2018 Cost of Service Application

Interrogatory Responses

EB-2017-0039

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Exhibit 1: 1-Staff-1

Letters of Comment

Following publication of the Notice of Application, the OEB received two letters of comment. Sections 2.1.6 of the Filing Requirements state that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment sent to the Board related to the distributor's application. If the applicant has not received a copy of the letters or comments received at the community meetings, they may be accessed from the public record for this proceeding.

Please file a response to the matters raised in the letters of comment referenced above. Going forward, please ensure that responses to any matters raised in subsequent comments or letter are filed in this proceeding. All responses must be filed before the argument (submission) phase of this proceeding.

Response

Essex Powerlines Corporation ("EPLC") has included a response to the two (2) letters of comment as Attachments 1-A and 1-B respectively. EPLC will respond to any subsequent letters prior to the argument phase of this proceeding.

Exhibit 1: 1-Staff-2

Updated Revenue Requirement Work Form

Upon completing all interrogatories from OEB staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Sheets 10 (Load Forecast), 11 (Cost Allocation), 12 (Residential Rate Design) and 13 (Rate Design) should be updated, as necessary. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an exploratory note. Such notes should be documented on Sheet 14 Tracking Sheet, and may also be included on others sheets in the RRWF to assist understanding of changes.

Response

EPLC has included an updated RRWF in working Microsoft Excel format as Attachment 1-C. A summary of changes can be found in Sheet 14 Tracking Sheet.

Exhibit 1: 1-Staff-3

New Services Service Quality Indicator

REF: 1.4.2 Business Plan & Objectives – Customer and Community Value – New Services Service Quality Indicator (Exhibit 1 page 15)

Essex Powerlines provided the percentage of connections for new services under 750V that were connected within five business days over the last eight years. The percentage of connections are trending downward to 2016, which is just above the requirement from the Distribution System Code.

a) Please explain the downward trend of the number of connections connected within five business days.

b) What has Essex Powerlines done to mitigate this decline in service quality indicator?

Response

a) With the current level of trained staff resources employed, EPLC can only connect and respond to a certain number of events. The type and complexity of the service connection also has a significant impact on the work required to connect a service. Connecting a home in a subdivision is relatively straightforward, once the basic infrastructure is in place through system expansion but connecting an in-fill house may require considerable more secondary and metering work (work that does not qualify as expansion).

Despite the number of service connection requests increasing significantly, EPLC has been able re-organize its internal processes and has managed to respond to these increased requests within the expected service quality requirements.

b) As mentioned in a) above, EPLC has reviewed internal processes and workflow with the view to increasing the number of connection requests that can be handled by existing staff. The review process included: improved records management, work flow analysis, improved scheduling and expanding work hours.

Commensurate with that review, EPLC is in the process of performing a detailed succession planning analysis of various EPLC staff.

EPLC continues to review its own internal procedures and feels that this dual approach is an effective strategy for the foreseeable future.

Exhibit 1: 1-Staff-4

Regulated ROE Targets

Ref: 1.4.2 Business Plan & Objectives – Customer and Community Value – Regulated ROE Targets (Exhibit 1 page 31)

Essex Powerlines stated that it has been formally monitoring its actual return on equity (ROE) since 2015.

a) Please provide the actual ROE for each year starting 2010.

Response

a) The table below provides EPLC's actual ROE for each year starting in 2010.

Description	2010	2011	2012	2013	2014	2015	2016
Regulated ROE	9.67%	10.83%	8.15%	11.20%	9.73%	11.58%	7.25%

Exhibit 1: 1-Staff-5

SmartMAP

Ref: 1.4.2 Business Plan & Objectives – Best-In-Class Solutions & Shared Services (Exhibit 1 page 32)

Essex Powerlines has invested in the new software product called SmartMap 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.

a) Please describe how this system is used in Essex Powerlines' asset management practices for the purposes of asset replacement, planning system development, and planning distribution contingencies.

b) Please provide examples of cost savings or efficiencies that SmartMap has provided since its implementation.

c) What is the yearly cost to maintain this system?

d) Does the SmartMap currently have the ability to communicate with neighbouring utilities and coordinate outage restoration? If so, how does it accomplish this? If not, does SmartMap have this capability and does Essex Powerlines plan to pursue this capability?

Response

a) EPLC is currently using SmartMAP for various planning and asset management purposes. Currently, EPLC is primarily using SmartMAP to assess transformer loading, asset right-sizing, addressing voltage complaints, circuit loading, short circuit analysis, load flow analysis and outage restoration scenarios.

b) SmartMAP has allowed EPLC to enhance knowledge of the current state of its distribution system in near real-time since implementation. SmartMAP, through detailed asset loading information, has helped EPLC engineers quickly identify distribution assets that are likely to fail based on loading trends and historical failure rates in particular areas. Further, during outages, SmartMAP has significantly aided EPLC's operations department in the identification and resolution of outages. This, in turn, results in less overtime/after hours work, less troubleshooting and truck rolls and improved overall reliability through shorter outage times.

c) EPLC's yearly software subscription cost is $65,000.

d) SmartMAP does not currently have the ability to communicate with neighbouring utilities however this is functionality that EPLC is investigating as it discusses the Self-Healing Grid with Hydro One.

Exhibit 1: 1-Staff-6

SmartMAP

Ref: 1.4.2 Business Plan & Objectives – Essex Powerlines – An efficient single voltage utility (Exhibit 1 page 33)

Essex Powerlines stated that "Essex Powerlines 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."

Essex Powerlines also stated that it "has a small number of step down transformers in remote areas however, Essex Powerlines plans to convert them when most technically and financially feasible."

a) Please provide the actual total capital dollars spent on projects related to voltage conversion since 2010.

b) Has Essex Powerlines prematurely replaced distribution lines which were not at end-of-life as a result of this initiative? Of the total costs provided in a) what percentage of projects were premature replacements?

c) Does Essex Powerlines still need to stock spares for the small number of step down transformers in the remote areas? Please provide the yearly savings in reduced inventory due to the conversion initiative and a breakdown of the equipment no longer required.

d) Please provide a high level summary of Essex Powerlines' spares inventory for each year from 2010-2018. This should be grouped by asset type and provide an explanation of variances.

e) Please provide the reduced maintenance costs due to the conversion initiative and a breakdown of the activities no longer required. Since there is less maintenance work required are the maintenance staff reassigned to other duties or does this lead to the need for less staff.

Response

a) Please see actual capital dollars spent on projects related to voltage conversion below:

Description	2010	2011	2012	2013	2014	2015	2016	2017	2018
Single Voltage Utility - Conversion	$633,783	$ 423,196	$ 929,490	$ 935,091	$ 852,182	$ 547,174	$ 85,942	$ 617,735	$ -

b) EPLC estimates that less than 5% of all assets replaced as part of EPLC's Single Voltage Utility initiative were premature replacements (ie replaced prior to TUL). Almost all assets downstream of the converted substations were installed at the time of the substation installation. Some lines were upgraded in preparation for Single Voltage Utility initiative. UG lines TUL is 30 years and OH lines is 45 years.

For example, in LaSalle:

Malden station - was originally built, owned and operated by Ontario Hydro. This station was built in the 1950 with the F-1 and F-2 feeders being the first to be installed. The F-3 was added later, approximately 1960. The station was taken over by Sandwich West Hydro in the middle to late 1970's and maintained and operated by the local utility. There has not been a major improvement or expansion of this sub as it is the oldest of the 3 substations that are in LaSalle.

Huron Station - this area was taken over by Sandwich West Hydro in the early 1950's from Ontario Hydro. The electrical plant was installed in the early 1940's and the development was built just after the war. Most of the construction was done by the early 1950's. Some of the streets have been updated with new secondary buss and primary insulators rated for 16 KV, but a majority of the poles are still of the vintage 1940's.

