828,066)
16	**Utility Rate Base**	$59,927,210	$59,927,210	$54,221,302	$54,221,302	$54,221,302	$54,221,302
17	Deemed Equity Portion of Rate Base	$23,970,884	$23,970,884	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	7.61%	8.78%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	8.78%	8.78%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-1.17%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	5.10%	5.56%	4.09%	0.00%	-17.71%	0.00%
22	Requested Rate of Return on Rate Base	5.56%	5.56%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-0.47%	0.00%	4.09%	0.00%	-17.71%	0.00%
24	Target Return on Equity	$2,104,644	$2,104,644	$ -	$ -	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	$280,095	($0)	($2,220,247)	$ -	$9,600,817	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$381,081 (1)		($3,020,744) (1)		$13,062,336 (1)	

Notes:

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$7,710,275		$7,710,275		$7,710,275	
2	Amortization/Depreciation	$1,848,004		$1,848,004		$1,848,004	
3	Property Taxes	$42,538		$42,538		$42,538	
5	Income Taxes (Grossed up)	$227,249		$227,249		$227,249	
6	Other Expenses	$ -		$ -		$ -	
7	Return						
	Deemed Interest Expense	$1,230,186		$ -		$ -	
	Return on Deemed Equity	$2,104,644		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$13,162,895		$9,828,066		$9,828,066	
9	Revenue Offsets	$691,821		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$12,471,074		$9,828,066		$9,828,066	
11	Distribution revenue	$12,471,074		$ -		$ -	
12	Other revenue	$691,821		$ -		$ -	
13	**Total revenue**	$13,162,895		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($0)	(1)	($9,828,066)	(1)	($9,828,066)	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application		Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$13,162,895	$9,828,066	**($0)**	$9,828,066	**($1)**
Grossed-Up Revenue Deficiency/(Sufficiency)	$381,081	($3,020,744)	**($9)**	$13,062,336	**($1)**
Base Revenue Requirement (to be recovered from Distribution Rates)	$12,471,074	$9,828,066	**($0)**	$9,828,066	**($1)**
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$280,095	$ -	**($1)**	$ -	**($1)**

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Load Forecast Summary

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

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

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

Stage in Process: Initial Application

	Customer Class	**Initial Application**						**Per Board Decision**		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA (1)** Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA (1)** Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA (1)** Annual
1	Residential	27,484	245,374,118							
2	General Service < 50 kW	1,977	62,707,450							
3	General Service > 50 kW	219	176,280,306	446,253						
4	Intermediate Use									
5	Street Lights	2,740	2,799,882	8,848						
6	Unmetered Scattered Load	140	1,554,368							
7	Sentinel Lights	173	335,758	2,080						
8	Embedded Distributor	3	29,865,554	80,869						
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		**518,917,436**	**538,051**		**-**	**-**		**-**	**-**

Notes:

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Cost Allocation and Rate Design

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

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential	$ 8,442,067	70.48%	$ 9,665,793	73.43%
2	General Service < 50 kW	$ 1,585,605	13.24%	$ 1,437,710	10.92%
3	General Service > 50 kW	$ 1,457,177	12.17%	$ 1,707,614	12.97%
4	Intermediate Use	$ 58,824	0.49%	$ -	
5	Street Lights	$ 351,854	2.94%	$ 178,906	1.36%
6	Unmetered Scattered Load	$ 23,468	0.20%	$ 51,178	0.39%
7	Sentinel Lights	$ 58,914	0.49%	$ 23,079	0.18%
8	Embedded Distributor	$ -		$ 98,616	0.75%
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 11,977,910	100.00%	**$ 13,162,895**	100.00%
			Service Revenue Requirement (from Sheet 9)	**$ 13,162,895.35**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) ***Calculated Class Revenues***

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential	$ 8,612,319	$ 8,810,192	$ 8,889,902	$ 521,363
2	General Service < 50 kW	$ 1,585,914	$ 1,622,351	$ 1,622,351	$ 82,393
3	General Service > 50 kW	$ 1,528,407	$ 1,563,523	$ 1,563,524	$ 74,371
4	Intermediate Use	$ -	$ -	$ -	$ -
5	Street Lights	$ 187,611	$ 191,922	$ 191,922	$ 9,623
6	Unmetered Scattered Load	$ 62,175	$ 63,604	$ 58,609	$ 2,805
7	Sentinel Lights	$ 27,447	$ 28,078	$ 26,669	$ 1,025
8	Embedded Distributor	$ 187,106	$ 191,405	$ 118,097	$ 242
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 12,190,979	$ 12,471,074	$ 12,471,074	$ 691,821

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2010 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	100.23%	96.54%	97.37%	85 - 115
2	General Service < 50 kW	49.56%	118.57%	118.57%	80 - 120
3	General Service > 50 kW	159.99%	95.92%	95.92%	80 - 120
4	Intermediate Use	336.93%	#DIV/0!	#DIV/0!	80 - 120
5	Street Lights	32.36%	112.65%	112.65%	80 - 120
6	Unmetered Scattered Load	132.66%	129.76%	120.00%	80 - 120
7	Sentinel Lights	38.09%	126.10%	120.00%	80 - 120
8	Embedded Distributor	N/A	194.34%	120.00%	80 - 120
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

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

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
		2018	2019	2020	
1	Residential	97.37%	97.37%	97.37%	85 - 115
2	General Service < 50 kW	118.57%	118.57%	118.57%	80 - 120
3	General Service > 50 kW	95.92%	95.92%	95.92%	80 - 120
4	Intermediate Use	#DIV/0!	#DIV/0!	#DIV/0!	80 - 120
5	Street Lights	112.65%	112.65%	112.65%	80 - 120
6	Unmetered Scattered Load	120.00%	120.00%	120.00%	80 - 120
7	Sentinel Lights	120.00%	120.00%	120.00%	80 - 120
8	Embedded Distributor	120.00%	120.00%	120.00%	80 - 120
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2018 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2019 and 2020 Price Cap IR models, as necessary. For 2019 and 2020, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential Class	
Customers	27,484
kWh	245,374,118

Proposed Residential Class Specific Revenue Requirement[1]	$ 8,889,902.49

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	$ 20.31
Distribution Volumetric Rate ($/kWh)	$ 0.0078

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	20.31	27,484	$ 6,698,400.48	77.78%
Variable	0.0078	245,374,118	$ 1,913,918.12	22.22%
TOTAL	-	-	$ 8,612,318.60	-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	2

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed	$ 6,914,296.82	20.96	$ 6,912,775.68
Variable	$ 1,975,605.67	0.0081	$ 1,987,530.36
TOTAL	$ 8,889,902.49	-	$ 8,900,306.04

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed	88.89%	$ 7,902,099.66	$ 23.96	$ 7,902,199.68
Variable	11.11%	$ 987,802.84	$ 0.0040	$ 981,496.47
TOTAL	-	$ 8,889,902.49	-	$ 8,883,696.15

Checks[3]	
Change in Fixed Rate	$ 3.00
Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement	($6,206.34)
	-0.07%

Notes:

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

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

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Rate Design and Revenue Reconciliation

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

Stage in Process: ***Initial Application***

	Customer and Load Forecast					Class Allocated Revenues (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)			Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1)	
	Customer Class From sheet 10. Load Forecast	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable
1	Residential	kWh	27,484	245,374,118	-	$ 8,889,902	$ 7,902,100	$ 987,803	88.89%	11.11%
2	General Service < 50 kW	kWh	1,977	62,707,450	-	$ 1,622,351	$ 852,573	$ 769,778	52.55%	47.45%
3	General Service > 50 kW	kW	219	176,280,306	446,253	$ 1,563,524	$ 625,559	$ 937,964	40.01%	59.99%
4	Intermediate Use	kW	-	-	-	$ -				
5	Street Lights	kW	2,740	2,799,882	8,848	$ 191,922	$ 110,997	$ 80,925	57.83%	42.17%
6	Unmetered Scattered Load	kWh	140	1,554,368	-	$ 58,609	$ 15,092	$ 43,517	25.75%	74.25%
7	Sentinel Lights	kW	173	335,758	2,080	$ 26,669	$ 6,879	$ 19,791	25.79%	74.21%
8	Embedded Distributor	kW	3	29,865,554	80,869	$ 118,097	$ 19,800	$ 98,297	16.77%	83.23%
9			-	-	-					
10			-	-	-					
11			-	-	-					
12			-	-	-					
13			-	-	-					
14			-	-	-					
15			-	-	-					
16			-	-	-					
17			-	-	-					
18			-	-	-					
19			-	-	-					
20			-	-	-					

			Distribution Rates					Revenue Reconciliation		
			Monthly Service Charge		Volumetric Rate					
	Customer Class	Transformer Ownership Allowance [1] ($)	Rate	No. of decimals	Rate		No. of decimals	MSC Revenues	Volumetric revenues	Revenues less Transformer Ownership Allowance
1	Residential		$23.96	2	$0.0040	/kWh	4	$ 7,902,199.68	$ 981,496.4720	$ 8,883,696.15
2	General Service < 50 kW		$35.94		$0.0123	/kWh		$ 852,640.56	$ 771,301.6350	$ 1,623,942.20
3	General Service > 50 kW	$ 69,367	$238.04		$2.2573	/kW		$ 625,569.12	$ 1,007,327.7998	$ 1,563,529.92
4	Intermediate Use		$0.00			/kW		$ -	$ -	$ -
5	Street Lights		$3.38		$9.1461	/kW		$ 111,134.40	$ 80,924.6928	$ 192,059.09
6	Unmetered Scattered Load		$8.98		$0.0280	/kWh		$ 15,086.40	$ 43,522.3040	$ 58,608.70
7	Sentinel Lights		$3.31		$9.5148	/kW		$ 6,871.56	$ 19,790.7840	$ 26,662.34
8	Embedded Distributor		$550.00		$1.2155	/kW		$ 19,800.00	$ 98,296.7557	$ 118,096.76
9								$ -	$ -	$ -
10								$ -	$ -	$ -
11								$ -	$ -	$ -
12								$ -	$ -	$ -
13								$ -	$ -	$ -
14								$ -	$ -	$ -
15								$ -	$ -	$ -
16								$ -	$ -	$ -
17								$ -	$ -	$ -
18								$ -	$ -	$ -
19								$ -	$ -	$ -
20								$ -	$ -	$ -

Total Transformer Ownership Allowance $ 69,367

	Total Distribution Revenues	$12,466,595.16
Rates recover revenue requirement	**Base Revenue Requirement**	$12,471,074.35
	Difference	-$ 4,479.19
	% Difference	-0.036%

Notes:

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

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Tracking Form

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

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

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

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

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference (1)	Item / Description (2)	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 3,334,829	5.56%	$ 59,927,210	$ 76,078,771	$ 5,705,908	$ 1,848,004	$ 227,249	$ 7,710,275	$ 13,162,895	$ 691,821	$ 12,471,074	$ 381,081
1														

Exhibit 7:

Cost Allocation

Table of Contents

List of Attachments

7.1 Background

This section summarizes EPLC's methodology of Cost Allocation for the 2018 Test Year.

For clarity, EPLC followed the Board's Cost Allocation Report (March 31st, 2011), the Board's letter relating to the treatment of Streetlighting connection (June 12th, 2015) and the 2018 Cost Allocation Model (Version 3.5).

7.2 Rate Classes

7.2.1 Changes to Rate Classes

EPLC is requesting the following changes to Rate Classes as part of this Application:

- Elimination of the General Service > 3,000 to 4,999 kW ("Intermediate") Rate Class. The sole customer this class was originally design for is no longer in service as originally configured.
- Expansion of the General Service > 50 to 2,999 kW ("GS>50") Rate Class to 50 to 4,999 kW. This change will reduce EPLC's number of Rate Classes while also reducing customer confusion for the few customers that could potentially transition between the GS>50 and Intermediate classes as they currently exist.
- Addition of an Embedded Distributor Rate Class. Please see section 7.2.4 below for more information.

7.2.2 Unmetered Loads

As part of regular business operations, EPLC regularly communicates with its unmetered load customers to aid and assist, where necessary, as it relates to how EPLC and other distributors operate and our overall effect on unmetered load customers (including Unmetered Scattered Load, Street Lighting, and Sentinel Lighting).

7.2.3 Standby Rates

EPLC is not currently requesting a separate Standby Rate as part of this Application.

7.2.4 Host Distributor

Effective January 1st, 2007, EPLC became a Host Distributor to Hydro One Networks Inc. ("HONI") as HONI de-registered six wholesale meters with the Independent Electricity System Operator. These de-registrations occurred downstream of EPLC wholesale meters at the Keith and Malden delivery points. HONI and EPLC have jointly re-configured load across their systems to reduce the number of embedded points to three.

EPLC has discussed the proposed cost allocation methodology in this Application with HONI. HONI was not in a position to comment prior to the submission of this Application. Based on initial feedback, EPLC has made changes to the Demand Allocators for the Embedded

Distributor rate class to address HONI's initial concern that a large portion of its load does not flow through EPLC distribution assets.

7.2.5 MicroFIT

EPLC is not currently requesting a separate MicroFIT rate class as part of this Application. EPLC understands and acknowledges that the Cost Allocation Model will calculate unit costs that will be used by the Board at a later time.

7.3 Cost Allocation Study

7.3.1 Overview

EPLC followed the Board's Cost Allocation Report (March 31st, 2011), the Board's letter relating to the treatment of Streetlighting connection (June 12th, 2015) and the 2018 Cost Allocation Model (Version 3.5).

A copy of the Cost Allocation Model has been filed as evidence in Excel format. Each tab within the Cost Allocation Model has been described in detail below.

7.3.2 Tab I2: LDC Class

For the purpose of this Application, EPLC is proposing the following rate classes:

- Residential;
- General Service < 50 kW ("GS<50");
- General Service > 50 to 4,999 kW ("GS>50");
- Street Lighting;
- Sentinel Lighting;
- Unmetered Scattered Load ("USL");
- Embedded Distributor ("ED");

7.3.3 Tab I3: Trial Balance Data

For Tab I3, EPLC used Service Revenue Requirement as calculated in Exhibit 6 and Rate Base as calculated in Exhibit 2.

Figures 1 and 2 below detail the Service Revenue Requirement and Rate Base calculations used for this Tab.

Figure 1 – Service Revenue Requirement

Description	Amount
OM&A Expenses	$ 7,710,275
Amortization/Depreciation	$ 1,848,004
Property Taxes	$ 42,538
Income Taxes (Grossed Up)	$ 227,249
Return:	
Deemed Interest Expense	$ 1,230,186
Return on Deemed Equity	$ 2,104,644
Service Revenue Requirement	**$ 13,162,895**
Other Revenue	$ 691,821
Base Revenue Requirement	**$ 12,471,074**

Figure 2 – Rate Base

Description	Amount
2018 Average Gross Fixed Assets	$ 84,365,384
2018 Average Accumulated Depreciation	$ (30,144,082)
2018 Average Net Book Value	**$ 54,221,302**
Working Capital Base	$ 76,078,771
Working Capital Allowance Factor	7.50%
Working Capital Allowance	$ 5,705,908
Rate Base	**$ 59,927,210**

7.3.4 Tab I4: BO Assets

EPLC used a consistent methodology for breaking out its assets with its previous 2010 Cost of Service Application (EB-2009-0143). EPLC used best available information from its financial and billing systems as well as engineering/design records.

EPLC does not own any transmission assets or distribution assets with voltages greater than 50 kV therefore no values were allocated to these categories.

7.3.5 Tab I5.1: Miscellaneous Data

EPLC determined the Structure KM value using detailed records within its GIS system. EPLC believes that this value best represents this required input.

EPLC utilized the deemed rate of 40% for the Deemed Equity Component of Rate Base.

EPLC utilized the deemed rate of 7.5% for the Working Capital Allowance to be Included in Rate Base.

EPLC calculated the Portion of Pole Leasing Revenue from Secondary by dividing total poles with secondary only (2,311) by the total poles owned by EPLC (6,208) resulting in a value of 37.23%.

7.3.6 Tab I5.2: Weighting Factors

The Weighting Factors for Services was calculated by determining the estimated average cost of servicing the residential, GS<50 and GS>50 rate classes. EPLC then allocated a weighting factor of 1 to the Residential rate class and calculated the relative weighting factor for GS<50 and GS>50. EPLC determined that a weighting factor of 0.5 for the Street Lighting and Sentinel Lighting classes was reasonable based on their relative work requirements to the Residential Class and based on comparable submissions. EPLC calculated a weighting factor of 2 and 5 for the USL and Embedded Distributor classes based on an assessment of work required to support each respective class in relation to the Residential class.

Figure 3 – Services Weighting Factors

Rate Class	Services Weighting Factors
Residential	1
GS<50	2.6
GS>50	2.1
Street Light	0.5
Sentinel	0.5
USL	2
ED	5

The Weighting Factor for Billing and Collecting was calculated by allocating assessed costs for Billing and Collecting Costs to a low volume grouping (Residential) and a mid-high volume grouping (GS<50, GS>50). EPLC then divided the allocated costs divided by the total number of bills issued for the class in 2016 in order to determine a total cost per bill. As directed in the instructions, EPLC then assigned a weighting factor of 1.00 to Residential and further calculated the associated weighting factor for the large volume grouping. EPLC determined that a weighting factor of 1.00 for the Street Lighting, and Sentinel Lighting classes was reasonable based on their similar work requirements to the Residential Class. EPLC also determined that a Weighting Factor of 2 and 5 for the USL and Embedded Distributor rate classes was appropriate based on their relative work required in relation to the Residential rate class. Figure 4 below outlines the results of this calculation.

Figure 4 – Billing & Collecting Weighting Factors

Rate Class	Billing & Collecting Weighting Factors
Residential	1.00
GS<50	1.60
GS>50	1.60
Street Light	1.00
Sentinel	1.00
USL	2.00
ED	5.00

7.3.7 Tab I6.1: Revenue

EPLC utilized its weather normalized 2018 Load Forecast as filed in Exhibit 3. This forecast includes Wholesale Market Participants ("WMP") and estimated CDM savings. Figure 5 below summarizes the entries used in the Cost Allocation Model.

Figure 5 – 2018 Load Forecast Results

Rate Class	Customers/ Connections	kWh	kW
Residential	27,484	245,374,118	-
GS<50	1,977	62,707,450	-
GS>50	219	176,280,306	446,253
Street Light	2,740	2,799,882	8,848
Sentinel	173	335,758	2,080
USL	140	1,554,368	-
ED	3	29,865,554	80,869
Total	**32,736**	**518,917,436**	**538,051**

In order to forecast the Transformer Ownership Allowance credit ("TOA") in 2018, EPLC assessed 2016 eligible customers (11) and carried their respective demand forward to 2018 as their load is not expected to materially change. EPLC does not foresee new or existing customers becoming eligible for TOA in the near future. Figure 6 below demonstrates EPLC's methodology.

Figure 6 – 2018 TOA Allocation

Rate Class	2016 Total kW	2016 Total kW w/ TOA	2018 Forecast	2018 Forecast w/ TOA
GS>50	532,036	416,425	446,253	330,642
Total	**532,036**	**416,425**	**446,253**	**330,642**

EPLC has three WMPs since August 2012 that qualify as GS>50 customers. Consistent with Exhibit 3 and the Load Forecast, EPLC has removed WMP kWh from the GS>50 class in row 29.

7.3.8 Tab I6.2: Customer Data

EPLC utilized historical data from its billing system to populate Historical Bad Debt and Late Payment Charges.

EPLC utilized 2016 billing data to calculate Number of Bills in row 17, including re-issued bills during the same calendar year.

The forecasted number of customers presented in the load forecast by Elenchus (Exhibit 3) was used to populate row 21 with the exception of 5 distinct municipal street lighting accounts which were directly entered in cell J21.

EPLC does not have any bulk customers therefore row 22 was left blank.

All EPLC customers are considered Primary therefore row 23 remains the same as row 21 with the exception of Street Lighting. EPLC utilized the Cost Allocation Model's calculation for Street Lighting in cell J23 and J24 respectively.

EPLC customers that receive the TOA in 2016 were subtracted from the Primary Customer base in lines 24 and 25 to reflect the EPLC's Line Transformer Customer Base and Secondary Customer Base.

7.3.9 Tab I7.1: Meter Capital

The purpose of Tab I7.1 is to determine the weighting factors for the Cost Weighted Meter Capital allocator which is used to allocate accounts 1860 (Meters), 5065 (Meter Expense) and 5175 (Maintenance of Meters).

The costs referenced below in Figure 7 reflect EPLC actual installed costs.

Figure 7 – Metering Types & Associated Costs

Meter Types	Cost Per Meter (Installed)
Single Phase 200 Amp - Urban	333
Single Phase 200 Amp - Rural	333
Central Meter 1 Phase	394
Network Meter (Costs to be updated)	445
Micro- Fit 1 Phase	361
Central Meter 1 Phase - Demand	780
Demand without IT	948
Demand with IT	997
Demand with IT and Interval Capability - Sec	1,201
Demand with IT and Interval Capability - Pri	1,363
Dem w IT / Ant	1,198
Solar 3 Phase	818
600 Volt Delta	689

7.3.10 Tab I7.2: Meter Reading

The purpose of Tab I7.2 is to allocate the cost of meter reading across EPLC's rate classes. EPLC currently employs only two methods of reading its meters. The majority are smart meter reads which are now automated and straight forward. The remaining meter reads are interval meter reads which require relatively greater cost per unit when compared to their smart meter counterparts (ie 3rd party costs, MV90 data collection costs, etc). EPLC currently estimates the Meter Reading Weighting Factors as described in Figure 8 below.

Figure 8 – Meter Read Weighting Factors

Meter Read Type	Meter Read Weighting Factors
Smart Meter	1.00
Smart Meter w/ Demand	1.00
Interval	25.00

7.3.11 Tab I8: Demand

EPLC contracted Elenchus to complete a review of the Demand Allocators required in Tab I8 of the Cost Allocation Model. Values in Tab I8 have been determined by Elenchus using the methodology outlined in Attachment 7-C of this Exhibit.

7.3.12 Tab I9: Direction Allocation

EPLC applied $86,000 in directly allocated administrative costs to the Embedded Distributor rate class as a result of the added complexity to EPLC's settlement system and processes that are directly related to this rate class through the de-registration of wholesale metering points. This expense represents the cost of settlement as well as regulatory and senior management review.

HONI has received a summary of these proposed changes but was not able to offer final comment.

7.4 Class Revenue Requirements

Figure 9 below demonstrates the allocated cost by rate class from EPLC's 2010 Cost of Service application and the updated 2018 study results, consistent with Appendix 2-P.

Figure 9 – 2010 vs. Test Year Allocated Costs

Rate Class	Costs Allocated from 2010 Study	%	Costs Allocated from Test Year Study	%
Residential	$ 8,442,067	70.48%	$ 9,665,793	73.432%
GS<50	$ 1,585,605	13.24%	$ 1,437,710	10.922%
GS>50	$ 1,457,177	12.17%	$ 1,707,614	12.973%
Intermediate	$ 58,824	0.49%	$ -	0.000%
Street Light	$ 351,854	2.94%	$ 178,906	1.359%
Sentinel	$ 23,468	0.20%	$ 23,079	0.175%
USL	$ 58,914	0.49%	$ 51,178	0.389%
ED	$ -	0.00%	$ 98,616	0.749%
Total	**$ 11,977,910**	**100.00%**	**$ 13,162,895**	**100.00%**

Figure 10 below outlines the calculated revenue by class consistent with sheet 11 of the RRWF model (formerly Appendix 2-P).

Figure 10 – Calculated Class Revenue

Rate Class	2018 Base Revenue at Existing Rates	2018 Base Revenue Allocated at Existing Rates (1.0230)	2018 Proposed Base Revenue	Miscellaneous Revenue
Residential	$ 8,612,319	$ 8,810,192	$ 8,889,902	$ 521,363
GS<50	$ 1,585,914	$ 1,622,351	$ 1,622,351	$ 82,393
GS>50	$ 1,528,407	$ 1,563,523	$ 1,563,524	$ 74,371
Intermediate	$ -	$ -	$ -	$ -
Street Light	$ 187,611	$ 191,922	$ 191,922	$ 9,623
Sentinel	$ 27,447	$ 28,078	$ 26,669	$ 1,025
USL	$ 62,175	$ 63,604	$ 58,609	$ 2,805
ED	$ 187,106	$ 191,405	$ 118,097	$ 242
Total	**$ 12,190,979**	**$ 12,471,074**	**$ 12,471,074**	**$ 691,821**

7.5 Revenue to Cost Ratios

The outputs of a Cost Allocation study are generally presented in the form of Revenue to Cost ("RTC") ratios. These ratios represent the percentage of Distribution Revenue collected by rate class, compared to the cost allocated to that same class. Ratios under 100% indicate that a specific class is under-contributing and is being subsidized by other classes whereas ratios over 100% indicate that a specific class is over-contributing and subsidizing other rate classes.

The Board published a range of acceptable ratios on March 31st, 2011. Further, the Board provided clarity to the treatment of Street Lighting connections on June 12th, 2015.

Figure 11 below, completed consistently with Tab 11 of the RRWF worksheet and formerly Appendix 2-P, lists EPLC's previously approved ratios, summarizes the results of EPLC's Cost Allocation study as well as EPLC's proposed ratios.

Figure 11 – Revenue to Cost Ratios

Rate Class	Previously Approved Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
Residential	100.23%	96.54%	97.37%	85% to 115%
General Service < 50 kW	49.56%	118.57%	118.57%	80% to 120%
General Service > 50 kW	159.99%	95.92%	95.92%	80% to 120%
Intermediate Use	336.93%	0.00%	0.00%	80% to 120%
Street Lights	32.36%	112.65%	112.65%	80% to 120%
Unmetered Scattered Load	132.66%	129.76%	120.00%	80% to 120%
Sentinel Lights	38.09%	126.10%	120.00%	80% to 120%
Embedded Distributor	N/A	194.34%	120.00%	80% to 120%

In order to determine the proposed ratios presented above, EPLC moved all status quo RTC ratios (resulting from the Cost Allocation Study) to the closest available policy range threshold. Given that the Embedded Distributor class was new and there is no current policy range established, EPLC chose 120% as the proposed ratio. This resulted in EPLC under earning therefore EPLC moved the primary cost contributor (Residential) proportionately until revenue neutrality was reached. This resulted in the Residential rate class having proposed RTC ratios of 97.37%.

Attachment 7-A

Cost Allocation Model Tabs I6.1, I6.2, O1 & O2

Ontario Energy Board

2018 Cost Allocation Model

EB-2017-0039

Sheet I6.1 Revenue Worksheet - 1

Total kWhs from Load Forecast	518,917,436

Total kWs from Load Forecast	538,051

Deficiency/sufficiency (RRWF 8. cell F51)	- 280,095

Miscellaneous Revenue (RRWF 5. cell F48)	691,821

			1	2	3	5	7	8	9	10
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**GS >50-Intermediate**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**
Billing Data										
Forecast kWh	**CEN**	518,917,436	245,374,118	62,707,450	176,280,306		2,799,882	335,758	1,554,368	29,865,554
Forecast kW	**CDEM**	538,051	-	-	446,253		8,848	2,080	-	80,869
Forecast kW, included in CDEM, of customers receiving line transformer allowance		115,611			115,611					
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-								
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	508,048,486	246,273,348	62,262,858	164,956,718		2,799,882	335,758	1,554,368	29,865,554
Existing Monthly Charge			$20.31	$35.13	$232.69		$3.30	$3.41	$9.53	$232.69
Existing Distribution kWh Rate			$0.0078	$0.0120					$0.0297	
Existing Distribution kW Rate					$2.2101		$8.9407	$9.7922		$2.2101
Existing TOA Rate				$0.60	$0.60					
Additional Charges										
Distribution Revenue from Rates		$12,260,346	$8,612,319	$1,585,914	$1,597,774	$0	$187,611	$27,447	$62,175	$187,106
Transformer Ownership Allowance		$69,367	$0	$0	$69,367	$0	$0	$0	$0	$0
Net Class Revenue	**CREV**	$12,190,979	$8,612,319	$1,585,914	$1,528,407	$0	$187,611	$27,447	$62,175	$187,106

Ontario Energy Board

2018 Cost Allocation Model

EB-2017-0039

Sheet I6.2 Customer Data Worksheet - 1

			1	2	3	5	7	8	9	10
	ID	Total	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
Billing Data										
Bad Debt 3 Year Historical Average	BDHA	$164,142	$122,315	$34,461	$7,366	$0	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$119,824	$76,262	$18,352	$25,052	$0	$48	$55	$54	$0
Number of Bills	CNB	353,209	323,868	24,534.00	2,744.00		60.00	372.00	1,595.00	36
Number of Devices	CDEV		27,484	1,977	219		2,740	173	140	3
Number of Connections (Unmetered)	CCON	32,736	27,484	1,977	219		2,740	173	140	3
Total Number of Customers	CCA	30,001	27,484	1,977	219		5	173	140	3
Bulk Customer Base	CCB	-								
Primary Customer Base	CCP	30,283	27,484	1,977	217		289	173	140	3
Line Transformer Customer Base	CCLT	30,272	27,484	1,975	211	-	289	173	140	
Secondary Customer Base	CCS	29,988	27,484	1,975	211	-	5	173	140	
Weighted - Services	CWCS	34,836	27,484	5,140	460	-	1,370	87	280	15
Weighted Meter -Capital	CWMC	10,790,525	9,272,145	1,277,023	237,266	-	-	-	-	4,090
Weighted Meter Reading	CWMR	35,011	27,484	1,977	5,475	-	-	-	-	75
Weighted Bills	CWNB	371,315	323,868	39,254	4,390	-	60	372	3,190	180

Bad Debt Data

Historic Year:	2014	143,700	97,622	23,979	22,098	-	-	-	-	-
Historic Year:	2015	164,888	137,806	27,081	-	-	-	-	-	-
Historic Year:	2016	183,840	131,516	52,324	-	-	-	-	-	-
Three-year average		**164,142**	**122,315**	**34,461**	**7,366**	**-**	**-**	**-**	**-**	**-**

Street Lighting Adjustment Factors

NCP Test Results	4 NCP

	Primary Asset Data		Line Transformer Asset Data	
Class	**Customers/ Devices**	**4 NCP**	**Customers/ Devices**	**4 NCP**
Residential	27,484	275,543	27,484	275,543
Street Light	2,740	2,846	2,740	2,846

Street Lighting Adjustment Factors	
Primary	9.6515
Line Transformer	9.6515

Ontario Energy Board

2018 Cost Allocation Model

EB-2017-0039

Sheet O1 Revenue to Cost Summary Worksheet - 1

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

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50-Regular	5 GS >50-Intermediate	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor
crev	Distribution Revenue at Existing Rates	$12,190,979	$8,612,319	$1,585,914	$1,528,407	$0	$187,611	$27,447	$62,175	$187,106
mi	Miscellaneous Revenue (mi)	$691,821	$521,363	$82,393	$74,371	$0	$9,623	$1,025	$2,805	$242
		Miscellaneous Revenue Input equals Output								
	Total Revenue at Existing Rates	$12,882,800	$9,133,681	$1,668,306	$1,602,779	$0	$197,234	$28,472	$64,980	$187,348
	Factor required to recover deficiency (1 + D)	1.0230								
	Distribution Revenue at Status Quo Rates	$12,471,074	$8,810,192	$1,622,351	$1,563,523	$0	$191,922	$28,078	$63,604	$191,405
	Miscellaneous Revenue (mi)	$691,821	$521,363	$82,393	$74,371	$0	$9,623	$1,025	$2,805	$242
	Total Revenue at Status Quo Rates	$13,162,895	$9,331,554	$1,704,744	$1,637,895	$0	$201,545	$29,102	$66,408	$191,647
	Expenses									
di	Distribution Costs (di)	$1,865,349	$1,259,208	$212,083	$352,515	$0	$29,162	$3,657	$6,302	$2,421
cu	Customer Related Costs (cu)	$2,070,141	$1,761,828	$216,126	$46,038	$0	$29,581	$3,134	$12,475	$958
ad	General and Administration (ad)	$3,731,323	$2,858,458	$406,196	$383,796	$0	$55,531	$6,454	$17,660	$3,226
dep	Depreciation and Amortization (dep)	$1,848,004	$1,323,917	$206,824	$288,660	$0	$19,324	$2,989	$4,408	$1,883
INPUT	PILs (INPUT)	$227,249	$157,092	$25,294	$40,613	$0	$2,890	$437	$659	$263
INT	Interest	$1,230,186	$850,399	$136,927	$219,855	$0	$15,647	$2,364	$3,569	$1,425
	Total Expenses	$10,972,251	$8,210,902	$1,203,450	$1,331,478	$0	$152,136	$19,035	$45,073	$10,177
	Direct Allocation	$86,000	$0	$0	$0	$0	$0	$0	$0	$86,000
NI	Allocated Net Income (NI)	$2,104,644	$1,454,891	$234,260	$376,135	$0	$26,770	$4,044	$6,105	$2,439
	Revenue Requirement (includes NI)	$13,162,895	$9,665,793	$1,437,710	$1,707,614	$0	$178,906	$23,079	$51,178	$98,616
		Revenue Requirement Input equals Output								
	Rate Base Calculation									
	Net Assets									
dp	Distribution Plant - Gross	$94,354,574	$65,563,703	$10,510,022	$16,549,592	$0	$1,181,184	$177,850	$267,931	$104,293
gp	General Plant - Gross	$10,414,080	$7,209,958	$1,161,764	$1,845,566	$0	$134,334	$20,047	$30,568	$11,844
accum dep	Accumulated Depreciation	($30,144,083)	($21,075,318)	($3,342,585)	($5,208,761)	$0	($351,989)	($54,504)	($79,464)	($31,462)
co	Capital Contribution	($20,403,273)	($14,210,027)	($2,292,508)	($3,505,256)	$0	($272,769)	($39,196)	($61,535)	($21,982)
	Total Net Plant	$54,221,299	$37,488,316	$6,036,693	$9,681,140	$0	$690,761	$104,197	$157,500	$62,692
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$68,325,958	$33,120,584	$8,373,550	$22,184,548	$0	$376,548	$45,155	$209,042	$4,016,531
	OM&A Expenses	$7,666,812	$5,879,494	$834,405	$782,350	$0	$114,274	$13,246	$36,437	$6,606
	Directly Allocated Expenses	$86,000	$0	$0	$0	$0	$0	$0	$0	$86,000
	Subtotal	*$76,078,770*	*$39,000,078*	*$9,207,955*	*$22,966,897*	*$0*	*$490,822*	*$58,401*	*$245,480*	*$4,109,137*
	Working Capital	$5,705,908	$2,925,006	$690,597	$1,722,517	$0	$36,812	$4,380	$18,411	$308,185
	Total Rate Base	$59,927,207	$40,413,321	$6,727,290	$11,403,658	$0	$727,572	$108,577	$175,911	$370,878
		Rate Base Input equals Output								
	Equity Component of Rate Base	$23,970,883	$16,165,329	$2,690,916	$4,561,463	$0	$291,029	$43,431	$70,365	$148,351
	Net Income on Allocated Assets	$2,104,644	$1,120,652	$501,293	$306,417	$0	$49,409	$10,067	$21,335	$95,470
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$2,104,644	$1,120,652	$501,293	$306,417	$0	$49,409	$10,067	$21,335	$95,470
	RATIOS ANALYSIS									
	REVENUE TO EXPENSES STATUS QUO%	100.00%	96.54%	118.57%	95.92%	0.00%	112.65%	126.10%	129.76%	194.34%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($280,095)	($532,112)	$230,596	($104,835)	$0	$18,328	$5,393	$13,801	$88,733
		Deficiency Input equals Output								
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	($334,239)	$267,034	($69,719)	$0	$22,639	$6,024	$15,230	$93,032
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.78%	6.93%	18.63%	6.72%	0.00%	16.98%	23.18%	30.32%	64.35%

Ontario Energy Board

2018 Cost Allocation Model

EB-2017-0039

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - 1

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	1	2	3	5	7	8	9	10
Summary	**Residential**	**GS <50**	**GS>50-Regular**	**GS >50-Intermediate**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**
Customer Unit Cost per month - Avoided Cost	$5.50	$8.09	-$2.93	0	$0.88	$1.32	$6.17	$29.63
Customer Unit Cost per month - Directly Related	$10.00	$15.08	$11.43	0	$1.75	$2.69	$12.27	$53.73
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$19.34	$32.70	$30.04	0	$4.58	$8.64	$25.30	$85.97
Existing Approved Fixed Charge	$20.31	$35.13	$232.69	$0.00	$3.30	$3.41	$9.53	$232.69

Attachment 7-B

RRWF Cost Allocation

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Cost Allocation and Rate Design

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

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential	$ 8,442,067	70.48%	$ 9,665,793	73.43%
2	General Service < 50 kW	$ 1,585,605	13.24%	$ 1,437,710	10.92%
3	General Service > 50 kW	$ 1,457,177	12.17%	$ 1,707,614	12.97%
4	Intermediate Use	$ 58,824	0.49%	$ -	
5	Street Lights	$ 351,854	2.94%	$ 178,906	1.36%
6	Unmetered Scattered Load	$ 23,468	0.20%	$ 51,178	0.39%
7	Sentinel Lights	$ 58,914	0.49%	$ 23,079	0.18%
8	Embedded Distributor	$ -		$ 98,616	0.75%
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 11,977,910	100.00%	**$ 13,162,895**	100.00%
			Service Revenue Requirement (from Sheet 9)	**$ 13,162,895.35**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)		LF X current approved rates X (1+d) (7C)		LF X Proposed Rates (7D)		Miscellaneous Revenues (7E)	
1	Residential	$	8,612,319	$	8,810,192	$	8,889,902	$	521,363
2	General Service < 50 kW	$	1,585,914	$	1,622,351	$	1,622,351	$	82,393
3	General Service > 50 kW	$	1,528,407	$	1,563,523	$	1,563,524	$	74,371
4	Intermediate Use	$	-	$	-	$	-	$	-
5	Street Lights	$	187,611	$	191,922	$	191,922	$	9,623
6	Unmetered Scattered Load	$	62,175	$	63,604	$	58,609	$	2,805
7	Sentinel Lights	$	27,447	$	28,078	$	26,669	$	1,025
8	Embedded Distributor	$	187,106	$	191,405	$	118,097	$	242
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									
	Total	$	12,190,979	$	12,471,074	$	12,471,074	$	691,821

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2010 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	100.23%	96.54%	97.37%	85 - 115
2	General Service < 50 kW	49.56%	118.57%	118.57%	80 - 120
3	General Service > 50 kW	159.99%	95.92%	95.92%	80 - 120
4	Intermediate Use	336.93%	#DIV/0!	#DIV/0!	80 - 120
5	Street Lights	32.36%	112.65%	112.65%	80 - 120
6	Unmetered Scattered Load	132.66%	129.76%	120.00%	80 - 120
7	Sentinel Lights	38.09%	126.10%	120.00%	80 - 120
8	Embedded Distributor	N/A	194.34%	120.00%	80 - 120
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

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

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
		2018	2019	2020	
1	Residential	97.37%	97.37%	97.37%	85 - 115
2	General Service < 50 kW	118.57%	118.57%	118.57%	80 - 120
3	General Service > 50 kW	95.92%	95.92%	95.92%	80 - 120
4	Intermediate Use	#DIV/0!	#DIV/0!	#DIV/0!	80 - 120
5	Street Lights	112.65%	112.65%	112.65%	80 - 120
6	Unmetered Scattered Load	120.00%	120.00%	120.00%	80 - 120
7	Sentinel Lights	120.00%	120.00%	120.00%	80 - 120
8	Embedded Distributor	120.00%	120.00%	120.00%	80 - 120
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2018 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2019 and 2020 Price Cap IR models, as necessary. For 2019 and 2020, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Attachment 7-C

Elenchus Demand Allocation Methodology

2018 Essex Hourly Load Profile

Essex provided Elenchus with data for 2016 actual hourly kWh for General Service > 50 kW and Embedded Distributor, but was unable to provide reliable data for the remaining rate classes. Due to a data availability issue with smart meter data, Elenchus obtained hourly data for the remaining rate classes from London Hydro to approximate the shape of the Essex's load profiles for those rate classes.

For the rate classes relying on London Hydro data, the hourly loads for each class were revised to reflect Essex's 2018 load forecast. For General Service > 50 kW and Embedded Distributor classes, the hourly leads were adjusted to account for changes in the relative loads from 2016 to 2018. This was done by scaling the hourly loads of each class to levels consistent with the 2018 load forecast while maintaining the hourly load shapes.

The 12 monthly coincident and non-coincident peaks for the rate classes were determined. The allocators were then derived as follows.

- The 1, 4 and 12 NCP values for each class were calculated by selecting the peak hour in the year (1 NCP), summing the four highest monthly peaks (4 NCP) and summing the 12 monthly peaks for each class (12 NCP), respectively.
- The total 1, 4 and 12 NCP values are the totals of the corresponding class NCP values.
- The 1, 4 and 12 CP values for each class were derived by identifying the hour in each month when the coincident peak occurred and then selecting the peak in the year (1 CP), adding the demands during the four highest coincident peak hours (4 CP) and summing the demand for each class during the 12 monthly coincident peak hours (12 CP), respectively.
- The total 1, 4 and 12 CP values are the totals of the corresponding class CP values, which are the values used to identify the relevant coincident peak hours.

Weather Normalization

Data for the Residential and General Service < 50 kW classes were weather normalized to reflect load profiles in a year of typical weather in Windsor. The weather normalization process to determine Essex's weather sensitive load uses daily heating degree days and cooling degree days as measured at Environment Canada's Windsor Riverside and London Airport weather stations to take into account temperature sensitivity. Environment Canada defines heating degree days and cooling degree days as the difference between the average daily temperature and 18°C for each day (below for heating, above for cooling). For example, a single day with a temperature of 20°C is considered to have two cooling degree days.

The typical weather of a given day was determined with a heating degree day and cooling degree day ranking process. Instead of looking at the typical weather of particular date, heating and cooling degree days from Windsor Riverside's weather station were ranked within each month from highest to lowest. The equivalently ranked days within a given month over the past 10 years were used to determine the average heating and cooling degree days for that ranked day. For example, the highest heating degree day in each of the past 10 Januarys are averaged to determine the normal highest heating degree day for January. This process maintains the shape of the load profiles by determining typical monthly peaks for the Residential and General Service < 50 kW classes without smoothing out those peaks.

The normal ranked heating and cooling degree days were then matched with the corresponding London Airport ranked days in 2016. The differences between London's actual heating and cooling degree days and their corresponding Windsor normal heating and cooling degree days were calculated to be used with regression results to adjust 2016 London Hydro hourly loads to Essex normal hourly loads.

The weather normalization regression calculated the impact of London's heating and cooling degree days at each hour of the day on London Hydro's hourly load (see appendix). This method considers that weather may impact electricity use differently at various hours of the day. The results reflect the impact of a single heating or cooling degree day at a given hour of the day on the load for that hour. The hourly results were combined with the London actual and Windsor normal heating and cooling degree day differences, as described in the above paragraph, to determine the weather normalization adjustment required for each hour in 2016. The weather normalization adjustments were then applied to the initial load profiles and the normalized load profiles were re-scaled to Essex's 2018 load forecast.

The table below shows Essex's final weather normalized demand allocators with the scaling adjustment.

	Residential	GS < 50 kW	GS > 50 kW	Embedded	Street Light	Sentinel Light	USL	Total
1CP	70,732	12,496	33,413	150	-	-	178	121,263
4CP	273,003	49,404	126,244	709	-	-	711	468,838
12CP	583,671	120,329	307,047	926	3,363	349	2,125	1,067,520

1NCP	73,521	14,064	37,065	444	713	117	189	132,840
4NCP	275,543	55,055	140,401	1,384	2,846	434	731	502,522
12NCP	616,780	138,117	348,326	1,953	8,513	1,059	2,125	1,186,462

APPENDIX

Residential Weather Normalization Regression Results

	coefficient	std. error	t-ratio	p-value
HDD1	0.001516531	6.46E-05	23.46795097	6.18E-120
HDD2	0.001418183	6.46E-05	21.94603654	2.49E-105
HDD3	0.001381473	6.46E-05	21.37796238	4.10E-100
HDD4	0.00136472	6.46E-05	21.11870312	8.91E-98
HDD5	0.001311628	6.46E-05	20.29711683	1.51E-90
HDD6	0.001188816	6.46E-05	18.39664158	7.12E-75
HDD7	0.001241104	6.46E-05	19.20578381	2.28E-81
HDD8	0.001588629	6.46E-05	24.58365215	3.18E-131
HDD9	0.001552865	6.46E-05	24.03020595	1.46E-125
HDD10	0.001359006	6.46E-05	21.0302856	5.50E-97
HDD11	0.001257243	6.46E-05	19.4555355	2.00E-83
HDD12	0.001209134	6.46E-05	18.71104947	2.29E-77
HDD13	0.001206054	6.46E-05	18.66339231	5.51E-77
HDD14	0.001072537	6.46E-05	16.59724532	2.15E-61
HDD15	0.000889967	6.46E-05	13.77202916	6.29E-43
HDD16	0.000650839	6.46E-05	10.07157023	8.57E-24
HDD17	0.000715929	6.46E-05	11.0788302	1.98E-28
HDD18	0.001424373	6.46E-05	22.04182803	3.20E-106
HDD19	0.001665241	6.46E-05	25.76919208	9.42E-144
HDD20	0.001625338	6.46E-05	25.15171565	3.70E-137
HDD21	0.001603763	6.46E-05	24.81784179	1.18E-133
HDD22	0.001733918	6.46E-05	26.83195517	1.91E-155
HDD23	0.00186557	6.46E-05	28.86924569	4.54E-179
HDD24	0.00174133	6.46E-05	26.946664	9.83E-157
CDD1	0.009383382	0.000353918	26.51284237	6.88E-152
CDD2	0.00822855	0.000353918	23.24985461	8.72E-118
CDD3	0.007356582	0.000353918	20.78609819	8.10E-95
CDD4	0.006668223	0.000353918	18.84113396	2.08E-78
CDD5	0.006072909	0.000353918	17.15906657	1.85E-65
CDD6	0.005456424	0.000353918	15.41718184	2.81E-53
CDD7	0.005434214	0.000353918	15.35442818	7.33E-53
CDD8	0.007159626	0.000353918	20.22959655	5.76E-90
CDD9	0.009549774	0.000353918	26.98298681	3.84E-157
CDD10	0.011969641	0.000353918	33.82034544	6.34E-243
CDD11	0.014350161	0.000353918	40.54653093	0.00E+00
CDD12	0.016492899	0.000353918	46.60085731	0.00E+00
CDD13	0.018201183	0.000353918	51.42763296	0.00E+00
CDD14	0.019403592	0.000353918	54.82505036	0.00E+00
CDD15	0.020312421	0.000353918	57.3929564	0.00E+00

CDD16	0.020697023	0.000353918	58.47965564	0.00E+00
CDD17	0.020542007	0.000353918	58.04165612	0.00E+00
CDD18	0.020097008	0.000353918	56.78430511	0.00E+00
CDD19	0.01885623	0.000353918	53.278474	0.00E+00
CDD20	0.017303213	0.000353918	48.89040793	0.00E+00
CDD21	0.01656928	0.000353918	46.81667357	0.00E+00
CDD22	0.015384513	0.000353918	43.469103	0.00E+00
CDD23	0.013620832	0.000353918	38.48580225	0.00E+00
CDD24	0.011764294	0.000353918	33.24013552	5.59E-235
HOUR1	0.075053542	0.00104776	71.63236676	0
HOUR2	0.068695225	0.001047765	65.56355615	0
HOUR3	0.065227809	0.001047771	62.25390347	0
HOUR4	0.063975141	0.001047776	61.05804489	0
HOUR5	0.066576524	0.001047781	63.54049598	0
HOUR6	0.075941295	0.001047786	72.47785413	0
HOUR7	0.087088422	0.001047791	83.11618328	0
HOUR8	0.090069479	0.001047797	85.96084247	0
HOUR9	0.091419501	0.001047802	87.24884824	0
HOUR10	0.094499785	0.001047807	90.1881576	0
HOUR11	0.097890251	0.001047812	93.42346768	0
HOUR12	0.100704167	0.001047817	96.10850501	0
HOUR13	0.101027844	0.001047823	96.41693217	0
HOUR14	0.102313687	0.001047828	97.6436042	0
HOUR15	0.106734817	0.001047833	101.862426	0
HOUR16	0.11782737	0.001047838	112.4480505	0
HOUR17	0.130666281	0.001047843	124.7001914	0
HOUR18	0.132565705	0.001047849	126.5122604	0
HOUR19	0.134250409	0.001047854	128.1193981	0
HOUR20	0.137739554	0.001047859	131.448545	0
HOUR21	0.135668334	0.001047864	129.471281	0
HOUR22	0.122444188	0.00104787	116.8506054	0
HOUR23	0.10213463	0.001047875	97.46835873	0
HOUR24	0.08463163	0.00104788	80.76462436	0
Trend	-8.78E-08	2.34E-08	-3.746341907	0.000180009

Mean dependent var	0.124033406	S.D. dependent var	0.039385035
Sum squared resid	4.075780369	S.E. of regression	0.015273779
R-squared	0.850223234	Adjusted R-squared	0.849605987
F(72, 17471)	1377.443478	P-value(F)	0
Log-likelihood	48505.01956	Akaike criterion	-96864.03912
Schwarz criterion	-96296.64901	Hannan-Quinn	-96677.22205
rho	0.935985189	Durbin-Watson	0.127876525

GS < 50 Weather Normalization Regression Results

	coefficient	std. error	t-ratio	p-value
HDD1	0.000375466	3.53E-05	10.62250807	2.82E-26
HDD2	0.000379211	3.53E-05	10.72844904	9.07E-27
HDD3	0.000356009	3.53E-05	10.07203138	8.53E-24
HDD4	0.000375751	3.53E-05	10.63056393	2.59E-26
HDD5	0.000367158	3.53E-05	10.38746777	3.35E-25
HDD6	0.000372721	3.53E-05	10.54483392	6.42E-26
HDD7	0.000349567	3.53E-05	9.889780752	5.30E-23
HDD8	0.000260741	3.53E-05	7.376750687	1.69E-13
HDD9	0.0001445	3.53E-05	4.088118481	4.37E-05
HDD10	0.000143437	3.53E-05	4.058056548	4.97E-05
HDD11	0.000145598	3.53E-05	4.119174623	3.82E-05
HDD12	0.00014397	3.53E-05	4.073136864	4.66E-05
HDD13	5.77E-05	3.53E-05	1.631841961	1.03E-01
HDD14	7.51E-05	3.53E-05	2.125729968	0.033539736
HDD15	1.06E-05	3.53E-05	0.30067131	0.763668726
HDD16	0.000104934	3.53E-05	2.968735022	0.002994341
HDD17	0.000231782	3.53E-05	6.557467304	5.63E-11
HDD18	0.00031753	3.53E-05	8.983400321	2.89E-19
HDD19	0.000360158	3.53E-05	10.18942202	2.59E-24
HDD20	0.000351679	3.53E-05	9.949517048	2.92E-23
HDD21	0.000380654	3.53E-05	10.76926825	5.84E-27
HDD22	0.000396577	3.53E-05	11.21977629	4.10E-29
HDD23	0.000404131	3.53E-05	11.43348707	3.64E-30
HDD24	0.000397871	3.53E-05	11.25637344	2.72E-29
CDD1	0.001332356	0.000193585	6.882555482	6.08E-12
CDD2	0.001271743	0.000193585	6.56944494	5.19E-11
CDD3	0.001369898	0.000193585	7.076481796	1.53E-12
CDD4	0.001192862	0.000193585	6.161969599	7.34E-10
CDD5	0.001201846	0.000193585	6.208374977	5.47E-10
CDD6	0.001143739	0.000193585	5.908212784	3.52E-09
CDD7	0.000777456	0.000193585	4.016106026	5.94E-05
CDD8	0.00155012	0.000193585	8.007455459	1.24E-15
CDD9	0.002120607	0.000193585	10.95442343	7.80E-28
CDD10	0.002522283	0.000193585	13.02935902	1.26E-38
CDD11	0.002800061	0.000193585	14.46428078	3.81E-47
CDD12	0.002972188	0.000193585	15.35343349	7.44E-53
CDD13	0.002841648	0.000193585	14.67910231	1.71E-48
CDD14	0.003096852	0.000193585	15.99740977	3.39E-57
CDD15	0.002859718	0.000193585	14.77244733	4.36E-49
CDD16	0.00304231	0.000193585	15.71566385	2.82E-55

CDD17	0.00282838	0.000193585	14.61056787	4.62E-48
CDD18	0.002514755	0.000193585	12.99047203	2.09E-38
CDD19	0.00225252	0.000193585	11.63584601	3.53E-31
CDD20	0.001422493	0.000193585	7.348172562	2.10E-13
CDD21	0.002072448	0.000193585	10.70564862	1.16E-26
CDD22	0.001847557	0.000193585	9.543928234	1.55E-21
CDD23	0.001671764	0.000193585	8.63583094	6.33E-18
CDD24	0.0015552	0.000193585	8.033699468	1.01E-15
HOUR1	0.031108147	0.000573099	54.28059744	0
HOUR2	0.030346578	0.000573102	52.95147214	0
HOUR3	0.030327353	0.000573105	52.91766398	0
HOUR4	0.029716114	0.000573107	51.85086634	0
HOUR5	0.030155759	0.00057311	52.61773046	0
HOUR6	0.03106563	0.000573113	54.20506353	0
HOUR7	0.033837297	0.000573116	59.04093028	0
HOUR8	0.039381358	0.000573119	68.71413229	0
HOUR9	0.045564165	0.000573122	79.50174053	0
HOUR10	0.049464857	0.000573124	86.30735648	0
HOUR11	0.051773168	0.000573127	90.33449913	0
HOUR12	0.052584732	0.00057313	91.75007059	0
HOUR13	0.054280267	0.000573133	94.70797776	0
HOUR14	0.05347251	0.000573136	93.29814218	0
HOUR15	0.054222473	0.000573139	94.60619781	0
HOUR16	0.051274443	0.000573142	89.46209448	0
HOUR17	0.047141497	0.000573144	82.25064677	0
HOUR18	0.044292275	0.000573147	77.27905063	0
HOUR19	0.042866195	0.00057315	74.79052373	0
HOUR20	0.042190783	0.000573153	73.61173647	0
HOUR21	0.039560256	0.000573156	69.02182046	0
HOUR22	0.036395081	0.000573159	63.49914071	0
HOUR23	0.033781645	0.000573161	58.93913953	0
HOUR24	0.031909075	0.000573164	55.6717723	0
Trend	-1.37E-07	1.28E-08	-10.6993347	1.24E-26

Mean dependent var	0.044415784	S.D. dependent var	0.012446441
Sum squared resid	1.219399594	S.E. of regression	0.008354378
R-squared	0.551304428	Adjusted R-squared	0.549455302
F(72, 17471)	298.1432378	P-value(F)	0
Log-likelihood	59090.22379	Akaike criterion	-118034.448
Schwarz criterion	-117467.0575	Hannan-Quinn	-117847.631
rho	0.457066883	Durbin-Watson	1.085864146

Exhibit 8:

Rate Design

Table of Contents

List of Attachments

8.1 Distribution Rates

8.1.1 Overview

This Exhibit is intended to provide details relating to EPLC's rate design calculation and methodologies used in determining rates for the 2018 Test Year.

EPLC has determined its 2018 Test Year Service Revenue Requirement to be $13,162,895. EPLC also determined its total Revenue Offsets to be $691,821 which results in a Base Revenue Requirement of $12,471,074.

EPLC's Base Revenue Requirement calculation is based on 2018 Test Year capital and operating forecasts, weather and CDM adjusted usage, forecasted customer counts and regulated return on rate base. Figure 1 below summarizes EPLC's Base Revenue Requirement.

Figure 1 – EPLC Proposed 2018 Revenue Requirement

Description	Amount
OM&A Expenses	$ 7,710,275
Amortization Expense	$ 1,848,004
Property Taxes	$ 42,538
Income Taxes (Grossed Up)	$ 227,249
Deemed Interest Expense	$ 1,230,186
Return on Deemed Equity	$ 2,104,644
Service Revenue Requirement	**$ 13,162,895**
Revenue Offsets	$ 691,821
Base Revenue Requirement	**$ 12,471,074**

The Base Revenue Requirement is allocated to EPLC's rate classes based on the Cost Allocation study outlined in Exhibit 7 of this Application. Figure 2 below outlines the resulting cost allocations by rate class.

Figure 2 – EPLC Proposed 2018 Revenue Requirement by Rate Class

Rate Class	Service Revenue Requirement	Allocated Other Revenue	Base Revenue Requirement
Residential	$ 9,411,265	$ 521,363	$ 8,889,902
General Service Less Than 50 kW	$ 1,704,744	$ 82,393	$ 1,622,351
General Service 50 to 4,999 kW	$ 1,637,895	$ 74,371	$ 1,563,524
Unmetered Scattered Load	$ 61,414	$ 2,805	$ 58,609
Sentinel Lighting	$ 27,694	$ 1,025	$ 26,669
Street Lighting	$ 201,545	$ 9,623	$ 191,922
Embedded Distributor	$ 118,339	$ 242	$ 118,097
Total	**$ 13,162,895**	**$ 691,821**	**$ 12,471,074**

8.1.2 Fixed/Variable Proportion

Figure 3 below outlines EPLC's current split between fixed and variable distribution revenue. The information below is based on applying existing Board approved monthly service and volumetric charges to the forecasted number of customers and volumes for the 2018 Test Year, excluding all rate riders and the Transformer Ownership Allowance.

Figure 3 – Current Fixed/Variable Distribution Revenue Split

Rate Class	2018 Projected Distribution Revenue at Existing Rates				
	Fixed Charge Revenue	Variable Revenue	Total Revenue	% Fixed Revenue	% Variable Revenue
Residential	$ 6,698,400	$ 1,913,918	$ 8,612,319	77.78%	22.22%
General Service Less Than 50 kW	$ 833,424	$ 752,489	$ 1,585,914	52.55%	47.45%
General Service 50 to 4,999 kW	$ 611,509	$ 916,898	$ 1,528,407	40.01%	59.99%
Unmetered Scattered Load	$ 16,010	$ 46,165	$ 62,175	25.75%	74.25%
Sentinel Lighting	$ 7,079	$ 20,368	$ 27,447	25.79%	74.21%
Street Lighting	$ 108,504	$ 79,107	$ 187,611	57.83%	42.17%
Embedded Distributor	$ 8,377	$ 178,729	$ 187,106	4.48%	95.52%
Total	**$ 8,283,304**	**$ 3,907,675**	**$ 12,190,979**	**67.95%**	**32.05%**

Proposed Monthly Service Charge

For the purpose of determining the proposed monthly service charge, EPLC proposes to maintain the existing fixed/variable split for all customer classes with the exception of residential (reasoning below in Section 8.1.4) and the newly proposed Embedded Distributor rate class. The Embedded Distributor monthly service charge was derived as a mid-point between EPLC's currently approved Intermediate fixed rate and the GS>50 class. HONI is currently subject to both fixed charges across its three customers. Figure 4 below outlines EPLC's proposed splits.

Figure 4 – Proposed Monthly Service Charge

Rate Class	Total Base Revenue Requirement	% Fixed Revenue	Fixed Revenue	2018 Customers / Connections	Proposed MSC
Residential	$ 8,889,902	88.89%	$ 7,902,100	27,484	$ 23.96
General Service Less Than 50 kW	$ 1,622,351	52.55%	$ 852,573	1,977	$ 35.94
General Service 50 to 4,999 kW	$ 1,563,524	40.01%	$ 625,559	219	$ 238.04
Unmetered Scattered Load	$ 58,609	25.75%	$ 15,092	140	$ 8.98
Sentinel Lighting	$ 26,669	25.79%	$ 6,879	173	$ 3.31
Street Lighting	$ 191,922	57.83%	$ 110,997	2,740	$ 3.38
Embedded Distributor	$ 118,097	16.76%	$ 19,797	3	$ 550.00
Total	**$ 12,471,074**		**$ 9,532,996**	**32,736**	

Figure 5 below outlines a comparison between Board Approved 2017 monthly service charges for all rate classes versus the proposed monthly service charges and information from the Cost Allocation model outlined in Exhibit 7 of this Application.

Figure 5 – Monthly Service Charge Comparison

Rate Class	Current 2017 MSC	Proposed 2018 MSC	Minimum System w/ PLCC Adjustment
Residential	$ 20.31	$ 23.96	$ 19.34
General Service Less Than 50 kW	$ 35.13	$ 35.94	$ 32.70
General Service 50 to 4,999 kW	$ 232.69	$ 238.04	$ 30.04
Unmetered Scattered Load	$ 9.53	$ 8.98	$ 25.30
Sentinel Lighting	$ 3.41	$ 3.31	$ 8.64
Street Lighting	$ 3.30	$ 3.38	$ 4.58
Embedded Distributor	$ 232.69	$ 550.00	$ 85.97

Proposed Volumetric/Variable Charge

EPLC calculated the variable distribution charge by dividing the variable distribution portion of Base Revenue by the applicable 2018 Test Year usage, consumption or demand.

Figure 6 below outlines EPLC's calculation of the proposed variable charges, by rate class for the 2018 Test Year with considerations for Transformer Ownership Allowance. The Transformer Ownership Allowance applies solely to the General Service 50 to 4,999 kW rate class.

Figure 6 – Proposed Volumetric/Variable Charge

Rate Class	Total Base Revenue Requirement	Base Fixed Revenue	Base Variable Revenue	Tranformer Ownership Allowance	Adjusted Variable Revenue	Total Variable Revenue
Residential	$ 8,889,902	$ 7,902,100	$ 987,803	$ -	987,803	$ 0.0040
General Service Less Than 50 kW	$ 1,622,351	$ 852,573	$ 769,778	$ -	769,778	$ 0.0123
General Service 50 to 4,999 kW	$ 1,563,524	$ 625,559	$ 937,964	$ 69,367	1,007,331	$ 2.2573
Unmetered Scattered Load	$ 58,609	$ 15,092	$ 43,517	$ -	43,517	$ 0.0280
Sentinel Lighting	$ 26,669	$ 6,879	$ 19,791	$ -	19,791	$ 9.5148
Street Lighting	$ 191,922	$ 110,997	$ 80,925	$ -	80,925	$ 9.1557
Embedded Distributor	$ 118,097	$ 19,797	$ 98,300	$ -	98,300	$ 1.2155
Total	**$ 12,471,074**	**$ 9,532,996**	**$ 2,938,078**	**$ 69,367**	**3,007,445**	

Figure 7 below outlines a comparison between Board Approved 2017 variable charges for all rate classes versus the proposed variable charges.

Figure 7 - Variable Charge Comparison

Rate Class	Current 2017 Variable	Proposed 2018 Variable
Residential	$ 0.0078	$ 0.0040
General Service Less Than 50 kW	$ 0.0120	$ 0.0123
General Service 50 to 4,999 kW	$ 2.2101	$ 2.2573
Unmetered Scattered Load	$ 0.0297	$ 0.0280
Sentinel Lighting	$ 9.7922	$ 9.5148
Street Lighting	$ 8.9407	$ 9.1557
Embedded Distributor	$ 2.2101	$ 1.2155

8.1.3 Proposed Distribution Rate

Figure 8 below outlines EPLC's proposed 2018 Test Year distribution rates by rate class. These rates include adjustments for transformer ownership allowance.

Figure 8 – Proposed 2018 Distribution Rates

Rate Class	Proposed MSC	Billing Determinant	Proposed Volumetric Charge
Residential	$ 23.96	kWh	$ 0.0040
General Service Less Than 50 kW	$ 35.94	kWh	$ 0.0123
General Service 50 to 4,999 kW	$ 238.04	kW	$ 2.2573
Unmetered Scattered Load	$ 8.99	kWh	$ 0.0280
Sentinel Lighting	$ 3.31	kW	$ 9.5148
Street Lighting	$ 3.38	kW	$ 9.1461
Embedded Distributor	$ 550.00	kW	$ 1.2155

8.1.4 Rate Design Policy Consultation

The Board released *"A New Distribution Rate Design for Residential Electricity Customers"* on April 2nd, 2015 (EB-2012-0410). This new policy stated that delivery costs will be recovered from residential customers solely through a fixed monthly service charge. The Board also determined that the new policy will be implemented by distributors over the course of four years to mitigate any customer bill impact.

EPLC has designed its rates in accordance with this policy and consistent with Sheet 12 of the Revenue Requirement Work Form attached as part of Exhibit 6 of this Application.

Figure 9 below outlines the changes as a result of the Board's policy.

Figure 9 – Residential Rate Design Comparison

Charge Type	Test Year Base Rates @ Current F/V Split	Test Year F / V % Proportion	New Base Rates	New F / V Split	Change in Rate	Change in Proportion
MSC	$ 20.96	77.78%	$ 23.96	88.89%	$ 3.00	11.11%
Volumetric	$ 0.0081	22.22%	$ 0.0040	11.11%	$ (0.0041)	-11.11%

8.1.5 Revenue Reconciliation

Consistent with Sheet 13 of the Revenue Requirement Work Form submitted with this Application as part of Exhibit 6, Figure 10 below outlines EPLC's Revenue Reconciliation based on 2018 proposed distribution rates and the total Base Revenue Requirement.

Figure 10 – 2018 Test Year Revenue Reconciliation

Rate Class	Revenues at Proposed Rates	Class Specific Revenue (Less TOA)	Difference
Residential	$ 8,889,902	$ 8,883,696	$ (6,206)
General Service Less Than 50 kW	$ 1,622,351	$ 1,623,942	$ 1,591
General Service 50 to 4,999 kW	$ 1,563,524	$ 1,563,530	$ 6
Unmetered Scattered Load	$ 58,609	$ 58,609	$ (1)
Sentinel Lighting	$ 26,669	$ 26,662	$ (7)
Street Lighting	$ 191,922	$ 192,059	$ 137
Embedded Distributor	$ 118,097	$ 118,097	$ 0
Total	**$ 12,471,074**	**$ 12,466,595**	**$ (4,479)**

8.2 Smart Metering Entity Charge

The Board issued a Decision and Order (EB-2012-0100/EB-2012-0211) establishing the Smart Metering Entity Charge on March 28th, 2013. The Smart Metering Entity Charge is a fixed charge of $0.79 per month for Residential and General Service < 50 kW customers effective May 1st, 2013 until October 31st, 2018 or as directed by the Board.

For the purpose of this Application, EPLC proposes to continue with the Smart Metering Entity Charge until October 31st, 2018 or as directed by the Board.

8.3 Low Voltage Service Rates

8.3.1 Historical Low Voltage Charges

EPLC is an Embedded Distributor to HONI and pays HONI Low Voltage ("LV") at 20 separate points based on HONI's approved sub-transmission rates. EPLC records these costs in Account 4750 (Charges Low Voltage). EPLC subsequently charges all of its customers an LV charge and records these revenues in Account 4705 (Billed Low Voltage). Every month, EPLC records the difference between the two accounts in Account 1550. A summary of these variances can be found in Exhibit 9 of this Application.

8.3.2 Forecasted Low Voltage Charges

EPLC proposes to use Board Approved 2017 HONI Low Voltage charges as the basis for its 2018 proposed rates. Using these rates will better align charges to EPLC customers and reduce the overall magnitude of deferrals and variances. Figure 11 below outlines EPLC's calculation of its estimated 2017 LV charges.

Figure 11 – Estimated 2017 HONI LV Charges

Description	2016 Annual Billing Determinants	2017 Approved Rates	Estimated 2017 Low Voltage Payable
Meter Charge	12	$ 764.01	$ 9,168.12
Service Charge	180	$ 492.55	$ 88,659.00
Specific ST Lines	96	$ 812.8973	$ 78,038.14
Common ST Lines	1,118,807.55	$ 1.2052	$ 1,348,386.86
Total			**$ 1,524,252.12**

8.3.3 Proposed Low Voltage Charges

EPLC derived LV rates outlined in this section using the same rate class allocation methodology used in the calculation of the RTSR Connection Charge outlined in Section 8.4 below. The resulting percentages were applied against the 2017 estimated LV payable described in Figure 12 below ($1,524,252).

Figure 12 – Estimated LV Charged – Allocated by Rate Class

Rate Class	2018 Forecast - Uplifted		2018 Proposed RTSR		Basis for Allocation ($)	Allocation Percent	Allocated Low Voltage
	kWh	kW	kWh	kW			
Residential	254,084,899		$ 0.0030		$ 762,254.70	49.59%	$ 755,844.47
General Service < 50 kW	64,933,564		$ 0.0029		$ 188,307.34	12.25%	$ 186,723.76
General Service > 50 to 4999 kW	182,538,257	446,253		$ 1.2826	$ 572,364.61	37.23%	$ 567,551.28
Unmetered Scattered Load	1,609,548		$ 0.0029		$ 4,667.69	0.30%	$ 4,628.44
Sentinel Lighting	347,677	2,080		$ 0.8817	$ 1,833.94	0.12%	$ 1,818.51
Street Lighting	2,899,278	8,848		$ 0.8760	$ 7,750.85	0.50%	$ 7,685.67
Embedded Distributor	30,925,781	80,869		N/A	$ -	0.00%	$ -
Total	**537,339,005**	**538,051**			**$ 1,537,179.12**	**100.00%**	**$ 1,524,252.12**

EPLC used the 2018 forecasted kWh and kW to determine the appropriate LV rate by rate class rounded to four decimal places. The resulting LV rates are outlined below as Figure 13.

Figure 13 – Proposed 2018 LV Rates

Rate Class	Allocated Low Voltage	2018 Forecast		2018 Proposed Low Voltage	
		kWh	kW	kWh	kW
Residential	$ 755,844.47	245,374,118		$ 0.0031	
General Service < 50 kW	$ 186,723.76	62,707,450		$ 0.0030	
General Service > 50 to 4999 kW	$ 567,551.28		446,253		$ 1.2718
Unmetered Scattered Load	$ 4,628.44	1,554,368		$ 0.0030	
Sentinel Lighting	$ 1,818.51		2,080		$ 0.8743
Street Lighting	$ 7,685.67		8,848		$ 0.8686
Embedded Distributor	$ -		80,869		$ -
Total	**$ 1,524,252.12**				

8.4 Retail Transmission Service Rates

EPLC's load is not subject to the IESO's Uniform Transmission Rates ("UTR") and is solely subject to Hydro One's Retail Transmission Service Rates ("RTSRs"). For each distributor rate class, there are two applicable RTSR rates; one for Network and one for Line & Connection. The Network charge is intended to recover UTR wholesale network service charge and the RTSR Line & Connection charge is intended to recover the UTR wholesale line and transformation connection charges. EPLC has deferral accounts setup to capture the timing variances between the RTSR charges paid to HONI and what is recovered from EPLC customers.

8.4.1 2018 Proposed Retail Transmission Service Rates

For the purpose of calculating RTSR rates for 2018, EPLC has completed the Board's 2018 RTSR Workform for Electricity Distributors (version 1.1). The RTSR Workform for Electricity Distributors is included as Attachment 8-C of this Exhibit. Figure 14 below outlines EPLC's proposed 2018 RTSR rates by customer class.

Figure 14 – EPLC Proposed RTSR Rates

Rate Class	Unit	Proposed Network	Proposed Line & Connection
Residential	kWh	$ 0.0046	$ 0.0030
General Service Less Than 50 kW	kWh	$ 0.0039	$ 0.0029
General Service 50 to 4,999 kW	kW	$ 1.6326	$ 1.1567
General Service 50 to 4,999 kW – Interval Metered	kW	$ 2.0111	$ 1.2826
Unmetered Scattered Load	kWh	$ 0.0039	$ 0.0029
Sentinel Lighting	kW	$ 1.2569	$ 0.8817
Street Lighting	kW	$ 1.2393	$ 0.8760
Embedded Distributor	N/A	N/A	N/A

8.5 Regulatory Charges

8.5.1 Wholesale Market Service Charge

The Wholesale Market Service Charge ("WMS") allows EPLC to recover costs charged by the IESO to recover the operational costs associated with the IESO administered markets and the IESO controlled grid. The WMS Charge is periodically set by the Board and is an energy based rate ($/kWh).

On December 15th, 2016, the Board issued a Decision and Order (EB-2016-0362) determining that the WMS rate to be used by distributors effective January 1st, 2017 is $0.0032 per kWh. The Board also introduced a Capacity-Based Demand component of WMS that shall be billed to Class B Global Adjustment customers of $0.0004 per kWh for a total WMS rate of $0.0036 per kWh. Class A Global Adjustment customers shall be billed the Capacity-Based Demand component based on actual costs and in proportion to their contribution towards peak.

EPLC proposes to use the WMS rate of $0.0032 per kWh plus the applicable Capacity-Based Demand component until updated by the Board.

8.5.2 Rural or Remote Electricity Rate Protection Charge

The Rural or Remote Electricity Rate Protection Charge ("RRRP") is a source of revenue for identified rural or remote electricity distributors whose costs are higher because they serve small numbers of customers over large geographic areas or in remote regions. The RRRP revenue allows eligible distributors to reduce the amount they would otherwise have to charge affected customers for distribution service.

EPLC does not have any eligible RRRP customers however collects RRRP to remit back to the IESO to distributes applicable revenues to eligible distributors.

On June 22nd 2017, the Board issued a Decision and Order (EB-2017-0234) determining that the RRRP rate to be used by distributors effective July 1st, 2017 is $0.0003 per kWh.

EPLC proposes to use the RRRP rate of $0.0003 per kWh until updated by the Board.

8.5.3 Standard Supply Service – Administrative Charge

EPLC proposes to use the previously approved Standard Supply Service rate of $0.25 per customer unless otherwise directed by the Board.

8.5.4 Ontario Energy Support Program ("OESP")

On April 25th 2017, the Board issued an Order for the Ontario Electricity Support Program ("OESP") Credits (EB-2016-0376) determining the applicable OESP credits effective May 1st, 2017. Figure 15 below outlines the applicable OESP credits.

Figure 15 – Board Approved OESP Credits

Class	Tariff Value	OESP Monthly Credit Amount
A	T10	$35
B	T11	$40
C	T1	$45
D	T2	$51
E	T12	$52
F	T3	$57
G	T13	$60
H	T4	$63
I	T5	$68
J	T6	$75
K	T7	$83
L	T8	$90
M	T9	$113

EPLC proposes to use the OESP credits shown in Figure 15 above unless otherwise directed by the Board.

8.6 MicroFIT

EPLC currently has a MicroFIT monthly service charge of $5.40 as approved by the Board on September 20th, 2012.

EPLC proposed to continue with the $5.40 monthly service charge as approved until updated by the Board.

8.7 Transformer Ownership Allowance

EPLC currently provides a Transformer Ownership Allowance ("TOA") to customers that own their own transformation assets. The TOA is intended to represent the avoided EPLC cost of providing step down transformation to a customer's utilization voltage. Generally, the cost of transformation is included in distribution rates therefore it is appropriate to provide a rebate to customers that provide their own respective transformation.

EPLC currently has an approved TOA credit of ($0.60) per kW of billed demand.

Figure 16 below outlines EPLC's forecasted demand for the 2018 Test Year and the associated estimated TOA. EPLC used 2016 demand for the purpose of billed demand below.

Figure 16 – EPLC Proposed RTSR Rates

Year	Billed Demand (kW)	Rate ($/kW)	Transformer Ownership Allowance ($)
2018	115,610.84	$ (0.60)	$ (69,366.50)

8.8 Specific Service Charges

EPLC requests no changes to its existing Specific Service Charges. Figure 17 below outlines EPLC's proposed Specific Service Charges for this Application.

On April 15th, 2015, the Board announced amendments to the Distribution System Code that requires all distributors to issue monthly bills for all customers by December 31st, 2016. EPLC is currently compliant with this requirement and all customers are on a monthly billing cycle.

Figure 17 – EPLC Proposed SSCs

Description	Unit	Rate
Customer Administration		
Arrears Certificate	$	15.00
Statement of Account	$	15.00
Duplicate Invoices for Previous Billing	$	15.00
Request for Other Billing Information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Account History	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Legal Letter Charge	$	15.00
Account Set Up Charge/Change of Occupancy Charge (plus credit agency charge if applicab	$	30.00
Special Meter Reads	$	30.00
Meter Dispute Charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non Payment of Account		
Late Payment - per Month	%	1.50
Late Payment - per Annum	%	19.56
Collection of Account Charge - No Disconnection	$	30.00
Collection of Account Charge - No Disconnection - After Regular Hours	$	165.00
Disconnect/Reconnect Charge - At Meter - During Regular Hours	$	65.00
Disconnect/Reconnect Charge - At Meter - After Regular Hours	$	185.00
Disconnect/Reconnect Charge - At Pole - During Regular Hours	$	185.00
Disconnect/Reconnect Charge - At Pole - After Regular Hours	$	415.00
Install/Remove Load Control Device - During Regular Hours	$	65.00
Install/Remove Load Control Device - After Regular Hours	$	185.00
Other Charges		
Service Call - Customer Owned Equipment	$	30.00
Service Call - After Regular Hours	$	165.00
Temporary Service Install & Remove - Overhead - No Transformer	$	500.00
Temporary Service Install & Remove - Overhead - With Transformer	$	300.00
Temporary Service Install & Remove - Underground - No Transformer	$	1,000.00
Specific Charge for Access to the Power Poles - per Pole/Year	$	22.35

8.9 Retail Service Charges

EPLC's current Retail Service Charges are consistent with the Board's standard rates. EPLC requests no changes to its existing Retail Service Charges. Figure 18 below outlines EPLC's proposed Retail Service Charges for this Application.

Figure 18 – EPLC Proposed Retail Service Charges

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

8.10 Loss Adjustment Factors

8.10.1 Overview

As a result of EPLC's Voltage Conversion Program (for additional information, please see Exhibit 1, section 1.4), EPLC has realized significant reductions in distribution losses. This section demonstrates EPLC's calculation of losses for the 2018 Test Year which has resulted in a secondary distribution loss reduction of 2.47%.

8.10.2 Calculation of Losses

EPLC has calculated the total loss factor for the 2018 Test Year based on the average wholesale and retail kWh for years 2012-2016. Figure 19 below, which is consistent with Board Appendix 2-R and Attachment 8-D of this Exhibit, summarizes EPLC's total loss factor calculation.

Figure 19 – EPLC Total Loss Factor Calculation

Description	2012 (Actual)	2013 (Actual)	2014 (Actual)	2015 (Actual)	2016 (Actual)	5 Year Average
Losses within Distributor's System						
Wholesale kWh Delivered to EPLC (with Losses)	543,701,676	557,841,472	552,333,503	555,351,796	572,432,535	556,332,196
Wholesale kWh Delivered to EPLC (without Losses)	534,090,993	546,079,224	542,856,165	545,834,271	562,515,905	546,275,312
Wholesale kWh Delivered to Large Users	-	-	-	-	-	-
Net Wholesale kWh Delivered to EPLC	**534,090,993**	**546,079,224**	**542,856,165**	**545,834,271**	**562,515,905**	**546,275,312**
Retail kWh Delivered by EPLC	531,968,130	528,862,603	523,361,255	520,201,702	542,679,868	529,414,712
Portion of Retail kWh Delivered to Large Use Customers	-	-	-	-	-	-
Net Retail kWh Delivered by EPLC	**531,968,130**	**528,862,603**	**523,361,255**	**520,201,702**	**542,679,868**	**529,414,712**
Loss Factor in EPLC System	1.0040	1.0326	1.0372	1.0493	1.0366	1.0318
Supply Facility Loss Factor	1.0036	1.0035	1.0034	1.0036	1.0036	1.0035
Total Loss Factor	**1.0076**	**1.0361**	**1.0408**	**1.0530**	**1.0403**	**1.0355**

Figure 20 below demonstrates EPLC's calculation of the Supply Facility Loss Factor. EPLC purchases kWh directly from the IESO. EPLC utilitized the recommended Supply Facility Loss factor for electricity purchased from the IESO of 1.0045% and applied a loss factor of 1 to all Embedded Generation.

Figure 20 – EPLC Supply Facility Loss Factor Calculation

Description	2012	2013	2014	2015	2016	Total
Purchased kWh						
Direct	429,108,261	430,189,012	417,827,612	438,158,470	461,694,529	2,176,977,883
Embedded Generation	114,593,416	127,652,460	134,505,892	117,193,326	110,738,006	604,683,099
Total	**543,701,676**	**557,841,472**	**552,333,503**	**555,351,796**	**572,432,535**	**2,781,660,982**
Supply Facilities Loss Factor						
Direct	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045
Embedded Generation	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Weighted Average	**1.0036**	**1.0035**	**1.0034**	**1.0036**	**1.0036**	**1.0035**

Figure 21 – EPLC's Proposed Loss Factors

Description	2017 Approved	2018 Proposed
Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0602	1.0355
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0496	1.0251

The resulting Primary and Secondary loss factors are presented above as Figure 21. The proposed loss factors, which represents a 2.47% decrease, is a significant improvement for all EPLC customers.

8.11 Conditions of Service Rates

EPLC does not have any rates and/or charges in its current Conditions of Service that are not currently reflected on its OEB approved Tariff Sheet.

8.12 Tariff of Rates & Charges

EPLC's current Tariff of Rates and Charges, which is reflective of EB-2016-0069, is included as Attachment 8-E of this Exhibit.

EPLC's proposed Tariff of Rates and Charges is included as Attachment 8-F of this Exhibit.

8.13 Bill Impacts

Figure 22 below outlines EPLC's proposed 2018 Total Bill Impacts. EPLC has also included in this Exhibit and in accordance with Board Appendix 2-W, Attachment 8-G.

Figure 22 – EPLC's Proposed 2018 Total Bill Impacts

Rate Class	kWh	kW	2017 BAP Rates	2018 Proposed Rates	$ Increase (Decrease)	% Increase (Decrease)
Residential	750	-	$ 126.61	$ 126.10	$ (0.51)	-0.40%
General Service Less Than 50 kW	2,000	-	$ 322.06	$ 319.92	$ (2.14)	-0.66%
General Service 50 to 4,999 kW	40,000	100	$ 6,600.60	$ 6,209.96	$ (390.64)	-5.92%
Unmetered Scattered Load	700	-	$ 139.72	$ 130.22	$ (9.50)	-6.80%
Sentinel Lighting	36	0.1	$ 10.34	$ 9.94	$ (0.39)	-3.81%
Street Lighting	36	0.1	$ 10.09	$ 9.99	$ (0.11)	-1.07%
Embedded Distributor	200,000	500	$ 50,648.72	$ 50,306.09	$ (342.63)	-0.68%

The bill impacts associated with Figure 22 above includes:

- Distribution rate increases;
- Elimination of the Tax Change rate rider (2017);
- Elimination of the Disposition of Global Adjustment rate rider (2015);
- Addition of new rate riders as outlined in Exhibit 9 of this Application;

Based on the analysis above, EPLC submits that since all rates classes are experiencing a total bill decrease (ie. More favourable to customers) and that no class exceeds the 10% threshold, therefore EPLC's proposed 2018 distribution rates are reasonable and do not require any rate mitigation.

Figure 23 below outlines EPLC's proposed Distribution increase (sub-total A, not including reduction in distribution losses).

Figure 23 – EPLC's Proposed 2018 Distribution Bill Impacts (Sub-Total A)

Rate Class	kWh	kW	2017 BAP Rates	2018 Proposed Rates	$ Increase (Decrease)	% Increase (Decrease)
Residential	750	-	$ 26.85	$ 27.75	$ 0.90	3.35%
General Service Less Than 50 kW	2,000	-	$ 59.72	$ 61.33	$ 1.61	2.70%
General Service 50 to 4,999 kW	40,000	100	$ 451.78	$ 463.77	$ 11.99	2.65%
Unmetered Scattered Load	700	-	$ 30.18	$ 28.58	$ (1.60)	-5.30%
Sentinel Lighting	36	0.1	$ 4.38	$ 4.26	$ (0.12)	-2.80%
Street Lighting	36	0.1	$ 4.19	$ 4.29	$ 0.11	2.53%
Embedded Distributor	200,000	500	$ 1,337.74	$ 1,157.75	$ (179.99)	-13.45%

8.14 Rate Mitigation

EPLC submits that the bill impacts proposed in this Exhibit for 2018 distribution rates are reasonable and do not require any Rate Mitigation.

<u>Attachment 8-A</u>

Rate Design Policy for Residential Customers

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential Class	
Customers	27,484
kWh	245,374,118

Proposed Residential Class Specific Revenue Requirement[1]	$ 8,889,902.49

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	$ 20.31
Distribution Volumetric Rate ($/kWh)	$ 0.0078

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	20.31	27,484	$ 6,698,400.48	77.78%
Variable	0.0078	245,374,118	$ 1,913,918.12	22.22%
TOTAL	-	-	$ 8,612,318.60	-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	2

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed	$ 6,914,296.82	20.96	$ 6,912,775.68
Variable	$ 1,975,605.67	0.0081	$ 1,987,530.36
TOTAL	$ 8,889,902.49	-	$ 8,900,306.04

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed	88.89%	$ 7,902,099.66	$ 23.96	$ 7,902,199.68
Variable	11.11%	$ 987,802.84	$ 0.0040	$ 981,496.47
TOTAL	-	$ 8,889,902.49	-	$ 8,883,696.15

Checks[3]	
Change in Fixed Rate	$ 3.00
Difference Between Revenues @ Proposed Rates	($6,206.34)
and Class Specific Revenue Requirement	-0.07%

Notes:

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

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

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

<u>Attachment 8-B</u>

Revenue Reconciliation

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2018 Filers

Rate Design and Revenue Reconciliation

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

Stage in Process:	*Initial Application*

	Customer and Load Forecast					Class Allocated Revenues			Fixed / Variable Splits [2]			Distribution Rates					Revenue Reconciliation		
						From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design			Percentage to be entered as a fraction between 0 and 1			Monthly Service Charge		Volumetric Rate					
	Customer Class From sheet 10. Load Forecast	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Rate	No. of decimals	Rate		No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership
1	Residential	kWh	27,484	245,374,118	-	$ 8,889,902	$ 7,902,100	$ 987,803	88.89%	11.11%		$23.96	2	$0.0040	/kWh	4	$ 7,902,199.68	$ 981,496.4720	$ 8,883,696.15
2	General Service < 50 kW	kWh	1,977	62,707,450	-	$ 1,622,351	$ 852,573	$ 769,778	52.55%	47.45%		$35.94		$0.0123	/kWh		$ 852,640.56	$ 771,301.6350	$ 1,623,942.20
3	General Service > 50 kW	kW	219	176,280,306	446,253	$ 1,563,524	$ 625,559	$ 937,964	40.01%	59.99%	$ 69,367	$238.04		$2.2573	/kW		$ 625,569.12	$ 1,007,327.7998	$ 1,563,529.92
4	Intermediate Use	kW	-	-	-	$ -						$0.00			/kW		$ -	$ -	$ -
5	Street Lights	kW	2,740	2,799,882	8,848	$ 191,922	$ 110,997	$ 80,925	57.83%	42.17%		$3.38		$9.1461	/kW		$ 111,134.40	$ 80,924.6928	$ 192,059.09
6	Unmetered Scattered Load	kWh	140	1,554,368	-	$ 58,609	$ 15,092	$ 43,517	25.75%	74.25%		$8.98		$0.0280	/kWh		$ 15,086.40	$ 43,522.3040	$ 58,608.70
7	Sentinel Lights	kW	173	335,758	2,080	$ 26,669	$ 6,879	$ 19,791	25.79%	74.21%		$3.31		$9.5148	/kW		$ 6,871.56	$ 19,790.7840	$ 26,662.34
8	Embedded Distributor	kW	3	29,865,554	80,869	$ 118,097	$ 19,800	$ 98,297	16.77%	83.23%		$550.00		$1.2155	/kW		$ 19,800.00	$ 98,296.7557	$ 118,096.76
9			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -

Total Transformer Ownership Allowance $ 69,367

Total Distribution Revenues	$12,466,595.16
Base Revenue Requirement	$12,471,074.35
Difference	-$ 4,479.19
% Difference	-0.036%

Rates recover revenue requirement

Notes:

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

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

Attachment 8-C

OEB RTSR Workform

Ontario Energy Board

v 1.1

2018 RTSR Workform for Electricity Distributors

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

Utility Name	Essex Powerlines Corporation
Service Territory	Amhestburg, LaSalle, Leamington, Tecumseh
Assigned EB Number	EB-2017-0039
Name and Title	Kristopher Taylor, Director of Corporate Strategy
Phone Number	519-946-2000
Email Address	ktaylor@essexpower.ca
Date	August 28th, 2017
Last COS Re-based Year	**2010**

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

Ontario Energy Board

v 1.1

2018 RTSR Workform for Electricity Distributors

Ontario Energy Board

v 1.1

2018 RTSR Workform for Electricity Distributors

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

Rate Class	Unit	RTSR-Network	RTSR-Connection
Residential	kWh	0.0048	0.0032
General Service Less Than 50 kW	kWh	0.0041	0.0030
General Service 50 to 4,999 kW	kW	1.6986	1.2157
General Service 50 to 4,999 kW – Interval Metered	kW	2.0924	1.3480
Embedded Distributor	kW		
Unmetered Scattered Load	kWh	0.0041	0.0030
Sentinel Lighting	kW	1.3077	0.9267
Street Lighting	kW	1.2894	0.9207
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			

Ontario Energy Board

v 1.1

2018 RTSR Workform for Electricity Distributors

Rate Class	Rate Description	Unit	Rate	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor *eg: (1.0325)*	Loss Adjusted Billed kWh
Residential	RTSR - Network	kWh	0.0048	255,390,422		1.0355	264,456,782
Residential	RTSR - Connection	kWh	0.0032	255,390,422		1.0355	264,456,782
General Service Less Than 50 kW	RTSR - Network	kWh	0.0041	66,808,993		1.0355	69,180,712
General Service Less Than 50 kW	RTSR - Connection	kWh	0.0030	66,808,993		1.0355	69,180,712
General Service 50 to 4,999 kW	RTSR - Network	kW	1.6986	219,618,449	563,949		
General Service 50 to 4,999 kW	RTSR - Connection	kW	1.2157	219,618,449	563,949		
General Service 50 to 4,999 kW – Interval Metered	RTSR - Network	kW	2.0924	219,618,449	563,949		
General Service 50 to 4,999 kW – Interval Metered	RTSR - Connection	kW	1.3480	219,618,449	563,949		
Embedded Distributor	RTSR - Network	kW					
Embedded Distributor	RTSR - Connection	kW					
Unmetered Scattered Load	RTSR - Network	kWh	0.0041	1,554,368		1.0355	1,609,548
Unmetered Scattered Load	RTSR - Connection	kWh	0.0030	1,554,368		1.0355	1,609,548
Sentinel Lighting	RTSR - Network	kW	1.3077	335,758	2,080		
Sentinel Lighting	RTSR - Connection	kW	0.9267	335,758	2,080		
Street Lighting	RTSR - Network	kW	1.2894	4,268,688	13,490		
Street Lighting	RTSR - Connection	kW	0.9207	4,268,688	13,490		

Ontario Energy Board

v 1.1

2018 RTSR Workform for Electricity Distributors

Uniform Transmission Rates	Unit	2016	2017	2018
Rate Description		Rate	Rate	Rate
Network Service Rate	kW	$ 3.66	$ 3.66	$ 3.66
Line Connection Service Rate	kW	$ 0.87	$ 0.87	$ 0.87
Transformation Connection Service Rate	kW	$ 2.02	$ 2.02	$ 2.02