Sunnyside station - was built in the late 1960's. It was built by Sandwich West Hydro who was the provider of service to the community at that time. It was a 5000 KVA transformer with 3 feeders exiting the station by means of underground lines to potheads and switches on poles at the front of the station. There is complete capability of switching between feeders and paralleling with themselves when needed. It has a capability of paralleling with Malden Station in the event of catastrophic failure, but neither station can carry all the load from both stations at one time. Front Road was rebuilt in the mid 1970's.

c) EPLC has standardized its stepdown stock and currently stocks one new 75 kVA stepdown. This size was determined since EPLC does not have any existing load greater than 75 kVA for single phase and 225 kVA for three phase that would require the use of this asset. These stepdowns are currently used to feed customer-owned private lines that customers were not willing to convert. There are currently 9 of these scenarios currently within EPLC's distribution system. EPLC currently installs these stepdowns at or as close as possible to the ownership demarcation point to private lines. EPLC no longer requires new emergency replacement stock for 4kV or 8kV transformers as a result of the Single Voltage Utility initiative.

d) Please refer to the table below for a high level summary of EPLC inventory between 2010-2018.

Description	2010	2011	2012	2013	2014	2015	2016	2017	2018
Transformers	160	137	105	115	97	87	78	90	108.6
2/0 Primary Cable (km)	2.5	1.3	2.3	2.7	3.7	2.3	1	2.3	2.3
Poles	48	37	56	61	73	44	51	54	53.0
Meters	956	343	339	539	556	772	1017	1093	701.9

e) As a result of initiatives such as the Single Voltage Utility, EPLC has been able to control system operations and maintenance costs over a period of time and has been able to re-assign staff to other initiatives:

Description	2010	2011	2012	2013	2014	2015	2016	2017
System O&M ($000's)	$ 2,264	$ 2,618	$ 3,203	$ 2,722	$ 2,994	$ 3,141	$ 3,171	$ 2,792

Further and specifically through the Single Voltage Utility initiative, EPLC has eliminated the need for substation maintenance expense:

Description	2010	2011	2012	2013	2014	2015	2016	2017	2018
Station Operations	$ 17,932	$ 16,130	$ 26,197	$ 25,806	$ 95,716	$ 42,106	$ -	$ -	$ -

Exhibit 1: 1-Staff-7

Self-Healing Grid

Ref: 1.4.2 Business Plan & Objectives – The Self-Healing Grid

Essex Powerlines anticipates that the self-healing grid is capable of reducing the impact of Loss of Supply incidents to its customers. The loss of supply incidents cause over 75% of Essex Powerlines total customer hours of outage.

a) Please provide the loss of supply outage hours broken down into upstream station outage and upstream feeder outage.

b) Please provide Essex Powerlines' current outage contingency plans to redirect loss of supply.

c) Please provide the SmartMap's contingency philosophy to redirect loss of supply.

d) Did Essex Powerlines complete a study comparing the incremental cost of each sensor on the system to the diminishing returns of improved reliability?

Response

a) EPLC does not currently track loss of supply events by upstream station or upstream feeder outage as final outage causation would be determined by Hydro One and not necessarily flow to EPLC.

b) Currently, EPLC resolves upstream loss of supply events with Hydro One directly through their OGCC and local superintendents. EPLC's priority is to manually transfer as much load, safely, to other feeders in order to isolate and minimize the EPLC customer impact. Each occurrence is unique and requires specific knowledge of the distribution system.

c) SmartMAP is not currently configured to automatically redirect loss of supply however it is EPLC's understanding that this functionality is planned to be developed and released in a future version.

d) EPLC completed the GEA Plan (Initial Application, Exhibit 1, Attachment 1-G) which suggested ideal locations for sensors to ensure widespread functionality and operability. EPLC did not specifically study diminishing returns of improved reliability.

Exhibit 1: 1-Staff-8

Customer Engagement

Ref: Innovative Survey Overview & Results – 2014

Ref: Convergys Survey Overview, Results & Recommendations - 2016

In both surveys, customers appear to be unsatisfied with Essex Powerlines' communication with them.

a) What were the specific issues customers had with Essex Powerlines' communication?

b) How has Essex Powerlines addressed this issue in this application?

Response

a) Based on feedback received from the surveyors, the communication concerns were largely related to communication during outages.

b) Please refer to EPLC response to 1-SEC-7 below.

Exhibit 1: 1-Staff-9

Customer Engagement

Ref: Attachment 1-G 2018 Rate Application Review – Customer Consultation Workbook

Ref: Attachment 1-G Essex Power Corp. Ratepayer Telephone Survey

Essex Powerlines included in Attachment 1-G a "2018 Rate Application Review – Customer Consultation Workbook", which included a number of feedback questions.

a) How many customers reviewed this workbook and answered all the feedback questions?

b) Please provide the responses to the feedback questions included in the workbook.

In the Innovative Research Group Telephone Survey the System Challenges & Priorities section asks customers "*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?*" The question does not relate "not getting full value" of the equipment to the revenue requirement or bill impact.

c) Please explain what happens to an asset, from an accounting perspective, when Essex Powerlines retires an asset before end-of-life.

d) If the early retirement of equipment causes revenue requirement to increase why does the survey not explain that to customers?

In the Innovative Research Group Telephone Survey the System Challenges & Priorities section asks customers "*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?"*

e) Please explain if this question implies that resources are limited and is asking the customer to choose between modernizing the distribution system and other investments.

Response

a) EPLC unfortunately did not receive any formal responses to questions in the workbook.

b) EPLC unfortunately did not receive any formal responses to questions in the workbook.

c) From an accounting perspective, the remaining net book value of the asset is written off and a loss is taken by the distributor for the same amount.

d) EPLC's intent with the survey was to keep the material as short and as simple as possible to encourage participation. As such, this connection was not explicitly expressed in terms of revenue requirement impact, however EPLC feels that the link between capital spending to replace equipment and reduce outages, along with the reference to "value", implies there is a trade-off EPLC is asking the customer to consider.

e) The intent of this question was to determine whether or not customers thought it was important for EPLC to invest in grid modernization.

Exhibit 1: 1-Staff-10

Board Recommendation

Ref: EB-2014-0301, EB-2014-0072, Decision and Order, June 9, 2015 (page 15-16)

In the Decision and Order referenced above Essex Powerlines indicated that any financial consequence in excess of $380,000 would put Essex Powerlines off-side of its debt servicing covenants. The OEB expressed its concern with the apparent risks assumed by Essex Powerlines in structuring its debt arrangement and the thin margin of risk it can absorb. As a result, the OEB recommended that Essex Powerlines files sufficient information to enable the OEB to fully review the inherent risks of its financial arrangements.

a) Please provide the largest loss that Essex Powerlines can absorb currently without putting it off-side of its debt servicing covenants.

b) Please explain how Essex Powerlines has changed its debt structure since the Decision and Order to mitigate financial risks.

Response

a) Given that the price of electricity in Ontario, as opposed to distribution services, are a "pass-through" by the LDC and are therefore to recover actual incurred costs. As such, Ontario LDCs such as EPLC are not in a position to absorb any financial loss that are outside the area for which LDCs are required to take risk and such risks incorporated into the rate model. This is consistent with EPLC's position stated as part of EB-2014-0301 and EB-2014-0072. EPLC has calculated its debt servicing covenants as at December 31st, 2017 provided below, which are currently all compliant with the terms outlined by EPLC's lenders.

Debt Serviceability: 1.26 (Minimum target 1.20)

Debt to Capital: 0.48 (Maximum target 0.6)

b) EPLC is continuously working with its lenders to improve its ability to borrow and to mitigate financial risk to the organization and EPLC customers. EPLC has successfully re-negotiated its long term debt with shareholders at a more favorable rate and is well-positioned to accommodate incremental capital work in the near future related to substantial infrastructure currently being constructed to service the south shore of Essex County (SECTR project).

Exhibit 1: 1-Staff-11

Rate Base Variance Analysis

Ref: 2015 Actual Vs. 2016 Actual (Exhibit 2 Page 45-50)

Essex Powerlines stated that the increase to the Intangible Plant category was due to the relocation of assets to better align with direction in the APH.

a) Please explain why the debit balances in account 1611 and 1612 does not equal the credit balance in account 1806 and 1925.

Response

a) EPLC had additions of land rights and software in 2016 of $2,643 and $4,631 respectively. The differences between 2015 actuals and 2016 actuals are directly related to these additions.