Hydro One Sub-Transmission Rates	Unit	2016 Jan 2016	2016 Feb - Dec 2016	2017	2018
Rate Description		Rate		Rate	Rate
Network Service Rate	kW	$ 3.4121	$ 3.3396	$ 3.1942	$ 3.1942
Line Connection Service Rate	kW	$ 0.7879	$ 0.7791	$ 0.7710	$ 0.7710
Transformation Connection Service Rate	kW	$ 1.8018	$ 1.7713	$ 1.7493	$ 1.7493
Both Line and Transformation Connection Service Rate	kW	$ 2.5897	$ 2.5504	$ 2.5203	$ 2.5203

If needed, add extra host here. (I)	Unit	2016	2017	2018
Rate Description		Rate	Rate	Rate
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

If needed, add extra host here. (II)	Unit	Effective January 1, 2016	Effective January 1, 2017	Effective January 1, 2018
Rate Description		Rate	Rate	Rate
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

		Historical 2016	Current 2017	Forecast 2018
Low Voltage Switchgear Credit (if applicable, enter as a negative value)	$			

Ontario Energy Board

v 1.1

2018 RTSR Workform for Electricity Distributors

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	77,768	$3.41	$ 265,353	34,921	$0.79	$ 27,514	78,524	$1.80	$ 141,485	$ 169,000
February	72,959	$3.34	$ 243,665	33,806	$0.78	$ 26,338	74,707	$1.77	$ 132,329	$ 158,667
March	71,387	$3.34	$ 238,404	31,996	$0.78	$ 24,928	71,902	$1.77	$ 127,359	$ 152,287
April	61,964	$3.34	$ 206,937	30,495	$0.78	$ 23,758	67,394	$1.77	$ 119,375	$ 143,134
May	94,967	$3.34	$ 317,153	45,700	$0.78	$ 35,605	99,294	$1.77	$ 175,880	$ 211,485
June	117,611	$3.34	$ 392,774	54,248	$0.78	$ 42,264	120,505	$1.77	$ 213,450	$ 255,714
July	127,201	$3.34	$ 424,802	59,238	$0.78	$ 46,152	129,907	$1.77	$ 230,104	$ 276,256
August	126,187	$3.34	$ 421,414	57,670	$0.78	$ 44,931	128,216	$1.77	$ 227,109	$ 272,039
September	129,454	$3.34	$ 432,324	60,079	$0.78	$ 46,807	131,245	$1.77	$ 232,475	$ 279,282
October	81,920	$3.34	$ 273,580	35,783	$0.78	$ 27,879	83,872	$1.77	$ 148,562	$ 176,441
November	76,740	$3.34	$ 256,281	31,674	$0.78	$ 24,677	77,890	$1.77	$ 137,967	$ 162,644
December	80,507	$3.34	$ 268,861	36,016	$0.78	$ 28,060	81,021	$1.77	$ 143,513	$ 171,573
Total	1,118,667	$ 3.34	$ 3,741,548	511,625	$ 0.78	$ 398,914	1,144,477	$ 1.77	$ 2,029,608	$ 2,428,522

Add Extra Host Here (I) (if needed)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Ontario Energy Board

v 1.1

2018 RTSR Workform for Electricity Distributors

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

Add Extra Host Here (II) (if needed)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	77,768	$3.41	$ 265,353	34,921	$0.79	$ 27,514	78,524	$1.80	$ 141,485	$ 169,000
February	72,959	$3.34	$ 243,665	33,806	$0.78	$ 26,338	74,707	$1.77	$ 132,329	$ 158,667
March	71,387	$3.34	$ 238,404	31,996	$0.78	$ 24,928	71,902	$1.77	$ 127,359	$ 152,287
April	61,964	$3.34	$ 206,937	30,495	$0.78	$ 23,758	67,394	$1.77	$ 119,375	$ 143,134
May	94,967	$3.34	$ 317,153	45,700	$0.78	$ 35,605	99,294	$1.77	$ 175,880	$ 211,485
June	117,611	$3.34	$ 392,774	54,248	$0.78	$ 42,264	120,505	$1.77	$ 213,450	$ 255,714
July	127,201	$3.34	$ 424,802	59,238	$0.78	$ 46,152	129,907	$1.77	$ 230,104	$ 276,256
August	126,187	$3.34	$ 421,414	57,670	$0.78	$ 44,931	128,216	$1.77	$ 227,109	$ 272,039
September	129,454	$3.34	$ 432,324	60,079	$0.78	$ 46,807	131,245	$1.77	$ 232,475	$ 279,282
October	81,920	$3.34	$ 273,580	35,783	$0.78	$ 27,879	83,872	$1.77	$ 148,562	$ 176,441
November	76,740	$3.34	$ 256,281	31,674	$0.78	$ 24,677	77,890	$1.77	$ 137,967	$ 162,644
December	80,507	$3.34	$ 268,861	36,016	$0.78	$ 28,060	81,021	$1.77	$ 143,513	$ 171,573
Total	1,118,667	$ 3.34	$ 3,741,548	511,625	$ 0.78	$ 398,914	1,144,477	$ 1.77	$ 2,029,608	$ 2,428,522

Ontario Energy Board

v 1.1

2018 RTSR Workform for Electricity Distributors

The purpose of this sheet is to calculate the expected billing when current 2017 Uniform Transmission Rates are applied against historical 2016 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
February	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
March	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
April	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
May	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
June	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
July	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
August	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
September	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
October	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
November	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
December	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	77,768	$ 3.1942	$ 248,408	34,921	$ 0.7710	$ 26,924	78,524	$ 1.7493	$ 137,363	$ 164,287
February	72,959	$ 3.1942	$ 233,047	33,806	$ 0.7710	$ 26,064	74,707	$ 1.7493	$ 130,685	$ 156,749
March	71,387	$ 3.1942	$ 228,024	31,996	$ 0.7710	$ 24,669	71,902	$ 1.7493	$ 125,777	$ 150,446
April	61,964	$ 3.1942	$ 197,927	30,495	$ 0.7710	$ 23,511	67,394	$ 1.7493	$ 117,892	$ 141,404
May	94,967	$ 3.1942	$ 303,345	45,700	$ 0.7710	$ 35,235	99,294	$ 1.7493	$ 173,695	$ 208,931
June	117,611	$ 3.1942	$ 375,673	54,248	$ 0.7710	$ 41,825	120,505	$ 1.7493	$ 210,799	$ 252,624
July	127,201	$ 3.1942	$ 406,307	59,238	$ 0.7710	$ 45,673	129,907	$ 1.7493	$ 227,246	$ 272,919
August	126,187	$ 3.1942	$ 403,067	57,670	$ 0.7710	$ 44,464	128,216	$ 1.7493	$ 224,288	$ 268,752
September	129,454	$ 3.1942	$ 413,501	60,079	$ 0.7710	$ 46,321	131,245	$ 1.7493	$ 229,587	$ 275,908
October	81,920	$ 3.1942	$ 261,669	35,783	$ 0.7710	$ 27,589	83,872	$ 1.7493	$ 146,717	$ 174,306
November	76,740	$ 3.1942	$ 245,123	31,674	$ 0.7710	$ 24,421	77,890	$ 1.7493	$ 136,253	$ 160,674
December	80,507	$ 3.1942	$ 257,155	36,016	$ 0.7710	$ 27,768	81,021	$ 1.7493	$ 141,731	$ 169,499
Total	1,118,667	$ 3.19	$ 3,573,245	511,625	$ 0.77	$ 394,463	1,144,477	$ 1.75	$ 2,002,034	$ 2,396,497

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Ontario Energy Board v 1.1

2018 RTSR Workform for Electricity Distributors

The purpose of this sheet is to calculate the expected billing when current 2017 Uniform Transmission Rates are applied against historical 2016 transmission units.

Total	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	77,768	$3.19	$ 248,408	34,921	$0.77	$ 26,924	78,524	$1.75	$ 137,363	$ 164,287
February	72,959	$3.19	$ 233,047	33,806	$0.77	$ 26,064	74,707	$1.75	$ 130,685	$ 156,749
March	71,387	$3.19	$ 228,024	31,996	$0.77	$ 24,669	71,902	$1.75	$ 125,777	$ 150,446
April	61,964	$3.19	$ 197,927	30,495	$0.77	$ 23,511	67,394	$1.75	$ 117,892	$ 141,404
May	94,967	$3.19	$ 303,345	45,700	$0.77	$ 35,235	99,294	$1.75	$ 173,695	$ 208,931
June	117,611	$3.19	$ 375,673	54,248	$0.77	$ 41,825	120,505	$1.75	$ 210,799	$ 252,624
July	127,201	$3.19	$ 406,307	59,238	$0.77	$ 45,673	129,907	$1.75	$ 227,246	$ 272,919
August	126,187	$3.19	$ 403,067	57,670	$0.77	$ 44,464	128,216	$1.75	$ 224,288	$ 268,752
September	129,454	$3.19	$ 413,501	60,079	$0.77	$ 46,321	131,245	$1.75	$ 229,587	$ 275,908
October	81,920	$3.19	$ 261,669	35,783	$0.77	$ 27,589	83,872	$1.75	$ 146,717	$ 174,306
November	76,740	$3.19	$ 245,123	31,674	$0.77	$ 24,421	77,890	$1.75	$ 136,253	$ 160,674
December	80,507	$3.19	$ 257,155	36,016	$0.77	$ 27,768	81,021	$1.75	$ 141,731	$ 169,499
Total	1,118,667	$ 3.19	$ 3,573,245	511,625	$ 0.77	$ 394,463	1,144,477	$ 1.75	$ 2,002,034	$ 2,396,497

Ontario Energy Board

v 1.1

2018 RTSR Workform for Electricity Distributors

The purpose of this sheet is to calculate the expected billing when forecasted 2018 Uniform Transmission Rates are applied against historical 2016 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
February	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
March	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
April	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
May	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
June	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
July	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
August	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
September	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
October	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
November	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
December	-	$ 3.6600	$ -	-	$ 0.8700	$ -	-	$ 2.0200	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	77,768	$ 3.1942	$ 248,408	34,921	$ 0.7710	$ 26,924	78,524	$ 1.7493	$ 137,363	$ 164,287
February	72,959	$ 3.1942	$ 233,047	33,806	$ 0.7710	$ 26,064	74,707	$ 1.7493	$ 130,685	$ 156,749
March	71,387	$ 3.1942	$ 228,024	31,996	$ 0.7710	$ 24,669	71,902	$ 1.7493	$ 125,777	$ 150,446
April	61,964	$ 3.1942	$ 197,927	30,495	$ 0.7710	$ 23,511	67,394	$ 1.7493	$ 117,892	$ 141,404
May	94,967	$ 3.1942	$ 303,345	45,700	$ 0.7710	$ 35,235	99,294	$ 1.7493	$ 173,695	$ 208,931
June	117,611	$ 3.1942	$ 375,673	54,248	$ 0.7710	$ 41,825	120,505	$ 1.7493	$ 210,799	$ 252,624
July	127,201	$ 3.1942	$ 406,307	59,238	$ 0.7710	$ 45,673	129,907	$ 1.7493	$ 227,246	$ 272,919
August	126,187	$ 3.1942	$ 403,067	57,670	$ 0.7710	$ 44,464	128,216	$ 1.7493	$ 224,288	$ 268,752
September	129,454	$ 3.1942	$ 413,501	60,079	$ 0.7710	$ 46,321	131,245	$ 1.7493	$ 229,587	$ 275,908
October	81,920	$ 3.1942	$ 261,669	35,783	$ 0.7710	$ 27,589	83,872	$ 1.7493	$ 146,717	$ 174,306
November	76,740	$ 3.1942	$ 245,123	31,674	$ 0.7710	$ 24,421	77,890	$ 1.7493	$ 136,253	$ 160,674
December	80,507	$ 3.1942	$ 257,155	36,016	$ 0.7710	$ 27,768	81,021	$ 1.7493	$ 141,731	$ 169,499
Total	1,118,667	$ 3.19	$ 3,573,245	511,625	$ 0.77	$ 394,463	1,144,477	$ 1.75	$ 2,002,034	$ 2,396,497

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Ontario Energy Board

v 1.1

2018 RTSR Workform for Electricity Distributors

The purpose of this sheet is to calculate the expected billing when forecasted 2018 Uniform Transmission Rates are applied against historical 2016 transmission units.

Total	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	77,768	$ 3.19	248,408	34,921	$ 0.77	26,924	78,524	$ 1.75	137,363	$ 164,287
February	72,959	$ 3.19	233,047	33,806	$ 0.77	26,064	74,707	$ 1.75	130,685	$ 156,749
March	71,387	$ 3.19	228,024	31,996	$ 0.77	24,669	71,902	$ 1.75	125,777	$ 150,446
April	61,964	$ 3.19	197,927	30,495	$ 0.77	23,511	67,394	$ 1.75	117,892	$ 141,404
May	94,967	$ 3.19	303,345	45,700	$ 0.77	35,235	99,294	$ 1.75	173,695	$ 208,931
June	117,611	$ 3.19	375,673	54,248	$ 0.77	41,825	120,505	$ 1.75	210,799	$ 252,624
July	127,201	$ 3.19	406,307	59,238	$ 0.77	45,673	129,907	$ 1.75	227,246	$ 272,919
August	126,187	$ 3.19	403,067	57,670	$ 0.77	44,464	128,216	$ 1.75	224,288	$ 268,752
September	129,454	$ 3.19	413,501	60,079	$ 0.77	46,321	131,245	$ 1.75	229,587	$ 275,908
October	81,920	$ 3.19	261,669	35,783	$ 0.77	27,589	83,872	$ 1.75	146,717	$ 174,306
November	76,740	$ 3.19	245,123	31,674	$ 0.77	24,421	77,890	$ 1.75	136,253	$ 160,674
December	80,507	$ 3.19	257,155	36,016	$ 0.77	27,768	81,021	$ 1.75	141,731	$ 169,499
Total	1,118,667	$ 3.19	$ 3,573,245	511,625	$ 0.77	$ 394,463	1,144,477	$ 1.75	$ 2,002,034	$ 2,396,497

Ontario Energy Board

v 1.1

2017 RTSR Workform for Electricity Distributors

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

Rate Class	Rate Description	Unit	Current RTSR-Network	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR Network
Residential	RTSR - Network	kWh	0.0048	264,456,782		1,269,393	34.1%	1,220,077	0.0046
General Service Less Than 50 kW	RTSR - Network	kWh	0.0041	69,180,712		283,641	7.6%	272,621	0.0039
General Service 50 to 4,999 kW	RTSR - Network	kW	1.6986		563,949	957,924	25.8%	920,708	1.6326
General Service 50 to 4,999 kW – Interval Metered	RTSR - Network	kW	2.0924		563,949	1,180,007	31.7%	1,134,164	2.0111
Embedded Distributor	RTSR - Network	kW				0	0.0%	0	0.0000
Unmetered Scattered Load	RTSR - Network	kWh	0.0041	1,609,548		6,599	0.2%	6,343	0.0039
Sentinel Lighting	RTSR - Network	kW	1.3077		2,080	2,720	0.1%	2,614	1.2569
Street Lighting	RTSR - Network	kW	1.2894		13,490	17,394	0.5%	16,718	1.2393

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

Rate Class	Rate Description	Unit	Current RTSR-Connection	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR-Connection
Residential	RTSR - Connection	kWh	0.0032	264,456,782		846,262	33.6%	805,178	0.0030
General Service Less Than 50 kW	RTSR - Connection	kWh	0.0030	69,180,712		207,542	8.2%	197,467	0.0029
General Service 50 to 4,999 kW	RTSR - Connection	kW	1.2157		563,949	685,593	27.2%	652,309	1.1567
General Service 50 to 4,999 kW – Interval Metered	RTSR - Connection	kW	1.3480		563,949	760,203	30.2%	723,298	1.2826
Embedded Distributor	RTSR - Connection	kW				0	0.0%	0	0.0000
Unmetered Scattered Load	RTSR - Connection	kWh	0.0030	1,609,548		4,829	0.2%	4,594	0.0029
Sentinel Lighting	RTSR - Connection	kW	0.9267		2,080	1,928	0.1%	1,834	0.8817
Street Lighting	RTSR - Connection	kW	0.9207		13,490	12,420	0.5%	11,817	0.8760

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

Rate Class	Rate Description	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR-Network
Residential	RTSR - Network	kWh	0.0046	264,456,782		1,220,077	34.1%	1,220,077	**0.0046**
General Service Less Than 50 kW	RTSR - Network	kWh	0.0039	69,180,712		272,621	7.6%	272,621	**0.0039**
General Service 50 to 4,999 kW	RTSR - Network	kW	1.6326		563,949	920,708	25.8%	920,708	**1.6326**
General Service 50 to 4,999 kW – Interval Metered	RTSR - Network	kW	2.0111		563,949	1,134,164	31.7%	1,134,164	**2.0111**
Embedded Distributor	RTSR - Network	kW	0.0000			0	0.0%	0	**0.0000**
Unmetered Scattered Load	RTSR - Network	kWh	0.0039	1,609,548		6,343	0.2%	6,343	**0.0039**
Sentinel Lighting	RTSR - Network	kW	1.2569		2,080	2,614	0.1%	2,614	**1.2569**
Street Lighting	RTSR - Network	kW	1.2393		13,490	16,718	0.5%	16,718	**1.2393**

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

Rate Class	Rate Description	Unit	Adjusted RTSR-Connection	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR-Connection
Residential	RTSR - Connection	kWh	0.0030	264,456,782		805,178	33.6%	805,178	**0.0030**
General Service Less Than 50 kW	RTSR - Connection	kWh	0.0029	69,180,712		197,467	8.2%	197,467	**0.0029**
General Service 50 to 4,999 kW	RTSR - Connection	kW	1.1567		563,949	652,309	27.2%	652,309	**1.1567**
General Service 50 to 4,999 kW – Interval Metered	RTSR - Connection	kW	1.2826		563,949	723,298	30.2%	723,298	**1.2826**
Embedded Distributor	RTSR - Connection	kW	0.0000			0	0.0%	0	**0.0000**
Unmetered Scattered Load	RTSR - Connection	kWh	0.0029	1,609,548		4,594	0.2%	4,594	**0.0029**
Sentinel Lighting	RTSR - Connection	kW	0.8817		2,080	1,834	0.1%	1,834	**0.8817**
Street Lighting	RTSR - Connection	kW	0.8760		13,490	11,817	0.5%	11,817	**0.8760**

Attachment 8-D

Loss Factors

File Number:	EB-2017-0039
Exhibit:	8
Attachment	8-D
Page:	1 of 1
Date:	August 28th, 2017

Appendix 2-R
Loss Factors

		Historical Years					5-Year Average
		2012	2013	2014	2015	2016	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	543,701,676	557,841,472	552,333,503	555,351,796	572,432,535	556,332,196
A(2)	"Wholesale" kWh delivered to distributor (lower value)	534,090,993	546,079,224	542,856,165	545,834,271	562,515,905	546,275,312
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	-	-	-	-	-	-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	534,090,993	546,079,224	542,856,165	545,834,271	562,515,905	546,275,312
D	"Retail" kWh delivered by distributor	531,968,130	528,862,603	523,361,255	520,201,702	542,679,868	529,414,712
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	-	-	-	-	-	-
F	Net "Retail" kWh delivered by distributor = **D - E**	531,968,130	528,862,603	523,361,255	520,201,702	542,679,868	529,414,712
G	Loss Factor in Distributor's system = **C / F**	1.0040	1.0326	1.0372	1.0493	1.0366	1.0318
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0036	1.0035	1.0034	1.0036	1.0036	1.0035
	Total Losses						
I	Total Loss Factor = **G x H**	1.0076	1.0361	1.0408	1.0530	1.0403	1.0355

Notes:

A(1) If directly connected to the IESO-controlled grid, kWh pertains to the virtual meter on the primary or high voltage side of the transformer at the interface with the transmission grid. This corresponds to the "With Losses" kWh value provided by the IESO's MV-WEB. It is the higher of the two values provided by MV-WEB.

If fully embedded within a host distributor, kWh pertains to the virtual meter on the primary or high voltage side of the transformer, at the interface between the host distributor and the transmission grid. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh w Losses" should be reported. This corresponds to the higher of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

A(2) If directly connected to the IESO-controlled grid, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface with the transmission grid. This corresponds to the "Without Losses" kWh value provided by the IESO's MV-WEB. It is the lower of the two kWh values provided by MV-WEB.

If fully embedded with the host distributor, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface between the embedded distributor and the host distributor. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh" should be reported. This corresponds to the lower of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

Additionally, kWh pertaining to distributed generation directly connected to the distributor's own distribution network should be included in **A(2)**.

B If a Large Use Customer is metered on the secondary or low voltage side of the transformer, the default loss is 1% (i.e., **B** = 1.01 X **E**).

D kWh corresponding to D should equal metered or estimated kWh at the customer's delivery point.

G and **I** These loss factors pertain to secondary-metered customers with demand less than 5,000 kW.

H If directly connected to the IESO-controlled grid, SFLF = 1.0045.

If fully embedded within a host distributor, SFLF = loss factor re losses in transformer at grid interface X loss factor re losses in host distributor's system. If the host distributor is Hydro One Networks Inc., SFLF = 1.0060 X 1.0278 = 1.0340. If partially embedded, SFLF should be calculated as the weighted average of above.

Distributors that wish to propose a different SFLF should provide appropriate justification for any such proposal including supporting calculations and any other relevant material.

Attachment 8-E

EPLC 2017OEB Approved Tariff Sheets

Essex Powerlines Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2017

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

EB-2016-0069

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartments building also qualify as residential customers. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	20.31
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Rate Rider for Application of Tax Change (2017) - effective until April 30, 2018	$	(0.10)
Distribution Volumetric Rate	$/kWh	0.0078
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Disposition of Global Adjustment Account (2015) - approved on an interim basis and effective until April 30, 2018, applicable only for Non-RPP Customers	$/kWh	0.0066
Retail Transmission Rate - Network Service Rate	$/kWh	0.0048
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0032

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - Not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2017

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

EB-2016-0069

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	35.13
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0120
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Disposition of Global Adjustment Account (2015) - approved on an interim basis and effective until April 30, 2018, applicable only for Non-RPP Customers	$/kWh	0.0066
Rate Rider for Application of Tax Change (2017) - effective until April 30, 2018	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0041
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0030

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - Not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2017

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

EB-2016-0069

GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 3,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	232.69
Distribution Volumetric Rate	$/kW	2.2101
Low Voltage Service Rate	$/kW	0.3506
Rate Rider for Disposition of Global Adjustment Account (2015) - approved on an interim basis and effective until April 30, 2018, applicable only for Non-RPP Customers	$/kW	2.5358
Rate Rider for Application of Tax Change (2017) - effective until April 30, 2018	$/kW	(0.0192)
Retail Transmission Rate - Network Service Rate	$/kW	1.6986
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.2157
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.0924
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	1.3480

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - Not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2017

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

EB-2016-0069

GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 3,000 kW but less than 5,000 kW.Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	1,528.73
Distribution Volumetric Rate	$/kW	1.4176
Low Voltage Service Rate	$/kW	0.4094
Rate Rider for Application of Tax Change (2017) - effective until April 30, 2018	$/kW	(0.0078)
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.0924
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	1.3480

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - Not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2017
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2016-0069

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical consumption of the proposed unmetered load. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	9.53
Distribution Volumetric Rate	$/kWh	0.0297
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Disposition of Global Adjustment Account (2015) - approved on an interim basis and effective until April 30, 2018, applicable only for Non-RPP Customers	$/kWh	0.0066
Rate Rider for Application of Tax Change (2017) - effective until April 30, 2018	$/kWh	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0041
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0030

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - Not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2017
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2016-0069

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	3.41
Distribution Volumetric Rate	$/kW	9.7922
Low Voltage Service Rate	$/kW	0.2816
Rate Rider for Disposition of Global Adjustment Account (2015) - approved on an interim basis and effective until April 30, 2018, applicable only for Non-RPP Customers	$/kW	2.3785
Rate Rider for Application of Tax Change (2017) - effective until April 30, 2018	$/kW	(0.0492)
Retail Transmission Rate - Network Service Rate	$/kW	1.3077
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	0.9267

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - Not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2017
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2016-0069

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	3.30
Distribution Volumetric Rate	$/kW	8.9407
Low Voltage Service Rate	$/kW	0.2798
Rate Rider for Disposition of Global Adjustment Account (2015) - approved on an interim basis and effective until April 30, 2018, applicable only for Non-RPP Customers	$/kW	2.1886
Rate Rider for Application of Tax Change (2017) - effective until April 30, 2018	$/kW	(0.0544)
Retail Transmission Rate - Network Service Rate	$/kW	1.2894
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	0.9207

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - Not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2017

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

EB-2016-0069

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

ALLOWANCES

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

Essex Powerlines Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2017

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

EB-2016-0069

SPECIFIC SERVICE CHARGES

APPLICATION

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

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

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

Customer Administration

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

Non-Payment of Account

Late payment - per month	%	1.50
Late payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Collection of account charge - no disconnection - after regular hours	$	165.00
Disconnect/reconnect charge - at meter - during regular hours	$	65.00
Disconnect/reconnect charge - at meter - after hours	$	185.00
Disconnect/reconnect at pole - during regular hours	$	185.00
Disconnect/reconnect at pole - after regular hours	$	415.00
Install/remove load control device - during regular hours	$	65.00
Install/remove load control device - after regular hours	$	185.00

Other

Service call - customer owned equipment	$	30.00
Service call - after regular hours	$	165.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - underground - no transformer	$	300.00
Temporary service install & remove - overhead - with transformer	$	1,000.00
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments)	$	22.35

Essex Powerlines Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2017

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

EB-2016-0069

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

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

LOSS FACTORS

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

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0602
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0496

<u>Attachment 8-F</u>

EPLC 2018 Proposed Tariff Sheets

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2018
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartments building also qualify as residential customers. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	23.96
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0040
Low Voltage Service Rate	$/kWh	0.0031
Rate Rider for Group 1 Deferral / Variance Account Balances (Excluding Global Adjustment) - effective until April 30, 2019	$/kWh	(0.0024)
Rate Rider for RSVA - Power - Global Adjustment - effective until April 30, 2019	$/kWh	0.0030
Rate Rider for the Disposition of Group 2 Accounts - effective until April 30, 2019	$	(0.25)
Rate Rider for the Disposition of Accounts 1575 & 1576 - effective until April 30, 2020	$	3.3430
Rate Rider for the Disposition of LRAM - effective until April 30, 2019	$/kWh	0.0005
Rate Rider for the Disposition of Stranded Meters - effective until April 30, 2021	$/kWh	1.0331
Retail Transmission Rate - Network Service Rate	$/kWh	0.0046
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0030

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Elecrticity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2018
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	35.94
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0123
Low Voltage Service Rate	$/kWh	0.0030
Rate Rider for Group 1 Deferral / Variance Account Balances (Excluding Global Adjustment) - effective until April 30, 2021	$/kWh	(0.0024)
Rate Rider for RSVA - Power - Global Adjustment - effective until April 30, 2019	$/kWh	0.0030
Rate Rider for the Disposition of Group 2 Accounts - effective until April 30, 2019	$/kWh	(0.0003)
Rate Rider for the Disposition of Accounts 1575 & 1576 - effective until April 30, 2020	$/kWh	(0.0045)
Rate Rider for the Disposition of LRAM - effective until April 30, 2020	$/kWh	0.0014
Rate Rider for the Disposition of Stranded Meters - effective until April 30, 2021	$/kWh	1.0331
Retail Transmission Rate - Network Service Rate	$/kWh	0.0039
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0029

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Elecrticity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2018
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 4,999 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	238.04
Distribution Volumetric Rate	$/kW	2.2573
Low Voltage Service Rate	$/kW	1.2718
Retail Transmission Rate - Network Service Rate	$/kW	1.6326
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.1567
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.0111
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	1.2826
Rate Rider for Group 1 Deferral / Variance Account Balances (Excluding Global Adjustment) - effective until April 30, 2019	$/kW	2.3747
Rate Rider for Deferral / Variance Account Balances (Excluding Global Adjustment) Non-WMP - effective until April 30, 2019	$/kW	(2.8397)
Rate Rider for RSVA - Power - Global Adjustment - effective until April 30, 2019	$/kWh	0.0030
Rate Rider for the Disposition of Group 2 Accounts - effective until April 30, 2019	$/kW	(0.1351)
Rate Rider for the Disposition of Accounts 1575 & 1576 - effective until April 30, 2020	$/kW	(1.7750)
Rate Rider for the Disposition of LRAM - effective until April 30, 2020	$/kW	0.0881

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2018
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification applies to an electricity distributor licensed by the Ontario Energy Board that is provided with electricity by means of this distributor's facilities. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	550.00
Distribution Volumetric Rate	$/kW	1.2155

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2018

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

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical consumption of the proposed unmetered load. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	8.98
Distribution Volumetric Rate	$/kWh	0.0280
Low Voltage Service Rate	$/kWh	0.0030
Rate Rider for Group 1 Deferral / Variance Account Balances (Excluding Global Adjustment) - effective until April 30, 2021	$/kWh	(0.0022)
Rate Rider for RSVA - Power - Global Adjustment - effective until April 30, 2019	$/kWh	0.0030
Rate Rider for the Disposition of Group 2 Accounts - effective until April 30, 2019	$/kWh	(0.0003)
Rate Rider for the Disposition of Accounts 1575 & 1576 - effective until April 30, 2020	$/kWh	(0.0045)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0039
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0029

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2018

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

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	3.31
Distribution Volumetric Rate	$/kW	9.5148
Low Voltage Service Rate	$/kW	0.8743
Rate Rider for Group 1 Deferral / Variance Account Balances (Excluding Global Adjustment) - effective until April 30, 2021	$/kW	(0.3852)
Rate Rider for RSVA - Power - Global Adjustment - effective until April 30, 2019	$/kWh	0.0030
Rate Rider for the Disposition of Group 2 Accounts - effective until April 30, 2019	$/kW	(0.0552)
Rate Rider for the Disposition of Accounts 1575 & 1576 - effective until April 30, 2020	$/kW	(0.7253)
Retail Transmission Rate - Network Service Rate	$/kW	1.2444
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	0.8817

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2018

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

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	3.38
Distribution Volumetric Rate	$/kW	9.1557
Low Voltage Service Rate	$/kW	0.8686
Rate Rider for Group 1 Deferral / Variance Account Balances (Excluding Global Adjustment) - effective until April 30, 2019	$/kW	(0.5947)
Rate Rider for RSVA - Power - Global Adjustment - effective until April 30, 2019	$/kWh	0.0030
Rate Rider for the Disposition of Group 2 Accounts - effective until April 30, 2019	$/kW	(0.1082)
Rate Rider for the Disposition of Accounts 1575 & 1576 - effective until April 30, 2020	$/kW	(1.4219)
Rate Rider for the Disposition of LRAM - effective until April 30, 2020	$/kW	0.5070
Retail Transmission Rate - Network Service Rate	$/kW	1.2270
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	0.8760

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2018

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

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2018
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

SPECIFIC SERVICE CHARGES

APPLICATION

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

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

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

Customer Administration		
Arrears certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income tax letter	$	15.00
Account history	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Collection of account charge - no disconnection - after regular hours	$	165.00
Disconnect/Reconnect at Meter - during regular hours	$	65.00
Disconnect/Reconnect at Meter - after regular hours	$	185.00
Disconnect/Reconnect at Pole - during regular hours	$	185.00
Disconnect/Reconnect at Pole - after regular hours	$	415.00
Install/Remove Load Control Device - during regular hours	$	65.00
Install/Remove Load Control Device - after regular hours	$	185.00
Other		
Service call - customer owned equipment	$	30.00
Service call - after regular hours	$	165.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - underground - no transformer	$	300.00
Temporary service install & remove - overhead - with transformer	$	1,000.00
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	22.35

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2018
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

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

LOSS FACTORS

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

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0355
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0251

Attachment 8-G

EPLC Bill Impacts

Rate Impact Summary

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total						Total	
		A		B		C		A + B + C	
		$	%	$	%	$	%	$	%
Residential - RPP	kWh	$ 0.90	3.4%	$ 0.08	0.3%	$ (0.38)	-1.1%	$ (0.51)	-0.4%
GS<50 - RPP	kWh	$ 1.61	2.7%	$ (0.73)	-1.1%	$ (1.70)	-2.1%	$ (2.14)	-0.7%
GS 50-4,999 - Non-RPP	kW	$ 11.99	2.7%	$(278.96)	-35.3%	$ (341.84)	-2.1%	$ (390.64)	-5.9%
Embedded Distributor - Non-RPP	kW	$(179.99)	-13.5%	$(283.95)	-17.8%	$ (283.95)	-17.8%	$ (342.63)	-0.7%
USL - RPP	kWh	$ (1.60)	-5.3%	$ (8.00)	-22.0%	$ (8.34)	-20.0%	$ (9.50)	-6.8%
Sentinel Lights - Non-RPP	kW	$ (0.12)	-2.8%	$ (0.33)	-7.0%	$ (0.35)	-7.0%	$ (0.39)	-3.8%
Street Lights - Non-RPP	kW	$ 0.11	2.5%	$ (0.08)	-1.7%	$ (0.09)	-2.0%	$ (0.11)	-1.1%
Residential 10th Percentile - RPP	kWh	$ 2.78	12.1%	$ 0.81	3.4%	$ 1.02	3.7%	$ 0.72	1.2%

Customer Class:	Residential
RPP / Non-RPP:	RPP
Consumption	750 kWh
Demand	0 kW
Current Loss Factor	1.0602
Proposed/Approved Loss Factor	1.0355

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 20.31	1	$ 20.31	$ 23.96	1	$ 23.96	$ 3.68	18.12%
Distribution Volumetric Rate	kWh	$ 0.0078	750	$ 5.85	$ 0.0040	750	$ 3.00	-$ 2.85	-48.72%
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Rate Rider for Application of Tax Change (2017) - effective until April 30, 2018	Monthly	-$ 0.1000	1	-$ 0.10	$ -	1	$ -	$ 0.10	-100.00%
Sub-Total A (excluding pass through)				**$ 26.85**			**$ 27.75**	**$ 0.90**	**3.35%**
Rate Rider for Group 1 Deferral / Variance Account Balances (Excluding Global Adjustment) - effective until April 30, 2019	kWh	$ -	750	$ -	-$ 0.0024	750	-$ 1.80	-$ 1.80	
Rate Rider for RSVA - Power - Global Adjustment - effective until April 30, 2019	kWh	$ -	750	$ -	$ 0.0030	750	$ 2.25	$ 2.25	
Rate Rider for the Disposition of Group 2 Accounts - effective until April 30, 2019	Monthly	$ -	1	$ -	-$ 0.2500	1	-$ 0.25	-$ 0.25	
Rate Rider for the Disposition of Account 1576 - effective until April 30, 2020	Monthly	$ -	1	$ -	-$ 3.3430	1	-$ 3.34	-$ 3.34	
Rate Rider for the Disposition of LRAM - effective until April 30, 2020	kWh	$ -	750	$ -	$ 0.0005	750	$ 0.38	$ 0.38	
Rate Rider for the Recovery of Stranded Meters - effective until April 30, 2021	Monthly	$ -	1	$ -	$ 1.0331	1	$ 1.03	$ 1.03	
Low Voltage Service Charge	kWh	$ 0.0010	750	$ 0.75	$ 0.0031	750	$ 2.31	$ 1.56	208.04%
Line Losses on Cost of Power	kWh	$ 0.0349	45.15	$ 1.58	$ 0.0349	26.625	$ 0.93	-$ 0.65	-41.03%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 29.18**			**$ 29.25**	**$ 0.08**	**0.27%**
RTSR - Network	kWh	$ 0.0048	795.15	$ 3.82	$ 0.0046	776.625	$ 3.57	-$ 0.24	-6.40%
RTSR - Line and Transformation Connection	kWh	$ 0.0032	795.15	$ 2.54	$ 0.0030	776.625	$ 2.33	-$ 0.21	-8.43%
Sub-Total C - Delivery (including Sub-Total B)				**$ 35.54**			**$ 35.16**	**-$ 0.38**	**-1.07%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0036	795.15	$ 2.86	$ 0.0036	776.625	$ 2.80	-$ 0.07	-2.33%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0003	795.15	$ 0.24	$ 0.0003	776.625	$ 0.23	-$ 0.01	-2.33%
TOU - Off Peak	kWh	$ 0.0770	480	$ 36.96	$ 0.0770	480	$ 36.96	$ -	0.00%
TOU - Mid Peak	kWh	$ 0.1130	135	$ 15.26	$ 0.1130	135	$ 15.26	$ -	0.00%
TOU - On Peak	kWh	$ 0.1570	135	$ 21.20	$ 0.1570	135	$ 21.20	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 112.05**			**$ 111.60**	**-$ 0.45**	**-0.40%**
HST		13%		$ 14.57	13%		$ 14.51	-$ 0.06	-0.40%
Total Bill on TOU				**$ 126.61**			**$ 126.10**	**-$ 0.51**	**-0.40%**

Customer Class:	Residential	
RPP / Non-RPP:	RPP	
Consumption	254	kWh
Demand	0	kW
Current Loss Factor	1.0602	
Proposed/Approved Loss Factor	1.0355	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 20.31	1	$ 20.31	$ 23.96	1	$ 23.96	$ 3.68	18.12%
Distribution Volumetric Rate	kWh	$ 0.0078	254	$ 1.98	$ 0.0040	254	$ 1.02	-$ 0.97	-48.72%
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Rate Rider for Application of Tax Change (2017) - effective until April 30, 2018	Monthly	-$ 0.1000	1	-$ 0.10	$ -	1	$ -	$ 0.10	-100.00%
Sub-Total A (excluding pass through)				**$ 22.98**			**$ 25.77**	**$ 2.78**	**12.12%**
Rate Rider for Group 1 Deferral / Variance Account Balances (Excluding Global Adjustment) - effective until April 30, 2019	kWh	$ -	254	$ -	-$ 0.0024	254	-$ 0.61	-$ 0.61	
Rate Rider for RSVA - Power - Global Adjustment - effective until April 30, 2019	kWh	$ -	254	$ -	$ 0.0030	254	$ 0.76	$ 0.76	
Rate Rider for the Disposition of Group 2 Accounts - effective until April 30, 2019	Monthly	$ -	1	$ -	-$ 0.2500	1	-$ 0.25	-$ 0.25	
Rate Rider for the Disposition of Account 1576 - effective until April 30, 2020	Monthly	$ -	1	$ -	-$ 3.3430	1	-$ 3.34	-$ 3.34	
Rate Rider for the Disposition of LRAM - effective until April 30, 2019	kWh	$ -	254	$ -	$ 0.0005	254	$ 0.13	$ 0.13	
Rate Rider for the Recovery of Stranded Meters - effective until April 30, 2021	Monthly	$ -	1	$ -	$ 1.0331	1	$ 1.03	$ 1.03	
Low Voltage Service Charge	kWh	$ 0.0010	254	$ 0.25	$ 0.0031	254	$ 0.78	$ 0.53	208.04%
Line Losses on Cost of Power	kWh	$ 0.0349	15.2908	$ 0.53	$ 0.0349	9.017	$ 0.31	-$ 0.22	-41.03%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 23.77**			**$ 24.58**	**$ 0.81**	**3.42%**
RTSR - Network	kWh	$ 0.0048	269.291	$ 1.29	$ 0.0046	263.017	$ 1.21	-$ 0.08	-6.40%
RTSR - Line and Transformation Connection	kWh	$ 0.0032	269.291	$ 0.86	$ 0.0030	263.017	$ 0.79	-$ 0.07	-8.43%
Sub-Total C - Delivery (including Sub-Total B)				**$ 25.92**			**$ 26.58**	**$ 1.02**	**3.71%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0036	269.291	$ 0.97	$ 0.0036	263.017	$ 0.95	-$ 0.02	-2.33%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0003	269.291	$ 0.08	$ 0.0003	263.017	$ 0.08	-$ 0.00	-2.33%
TOU - Off Peak	kWh	$ 0.0770	162.56	$ 12.52	$ 0.0770	162.56	$ 12.52	$ -	0.00%
TOU - Mid Peak	kWh	$ 0.1130	45.72	$ 5.17	$ 0.1130	45.72	$ 5.17	$ -	0.00%
TOU - On Peak	kWh	$ 0.1570	45.72	$ 7.18	$ 0.1570	45.72	$ 7.18	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 51.83**			**$ 52.47**	**$ 0.63**	**1.22%**
HST		13%		$ 6.74	13%		$ 6.82	$ 0.08	1.22%
Total Bill on TOU				**$ 58.57**			**$ 59.29**	**$ 0.72**	**1.22%**

Customer Class:	General Service < 50 kW
RPP / Non-RPP:	RPP
Consumption	2000 kWh
Demand	0 kW
Current Loss Factor	1.0602
Proposed/Approved Loss Factor	1.0355

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 35.13	1	$ 35.13	$ 35.94	1	$ 35.94	$ 0.84	2.39%
Distribution Volumetric Rate	kWh	$ 0.0120	2000	$ 24.00	$ 0.0123	2000	$ 24.60	$ 0.60	2.50%
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Rate Rider for Application of Tax Change (2017) - effective until April 30, 2018	kWh	-$ 0.0001	2000	-$ 0.20	$ -	2000	$ -	$ 0.20	-100.00%
Sub-Total A (excluding pass through)				**$ 59.72**			**$ 61.33**	**$ 1.61**	**2.70%**
Rate Rider for Group 1 Deferral / Variance Account Balances (Excluding Global Adjustment) - effective until April 30, 2019	kWh	$ -	2000	$ -	-$ 0.0024	2000	-$ 4.80	-$ 4.80	
Rate Rider for RSVA - Power - Global Adjustment - effective until April 30, 2019	kWh	$ -	2000	$ -	$ 0.0030	2000	$ 6.00	$ 6.00	
Rate Rider for the Disposition of Group 2 Accounts - effective until April 30, 2019	kWh	$ -	2000	$ -	-$ 0.0003	2000	-$ 0.60	-$ 0.60	
Rate Rider for the Disposition Account 1576 - effective until April 30, 2020	kWh	$ -	2000	$ -	-$ 0.0045	2000	-$ 9.00	-$ 9.00	
Rate Rider for the Disposition of LRAM - effective until April 30, 2020	kWh	$ -	2000	$ -	$ 0.0014	2000	$ 2.80	$ 2.80	
Rate Rider for the Recovery of Stranded Meters - effective until April 30, 2021	Monthly	$ -	1	$ -	$ 1.0331	1	$ 1.03	$ 1.03	
Low Voltage Service Charge	kWh	$ 0.0010	2000	$ 2.00	$ 0.0030	2000	$ 5.96	$ 3.96	197.77%
Line Losses on Cost of Power	kWh	$ 0.0349	120.4	$ 4.20	$ 0.0349	71	$ 2.48	-$ 1.72	-41.03%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 65.92**			**$ 65.20**	**-$ 0.73**	**-1.10%**
RTSR - Network	kWh	$ 0.0041	2120.4	$ 8.69	$ 0.0039	2071	$ 8.08	-$ 0.62	-7.09%
RTSR - Line and Transformation Connection	kWh	$ 0.0030	2120.4	$ 6.36	$ 0.0029	2071	$ 6.01	-$ 0.36	-5.59%
Sub-Total C - Delivery (including Sub-Total B)				**$ 80.98**			**$ 79.28**	**-$ 1.70**	**-2.10%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0036	2120.4	$ 7.63	$ 0.0036	2071	$ 7.46	-$ 0.18	-2.33%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0003	2120.4	$ 0.64	$ 0.0003	2071	$ 0.62	-$ 0.01	-2.33%
TOU - Off Peak	kWh	$ 0.0770	1280	$ 98.56	$ 0.0770	1280	$ 98.56	$ -	0.00%
TOU - Mid Peak	kWh	$ 0.1130	360	$ 40.68	$ 0.1130	360	$ 40.68	$ -	0.00%
TOU - On Peak	kWh	$ 0.1570	360	$ 56.52	$ 0.1570	360	$ 56.52	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 285.01**			**$ 283.12**	**-$ 1.89**	**-0.66%**
HST		13%		$ 37.05	13%		$ 36.81	-$ 0.25	-0.66%
Total Bill on TOU				**$ 322.06**			**$ 319.92**	**-$ 2.14**	**-0.66%**

Customer Class:	General Service > 50 to 4999 kW	
RPP / Non-RPP:	non-RPP	
Consumption	40000	kWh
Demand	100	kW
Current Loss Factor	1.0602	
Proposed/Approved Loss Factor	1.0355	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 232.69	1	$ 232.69	$ 238.04	1	$ 238.04	$ 5.59	2.40%
Distribution Volumetric Rate	kW	$ 2.2101	100	$ 221.01	$ 2.2573	100	$ 225.73	$ 4.72	2.24%
Rate Rider for Application of Tax Change (2017) - effective until April 30, 2018	kW	-$ 0.0192	100	-$ 1.92	$ -	100	$ -	$ 1.92	-100.00%
Sub-Total A (excluding pass through)				**$ 451.78**			**$ 463.77**	**$ 11.99**	**2.65%**
Rate Rider for Disposition of Global Adjustment Account (2015) - approved on an interim basis and effective until April 30. 2018, applicable only for Non-RPP Customers	kW	$ 2.5358	100	$ 253.58	$ -	100	$ -	-$ 253.58	-100.00%
Rate Rider for Group 1 Deferral / Variance Account Balances (Excluding Global Adjustment) - effective until April 30, 2019	kW	$ -	100	$ -	$ 2.3747	100	$ 237.47	$ 237.47	
Rate Rider for Deferral / Variance Account Balances (Excluding Global Adjustment) Non-WMP - effective until April 30, 2019	kW	$ -	100	$ -	-$ 2.8397	100	-$ 283.97	-$ 283.97	
Rate Rider for RSVA - Power - Global Adjustment - effective until April 30, 2019	kWh	$ -	40000	$ -	$ 0.0030	40000	$ 120.00	$ 120.00	
Rate Rider for the Disposition of Group 2 Accounts - effective until April 30, 2019	kW	$ -	100	$ -	-$ 0.1351	100	-$ 13.51	-$ 13.51	
Rate Rider for the Disposition of Account 1576 - effective until April 30, 2020	kW	$ -	100	$ -	-$ 1.7750	100	-$ 177.50	-$ 177.50	
Rate Rider for the Disposition of LRAM - effective until April 30, 2020	kW	$ -	100	$ -	$ 0.0881	100	$ 8.81	$ 8.81	
Low Voltage Service Charge	kW	$ 0.3506	100	$ 35.06	$ 1.2718	100	$ 127.18	$ 92.12	262.75%
Line Losses on Cost of Power	kWh	$ 0.0210	2408	$ 50.67	$ 0.0210	1420	$ 29.88	-$ 20.79	-41.03%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 791.09**			**$ 512.13**	**-$ 278.96**	**-35.26%**
RTSR - Network	kW	$ 2.0924	106.02	$ 221.84	$ 1.6326	103.55	$ 169.06	-$ 52.78	-23.79%
RTSR - Line and Transformation Connection	kW	$ 1.3480	106.02	$ 142.91	$ 1.2826	103.55	$ 132.81	-$ 10.10	-7.07%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,155.85**			**$ 814.00**	**-$ 341.84**	**-29.58%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0036	42408	$ 152.67	$ 0.0036	41420	$ 149.11	-$ 3.56	-2.33%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0003	42408	$ 12.72	$ 0.0003	41420	$ 12.43	-$ 0.30	-2.33%
Average IESO Wholesale Market Price	kWh	$ 0.1130	40000	$ 4,520.00	$ 0.1130	40000	$ 4,520.00	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 5,841.24**			**$ 5,495.54**	**-$ 345.70**	**-5.92%**
HST		13%		$ 759.36	13%		$ 714.42	-$ 44.94	-5.92%
Total Bill on TOU				**$ 6,600.60**			**$ 6,209.96**	**-$ 390.64**	**-5.92%**

Customer Class:	Unmetered Scattered Load
RPP / Non-RPP:	non-RPP
Consumption	700 kWh
Demand	0 kW
Current Loss Factor	1.0602
Proposed/Approved Loss Factor	1.0355

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 9.53	1	$ 9.53	$ 8.98	1	$ 8.98	-$ 0.55	5.77%
Distribution Volumetric Rate	kWh	$ 0.0297	700	$ 20.79	$ 0.0280	700	$ 19.60	-$ 1.19	-5.72%
Rate Rider for Application of Tax Change (2017) - effective until April 30, 2018	kWh	-$ 0.0002	700	-$ 0.14	$ -	700	$ -	$ 0.14	-100.00%
Sub-Total A (excluding pass through)				**$ 30.18**			**$ 28.58**	**-$ 1.60**	**-5.30%**
Rate Rider for Disposition of Global Adjustment Account (2015) - approved on an interim basis and effective until April 30. 2018, applicable only for Non-RPP Customers	kWh	$ 0.0066	700	$ 4.62	$ -	700	$ -	-$ 4.62	-100.00%
Rate Rider for Group 1 Deferral / Variance Account Balances (Excluding Global Adjustment) - effective until April 30, 2019	kWh	$ -	700	$ -	-$ 0.0022	700	-$ 1.54	-$ 1.54	
Rate Rider for RSVA - Power - Global Adjustment - effective until April 30, 2019	kWh	$ -	700	$ -	$ 0.0030	700	$ 2.10	$ 2.10	
Rate Rider for the Disposition of Group 2 Accounts - effective until April 30, 2019	kWh	$ -	700	$ -	-$ 0.0003	700	-$ 0.21	-$ 0.21	
Rate Rider for the Disposition of Account 1576 - effective until April 30, 2020	kWh	$ -	700	$ -	-$ 0.0045	700	-$ 3.15	-$ 3.15	
Low Voltage Service Charge	kWh	$ 0.0010	700	$ 0.70	$ 0.0030	700	$ 2.08	$ 1.38	197.77%
Line Losses on Cost of Power	kWh	$ 0.0210	42.14	$ 0.89	$ 0.0210	24.85	$ 0.52	-$ 0.36	-41.03%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 36.39**			**$ 28.39**	**-$ 8.00**	**-21.98%**
RTSR - Network	kWh	$ 0.0041	742.14	$ 3.04	$ 0.0039	724.85	$ 2.83	-$ 0.22	-7.09%
RTSR - Line and Transformation Connection	kWh	$ 0.0030	742.14	$ 2.23	$ 0.0029	724.85	$ 2.10	-$ 0.12	-5.59%
Sub-Total C - Delivery (including Sub-Total B)				**$ 41.66**			**$ 33.32**	**-$ 8.34**	**-20.02%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0036	742.14	$ 2.67	$ 0.0036	724.85	$ 2.61	-$ 0.06	-2.33%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0003	742.14	$ 0.22	$ 0.0003	724.85	$ 0.22	-$ 0.01	-2.33%
Average IESO Wholesale Market Price	kWh	$ 0.1130	700	$ 79.10	$ 0.1130	700	$ 79.10	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 123.65**			**$ 115.24**	**-$ 8.41**	**-6.80%**
HST		13%		$ 16.07	13%		$ 14.98	-$ 1.09	-6.80%
Total Bill on TOU				**$ 139.72**			**$ 130.22**	**-$ 9.50**	**-6.80%**

Customer Class:	Sentinel Lighting
RPP / Non-RPP:	non-RPP
Consumption	36 kWh
Demand	0.1 kW
Current Loss Factor	1.0602
Proposed/Approved Loss Factor	1.0355

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 3.41	1	$ 3.41	$ 3.31	1	$ 3.31	-$ 0.09	-2.64%
Distribution Volumetric Rate	kW	$ 9.7922	0.1	$ 0.98	$ 9.5148	0.1	$ 0.95	-$ 0.03	-2.83%
Rate Rider for Application of Tax Change (2017) - effective until April 30, 2018	kW	-$ 0.0492	0.1	-$ 0.00	$ -	0.1	$ -	$ 0.00	-100.00%
Sub-Total A (excluding pass through)				**$ 4.38**			**$ 4.26**	**-$ 0.12**	**-2.80%**
Rate Rider for Disposition of Global Adjustment Account (2015) - approved on an interim basis and effective until April 30. 2018, applicable only for Non-RPP Customers	kW	$ 2.3785	0.1	$ 0.24	$ -	0.1	$ -	-$ 0.24	-100.00%
Rate Rider for Group 1 Deferral / Variance Account Balances (Excluding Global Adjustment) - effective until April 30, 2019	kW	$ -	0.1	$ -	-$ 0.3852	0.1	-$ 0.04	-$ 0.04	
Rate Rider for RSVA - Power - Global Adjustment - effective until April 30, 2019	kWh	$ -	36	$ -	$ 0.0030	36	$ 0.11	$ 0.11	
Rate Rider for the Disposition of Group 2 Accounts - effective until April 30, 2019	kW	$ -	0.1	$ -	-$ 0.0552	0.1	-$ 0.01	-$ 0.01	
Rate Rider for the Disposition of Account 1576 - effective until April 30, 2020	kW	$ -	0.1	$ -	-$ 0.7253	0.1	-$ 0.07	-$ 0.07	
Low Voltage Service Charge	kW	$ 0.2816	0.1	$ 0.03	$ 0.8743	0.1	$ 0.09	$ 0.06	210.47%
Line Losses on Cost of Power	kWh	$ 0.0210	2.1672	$ 0.05	$ 0.0210	1.278	$ 0.03	-$ 0.02	-41.03%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 4.70**			**$ 4.37**	**-$ 0.33**	**-7.00%**
RTSR - Network	kW	$ 1.3077	0.10602	$ 0.14	$ 1.2444	0.10355	$ 0.13	-$ 0.01	-7.06%
RTSR - Line and Transformation Connection	kW	$ 0.9267	0.10602	$ 0.10	$ 0.8817	0.10355	$ 0.09	-$ 0.01	-7.07%
Sub-Total C - Delivery (including Sub-Total B)				**$ 4.93**			**$ 4.59**	**-$ 0.35**	**-7.00%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0036	38.1672	$ 0.14	$ 0.0036	37.278	$ 0.13	-$ 0.00	-2.33%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0003	38.1672	$ 0.01	$ 0.0003	37.278	$ 0.01	-$ 0.00	-2.33%
Average IESO Wholesale Market Price	kWh	$ 0.1130	36	$ 4.07	$ 0.1130	36	$ 4.07	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 9.15**			**$ 8.80**	**-$ 0.35**	**-3.81%**
HST		13%		$ 1.19	13%		$ 1.14	-$ 0.05	-3.81%
Total Bill on TOU				**$ 10.34**			**$ 9.94**	**-$ 0.39**	**-3.81%**

Customer Class:	Street Lighting
RPP / Non-RPP:	non-RPP
Consumption	36 kWh
Demand	0.1 kW
Current Loss Factor	1.0602
Proposed/Approved Loss Factor	1.0355

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 3.30	1	$ 3.30	$ 3.38	1	$ 3.38	$ 0.08	2.42%
Distribution Volumetric Rate	kW	$ 8.9407	0.1	$ 0.89	$ 9.1461	0.1	$ 0.91	$ 0.02	2.30%
Rate Rider for Application of Tax Change (2017) - effective until April 30, 2018	kW	-$ 0.0544	0.1	-$ 0.01	$ -	0.1	$ -	$ 0.01	-100.00%
Sub-Total A (excluding pass through)				**$ 4.19**			**$ 4.29**	**$ 0.11**	**2.53%**
Rate Rider for Disposition of Global Adjustment Account (2015) - approved on an interim basis and effective until April 30. 2018, applicable only for Non-RPP Customers	kW	$ 2.1886	0.1	$ 0.22	$ -	0.1	$ -	-$ 0.22	-100.00%
Rate Rider for Group 1 Deferral / Variance Account Balances (Excluding Global Adjustment) - effective until April 30, 2019	kW	$ -	0.1	$ -	-$ 0.5947	0.1	-$ 0.06	-$ 0.06	
Rate Rider for RSVA - Power - Global Adjustment - effective until April 30, 2019	kWh	$ -	36	$ -	$ 0.0030	36	$ 0.11	$ 0.11	
Rate Rider for the Disposition of Group 2 Accounts - effective until April 30, 2019	kW	$ -	0.1	$ -	-$ 0.1082	0.1	-$ 0.01	-$ 0.01	
Rate Rider for the Disposition of Account 1576 - effective until April 30, 2020	kW	$ -	0.1	$ -	-$ 1.4219	0.1	-$ 0.14	-$ 0.14	
Rate Rider for the Disposition of LRAM - effective until April 30, 2020	kW	$ -	0.1	$ -	$ 0.5070	0.1	$ 0.10	$ 0.10	
Low Voltage Service Charge	kW	$ 0.2798	0.1	$ 0.03	$ 0.8686	0.1	$ 0.09	$ 0.06	210.45%
Line Losses on Cost of Power	kWh	$ 0.0210	2.1672	$ 0.05	$ 0.0210	1.278	$ 0.03	-$ 0.02	-41.03%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 4.48**			**$ 4.41**	**-$ 0.08**	**-1.69%**
RTSR - Network	kW	$ 1.2894	0.10602	$ 0.14	$ 1.2270	0.10355	$ 0.13	-$ 0.01	-7.06%
RTSR - Line and Transformation Connection	kW	$ 0.9207	0.10602	$ 0.10	$ 0.8760	0.10355	$ 0.09	-$ 0.01	-7.07%
Sub-Total C - Delivery (including Sub-Total B)				**$ 4.72**			**$ 4.62**	**-$ 0.09**	**-1.96%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0036	38.1672	$ 0.14	$ 0.0036	37.278	$ 0.13	-$ 0.00	-2.33%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0003	38.1672	$ 0.01	$ 0.0003	37.278	$ 0.01	-$ 0.00	-2.33%
Average IESO Wholesale Market Price	kWh	$ 0.1130	36	$ 4.07	$ 0.1130	36	$ 4.07	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 8.93**			**$ 8.84**	**-$ 0.10**	**-1.07%**
HST		13%		$ 1.16	13%		$ 1.15	-$ 0.01	-1.07%
Total Bill on TOU				**$ 10.09**			**$ 9.99**	**-$ 0.11**	**-1.07%**

Customer Class:	Embedded Distributor
RPP / Non-RPP:	non-RPP
Consumption	200000 kWh
Demand	500 kW
Current Loss Factor	1.0602
Proposed/Approved Loss Factor	1.0355

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 232.69	1	$ 232.69	$ 550.00	1	$ 550.00	$ 317.31	136.37%
Distribution Volumetric Rate	kW	$ 2.2101	500	$ 1,105.05	$ 1.2155	500	$ 607.75	-$ 497.20	-44.99%
Sub-Total A (excluding pass through)				**$ 1,337.74**			**$ 1,157.75**	**-$ 179.99**	**-13.45%**
Rate Rider for Disposition of Global Adjustment Account (2015) - approved on an interim basis and effective until April 30. 2018, applicable only for Non-RPP Customers	kW	$ -	500	$ -	$ -	500	$ -	$ -	
Rate Rider for Deferral / Variance Account Balances (Excluding Global Adjustment)	kW	$ -	500	$ -	$ -	500	$ -	$ -	
Rate Rider for Deferral / Variance Account Balances (Excluding Global Adjustment) Non-WMP	kW	$ -	500	$ -	$ -	500	$ -	$ -	
Rate Rider for Group 2 Accounts	kW	$ -	500	$ -	$ -	500	$ -	$ -	
Rate Rider for Accounts 1575 & 1576	kW	$ -	500	$ -	$ -	500	$ -	$ -	
LRAM Rider	kW	$ -	500	$ -	$ -	500	$ -	$ -	
Low Voltage Service Charge	kW	$ -	500	$ -	$ -	500	$ -	$ -	
Line Losses on Cost of Power	kWh	$ 0.0210	12040	$ 253.37	$ 0.0210	7100	$ 149.41	-$ 103.96	-41.03%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,591.11**			**$ 1,307.16**	**-$ 283.95**	**-17.85%**
RTSR - Network	kWh	$ -	212040	$ -	$ -	207100	$ -	$ -	
RTSR - Line and Transformation Connection	kWh	$ -	212040	$ -	$ -	207100	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,591.11**			**$ 1,307.16**	**-$ 283.95**	**-17.85%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0036	212040	$ 763.34	$ 0.0036	207100	$ 745.56	-$ 17.78	-2.33%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0003	212040	$ 63.61	$ 0.0003	207100	$ 62.13	-$ 1.48	-2.33%
TOU - Off Peak	kWh	$ 0.0770	128000	$ 9,856.00	$ 0.0770	128000	$ 9,856.00	$ -	0.00%
TOU - Mid Peak	kWh	$ 0.1130	36000	$ 4,068.00	$ 0.1130	36000	$ 4,068.00	$ -	0.00%
TOU - On Peak	kWh	$ 0.1570	36000	$ 5,652.00	$ 0.1570	36000	$ 5,652.00	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 44,821.88**			**$ 44,518.66**	**-$ 303.21**	**-0.68%**
HST		13%		$ 5,826.84	13%		$ 5,787.43	-$ 39.42	-0.68%
Total Bill on TOU				**$ 50,648.72**			**$ 50,306.09**	**-$ 342.63**	**-0.68%**

Exhibit 9:

Deferral & Variance

Table of Contents

List of Attachments

9.1 Overview

In this Exhibit, Essex Powerlines Corporation ("EPLC") proposes to dispose of various Group One and Group Two Deferral and Variance Account ("DVAs"). As part of this Application, EPLC is seeking to dispose of balances as of December 31st, 2016 with forecasted interest up to and including April 30th, 2018. This Exhibit outlines the details of EPLC's DVA balances.

EPLC has followed the Board's guidance through the Accounting Procedures Handbook ("APH"), the Report of the Board on Electricity Distributor's Deferral and Variance Account Review Initiative ("EDDVAR"), as well as the Accounting Procedures Handbook Frequently Asked Questions ("APHFAQ") to guide the processes and procedures used to record amounts in its DVAs.

For the purpose of this Application, EPLC utilized the Board's 2018 Deferral/Variance Account Workform (version 1.3) which is included as Attachment 9-A of this Exhibit.

EPLC is not requesting any new accounts or sub-accounts in this Application.

EPLC has included adjustments related to its Group 1 and Group 2 variance account balances. Principal and interest adjustments are included in the 2015 adjustment columns in the Board's DVA continuity schedule. All of the adjustments included in this Application, except one, were consistent with the Board's recent audit findings.

EPLC confirms that the IESO Global Adjustment Charge is pro-rated into Regulated Price Plan ("RPP") and the Non-RPP portions.

9.2 Account Balances

EPLC DVA balances as of December 31st, 2016 are presented below as Figure 1.

Figure 1 – EPLC DVA Balances – December 31st, 2016

USoA	Description	Principle Balance	Interest Balance	Total
Group One				
1550	Low Voltage	$ 2,657,799	$ 38,400	$ 2,696,199
1551	Smart Metering Entity Charge	$ (38,419)	$ (945)	$ (39,364)
1568	LRAMVA	$ 504,108	$ 9,392	$ 513,500
1580	RSVA - Wholesale Market Service Charge	$ (822,759)	$ (16,693)	$ (839,452)
1580	Variance WMS – Sub-account CBR Class A	$ -	$ -	$ -
1580	Variance WMS – Sub-account CBR Class B	$ 131,549	$ 447	$ 131,996
1584	RSVA Network	$ (395,066)	$ (40,886)	$ (435,952)
1586	RSVA Connection	$ 421,225	$ (13,771)	$ 407,454
1588	RSVA - Power (excluding Global Adjustment)	$ (3,005,038)	$ 260,749	$ (2,744,289)
1589	RSVA - Global Adjustment	$ 810,446	$ (293,235)	$ 517,211
1590	Disposition and Recovery of Regulatory Assets (2010)	$ (174,821)	$ (67,147)	$ (241,968)
1595	Disposition and Recovery of Regulatory Assets (2012)	$ 149,130	$ 44,614	$ 193,744
1595	Disposition and Recovery of Regulatory Assets (2014)	$ 2,219	$ (22,555)	$ (20,336)
	Subtotal	**$ 240,373**	**$ (101,630)**	**$ 138,743**
Group Two				
1508	Other Regulatory Assets - IFRS Transition Costs	$ (275,453)	$ (12,350)	$ (287,803)
1518	RCVA Retail	$ 158,620	$ 5,982	$ 164,602
1525	Misc. Deferred Debits	$ 83,197	$ 694	$ 83,891
1531	Renewable Generation Connection Capital	$ 68,938	$ 656	$ 69,594
1534	Smart Grid Capital	$ 512,740	$ 13,084	$ 525,824
1535	Smart Grid OM&A	$ 91,626	$ 4,442	$ 96,068
1548	RCVA STR	$ (1,915)	$ (255)	$ (2,170)
1555	Smart Meter Capital & Recovery Offset	$ -	$ -	$ -
1572	Extraordinary Event Costs	$ 80,414	$ 6,822	$ 87,236
1576	CGAAP Accounting Changes	$ (2,558,929)	$ -	$ (2,558,929)
1582	RSVA One Time	$ -	$ -	$ -
1592	PILs & Tax Variance	$ (202,758)	$ (7,952)	$ (210,710)
	Subtotal	**$ (2,043,520)**	**$ 11,123**	**$ (2,032,397)**
	Total	**$ (1,803,147)**	**$ (90,507)**	**$ (1,893,654)**

9.2.1 Reconciliation of Accounts

EPLC confirms that balances presented in section 9.2 reconcile to the 2016 Audited Financial Statements ("AFS") and to EPLC's 2016 Reporting and Record Keeping Requirements ("RRR") filing. Figure 2 below summarizes the reconciliation.

Figure 2 – 2016 DVA Reconciliation

USoA	Description	Balance 12/31/2016	Per RRR & AFS	Variance
Group One				
1550	Low Voltage	$ 2,696,199	$ 2,696,200	$ (1)
1551	Smart Metering Entity Charge	$ (39,364)	$ (39,364)	$ (0)
1568	LRAMVA	$ 513,500	$ 343,485	$ 170,015
1580	RSVA - Wholesale Market Service Charge	$ (839,452)	$ (789,770)	$ (49,682)
1580	Variance WMS – Sub-account CBR Class A	$ -	$ -	$ -
1580	Variance WMS – Sub-account CBR Class B	$ 131,996	$ 82,315	$ 49,681
1584	RSVA Network	$ (435,952)	$ (435,952)	$ (0)
1586	RSVA Connection	$ 407,454	$ 407,455	$ (1)
1588	RSVA - Power (excluding Global Adjustment)	$ (2,744,289)	$ (2,744,288)	$ (0)
1589	RSVA - Global Adjustment	$ 517,211	$ 517,212	$ (0)
1590	Disposition and Recovery of Regulatory Assets (2010)	$ (241,968)	$ (241,968)	$ -
1595	Disposition and Recovery of Regulatory Assets (2012)	$ 193,744	$ 193,744	$ (1)
1595	Disposition and Recovery of Regulatory Assets (2014)	$ (20,336)	$ (20,336)	$ (0)
	Subtotal	**$ 138,743**	**$ (31,266)**	**$ 170,009**
Group Two				
1508	Other Regulatory Assets - IFRS Transition Costs	$ (287,803)	$ (287,802)	$ (1)
1518	RCVA Retail	$ 164,602	$ 164,603	$ (1)
1525	Misc. Deferred Debits	$ 83,891	$ 83,891	$ (0)
1531	Renewable Generation Connection Capital	$ 69,594	$ 69,594	$ (0)
1534	Smart Grid Capital	$ 525,824	$ 525,823	$ 1
1535	Smart Grid OM&A	$ 96,068	$ 96,068	$ 1
1548	RCVA STR	$ (2,170)	$ (2,171)	$ 1
1555	Smart Meter Capital & Recovery Offset	$ -	$ -	$ -
1572	Extraordinary Event Costs	$ 87,236	$ 87,236	$ (0)
1576	CGAAP Accounting Changes	$ (2,558,929)	$ (2,558,928)	$ (1)
1582	RSVA One Time	$ -	$ -	$ -
1592	PILs & Tax Variance	$ (210,710)	$ (210,710)	$ 0
	Subtotal	**$ (2,032,397)**	**$ (2,032,397)**	**$ 0**
	Total	**$ (1,893,654)**	**$ (2,063,663)**	**$ 170,009**

Aside from minor rounding related variances, please note that the variance identified in Account 1592 is offset by a corresponding balance in a 1592 sub-account.

9.2.2 Cost of Power Reconciliation

EPLC has not recorded any profit or loss from the flow through of energy revenues and expenses. Any temporary variances are included in the Retail Settlement Variance Account ("RSVA") balances.

Figure 3 below outline the flow of various cost of power revenues and expenses and show the net variance to be zero.

Figure 3 – Energy Revenue & Cost of Power Expense Analysis

USoA	Description	Actual						
		2010	2011	2012	2013	2014	2015	2016
Energy Revenues								
4006	Residential Energy Sales	$ (15,583,595.62)	$ (16,748,866.31)	$ (19,092,331.37)	$ (17,138,147.23)	$ (22,035,090.29)	$ (23,404,451.96)	$ (28,406,789.00)
4010	Commercial Energy Sales	$ (4,188,629.47)	$ (4,445,452.79)	$ (5,021,690.67)	$ (5,596,168.67)	$ (5,213,338.15)	$ (5,643,194.32)	$ (6,278,762.03)
4015	Industrial Energy Sales	$ (2,247,269.96)	$ (2,219,666.69)	$ (2,034,418.96)	$ (2,818,924.86)	$ (2,414,881.75)	$ (3,052,200.27)	$ (3,626,110.21)
4025	Street Lighting Energy Sales	$ (188,178.30)	$ (215,085.71)	$ (240,345.43)	$ (270,970.36)	$ (244,669.77)	$ (249,467.74)	$ (205,810.32)
4030	Sentinel Lighting Energy Sales	$ (106,702.86)	$ (114,036.82)	$ (126,745.11)	$ (127,472.17)	$ (27,620.41)	$ (143,354.99)	$ (156,477.08)
4035	General Energy Sales	$ (9,477,840.54)	$ (10,763,504.77)	$ (10,760,219.37)	$ (11,144,012.55)	$ (12,715,684.77)	$ (15,059,351.18)	$ (16,019,680.12)
4050	Revenue Adjustment	$ (59,514.78)	$ (176,595.83)	$ 172,033.84	$ -	$ -	$ -	$ -
4055	Energy Sales for Resale	$ (7,368,316.73)	$ (6,403,504.88)	$ (4,693,254.56)	$ (5,441,763.08)	$ (6,439,141.58)	$ (6,732,371.80)	$ (8,456,231.54)
4062	Wholesale Market Service	$ (3,869,445.60)	$ (3,686,257.99)	$ (3,771,377.85)	$ (2,288,747.47)	$ (2,261,796.94)	$ (2,120,789.99)	$ (2,969,459.15)
4066	Network	$ (2,943,205.60)	$ (3,367,535.04)	$ (3,606,708.86)	$ (3,821,303.72)	$ (3,498,235.91)	$ (3,473,406.32)	$ (3,085,439.91)
4068	Connection	$ (2,615,702.69)	$ (2,675,457.47)	$ (2,500,550.85)	$ (2,401,566.52)	$ (2,159,619.45)	$ (1,887,851.53)	$ (1,848,460.41)
4075	Low Voltage Charges	$ (539,791.23)	$ (504,629.91)	$ (506,901.54)	$ (493,125.92)	$ (493,310.15)	$ (495,977.32)	$ (548,257.32)
4076	Smart Metering Entity Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Subtotal	**$ (49,188,193.38)**	**$ (51,320,594.21)**	**$ (52,182,510.73)**	**$ (51,542,202.55)**	**$ (57,503,389.17)**	**$ (62,262,417.42)**	**$ (71,601,477.09)**
Cost of Power Expenses								
4705	Power Purchased	$ 39,264,299.31	$ 40,910,117.96	$ 41,969,005.46	$ 34,467,556.08	$ 36,636,536.66	$ 36,289,025.81	$ 40,684,265.96
4707	Charges - Global Adjustment	$ -	$ -	$ -	$ 8,069,902.81	$ 12,453,890.06	$ 17,969,067.56	$ 22,465,594.34
4708	Wholesale Market Service	$ 3,869,445.60	$ 3,686,257.99	$ 3,771,377.87	$ 2,288,747.27	$ 2,261,796.97	$ 2,120,789.99	$ 2,969,459.15
4714	Network	$ 2,943,205.60	$ 3,367,535.05	$ 3,606,708.83	$ 3,821,303.72	$ 3,498,235.91	$ 3,473,406.32	$ 3,085,439.91
4716	Connection	$ 2,615,702.69	$ 2,675,457.47	$ 2,500,550.85	$ 2,401,566.52	$ 2,159,619.45	$ 1,887,851.53	$ 1,848,460.41
4750	Low Voltage Charges	$ 539,791.23	$ 504,629.91	$ 506,901.54	$ 493,125.92	$ 493,310.26	$ 495,977.32	$ 548,257.32
4751	Smart Metering Entity Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Subtotal	**$ 49,232,444.43**	**$ 51,143,998.38**	**$ 52,354,544.55**	**$ 51,542,202.32**	**$ 57,503,389.31**	**$ 62,236,118.53**	**$ 71,601,477.09**
	Total	**$ 44,251.05**	**$ (176,595.83)**	**$ 172,033.82**	**$ (0.23)**	**$ 0.14**	**$ (26,298.89)**	**$ -**

Energy Revenues represents the various cost of power components recovered by EPLC electricity customers and remitted to the Independent Electricity System Operator ("IESO") or Hydro One Networks Inc. ("HONI"). Cost of Power expenses represents flow through expense payable to the IESO or HONI.

9.2.3 Carrying Charges

EPLC has calculated interest based on the opening monthly principle balances for DVAs. EPLC has also used the Board's prescribed interest rates in order to facilitate this calculation.

Consistent with the Board's Filing Requirements, EPLC has used the most recent posted rate available (Q3 2017, 1.10%) in order to forecast carrying charges up to April 30th, 2018.

Figure 4 below outlines the historical Board Prescribed Interest Rates from 2006-2017.

Figure 4 – Board Prescribed Interest Rates

Year	Quarter	Prescribed Interest Rate	Year	Quarter	Prescribed Interest Rate	Year	Quarter	Prescribed Interest Rate
2006	Q1		2010	Q1	0.55%	2014	Q1	1.47%
	Q2	4.14%		Q2	0.55%		Q2	1.47%
	Q3	4.59%		Q3	0.89%		Q3	1.47%
	Q4	4.59%		Q4	1.30%		Q4	1.47%
2007	Q1	4.59%	2011	Q1	1.47%	2015	Q1	1.47%
	Q2	4.59%		Q2	1.47%		Q2	1.10%
	Q3	4.59%		Q3	1.47%		Q3	1.10%
	Q4	5.14%		Q4	1.47%		Q4	1.10%
2008	Q1	5.14%	2012	Q1	1.47%	2016	Q1	1.10%
	Q2	4.08%		Q2	1.47%		Q2	1.10%
	Q3	3.35%		Q3	1.47%		Q3	1.10%
	Q4	3.35%		Q4	1.47%		Q4	1.10%
2009	Q1	2.45%	2013	Q1	1.47%	2017	Q1	1.10%
	Q2	1.00%		Q2	1.47%		Q2	1.10%
	Q3	0.55%		Q3	1.47%		Q3	1.10%
	Q4	0.55%		Q4	1.47%		Q4	

9.3 Proposed Disposition

EPLC is requesting a disposition of $3,498,733 to be refunded to customers based on 2016 year end balances net of any timing related adjustments. EPLC has also included interest up to April 30th, 2018 as described in section 9.2 above.

A summary of EPLC's requested disposition is detailed below as Figure 5.

Figure 5 – EPLC Balances for Disposition

USoA	Description	Balance 12/31/2016	Interest to 04/30/2018	Balance for Disposition
Group One				
1550	Low Voltage	$ 2,696,199	$ 38,848	$ 2,735,047
1551	Smart Metering Entity Charge	$ (39,364)	$ (562)	$ (39,926)
1568	LRAMVA	$ 513,500	$ 7,368	$ 520,868
1580	RSVA - Wholesale Market Service Charge	$ (839,452)	$ (12,026)	$ (851,478)
1580	Variance WMS – Sub-account CBR Class A	$ -	$ -	$ -
1580	Variance WMS – Sub-account CBR Class B	$ 131,996	$ 1,923	$ 133,919
1584	RSVA Network	$ (435,952)	$ (5,774)	$ (441,726)
1586	RSVA Connection	$ 407,454	$ 6,157	$ 413,611
1588	RSVA - Power (excluding Global Adjustment)	$ (2,744,289)	$ (43,923)	$ (2,788,212)
1589	RSVA - Global Adjustment	$ 517,211	$ 11,846	$ 529,057
1590	Disposition and Recovery of Regulatory Assets (2010)	$ (241,968)	$ (2,555)	$ (244,523)
1595	Disposition and Recovery of Regulatory Assets (2012)	$ 193,744	$ 2,180	$ 195,924
1595	Disposition and Recovery of Regulatory Assets (2014)	$ (20,336)	$ 32	$ (20,304)
	Subtotal	**$ 138,743**	**$ 3,514**	**$ 142,257**
Group Two				
1508	Other Regulatory Assets - IFRS Transition Costs	$ (287,803)	$ (4,026)	$ (291,829)
1518	RCVA Retail	$ 164,602	$ 2,318	$ 166,920
1525	Misc. Deferred Debits	$ 83,891	$ 1,216	$ 85,107
1531	Renewable Generation Connection Capital	$ 69,594	$ 1,008	$ 70,602
1534	Smart Grid Capital	$ 525,824	$ 7,494	$ 533,318
1535	Smart Grid OM&A	$ 96,068	$ 1,339	$ 97,407
1548	RCVA STR	$ (2,170)	$ (28)	$ (2,198)
1555	Smart Meter Capital & Recovery Offset	$ -	$ -	$ -
1572	Extraordinary Event Costs	$ 87,236	$ 1,175	$ 88,411
1576	CGAAP Accounting Changes	$ (2,558,929)	$ -	$ (4,175,054)
1582	RSVA One Time	$ -	$ -	$ -
1592	PILs & Tax Variance	$ (210,710)	$ (2,964)	$ (213,674)
	Subtotal	**$ (2,032,397)**	**$ 7,532**	**$ (3,640,990)**
	Total	**$ (1,893,654)**	**$ 11,046**	**$ (3,498,733)**

9.4 Group One Account Analysis

EPLC last disposed of Group One Accounts as part of its 2015 IRM filing (EB-2014-0072) for 2013 balances.

The subsequent subsections of 9.4 below detail EPLC's various disposition claims by Group One Account currently in use.

9.4.1 Account 1550: Low Voltage Variance Account

EPLC requests disposition of Account 1550 in the amount of $2,735,047 as a collection from customers, including interest up to April 30th, 2018. Details of the requested claim can be found below as Figure 6.

Figure 6 – Account 1550 Claim

Description	Principal	Interest	Total
December 31st, 2016 Balance	$ 2,657,799	$ 38,400	$ 2,696,199
Adjustments	$ -	$ -	$ -
Balance for Disposition	**$ 2,657,799**	**$ 38,400**	**$ 2,696,199**
Interest January to December 2017		$ 29,236	$ 29,236
Interest January to April 2018		$ 9,612	$ 9,612
Total Claim	**$ 2,657,799**	**$ 77,248**	**$ 2,735,047**

EPLC uses this account to record the variances between the Low Voltage charges it receives from HONI and the amount billed to EPLC customers based on EPLC's approved Low Voltage rates, which are collected in Account 4075 along with any accruals.

9.4.2 Account 1551: Smart Metering Entity ("SME") Charge Variance Account

EPLC requests disposition of Account 1551 in the amount of $39,925 to be refunded to customers, including interest up to April 30th, 2018. Details of the requested claim can be found below as Figure 7.

Figure 7 – Account 1551 Claim

Description	Principal	Interest	Total
December 31st, 2016 Balance	$ (38,419)	$ (945)	$ (39,364)
Adjustments	$ -	$ -	$ -
Balance for Disposition	**$ (38,419)**	**$ (945)**	**$ (39,364)**
Interest January to December 2017		$ (423)	$ (423)
Interest January to April 2018		$ (139)	$ (139)
Total Claim	**$ (38,419)**	**$ (1,507)**	**$ (39,925)**

EPLC uses this account to record the variances between the Smart Metering Entity charges paid to the IESO and the amounts billed to EPLC customers.

9.4.3 Account 1568: LRAMVA

EPLC requests disposition of Account 1568 in the amount of $520,868 as a collection from customers, including interest up to April 30th, 2018. Details of the requested claim can be found below as Figure 8.

Figure 8 – Account 1568 Claim

Description	Principal	Interest	Total
December 31st, 2016 Balance	$ 504,108	$ 9,392	$ 513,500
Adjustments	$ -	$ -	$ -
Balance for Disposition	**$ 504,108**	**$ 9,392**	**$ 513,500**
Interest January to December 2017		$ 5,545	$ 5,545
Interest January to April 2018		$ 1,823	$ 1,823
Total Claim	**$ 504,108**	**$ 16,760**	**$ 520,868**

EPLC uses this account to accrue lost revenue from Conservation and Demand Management activities. Further details relating to EPLC's LRAMVA claim can be found in Exhibit 4. EPLC's claim is based on Evaluation, Measurement and Verification by the Independent Electricity System Operator. EPLC's previously approved LRAMVA claims are also included as Attachment 9-B.

9.4.4 Account 1580: Wholesale Market Services Variance Account

EPLC requests disposition of Account 1580 in the amount of $851,478 to be refunded to customers, including interest up to April 30th, 2018. Details of the requested claim can be found below as Figure 9.

Figure 9 – Account 1580 Claim

Description	Principal	Interest	Total
December 31st, 2016 Balance	$ (822,759)	$ (16,693)	$ (839,452)
Adjustments	$ -	$ -	$ -
Balance for Disposition	**$ (822,759)**	**$ (16,693)**	**$ (839,452)**
Interest January to December 2017		$ (9,050)	$ (9,050)
Interest January to April 2018		$ (2,975)	$ (2,975)
Total Claim	**$ (822,759)**	**$ (28,719)**	**$ (851,478)**

EPLC uses this account to record the variances between the Wholesale Market Service charges paid to the IESO and the amounts billed to EPLC customers. EPLC has traditionally and consistently used the accrual approach for this account.

9.4.5 Account 1580: WMS Sub-Account CBR Class B

EPLC requests disposition of Account 1580 in the amount of $133,919 as a collection from customers, including interest up to April 30th, 2018. Details of the requested claim can be found below as Figure 10.

Figure 10 – Account 1580 Sub-Account CBR Class B Claim

Description	Principal	Interest	Total
December 31st, 2016 Balance	$ 131,549	$ 447	$ 131,996
Adjustments	$ -	$ -	$ -
Balance for Disposition	**$ 131,549**	**$ 447**	**$ 131,996**
Interest January to December 2017		$ 1,447	$ 1,447
Interest January to April 2018		$ 476	$ 476
Total Claim	**$ 131,549**	**$ 2,370**	**$ 133,919**

EPLC uses this account to record the variances between the Wholesale Market Service charges paid to the IESO and the amounts billed specifically to Class B Global Adjustment EPLC customers. EPLC has traditionally and consistently used the accrual approach for this account.

9.4.6 Account 1584: Retail Transmission Network Variance Account

EPLC requests disposition of Account 1584 in the amount of $441,726 to be refunded to customers, including interest up to April 30th, 2018. Details of the requested claim can be found below as Figure 11.

Figure 11 – Account 1584 Claim

Description	Principal	Interest	Total
December 31st, 2016 Balance	$ (395,066)	$ (40,886)	$ (435,952)
Adjustments	$ -	$ -	$ -
Balance for Disposition	**$ (395,066)**	**$ (40,886)**	**$ (435,952)**
Interest January to December 2017		$ (4,346)	$ (4,346)
Interest January to April 2018		$ (1,429)	$ (1,429)
Total Claim	**$ (395,066)**	**$ (46,660)**	**$ (441,726)**

EPLC uses this account to record the variances between the Retail Transmission Network charges paid to HONI and the amounts billed EPLC customers.

9.4.7 Account 1586: Retail Transmission Connection Variance Account

EPLC requests disposition of Account 1586 in the amount of $413,611 as a collection from customers, including interest up to April 30th, 2018. Details of the requested claim can be found below as Figure 12.

Figure 12 – Account 1586 Claim

Description	Principal	Interest	Total
December 31st, 2016 Balance	$ 421,225	$ (13,771)	$ 407,454
Adjustments	$ -	$ -	$ -
Balance for Disposition	**$ 421,225**	**$ (13,771)**	**$ 407,454**
Interest January to December 2017		$ 4,633	$ 4,633
Interest January to April 2018		$ 1,523	$ 1,523
Total Claim	**$ 421,225**	**$ (7,614)**	**$ 413,611**

EPLC uses this account to record the variances between the Retail Transmission Connection charges paid to HONI and the amounts billed EPLC customers.

9.4.8 Account 1588: Cost of Power Variance Account

EPLC requests disposition of Account 1588 in the amount of $2,788,212 to be refunded to customers, including interest up to April 30th, 2018. Details of the requested claim can be found below as Figure 13.

Figure 13 – Account 1588 Claim

Description	Principal	Interest	Total
December 31st, 2016 Balance	$ (3,005,038)	$ 260,749	$ (2,744,289)
Adjustments	$ -	$ -	$ -
Balance for Disposition	**$ (3,005,038)**	**$ 260,749**	**$ (2,744,289)**
Interest January to December 2017		$ (33,055)	$ (33,055)
Interest January to April 2018		$ (10,868)	$ (10,868)
Total Claim	**$ (3,005,038)**	**$ 216,826**	**$ (2,788,212)**

EPLC uses this account to record the variances between the amounts it pays the IESO and HONI for electricity and the amounts billed EPLC customers. Variances are generally the result of timing and quantity variances. EPLC has traditionally and consistently used the accrual approach for this account. EPLC is currently following the guidance of the Board's May 23, 2017 letter pertaining to the period that is being requested above for Account 1588.

9.4.9 Account 1589: Global Adjustment Variance Account

EPLC requests disposition of Account 1589 in the amount of $529,057 as a collection from customers, including interest up to April 30th, 2018. Details of the requested claim can be found below as Figure 14.

Figure 14 – Account 1589 Claim

Description	Principal	Interest	Total
December 31st, 2016 Balance	$ 810,446	$ (293,235)	$ 517,211
Adjustments	$ -	$ -	$ -
Balance for Disposition	**$ 810,446**	**$ (293,235)**	**$ 517,211**
Interest January to December 2017		$ 8,915	$ 8,915
Interest January to April 2018		$ 2,931	$ 2,931
Total Claim	**$ 810,446**	**$ (281,389)**	**$ 529,057**

EPLC uses this account to record the variances between the amounts it pays the IESO and HONI for electricity and the amounts billed EPLC customers. Variances are generally the result of timing and quantity variances. EPLC does not have any Class A Global Adjustment customers for the disposition period defined above however does have them effective 2017. EPLC is in the process of upgrading its processes to be able to account for this new classification of customer. EPLC has traditionally and consistently used the accrual approach for this account. EPLC is currently following the guidance of the Board's May 23, 2017 letter pertaining to the period that is being requested above for Account 1589.

EPLC settles with the IESO for Global Adjustment ("GA"). GA is currently applicable to all provincial customers who pay the Hourly Ontario Energy Price ("HOEP") or have signed a retail contract. GA accounts for the differences between the market price and the rates paid to both regulated and contracted generators along with other provincial items such as CDM programs.

The GA varies from month to month as a result of movement in HOEP and generator contractual terms. GA charges are currently based on two (2) primary categories:

- **Class A Customers:** Class A GA customers were originally defined as customers with peak demand greater than 5 MW. Recently, the Province has made changes to eligibility requirements of the Class A classification to allow customers with a peak demand greater than 1 MW and targeted customers with peak demand greater than 500 kW to opt-in to this designation. For the purpose of this application and for historical balances related to account 1589, Class A GA customers did not contribute to any of the existing balances since EPLC did not previously have any Class A GA customers.

- **Class B Customers:** Class B GA customers include customers with peak demand below 5MW (or who have opted into this category) and residential and business customers who have a retail contract for electricity. As of December 31st, 2016, all of EPLC's larger volume customers were included as Class B. For Class B GA customers, the IESO provides three variations of the GA which are to be used by distributors to bill customers which include:

    - **1st Estimate:** The IESO publishes the 1st Estimate for the upcoming month on the last business day of the preceding month (ie. 1st Estimate for July is published at the end of June). EPLC bills all customers classes based on the 1st Estimate.

    - **2nd Estimate:** The IESO publishes the 2nd Estimate on the last business day of a given month (ie. 2nd Estimate for July is published on the last day of July). EPLC uses the 2nd Estimate for settlement purposes and does not currently bill any customer classes based on the 2nd estimate.

- **Actual GA:** The IESO publishes the Actual GA rate on the 10th business day of each following month (ie the Actual GA rate for July is published on the 10th business day of August). EPLC does not currently bill any customers based on the Actual GA rate.

Before the 4th business day of each month, EPLC submits a reconciliation of all purchases and consumption for its service territory to the IESO. The purchase data is sourced from EPLC's Advanced Metering Infrastructure system which ensures the correct consumption and pricing information is submitted, including considerations for embedded generation. The consumption data is sourced from EPLC's Customer Information System and the data is then segregated by RPP and Non-RPP. EPLC utilizes an accrual accounting estimate to account for the remaining unbilled portion of consumption for both the RPP and Non-RPP designations.

EPLC uses the IESO reconciliation mentioned above as the basis for its monthly accounting accrual entries and reverses these accruals when the actual IESO invoice is received.

EPLC has completed the IESO RPP Self-Certification process required by all distributors which is included as Attachment 9-D of this Exhibit.

9.4.10 Account 1595 (2010): Disposition of Regulatory Balances

EPLC requests disposition of Account 1595 (2010) in the amount of $244,523 to be refunded to customers, including interest up to April 30th, 2018. Details of the requested claim can be found below as Figure 15.

Figure 15 – Account 1595 (2010) Claim

Description	Principal	Interest	Total
December 31st, 2016 Balance	$ (174,821)	$ (67,147)	$ (241,968)
Adjustments	$ -	$ -	$ -
Balance for Disposition	**$ (174,821)**	**$ (67,147)**	**$ (241,968)**
Interest January to December 2017		$ (1,923)	$ (1,923)
Interest January to April 2018		$ (632)	$ (632)
Total Claim	**$ (174,821)**	**$ (69,702)**	**$ (244,523)**

EPLC uses this account to record the disposition of DVA balances that were previously approved by the Board for refund or recovery. EPLC uses the appropriate sub-account listed herein as subsections 9.4.10 through 9.4.12 to track the various years where dispositions were approved.

The amounts requested for disposition in Figure 15 above relate to residual balances from rate riders in 2010.

9.4.11 Account 1595 (2012): Disposition of Regulatory Balances

EPLC requests disposition of Account 1595 (2012) in the amount of $195,924 as a collection from customers, including interest up to April 30th, 2018. Details of the requested claim can be found below as Figure 16.