Exhibit 1: 1-SEC-1

[Ex.1] Please provide a copy of all documents provided to the Applicant's Board of Directors for the purposes of approving the application and the underlying budget.

Response

EPLC provided updates to the Essex Power Corporation Board of Directors on April 26th, 2017, July 26th, 2017 and September 15th, 2017.

A Cost of Service review update was made to the EPLC Board of Directors September 15th, 2017.

3.1 **2018 COST OF SERVICE APPLICATION AND RATE COMPARISON -** Information Item

Joe Barile, General Manager, EPL, provided the Board with an overview of EPL's 2018 of Service Application and Rate Comparison. Report included, background on requirement to file COS, Impact to Ratepayers, Shareholders, Rate Comparisons and critical Timeline. Administration will keep the Board apprised of the application status.

It was moved by R Pula and

Seconded by A DiCarlo: ***That the 2018 COS Application and Rate Comparison be received as an information item.***

MOTION CARRIED

The revised 2018 budget and business plans were approved by EPLC's Board of Directors on November 29th, 2017. An excerpt from the meeting minutes is provided below:

2. **FINANCIAL**

2.1 Year to Date EPL Financial Statements dated October 31, 2017

It was moved by R Pula and

Seconded by K Antaya: ***That the Year to Date EPL Financial Statements dated October 31, 2017 be approved as presented***

CARRIED

3. 2018 BUSINESS PLAN AND 2018-2020 BUDGET

3.1 2018 Essex Powerlines Business Plan

Joe Barile, General Manager reviewed the 2018 EPL Business Plan and 2018-2020 Budget to the Board. The 2018 EPL Business Plan included an Operational Overview and 2018 Objectives, Human Resource Outlook, Health and Safety Overview and a Regulatory Outlook

It was moved by R Pula and

Seconded by K Antaya ***That the 2018 Essex Powerlines Business Plan be approved as presented.***

CARRIED

3.2 2017 Projected & 2018-2020 Budget

It was moved by R Pula and

Seconded by K Antaya: ***That the 2017 Projected & 2018-2020 Essex Powerlines Budget be approved as presented.***

Exhibit 1: 1-SEC-2

[Ex.1] Please provide a copy of the Applicant's most recent business plan and/or strategic plan.

Response

EPLC has included, as Attachment 1-D, a copy of its most recent business plan.

Exhibit 1: 1-SEC-3

[Ex.1] Please provide copies of all benchmarking studies, reports, and analysis that the Applicant has undertaken or participated in since 2010, and are not already included in the application.

Response

EPLC has participated in the MEARIE Management Salary Survey of Local Distribution Companies for the years 2010 through 2017 as well as a pole replacement study/benchmark across North America. All of these documents are marked as strictly confidential and are not included in this response.

Exhibit 1: 1-SEC-4

[Ex.1] Please provide a list of measurable outcomes that ratepayers can expect the Applicant to achieve during the test year. Please explain how those outcomes are incremental and commensurate with the rate increase the Applicant is seeking in this application.

Response

i) **Substation Maintenance** – Through the Single Voltage Utility initiative, EPLC has been able to fully eliminate ongoing substation maintenance expense resulting in yearly savings of $78,499 compared to the 2010 BAP.

ii) **Loss Factor Reduction** - Through the Single Voltage Utility initiative, EPLC has been able to reduce its distribution loss factor by 2.47% which results in the projected customer savings listed below:

Rate Class	Cost of Power Reduction	Delivery Reduction	Regulatory Reduction	Total Reduction	Reduction as % of Distribution Charge	Reduction as % of Total Bill
Residential	$ (0.65)	$ (0.14)	$ (0.07)	$ (0.86)	-3.10%	-0.68%
GS<50	$ (1.72)	$ (0.34)	$ (0.19)	$ (2.25)	-3.67%	-0.70%
GS>50	$ (20.79)	$ (7.20)	$ (3.85)	$ (31.84)	-6.87%	-0.51%
USL	$ (0.36)	$ (0.12)	$ (0.07)	$ (0.55)	-1.91%	-0.42%
Sentinel Light	$ (0.02)	$ (0.01)	$ (0.00)	$ (0.03)	-0.67%	-0.29%
Streetlight	$ (0.02)	$ (0.01)	$ (0.00)	$ (0.03)	-0.67%	-0.29%

iii) **Reduction of superintendents –** Through staffing efficiencies, EPLC has been able to eliminate the need for one superintendent thereby reducing EPLC labour costs by approximately $80,000 per year.

iv) **Meter reading reductions –** Consistent with Exhibit 4, Section 4.2.3, EPLC has been able to reduce its 3rd party meter reading costs as a result of the integration of smart metering infrastructure.

v) **Control Roof Efficiencies –** Through the deployment of EPLC's proposed 3rd Party Control Room services, EPLC will enhance customer communication during outages,

provide improved 24/7 customer service and outage management. Improved outage management will lead to fewer and less lengthy truck rolls and labour hours to diagnose outages and other system conditions.

vi) **Paperless billing –** EPLC is currently marketing and encouraging paperless billing which will result in reduction to billing & collecting costs while providng EPLC customers enhanced online tools to improve customer communication and education.

vii) **Health & Safety –** EPLC is continuously improving its Health & Safety initiatives. Both EPLC's employees and customers alike will benefit from a safer and more reliable distribution system.

viii) **Cybersecurity enhanced –** As part of this Application, EPLC is applying to significant enhance its Cybersecurity, consistent with the Board's direction. This will provide customers with enhanced data privacy, reduce the risk of cyber attacks and enhance the reliability of EPLC's IT infrastructure.

ix) **Migration to cloud email –** EPLC is currently moving many of its software services including email to cloud based in conjunction with its cybersecurity initiative. This will enhance overall system security and improve employee access to information.

x) **In-house settlement services –** EPLC has moved all settlement functions, which were previously completed by various third parties, in-house. This change will result in approximately $40,000 in efficiencies per year and enhanced knowledge within EPLC.

Exhibit 1: 1-SEC-5

[Ex.1, p.35] Please provide a step-by-step explanation of the Applicant's budgeting process.

Response

Please refer to Exhibit 4, Section 4.2.1. It should be noted that EPLC's capital budgeting process is the same.

Exhibit 1: 1-SEC-6

Does the Applicant have a corporate scorecard? If so, please provide copies of each of the 2010 to 2017 versions. If not, please explain what metrics the management and Board of Directors use to measure and monitor the Applicant's activities.

Response

EPLC does not currently have a corporate scorecard however it is currently developing one. Many of the metrics outlined in EPLC's pre-filed evidence (Exhibit 1, Section 1.4.1) as well as the Board's scorecard are intended to be part of the corporate scorecard which is how EPLC is currently monitoring its activities.

Exhibit 1: 1-SEC-7

[Ex.1, p.62] Please explain what activities or investments the Applicant is undertaking, or not undertaking, based on its customer engagement activities.

Response

EPLC has heard from its customers, on multiple occasions, that their three primary concerns are affordability, reliability and communication.

EPLC is proposing to enhance customer communication through investment in a 24/7 Control Room. This investment will improve communication to customers calling after hours and will convey near real-time information about outage restoration and other potential issues. Further, EPLC has implemented various social media communication throughout its operation to better communicate with its customers.

As it relates to reliability, EPLC is continuing its investment in the Self-Healing Grid to reduce Loss of Supply incidents that occur outside of EPLC's service territory. In addition, continued use of SmartMAP as an outage, engineering and asset management tool will support continuous improvement as it pertains to reliability for EPLC customers.

Lastly, to address EPLC's customer concerns related to affordability, as part of this Application EPLC is proposing to reduce the cost of the total bill across all customer classes.

Exhibit 1: 1-SEC-8

[Ex.1, p.15] With respect to the Applicant's Key Performance Metrics:

a. Please revise the tables for each metric to include 2017 performance.

b. [p.18] Please define a 'Cyber Security incident'.

c. [p.22] Please explain what the Applicant considers "reasonable year over year increases" in OM&A per customer.

d. [p.26] The Applicant states "[t]he majority of EPLC's historical turnover presented above is directly related to retirements." Please revise the Retention & Turnover table to show turnover not related to retirements. Please include 2017 information as requested in part (a).

e. [p.28] The Applicant states that "EPLC's target is to maintain just and reasonable rates for its customers that, where possible, are aligned with the rate of inflation." Please confirm the Applicant's proposed distribution rates for residential, GS<50 and GS>50 rate classes is above the inflation rate.

f. [p.31] Please provide the Applicant's regulated ROE since 2010.