Figure 16 – Account 1595 (2012) Claim

Description	Principal	Interest	Total
December 31st, 2016 Balance	$ 149,130	$ 44,614	$ 193,744
Adjustments	$ -	$ -	$ -
Balance for Disposition	**$ 149,130**	**$ 44,614**	**$ 193,744**
Interest January to December 2017		$ 1,640	$ 1,640
Interest January to April 2018		$ 539	$ 539
Total Claim	**$ 149,130**	**$ 46,794**	**$ 195,924**

EPLC uses this account to record the disposition of DVA balances that were previously approved by the Board for refund or recovery. EPLC uses the appropriate sub-account listed herein as subsections 9.4.10 through 9.4.12 to track the various years where dispositions were approved.

The amounts requested for disposition in Figure 16 above relate to residual balances from rate riders in 2012.

9.4.12 Account 1595 (2014): Disposition of Regulatory Balances

EPLC requests disposition of Account 1595 (2014) in the amount of $20,303 to be refunded to customers, including interest up to April 30th, 2018. Details of the requested claim can be found below as Figure 17.

Figure 17 – Account 1595 (2014) Claim

Description	Principal	Interest	Total
December 31st, 2016 Balance	$ 2,219	$ (22,555)	$ (20,336)
Adjustments	$ -	$ -	$ -
Balance for Disposition	**$ 2,219**	**$ (22,555)**	**$ (20,336)**
Interest January to December 2017		$ 24	$ 24
Interest January to April 2018		$ 8	$ 8
Total Claim	**$ 2,219**	**$ (22,523)**	**$ (20,303)**

EPLC uses this account to record the disposition of DVA balances that were previously approved by the Board for refund or recovery. EPLC uses the appropriate sub-account listed herein as subsections 9.4.10 through 9.4.12 to track the various years where dispositions were approved.

The amounts requested for disposition in Figure 17 above relate to residual balances from rate riders in 2014.

9.5 Group Two Account Analysis

EPLC last disposed of various Group Two Accounts as part of its 2010 Cost of Service filing (EB-2009-0143) for 2009 balances.

The subsequent subsections of 9.4 below detail EPLC's various disposition claims by Group Two Account currently in use.

9.5.1 Account 1508: Other Regulatory Assets

EPLC requests disposition of Account 1508 in the amount of $291,829 to be refunded to customers, including interest up to April 30th, 2018. Details of the requested claim can be found below as Figure 18.

Amounts in 1508 relate solely to deferred IFRS transition costs. Further breakdown of these costs can be found in Attachment 9-C of this Exhibit consistent with Appendix 2-YA.

Figure 18 – Account 1508 Claim

Description	Principal	Interest	Total
December 31st, 2016 Balance	$ (275,453)	$ (12,350)	$ (287,803)
Adjustments	$ -	$ -	$ -
Balance for Disposition	**$ (275,453)**	**$ (12,350)**	**$ (287,803)**
Interest January to December 2017		$ (3,030)	$ (3,030)
Interest January to April 2018		$ (996)	$ (996)
Total Claim	**$ (275,453)**	**$ (16,376)**	**$ (291,829)**

9.5.2 Account 1518 RCVA Retail Account

EPLC requests disposition of Account 1508 in the amount of $166,920 as a collection from customers, including interest up to April 30th, 2018. Details of the requested claim can be found below as Figure 19.

Figure 19 – Account 1518 Claim

Description	Principal	Interest	Total
December 31st, 2016 Balance	$ 158,620	$ 5,982	$ 164,602
Adjustments	$ -	$ -	$ -
Balance for Disposition	**$ 158,620**	**$ 5,982**	**$ 164,602**
Interest January to December 2017		$ 1,745	$ 1,745
Interest January to April 2018		$ 574	$ 574
Total Claim	**$ 158,620**	**$ 8,300**	**$ 166,920**

EPLC uses Account 1518 for the purpose of recording revenues and expenses associated with distributor-consolidated billing, retailer-consolidated billing and the establishing of service agreements;

9.5.3 Account 1525 Misc. Deferred Debits

EPLC requests disposition of Account 1525 in the amount of $85,107 as a collection from customers, including interest up to April 30th, 2018. Details of the requested claim can be found below as Figure 20.

Figure 20 – Account 1525 Claim

Description	Principal	Interest	Total
December 31st, 2016 Balance	$ 83,197	$ 694	$ 83,891
Adjustments	$ -	$ -	$ -
Balance for Disposition	**$ 83,197**	**$ 694**	**$ 83,891**
Interest January to December 2017		$ 915	$ 915
Interest January to April 2018		$ 301	$ 301
Total Claim	**$ 83,197**	**$ 1,910**	**$ 85,107**

EPLC uses Account 1525 for the purpose of tracking costs of previous rate rebasing applications that were subsequently deferred, that added value to this Application and were not counted as part of Board Appendix 2-M (Regulatory Costs).

9.5.4 Account 1531 Renewable Generation Connection Capital

EPLC requests disposition of Account 1531 in the amount of $70,602 as a collection from customers, including interest up to April 30th, 2018. Details of the requested claim can be found below as Figure 21.

Figure 21 – Account 1531 Claim

Description	Principal	Interest	Total
December 31st, 2016 Balance	$ 68,938	$ 656	$ 69,594
Adjustments	$ -	$ -	$ -
Balance for Disposition	**$ 68,938**	**$ 656**	**$ 69,594**
Interest January to December 2017		$ 758	$ 758
Interest January to April 2018		$ 249	$ 249
Total Claim	**$ 68,938**	**$ 1,664**	**$ 70,602**

EPLC uses Account 1531 for the purpose of recording expenses relating to specific, eligible renewable generation connection costs consistent with the APH.

The Burden Reduction Act, 2017 Schedule 10, Section (5) amended section 79.1 (1) which required the OEB to provide rate protection for costs incurred to make an eligible investment in order to connect a qualifying generation facility.

As a result, EPLC has not included Board Appendices 2-FA and 2-FC since the Renewable Expansion Investment costs are below materiality in each respective year. Further details about how EPLC intends to recover these costs are further described in Exhibit 9 of this Application.

9.5.5 Account 1534 Smart Grid Capital

EPLC requests disposition of Account 1534 in the amount of $533,318 as a collection from customers, including interest up to April 30th, 2018. Details of the requested claim can be found below as Figure 22.

Figure 22 – Account 1534 Claim

Description	Principal	Interest	Total
December 31st, 2016 Balance	$ 512,740	$ 13,084	$ 525,824
Adjustments	$ -	$ -	$ -
Balance for Disposition	**$ 512,740**	**$ 13,084**	**$ 525,824**
Interest January to December 2017		$ 5,640	$ 5,640
Interest January to April 2018		$ 1,854	$ 1,854
Total Claim	**$ 512,740**	**$ 20,578**	**$ 533,318**

Amounts in 1534 relate to investments made in conjunction with EPLC's Green Energy Act and Smart Grid Plan. Further information and breakdown of these costs can be found in Attachment 2-C of Exhibit2.

9.5.6 Account 1535 Smart Grid OM&A

EPLC requests disposition of Account 1535 in the amount of $97,407 as a collection from customers, including interest up to April 30th, 2018. Details of the requested claim can be found below as Figure 23.

Figure 23 – Account 1535 Claim

Description	Principal	Interest	Total
December 31st, 2016 Balance	$ 91,626	$ 4,442	$ 96,068
Adjustments	$ -	$ -	$ -
Balance for Disposition	**$ 91,626**	**$ 4,442**	**$ 96,068**
Interest January to December 2017		$ 1,008	$ 1,008
Interest January to April 2018		$ 331	$ 331
Total Claim	**$ 91,626**	**$ 5,781**	**$ 97,407**

Amounts in 1535 relate to investments made in conjunction with EPLC's Green Energy Act and Smart Grid Plan. Further information and breakdown of these costs can be found in Attachment 2-C of Exhibit2.

9.5.7 Account 1548: RCVA Service Transaction Request

EPLC requests disposition of Account 1548 in the amount of $2,198 to be refunded to customers, including interest up to April 30th, 2018. Details of the requested claim can be found below as Figure 24.

Figure 24 – Account 1548 Claim

Description	Principal	Interest	Total
December 31st, 2016 Balance	$ (1,915)	$ (255)	$ (2,170)
Adjustments	$ -	$ -	$ -
Balance for Disposition	**$ (1,915)**	**$ (255)**	**$ (2,170)**
Interest January to December 2017		$ (21)	$ (21)
Interest January to April 2018		$ (7)	$ (7)
Total Claim	**$ (1,915)**	**$ (283)**	**$ (2,198)**

EPLC uses Account 1548 for the purpose of recording revenues and expenses associated with Service Transaction Request services (ie. Request fees, processing fees, information request fees, default fees, etc.).

9.5.8 Account 1555: Smart Meter Capital

As part of the 2015 IRM (EB-2014-0072), EPLC applied for final disposition of Smart Metering Costs. Also in its 2015 IRM, EPLC stated that stranded meters would be brought forward at its next Cost of Service Application.

In this Application, EPLC is seeking disposition of $1,095,650 which represents the Net Book Value of stranded metering assets as at April 30th, 2018.

EPLC has prepared this section in accordance with the Board's *Guideline G-2011-0001, Smart Meter Funding and Cost Recovery – Final Disposition (December 15th, 2011)*.

As per Appendix A-1 of Board Guideline G-2011-0001, EPLC left stranded meters in Account 1860 and did not move any associated costs to Account 1555. The amount used in the calculation of stranded meters is based on balances accumulated in Account 1860 including labour, labour overhead, materials and expenses and vehicle related expenses, all allocated at standard EPLC rates. EPLC has been diligent in the deployment of smart meters as indicated by its installed cost below the provincial average.

Accumulated amortization of stranded metering assets was derived by estimating the year of installation, factoring the actual year of removal and using a 25 year useful life up to April 30th, 2018.

No carrying charges have been recorded for stranded metering assets, in accordance with the Accounting Procedures Handbook.

Further information about EPLC's proposed rate rider for the recovery of stranded meters is described below in section 9.7.3 of this Exhibit.

9.5.9 Account 1572: Extra-Ordinary Event Costs

EPLC requests disposition of Account 1572 in the amount of $88,411 as a collection from customers, including interest up to April 30th, 2018. Details of the requested claim can be found below as Figure 26.

Figure 26 – Account 1572 Claim

Description	Principal	Interest	Total
December 31st, 2016 Balance	$ 80,414	$ 6,822	$ 87,236
Adjustments	$ -	$ -	$ -
Balance for Disposition	**$ 80,414**	**$ 6,822**	**$ 87,236**
Interest January to December 2017		$ 885	$ 885
Interest January to April 2018		$ 291	$ 291
Total Claim	**$ 80,414**	**$ 7,997**	**$ 88,411**

EPLC uses Account 1572 for the purpose of recording expenses associated with Extra-Ordinary Events. EPLC experienced one Extra-Ordinary Event in 2010 when EPLC's service territory in Leamington experienced a tornado. The amount requested for disposition represents the costs associated with remedying the effects of the Leamington Tornado on EPLC's distribution system.

9.5.10 Account 1576: Accounting Changes Under CGAAP

EPLC requests disposition of Account 1576 in the amount of $4,394,960 to be refunded to customers. Details of the requested claim can be found below as Figure 27.

Figure 27 – Account 1576 Claim

Description	Principle Balance	Interest	Total
December 31st, 2016 Balance	$ (2,558,929)	$ -	$ (2,558,929)
Adjustments	$ (867,291)	$ -	$ (867,291)
Revised December 31st, 2016 Balance	**$ (3,426,220)**	**$ -**	**$ (3,426,220)**
2017 Forecast	$ (528,928)	$ -	$ (528,928)
Forecasted December 31st, 2017 Balar	**$ (3,955,148)**	**$ -**	**$ (3,955,148)**
WACC			5.56%
Number of Years for Disposition			2
Return on Rate Base			$ (439,812)
Total Claim			**$ (4,394,960)**

The Board issued a letter on July 17, 2012 providing direction to electricity distributors that had chosen to defer the adoption of IFRS and remain on CGAAP. The letter mandated IFRS compliant capitalization and depreciation accounting changes as of January 1st, 2013. The Board also established Account 1576 which allowed electricity distributors to record the financial differences that arose as a result of the accounting changes.

The Board issued another letter on June 25, 2013 which required a rate of return to be applied to the balance of 1576 upon its disposition in rates.

Consistent with Board Appendix 2-EC and included as Attachment 9-E of this Exhibit, EPLC has calculated the differences as a result of the accounting changes, which are summarized in Figure 29 above.

EPLC proposes to dispose of its Account 1576 balance over a two year period which will allow a greater smoothing of the credit to customers and reduce the customer impact in year three.

9.5.11 Account 1592: PILs & Tax Variances

EPLC requests disposition of Account 1592 in the amount of $213,674 to be refunded to customers, including interest up to April 30th, 2018. Details of the requested claim can be found below as Figure 28.

Figure 28 – Account 1592 Claim

Description	Principal	Interest	Total
December 31st, 2016 Balance	$ (202,758)	$ (7,952)	$ (210,710)
Adjustments	$ -	$ -	$ -
Balance for Disposition	**$ (202,758)**	**$ (7,952)**	**$ (210,710)**
Interest January to December 2017		$ (2,230)	$ (2,230)
Interest January to April 2018		$ (733)	$ (733)
Total Claim	**$ (202,758)**	**$ (10,916)**	**$ (213,674)**

EPLC uses Account 1592 to track the incremental input tax credits received on distribution revenue requirement items that were previously subjected to PST and were subsequently moved to HST. As directed by the Board, distributors are to share 50% of the savings with customers. These savings are reflected above in Figure 29.

9.6 Account Status

9.6.1 New Accounts

EPLC is not currently seeking the creation of any new DVAs.

9.6.2 Continuation of Accounts

EPLC plans to use the following Group One accounts, which are all currently active. EPLC notes that the Board may require the use of new accounts, from time to time.

- Account 1550 – Low Voltage;
- Account 1551 – Smart Metering Entity;
- Account 1568 – LRAMVA;
- Account 1580 – RSVA WMS;
- Account 1584 – RSVA Retail Transmission Network;
- Account 1586 – RSVA Retail Transmission Connection;
- Account 1588 – RSVA Power;
- Account 1589 – RSVA Global Adjustment;
- Account 1595 – Disposition of Regulatory Balances;

EPLC also plans to use the following Group Two accounts (if and where necessary):

- Account 1508 – Other Regulatory Assets;
- Account 1518 – RCVA Retail;
- Account 1531 – Renewable Generation Connection Capital;
- Account 1548 – RCVA STR;
- Account 1572 – Extra-Ordinary Costs;
- Account 1582 – RSVA One Time;
- Account 1592 – PILs and Tax Variance;

9.6.3 Discontinuation of Accounts

EPLC proposes the discontinuation of the following accounts. Upon approval of disposition of the accounts below, these accounts will no longer be required.

- Account 1508 – Sub-Account Deferred IFRS Transition costs
- Account 1534 – Smart Grid Capital;

- Account 1535 – Smart Grid OM&A
- Account 1555 – Smart Meter Capital and Recovery Offset;
- Account 1576 – Accounting Changes Under CGAAP;

9.7 Calculation of Rate Riders

9.7.1 Overview

As part of this Application, EPLC is currently seeking to dispose of its Group One and various Group 2 accounts summarized above. This section will outline EPLC's methodology in determining and calculating the Rate Riders required for recovery and reimbursement to customers.

9.7.2 Billing Determinants Utilized

For the purpose of billing determinants used to calculate Rate Riders in this Application, EPLC used the 2018 Test Year data presented below ass Figure 29, which is consistent with the Load Forecast presented in Exhibit 3 of this Application.

Figure 29 – 2018 Test Year Billing Determinants

Rate Class	2018		
	Cust/Conn	kWh	kW
Residential	27,484	245,374,118	-
GS<50	1,977	62,707,450	-
GS>50	219	176,280,306	446,253
Embedded Distributor	3	29,865,554	80,869
Street Light	2,740	2,799,882	8,848
Sentinel Light	173	335,758	2,080
USL	140	1,554,368	-
Total	**32,736**	**518,917,436**	**538,051**

The Board's Filing Requirements indicate that:

- *"…distributors must establish separate rate riders to recover the balances in the RSVAs from Market Participants ("MPs") who must not be allocated the RSVA account balances related to charges for which the MPs settle directly with the IESO.";*

- *"Distributors who serve Class A customers per O.Reg 429/04 must propose an appropriate allocation for the recovery of the global adjustment variance balance based on their settlement process with the IESO.";*

As of December 31st, 2016, EPLC has zero Class A customers and three (3) WMP customers that currently reside in the GS >50-4,999 kW rate class. Figure 30 below summarizes the WMP consideration.

Figure 30 – 2018 WMP Billing Determinants

Rate Class	Cust/Conn	kWh	kW
Residential	0	-	-
GS<50	0	-	-
GS>50	3	11,323,656	19,965
Embedded Distributor	0	-	-
Street Light	0	-	-
Sentinel Light	0	-	-
USL	0	-	-
Total	**3**	**11,323,656**	**19,965**

Also, for the purpose of this Application, EPLC has excluded the proposed Embedded Distributor rate class from the proposed dispositions calculated herein. EPLC settles the actual global adjustment rate with the Embedded Distributor, does not propose to charge the rate class any RTSR charges and submits that the Embedded Distributor does not materially contribute to any other Group One or Group Two variance.

In order to properly determine the global adjustment Rate Riders, an appropriate split between RPP and Non-RPP customers was calculated for the 2018 Test Year by determining the 2016 Actual Non-RPP results as a percentage of total 2016 Actual consumption by rate class. EPLC carried this proportion forward into the 2018 Test Year as summarized in Figure 31 below.

Figure 31 – 2018 Non-RPP Billing Determinants

Rate Class	% of 2016 kWh	2018 Non-RPP kWh	% of 2016 kW	2018 Non-RPP kW
Residential	4.52%	11,097,095	0.00%	-
GS<50	27.06%	16,969,882	0.00%	-
GS>50	90.18%	158,969,973	90.18%	402,432
Embedded Distributor	100.00%	29,865,554	100.00%	80,869
Street Light	100.00%	2,799,882	100.00%	8,848
Sentinel Light	8.74%	29,354	8.74%	182
USL	30.10%	467,938	0.00%	-
Total		**220,199,678**		**492,331**

After adjusting for WMPs and Non-RPP customers, the resulting billing determinants were derived as per Figure 32 below.

Figure 32 – 2018 Adjusted Billing Determinants

Rate Class	Cust/Conn	kWh	kW	Non-RPP kWh	Non-RPP kW
Residential	27,484	245,374,118	-	11,097,095	-
GS<50	1,977	62,707,450	-	16,969,882	-
GS>50	216	164,956,650	426,288	147,646,317	382,467
GS>50 - WMP	3	11,323,656	19,965	11,323,656	19,965
Embedded Distributor	3	29,865,554	80,869	29,865,554	80,869
Street Light	2,740	2,799,882	8,848	2,799,882	8,848
Sentinel Light	173	335,758	2,080	29,354	182
USL	140	1,554,368	-	467,938	-
Total	**32,736**	**518,917,436**	**538,051**	**220,199,678**	**492,331**
Total Excluding Embedded Distributor		489,051,882		190,334,124	
Total Excluding Embedded Distributor & WMP		477,728,226		179,010,468	

9.7.3 Proposed Rate Riders

EPLC has calculated the Rate Riders, each further described below in this Section, in accordance with the Electricity Distributor's Deferral and Variance Account Review, provided by the Board. These Rate Riders can be summarized as follows:

- Disposition of Group 1 Deferral / Variance Accounts (excluding GA);
- Disposition of Group 1 Deferral / Variance Accounts (excluding GA and WMP);
- Disposition of RSVA Power – Global Adjustment;
- Disposition of Group 2 Accounts;
- Disposition of deferrals resulting from accounting changes under CGAAP;
- Disposition of LRAM/LRAMVA Deferrals;

Group 1 Deferral / Variance Accounts (excl. GA) Rate Riders

Figure 33 below outlines EPLC's calculation of Rate Riders, by class, for the disposition of the following Group 1 Deferral/Variance Accounts:

- Account 1550 – Allocated based on kWh to all customer classes excluding Embedded Distributor;

- Account 1551 – Allocated based on kWh to the residential and General Service <50 kW customer classes only;
- Account 1584 – Allocated based on kWh to all customer classes excluding Embedded Distributor;
- Account 1586 - Allocated based on kWh to all customer classes excluding Embedded Distributor;
- Account 1595 - Allocated based on kWh to all customer classes excluding Embedded Distributor;

Figure 33 – Proposed Group 1 Deferral/Variance Account Rate Riders

Rate Class	Units	Allocated Balance	Proposed Rate Rider
Residential	kWh	$ (601,105)	$ (0.0024)
GS<50	kWh	$ (146,307)	$ (0.0023)
GS>50	kW	$ 1,059,710	$ 2.3747
Embedded Distributor	kW	$ -	$ -
Street Light	kW	$ (5,261)	$ (0.5947)
Sentinel Light	kW	$ (801)	$ (0.3852)
USL	kWh	$ (3,381)	$ (0.0022)
Total		**$ 302,854**	

EPLC proposes to dispose of the balances above over one year beginning May 1st, 2018.

Group 1 Deferral / Variance Accounts (excl. GA) – Non-WMP Rate Riders

Figure 34 below outlines EPLC's calculation of Rate Riders, by class, for the disposition of the following Group 1 Deferral/Variance Accounts:

- Account 1580 – Allocated based on kWh to all customer classes except WMP customers;
- Account 1588 – Allocated based on kWh to all customer classes except WMP customers;

Figure 34 – Proposed Group 1 Deferral/Variance Account – Non-WMP Rate Rider

Rate Class	Units	Allocated Balance	Proposed Rate Rider
Residential	kWh	$ -	$ -
GS<50	kWh	$ -	$ -
GS>50	kW	$ (1,210,522)	$ (2.8397)
Embedded Distributor	kW	$ -	$ -
Street Light	kW	$ -	$ -
Sentinel Light	kW	$ -	$ -
USL	kWh	$ -	$ -
Total		**$ (1,210,522)**	

EPLC proposes to dispose of the balances above over one year beginning May 1st, 2018.

RSVA Power – Global Adjustment Rate Rider

Figure 35 below outlines EPLC's calculation of Rate Riders, by class, for the disposition of Account 1589 allocated to Non-WMP customers. Balances were allocated based on kWh and as directed by the Board, the Rate Rider for all customer classes will be consumption based.

Figure 35 – Proposed RSVA Power – Global Adjustment Rate Rider

Rate Class	Units	Allocated Balance	Proposed Rate Rider
Residential	kWh	$ 32,797	$ 0.0030
GS<50	kWh	$ 50,154	$ 0.0030
GS>50	kWh	$ 436,362	$ 0.0030
Embedded Distributor	kWh	$ -	$ -
Street Light	kWh	$ 8,275	$ 0.0030
Sentinel Light	kWh	$ 87	$ 0.0030
USL	kWh	$ 1,383	$ 0.0030
Total		**$ 529,057**	

EPLC proposes to dispose of the balances above over one year beginning May 1st, 2018.

Group 2 Account Rate Rider

Figure 36 below outlines EPLC's calculation of Rate Riders, by class, for the disposition of the following Group 2 Accounts:

- Account 1508 – Allocated based on kWh to all customer classes excluding Embedded Distributor;
- Account 1518 – Allocated based on kWh to all customer classes excluding Embedded Distributor;
- Account 1525 – Allocated based on kWh to all customer classes excluding Embedded Distributor;
- Account 1531 – Allocated based on kWh to all customer classes excluding Embedded Distributor;
- Account 1534 – Allocated based on kWh to all customer classes excluding Embedded Distributor;
- Accoutn 1535 – Allocated based on kWh to all customer classes excluding Embedded Distributor;
- Account 1548 – Allocated based on kWh to all customer classes excluding Embedded Distributor;
- Account 1555 – Allocated based on kWh to all customer classes excluding Embedded Distributor;
- Account 1572 – Allocated based on kWh to all customer classes excluding Embedded Distributor;
- Account 1592 – Allocated based on kWh to all customer classes excluding Embedded Distributor;

Figure 36 – Proposed Group 2 Account Rate Rider

Rate Class	Units	Allocated Balance	Proposed Rate Rider
Residential	# Customers	$ (83,753)	$ (0.25)
GS<50	kWh	$ (21,404)	$ (0.0003)
GS>50	kW	$ (60,169)	$ (0.1348)
Embedded Distributor	kW	$ -	$ -
Street Light	kW	$ (956)	$ (0.0003)
Sentinel Light	kW	$ (115)	$ (0.0551)
USL	kWh	$ (531)	$ (0.0003)
Total		**$ (166,926)**	

EPLC proposes to dispose of the balances above over one year beginning May 1st, 2018.

Disposition of Accounting Changes Under CGAAP Rate Rider

Figure 37 below outlines EPLC's calculation of Rate Riders, by class, for the disposition of Account 1576 allocated to all customer classes. Balances were allocated based on kWh for all customer classes.

Figure 37 – Proposed CGAAP Accounting Changes Rate Rider

Rate Class	Units	Allocated Balance	Proposed Rate Rider
Residential	# Customers	$ (2,205,102)	$ (3.3430)
GS<50	kWh	$ (563,533)	$ (0.0045)
GS>50	kW	$ (1,584,177)	$ (1.7750)
Embedded Distributor	kW	$ -	$ -
Street Light	kW	$ (25,162)	$ (1.4219)
Sentinel Light	kW	$ (3,017)	$ (0.7253)
USL	kWh	$ (13,969)	$ (0.0045)
Total		**$ (4,394,960)**	

EPLC proposes to dispose of the balances above over two years beginning May 1st, 2018.

LRAM and LRAMVA Rate Rider

Figure 38 below outlines EPLC's calculation of Rate Riders, by class, for the disposition of Account 1576 allocated to the residential, General Service < 50 kW, General Service > 50 kW and Street Lighting customer classes. Balances were allocated based on kWh for all customer classes.

Figure 38 – Proposed LRAM/LRAMVA Rate Rider

Rate Class	Units	Allocated Balance	Proposed Rate Rider
Residential	kWh	$ 263,016	$ 0.0005
GS<50	kWh	$ 170,209	$ 0.0014
GS>50	kW	$ 78,672	$ 0.0881
Embedded Distributor	kW	$ -	$ -
Street Light	kW	$ 8,973	$ 0.5070
Sentinel Light	kW	$ -	$ -
USL	kWh	$ -	$ -
Total		**$ 520,870**	

EPLC proposes to dispose of the balances above over two years beginning May 1st, 2018.

Stranded Meter Rate Rider ("SMRR")

Figure 39 below outlines EPLC's calculation of Rate Riders, by class, for the disposition of stranded meters in accordance with the Board's Guideline G-2011-0001, allocated to the residential and General Service < 50 kW customer classes. Balances were allocated based on number of customers for both customer classes.

Figure 39 – Proposed SMRR Rate Rider

Rate Class	Units	Allocated Balance	Proposed Rate Rider
Residential	# Customers	$ 1,022,126	$ 1.0331
GS<50	# Customers	$ 73,524	$ 1.0331
GS>50	kW	$ -	$ -
Embedded Distributor	kW	$ -	$ -
Street Light	kW	$ -	$ -
Sentinel Light	kW	$ -	$ -
USL	kWh	$ -	$ -
Total		**$ 1,095,650**	

EPLC proposes to dispose of the balances above over three years beginning May 1st, 2018.

Attachment 9-A

EPLC DVA Disposition Model

Ontario Energy Board

2018 Deferral/Variance Account Workform

Utility Name	Essex Powerlines Corporation
Service Territory	*Amherstburg, LaSalle, Leamington, Tecumseh*
Assigned EB Number	EB-2017-0039
Name of Contact and Title	Kristopher Taylor, Director of Corporate Strategy
Phone Number	519-946-2000
Email Address	ktaylor@essexpower.ca

General Notes

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

Ontario Energy Board

2018 Deferral/Variance Account Workform

Instructions for Tabs 2 to 7

Tab	Tab Details	Step	Instructions
2 - Continuity Schedule	This tab is the continuity schedule that shows all the accounts and the accumulation of the balances a utility has.	1	Complete the DVA continuity schedule. For all accounts, except for Account 1595, start inputting data from the year in which the GL balance was last disposed. For example, if in the 2017 rate application, DVA balances as at December 31, 2015 were approved for disposition, start the continuity schedule from 2015 by entering the closing 2014 balances in the Adjustments column under 2014. For all Account 1595 sub-accounts, complete the DVA continuity schedule for each Account 1595 vintage year that has a GL balance as at December 31, 2016 regardless of whether the account is being requested for disposition in the current application. For each Account 1595 sub-account, start inputting data from the year the sub-account started to accumulate a balance (i.e. the vintage year). For example, Account 1595 (2014) would have information starting in 2014, when the relevant balances approved for disposition were first transferred into Account 1595 (2014). The DVA continuity schedule currently starts from 2011, if a utility has an Account 1595 with a vintage year prior to 2011, then a separate schedule should be provided starting from the vintage year.
		2a	If you had any Class A customers at any point during the period that the Account 1589 GA balance accumulated (e.g. last disposition was for 2014 balances in the 2016 rate application, current balance requested for disposition accumulated from 2015 to 2016), check off the checkbox in cell BS13. If the checkbox is not checked off, then proceed to tabs 4 to 7 and complete the tabs accordingly. If the checkbox is checked off, tab 5.1 relating to Class A customer consumption will be generated, see step 7 to 10 below for further details.
		2b	If the checkbox in step 2a is checked off, another checkbox will pop up to the right of the checkbox. If you had any Class A customers at any point during the period that the Account 1580, sub-account CBR Class B balance accumulated (i.e. 2015 and 2016 or 2016), check off the checkbox. If the checkbox is not checked off, then the balance in the Account 1580, sub-account CBR Class B will be allocated and disposed with Account 1580 WMS, as a part of the general DVA rate rider. If the checkbox is checked off, then tab 5.3 will be generated. This tab will calculate the billing determinants applicable to Account 1580 sub-account CBR Class B, using information inputted in tab 5.1. See step 12 below for further details. The CBR Class B balance will be allocated in tab 5 and the rate rider will be calculated in tab 6.
		3	Enter the number of utility specific 1508 sub-accounts that are approved for the utility in the textbox in cell B50. The DVA continuity schedule will generate the number of utility specific 1508 sub-accounts starting in row 51. Input the name and the balances of the sub-account(s) starting in row 51. If a utility does not have utility specific 1508 sub-accounts, the generic 1508 sub-account Other will still be listed in the DVA continuity schedule. Check off the "check to dispose of account" checkbox in column BT for sub-accounts requested for disposition.
3. Appendix A	This tab shows the year end balance variances between the continuity schedule and that reported in the RRR.	4	Provide an explanation for the variances identified.
4 - Billing Determinant	This tab shows the billing determinants that will be used to allocate account balances and calculate rate riders.	5	Complete the billing determinant table. Note that columns O and P are generated when a utility indicates they have Class A customers in tab 2. Information in these columns are populated based on data from tab 5.1.
5 - Allocating Def-Var Balances	This tab allocates the DVA balance (except for CBR Class B if Class A customers exist).	6	Review the allocated balances to ensure the allocation is appropriate. Note that the allocations for Account 1589, Account 1580, sub-account CBR Class B will be determined after tabs 5.1 to 5.3a have been completed.
5.1 - Class A Data Consumption	This is a new tab that is to be completed if there were any Class A customers at any point during the period the GA balance accumulated. The tab also considers Class A/B transition customers. The data on this tab is used for the purposes of determining the GA rate rider, CBR Class B rate rider (if applicable), as well as customer specific GA and CBR Class B charges for transition customers (if applicable).	7	This tab is generated when the utility checks in tab 2 that they have Class A customers during the period that the GA balance accumulated. Under #1, enter the year the Account 1589 GA balance was last disposed.
		8	Under #2a, indicate whether you had any customers that transitioned between Class A and B during the period the Account 1589 GA balance accumulated. If no, proceed to #3b in step 10. If yes, #2b and tab 5.2 will be generated. Proceed to #2b. Under #2b, indicate whether you had any customers that transitioned between Class A and B during the period the Account 1580, sub-account CBR Class B balance accumulated. If no, proceed to #3a in step 9. If yes, tab 5.3a will be generated. Proceed to #3a in step 9.
		9	Under #3a, enter the number of transition customers during the period the Account 1589 GA balance accumulated. A table will be generated based on the number of customers. Complete the table accordingly for each transition customer identified (i.e. kWh/kW for half year periods, and the customer class during the half year). This data will automatically be used in the GA balance and CBR Class B balance allocation to transition customers in tabs 5.2 and 5.3a, respectively. Each transition customer identified in tab 5.1, table 3a will be assigned a customer number and the number will correspond to the same transition customers populated in tabs 5.2 and 5.3a. The data in tab 5.1 will also be used in the calculation of billing determinants in the allocation of GA and CBR Class B balances to the rate classes, as applicable.
		10	Under #3b, enter the number of customers who were Class A customers during the entire period since the year the Account 1589 GA balance accumulated (i.e. did not transition between Class A and B during the period). A table will be generated based on the number of customers. Complete the table accordingly for each Class A customer identified. This data will be used in the calculation of billing determinants in the allocation of GA and CBR Class B balances to the rate classes, as applicable.
5.2 - GA Allocation	This tab has been revised. It allocates the GA balance to each transition customer for the period in which these customers were Class B customers and contributed to the GA balance (i.e. former Class B customers who contributed to the GA balance but are now Class A customers and former Class A customers who are now Class B customers contributing to the GA balance).	11	This tab is generated when the utility indicates that they have transition customers in tab 5.1, #2a during the period where the GA balance accumulated. In row 20, enter the total Class B consumption which equals to Non-RPP consumption less WMP consumption and consumption for Class A customers (who were Class A for partial and full year). The rest of the information in this tab will be auto-populated and will calculate the customer specific allocation of the GA balance to transition customers in the bottom table. All transition customers who are allocated a specific GA amount are not to be charged the general Non-RPP Class B GA rate rider as calculated in tab 6.
5.3 - CBR	This is a new tab that calculates the CBR Class B rate rider if there were Class A customers at any point during the period that the CBR Class B balance accumulated.	12	This tab is generated when the utility checks in tab 2 that they have Class A customers during the period that Account 1580, sub-account CBR Class B balance accumulated. Select one of two options pertaining to the years in which the CBR Class B balance accumulated, either 2015 and 2016, or 2016 only in cell B13. The rest of the information in the tab is auto-populated and will be used in the calculation of the CBR Class B rate rider calculated in tab 6.
5.3a - CBR_B Allocation	This is a new tab that allocates the CBR Class B balance to each transition customer for the period in which these customers were Class B customers and contributed to the CBR Class B balance (i.e. former Class B customers who contributed to the balance but are now Class A customers and former Class A customers who are now Class B contributing to the balance).	13	This tab is generated when the utility indicates that they have transition customers in tab 5.1, #2b during the period where the CBR Class B balance accumulated. In row 20, enter the total Class B consumption which equals to total consumption less WMP consumption and consumption for Class A customers (who were Class A for partial and full year). The rest of the information in this tab will be auto-populated and will calculate the customer specific allocation of the CBR Class B balance to transition customers in the bottom table. Note that the transition customers for the GA may be different than the transition customers for CBR Class B as this would depend on the period in which the GA and CBR Class B balances accumulated. All transition customers who are allocated a specific CBR Class B amount is not to be charged the general CBR Class B rate rider.
6 - Calculation of Def-Var RR	This tab calculates all the applicable DVA ate riders.	14	Enter the proposed rate rider recovery period if different than the default 12 month period. For each rate class of each rate rider, select whether the rate rider is to be calculated on a kWh/kW or number of customers basis. The rest of the information in the tab is auto-populated and the rate riders are calculated accordingly .
7 + 7.a GA Analysis	This is a new GA Analysis Workform that is to be completed.	15	Complete tab 7.a according to the instructions in tab 7.

Ontario Energy Board

2018 Deferral/Variance Account Workform

This continuity schedule must be completed for each account and sub-account that the utili from the year in which the GL balance was last disposed. For example, if in the 2017 rate app Adjustment column under 2014. For each Account 1595 sub-account, start inputting data fro balances approved for disposition was first transferred into Account 1595 (2014). The DVA c vintage year. For any new accounts that have never been disposed, start inputting data from

Enter the number of utility specific Account 1508 sub-accounts that have been previously approved, regardless of whether disposition is being requested. If none, enter 1 and the generic sub-account will still be

1

Identify and name each sub-account and complete the continuity schedule in the line(s) generated in the continuity schedule. Indicate whether the sub-account is requested for

Account Descriptions	Account Number
Group 1 Accounts	
LV Variance Account	1550
Smart Metering Entity Charge Variance Account	1551
RSVA - Wholesale Market Service Charge[9]	1580
Variance WMS – Sub-account CBR Class A[9]	1580
Variance WMS – Sub-account CBR Class B[9]	1580
RSVA - Retail Transmission Network Charge	1584
RSVA - Retail Transmission Connection Charge	1586
RSVA - Power (excluding Global Adjustment)[12]	1588
RSVA - Global Adjustment [12]	1589
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595
Disposition and Recovery/Refund of Regulatory Balances (2012)[7]	1595
Disposition and Recovery/Refund of Regulatory Balances (2013)[7]	1595
Disposition and Recovery/Refund of Regulatory Balances (2014)[7]	1595
Disposition and Recovery/Refund of Regulatory Balances (2015)[7]	1595
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595
Not to be disposed of until a year after rate rider has expired and that balance has been audited	
Group 1 Sub-Total (including Account 1589 - Global Adjustment)	
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)	
RSVA - Global Adjustment 12	**1589**
Group 2 Accounts	
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508
Other Regulatory Assets - Sub-Account - Other	1508
Sub-account CBR class B - Principal	1508
Sub-account CBR class B - Interest	1508
	1508
	1508
Retail Cost Variance Account - Retail	1518
Misc. Deferred Debits	1525
Retail Cost Variance Account - STR	1548
Board-Approved CDM Variance Account	1567
Extra-Ordinary Event Costs	1572
Deferred Rate Impact Amounts	1574
RSVA - One-time	1582
Other Deferred Credits	2425
Group 2 Sub-Total	
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592
Total of Group 1 and Group 2 Accounts (including 1592)	
LRAM Variance Account[11]	**1568**
Total including Account 1568	
Renewable Generation Connection Capital Deferral Account[8]	1531
Renewable Generation Connection OM&A Deferral Account[8]	1532
Renewable Generation Connection Funding Adder Deferral Account	1533
Smart Grid Capital Deferral Account	1534
Smart Grid OM&A Deferral Account	1535
Smart Grid Funding Adder Deferral Account	1536
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555
Smart Meter OM&A Variance[4]	1556
Meter Cost Deferral Account (MIST Meters)[10]	1557
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575
Accounting Changes Under CGAAP Balance + Return Component[5]	1576

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: figure and credit balance are to have a negative figure) as per the related OEB decision.

1 For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transacti column.

2 Please provide explanations for the nature of the adjustments. If the adjustment relates to previously OEB Approved dispo

3 As per the January 6, 2011 Letter from the OEB regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does anticipate that licensed distributors that cannot adapt their invoices as of January 1, account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will be addressed throu

4 Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance A Meter Disposition and Cost Recovery (G-2011-0001)

5 The OEB requires that disposition of Account 1575 and Account 1576 shall require the use of separate rate riders. In the "A 1575 and 1576 rate rider calculation from the applicable Chapter 2-E appendix line "Amount included in Deferral and Varia

Depending on the disposition period, balances may exist in Account 1575 and Account 1576 even if the accounts have bee the case and leave the checkbox "Check to Dispose of Account" in the Total Claim column unchecked.

6 If the LDC's rate year begins on January 1, 2018, the projected interest is recorded from January 1, 2017 to December 31, decision. If the LDC's rate year begins on May 1, 2018, the projected interest is recorded from January 1, 2017 to April 30 2017 rate decision.

7 The individual sub-accounts as well as the total for all Account 1595 sub-accounts are to agree to the RRR data. Differenc For each Account 1595 sub-account, the transfer of the balance approved for disposition into Account 1595 is to be recor The two are not to be netted together and recorded in one column in the first year.
The audited balance in the account is only to be disposed a year after the recovery/refund period has been completed. Ge 1595 is only to be disposed once on a final basis. No further dispositions of these accounts are generally expected therea account is requested for disposition.

8 As per the Filing Requirements for 2018 rate applications, request for rate protection on eligible investments are subject to portion of Account 1531 should be transferred to rate base. The Direct Benefits portion of Account 1532 should be include for reference only. Account 1532 is included in the Group 2 allocation of balances that are used to calculate the rate riders.

9 Account 1580 RSVA WMS balance inputted into this schedule is to exclude any amounts relating to CBR. CBR amounts ar 1580, sub-account CBR Class A, accounting guidance for this sub-account is to be followed. If a balance exists for Accour

10 Account 1557 is to be recovered in a manner similar to the Smart Meter accounts. Distributors should request for dispositi application, outside of this continuity schedule.

11 Input the LRAMVA balance in the continuity schedule as calculated from the LRAMVA model. The associated rate riders w

12 Effective May 23, 2017, per the OEB's letter titled *Guidance on Disposition of Accounts 1588 and 1589* , applicants must and 1589 . This is to include true ups that impact the GA as well. The amount requested for disposition starts with the audit true-up claims are to be shown in the Adjustment column in that year. Note that this true-up claim will need to be reversed in reflected at the end of the last year of the account balance that was previously disposed, then no adjustment would have to adjustment is appropriately captured in the last year of the previously disposed period and the first year of the current perio Note that if a distributor has any balance in Account 1589 that pertains to Class A, this must be excluded from the balance r

ard

eferral/Variance Account Workform

This continuity schedule must be completed for each account and sub-account that the utility has approved for use as at Dec. 31, 2016, regardless of whether disposition is being requested for the account. For all accounts, except for Account 1595, start in from the year in which the GL balance was last disposed. For example, if in the 2017 rate application, DVA balances as at December 31, 2015 were approved for disposition, start the continuity schedule from 2015 by entering the approved closing 2014 balanc Adjustment column under 2014. For each Account 1595 sub-account, start inputting data from the year the sub-account started to accumulate a balance (i.e. the vintage year). For example, Account 1595 (2014), data should be inputted starting in 2014 when balances approved for disposition was first transferred into Account 1595 (2014). The DVA continuity schedule currently starts from 2011, if a utility has an Account 1595 with a vintage year prior to 2011, then a separate schedule should be provided starting vintage year. For any new accounts that have never been disposed, start inputting data from the year the account was approved to be used.

Account Descriptions	Account Number	2011 Opening Principal Amounts as of Jan-1-11	Transactions(1) Debit / (Credit) during 2011	OEB-Approved Disposition during 2011	Principal Adjustments(2) during 2011	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	OEB-Approved Disposition during 2011	Interest Adjustments(1) during 2011	Closing Interest Amounts as of Dec-31-11
Group 1 Accounts											
LV Variance Account	1550		$335,155			$335,155	-$340	$320			-$20
Smart Metering Entity Charge Variance Account	1551										
RSVA - Wholesale Market Service Charge[5]	1580	-$947,154	-$1,042,317			-$1,989,471	-$28,891	-$14,343			-$43,234
Variance WMS – Sub-account CBR Class A[5]	1580										
Variance WMS – Sub-account CBR Class B[5]	1580										
RSVA - Retail Transmission Network Charge	1584	$1,162,959	-$167,078			$995,881	$2,910	$12,936			$15,846
RSVA - Retail Transmission Connection Charge	1586	-$326,923	-$555,670			-$882,593	-$301	-$5,490			-$5,791
RSVA - Power (excluding Global Adjustment)[12]	1588	$1,675,944	$3,070,788			$4,746,732	-$3,378	-$65,083			-$68,461
RSVA - Global Adjustment[12]	1589	-$3,248,056	-$2,047,537			-$5,295,593	$468	$39,173			$39,641
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2013)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2014)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595					$0					$0
Not to be disposed of until a year after rate rider has expired and that balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$1,683,230	-$406,659	$0	$0	-$2,089,889	-$29,532	-$32,487	$0	$0	-$62,019
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$1,564,826	$1,640,878	$0	$0	$3,205,704	-$30,000	-$71,660	$0	$0	-$101,660
RSVA - Global Adjustment 12	**1589**	-$3,248,056	-$2,047,537	$0	$0	-$5,295,593	$468	$39,173	$0	$0	$39,641
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Other	1508	$0				$0	$0				$0
Sub-account CBR class B - Principal	1508					$0					$0
Sub-account CBR class B - Interest	1508					$0					$0
	1508					$0					$0
	1508					$0					$0
Retail Cost Variance Account - Retail	1518	$6,127	$17,135			$23,262	$71	$174			$245
Misc. Deferred Debits	1525	$2,237,720	-$434,292			$1,803,428	$0				$0
Retail Cost Variance Account - STR	1548	-$2,356	-$229			-$2,585	-$48	-$30			-$78
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$85,319				$85,319	$6,624				$6,624
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total			-$417,386	$0	$0	$1,909,424	$6,647	$144	$0	$0	$6,791
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$35,882				-$35,882	$0				$0
Total of Group 1 and Group 2 Accounts (including 1592)		-$1,719,112	-$824,045	$0	$0	-$216,347	-$22,885	-$32,343	$0	$0	-$55,228
LRAM Variance Account[11]	**1568**	$0				$0	$0				$0
Total including Account 1568			-$824,045	$0	$0	-$216,347	-$22,885	-$32,343	$0	$0	-$55,228
Renewable Generation Connection Capital Deferral Account[8]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[8]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555	$0				$0	$0				$0
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557										
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575					$0					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576										

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related OEB decision.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year. Do not include interest, adjustments, or OEB approved dispositions in this column.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously OEB Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

As per the January 6, 2011 Letter from the OEB regarding the implementation of the Ontario Clean Energy Benefit:

"By way of exception... The Board does anticipate that licensed distributors that cannot adapt their invoices as of January 1, 2011 will require a variance account for OCEB purposes... The Board expects that any principal balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will be addressed through the monthly settlement process with the IESO or the host distributor, as applicable."

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance Account rate rider. For details on how to dispose of balances in Smart Meter accounts see the OEB's Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

The OEB requires that disposition of Account 1575 and Account 1576 shall require the use of separate rate riders. In the "Adjustments during 2016" column of the continuity schedule, please enter the amounts to be included in the Account 1575 and 1576 rate rider calculation from the applicable Chapter 2-E appendix line "Amount included in Deferral and Variance Account Rate Rider Calculation".

Depending on the disposition period, balances may exist in Account 1575 and Account 1576 even if the accounts have been approved for disposition in a previous decision. Report these account balances in the continuity schedule if this is the case and leave the checkbox "Check to Dispose of Account" in the Total Claim column unchecked.

If the LDC's rate year begins on January 1, 2018, the projected interest is recorded from January 1, 2017 to December 31, 2017 on the December 31, 2016 balances adjusted for the disposed balances approved by the OEB in the 2017 rate decision. If the LDC's rate year begins on May 1, 2018, the projected interest is recorded from January 1, 2017 to April 30, 2018 on the December 31, 2016 balances adjusted for the disposed interest balances approved by the OEB in the 2017 rate decision.

The individual sub-accounts as well as the total for all Account 1595 sub-accounts are to agree to the RRR data. Differences need to be explained.

For each Account 1595 sub-account, the transfer of the balance approved for disposition into Account 1595 is to be recorded in the "OEB Approved Disposition" column. The recovery/refund is to be recorded in the "Transaction" column. The two are not to be netted together and recorded in one column in the first year.

The audited balance in the account is only to be disposed a year after the recovery/refund period has been completed. Generally, no further transactions would be expected to flow through the account after that. Any vintage year of Account 1595 is only to be disposed once on a final basis. No further dispositions of these accounts are generally expected thereafter, unless justified by the distributor. Select the "Check to dispose of account" checkbox in Total Claims column if the account is requested for disposition.

As per the Filing Requirements for 2018 rate applications, request for rate protection on eligible investments are subject to a materiality threshold. If the materiality threshold is met, per the APH March 2015 Guidance, the Direct Benefits portion of Account 1531 should be transferred to rate base. The Direct Benefits portion of Account 1532 should be included in the DVA continuity schedule to be requested for disposition. In this continuity schedule, Account 1531 is listed for reference only. Account 1532 is included in the Group 2 allocation of balances that are used to calculate the rate riders. Only input the Direct Benefits portion of the account balances in this continuity schedule.

Account 1580 RSVA WMS balance inputted into this schedule is to exclude any amounts relating to CBR. CBR amounts are to be inputted into Account 1580, sub-accounts CBR Class A and B separately. There is no disposition of Account 1580, sub-account CBR Class A, accounting guidance for this sub-account is to be followed. If a balance exists for Account 1580, sub-account CBR Class A as at Dec. 31, 2016, the balance must be explained.

Account 1557 is to be recovered in a manner similar to the Smart Meter accounts. Distributors should request for disposition upon completion of the MIST meter deployment. A prudence review and disposition should be done in the application, outside of this continuity schedule.

Input the LRAMVA balance in the continuity schedule as calculated from the LRAMVA model. The associated rate riders will be calculated in the DVA continuity schedule.

Effective May 23, 2017, per the OEB's letter titled *Guidance on Disposition of Accounts 1588 and 1589*, applicants must reflect RPP Settlement true-up claims pertaining to the period that is being requested for disposition in Accounts 1588 and 1589 . This is to include true ups that impact the GA as well. The amount requested for disposition starts with the audited account balance. If the audited account balance does not reflect the true-up claims for that year, the impacts of the true-up claims are to be shown in the Adjustment column in that year. Note that this true-up claim will need to be reversed in the amount requested for disposition in the following year. However, if the RPP Settlement true-up claim was not reflected at the end of the last year of the account balance that was previously disposed, then no adjustment would have to be made in the first year at the beginning of the current period being requested for disposition. This way the adjustment is appropriately captured in the last year of the previously disposed period and the first year of the current period requested for disposition.

Note that if a distributor has any balance in Account 1589 that pertains to Class A, this must be excluded from the balance requested for disposition.

oard

eferral/Variance Account Workform

This continuity schedule must be completed for each account and sub-account that the utilputting data from the year in which the GL balance was last disposed. For example, if in the 2017 rate appce in the Adjustment column under 2014. For each Account 1595 sub-account, start inputting data frothe relevant balances approved for disposition was first transferred into Account 1595 (2014). The DVA cj from the vintage year. For any new accounts that have never been disposed, start inputting data from

Account Descriptions	Account Number	2012 Opening Principal Amounts as of Jan-1-12	Transactions(1) Debit / (Credit) during 2012	OEB-Approved Disposition during 2012	Principal Adjustments(2) during 2012	Closing Principal Balance as of Dec-31-12	Opening Interest Amounts as of Jan-1-12	Interest Jan-1 to Dec-31-12	OEB-Approved Disposition during 2012	Interest Adjustments(2) during 2012	Closing Interest Amounts as of Dec-31-12
Group 1 Accounts											
LV Variance Account	1550	$335,155	$373,036	-$18,134		$726,325	-$20	$6,737	-$2,515		$9,232
Smart Metering Entity Charge Variance Account	1551										
RSVA - Wholesale Market Service Charge[9]	1580	-$1,989,471	-$1,584,483	-$995,694		-$2,578,260	-$43,234	-$38,275	-$2,594		-$78,915
Variance WMS – Sub-account CBR Class A[9]	1580										
Variance WMS – Sub-account CBR Class B[9]	1580										
RSVA - Retail Transmission Network Charge	1584	$995,881	-$648,746	$1,142,986		-$795,851	$15,846	$9,476	$45,254		-$19,932
RSVA - Retail Transmission Connection Charge	1586	-$882,593	-$384,485	-$340,358		-$926,720	-$5,791	-$16,490	$6,473		-$28,754
RSVA - Power (excluding Global Adjustment)[12]	1588	$4,746,732	$4,757,761	$1,710,789		$7,793,704	-$68,461	-$57,449	-$70,318		-$55,592
RSVA - Global Adjustment [12]	1589	-$5,295,593	-$3,436,249	-$3,248,056		-$5,483,786	$39,641	$65,794	-$62,091		$167,526
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2013)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2014)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0				$0	$0				$0
Not to be disposed of until a year after rate rider has expired and that balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$2,089,889	-$923,166	-$1,748,467	$0	-$1,264,588	-$62,019	-$30,207	-$85,791	$0	-$6,435
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$3,205,704	$2,513,083	$1,499,589	$0	$4,219,198	-$101,660	-$96,001	-$23,700	$0	-$173,961
RSVA - Global Adjustment 12	**1589**	-$5,295,593	-$3,436,249	-$3,248,056	$0	-$5,483,786	$39,641	$65,794	-$62,091	$0	$167,526
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0			-$120,403	-$120,403	$0			-$2,372	-$2,372
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Other	1508	$0				$0	$0				$0
Sub-account CBR class B - Principal	1508	$0				$0	$0				$0
Sub-account CBR class B - Interest	1508	$0				$0	$0				$0
	1508	$0				$0	$0				$0
	1508	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	$23,262	$20,722			$43,984	$245	$450			$695
Misc. Deferred Debits	1525	$1,803,428	-$227,049		-$1,506,379	$70,000	$0				$0
Retail Cost Variance Account - STR	1548	-$2,585	-$310			-$2,895	-$78	-$37			-$115
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$85,319			-$4,905	$80,414	$6,624	-$3,886		-$42	$2,696
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$1,909,424	-$206,637	$0	-$1,631,687	$71,100	$6,791	-$3,473	$0	-$2,414	$904
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$35,882				-$35,882	$0				$0
Total of Group 1 and Group 2 Accounts (including 1592)		-$216,347	-$1,129,803	-$1,748,467	-$1,631,687	-$1,229,370	-$55,228	-$33,680	-$85,791	-$2,414	-$5,531
LRAM Variance Account[11]	**1568**	$0				$0	$0				$0
Total including Account 1568		-$216,347	-$1,129,803	-$1,748,467	-$1,631,687	-$1,229,370	-$55,228	-$33,680	-$85,791	-$2,414	-$5,531
Renewable Generation Connection Capital Deferral Account[8]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[8]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0	$2,833			$2,833	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555	$0				$0	$0				$0
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557										
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$0				$0					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0					

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: figure and credit balance are to have a negative figure) as per the related OEB decision.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transacti column.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously OEB Approved dispo

As per the January 6, 2011 Letter from the OEB regarding the implementation of the Ontario Clean Energy Benefit:

"By way of exception... The Board does anticipate that licensed distributors that cannot adapt their invoices as of January 1, account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will be addressed throu

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance A Meter Disposition and Cost Recovery (G-2011-0001)

The OEB requires that disposition of Account 1575 and Account 1576 shall require the use of separate rate riders. In the "A 1575 and 1576 rate rider calculation from the applicable Chapter 2-E appendix line "Amount included in Deferral and Varia

Depending on the disposition period, balances may exist in Account 1575 and Account 1576 even if the accounts have bee the case and leave the checkbox "Check to Dispose of Account" in the Total Claim column unchecked.

If the LDC's rate year begins on January 1, 2018, the projected interest is recorded from January 1, 2017 to December 31 decision. If the LDC's rate year begins on May 1, 2018, the projected interest is recorded from January 1, 2017 to April 30 2017 rate decision.

The individual sub-accounts as well as the total for all Account 1595 sub-accounts are to agree to the RRR data. Differenc For each Account 1595 sub-account, the transfer of the balance approved for disposition into Account 1595 is to be recorc The two are not to be netted together and recorded in one column in the first year.

The audited balance in the account is only to be disposed a year after the recovery/refund period has been completed. Ge 1595 is only to be disposed once on a final basis. No further dispositions of these accounts are generally expected thereaf account is requested for disposition.

As per the Filing Requirements for 2018 rate applications, request for rate protection on eligible investments are subject to portion of Account 1531 should be transferred to rate base. The Direct Benefits portion of Account 1532 should be include for reference only. Account 1532 is included in the Group 2 allocation of balances that are used to calculate the rate riders. Account 1580 RSVA WMS balance inputted into this schedule is to exclude any amounts relating to CBR. CBR amounts ar 1580, sub-account CBR Class A, accounting guidance for this sub-account is to be followed. If a balance exists for Accour Account 1557 is to be recovered in a manner similar to the Smart Meter accounts. Distributors should request for dispositi application, outside of this continuity schedule.

Input the LRAMVA balance in the continuity schedule as calculated from the LRAMVA model. The associated rate riders w Effective May 23, 2017, per the OEB's letter titled *Guidance on Disposition of Accounts 1588 and 1589*, applicants must and 1589. This is to include true ups that impact the GA as well. The amount requested for disposition starts with the audit true-up claims are to be shown in the Adjustment column in that year. Note that this true-up claim will need to be reversed in reflected at the end of the last year of the account balance that was previously disposed, then no adjustment would have to adjustment is appropriately captured in the last year of the previously disposed period and the first year of the current perio Note that if a distributor has any balance in Account 1589 that pertains to Class A, this must be excluded from the balance r

ard

eferral/Variance Account Workform

This continuity schedule must be completed for each account and sub-account that the utili
from the year in which the GL balance was last disposed. For example, if in the 2017 rate app
Adjustment column under 2014. For each Account 1595 sub-account, start inputting data fro
balances approved for disposition was first transferred into Account 1595 (2014). The DVA c
vintage year. For any new accounts that have never been disposed, start inputting data from

2013

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-13	Transactions(1) Debit / (Credit) during 2013	OEB-Approved Disposition during 2013	Principal Adjustments(2) during 2013	Closing Principal Balance as of Dec-31-13	Opening Interest Amounts as of Jan-1-13	Interest Jan-1 to Dec-31-13	OEB-Approved Disposition during 2013	Interest Adjustments(2) during 2013	Closing Interest Amounts as of Dec-31-13
Group 1 Accounts											
LV Variance Account	1550	$726,325	$609,899			$1,336,224	$9,232	$13,711			$22,943
Smart Metering Entity Charge Variance Account	1551	$0	$46,737			$46,737	$0				$0
RSVA - Wholesale Market Service Charge[9]	1580	-$2,578,260	-$800,162			-$3,378,422	-$78,915	-$32,495			-$111,410
Variance WMS – Sub-account CBR Class A[9]	1580										
Variance WMS – Sub-account CBR Class B[9]	1580										
RSVA - Retail Transmission Network Charge	1584	-$795,851	-$186,687			-$982,538	-$19,932	$2,049			-$17,883
RSVA - Retail Transmission Connection Charge	1586	-$926,720	-$1,336,054			-$2,262,774	-$28,754	-$25,472			-$54,226
RSVA - Power (excluding Global Adjustment)[12]	1588	$7,793,704	$6,331,346		-$6,419,261	$7,705,789	-$55,592	-$161,736			-$217,328
RSVA - Global Adjustment [12]	1589	-$5,483,786	-$5,767,265		$6,419,261	-$4,831,790	$167,526	$184,331			$351,857
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012)[7]	1595	$0	-$209,381			-$209,381	$0	-$48,626		$69,076	$20,450
Disposition and Recovery/Refund of Regulatory Balances (2013)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2014)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0				$0	$0				$0
Not to be disposed of until a year after rate rider has expired and that balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$1,264,588	-$1,311,567	$0	$0	-$2,576,155	-$6,435	-$68,238	$0	$69,076	-$5,597
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$4,219,198	$4,455,698	$0	-$6,419,261	$2,255,635	-$173,961	-$252,569	$0	$69,076	-$357,454
RSVA - Global Adjustment 12	**1589**	-$5,483,786	-$5,767,265	$0	$6,419,261	-$4,831,790	$167,526	$184,331	$0	$0	$351,857
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	-$120,403	-$48,900			-$169,303	-$2,372				-$2,372
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Other	1508	$0				$0	$0				$0
Sub-account CBR class B - Principal	1508	$0				$0	$0				$0
Sub-account CBR class B - Interest	1508	$0				$0	$0				$0
	1508	$0				$0	$0				$0
	1508	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	$43,984	$27,365			$71,349	$695	$823			$1,518
Misc. Deferred Debits	1525	$70,000	-$52,500			$17,500	$0				$0
Retail Cost Variance Account - STR	1548	-$2,895	-$202			-$3,097	-$115	-$44			-$159
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$80,414				$80,414	$2,696	$191			$2,887
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$71,100	-$74,237	$0	$0	-$3,137	$904	$970	$0	$0	$1,874
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$35,882				-$35,882	$0				$0
Total of Group 1 and Group 2 Accounts (including 1592)		-$1,229,370	-$1,385,804	$0	$0	-$2,615,174	-$5,531	-$67,268	$0	$69,076	-$3,723
LRAM Variance Account[11]	**1568**	$0	$69,099			$69,099	$0	$466			$466
Total including Account 1568		-$1,229,370	-$1,316,705	$0	$0	-$2,546,075	-$5,531	-$66,802	$0	$69,076	-$3,257
Renewable Generation Connection Capital Deferral Account[6]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[6]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$2,833	$171,162			$173,995	$0				$0
Smart Grid OM&A Deferral Account	1535	$0	$46,262			$46,262	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555	$0				$0	$0				$0
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557										
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$0				$0					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0	-$465,810			-$465,810					

2014

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-14	Transactions(1) Debit / (Credit) during 2014	OEB-Approved Disposition during 2014	Principal Adjustments(2) during 2014	Closing Principal Balance as of Dec-31-14	Opening Interest Amounts as of Jan-1-14	Interest Jan-1 to Dec-31-14	OEB-Approved Disposition during 2014	Interest Adjustments(2) during 2014	Closing Interest Amounts as of Dec-31-14
Group 1 Accounts											
LV Variance Account	1550	$1,336,224	$519,336	$708,191		$1,147,369	$22,943	$23,097	$19,695		$26,345
Smart Metering Entity Charge Variance Account	1551	$46,737	-$6,484			$40,253	$0				$0
RSVA - Wholesale Market Service Charge[9]	1580	-$3,378,422	-$812,442	-$3,573,954		-$616,910	-$111,410	-$68,100	-$147,000		-$32,510
Variance WMS – Sub-account CBR Class A[9]	1580										
Variance WMS – Sub-account CBR Class B[9]	1580										
RSVA - Retail Transmission Network Charge	1584	-$982,538	-$550,711	$347,134		-$1,880,383	-$17,883	-$3,332	$31,682		-$52,897
RSVA - Retail Transmission Connection Charge	1586	-$2,262,774	-$459,985	-$1,267,076		-$1,455,683	-$54,226	-$38,573	-$45,501		-$47,298
RSVA - Power (excluding Global Adjustment)[12]	1588	$7,705,789	$984,736	$9,554,493		-$863,968	-$217,328	$252,886	$49,174		-$13,616
RSVA - Global Adjustment [12]	1589	-$4,831,790	-$443,609	-$8,731,842		$3,456,443	$351,857	-$235,143	-$54,573		$171,287
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$0	-$185,412			-$185,412	$0	-$56,984			-$56,984
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012)[7]	1595	-$209,381				-$209,381	$20,450	-$68,821			-$48,371
Disposition and Recovery/Refund of Regulatory Balances (2013)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2014)[7]	1595	$0	$1,717,199	$3,109,577		-$1,392,378	$0	-$19,768			-$19,768
Disposition and Recovery/Refund of Regulatory Balances (2015)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0				$0	$0				$0
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$2,576,155	$762,628	$146,523	$0	-$1,960,050	-$5,597	-$214,738	-$146,523	$0	-$73,812
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$2,255,635	$1,206,237	$8,878,365	$0	-$5,416,493	-$357,454	$20,405	-$91,950	$0	-$245,099
RSVA - Global Adjustment 12	**1589**	-$4,831,790	-$443,609	-$8,731,842	$0	$3,456,443	$351,857	-$235,143	-$54,573	$0	$171,287
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	-$169,303	-$49,556			-$218,859	-$2,372				-$2,372
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Other	1508	$0				$0	$0				$0
Sub-account CBR class B - Principal	1508	$0				$0	$0				$0
Sub-account CBR class B - Interest	1508	$0				$0	$0				$0
	1508	$0				$0	$0				$0
	1508	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	$71,349	$29,825			$101,174	$1,518	$1,272			$2,790
Misc. Deferred Debits	1525	$17,500	$45,112			$62,612	$0				$0
Retail Cost Variance Account - STR	1548	-$3,097	$41			-$3,056	-$159	-$45			-$204
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$80,414				$80,414	$2,887				$2,887
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		-$3,137	$25,422	$0	$0	$22,285	$1,874	$1,227	$0	$0	$3,101
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$35,882	-$71,487			-$107,369	$0				$0
Total of Group 1 and Group 2 Accounts (including 1592)		-$2,615,174	$716,563	$146,523	$0	-$2,045,134	-$3,723	-$213,511	-$146,523	$0	-$70,711
LRAM Variance Account[11]	**1568**	$69,099	$103,801			$172,900	$466	$1,715			$2,181
Total including Account 1568		-$2,546,075	$820,364	$146,523	$0	-$1,872,234	-$3,257	-$211,796	-$146,523	$0	-$68,530
Renewable Generation Connection Capital Deferral Account[6]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[6]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$173,995	$282,552			$456,547	$0				$0
Smart Grid OM&A Deferral Account	1535	$46,262	$616			$46,878	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555	$0				$0	$0				$0
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$0				$0					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	-$465,810	-$157,214			-$623,024					

2015

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-15	Transactions(1) Debit / (Credit) during 2015	OEB-Approved Disposition during 2015	Principal Adjustments(2) during 2015	Closing Principal Balance as of Dec-31-15	Opening Interest Amounts as of Jan-1-15	Interest Jan-1 to Dec-31-15	OEB-Approved Disposition during 2015
Group 1 Accounts									
LV Variance Account	1550	$1,147,369	$998,522	$628,034	-$121,423	$1,396,434	$26,345	$14,002	$15,557
Smart Metering Entity Charge Variance Account	1551	$40,253	-$2,946	$46,737	$0	-$9,430	$0	$518	$916
RSVA - Wholesale Market Service Charge[9]	1580	-$616,910	-$1,047,928	$195,532	$1,451,124	-$409,246	-$32,510	-$12,804	$39,422
Variance WMS – Sub-account CBR Class A[9]	1580	$0				$0	$0		
Variance WMS – Sub-account CBR Class B[9]	1580	$0			$131,549	$131,549	$0		
RSVA - Retail Transmission Network Charge	1584	-$1,880,383	-$427,797	-$1,329,672	-$202,441	-$1,180,949	-$52,897	-$16,917	-$75,627
RSVA - Retail Transmission Connection Charge	1586	-$1,455,683	$330,582	-$995,698	-$127,747	-$257,150	-$47,298	-$10,107	-$28,242
RSVA - Power (excluding Global Adjustment)[12]	1588	-$863,968	-$1,719,979	-$1,848,704	-$1,698,386	-$2,433,629	-$13,616	$1,665	-$302,737
RSVA - Global Adjustment [12]	1589	$3,456,443	-$6,884	$3,900,052	$1,094,744	$644,251	$171,287	$18,958	$482,871
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$0				$0	$0		
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	-$185,412			$10,591	-$174,821	-$56,984	-$2,071	
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$0			$0		$0		
Disposition and Recovery/Refund of Regulatory Balances (2012)[7]	1595	-$209,381		-$209,381	$149,130	$149,130	-$48,371	-$796	$20,450
Disposition and Recovery/Refund of Regulatory Balances (2013)[7]	1595	$0			$0	$0	$0		
Disposition and Recovery/Refund of Regulatory Balances (2014)[7]	1595	-$1,392,378	$1,947,528		-$552,789	$2,361	-$19,768	-$2,698	
Disposition and Recovery/Refund of Regulatory Balances (2015)[7]	1595	$0	$2,317,932	$970,837	$420,676	$1,767,771	$0	-$407	
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0				$0	$0		
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$1,960,050	$2,389,030	$1,357,737	$555,028	-$373,729	-$73,812	-$10,657	$152,610
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$5,416,493	$2,395,914	-$2,542,315	-$539,716	-$1,017,980	-$245,099	-$29,615	-$330,261
RSVA - Global Adjustment 12	**1589**	$3,456,443	-$6,884	$3,900,052	$1,094,744	$644,251	$171,287	$18,958	$482,871
Group 2 Accounts									
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	-$218,859	-$50,000			-$268,859	-$2,372	-$8,059	
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0		
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0	$2,208	
Other Regulatory Assets - Sub-Account - Other	1508	$0				$0	$0		
Sub-account CBR class B - Principal	1508	$0				$0	$0		
Sub-account CBR class B - Interest	1508	$0				$0	$0		
	1508	$0				$0	$0		
	1508	$0				$0	$0		
Retail Cost Variance Account - Retail	1518	$101,174	$31,883		-$3,673	$129,384	$2,790	$1,369	
Misc. Deferred Debits	1525	$62,612	$43,623		-$58,424	$47,811	$0		
Retail Cost Variance Account - STR	1548	-$3,056	$798		$76	-$2,182	-$204	-$32	
Board-Approved CDM Variance Account	1567	$0				$0	$0		
Extra-Ordinary Event Costs	1572	$80,414				$80,414	$2,887	$3,051	
Deferred Rate Impact Amounts	1574	$0				$0	$0		
RSVA - One-time	1582	$0				$0	$0		
Other Deferred Credits	2425	$0				$0	$0		
Group 2 Sub-Total		$22,285	$26,304	$0	-$62,021	-$13,432	$3,101	-$1,463	$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0		
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$107,369				-$107,369	$0		
Total of Group 1 and Group 2 Accounts (including 1592)		-$2,045,134	$2,415,334	$1,357,737	$493,007	-$494,530	-$70,711	-$12,120	$152,610
LRAM Variance Account[11]	**1568**	$172,900	$142,419			$315,319	$2,181	$2,791	
Total including Account 1568		-$1,872,234	$2,557,753	$1,357,737	$493,007	-$179,211	-$68,530	-$9,329	$152,610
Renewable Generation Connection Capital Deferral Account[6]	1531	$0	$35,010			$35,010	$0	$224	
Renewable Generation Connection OM&A Deferral Account[6]	1532	$0				$0	$0		
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0		
Smart Grid Capital Deferral Account	1534	$456,547	$105,028		-$102,547	$459,028	$0	$8,032	
Smart Grid OM&A Deferral Account	1535	$46,878	$23,042			$69,920	$0	$3,560	
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0		
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$0				$0	$0		
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	$0				$0	$0		
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555	$0				$0	$0		
Smart Meter OM&A Variance[4]	1556	$0				$0	$0		
Meter Cost Deferral Account (MIST Meters)[10]	1557	$0				$0	$0		
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$0				$0			
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	-$623,024	-$781,900			-$1,404,924			

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (e.g:
figure and credit balance are to have a negative figure) as per the related OEB decision.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transacti
column.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously OEB Approved dispo

As per the January 6, 2011 Letter from the OEB regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does anticipate that licensed distributors that cannot adapt their invoices as of January 1,
account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will be addressed throu

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance A
Meter Disposition and Cost Recovery (G-2011-0001)
The OEB requires that disposition of Account 1575 and Account 1576 shall require the use of separate rate riders. In the "A
1575 and 1576 rate rider calculation from the applicable Chapter 2-E appendix line "Amount included in Deferral and Varia

Depending on the disposition period, balances may exist in Account 1575 and Account 1576 even if the accounts have bee
the case and leave the checkbox "Check to Dispose of Account" in the Total Claim column unchecked.
If the LDC's rate year begins on January 1, 2018, the projected interest is recorded from January 1, 2017 to December 31
decision. If the LDC's rate year begins on May 1, 2018, the projected interest is recorded from January 1, 2017 to April 30
2017 rate decision.

The individual sub-accounts as well as the total for all Account 1595 sub-accounts are to agree to the RRR data. Differenc
For each Account 1595 sub-account, the transfer of the balance approved for disposition into Account 1595 is to be recorc
The two are not to be netted together and recorded in one column in the first year.
The audited balance in the account is only to be disposed a year after the recovery/refund period has been completed. Ger
1595 is only to be disposed once on a final basis. No further dispositions of these accounts are generally expected thereaf
account is requested for disposition.

As per the Filing Requirements for 2018 rate applications, request for rate protection on eligible investments are subject to
portion of Account 1531 should be transferred to rate base. The Direct Benefits portion of Account 1532 should be include
for reference only. Account 1532 is included in the Group 2 allocation of balances that are used to calculate the rate riders
Account 1580 RSVA WMS balance inputted into this schedule is to exclude any amounts relating to CBR. CBR amounts ar
1580, sub-account CBR Class A, accounting guidance for this sub-account is to be followed. If a balance exists for Accour
Account 1557 is to be recovered in a manner similar to the Smart Meter accounts. Distributors should request for dispositi
application, outside of this continuity schedule.

Input the LRAMVA balance in the continuity schedule as calculated from the LRAMVA model. The associated rate riders w
Effective May 23, 2017, per the OEB's letter titled *Guidance on Disposition of Accounts 1588 and 1589*, applicants must
and 1589 . This is to include true ups that impact the GA as well. The amount requested for disposition starts with the audit
true-up claims are to be shown in the Adjustment column in that year. Note that this true-up claim will need to be reversed in
reflected at the end of the last year of the account balance that was previously disposed, then no adjustment would have to
adjustment is appropriately captured in the last year of the previously disposed period and the first year of the current perio
Note that if a distributor has any balance in Account 1589 that pertains to Class A, this must be excluded from the balance r

ard

eferral/Variance Account Workform

If you had any Class A customers at any point during the period that the Account 1589 GA balance accumulated (i.e. from the year the balance was last disposed to 2016), check off the checkbox

If you had Class A customer(s) during this period, Tab 5.1 will be generated and applicants must complete the information pertaining to Class A customers.

This continuity schedule must be completed for each account and sub-account that the utili from the year in which the GL balance was last disposed. For example, if in the 2017 rate app Adjustment column under 2014. For each Account 1595 sub-account, start inputting data fro balances approved for disposition was first transferred into Account 1595 (2014). The DVA c vintage year. For any new accounts that have never been disposed, start inputting data from

				2016										2017				Projected Interest on Dec-31-16 Balances				2.1.7 RRR	
Account Descriptions	Account Number	Interest Adjustments(2) during 2015	Closing Interest Amounts as of Dec-31-15	Opening Principal Amounts as of Jan-1-16	Transactions(1) Debit / (Credit) during 2016	OEB-Approved Disposition during 2016	Principal Adjustments(2) during 2016	Closing Principal Balance as of Dec-31-16	Opening Interest Amounts as of Jan-1-16	Interest Jan-1 to Dec-31-16	OEB-Approved Disposition during 2016	Interest Adjustments(2) during 2016	Closing Interest Amounts as of Dec-31-16	Principal Disposition during 2017 - instructed by OEB	Interest Disposition during 2017 - instructed by OEB	Closing Principal Balances as of Dec 31-16 Adjusted for Dispositions during 2017	Closing Interest Balances as of Dec 31-16 Adjusted for Dispositions during 2017	Projected Interest from Jan 1, 2017 to December 31, 2017 on Dec 31 -16 balance adjusted for disposition during 2017 (6)	Projected Interest from January 1, 2018 to April 30, 2018 on Dec 31 -16 balance adjusted for disposition during 2017 (6)	Total Interest	Total Claim	As of Dec 31-16	Variance RRR vs. 2016 Balance (Principal + Interest)
Group 1 Accounts																							
LV Variance Account	1550	-$7,882	$16,908	$1,396,434	$1,261,365			$2,657,799	$16,908	$21,492			$38,400			$2,657,799	$38,400	$29,236	$9,612	$77,248	$2,735,046.92	$2,696,200	$1
Smart Metering Entity Charge Variance Account	1551	-$194	-$592	-$9,430	-$28,989			-$38,419	-$592	-$353			-$945			-$38,419	-$945	-$423	-$139	-$1,507	-$39,925.38	-$39,364	$0
RSVA - Wholesale Market Service Charge[9]	1580	$73,343	-$11,393	-$409,246	-$413,513			-$822,759	-$11,393	-$5,300			-$16,693			-$822,759	-$16,693	-$9,050	-$2,975	-$28,719	-$851,477.96	-$789,769	$49,683
Variance WMS – Sub-account CBR Class A[9]	1580		$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	$0.00	$0	$0
Variance WMS – Sub-account CBR Class B[9]	1580	$447	$447	$131,549				$131,549	$447				$447			$131,549	$447	$1,447	$476	$2,370	$133,918.78	$82,315	-$49,681
RSVA - Retail Transmission Network Charge	1584	-$36,877	-$31,064	-$1,180,949	$785,883			-$395,066	-$31,064	-$9,822			-$40,886			-$395,066	-$40,886	-$4,346	-$1,429	-$46,660	-$441,726.12	-$435,952	-$1
RSVA - Retail Transmission Connection Charge	1586	$14,449	-$14,714	-$257,150	$678,375			$421,225	-$14,714	$943			-$13,771			$421,225	-$13,771	$4,633	$1,523	-$7,614	$413,610.98	$407,455	$1
RSVA - Power (excluding Global Adjustment)[12]	1588	-$5,375	$285,411	-$2,433,629	-$571,409			-$3,005,038	$285,411	-$24,662			$260,749			-$3,005,038	$260,749	-$33,055	-$10,868	$216,826	-$2,788,212.17	-$2,744,288	$1
RSVA - Global Adjustment [12]	1589	-$5,758	-$298,384	$644,251	$166,195			$810,446	-$298,384	$5,149			-$293,235			$810,446	-$293,235	$8,915	$2,931	-$281,389	$529,057.11	$517,212	$0
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595		$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	Check to Dispose of Account $0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	-$5,041	-$64,096	-$174,821				-$174,821	-$64,096	-$3,051			-$67,147			-$174,821	-$67,147	-$1,923	-$632	-$69,702	Check to Dispose of Account -$244,523.26	-$241,968	-$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$0	$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	Check to Dispose of Account $0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2012)[7]	1595	$111,388	$41,771	$149,130				$149,130	$41,771	$2,843			$44,614			$149,130	$44,614	$1,640	$539	$46,794	Check to Dispose of Account $195,923.75	$193,744	$0
Disposition and Recovery/Refund of Regulatory Balances (2013)[7]	1595	$0	$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	Check to Dispose of Account $0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2014)[7]	1595	-$1,727	-$24,193	$2,361	-$141			$2,220	-$24,193	$1,638			-$22,555			$2,220	-$22,555	$24	$8	-$22,523	Check to Dispose of Account -$20,302.97	-$20,336	-$0
Disposition and Recovery/Refund of Regulatory Balances (2015)[7]	1595	$8,146	$7,739	$1,767,771	$1,630,723			$3,398,494	$7,739	$43,531			$51,270			$3,398,494	$51,270	$37,383	$12,290	$100,944	Check to Dispose of Account $0.00	$3,449,764	$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595		$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	Check to Dispose of Account $0.00	$0	$0
Not to be disposed of until a year after rate rider has expired and that balance has been audited																							
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$144,919	-$92,160	-$373,729	$3,508,490	$0	$0	$3,134,761	-$92,160	$32,408	$0	$0	-$59,752	$0	$0	$3,134,761	-$59,752	$34,482	$11,337	-$13,933	-$378,610.32	$3,075,014	$5
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$150,677	$206,224	-$1,017,980	$3,342,294	$0	$0	$2,324,314	$206,224	$27,259	$0	$0	$233,483	$0	$0	$2,324,314	$233,483	$25,567	$8,406	$267,456	-$907,667.43	$2,557,802	$5
RSVA - Global Adjustment 12	**1589**	-$5,758	-$298,384	$644,251	$166,195	$0	$0	$810,446	-$298,384	$5,149	$0	$0	-$293,235	$0	$0	$810,446	-$293,235	$8,915	$2,931	-$281,389	$529,057.11	$517,212	$0
Group 2 Accounts																							
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$1,081	-$9,350	-$268,859	-$6,594			-$275,453	-$9,350	-$3,000			-$12,350			-$275,453	-$12,350	-$3,030	-$996	-$16,376	-$291,829.14	-$287,802	$1
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508		$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	$0.00	$0	$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	-$2,208	$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	$0.00	$0	$0
Other Regulatory Assets - Sub-Account - Other	1508		$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	Check to Dispose of Account $0.00	$0	$0
Sub-account CBR class B - Principal	1508		$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	Check to Dispose of Account $0.00	$0	$0
Sub-account CBR class B - Interest	1508		$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	Check to Dispose of Account $0.00	$0	$0
	1508		$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	Check to Dispose of Account $0.00	$0	$0
	1508		$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	Check to Dispose of Account $0.00	$0	$0
Retail Cost Variance Account - Retail	1518	$252	$4,411	$129,384	$29,236			$158,620	$4,411	$1,571			$5,982			$158,620	$5,982	$1,745	$574	$8,300	$166,920.46	$164,603	$1
Misc. Deferred Debits	1525		$0	$47,811	$35,386			$83,197	$0	$1,030			$1,030			$83,197	$1,030	$915	$301	$2,246	Check to Dispose of Account $85,442.80	$84,227	-$0
Retail Cost Variance Account - STR	1548	$4	-$232	-$2,182	$267			-$1,915	-$232	-$23			-$255			-$1,915	-$255	-$21	-$7	-$283	-$2,198.00	-$2,171	-$1
Board-Approved CDM Variance Account	1567		$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	$0.00	$0	$0
Extra-Ordinary Event Costs	1572		$5,938	$80,414				$80,414	$5,938	$884			$6,822			$80,414	$6,822	$885	$291	$7,997	$88,411.36	$87,236	$0
Deferred Rate Impact Amounts	1574		$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	$0.00	$0	$0
RSVA - One-time	1582		$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	$0.00	$0	$0
Other Deferred Credits	2425		$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	Check to Dispose of Account $0.00	$0	$0
Group 2 Sub-Total		-$871	$767	-$13,432	$58,295	$0	$0	$44,863	$767	$462	$0	$0	$1,229	$0	$0	$44,863	$1,229	$493	$162	$1,884	$46,747.48	$46,092	$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592		$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	$0.00	$0	$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592		$0	-$107,369	-$95,389			-$202,758	$0	-$7,952			-$7,952			-$202,758	-$7,952	-$2,230	-$733	-$10,916	-$213,673.60	-$210,710	-$0
Total of Group 1 and Group 2 Accounts (including 1592)		$144,048	-$91,393	-$494,530	$3,471,396	$0	$0	$2,976,866	-$91,393	$24,918	$0	$0	-$66,475	$0	$0	$2,976,866	-$66,475	$32,746	$10,766	-$22,964	-$545,536.44	$2,910,396	$5
LRAM Variance Account[11]	**1568**		$4,972	$315,319	$188,789			$504,108	$4,972	$4,420			$9,392			$504,108	$9,392	$5,545	$1,823	$16,760	$520,868.20	$343,485	-$170,015
Total including Account 1568		$144,048	-$86,421	-$179,211	$3,660,185	$0	$0	$3,480,974	-$86,421	$29,338	$0	$0	-$57,083	$0	$0	$3,480,974	-$57,083	$38,291	$12,589	-$6,204	-$24,668.24	$3,253,881	-$170,009
Renewable Generation Connection Capital Deferral Account[8]	1531		$224	$35,010	$33,928			$68,938	$224	$432			$656			$68,938	$656	$758	$249	$1,664	$70,601.63	$69,594	-$0
Renewable Generation Connection OM&A Deferral Account[8]	1532		$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	$0.00	$0	$0
Renewable Generation Connection Funding Adder Deferral Account	1533		$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	$0.00	$0	$0
Smart Grid Capital Deferral Account	1534	-$466	$7,566	$459,028	$53,712			$512,740	$7,566	$5,518			$13,084			$512,740	$13,084	$5,640	$1,854	$20,578	$533,318.43	$525,823	-$1
Smart Grid OM&A Deferral Account	1535		$3,560	$69,920	$21,706			$91,626	$3,560	$882			$4,442			$91,626	$4,442	$1,008	$331	$5,781	$97,407.25	$96,068	-$0
Smart Grid Funding Adder Deferral Account	1536		$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	$0.00	$0	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555		$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	$0.00	$0	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555		$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	$0.00	$0	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555		$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	$0.00	$0	$0
Smart Meter OM&A Variance[4]	1556		$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	$0.00	$0	$0
Meter Cost Deferral Account (MIST Meters)[10]	1557		$0	$0				$0	$0				$0			$0	$0	$0	$0	$0	$0.00	$0	$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575			$0				$0								$0					Check to Dispose of Account $0.00	$0	$0
Accounting Changes Under CGAAP Balance + Return Component[5]	1576			-$1,404,924	-$1,154,005		-$1,836,031	-$4,394,960								-$4,394,960					Check to Dispose of Account -$4,394,960.00	-$2,558,928	$1,836,032

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: figure and credit balance are to have a negative figure) as per the related OEB decision.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transacti column.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously OEB Approved dispo

As per the January 6, 2011 Letter from the OEB regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does anticipate that licensed distributors that cannot adapt their invoices as of January 1, account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will be addressed throu

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance Meter Disposition and Cost Recovery (G-2011-0001)
The OEB requires that disposition of Account 1575 and Account 1576 shall require the use of separate rate riders. In the " 1575 and 1576 rate rider calculation from the applicable Chapter 2-E appendix line "Amount included in Deferral and Varia

Depending on the disposition period, balances may exist in Account 1575 and Account 1576 even if the accounts have bee the case and leave the checkbox "Check to Dispose of Account" in the Total Claim column unchecked.
If the LDC's rate year begins on January 1, 2018, the projected interest is recorded from January 1, 2017 to December 31 decision. If the LDC's rate year begins on May 1, 2018, the projected interest is recorded from January 1, 2017 to April 30 2017 rate decision.

The individual sub-accounts as well as the total for all Account 1595 sub-accounts are to agree to the RRR data. Differenc
For each Account 1595 sub-account, the transfer of the balance approved for disposition into Account 1595 is to be recorc
The two are not to be netted together and recorded in one column in the first year.
The audited balance in the account is only to be disposed a year after the recovery/refund period has been completed. Ger 1595 is only to be disposed once on a final basis. No further dispositions of these accounts are generally expected thereaf account is requested for disposition.

As per the Filing Requirements for 2018 rate applications, request for rate protection on eligible investments are subject to portion of Account 1531 should be transferred to rate base. The Direct Benefits portion of Account 1532 should be include for reference only. Account 1532 is included in the Group 2 allocation of balances that are used to calculate the rate riders
Account 1580 RSVA WMS balance inputted into this schedule is to exclude any amounts relating to CBR. CBR amounts ar 1580, sub-account CBR Class A, accounting guidance for this sub-account is to be followed. If a balance exists for Accour
Account 1557 is to be recovered in a manner similar to the Smart Meter accounts. Distributors should request for dispositi application, outside of this continuity schedule.

Input the LRAMVA balance in the continuity schedule as calculated from the LRAMVA model. The associated rate riders w
Effective May 23, 2017, per the OEB's letter titled *Guidance on Disposition of Accounts 1588 and 1589* , applicants must and 1589 . This is to include true ups that impact the GA as well. The amount requested for disposition starts with the audit true-up claims are to be shown in the Adjustment column in that year. Note that this true-up claim will need to be reversed in reflected at the end of the last year of the account balance that was previously disposed, then no adjustment would have to adjustment is appropriately captured in the last year of the previously disposed period and the first year of the current perio
Note that if a distributor has any balance in Account 1589 that pertains to Class A, this must be excluded from the balance r

Ontario Energy Board

2018 Deferral/Variance Account Workform

Accounts that produced a variance on the continuity schedule are listed below.
Please provide a detailed explanation for each variance below.

Account Descriptions	Account Number	Variance RRR vs. 2016 Balance (Principal + Interest)	Explanation
LV Variance Account	1550	$ 0.73	Immaterial rounding variance
Smart Metering Entity Charge Variance Account	1551	$ 0.29	Immaterial rounding variance
RSVA - Wholesale Market Service Charge9	1580	$ 49,682.72	Consistent with EB-2016-0193, EPLC re-allocated an offsetting balance to sub-account CBR Class B9.
Variance WMS – Sub-account CBR Class B9	1580	$ (49,680.62)	Consistent with EB-2016-0193, EPLC re-allocated an offsetting balance to sub-account CBR Class B9.
RSVA - Retail Transmission Network Charge	1584	$ (0.55)	Immaterial rounding variance
RSVA - Retail Transmission Connection Charge	1586	$ 1.23	Immaterial rounding variance
RSVA - Power (excluding Global Adjustment)12	1588	$ 0.88	Immaterial rounding variance
RSVA - Global Adjustment 12	1589	$ 0.25	Immaterial rounding variance
Disposition and Recovery/Refund of Regulatory Balances (2010)7	1595	$ (0.33)	Immaterial rounding variance
Disposition and Recovery/Refund of Regulatory Balances (2012)7	1595	$ 0.46	Immaterial rounding variance
Disposition and Recovery/Refund of Regulatory Balances (2014)7	1595	$ (0.37)	Immaterial rounding variance
Disposition and Recovery/Refund of Regulatory Balances (2015)7	1595	$ 0.33	Immaterial rounding variance
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ 1.33	Immaterial rounding variance
Retail Cost Variance Account - Retail	1518	$ 0.52	Immaterial rounding variance
Misc. Deferred Debits	1525	$ (0.14)	Immaterial rounding variance
Retail Cost Variance Account - STR	1548	$ (1.43)	Immaterial rounding variance

Ontario Energy Board

2018 Deferral/Variance Account Workform

In the green shaded cells, enter the data related to the **proposed** load forecast. Do not enter data for the MicroFit class.

			A		B			C		D=A-C		F =B-C-E (deduct E if applicable)
Rate Class (Enter Rate Classes in cells below as they appear on your current tariff of rates and charges)	**Units**	**# of Customers**	**Total Metered kWh** [4]	**Total Metered kW** [4]	**Metered kWh for Non-RPP Customers** [4, 5]	**Metered kW for Non-RPP Customers** [4, 5]	**Distribution Revenue**	**Metered kWh for Wholesale Market Participants (WMP)** [4]	**Metered kW for Wholesale Market Participants (WMP)** [4]	**Total Metered kWh less WMP consumption** ***(if applicable)***	**Total Metered kW less WMP consumption** ***(if applicable)***	**Non-RPP Metered Consumption for Current Class B Customers (Non-RPP Consumption excluding WMP, Class A and Transition Customers' Consumption**
RESIDENTIAL SERVICE CLASSIFICATION	kWh	27,484	245,374,118	-	11,097,095	-		-	-	245,374,118	-	11,097,095
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICA	kWh	1,977	62,707,450	-	16,969,882	-		-	-	62,707,450	-	16,969,882
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATI	kW	219	176,280,306	446,253	158,969,973	402,432		11,323,656	19,965	164,956,650	426,288	147,646,317
EMBEDDED DISTRIBUTOR	kW	3						-	-	-	-	-
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	140	1,554,368	-	467,938	-		-	-	1,554,368	-	467,938
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	173	335,758	2,080	29,354	182		-	-	335,758	2,080	29,354
STREET LIGHTING SERVICE CLASSIFICATION	kW	2,740	2,799,882	8,848	2,799,882	8,848		-	-	2,799,882	8,848	2,799,882
										-	-	-
										-	-	-
										-	-	-
										-	-	-
										-	-	-
										-	-	-
										-	-	-
										-	-	-
										-	-	-
										-	-	-
										-	-	-
										-	-	-
										-	-	-
Total		**32,736**	**489,051,882**	**457,181**	**190,334,124**	**411,462**	**$ -**	**11,323,656**	**19,965**	**477,728,226**	**437,216**	**179,010,468**

Rate Class	1595 Recovery Share Proportion (2009) [1]	1595 Recovery Share Proportion (2010) [1]	1595 Recovery Share Proportion (2011) [1]	1595 Recovery Share Proportion (2012) [1]	1595 Recovery Share Proportion (2013) [1]	1595 Recovery Share Proportion (2014) [1]	1595 Recovery Share Proportion (2015) [1]	1595 Recovery Share Proportion (2016) [1]	1568 LRAM Variance Account Class Allocation[3] ($ amounts)	Number of Customers for Residential and GS<50 classes[2]
RESIDENTIAL SERVICE CLASSIFICATION		53%		0%		-31%			263,016	27,484
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICA		12%		-2%		-10%			170,209	1,977
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATI		34%		100%		141%			78,672	
EMBEDDED DISTRIBUTOR										
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION		0%		0%		0%				
SENTINEL LIGHTING SERVICE CLASSIFICATION		0%		0%		0%				
STREET LIGHTING SERVICE CLASSIFICATION		0.6%		0.7%		1%			8,973	
Total	**0%**	**100%**	**0%**	**100%**	**0%**	**100%**	**0%**	**0%**	**$ 520,870**	
								Balance as per Sheet 2	$ 520,868	
								Variance	$ 1	

[1] Account 1595 sub-accounts are to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented.