Response

a)

Customer Satisfaction Surveys

2010	2011	2012	2013	2014	2015	2016	2017
N/A	N/A	N/A	N/A	81.00%	81.00%	81.00%	N/A

New Services Connected

2010	2011	2012	2013	2014	2015	2016	2017
98.60%	98.30%	93.20%	92.70%	93.00%	92.30%	90.50%	90.29%

Appointments Scheduled

2010	2011	2012	2013	2014	2015	2016	2017
97.73%	96.95%	96.83%	96.49%	95.55%	98.52%	98.78%	93.57%

Appointments Met

2010	2011	2012	2013	2014	2015	2016	2017
94.90%	95.50%	95.70%	94.30%	94.70%	94.80%	90.80%	93.24%

Appointments Rescheduled

2010	2011	2012	2013	2014	2015	2016	2017
100%	100%	100%	100%	100%	100%	100%	100%

Telephone Accessibility

2010	2011	2012	2013	2014	2015	2016	2017
70.60%	67.00%	68.50%	66.40%	78.00%	79.20%	73.60%	75.18%

Telephone Call Abandon Rate

2010	2011	2012	2013	2014	2015	2016	2017
4.92%	5.79%	7.05%	1.65%	1.25%	1.42%	0.80%	0.75%

First Contact Resolution

2010	2011	2012	2013	2014	2015	2016	2017
N/A	N/A	N/A	N/A	99.60%	99.28%	98.25%	N/A

Billing Accuracy

2010	2011	2012	2013	2014	2015	2016	2017
N/A	N/A	N/A	N/A	99.84%	98.05%	99.90%	N/A

Cyber Security Incidents

2010	2011	2012	2013	2014	2015	2016	2017
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Total Average Customers Hours Out

2010	2011	2012	2013	2014	2015	2016	2017
6.738	5.289	4.53	5.37	3.82	2.23	2.54	3.33

Total Average Customers Hours Out – No LoS

2010	2011	2012	2013	2014	2015	2016	2017
4.481	1.773	0.89	2.24	1.16	1.34	0.63	0.84

Total Customer Outages – Frequency

2010	2011	2012	2013	2014	2015	2016	2017
3.318	2.823	3.83	3.58	2.46	1.84	3.20	1.33

Total Customer Outages – Frequency – No LoS

2010	2011	2012	2013	2014	2015	2016	2017
1.631	0.912	0.61	1.12	0.66	0.83	0.50	0.57

Line Losses

2010	2011	2012	2013	2014	2015	2016	2017
6.02%	6.02%	6.02%	6.02%	6.02%	6.02%	6.02%	6.02%

Outage Response Time (Hours)

2010	2011	2012	2013	2014	2015	2016	2017
N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.83

OM&A Costs per Customer

2010	2011	2012	2013	2014	2015	2016	2017
$194.46	$197.44	$214.46	$212.94	$235.64	$235.45	$235.44	$238.11

Efficiency Ranking

2010	2011	2012	2013	2014	2015	2016	2017
2 of 3	2 of 3	2 of 5	2 of 5	2 of 5	2 of 5	2 of 5	2 of 5

Cyber Security Incidents

2010	2011	2012	2013	2014	2015	2016	2017
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Lost Time (Hours)

2010	2011	2012	2013	2014	2015	2016	2017
N/A	N/A	8.00	56.00	0.00	8.00	72.00	N/A

Serious Electrical Incidents Index – EPLC Employee

2010	2011	2012	2013	2014	2015	2016	2017
0	0	0	0	0	0	0	0

Serious Electrical Incidents Index – 3rd Party

2010	2011	2012	2013	2014	2015	2016	2017
7	3	2	4	7	3	2	5

Compliance with O.Reg. 22/04

2010	2011	2012	2013	2014	2015	2016	2017
C	C	NI	NC	C	NI	NC	N/A

Sick Time (Days Lost)

2010	2011	2012	2013	2014	2015	2016	2017
N/A	↑	↑	↑	↓	↓	↑	N/A

Retention & Turnover

2010	2011	2012	2013	2014	2015	2016	2017
2	3	4	2	3	5	4	1

Professional Development

2010	2011	2012	2013	2014	2015	2016	2017
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Distribution Rate Impacts

2010	2011	2012	2013	2014	2015	2016	2017
N/A	0.18%	0.88%	0.05%	1.55%	0.00%	1.95%	1.75%

Distribution Rate Impacts Aligned with Inflation

2010	2011	2012	2013	2014	2015	2016	2017
N/A	-2.910%	-1.332%	-0.942%	-0.810%	-1.190%	0.140%	0.250%

Industry Comparability – OM&A Rank

2010	2011	2012	2013	2014	2015	2016	2017
18th	12th	10th	8th	13th	16th	11th	N/A

OM&A Costs per Customer

2010	2011	2012	2013	2014	2015	2016	2017
$194.46	$197.44	$214.46	$212.94	$235.64	$235.45	$235.44	$238.11

GRI Reporting Progress

2010	2011	2012	2013	2014	2015	2016	2017
N/A	N/A	C	C	C	B	B	N/A

Conservation & Demand Management Savings & Results

2010	2011	2012	2013	2014	2015	2016	2017
N/A	9.77%	30.23%	61.40%	108.00%	12.05%	40.09%	N/A

Renewable Connections

2010	2011	2012	2013	2014	2015	2016	2017
9	27	40	31	13	12	22	N/A

Regulated ROE

2010	2011	2012	2013	2014	2015	2016	2017
N/A	N/A	N/A	N/A	N/A	11.58%	7.25%	N/A

b) EPLC is still working on a formal metric to define a Cyber Security incident however it will be related to any/all unplanned system or customer privacy breach.

c) EPLC considers reasonable year over year increases to be generally in-line with the rate of inflation with adjustments for industry related changes such as The Fair Hydro Plan, Cyber Security, etc.

d) Please refer to the table below which shows turnover not related to retirements.

2010	2011	2012	2013	2014	2015	2016	2017
0	0	1	0	0	1	1	1

e) Confirmed, however it should be noted that the total bill impact is below the rate of inflation, partially as a result of the Single Voltage Utility initiative.

f) Please refer to EPLC response to 1-Staff-4.

Exhibit 1: 1-SEC-9

[Ex.1, p.34, Figure 6] Please confirm the figure shows total bill impacts, not "EPLC Loss Factor Bill Impacts".

Response

This is confirmed. Please see the revised Figure 6 below. Please note that the numbers below are consistent with information filed with EPLC's Initial Application.

Rate Class	Cost of Power Reduction	Delivery Reduction	Regulatory Reduction	Total Reduction	Reduction as % of Distribution Charge	Reduction as % of Total Bill
Residential	$ (0.65)	$ (0.14)	$ (0.07)	$ (0.86)	-3.10%	-0.68%
GS<50	$ (1.72)	$ (0.34)	$ (0.19)	$ (2.25)	-3.67%	-0.70%
GS>50	$ (20.79)	$ (7.20)	$ (3.85)	$ (31.84)	-6.87%	-0.51%
USL	$ (0.36)	$ (0.12)	$ (0.07)	$ (0.55)	-1.91%	-0.42%
Sentinel Light	$ (0.02)	$ (0.01)	$ (0.00)	$ (0.03)	-0.67%	-0.29%
Streetlight	$ (0.02)	$ (0.01)	$ (0.00)	$ (0.03)	-0.67%	-0.29%

Exhibit 1: 1-SEC-10

[Ex. 1, p.42] Please provide a copy of the most recent version of the presentation and/or documents provided for the:

a. Yearly council presentation at each of its shareholder Municipalities

b. Annual General Meeting

Response

a) Please see EPLC Attachments 1-E, 1-F and 1-G.

b) Please see EPLC Attachment 1-H.