[2] The proportion of customers for the Residential and GS<50 Classes will be used to allocate Account 1551.

Ontario Energy Board

2018 Deferral/Variance Account Workform

		Amounts from Sheet 2	Allocator	RESIDENTIAL SERVICE CLASSIFICATION	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	EMBEDDED DISTRIBUTOR	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	SENTINEL LIGHTING SERVICE CLASSIFICATION	STREET LIGHTING SERVICE CLASSIFICATION
LV Variance Account	1550	2,735,047	kWh	1,372,267	350,695	985,856	0	8,693	1,878	15,658
Smart Metering Entity Charge Variance Account	1551	(39,925)	# of Customers	(37,246)	(2,679)	0	0	0	0	0
RSVA - Wholesale Market Service Charge	1580	(717,559)	kWh	(368,558)	(94,188)	(247,769)	0	(2,335)	(504)	(4,205)
RSVA - Retail Transmission Network Charge	1584	(441,726)	kWh	(221,629)	(56,639)	(159,222)	0	(1,404)	(303)	(2,529)
RSVA - Retail Transmission Connection Charge	1586	413,611	kWh	207,523	53,034	149,087	0	1,315	284	2,368
RSVA - Power (excluding Global Adjustment)	1588	(2,788,212)	kWh	(1,432,101)	(365,986)	(962,753)	0	(9,072)	(1,960)	(16,341)
RSVA - Global Adjustment	1589	529,057	Non-RPP kWh	32,797	50,154	436,362	0	1,383	87	8,275
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	(244,523)	%	(128,562)	(29,328)	(84,270)	0	(663)	(177)	(1,523)
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	195,924	%	903	(3,261)	196,824	0	52	(34)	1,440
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	(20,303)	%	6,299	2,045	(28,566)	0	33	15	(129)
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2016)	1595	0	%	0	0	0	0	0	0	0
Total of Group 1 Accounts (excluding 1589)		**(907,667)**		**(601,105)**	**(146,307)**	**(150,811)**	**0**	**(3,381)**	**(801)**	**(5,261)**
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	(291,829)	kWh	(146,421)	(37,419)	(105,191)	0	(928)	(200)	(1,671)
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	0	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	0	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Other	1508	0	kWh	0	0	0	0	0	0	0
Retail Cost Variance Account - Retail	1518	166,920	kWh	83,750	21,403	60,167	0	531	115	956
Misc. Deferred Debits	1525	85,443	kWh	42,870	10,956	30,798	0	272	59	489
Retail Cost Variance Account - STR	1548	(2,198)	kWh	(1,103)	(282)	(792)	0	(7)	(2)	(13)
Board-Approved CDM Variance Account	1567	0	kWh	0	0	0	0	0	0	0
Extra-Ordinary Event Costs	1572	88,411	kWh	44,359	11,336	31,868	0	281	61	506
Deferred Rate Impact Amounts	1574	0	kWh	0	0	0	0	0	0	0
RSVA - One-time	1582	0	kWh	0	0	0	0	0	0	0
Other Deferred Credits	2425	0	kWh	0	0	0	0	0	0	0
Total of Group 2 Accounts		**46,747**		**23,455**	**5,994**	**16,850**	**0**	**149**	**32**	**268**
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	0	kWh	0	0	0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	(213,674)	kWh	(107,207)	(27,398)	(77,019)	0	(679)	(147)	(1,223)
Total of Account 1592		**(213,674)**		**(107,207)**	**(27,398)**	**(77,019)**	**0**	**(679)**	**(147)**	**(1,223)**
LRAM Variance Account **(Enter dollar amount for each class)**	1568	**520,868**		263,016	170,209	78,672	0	0	0	8,973
(Account 1568 - total amount allocated to classes)		520,870								
	Variance	**(1)**								
Renewable Generation Connection OM&A Deferral Account	1532	**0**	kWh	0	0	0	0	0	0	0
Total of Group 1 Accounts (1550, 1551, 1584, 1586 and 1595)		**2,598,104**		**1,199,554**	**313,866**	**1,059,710**	**0**	**8,025**	**1,663**	**15,285**
Total of Account 1580 and 1588 (not allocated to WMPs)		**(3,505,771)**		**(1,800,659)**	**(460,174)**	**(1,210,522)**	**0**	**(11,407)**	**(2,464)**	**(20,547)**
Balance of Account 1589 Allocated to Non-WMPs		**529,057**		**32,797**	**50,154**	**436,362**	**0**	**1,383**	**87**	**8,275**
Group 2 Accounts (including 1592, 1532)		**(166,926)**		**(83,753)**	**(21,404)**	**(60,169)**	**0**	**(531)**	**(115)**	**(956)**
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	0	kWh	0	0	0	0	0	0	0
Accounting Changes Under CGAAP Balance + Return Component	1576	(4,394,960)	kWh	(2,205,102)	(563,533)	(1,584,177)	0	(13,969)	(3,017)	(25,162)
Total Balance Allocated to each class for Accounts 1575 and 1576		**(4,394,960)**		**(2,205,102)**	**(563,533)**	**(1,584,177)**	**0**	**(13,969)**	**(3,017)**	**(25,162)**

Account 1589 reference calculation by customer and consumption	
Account 1589 / Number of Customers	$16.16
1589/total kwh	$0.0011

Ontario Energy Board

2018 Deferral/Variance Account Wo

		Amounts from Sheet 2	Allocator						
LV Variance Account	1550	2,735,047	kWh	0	0	0	0	0	0
Smart Metering Entity Charge Variance Account	1551	(39,925)	# of Customers	0	0	0	0	0	0
RSVA - Wholesale Market Service Charge	1580	(717,559)	kWh	0	0	0	0	0	0
RSVA - Retail Transmission Network Charge	1584	(441,726)	kWh	0	0	0	0	0	0
RSVA - Retail Transmission Connection Charge	1586	413,611	kWh	0	0	0	0	0	0
RSVA - Power (excluding Global Adjustment)	1588	(2,788,212)	kWh	0	0	0	0	0	0
RSVA - Global Adjustment	1589	529,057	Non-RPP kWh	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	0	%	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	(244,523)	%	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	0	%	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	195,924	%	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	0	%	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	(20,303)	%	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	0	%	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2016)	1595	0	%	0	0	0	0	0	0
Total of Group 1 Accounts (excluding 1589)		**(907,667)**		**0**	**0**	**0**	**0**	**0**	**0**
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	(291,829)	kWh	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	0	kWh	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	0	kWh	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Other	1508	0	kWh	0	0	0	0	0	0
Retail Cost Variance Account - Retail	1518	166,920	kWh	0	0	0	0	0	0
Misc. Deferred Debits	1525	85,443	kWh	0	0	0	0	0	0
Retail Cost Variance Account - STR	1548	(2,198)	kWh	0	0	0	0	0	0
Board-Approved CDM Variance Account	1567	0	kWh	0	0	0	0	0	0
Extra-Ordinary Event Costs	1572	88,411	kWh	0	0	0	0	0	0
Deferred Rate Impact Amounts	1574	0	kWh	0	0	0	0	0	0
RSVA - One-time	1582	0	kWh	0	0	0	0	0	0
Other Deferred Credits	2425	0	kWh	0	0	0	0	0	0
Total of Group 2 Accounts		**46,747**		**0**	**0**	**0**	**0**	**0**	**0**
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	0	kWh	0	0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	(213,674)	kWh	0	0	0	0	0	0
Total of Account 1592		**(213,674)**		**0**	**0**	**0**	**0**	**0**	**0**
LRAM Variance Account **(Enter dollar amount for each class)**	1568	**520,868**		0	0	0	0	0	0
(Account 1568 - total amount allocated to classes)		520,870							
	Variance	**(1)**							
Renewable Generation Connection OM&A Deferral Account	1532	**0**	kWh	0	0	0	0	0	0
Total of Group 1 Accounts (1550, 1551, 1584, 1586 and 1595)		**2,598,104**		**0**	**0**	**0**	**0**	**0**	**0**
Total of Account 1580 and 1588 (not allocated to WMPs)		**(3,505,771)**		**0**	**0**	**0**	**0**	**0**	**0**
Balance of Account 1589 Allocated to Non-WMPs		**529,057**		**0**	**0**	**0**	**0**	**0**	**0**
Group 2 Accounts (including 1592, 1532)		**(166,926)**		**0**	**0**	**0**	**0**	**0**	**0**
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	0	kWh	0	0	0	0	0	0
Accounting Changes Under CGAAP Balance + Return Component	1576	(4,394,960)	kWh	0	0	0	0	0	0
Total Balance Allocated to each class for Accounts 1575 and 1576		**(4,394,960)**		**0**	**0**	**0**	**0**	**0**	**0**

Account 1589 reference calculation by customer and consumption	
Account 1589 / Number of Customers	$16.16
1589/total kwh	$0.0011

Ontario Energy Board

2018 Deferral/Variance Account Wc

		Amounts from Sheet 2	Allocator							
LV Variance Account	1550	2,735,047	kWh	0	0	0	0	0	0	0
Smart Metering Entity Charge Variance Account	1551	(39,925)	# of Customers	0	0	0	0	0	0	0
RSVA - Wholesale Market Service Charge	1580	(717,559)	kWh	0	0	0	0	0	0	0
RSVA - Retail Transmission Network Charge	1584	(441,726)	kWh	0	0	0	0	0	0	0
RSVA - Retail Transmission Connection Charge	1586	413,611	kWh	0	0	0	0	0	0	0
RSVA - Power (excluding Global Adjustment)	1588	(2,788,212)	kWh	0	0	0	0	0	0	0
RSVA - Global Adjustment	1589	529,057	Non-RPP kWh	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	(244,523)	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	195,924	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	(20,303)	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2016)	1595	0	%	0	0	0	0	0	0	0
Total of Group 1 Accounts (excluding 1589)		**(907,667)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**

Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	(291,829)	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	0	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	0	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Other	1508	0	kWh	0	0	0	0	0	0	0
Retail Cost Variance Account - Retail	1518	166,920	kWh	0	0	0	0	0	0	0
Misc. Deferred Debits	1525	85,443	kWh	0	0	0	0	0	0	0
Retail Cost Variance Account - STR	1548	(2,198)	kWh	0	0	0	0	0	0	0
Board-Approved CDM Variance Account	1567	0	kWh	0	0	0	0	0	0	0
Extra-Ordinary Event Costs	1572	88,411	kWh	0	0	0	0	0	0	0
Deferred Rate Impact Amounts	1574	0	kWh	0	0	0	0	0	0	0
RSVA - One-time	1582	0	kWh	0	0	0	0	0	0	0
Other Deferred Credits	2425	0	kWh	0	0	0	0	0	0	0
Total of Group 2 Accounts		**46,747**		**0**	**0**	**0**	**0**	**0**	**0**	**0**

PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	0	kWh	0	0	0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	(213,674)	kWh	0	0	0	0	0	0	0
Total of Account 1592		**(213,674)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**

LRAM Variance Account **(Enter dollar amount for each class)**	1568	**520,868**		0	0	0	0	0	0	0
(Account 1568 - total amount allocated to classes)		520,870								
	Variance	**(1)**								

Renewable Generation Connection OM&A Deferral Account	1532	**0**	kWh	0	0	0	0	0	0	0

Total of Group 1 Accounts (1550, 1551, 1584, 1586 and 1595)	**2,598,104**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total of Account 1580 and 1588 (not allocated to WMPs)	**(3,505,771)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
Balance of Account 1589 Allocated to Non-WMPs	**529,057**		**0**	**0**	**0**	**0**	**0**	**0**	**0**

Group 2 Accounts (including 1592, 1532)	**(166,926)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**

IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	0	kWh	0	0	0	0	0	0	0
Accounting Changes Under CGAAP Balance + Return Component	1576	(4,394,960)	kWh	0	0	0	0	0	0	0
Total Balance Allocated to each class for Accounts 1575 and 1576		**(4,394,960)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**

Account 1589 reference calculation by customer and consumption	
Account 1589 / Number of Customers	$16.16
1589/total kwh	$0.0011

Ontario Energy Board

2018 Deferral/Variance Account Workform

Please indicate the Rate Rider Recovery Period (in years) | 1

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.)

1550, 1551, 1584, 1586, 1595

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Group 1 Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	245,374,118	-$ 601,105	- 0.0024	$/kWh
GENERAL SERVICE LESS THAN 50 KW S	kWh	62,707,450	-$ 146,307	- 0.0023	$/kWh
GENERAL SERVICE 50 TO 4,999 KW SER	kW	446,253	$ 1,059,710	2.3747	$/kW
EMBEDDED DISTRIBUTOR	kW	-	$ -	-	$/kW
UNMETERED SCATTERED LOAD SERVIC	kWh	1,554,368	-$ 3,381	- 0.0022	$/kWh
SENTINEL LIGHTING SERVICE CLASSIFI	kW	2,080	-$ 801	- 0.3852	$/kW
STREET LIGHTING SERVICE CLASSIFICA	kW	8,848	-$ 5,261	- 0.5947	$/kW
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
Total			**$ 302,854**		

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.) - NON-WMP

1580 and 1588

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Group 1 Balance - Non-WMP	Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	245,374,118	$ -	-	$/kWh
GENERAL SERVICE LESS THAN 50 KW S	kWh	62,707,450	$ -	-	$/kWh
GENERAL SERVICE 50 TO 4,999 KW SER	kW	426,288	-$ 1,210,522	- 2.8397	$/kW
EMBEDDED DISTRIBUTOR	kW	-	$ -	-	$/kW
UNMETERED SCATTERED LOAD SERVIC	kWh	1,554,368	$ -	-	$/kWh
SENTINEL LIGHTING SERVICE CLASSIFI	kW	2,080	$ -	-	$/kW
STREET LIGHTING SERVICE CLASSIFICA	kW	8,848	$ -	-	$/kW
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
Total			**-$ 1,210,522**		

Only for rate classes with WMP customers are the Deferral/Variance Account Rate Riders for Non-WMP calculated separately in the table above. For all rate classes without WMP customers, balances in Accounts 1580 and 1588 are included in Deferral/Variance Account Rate Riders calculated in the first table above and disposed through a combined Deferral/Variance Account and Rate Rider.

Rate Rider Calculation for RSVA - Power - Global Adjustment

Balance of Account 1589 Allocated to Non-WMPs

Rate Class (Enter Rate Classes in cells below)	Units	kWh	Allocated Global Adjustment Balance	Rate Rider for RSVA - Power - Global Adjustment	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	11,097,095	$ 32,797	0.0030	$/kWh
GENERAL SERVICE LESS THAN 50 KW S	kWh	16,969,882	$ 50,154	0.0030	$/kWh
GENERAL SERVICE 50 TO 4,999 KW SER	kWh	147,646,317	$ 436,362	0.0030	$/kWh
EMBEDDED DISTRIBUTOR	kWh	-	$ -	-	$/kWh
UNMETERED SCATTERED LOAD SERVIC	kWh	467,938	$ 1,383	0.0030	$/kWh
SENTINEL LIGHTING SERVICE CLASSIFI	kWh	29,354	$ 87	0.0030	$/kWh
STREET LIGHTING SERVICE CLASSIFICA	kWh	2,799,882	$ 8,275	0.0030	$/kWh
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
Total			**$ 529,057**		

Rate riders for Global Adjustment is to be calculated on the basis of kWh for all classes.

Rate Rider Calculation for Group 2 Accounts

Rate Class (Enter Rate Classes in cells below)	Units	# of Customers	Allocated Group 2 Balance	Rate Rider for Group 2 Accounts	
RESIDENTIAL SERVICE CLASSIFICATION	# of Customers	27,484	-$ 83,753	-$ 0.25	per customer per month
GENERAL SERVICE LESS THAN 50 KW S	kWh	62,707,450	-$ 21,404	-$ 0.0003	$/kWh
GENERAL SERVICE 50 TO 4,999 KW SER	kW	446,253	-$ 60,169	-$ 0.1348	$/kW
EMBEDDED DISTRIBUTOR	kW	-	$ -	$ -	$/kW
UNMETERED SCATTERED LOAD SERVIC	kWh	1,554,368	-$ 531	-$ 0.0003	$/kWh
SENTINEL LIGHTING SERVICE CLASSIFI	kW	2,080	-$ 115	-$ 0.0551	$/kW
STREET LIGHTING SERVICE CLASSIFICA	kW	8,848	-$ 956	-$ 0.1080	$/kW
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
		-	$ -	$ -	
Total			-$ 166,926		

As per the Board's letter issued July 16, 2015 outlining details regarding the implementation of the transition to fully fixed distribution charges for residential customers, Residential rates for group 2 accounts are to be on a per customer basis. Please choose "# of customers" for the

Rate Rider Calculation for Accounts 1575 and 1576

Please indicate the Rate Rider Recovery Period (in years) 2

Rate Class (Enter Rate Classes in cells below)	Units	# of Customers	Allocated Accounts 1575 and 1576 Balances	Rate Rider for Accounts 1575 and 1576	
RESIDENTIAL SERVICE CLASSIFICATION	# of Customers	27,484	-$ 2,205,102	- 3.3430	per customer per month
GENERAL SERVICE LESS THAN 50 KW S	kWh	62,707,450	-$ 563,533	- 0.0045	$/kWh
GENERAL SERVICE 50 TO 4,999 KW SER	kW	446,253	-$ 1,584,177	- 1.7750	$/kW
EMBEDDED DISTRIBUTOR	kW	-	$ -	-	$/kW
UNMETERED SCATTERED LOAD SERVIC	kWh	1,554,368	-$ 13,969	- 0.0045	$/kWh
SENTINEL LIGHTING SERVICE CLASSIFI	kW	2,080	-$ 3,017	- 0.7253	$/kW
STREET LIGHTING SERVICE CLASSIFICA	kW	8,848	-$ 25,162	- 1.4219	$/kW
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
Total			-$ 4,394,960		

As per the Board's letter issued July 16, 2015 outlining details regarding the implementation of the transition to fully fixed distribution charges for residential customers, Residential rates for group 2 accounts, including Accounts 1575 and 1576 are to be on a per customer basis. Please choose "# of customers" for the

Rate Rider Calculation for Accounts 1568

Please indicate the Rate Rider Recovery Period (in years) 2

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Account 1568 Balance	Rate Rider for Account 1568	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	245,374,118	$ 263,016	0.0005	$/kWh
GENERAL SERVICE LESS THAN 50 KW S	kWh	62,707,450	$ 170,209	0.0014	$/kWh
GENERAL SERVICE 50 TO 4,999 KW SER	kW	446,253	$ 78,672	0.0881	$/kW
EMBEDDED DISTRIBUTOR	kW	-	$ -	-	$/kW
UNMETERED SCATTERED LOAD SERVIC	kWh	1,554,368	$ -	-	$/kWh
SENTINEL LIGHTING SERVICE CLASSIFI	kW	2,080	$ -	-	$/kW
STREET LIGHTING SERVICE CLASSIFICA	kW	8,848	$ 8,973	0.5070	$/kW
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
Total			$ 520,870		

Attachment 9-B

EPLC Details of Historical LRAM & LRAMVA Claims

Elenchus
34 King Street East
Suite 600
Toronto, ON
M5C 2X8

September 25, 2013

Michelle Soucie
Operations & Regulatory Accounting Analyst
Essex Powerlines Corporation
2730 Highway 3
Oldcastle, ON N0R 1L0

Re: 2011 and 2012 LRAMVA

Dear Michelle;

Elenchus is pleased to attach the 2011 and 2012 LRAMVA Report For Essex Powerlines Corporation for inclusion in your 2014 IRM Rate Application.

Elenchus concludes that Essex Powerlines Corporation's electricity rates should be adjusted to reflect an LRAMVA claim of $109,212.

Thank you for allowing Elenchus to be of service. Please contact me should you have any questions about this report.

Yours Truly,

Martin Benum
Senior Advisor

Elenchus

Essex Powerlines Corporation 2011 and 2012 LRAMVA

Date Prepared: September 25, 2013

Elenchus

34 King Street East

Suite 600

Toronto, ON

M5C 2X8

elenchus

Tab 1 of 3

Report

Table of Contents

Executive Review

On April 26, 2012 the Ontario Energy Board ("OEB" or "the Board") issued Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003) which permit Essex Powerlines Corporation to make application for recovery of lost revenue that results from the successful operation of CDM initiatives within its boundaries.

The Guidelines delineate two distinct processes for recovery of lost revenues:

- Lost Revenue Adjustment Mechanism ("LRAM") accommodates the recovery of lost revenues resulting from CDM initiatives for the period from 2005 to the end of 2010 either through approved distribution rate funding by way of the third instalment of the incremental market adjusted revenue requirement ("MAAR") or through contracts with the OPA. The manner in which distributors were instructed to determine the LRAM amount was set out in the Board's Guidelines for Electricity Distributor Conservation and Demand Management, dated March 28, 2008 (EB-2008-0037) (the "2008 CDM Guidelines").

- Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") accommodates the recovery of lost revenues resulting from CDM initiatives for the period 2011-2014. The manner in which distributors were instructed to determine the LRAMVA amount is set out in the Board's Guidelines for Electricity Distributor Conservation and Demand Management, dated April 26, 2012 (EB-2012-0003) (the "2012 CDM Guidelines").

Essex Powerlines Corporation's ("EPLC") 2012 IRM Application EB-2011-0166 concluded EPLC's claims to LRAM for 2006 to 2009 programs with persistence to 2009. EPLC filed a 2010 COS of Service Application for which the Board denied LRAM claim for 2010 programs and 2010 persistence for 2006 to 2009 programs in the 2012 IRM Application. EPLC did not file for an LRAMVA claim in its 2013 IRM Application EB-2012-0123.

EPLC's CDM activities consist of programs initiated by the Ontario Power Authority (OPA) only. By way of this report EPLC is entitled to claim in its 2014 IRM application 2011 OPA CDM program activities, 2012 persistence of OPA CDM program activities from 2011 programs , and 2012 OPA CDM program activities. In addition EPLC may claim adjustments for previous years (2011) verified results in 2012.

Elenchus concludes that Essex Powerlines Corporation's electricity rates should be adjusted to reflect an LRAM claim of $109,212.

Introduction

The LRAM and LRAMVA are designed to ensure that Local Distribution Companies ("LDC") "remain whole" despite the lower consumption levels that are, by design, the result of successful conservation and demand management initiatives. There should not be a disincentive for LDC's to encourage energy efficiency and energy conservation efforts. Therefore, an LDC is compensated for these lost revenues.

Essex Powerlines Corporation's ("EPLC") 2012 IRM Application EB-2011-0166 concluded EPLC's claims to LRAM for 2006 to 2009 programs with persistence to 2009. EPLC filed a 2010 COS of Service Application for which the Board denied LRAM claim for 2010 programs and 2010 persistence for 2006 to 2009 programs in the 2012 IRM Application. EPLC did not file for an LRAMVA claim in its 2013 IRM Application EB-2012-0123.

EPLC's CDM activities consist of programs initiated by the Ontario Power Authority (OPA) only. This reviews claim is for 2011 OPA CDM program activities, 2012 persistence of OPA CDM program activities from 2011 programs, and 2012 OPA CDM program activities. In addition EPLC may claim adjustments for previous years (2011) verified results in 2012. The LRAMVA claim is based on the 2012 Guidelines for OPA programs initiated in 2011 and 2012. EPLC does not have any Board Approved programs.

The LRAMVA calculations are based on the sum of the electricity savings over the period of the claim, which are then valued at the appropriate distribution rate depending on the timing (year) of the savings and to which rate class they belonged.

The savings themselves are the product of an energy program evaluation process, often referred to as Evaluation, Measurement and Verification (EM&V). Fortunately, in the case of this claim, all savings estimates are for OPA programs and are provided by the OPA.

These savings estimates include persistence—the installation of energy conservation measures whose savings that last past the initial year that they are installed. A four-year program that installed 10 widgets per year with a savings of 1,000 kWh each would result in the following savings profile if the widgets lasted 4 or more years (which is common):

Example Savings Profile Showing Effect of Persistence

Year	In-Year Savings (kWh)	Cumulative Savings (kWh)
1	10,000	10,000

2	20,000	30,000
3	30,000	60,000
4	40,000	100,000

Savings from CDM programs typically follow a pattern similar to the one illustrated in the table above. Energy program evaluations determine the energy and demand savings estimates to a reasonable degree of accuracy and also determine the persistence including patterns, or effective useful life (EUL) of new measures being installed and the remaining useful life (RUL) of measures being replaced. It is assumed that the tables provided to each LDC by the OPA contain accurate interpretations and transcriptions of the results from those evaluations (available on the OPA Website).

There are "gross" savings and "net" savings for energy efficiency programs. OPA documentation details the differences between these two, and both are provided to LDC's by the OPA, but for the purposes of this LRAM claim only "net" savings are utilized. Net savings are determined to be those savings that would not have occurred unless the energy efficiency program was running. They are not natural conservation or savings that someone could claim would have occurred anyway. They do not include savings from "free riders."

Some energy efficiency programs are operated at a province-wide scale. These include some behavioural-based programs and some residential/consumer-orientated initiatives like discount coupons. In certain of these cases, savings are apportioned to LDC's by the OPA rather than an attempt made to track individual transactions (which is sometimes impossible).

The 2011 and 2012 program savings claimed by EPLC are the net energy and demand savings that can be attributed to the programs and initiatives that operated in EPLC's territory during the 2011 and 2012 period as apportioned to Essex Powerlines Corporation by the OPA according to its established formulae.

Assumptions

This report for EPLC was created with the following assumptions that are often peculiar to the 2011 - 2012 periods:

- “Consumer Program” classified as the Residential rate class
- “Business Program” classified as General Service <50 kW rate class
- “Industrial Program” classified as General Service >50 kW rate class
- “Home Assistance Program” classified as the Residential rate class
- “Pre-2011 Programs completed in 2011” classified as General Service >50 kW rate class
- “Industrial” and “Pre-2011 Programs” kWh savings were omitted because they are not assignable as a volumetric charge
- “Consumer” “Business” and “Home Assistance Program” kW savings were omitted because they are not assignable as a volumetric charge

For purposes of monetary estimation kWh savings are multiplied by the 2011 and 2012 volumetric distribution rates of the Residential and General Service <50 kW rate classes. kW savings are multiplied by the 2011 and 2012 volumetric distribution rates of the General Service 50 to 2,999 kW rate class. Please reference Appendix 2 and Appendix 3 for EPLC’s 2011 and 2012 schedule of rates and charges for the claim rate classes.

Energy (kWh) savings are assumed to be annual values. Peak Demand (kW) savings have been extended by the number of months (either 5 months for Demand Response programs or 12 months for all other programs).

Persistence of programs are assumed to be one year only for Demand Response programs or continuing into future years for all other programs.

2011 and 2012 LRAMVA Recommendation

Elenchus has concluded that Essex Powerlines Corporation can justifiably claim $109,212 in LRAMVA including carrying cost to April 30, 2014, allocated by rate class as shown in the Table 1 below. Please reference Attachment 1 for the complete calculation.

2011 and 2012 LRAMVA

Customer Class	Amount	Interest *	Total
Residential	$ 31,899	$ 960	$ 32,859
General Service Less Than 50 kW	$ 28,266	$ 806	$ 29,071
General Service Greater Than 50 kW	$ 45,854	$ 1,428	$ 47,283
Total	**$ 106,019**	**$ 3,194**	**$ 109,212**

* Carrying Costs to April 30, 2014

Table 1 2012 LRAMVA

Elenchus has calculated the following rate rider for disposition of the 2011 and 2012 LRAMVA claim as shown in the Table 2 below. This is based on a one year recovery. Billing determinants have been applied based on EPLC's 2010 Cost of Service load forecast.

2011 and 2012 LRAMVA Rate Rider Calculation

Effective: May 1, 2014 to April 30, 2015

Rate Class	Total	Billing Determinant		Rate Rider
Residential	$ 32,859	271,379,498	kWh	$ 0.0001
General Service Less Than 50 kW	$ 29,071	72,012,960	kWh	$ 0.0004
General Service Greater Than 50 kW	$ 47,283	467,092	kW	$ 0.1012
Total	**$ 109,212**			

Table 2 2012 LRAMVA Rate Rider

LRAMVA Declaration

EPLC may apply for the disposition of the balance in the 2011 and 2012 LRAMVA as part of it 2014 IRM application if EPLC's deems the amount to be significant. Elenchus would confirm this.

In support of its application for lost revenues, and specifically the actual results used in the determination of the LRAMVA balance to be disposed, EPLC must file the following:

- A statement indicating that the EPLC has used the most recent input assumptions available at the time of the program evaluation when calculating its lost revenue amount. Elenchus would confirm this.

- A statement indicating that the distributor has relied on the most recent and appropriate final CDM evaluation report from the OPA in support of its lost revenue calculation and a copy of this report. Elenchus would confirm using the OPA Annual CDM Report 2012 - Final Verified Results attached as Appendix 1 of this report.

- Separate tables for each rate class showing the lost revenue amounts requested by the year they are associated with and the year the lost revenues took place. Elenchus would confirm this as attached in Attachment 1to this report.

- Lost revenue calculations, determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board approved variable distribution charge appropriate to the class. Elenchus would confirm this as attached in Attachment 1 to this report.

- A statement, and if applicable a table, that indicates if carrying charges are being requested on the lost revenue amount. Elenchus would confirm this as attached in Attachment 1 to this report.
- Elenchus confirms EPLC is not including any claims for Board-approved programs.

Work Sited and Referenced

1. Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003) Issued: April 26, 2012
2. OPA 2012 Annual CDM Report – Final Verified Results on provincial conservation results to Local Distribution Company service territories – issued August 30, 2013
    - Please reference Appendix 1 attached to this report.

Tab 2 of 3

2011 and 2012 LRAMVA Calculation

Attachment 1 of 1

2011 and 2012 LRAMVA Calculation

Input Table One
2011 Programs in 2011
(Net kWh)

Amount	2011
RES	
2011	
Consumer Program	
Appliance Exchange	3,231
Appliance Retirement	48,406
Bi-Annual Retailer Event	192,162
Conservation Instant Coupon Booklet	121,822
HVAC Incentives	463,694
Consumer Program Total	829,315
2011 Total	**829,315**
RES Total	**829,315**
GSLT50	
2011	
Business Program	
Demand Response 3*	7,344
Direct Install Lighting	139,935
Retrofit	337,744
Business Program Total	485,023
2011 Total	**485,023**
GSLT50 Total	**485,023**

Input Table Two
2011 Persistence in 2012 and 2012 Programs
(Net kWh)

Amount	2012
RES	
2011	
Consumer Program	
Appliance Exchange	3,231
Appliance Retirement	48,406
Bi-Annual Retailer Event	192,162
Bi-Annual Retailer Event - previous year adjustment	14,277
Conservation Instant Coupon Booklet	121,822
Conservation Instant Coupon Booklet - previous year adjustment	1,802
HVAC Incentives	463,694
HVAC Incentives - previous year adjustment	-70,103
Consumer Program Total	775,291
2011 Total	**775,291**
2012	
Consumer Program	
Appliance Exchange	4,153
Appliance Retirement	16,070
Bi-Annual Retailer Event	175,123
Conservation Instant Coupon Booklet	9,143
HVAC Incentives	249,324
Consumer Program Total	453,813
Home Assistance Program	
Home Assistance Program	88,006
Home Assistance Program Total	88,006
2012 Total	**541,819**
RES Total	**1,317,110**
GSLT50	
2011	
Business Program	
Direct Install Lighting	139,935
Retrofit	337,744
Business Program Total	477,679
2011 Total	**477,679**
2012	
Business Program	
Demand Response 3*	2,742
Direct Install Lighting	23,662
Energy Audit	25,176
Retrofit	1,594,397
Business Program Total	1,645,977
2012 Total	**1,645,977**
GSLT50 Total	**2,123,656**

Input Table Three
2011 Programs in 2011
(Net kW)

	2011 Report Amount	Months	Annual Amount
GSGT50			
2011			
Industrial Program			
Demand Response 3*	1,749	5	8,745
Retrofit	93	12	1,116
Industrial Program Total	1,842		9,861
Pre-2011 Programs completed in 2011			
Electricity Retrofit Incentive Program	10	12	120
Pre-2011 Programs completed in 2011 Total	10	12	120
2011 Total	**1,852**		**9,981**
GSGT50 Total	**1,852**		**9,981**

Input Table Four
2011 Persistence in 2012 and 2012 Programs
(Net kW)

	2012 Report Amount	Months	Annual Amount
GSGT50			
2011			
Industrial Program			
Retrofit	93	12	1,116
Industrial Program Total	93		1,116
Pre-2011 Programs completed in 2011			
Electricity Retrofit Incentive Program	10	12	120
Pre-2011 Programs completed in 2011 Total	10		120
2011 Total	**103**		**1,236**
2012			
Industrial Program			
Demand Response 3*	1,811	5	9,055
Industrial Program Total	1,811		9,055
Pre-2011 Programs completed in 2011			
High Performance New Construction	1	12	12
Pre-2011 Programs completed in 2011 Total	1	12	12
2012 Total	**1,812**		**9,067**
GSGT50 Total	**1,915**		**10,303**

Output Table One

2011 and 2012 LRAMVA

2011 Programs in 2011

	Net kWh	2011 Rate	Amount		RES	GSLT 50	GSGT50
RES	829,315	0.0148	$ 12,274		$ 12,274		
GSLT 50	485,023	0.0088	$ 4,268			$ 4,268	
			$ 16,542				
	Net kW	**2011 Rate**	**Amount**				
GSGT50	9,981	2.4899	$ 24,851.69				$ 24,852
			2012 LRAMVA	**$ 41,394**	$ 12,274	$ 4,268	$ 24,852

2011 Persistence in 2012 and 2012 Programs

	Net kWh	2012 Rate	Amount		RES	GSLT 50	GSGT50
RES	1,317,110	0.0149	$ 19,625		$ 19,625		
GSLT 50	2,123,656	0.0113	$ 23,997			$ 23,997	
			$ 43,622				
	Net kW	**2012 Rate**	**Amount**				
GSGT50	10,303	2.0385	$ 21,002.67				$ 21,003
			2012 LRAMVA	**$ 64,625**	$ 19,625	$ 23,997	$ 21,003
			Total	**$ 106,019**	**$ 31,899**	**$ 28,266**	**$ 45,854**

Output Table Two
Calculated Carrying Costs to April 30, 2014

				LRAM LRAMVA			Allocated Carrying Costs		
Month	OEB Prescribed Annual Rate	Days in Month	Monthly Interest Rate	Residential	GS LT 50	GS GT 50	Residential	GS LT 50	GS GT 50
Jan-2011	1.47%	31	0.12%	$ 1,023	$ 356	$ 2,071	$ 1.28	$ 0.44	$ 2.59
Feb-2011	1.47%	28	0.11%	$ 2,046	$ 711	$ 4,142	$ 2.31	$ 0.80	$ 4.67
Mar-2011	1.47%	31	0.12%	$ 3,068	$ 1,067	$ 6,213	$ 3.83	$ 1.33	$ 7.76
Apr-2011	1.47%	30	0.12%	$ 4,091	$ 1,423	$ 8,284	$ 4.94	$ 1.72	$ 10.01
May-2011	1.47%	31	0.12%	$ 5,114	$ 1,778	$ 10,355	$ 6.38	$ 2.22	$ 12.93
Jun-2011	1.47%	30	0.12%	$ 6,137	$ 2,134	$ 12,426	$ 7.41	$ 2.58	$ 15.01
Jul-2011	1.47%	31	0.12%	$ 7,160	$ 2,490	$ 14,497	$ 8.94	$ 3.11	$ 18.10
Aug-2011	1.47%	31	0.12%	$ 8,183	$ 2,845	$ 16,568	$ 10.22	$ 3.55	$ 20.68
Sep-2011	1.47%	30	0.12%	$ 9,205	$ 3,201	$ 18,639	$ 11.12	$ 3.87	$ 22.52
Oct-2011	1.47%	31	0.12%	$ 10,228	$ 3,557	$ 20,710	$ 12.77	$ 4.44	$ 25.86
Nov-2011	1.47%	30	0.12%	$ 11,251	$ 3,913	$ 22,781	$ 13.59	$ 4.73	$ 27.52
Dec-2011	1.47%	31	0.12%	$ 12,274	$ 4,268	$ 24,852	$ 15.32	$ 5.33	$ 31.03
Jan-2012	1.47%	31	0.12%	$ 13,909	$ 6,268	$ 26,602	$ 17.37	$ 7.83	$ 33.21
Feb-2012	1.47%	29	0.12%	$ 15,545	$ 8,268	$ 28,352	$ 18.16	$ 9.66	$ 33.11
Mar-2012	1.47%	31	0.12%	$ 17,180	$ 10,268	$ 30,102	$ 21.45	$ 12.82	$ 37.58
Apr-2012	1.47%	30	0.12%	$ 18,816	$ 12,267	$ 31,853	$ 22.73	$ 14.82	$ 38.48
May-2012	1.47%	31	0.12%	$ 20,451	$ 14,267	$ 33,603	$ 25.53	$ 17.81	$ 41.95
Jun-2012	1.47%	30	0.12%	$ 22,086	$ 16,267	$ 35,353	$ 26.69	$ 19.65	$ 42.71
Jul-2012	1.47%	31	0.12%	$ 23,722	$ 18,267	$ 37,103	$ 29.62	$ 22.81	$ 46.32
Aug-2012	1.47%	31	0.12%	$ 25,357	$ 20,266	$ 38,853	$ 31.66	$ 25.30	$ 48.51
Sep-2012	1.47%	30	0.12%	$ 26,993	$ 22,266	$ 40,604	$ 32.61	$ 26.90	$ 49.06
Oct-2012	1.47%	31	0.12%	$ 28,628	$ 24,266	$ 42,354	$ 35.74	$ 30.30	$ 52.88
Nov-2012	1.47%	30	0.12%	$ 30,263	$ 26,266	$ 44,104	$ 36.56	$ 31.73	$ 53.29
Dec-2012	1.47%	31	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 39.83	$ 35.29	$ 57.25
Jan-2013	1.47%	31	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 39.72	$ 35.19	$ 57.09
Feb-2013	1.47%	28	0.11%	$ 31,899	$ 28,266	$ 45,854	$ 35.87	$ 31.79	$ 51.57
Mar-2013	1.47%	31	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 39.72	$ 35.19	$ 57.09
Apr-2013	1.47%	30	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 38.44	$ 34.06	$ 55.25
May-2013	1.47%	31	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 39.72	$ 35.19	$ 57.09
Jun-2013	1.47%	30	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 38.44	$ 34.06	$ 55.25
Jul-2013	1.47%	31	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 39.72	$ 35.19	$ 57.09
Aug-2013	1.47%	31	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 39.72	$ 35.19	$ 57.09
Sep-2013	1.47%	30	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 38.44	$ 34.06	$ 55.25
Oct-2013	1.47%	31	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 39.72	$ 35.19	$ 57.09
Nov-2013	1.47%	30	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 38.44	$ 34.06	$ 55.25
Dec-2013	1.47%	31	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 39.72	$ 35.19	$ 57.09
Jan-2014	1.47%	31	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 39.83	$ 35.29	$ 57.25
Feb-2014	1.47%	28	0.11%	$ 31,899	$ 28,266	$ 45,854	$ 35.97	$ 31.87	$ 51.71
Mar-2014	1.47%	31	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 39.83	$ 35.29	$ 57.25
Apr-2014	1.47%	30	0.12%	$ 31,899	$ 28,266	$ 45,854	$ 38.54	$ 34.15	$ 55.40
							$ 959.74	$ 805.89	$ 1,428.19

Output Table Three
2011 and 2012 LRAMVA

Customer Class	Amount	Interest *	Total
Residential	$ 31,899	$ 960	$ 32,859
General Service Less Than 50 kW	$ 28,266	$ 806	$ 29,071
General Service Greater Than 50 kW	$ 45,854	$ 1,428	$ 47,283
Total	**$ 106,019**	**$ 3,194**	**$ 109,212**

* Carrying Costs to April 30, 2014

2011 and 2012 LRAMVA Rate Rider Calculation

Effective: May 1, 2014 to April 30, 2015

Rate Class	Total	Billing Determinant		Rate Rider
Residential	$ 32,859	271,379,498	kWh	$ 0.0001
General Service Less Than 50 kW	$ 29,071	72,012,960	kWh	$ 0.0004
General Service Greater Than 50 kW	$ 47,283	467,092	kW	$ 0.1012
Total	**$ 109,212**			

Tab 3 of 3

Appendices

Appendix 1 of 3

Appendix 1 - OPA Final Verified 2012 Annual CDM Report

saveONenergy

Message from the Vice President:

The OPA is pleased to provide you with the enclosed Final 2012 Results Report. We have seen a 39% increase in energy savings for our new province-wide 2011-2014 suite of saveONenergy initiatives. Overall progress to targets is moving up with 29% of demand and 65% of energy savings achieved. Many LDCs, both large and small, continue to stay on track to meet or exceed their OEB targets. Conservation programs continue to be a valuable and cost effective resource for customers across the province, over the past two years the program cost to consumers remains within 3 cents per kWh.

Further to programmatic savings, capability building efforts launched in 2011 are yielding healthy enabled savings through Embedded Energy Managers and Audit initiative projects. The strong momentum continues in 2013.

We remain committed to ensuring LDCs are successful in meeting their objectives and our collective efforts to date have improved the current program suite by offering more local program opportunities, implementing a new expedited change management process, and enhancing incentives to make it easier for customers to participate in programs. We invite you to continue to provide your feedback to us and to celebrate our successes as we move forward.

The format of this report was developed in collaboration with the OPA-LDC Reporting and Evaluation Working Group and is designed to help populate LDC annual report templates that will be submitted to the OEB in late September. All results are now considered final for 2012. Any additional 2012 program activity not captured will be reported in the Final 2013 Results Report.

Please continue to monitor saveONenergy E-blasts for any further updates and should you have any other questions or comments please contact LDC.Support@powerauthority.on.ca.

We appreciate your ongoing collaboration and cooperation throughout the reporting and evaluation process. We look forward to another successful year.

Sincerely,

Andrew Pride

Table of Contents

OPA-Contracted Province-Wide CDM Programs FINAL 2012 Results

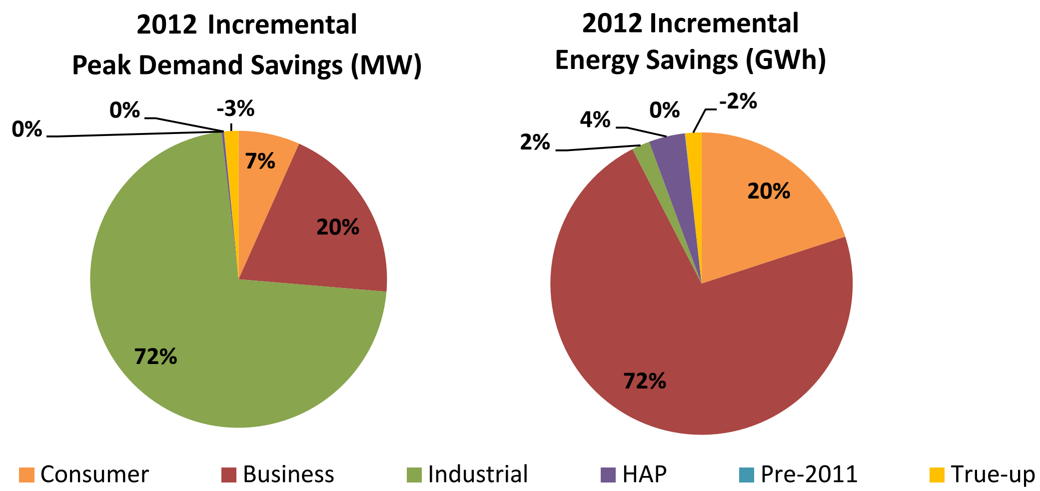
LDC: Essex Powerlines Corporation

FINAL 2012 Progress to Targets	2012 Incremental	Program-to-Date Progress to Target (Scenario 1)	Scenario 1: % of Target Achieved	Scenario 2: % of Target Achieved
Net Annual Peak Demand Savings (MW)	2.4	0.9	**12.8%**	**40.6%**
Net Energy Savings (GWh)	2.2	14.6	**67.9%**	**68.4%**

Scenario 1 = Assumes that demand resource resources have a persistence of 1 year

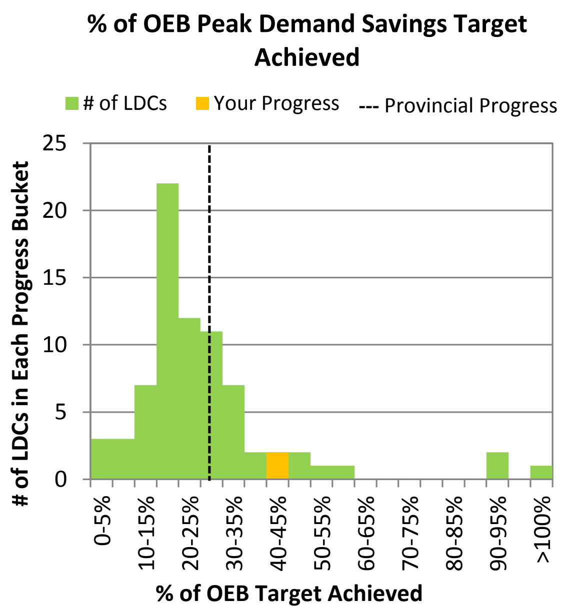
Scenario 2 = Assumes that demand response resources remain in your territory until 2014

Achievement by Sector



Comparison: Your Achievement vs. LDC Community Achievement (Progress to Target)

The following graphs assume that demand response resources remain in your territory until 2014 (aligns with Scenario 2)



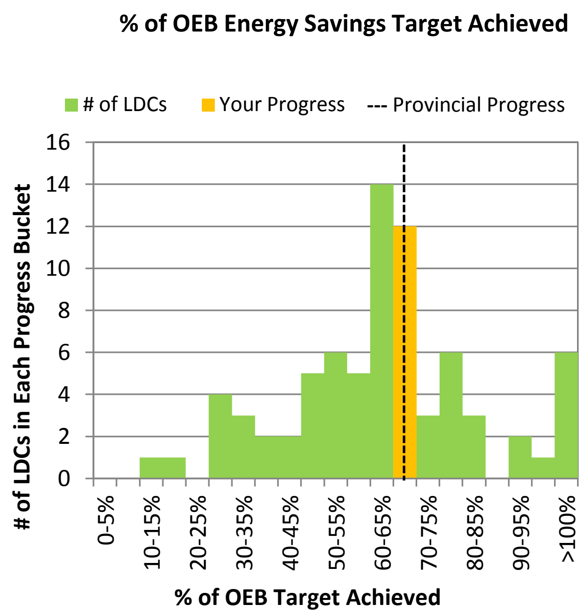


Table 1: **Essex Powerlines Corporation** Initiative and Program Level Savings by Year (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR) 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR) 2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	118	40			7	2			48,406	16,070			9	241,633
Appliance Exchange	Appliances	29	17			3	2			3,231	4,153			3	23,584
HVAC Incentives	Equipment	1,016	743			264	153			463,694	249,324			417	2,602,748
Conservation Instant Coupon Booklet	Items	3,256	202			8	2			121,822	9,143			9	514,715
Bi-Annual Retailer Event	Items	5,691	6,937			11	10			192,162	175,123			21	1,294,015
Retailer Co-op	Items	0	0			0	0			0	0			0	0
Residential Demand Response (switch/pstat)	Devices	85	0			48	0			0	0			0	0
Residential Demand Response (IHD)	Devices	0	0			0				0					
Residential New Construction	Homes	0	0			0	0			0	0			0	0
Consumer Program Total						**340**	**169**			**829,315**	**453,813**			**459**	**4,676,694**
Business Program															
Retrofit	Projects	10	27			56	295			337,744	1,594,397			343	6,111,172
Direct Install Lighting	Projects	40	7			52	7			139,935	23,662			43	578,708
Building Commissioning	Buildings	0	0			0	0			0	0			0	0
New Construction	Buildings	0	0			0	0			0	0			0	0
Energy Audit	Audits	0	1			0	5			0	25,176			5	75,529
Small Commercial Demand Response	Devices	0	0			0	0			0	0			0	0
Small Commercial Demand Response (IHD)	Devices	0	0			0				0				0	0
Demand Response 3	Facilities	3	3			188	189			7,344	2,742			0	10,086
Business Program Total						**296**	**495**			**485,023**	**1,645,977**			**391**	**6,775,495**
Industrial Program															
Process & System Upgrades	Projects	0	0			0	0			0	0			0	0
Monitoring & Targeting	Projects	0	0			0	0			0	0			0	0
Energy Manager	Projects	0	0			0	0			0	0			0	0
Retrofit	Projects	4				93				688,860				93	2,755,441
Demand Response 3	Facilities	4	4			1,749	1,811			102,648	43,656			0	146,305
Industrial Program Total						**1,841**	**1,811**			**791,509**	**43,656**			**93**	**2,901,745**
Home Assistance Program															
Home Assistance Program	Homes	0	149			0	6			0	88,006			6	264,017
Home Assistance Program Total						**0**	**6**			**0**	**88,006**			**6**	**264,017**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	7	0			10	0			56,015	0			10	224,061
High Performance New Construction	Projects	0	0			0	1			1,239	716			1	7,102
Toronto Comprehensive	Projects	0	0			0	0			0	0			0	0
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0			0	0			0	0
LDC Custom Programs	Projects	0	0			0	0			0	0			0	0
Pre-2011 Programs completed in 2011 Total						**10**	**1**			**57,254**	**716**			**11**	**231,163**
Other															
Program Enabled Savings	Projects	0	0			0	0			0	0			0	0
Time-of-Use Savings	Homes														
Other Total							**0**				**0**			**0**	**0**
Adjustments to Previous Year's Verified Results							**-39**				**-54,023**			**-39**	**-216,093**
Energy Efficiency Total						**503**	**482**			**2,053,107**	**2,185,769**			**959**	**14,692,723**
Demand Response Total (Scenario 1)						**1,984**	**2,000**			**109,992**	**46,398**			**0**	**156,391**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**2,487**	**2,443**			**2,163,100**	**2,178,144**			**920**	**14,633,021**
													Full OEB Target:	**7,190**	**21,540,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**12.8%**	**67.9%**

Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Due to the limited timeframe of data, which didn't include the summer months, 2012 IHD results have been deemed inconclusive. The IHD line item on the 2012 annual report will be left blank. Once a full year of data is available (2013 evaluation), and the savings are quantified, 2012 results will be updated to reflect the quantified savings.

Table 2: Adjustments to **Essex Powerlines Corporation** Verified Results due to Errors or Omissions (Scenario 1)

Initiative	Unit	**Incremental Activity** (new program activity occurring within the specified reporting period)				**Net Incremental Peak Demand Savings (kW)** (new peak demand savings from activity within the specified reporting period)				**Net Incremental Energy Savings (kWh)** (new energy savings from activity within the specified reporting period)				**Program-to-Date Verified Progress to Target** (excludes DR): **2014 Net Annual Peak Demand Savings (kW)**	**Program-to-Date Verified Progress to Target** (excludes DR): **2011-2014 Net Cumulative Energy Savings (kWh)**
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	0				0				0				0	0
Appliance Exchange	Appliances	0				0				0				0	0
HVAC Incentives	Equipment	-160				-40				-70,103				-40	-280,411
Conservation Instant Coupon Booklet	Items	54				0				1,802				0	7,210
Bi-Annual Retailer Event	Items	535				1				14,277				1	57,108
Retailer Co-op	Items	0				0				0				0	0
Residential Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Residential Demand Response (IHD)	Devices	0				0				0				0	0
Residential New Construction	Homes	0				0				0				0	0
Consumer Program Total						**-39**				**-54,023**				**-39**	**-216,093**
Business Program															
Retrofit	Projects	0				0				0				0	0
Direct Install Lighting	Projects	0				0				0				0	0
Building Commissioning	Buildings	0				0				0				0	0
New Construction	Buildings	0				0				0				0	0
Energy Audit	Audits	0				0				0				0	0
Small Commercial Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Small Commercial Demand Response (IHD)	Devices	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Business Program Total						**0**				**0**				**0**	**0**
Industrial Program															
Process & System Upgrades	Projects	0				0				0				0	0
Monitoring & Targeting	Projects	0				0				0				0	0
Energy Manager	Projects	0				0				0				0	0
Retrofit	Projects	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Industrial Program Total						**0**				**0**				**0**	**0**
Home Assistance Program															
Home Assistance Program	Homes	0				0				0				0	0
Home Assistance Program Total						**0**				**0**				**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	0				0				0				0	0
High Performance New Construction	Projects	0				0				0				0	0
Toronto Comprehensive	Projects	0				0				0				0	0
Multifamily Energy Efficiency Rebates	Projects	0				0				0				0	0
LDC Custom Programs	Projects	0				0				0				0	0
Pre-2011 Programs completed in 2011 Total						**0**				**0**				**0**	**0**
Other															
Program Enabled Savings	Projects	0				0				0				0	0
Time-of-Use Savings	Homes														
Other Total						**0**				**0**				**0**	**0**
Adjustments to Previous Year's Verified Results						**-39**				**-54,023**				**-39**	**-216,093**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Table 3: Essex Powerlines Corporation Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement		1.00				0.47				1.00				0.47		
Appliance Exchange		1.00				0.52				1.00				0.52		
HVAC Incentives		1.00				0.50				1.00				0.49		
Conservation Instant Coupon Booklet		1.00				1.00				1.00				1.05		
Bi-Annual Retailer Event		1.00				0.91				1.00				0.92		
Retailer Co-op		n/a				n/a				n/a				n/a		
Residential Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Residential Demand Response (IHD)		n/a				n/a				n/a				n/a		
Residential New Construction		n/a				n/a				n/a				n/a		
Business Program																
Retrofit		1.00				0.79				1.22				0.80		
Direct Install Lighting		0.68				0.94				0.85				0.94		
Building Commissioning		n/a				n/a				n/a				n/a		
New Construction		n/a				n/a				n/a				n/a		
Energy Audit		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (IHD)		n/a				n/a				n/a				n/a		
Demand Response 3*		n/a				n/a				n/a				n/a		
Industrial Program																
Process & System Upgrades		n/a				n/a				n/a				n/a		
Monitoring & Targeting		n/a				n/a				n/a				n/a		
Energy Manager		n/a				n/a				n/a				n/a		
Retrofit																
Demand Response 3*		n/a				n/a				n/a				n/a		
Home Assistance Program																
Home Assistance Program		0.40				1.00				0.44				1.00		
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program		n/a				n/a				n/a				n/a		
High Performance New Construction		1.00				0.50				1.00				0.50		
Toronto Comprehensive		n/a				n/a				n/a				n/a		
Multifamily Energy Efficiency Rebates		n/a				n/a				n/a				n/a		
LDC Custom Programs		n/a				n/a				n/a				n/a		
Other																
Program Enabled Savings		n/a				n/a				n/a				n/a		
Time-of-Use Savings		n/a				n/a				n/a				n/a		

Progress Towards CDM Targets

Results are attributed to target using current OPA reporting policies. Energy efficiency resources persist for the duration of the effective useful life. Any upcoming code changes are taken into account. Demand response resources persist for 1 year. Please see methodology tab for more detailed information.

Table 4: Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	2.5	0.5	0.5	0.5
2012 - Verified		2.4	0.4	0.4
2013				
2014				
Verified Net Annual Peak Demand Savings Persisting in 2014:				**0.9**
Essex Powerlines Corporation 2014 Annual CDM Capacity Target				**7.2**
Verified Portion of Peak Demand Savings Target Achieved in 2014(%):				**12.8%**

Table 5: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	2.2	2.1	2.1	2.0	8.3
2012 - Verified		2.2	2.1	2.1	6.4
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					**14.6**
Essex Powerlines Corporation 2011-2014 Annual CDM Energy Target					**21.5**
Verified Portion of Cumulative Energy Target Achieved (%):					**67.9%**

*2011 energy adjustments included in cumulative energy savings.

Table 6: Province-Wide Initiatives and Program Level Savings by Year

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	56,110	34,146			3,299	2,011			23,005,812	13,424,518			5,171	132,176,857
Appliance Exchange	Appliances	3,688	3,836			371	556			450,187	974,621			689	4,512,525
HVAC Incentives	Equipment	111,587	85,221			32,037	19,060			59,437,670	32,841,283			51,097	336,274,530
Conservation Instant Coupon Booklet	Items	559,462	30,891			1,344	230			21,211,537	1,398,202			1,575	89,040,754
Bi-Annual Retailer Event	Items	870,332	1,060,901			1,681	1,480			29,387,468	26,781,674			3,161	197,894,897
Retailer Co-op	Items	152	0			0	0			2,652	0			0	10,607
Residential Demand Response (switch/pstat)*	Devices	19,550	98,388			10,947	49,038			24,870	359,408			0	384,279
Residential Demand Response (IHD)	Devices	0	49,689			0				0					
Residential New Construction	Homes	7	19			0	2			743	17,152			2	54,430
Consumer Program Total						**49,681**	**72,377**			**133,520,941**	**75,796,859**			**61,696**	**760,348,879**
Business Program															
Retrofit	Projects	2,516	5,605			24,467	61,147			136,002,258	314,922,468			84,018	1,480,647,459
Direct Install Lighting	Projects	20,297	18,494			23,724	15,284			61,076,701	57,345,798			31,181	391,072,869
Building Commissioning	Buildings	0	0			0	0			0	0			0	0
New Construction	Buildings	10	69			123	764			411,717	1,814,721			888	7,091,031
Energy Audit	Audits	103	280			0	1,450			0	7,049,351			1,450	21,148,054
Small Commercial Demand Response	Devices	132	294			84	187			157	1,068			0	1,224
Small Commercial Demand Response (IHD)	Devices	0	0			0				0				0	0
Demand Response 3*	Facilities	145	151			16,218	19,389			633,421	281,823			0	915,244
Business Program Total						**64,617**	**98,221**			**198,124,253**	**381,415,230**			**117,535**	**1,900,875,881**
Industrial Program															
Process & System Upgrades	Projects	0	0			0	0			0	0			0	0
Monitoring & Targeting	Projects	0	0			0	0			0	0			0	0
Energy Manager	Projects	0	39			0	1,086			0	7,372,108			1,086	22,116,324
Retrofit	Projects	433				4,615				28,866,840				4,613	115,462,282
Demand Response 3*	Facilities	124	185			52,484	74,056			3,080,737	1,784,712			0	4,865,449
Industrial Program Total						**57,098**	**75,141**			**31,947,577**	**9,156,820**			**5,699**	**142,444,054**
Home Assistance Program															
Home Assistance Program	Homes	46	5,033			2	566			39,283	5,442,232			569	16,483,831
Home Assistance Program Total						**2**	**566**			**39,283**	**5,442,232**			**569**	**16,483,831**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	2,016	0			21,662	0			121,138,219	0			21,662	484,552,876
High Performance New Construction	Projects	145	69			5,098	3,251			26,185,591	11,901,944			8,349	140,448,197
Toronto Comprehensive	Projects	577	0			15,805	0			86,964,886	0			15,805	347,859,545
Multifamily Energy Efficiency Rebates	Projects	110	0			1,981	0			7,595,683	0			1,981	30,382,733
LDC Custom Programs	Projects	8	0			399	0			1,367,170	0			399	5,468,679
Pre-2011 Programs completed in 2011 Total						**44,945**	**3,251**			**243,251,550**	**11,901,944**			**48,195**	**1,008,712,030**
Other															
Program Enabled Savings	Projects	0	16			0	2,304			0	1,188,362			2,304	3,565,086
Time-of-Use Savings	Homes														
Other Total							**2,304**				**1,188,362**			**2,304**	**3,565,086**
Adjustments to Previous Year's Verified Results							**1,406**				**18,689,081**			**1,156**	**73,918,598**
Energy Efficiency Total						**136,610**	**109,191**			**603,144,419**	**482,474,435**			**235,998**	**3,826,263,564**
Demand Response Total (Scenario 1)						**79,733**	**142,670**			**3,739,185**	**2,427,011**			**0**	**6,166,196**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**216,343**	**253,267**			**606,883,604**	**503,590,526**			**237,154**	**3,906,348,358**
													Full OEB Target:	**1,330,000**	**6,000,000,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**17.8%**	**65.1%**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Due to the limited timeframe of data, which didn't include the summer months, 2012 IHD results have been deemed inconclusive. The IHD line item on the 2012 annual report will be left blank. Once a full year of data is available (2013 evaluation), and the savings are quantified, 2012 results will be updated to reflect the quantified savings.

Table 7: Adjustments to **Province-Wide** Verified Results due to Errors & Omissions (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR): 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR): 2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	0				0				0				0	0
Appliance Exchange	Appliances	0				0				0				0	0
HVAC Incentives	Equipment	-18,866				-5,278				-9,721,817				-5,278	-38,887,267
Conservation Instant Coupon Booklet	Items	8,216				16				275,655				16	1,102,621
Bi-Annual Retailer Event	Items	81,817				108				2,183,391				108	8,733,563
Retailer Co-op	Items	0				0				0				0	0
Residential Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Residential Demand Response (IHD)	Devices	0				0				0				0	0
Residential New Construction	Homes	19				1				13,767				1	55,069
Consumer Program Total						**-5,153**				**-7,249,004**				**-5,153**	**-28,996,015**
Business Program															
Retrofit	Projects	303				3,204				16,216,165				3,083	64,398,674
Direct Install Lighting	Projects	444				501				1,250,388				372	4,624,945
Building Commissioning	Buildings	0				0				0				0	0
New Construction	Buildings	12				828				3,520,620				828	14,082,482
Energy Audit	Audits	93				481				2,341,392				481	9,365,567
Small Commercial Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Small Commercial Demand Response (IHD)	Devices	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Business Program Total						**5,014**				**23,328,565**				**4,764**	**92,471,668**
Industrial Program															
Process & System Upgrades	Projects	0				0				0				0	0
Monitoring & Targeting	Projects	0				0				0				0	0
Energy Manager	Projects	0				0				0				0	0
Retrofit	Projects	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Industrial Program Total						**0**				**0**				**0**	**0**
Home Assistance Program															
Home Assistance Program	Homes	0				0				0				0	0
Home Assistance Program Total						**0**				**0**				**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	12				138				545,536				138	2,182,145
High Performance New Construction	Projects	34				1,407				2,065,200				1,407	8,260,800
Toronto Comprehensive	Projects	0				0				0				0	0
Multifamily Energy Efficiency Rebates	Projects	0				0				0				0	0
LDC Custom Programs	Projects	0				0				0				0	0
Pre-2011 Programs completed in 2011 Total						**1,545**				**2,610,736**				**1,545**	**10,442,945**
Other															
Program Enabled Savings	Projects	0				0				0				0	0
Time-of-Use Savings	Homes														
Other Total						**0**				**0**				**0**	**0**
Adjustments to Previous Year's Verified Results						**1,406**				**18,690,297**				**1,156**	**73,918,598**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Table 8: Province-Wide Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement		1.00				0.46				1.00				0.47		
Appliance Exchange		1.00				0.52				1.00				0.52		
HVAC Incentives		1.00				0.50				1.00				0.49		
Conservation Instant Coupon Booklet		1.00				1.00				1.00				1.05		
Bi-Annual Retailer Event		1.00				0.91				1.00				0.92		
Retailer Co-op		n/a				n/a				n/a				n/a		
Residential Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Residential Demand Response (IHD)		n/a				n/a				n/a				n/a		
Residential New Construction		3.65				0.49				7.17				0.49		
Business Program																
Retrofit		0.93				0.75				1.05				0.76		
Direct Install Lighting		0.69				0.94				0.85				0.94		
Building Commissioning		n/a				n/a				n/a				n/a		
New Construction		0.98				0.49				0.99				0.49		
Energy Audit		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (IHD)		n/a				n/a				n/a				n/a		
Demand Response 3*		n/a				n/a				n/a				n/a		
Industrial Program																
Process & System Upgrades		n/a				n/a				n/a				n/a		
Monitoring & Targeting		n/a				n/a				n/a				n/a		
Energy Manager		1.16				0.90				1.16				0.90		
Retrofit																
Demand Response 3*		n/a				n/a				n/a				n/a		
Home Assistance Program																
Home Assistance Program		0.32				1.00				0.99				1.00		
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program		n/a				n/a				n/a				n/a		
High Performance New Construction		1.00				0.50				1.00				0.50		
Toronto Comprehensive		n/a				n/a				n/a				n/a		
Multifamily Energy Efficiency Rebates		n/a				n/a				n/a				n/a		
LDC Custom Programs		n/a				n/a				n/a				n/a		
Other																
Program Enabled Savings		1.06				1.00				2.26				1.00		
Time-of-Use Savings		n/a				n/a				n/a				n/a		

Summary - Provincial Progress

Table 9: Province-Wide Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011	216.3	136.6	135.8	129.0
2012		253.3	109.8	108.2
2013				
2014				
Verified Net Annual Peak Demand Savings in 2014:				**237.2**
2014 Annual CDM Capacity Target				**1,330**
Verified Peak Demand Savings Target Achieved - 2011 (%):				**17.8%**

Table 10: Province-Wide Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011	606.9	603.0	601.0	582.3	2,393
2012		503.6	498.4	492.6	1,513
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					**3,906**
2011-2014 Cumulative CDM Energy Target:					**6,000**
Verified Portion of Energy Target Achieved - 2011 (%):					**65.1%**

*2011 energy adjustments included in cumulative energy savings.

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS	
Prescriptive Measures and Projects	**Gross Savings =** Activity * Per Unit Assumption **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
Engineered and Custom Projects	**Gross Savings =** Reported Savings * Realization Rate **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
Demand Response	**Peak Demand: Gross Savings = Net Savings =** contracted MW at contributor level * Provincial contracted to ex ante ratio **Energy: Gross Savings = Net Savings =** provincial ex post energy savings * LDC proportion of total provincial contracted MW All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)
Adjustments to Previous Year's Verified Results	All errors and omissions from the prior years Final Annual Results report will be adjusted within this report. Any errors and ommissions with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the cumulative effect of energy savings.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program			
Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection	Savings are considered to begin in the year the appliance is picked up.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year that the exchange event occurred	
HVAC Incentives	Results directly attributed to LDC based on customer postal code	Savings are considered to begin in the year that the installation occurred	

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the coupon was redeemed.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the event occurs.	
Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any “snapback” in energy consumption experienced after the event. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program			
Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
	Additional Note: project counts were derived by filtering out "Application Status" = "Post-Project Submission - Payment denied by LDC" and only including projects with an "Actual Project Completion Date" in 2012 and pulling both the "Application Name" field followed by the "Building Address 1" field from the Post Stage Retrofit Report and finally performing a count of the Building Addresses.		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011 or 2012.	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the actual project completion date.	
Energy Audit	Projects are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year of the audit date.	**Peak demand and energy savings** are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program			
Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated, no completed projects in 2011 or 2012.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011 or 2012.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
Energy Manager	Results are directly attributed to LDC based on LDC identified in the application; No completed projects in 2011 or 2012.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Home Assistance Program			

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	**Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Pre-2011 Programs completed in 2011			
Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	
Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation		
EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation		

ERII Sector (C&I vs. Industrial Mapping)	
Building Type	**Sector**
Agribusiness - Cattle Farm	C&I
Agribusiness - Dairy Farm	C&I
Agribusiness - Greenhouse	C&I
Agribusiness - Other	C&I
Agribusiness - Other,Mixed-Use - Office/Retail	C&I
Agribusiness - Other,Office,Retail,Warehouse	C&I
Agribusiness - Other,Office,Warehouse	C&I
Agribusiness - Poultry	C&I
Agribusiness - Poultry,Hospitality - Motel	C&I
Agribusiness - Swine	C&I
Convenience Store	C&I
Education - College / Trade School	C&I
Education - College / Trade School,Multi-Residential - Condominium	C&I
Education - College / Trade School,Multi-Residential - Rental Apartment	C&I
Education - College / Trade School,Retail	C&I
Education - Primary School	C&I
Education - Primary School,Education - Secondary School	C&I
Education - Primary School,Multi-Residential - Rental Apartment	C&I
Education - Primary School,Not-for-Profit	C&I
Education - Secondary School	C&I
Education - University	C&I
Education - University,Office	C&I
Hospital/Healthcare - Clinic	C&I
Hospital/Healthcare - Clinic,Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Clinic,Industrial	C&I
Hospital/Healthcare - Clinic,Retail	C&I
Hospital/Healthcare - Long-term Care	C&I
Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail,Office	C&I
Hospitality - Hotel	C&I
Hospitality - Hotel,Restaurant - Dining	C&I
Hospitality - Motel	C&I
Industrial	Industrial
Mixed-Use - Office/Retail	C&I
Mixed-Use - Office/Retail,Industrial	Industrial
Mixed-Use - Office/Retail,Mixed-Use - Other	C&I
Mixed-Use - Office/Retail,Mixed-Use - Other,Not-for-Profit,Warehouse	C&I
Mixed-Use - Office/Retail,Mixed-Use - Residential/Retail	C&I
Mixed-Use - Office/Retail,Office,Restaurant - Dining,Restaurant - Quick Serve,Retail,Warehouse	C&I

Mixed-Use - Office/Retail,Office,Warehouse	C&I
Mixed-Use - Office/Retail,Retail	C&I
Mixed-Use - Office/Retail,Warehouse	C&I
Mixed-Use - Office/Retail,Warehouse,Industrial	Industrial
Mixed-Use - Other	C&I
Mixed-Use - Other,Industrial	Industrial
Mixed-Use - Other,Not-for-Profit,Office	C&I
Mixed-Use - Other,Office	C&I
Mixed-Use - Other,Other: Please specify	C&I
Mixed-Use - Other,Retail,Warehouse	C&I
Mixed-Use - Other,Warehouse	C&I
Mixed-Use - Residential/Retail	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Condominium	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Rental Apartment	C&I
Mixed-Use - Residential/Retail,Retail	C&I
Multi-Residential - Condominium	C&I
Multi-Residential - Condominium,Multi-Residential - Rental Apartment	C&I
Multi-Residential - Condominium,Other: Please specify	C&I
Multi-Residential - Rental Apartment	C&I
Multi-Residential - Rental Apartment,Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Warehouse	C&I
Multi-Residential - Social Housing Provider	C&I
Multi-Residential - Social Housing Provider,Industrial	C&I
Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Not-for-Profit	C&I
Not-for-Profit,Office	C&I
Not-for-Profit,Other: Please specify	C&I
Not-for-Profit,Warehouse	C&I
Office	C&I
Office,Industrial	Industrial
Office,Other: Please specify	C&I
Office,Other: Please specify,Warehouse	C&I
Office,Restaurant - Dining	C&I
Office,Restaurant - Dining,Industrial	Industrial
Office,Retail	C&I
Office,Retail,Industrial	C&I
Office,Retail,Warehouse	C&I
Office,Warehouse	C&I
Office,Warehouse,Industrial	Industrial
Other: Please specify	C&I
Other: Please specify,Industrial	Industrial
Other: Please specify,Retail	C&I
Other: Please specify,Warehouse	C&I
Restaurant - Dining	C&I
Restaurant - Dining,Retail	C&I

Restaurant - Quick Serve	C&I
Restaurant - Quick Serve,Retail	C&I
Retail	C&I
Retail,Industrial	Industrial
Retail,Warehouse	C&I
Warehouse	C&I
Warehouse,Industrial	Industrial

Consumer Program Allocation Methodology

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Local Distribution Company	Allocation
Algoma Power Inc.	0.2%
Atikokan Hydro Inc.	0.0%
Attawapiskat Power Corporation	0.0%
Bluewater Power Distribution Corporation	0.6%
Brant County Power Inc.	0.2%
Brantford Power Inc.	0.7%
Burlington Hydro Inc.	1.4%
Cambridge and North Dumfries Hydro Inc.	1.0%
Canadian Niagara Power Inc.	0.5%
Centre Wellington Hydro Ltd.	0.1%
Chapleau Public Utilities Corporation	0.0%
COLLUS Power Corporation	0.3%
Cooperative Hydro Embrun Inc.	0.0%
E.L.K. Energy Inc.	0.2%
Enersource Hydro Mississauga Inc.	3.9%
ENTEGRUS	0.6%
ENWIN Utilities Ltd.	1.6%
Erie Thames Powerlines Corporation	0.4%
Espanola Regional Hydro Distribution Corporation	0.1%
Essex Powerlines Corporation	0.7%
Festival Hydro Inc.	0.3%
Fort Albany Power Corporation	0.0%
Fort Frances Power Corporation	0.1%
Greater Sudbury Hydro Inc.	1.0%
Grimsby Power Inc.	0.2%
Guelph Hydro Electric Systems Inc.	0.9%
Haldimand County Hydro Inc.	0.4%
Halton Hills Hydro Inc.	0.5%
Hearst Power Distribution Company Limited	0.1%
Horizon Utilities Corporation	4.0%
Hydro 2000 Inc.	0.0%
Hydro Hawkesbury Inc.	0.1%
Hydro One Brampton Networks Inc.	2.8%
Hydro One Networks Inc.	30.0%

Hydro Ottawa Limited	5.6%
Innisfil Hydro Distribution Systems Limited	0.4%
Kashechewan Power Corporation	0.0%
Kenora Hydro Electric Corporation Ltd.	0.1%
Kingston Hydro Corporation	0.5%
Kitchener-Wilmot Hydro Inc.	1.6%
Lakefront Utilities Inc.	0.2%
Lakeland Power Distribution Ltd.	0.2%
London Hydro Inc.	2.7%
Middlesex Power Distribution Corporation	0.1%
Midland Power Utility Corporation	0.1%
Milton Hydro Distribution Inc.	0.6%
Newmarket - Tay Power Distribution Ltd.	0.7%
Niagara Peninsula Energy Inc.	1.0%
Niagara-on-the-Lake Hydro Inc.	0.2%
Norfolk Power Distribution Inc.	0.3%
North Bay Hydro Distribution Limited	0.5%
Northern Ontario Wires Inc.	0.1%
Oakville Hydro Electricity Distribution Inc.	1.5%
Orangeville Hydro Limited	0.2%
Orillia Power Distribution Corporation	0.3%
Oshawa PUC Networks Inc.	1.2%
Ottawa River Power Corporation	0.2%
Parry Sound Power Corporation	0.1%
Peterborough Distribution Incorporated	0.7%
PowerStream Inc.	6.6%
PUC Distribution Inc.	0.9%
Renfrew Hydro Inc.	0.1%
Rideau St. Lawrence Distribution Inc.	0.1%
Sioux Lookout Hydro Inc.	0.1%
St. Thomas Energy Inc.	0.3%
Thunder Bay Hydro Electricity Distribution Inc.	0.9%
Tillsonburg Hydro Inc.	0.1%
Toronto Hydro-Electric System Limited	12.8%
Veridian Connections Inc.	2.4%
Wasaga Distribution Inc.	0.2%
Waterloo North Hydro Inc.	1.0%
Welland Hydro-Electric System Corp.	0.4%
Wellington North Power Inc.	0.1%
West Coast Huron Energy Inc.	0.1%
Westario Power Inc.	0.5%
Whitby Hydro Electric Corporation	0.9%
Woodstock Hydro Services Inc.	0.3%

Reporting Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity in a given year and resource savings persisting from previous years).

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).

Free-ridership: the percentage of participants who would have implemented the program measure or practice in the absence of the program.

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start' (please see table 5).

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net-to-Gross Ratio: The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

Program: a group of initiatives that target a particular market sector (i.e. Consumer, Industrial).

Realization Rate: A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.

Settlement Account: the grouping of demand response facilities (contributors) into one contractual agreement

Spillover: Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

Appendix 2 of 3

Appendix 2 - 2011 Schedule of Rates and Charges

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0082

RESIDENTIAL SERVICE CLASSIFICATION

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

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	12.57
Smart Meter Funding Adder – effective until April 30, 2012	$	1.96
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.17
Distribution Volumetric Rate	$/kWh	0.0148
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	(0.0003)
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	(0.0008)
Rate Rider for Tax Change – effective until April 30, 2012	$/kWh	(0.0001)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0065
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0049

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0082

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	25.89
Smart Meter Funding Adder – effective until April 30, 2012	$	1.96
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.19
Distribution Volumetric Rate	$/kWh	0.0088
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	(0.0003)
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	(0.0006)
Rate Rider for Tax Change – effective until April 30, 2012	$/kWh	(0.0001)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0047

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0082

GENERAL SERVICE 50 to 2,999 kW SERVICE CLASSIFICATION

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 3,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	262.15
Smart Meter Funding Adder – effective until April 30, 2012	$	1.96
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	5.69
Distribution Volumetric Rate	$/kW	2.4899
Low Voltage Service Rate	$/kW	0.3506
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	(0.1219)
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.2431)
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(0.0188)
Retail Transmission Rate – Network Service Rate	$/kW	2.3273
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.8648
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.8670
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.0667

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0082

GENERAL SERVICE 3,000 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 3,000 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	1,734.31
Smart Meter Funding Adder – effective until April 30, 2012	$	1.96
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	37.85
Distribution Volumetric Rate	$/kW	1.6082
Low Voltage Service Rate	$/kW	0.4094
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	(0.6753)
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(1.0514)
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(0.0178)
Retail Transmission Rate – Network Service Rate	$/kW	2.8670
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0667

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0082

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/ documentation with regard to electrical consumption of the proposed unmetered load. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	8.93
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.28
Distribution Volumetric Rate	$/kWh	0.0279
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	(0.0003)
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	(0.0007)
Rate Rider for Tax Change – effective until April 30, 2012	$/kWh	(0.0002)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0047

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0082

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	2.43
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.03
Distribution Volumetric Rate	$/kW	6.9763
Low Voltage Service Rate	$/kW	0.2816
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	(0.1061)
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.2610)
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(0.0545)
Retail Transmission Rate – Network Service Rate	$/kW	1.7918
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4215

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0082

STREET LIGHTING SERVICE CLASSIFICATION

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

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	2.20
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.02
Distribution Volumetric Rate	$/kW	5.9608
Low Voltage Service Rate	$/kW	0.2798
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	(0.0940)
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.1344)
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(0.0465)
Retail Transmission Rate – Network Service Rate	$/kW	1.7668
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4125

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0082

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

ALLOWANCES

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

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0082

SPECIFIC SERVICE CHARGES

APPLICATION

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

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

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

Customer Administration		
Arrears Certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income tax Letter	$	15.00
Account history	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge - no disconnection – after regular hours	$	165.00
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charge - At meter - After Regular Hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service install & remove – underground – no transformer	$	300.00
Temporary service install & remove – overhead – with transformer	$	1000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0082

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

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

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

LOSS FACTORS

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

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0602
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0496
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Appendix 3 of 3

Appendix 3 - 2012 Schedule of Rates and Charges

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0166

RESIDENTIAL SERVICE CLASSIFICATION

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

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	12.68
Distribution Volumetric Rate	$/kWh	0.0149
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	(0.0008)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	0.0023
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	(0.0003)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kWh	(0.0126)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kWh	0.0009
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kWh	(0.0002)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0069
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0046

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0166

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	33.19
Distribution Volumetric Rate	$/kWh	0.0113
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	(0.0006)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	0.0025
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	(0.0003)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kWh	(0.0126)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kWh	0.0002
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kWh	(0.0001)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0061
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0044

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0166

GENERAL SERVICE 50 to 2,999 kW SERVICE CLASSIFICATION

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 3,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	214.62
Distribution Volumetric Rate	$/kW	2.0385
Low Voltage Service Rate	$/kW	0.3506
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.2431)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	1.0218
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	(0.1219)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kW	(5.3132)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kW	0.0349
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kW	(0.0283)
Retail Transmission Rate – Network Service Rate	$/kW	2.4752
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7517
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	3.0491
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.9423

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0166

GENERAL SERVICE 3,000 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 3,000 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	1,408.58
Distribution Volumetric Rate	$/kW	1.3062
Low Voltage Service Rate	$/kW	0.4094
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(1.0514)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	4.7135
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	(0.6753)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kW	(23.9176)
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kW	(0.0266)
Retail Transmission Rate – Network Service Rate	$/kW	3.0491
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9423

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0166

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/ documentation with regard to electrical consumption of the proposed unmetered load. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	9.01
Distribution Volumetric Rate	$/kWh	0.0281
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	(0.0007)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	0.0021
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	(0.0003)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	(0.0126)
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kWh	(0.0003)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0061
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0044

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0166

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	2.74
Distribution Volumetric Rate	$/kW	7.868
Low Voltage Service Rate	$/kW	0.2816
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.2610)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	0.8496
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	(0.1061)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kW	(4.5914)
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kW	(0.0820)
Retail Transmission Rate – Network Service Rate	$/kW	1.9056
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3353

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0166

STREET LIGHTING SERVICE CLASSIFICATION

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

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	2.67
Distribution Volumetric Rate	$/kW	7.2326
Low Voltage Service Rate	$/kW	0.2798
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.1344)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	0.781
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	(0.0940)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kW	(4.1576)
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kW	(0.0699)
Retail Transmission Rate – Network Service Rate	$/kW	1.8790
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3268

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0166

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

ALLOWANCES

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

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0166

SPECIFIC SERVICE CHARGES

APPLICATION

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

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

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

Customer Administration		
Arrears Certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income tax Letter	$	15.00
Account history	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge - no disconnection – after regular hours	$	165.00
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charge - At meter - After Regular Hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service install & remove – underground – no transformer	$	300.00
Temporary service install & remove – overhead – with transformer	$	1000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0166

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

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

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

LOSS FACTORS

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

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0602
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0496

<u>Attachment 9-C</u>

One-Time Incremental IFRS Transition Costs

File Number:	EB-2017-0039
Exhibit:	9
Tab:	9-C
Page:	1 of 1
Date:	August 28th, 2017

Appendix 2-YA
One-Time Incremental IFRS Transition Costs

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include one-time incremental IFRS transition costs that are currently included in Account 1508, Other Regulatory Assets, sub-account Deferred IFRS Transition Costs Account, or Account 1508, Other Regulatory Assets, sub-account IFRS Transition Costs Variance Account.

Nature of One-Time Incremental IFRS Transition Costs [1]	**Audited Actual Costs Incurred 2010**	**Audited Actual Costs Incurred 2011**	**Audited Actual Costs Incurred 2012**	**Audited Actual Costs Incurred 2013**	**Audited Actual Costs Incurred 2014**	**Audited Actual Costs Incurred 2015**	**Audited Actual Costs Incurred 2016 [3]**	**Audited Carrying Charges To December 31, 2016**	**Forecasted Costs 2017 [3]**	**Forecasted Costs 2018 [3]**	**Carrying Charges January 1, 2017 to December 31, 2017 or April 30, 2017 (As appropriate)**	**Total Costs and Carrying Charges**	**Reasons why the costs recorded meet the criteria of one-time IFRS administrative incremental costs**
Professional accounting fees			$ 12,931	$ 1,100	$ 444		$ 43,406					$ 57,881	Accounting fees related to transition from CGAAP to IFRS
Professional legal fees												$ -	
Salaries, wages and benefits of staff added to support the transition to IFRS												$ -	
Associated staff training and development costs												$ -	
Costs related to system upgrades, or replacements or changes where IFRS was the major reason for conversion												$ -	
												$ -	
												$ -	
												$ -	
												$ -	
Amounts, if any, included in previous Board approved rates (amounts should be negative) [2]	-$ 33,333	-$ 50,000	-$ 50,000	-$ 50,000	-$ 50,000	-$ 50,000	-$ 50,000					-$ 333,333	
								-$ 12,350			-$ 4,027	-$ 16,377	
Insert description of additional item(s) and new rows if needed.												$ -	
Total	-$ 33,333	-$ 50,000	-$ 37,069	-$ 48,900		-$ 50,000		-$ 12,350		$ -		-$ 291,829	

Note:

1 The Deferred IFRS Transition Costs Account and the IFRS Transition Costs Variance Account are exclusively for necessary, incremental transition costs and shall not include ongoing IFRS compliance costs or impacts arising from adopting accounting policy changes that reflect changes in the timing of the recognition of income. The incremental costs in these accounts shall not include costs related to system upgrades, or replacements or changes where IFRS was not the major reason for conversion. In addition, incremental IFRS costs shall not include capital assets or expenditures.

2 If there were any amounts approved in previous Board approved rates, please state the EB #:

3 Any forecasted One-time costs past 2015 should be fully explained in the application, since distributors were required to adopt IFRS or an alternative accounting standard by January 1, 2015.

Attachment 9-D

IESO Self-Certification

Ontario Regulated Price Plan (RPP) Self-Certification

For LDCs with 12,500 or more customers

A. Attestation (Attested by the most senior officer of the organization)

With respect to the RPP claims submitted monthly to the IESO for the year ending 2016,

I Joe Barile, General Manager [name, position]

of Essex Powerlines Corporation ("EPLC") [company],

hereby certify that our organization's RPP processes and procedures provide reasonable assurance that RPP settlements are calculated and paid or received appropriately and pursuant to the RPP settlement guidelines issued by the Independent Electricity System Operator.

As the party responsible for establishing and maintaining disclosure, procedures and controls, I have assessed the organization's processes and procedures, and to the best of my knowledge the following statements are true:

1. The systems and processes for RPP claims are designed to effectively calculate RPP transactions in alignment with appropriate methodologies pursuant to OEB and IESO requirements.	☑
2. Sufficient controls have been designed and implemented to provide reasonable assurance of the validity and accuracy of RPP claims.	☑
3. Managers and staff responsible for RPP claims processes are sufficiently trained and execute RPP procedures according to design	☑
4. Processes, procedures and controls are documented and are available upon request to the IESO in a form that accurately describes the processes conducted to submit RPP claims. - **Our organization's systems or procedures have changed materially during the past year.**	☑ *Yes* ☐ *No* ☑
5. Reconciliations between the estimated claim amounts and actual post-billing claim amounts are being conducted (at minimum) quarterly.	☐
6. Periodic testing is conducted as a key measure to ensure the effectiveness of our procedures and controls for calculating RPP claims.	☑

B. Self-Reporting

1. In the past calendar year, the organization has designed and implemented new procedures or systems that materially change the nature of the processes and procedures employed to make RPP claims. *Description of changes is as follows:*

In 2016, EPLC did not design and implement new procedures or systems that materially changed the nature of the processes and procedures employed to make RPP claims. However, in 2017 and as a result of an OEB Audit dated April, 2016 with respect to Regulatory Accounting Procedures, Controls, and Oversight over Deferral and Variance Accounts and an OEB Audit dated March, 2017 of Group 1 and 2 Deferral and Variance Accounts ("OEB Audits"). EPLC anticipates updates to its current procedures and controls the scope of which has yet to be finalized.

2. The organization's internal testing process and/or normal reporting procedures related to the RPP claims have identified material exceptions with our RPP claims during the past year:

No.

3. Mitigation plans and/or efforts undertaken to address issues identified are summarized below:

As a result of the OEB Audits, EPLC has responded with a detailed Change Management Plan which it plans to commence instituting in 2017.

4. Assurance over RPP claims has been conducted by a third party. *If yes, please describe below:*

Yes ☐ *No* ☑

5. Other comments relevant to this certification:

In relation to Question 5 - Attestation -- EPLC did not, for 2016, reconcile between the estimated claim amounts and actual post-billing claim amounts on a quarterly basis. However, in March, 2017 as part of its response to the OEB Audits, EPLC together with the IESO did ensure that an accurate reconciliation for 2016 did occur.
In response to the OEB Audits, some of which addressed RPP processes and procedures, EPLC has drafted a detailed Change Management Plan which it plans to commence instituting in 2017.

Self-Certification

Company Name: Essex Powerlines Corporation

RPP Reporting Period (Month, Year Ended): December, 2016

Certifier Details:

Name: Joe Barile

Position: General Manager

Signature:

Date: March 31, 2017

Location: Oldcastle, Ontario

Attachment 9-E

2013 Accounting Changes Under CGAAP

File Number:	EB-2017-0039
Exhibit:	9
Attachment:	9-E
Schedule:	
Page:	1 of 1
Date:	August 28th, 2017

Appendix 2-EC
Account 1576 - Accounting Changes under CGAAP
2013 Changes in Accounting Policies under CGAAP

For applicants with a balance in Account 1576 and made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013. This is the first time the applicant is rebasing with changes in these accounting policies.

	Prior Years Rebasing	2013	2014	2015	2016	2017	2018 Rebasing Year
Reporting Basis	CGAAP	CGAAP	CGAAP	MIFRS - Note 5	MIFRS	MIFRS	MIFRS
	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast
		$	$		$		
PP&E Values under former CGAAP							
Opening net PP&E - Note 1		36,635,738	37,728,814	40,731,173	43,685,630	45,475,379	
Net Additions - Note 4		3,829,948	5,574,491	7,020,363	4,570,662	5,920,312	
Net Depreciation (amounts should be negative) - Note 4		-2,736,872	-2,572,132	-4,065,906	-2,780,913	-3,377,318	
Closing net PP&E (1)		37,728,814	40,731,173	43,685,630	45,475,379	48,018,373	
PP&E Values under revised CGAAP (Starts from 2012)							
Opening net PP&E - Note 1		36,635,738	38,162,559	41,817,980	45,665,369	48,901,599	
Net Additions - Note 4		3,321,218	5,085,331	6,331,254	4,343,082	5,433,708	
Net Depreciation (amounts should be negative) - Note 4		-1,794,397	-1,429,910	-2,483,865	-1,106,852	-2,361,785	
Closing net PP&E (2)		38,162,559	41,817,980	45,665,369	48,901,599	51,973,521	
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP		-433,745	-1,086,807	-1,979,739	-3,426,220	-3,955,148	

Effect on Deferral and Variance Account Rate Riders

Closing balance in Account 1576	-	3,955,148	**WACC**	5.56%
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	-	439,812	**# of years of rate rider disposition period**	2
Amount included in Deferral and Variance Account Rate Rider Calculation	-	4,394,961		

Notes:

1 For an applicant that made the capitalization and depreciation expense accounting policy changes on January 1, 2013, the PP&E values as of January 1, 2013 under both former CGAAP and revised CGAAP should be the same.

2 Return on rate base associated with Account 1576 balance is calculated as:
the variance account ending balance as of 2017 x WACC X # of years of rate rider disposition period
* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

3 Account 1576 is cleared by including the total balance in the deferral and variance account rate rider calculation.

4 Net additions are additions net of disposals; Net depreciation is additions to depreciation net of disposals.

5 Differences due to the adoption of MIFRS are to be shown separately in Account 1575 in Appendix 2-EA as Accounts 1575 and 1576 cannot be used interchangably.