Exhibit 1: 1-SEC-11

[Ex.1, 1-G] Please provide a copy of all responses to the open ended questions provided on pages 9, 24, 25 and 27 of the workbook

Response

EPLC unfortunately did not receive any responses to the open ended questions provided on pages 9, 24, 25 and 27 of the workbook.

Exhibit 1: 1-SEC-12

Please revise all Chapter 2 appendices to include 2017 actual information and any resulting changes (if any) to the 2018 test year forecast.

Response

Please review EPLC Attachment 1-J.

Exhibit 1: 1-VECC-1

Reference: Exhibit 1, page 21,24

a) Please provide the outage response time for 2017.

b) Please explain who typically is a "3rd party" with respect to the "Serious Electrical Incidents Index" (e.g. customer or electrical contractor etc.)

Response

a) EPLC's average outage response time for 2017 was 50 minutes.

b) 3rd party Serious Electrical Incidents refers to non-EPLC employee incidents including customers, contractors and 3rd parties. Generally, these incidents refer to contractors/3rd parties making contact with underground EPLC facilities that result in no injury.

Exhibit 1: 1-VECC-2

Reference: Exhibit 1, page 29

a) Please provide the OM&A cost per customer for 2016 and 2017.

Response

EPLC's OM&A cost per customer in 2016 and 2017 (estimate) are as follows:

2016 – $235.44 per customer

2017 - $238.11 per customer

Exhibit 1: 1-VECC-3

Reference: Exhibit 1, page 37

Pre-amble: In its customer survey Essex reports that only 60% of customers were happy with how the Utility communicated with them.

a) What is the source of the discontent with Essex's customer communication?

b) What steps are being taken to improve communication performance?

Response

a) Please refer to EPLC response to 1-Staff-8.

b) Please refer to EPLC response to 1-SEC-7.

Exhibit 1: 1-VECC-4

Reference: Exhibit 1, Attachment 1-D, Green Energy Plan, page 11

a) Are the "SmartMAP" and Line Monitoring applications investments being made in lieu of a full blown SCADA system?

b) If yes, what was the estimated cost of the avoided SCADA system (capital and, separately, annual OM&A)?

c) Please explain how (by what factor) annual service fees for SmartMAP are escalated each year.

d) Please provide the 2019-2023 forecast incremental capital costs for SmartMAP and the Line Monitoring System.

e) Has Essex examined the experience of any other utility which has used the SmartMAP/line monitoring solution in lieu of a full scale SCADA system. If yes, please report the results of that examination.

Response

a) SmartMAP and line monitoring devices are a portion of EPLC's plan to obtain grid visibility and improve operability, cost effectively. EPLC is also seeking to implement initiatives like 3rd Party Control Room services to fully complement the deployment of SmartMAP.

b) EPLC estimates that a fully integrated SCADA system would cost several millions of dollars in capital expenditures and hundreds of thousands of dollars in yearly O&M to effectively operate.

c) Annual service fees for SmartMAP are not expected to increase for the next 2 years. EPLC expects inflationary increases in subsequent years.

d) EPLC is not currently forecasting incremental capital costs for SmartMAP and Line Monitoring System in 2019-2023.

e) EPLC is the first LDC in Ontario to use SmartMAP/line monitoring solutions however other small/medium LDCs have since adopted this solution as well. EPLC has not yet examined the experience of these other LDCs.

Exhibit 1: 1-VECC-5

Reference: Exhibit 1, Attachment 1-D, Green Energy Plan, page 15

a) Has the Self-Healing Grid Study been commissioned already? If not when will this be contracted?

b) Please explain the process for selecting an author for the study.

c) Please explain how the forecast of 150k for the study was derived. Is this cost all to be borne by Essex?

d) Please explain the projected benefits of this study and explain how the study will be shared with other utilities.

Response

a) The Self-Healing Grid Study has not yet been commissioned. EPLC expects to commission this report within the next 2-3 years.

b) Since there will likely be limited candidates capable of completing such as study, EPLC will canvas various industry experts that are capable of completing such a study based on experience, qualifications of authors and balance experience with the 3rd parties proposed cost for completion of the study.

c) The forecast of $150k is an estimate at this point in time.

d) There are a variety of complexities that need to be studied and modelled throughout the implementation of the Self-Healing Grid such as pre-approved switching plans based on load flow studies, protection schemes, etc. In order to maximize EPLC's investment in the Self-Healing Grid, EPLC will endeavor to optimize the installation of equipment to minimize outage times. EPLC regularly shares and collaborates with other utilities through various organizations such as the EDA, USF, Grid Smart City, etc.

Exhibit 1: 1-VECC-6

Reference: Exhibit 1, Attachment 1-D, Green Energy Plan, page 15

a) Had Essex received prior approval from the OEB for booking into a deferral account the amounts related to the Smart Grid projects in 2012 through 2017? If yes please provide that Order/Decision or letter.

b) If not, please provide the Board reference which provides for using the account prior to Board's approval of a specific project.

Response

a) EPLC has not received prior approval from the OEB to book charges directly into a deferral account.

b) EPLC has recorded amounts into deferral accounts based on G-2009-0087 and EB-2209-0397.

Exhibit 1: 1-VECC-7

Reference: Exhibit 1, Attachment 1-E

a) Please provide the updated Scorecard showing years 2016 and 2017 results.

Response

a) Please refer to EPLC response to 1-SEC-8.

Exhibit 1: 1-VECC-8

Reference: Exhibit 1, Attachment 1-G

a) Essex appears to have undertaken two customer engagement studies (Convergys/Wave and Innovative Research). Please explain why two studies were done.

b) What differences are there in the results of the two studies?

c) Please provide the cost of each study.

Response

a) The two customer engagement studies were completed in the spirit of the OEB's RRFE which lists Customer Focus as a key metric. Further completing customer engagement surveys also aligns with EPLC's core value "Customer & Community Value".

b) The Convergys study was a general customer satisfaction survey and the Innovative Research study was focused on EPLC's draft DSP and its 2018 Cost of Service Application.

c) Convergys Study - $12,400

Innovative Research Study - $29,970

Exhibit 1: 1-VECC-9

Reference: Exhibit 1, Attachment 1-G/ Innovative Study, page 14

a) The result of the Innovative Study states that 60% of customers had an outage in the past year and almost half of these customers stated that it lasted more than 30 minutes. In the year this study was undertaken how many customers actually had outages lasting 30 or more minutes?

Response

a) The number of customers that actually experienced an outage greater than 30 minutes was 46,599 in 2016. The number of customers that experienced an outage greater than 30 minutes after eliminating Loss of Supply events was 5,887.

Exhibit 1: 1-VECC-10

Reference: Exhibit 1, page 40 & Exhibit 2, Attachment 2-C (DSP), pages 87-91, 109

a) In surveying Essex customers as to whether they supported its capital expenditures was it explained that the largest reason for customer outages were loss of supply (Hydro One) and that outages caused by these factors would not be impacted by Essex's capital expenditure program?

b) How does Essex measure the effect of its capital program on system reliability?

Response

a) This was not specifically identified to respondents however it should be noted that EPLC attempts to address Loss of Supply events (Hydro One) via its Self-Healing Grid initiative which is part of its planned capital expenditures.

b) EPLC tracks year over year outage metrics and looks at various trending to ensure that the desire impact to reliability is being realized. An example of the type of trending that EPLC completes and reviews can be found in EPLC's DSP (Exhibit 2, Attachment 2-C) Figure 3-20.

Exhibit 2: 2-Staff-12

Chapter 2 model

Ref: EPLC Chp2Appendice 20170828 – Appendix 2-BA – 2015 – 2018 Account 1995 and Account 2440

Essex Powerlines appears to have simply moved amounts from Account 1995 to Account 2440 for the amounts related to customer contributions on adoption to IFRS. This treatment is not consistent with the APH guidance provided in Section 510.

a) Please review the APH Section 510 and update the applicable evidence as needed.

Response

a) EPLC has updated Appendix 2-BA to show contributions received in 2015-2018 in Account 1995. Please refer to EPLC Attachment 1-J.

Exhibit 2: 2-Staff-13

Chapter 2 model

Ref: EPLC Chp2Appendice 20170828 – Appendix 2-BA

Ref: EPLC Chp2Appendice 20170828 – Appendix 2-EC

Please explain and/or refile the appropriate schedules for the following OEB staff observations:

a) Appendix 2-BA for 2012 CGAAP – certain disposals under the Cost column are shown as debits, and in some cases there are no corresponding disposals shown under the Accumulated Depreciation column. Please explain.

b) Appendix 2-BA for 2013 Former CGAAP – the closing net PP&E per Appendix 2-BA does not match Appendix 2-EC.

c) Appendix 2-BA for 2014 Revised CGAAP – Under the Cost column, the disposals for certain accounts are shown as debits. Please explain why are disposals shown as debits and not credits?

d) Appendix 2-BA for 2015 MIFRS shows a large credit amount under the Accumulated Depreciation column for disposals. Please explain why the entry is a credit.

e) Appendix 2-BA for 2016 MIFRS - Under the Cost column, the disposals for an account are shown as a debit and not credit. Please explain.

f) Appendix 2-BA for 2016 MIFRS shows several credit amounts under the Accumulated Depreciation column for disposals. Please explain why the entries are not debits.

Response

a) Account 1860: The amount of $210,816 should have been included as an asset addition in 2012. This figure has been updated and is included as Attachment 1-J.

Account 1860: The amount of $179,649 reflects the year over year change in spare meter inventory valuation.

b) Please refer to revised schedules 2-BA and 2-EC included as Attachment 1-J.

c) Account 1860: The amount of $237,709 reflects the year over year change in spare meter inventory valuation.

Account 1850: The amount of $27,678 reflects a change in the capitalized inventory level.

d) The $1,104,875 should have also been recorded under the additions category for depreciation. This figure has been updated and is included as Attachment 1-J.

e) Account 1830: The debit entry showing in the Cost column for disposals is the result of an OEB audit adjustment entry.

f) Accounts 1830, 1840, 1850, 1908, 1920, 1935, 1940, 1945, 1955 have credit entries in the Accumulated Depreciation column for disposals as a result on an OEB audit adjustment entry.

Exhibit 2: 2-Staff-14

Chapter 2 model

Ref: EPLC Chp2Appendice 20170828 – Appendix 2-BA

Ref: EPLC Chp2Appendice 20170828 – Appendix 2-EC

The long-term interest rate in the PILs Workform is 3.72% but is 3.54% under the cost of capital tab in RRWF and in Appendix 2-OB.

a) Please amend and refile the schedules as needed.

Response

a) A revised PILs Workform using the Board's updated cost of capital parameters has been included as Attachment 1-K.

Exhibit 2: 2-Staff-15

Capital Expenditures

Ref: Figure 37 – Capital Expenditures – By Project & Year (Exhibit 2 Page 89)

Essex Powerlines provided capital expenditures by project for each year from 2011-2018.

a) Please provide the same breakdown for 2010 actuals.

Response

Please refer to the revised table which includes 2010 actuals below:

Projects	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
System Access									
Subdivisions	$ 223,557	$ 540,677	$ 728,506	$ 240,014	$ 150,424	$1,020,249	$ 446,196	$ 375,000	$ 382,500
Residential Connection/Extension	$ 127,068	$ 188,901	$ 471,954	$ 429,496	$ 677,866	$ 872,062	$1,050,696	$ 386,636	$ 394,369
Municipal Requests	$1,367,880	$ 721,963	$ 140,953	$1,048,671	$1,577,009	$ 311,344	$ 12,336	$ 600,000	$ 612,000
New Service Upgrades - C&I	$ 125,733	$ 120,392	$ 226,150	$ 100,871	$ 21,124	$ 3,767	$ 99,080	$ 349,960	$ 356,959
Miscellaneous	$ 84,029	$ (69,558)	$ 149,705	$ (53,546)	$ 105,509	$ 133,539	$ 150,961	$ -	$ -
Subtotal - System Access	**$1,928,266**	**$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	$ 151,029	$ 115,417	$ 194,333	$ 478,275	$ 193,281	$ 335,898	$ 513,973	$ 460,478	$ 114,062
O/H Reactive Replacements	$ 83,374	$ 110,554	$ 6,908	$ -	$ 6,145	$ -	$ 104,563	$ 80,784	$ 82,400
U/G Reactive Replacements	$ 27,558	$ 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	$ 33,806	$ 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	$ 633,783	$ 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	$ 94,700	$ -	$ -	$ -	$ -	$ 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	$ 254,532	$ 57,308	$ 47,978	$ 108,721	$ 143,405	$ 178,078	$ 424,720	$ -	$ -
Leamington Tornado	$ 135,278								
Miscellaneous	$ 260,929	$ 51,431	$ 310,092	$ 216,870	$ 65,157	$ 232,675	$ 202,228	$ -	$ -
Subtotal - System Renewal	**$1,674,990**	**$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	$ 18,170	$ 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	$ 1,089	$ -	$ 56,878	$ 100,139	$ 7,712	$ 8,460	$ 156,282	$ 163,037	$ 166,297
Smart Metering Initiative	$ 337,747	$ -	$ 515,559	$ -	$ -	$2,051,075	$ 87,921	$ -	$ -
Self Healing Grid Reclosers	$ -	$ -	$ -	$ -	$ 61,005	$ -	$ 633,057	$ 264,843	$ 270,140
Miscellaneous	$ 239,396	$ 7,314	$ 50,649	$ (20,282)	$ (7,117)	$ 47,571	$ 48,019	$ -	$ -
Subtotal - System Service	**$ 596,402**	**$ 939,772**	**$ 885,435**	**$ 184,769**	**$ 176,502**	**$2,195,825**	**$1,005,363**	**$ 787,132**	**$ 707,281**
General Plant									
Bldgs & Fixtures	$ 1,080	$ 13,214	$ 844,622	$ 21,981	$ -	$ 48,914	$ 42,469	$ 286,800	$ 370,000
Office Furniture/Equip	$ 30,534	$ -	$ 29,967	$ 6,711	$ 876	$ 5,980	$ 20,672	$ 10,000	$ 10,000
Computer Equipment HW	$ 189,930	$ 27,112	$ -	$ 13,501	$ 25,333	$ 5,837	$ 117,329	$ 356,150	$ 161,809
Computer Software	$ 449,119	$ 17,981	$ 34,572	$ 52,989	$ 166,960	$ 17,043	$ 4,632	$ 254,500	$ 115,000
Transportation Equip	$ 223,803	$ 156,970	$ 198,529	$ 307,516	$ 248,438	$ 401,244	$ 136,662	$ 487,000	$ 270,000
Tools & Equipment	$ 51,986	$ 35,577	$ 163,983	$ 47,415	$ 45,486	$ 68,451	$ 62,365	$ 110,000	$ 110,000
Miscellaneous		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - General Plant	**$ 946,452**	**$ 250,855**	**$1,271,673**	**$ 450,112**	**$ 487,094**	**$ 547,468**	**$ 384,129**	**$1,504,450**	**$1,036,809**
Total	**$5,146,110**	**$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	**$5,146,110**	**$4,525,547**	**$6,572,392**	**$5,513,117**	**$6,207,502**	**$7,779,437**	**$5,274,104**	**$6,658,465**	**$6,183,000**

Exhibit 2: 2-Staff-16

Direct Buried Cable Replacement Program

Ref: Figure 37 – Capital Expenditures – By Project & Year (Exhibit 2 Page 89)

Essex Powerlines has significantly increased the Direct Buried Cable Replacement program in the 2018 test year.

a) Please provide the need that drives the increase in underground cable replacement.

b) How was the need not anticipated in previous years and done through a phased approach?

Response

a) The Direct Buried Cable Replacement Program specifically targets problem areas in EPLC's distribution system where end of life or near end of life assets (cable, transformers, etc) need to be replaced. Where possible, EPLC is also moving distribution assets from backyards to front yards in an attempt to eliminate future access issues.

b) With the completion of its Single Voltage Utility initiative, EPLC is now focussing on the Direct Buried Cable Replacement program although EPLC identified this need several years ago. Projects such as the Monopoly Subdivision conversion, Primary Cable Replacement and Lithgow Livefront Transformer replacement could be considered part of EPLC's historical Direct Buried Cable Replacement program/Infrastructure Renewal program when considering historical spending. In an effort to keep capital spending as smooth as possible, EPLC has previously deferred a more capital intensive Direct Buried Cable Replacement Program (continuing to replace/upgrade assets where required and as needed) consistent with EPLC's prioritization of capital projects (Exhibit 2, Attachment 2-C, Section 3.1).

Exhibit 2: 2-Staff-17

Cost of Power

Ref: Figure 17 – Cost of Power Summary

Essex Powerlines provided a cost of power summary table which includes the total power purchased and global adjustment. Essex Powerlines also stated that it used the "Regulated Price Plan Report – May 1, 2017 to April 30, 2018" report to calculate the commodity price used in this application.

a) Please provide a breakdown of the power purchased and global adjustment total including the rate and volumes used to calculate the total in excel format.

b) What rates did Essex Powerlines use to calculate power purchased and global adjustment for the period after April 30, 2018? If Essex Powerlines did not continue the rate from the report please provide justification on the proposed rate.

c) Please calculate what the cost of power would be if Essex Powerlines used the rate from the report for the whole year.

Response

a) EPLC has included a breakdown of the power purchased and global adjustment total including the rate and volumes used to calculated the total in excel format as Attachment 1-L.

b) EPLC carried forward the rate from the report.

c) EPLC used the rates from the report for the entire 2017/2018 calendar years.

Exhibit 2: 2-Staff-18

RTSR – Network cost

Ref: Figure 17 – Cost of power Summary

Ref: Figure 23 – Proposed Cost of Power – 2017/2018

For the 2018 test year there is a discrepancy for RTSR – Network total in Figure 17 and Figure 23. Please confirm which value is correct and update the tables.

Response

Figure 17 was inconsistent with the actual value presented in Figure 23. An updated Figure 17 is included below.

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	$ 2,330,333
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	$ 68,485,984

Exhibit 2: 2-Staff-19

Self-Healing Grid

Ref: Figure 17 – Cost of power Summary

Ref: Figure 23 – Proposed Cost of Power – 2017/2018

"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. 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."

a) If the customer interruption hours are largely caused by loss of external supply, please explain how the cited Essex Powerlines investments will enhance customer value.

Response

Please refer to EPLC response to 1-SEC-7.

Exhibit 2: 2-Staff-20

System O&M

Ref: Attachment 2-C – EPL Distribution System Plan – Table 2-1 Historical and forecast net capital expenditures and system O&M (Page 22)

Ref: Attachment 2-C – EPL Distribution System Plan – Table 4-17 Historical and forecast capital expenditures and system O&M

Essex Powerlines provided the above two tables which show an increase in System Service investments over the forecast period and also the corresponding system O&M. Essex Powerlines stated that System Service investments include investments for the self-healing grid, which should reduce outages and restoration costs.

a) Please explain why there is no corresponding decrease forecast for System O&M expenditures with the increase in spending in System Service investments.

b) Please reconcile the System O&M expenditures shown in Table 2-1 and Table 4-17.

Response

a) EPLC has factored in productivity in System O&M in relation to proposed increases in System Service investments. Please note that all forecasted increases to System O&M are below EPLC's typical budgeting assumption for inflation at 2%.

Category	Forecast ($ '000)				
	2018	2019	2020	2021	2022
System O&M	$ 3,067	$ 3,116	$ 3,162	$ 3,213	$ 3,264
Year Over Year Increase (%)		1.60%	1.48%	1.61%	1.59%

b) Table 4-17 should be revised to match Table 2-1 as per below:

Category	2013		2014		2015		2016		2017	
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Budget
	$ '000		$ '000		$ '000		$ '000		$ '000	
System Access	Note 1	$ 1,766	Note 1	$ 2,532	Note 1	$ 2,341	Note 1	$ 1,759	Note 1	$ 1,712
System Renewal	Note 1	$ 3,113	Note 1	$ 3,012	Note 1	$ 2,695	Note 1	$ 2,125	Note 1	$ 2,655
System Service	Note 1	$ 185	Note 1	$ 177	Note 1	$ 2,196	Note 1	$ 1,005	Note 1	$ 787
General Plant	Note 1	$ 450	Note 1	$ 487	Note 1	$ 547	Note 1	$ 384	Note 1	$ 1,504
Total Expenditure	**$ -**	**$ 5,513**	**$ -**	**$ 6,208**	**$ -**	**$ 7,779**	**$ -**	**$ 5,274**	**$ -**	**$ 6,658**
System O&M	Note 1	$ 2,722	Note 1	$ 2,994	Note 1	$ 3,141	Note 1	$ 3,171	Note 1	$ 2,794

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**
$ 3,067	$ 3,116	$ 3,162	$ 3,213	$ 3,264

Exhibit 2: 2-Staff-21

Substations

Ref: Attachment 2-C – EPL Distribution System Plan – Anticipated Sources of Cost Savings (Page 24)

Recently, Essex Powerlines 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 Essex Powerlines to reduce its stock, inventory, and kilometres of line under management while the number of customers has continued to increase.

a) Please confirm that Essex Powerlines does not have any distribution substations in its service territories.

b) Please provide the upstream Hydro One transmission/distribution stations that supplies power to each of Essex Powerlines service territories and also the distribution feeder identification.

c) Please provide the electronic single line diagram for each associated station and service area.

Response

a) EPLC confirms that it does not have any distribution substations in its service territories.

b) Amherstburg is fed by HONI owned upstream transformer stations Keith TS and Malden TS. The applicable distribution feeders are 23M3, 23M4, 23M5 (Keith TS) and 24M7 (Malden TS).

LaSalle is fed by HONI owned upstream transformer stations Keith TS and Malden TS. The applicable distribution feeders are 23M3, 23M4, 23M5 (Keith TS) and 24M7, 24M8, 24M9 and 24M10 (Malden TS).

Leamington is fed by HONI owned upstream transformer station Kingsville TS. The applicable distribution feeders are 3M4, 3M6 and 3M8.

Tecumseh is fed by HONI owned upstream transformer station Lauzon TS. The applicable distribution feeders are 56M4, 56M25 and 56M26.

c) Please refer to Attachment 1-M.

Exhibit 2: 2-Staff-22

Reactive Replacements

Ref: Attachment 2-C – EPL Distribution System Plan (Page 25)

"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."

a) Please provide quantitative evidence, in the form of a business case, cost-benefit analysis or equivalent, demonstrating that proactive capital projects and programs are more cost-effective (from a ratepayer perspective) than reactive replacements. Please explain in detail the assumptions employed in the analysis.

b) Essex Powerlines' planned capital work may be cost effective if the pre-emptive replacements do not exceed the number that would have failed in a normal year. How does Essex Powerlines guarantee that is the case?

c) Does Essex Powerlines' planned capital work investment strategy factor in the opportunity cost of foregoing remaining asset life (i.e.: how can customers be confident that Essex Powerlines' isn't just building rate base)?

Response

a) The following outlines EPLC's planning process for asset classes as an example:

Poles – EPLC replaces poles based on resistive testing that show the strength required to hold up the pole is beyond its design criteria. Design Criteria according to CSA for poles (consistent with ESA Regulation 22/04) is based on an ice storm with specific thresholds of ice buildup on the lines and specific wind speeds. The poles may not fail until we have this scenario. We do not wait for the poles to fall as we would revert to the significant reliability concerns related to unplanned forced outages and the result of higher costs as described in a) above. In the early 2000s, EPLC operated in a more reactive manner and generally could not complete planned work since we were constantly reacting to various emergency/unplanned events.

Replacement – Reactive Vs. Planned

i. Reactively replacing a failed pole would be about 1 per day with another ½ day of cleanup
ii. Planned replacement we can do 2 per day with less quantity of staff at the job site

Switchgear replacements – EPLC recently had a planned switchgear replacement in the schedule, but it failed just before it was planned to be replaced. We were able to get by in a temporary state, but it could have prevented a 3.5 hour outage to 203 customers. At least in a planned outage, the customers can prepare in advance for no power.

EPLC is replacing assets that show signs of weakness or have previously failed or are at TUL (age) or are difficult to access in backyards. We try not to replace assets that do not meet the following general guidelines:

i) Underground primary previous failures in same subdivision/area;
ii) Repeatedly overloaded transformers;
iii) Transformers installed in the same subdivision where one has already failed and are at TUL;
iv) Overheating beyond design temperature via infrared thermography;
v) Leaking oil;
vi) Using RCM;
vii) PMH's show signs of weakness through both failures, tracking, infrared, ultrasonic. These assets usually feed a larger number of customers are higher load customers like schools, apartments, arenas, commercial/industrial customer;

Several scenarios where a planned, proactive approach to capital planning is more cost effective and better for customers are described below:

- Cost of afterhours taking calls;
- OT/call-in costs;
- OT – meal allowance every 4 hours;
- Getting up in bucket truck to trouble shoot - Waiting time for second lineperson to get bucket truck from yard and bring to the site;
- Trouble shooting time – checking the asset to see what is wrong;
- Calling in the 3rd lineperson and utility person to get the assets out of stock, load the 3rd truck and bring out to site;
- Possibly working in bad weather increasing risk to employees;
- Supervisor – spends less time on planned vs reactive, getting outage information to public;
- Increased complaints regarding power outages;
- Loss of revenue from customer – longer outage than planned;
- Extensive Damage of other equipment for violent failure – Pole fire as an example;

- Environmental cleanup/Ground restoration;
- For digging/underground – emergency locates vs normal locate - $91.10 vs $36.65 per unit;
- Contractor callout cost for vacuuming, environmental cleanup – minimum 4 hour callout at premium rate;

b) While pre-emptive replacements generally exceed the number that would have failed over a given time period, EPLC listed several efficiency scenarios in response to a) above that would largely offset this cost.

c) Yes, EPLC considers the remaining useful life of an asset prior to replacement. If EPLC is planning to replace an asset prior to its planned useful life, it would need to satisfy one of the criteria set out above in response to a).

Exhibit 2: 2-Staff-23

Customer Satisfaction

Ref: Attachment 2-C – EPL Distribution System Plan Figure 2-5: Percentage of satisfied customers for surveyed customer classes in 2014 (Page 28)

Ref: Attachment 2-C – EPL Distribution System Plan (Page 29)

On page 29, Essex Powerlines stated:
"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"

Figure 2-5 shows that only 50% of residential customers and 37% of GS<50 customers think that bills are reasonable.

a) Please reconcile the above statement that residential and GS customers agree that Essex Powerlines should make the necessary investments even if it requires an increase to their bill, with the statistics in Figure 2-5.

b) Please provide the evidence that Essex Powerlines used to draw the above conclusion.

Response

a) Through its customer engagement activities (Exhibit 1, Attachment 1-F & 1-G), EPLC has heard that affordability is a concern of EPLC customers. Affordability however, refers to the entire electricity bill and not necessarily to EPLC's portion only. EPLC's customer engagement activities also identified system reliability as a major concern of EPLC customers. EPLC is actively balancing both of these offsetting concerns throughout this Application by applying to reduce to the total electricity bill while continuing to make needed and balanced investments in capital.

b) Please refer to Exhibit 1, Attachments 1-F & 1-G of EPLC's pre-filed evidence.

Exhibit 2: 2-Staff-24

Consultation with Hydro One

Ref: Attachment 2-C – EPL Distribution System Plan (Page 31-32)

"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."

a) Please describe how the planned asset transfer investments have been economically optimized.

b) Did Essex Powerlines carry out business case analyses to support the described asset transfers? If yes, please provide these analyses. If not, please explain why not.

c) Please demonstrate quantitatively that these investments are in ratepayers' interest.

d) Please confirm if approval is being sought for the budgeted expenditures to transfer assets between Essex Powerlines and Hydro One as part of Essex Powerlines' present cost of service application, if approval of these investments will be sought under an Incremental Capital Module to be filed later, or a combination of these approaches?

e) Has Essex Powerlines considered the rate impact of the capital contribution for Leamington TS over the timeframe of the distribution system plan? If not, why not?

Response

a) These asset transfers have not yet been economically optimized. Once more information is known, EPLC will assess and optimize the potential investments.

b) Formal business cases to support the described asset transfers has not yet been completed. Please see response to e) below for additional information.

c) Formal analysis has not yet been completed.

d) Some of the local distribution work required to re-configure the Leamington/Kingsville distribution systems is considered as part of EPLC's DSP since it was tangible, measurable and verifiable (Please refer to Exhibit 2, Attachment 2-C, page 45-47). Upstream transmission costs, capital contributions and major asset purchases are not included as part of this Application. See response to e) below for more information.

e) Consistent with Exhibit 2, Section 2.3, EPLC has considered the rate impact of a potential capital contributions for Leamington TS over the timeframe of the distribution system plan however have chosen not to include them at this time due to the minimal information available at the time of this application. The Board also currently reviewing cost allocation changes for large transmission investments through EB-2016-0003 through which EPLC has actively participated since inception.

Should a capital contribution be required of EPLC, EPLC is proposing to address this capital contribution through the application Incremental Capital Module at its earliest applicable IRM filing in order to avoid any large forecasting errors in the value of the capital contribution payable.

Exhibit 2: 2-Staff-25

Consultation with IESO

Ref: Attachment 2-C – EPL Distribution System Plan – Table 2-3: Reg investments projected in the 2018 Test Year (Page 34)

Ref: Figure 37 – Capital Expenditures – By Project & Year (Exhibit 2 Page 89)

Essex Powerlines showed the projected REG investments in 2018 is $110k but in the capital expenditure table referenced above the forecast for FIT & Generation Connections is $181k.

a) Please explain the difference between both tables and provide an explanation for the variance.

Response

a) Table 2-3 of EPLC DSP was intended to show the eligible REG investments forecasted for the 2018 Test Year. Exhibit 2, Figure 37 represents all capital costs related to FIT & Generation Connections, which includes non-REG related investments.

Exhibit 2: 2-Staff-26

System Reliability

Ref: Attachment 2-C – EPL Distribution System Plan – Figure 2-11: Customer interruption hours by cause code (2013 to 2016)

Ref: Attachment 2-C – EPL Distribution System Plan – Figure 2-13 to 2-15: Severity – Impacts of outages caused by defective equipment

Essex Powerlines has shown that most of the outage hours are caused by loss of supply from Hydro One. The second largest outage hours are due to defective equipment, which Essex Powerlines further attributes to defective underground equipment.

a) Please provide the causes for the loss of supply from Hydro One. If Essex Powerlines does not have all the causes please comment on general known causes in coordinating with Hydro One.

b) Does Essex Powerlines anticipate the construction of Leamington TS will help reduce the loss of supply from Hydro One? If so, by how much and how will this be accomplished.

c) Please explain each variable presented in Figure 2-13 to 2-15. What does the variable represent? How is it calculated? What is its significance?

Response

a) EPLC does not receive detailed outage causation from Hydro One for upstream Loss of Supply events. Causes can range from planned work to 3rd party contractor contacts with upstream transmission assets resulting in significant customer hours of outages for EPLC distribution customers. EPLC labels all outages outside of its distribution system as a Loss of Supply event.

b) While the construction of Leamington TS will enhance electrical infrastructure on the south shore of Essex County, EPLC has no means of quantifying the potential positive impact of the new station.

c) Figures 2-13 through 2-15 assess the severity and importance of outages caused by defective equipment (all), overhead defective equipment and underground defective equipment, by year with variance trend lines. Severity and Importance are calculated using the following formula:

$$S.I. = \frac{\sum(N_i \times r_i) / N}{\sum(N_i^L \times r_i) / N^L}$$

Where N_i is the number of events in rank I, r_i is the median of rank i, $N = \sum N_i$ and the superscript L refers to the lowest value set. The importance index is defined as the severity index multiplied by the total number of occurrences, or S.I. x N.

Exhibit 2: 2-Staff-27

Asset Management Process

Ref: Attachment 2-C – EPL Distribution System Plan – Table 3-1: EPL's asset management objectives and related corporate goals

Essex Powerlines uses an Asset Investment Strategy that provides an optimized resource investment plan based on desired asset performance and risk tolerance. Table 3-1 provides seven business objectives that describe how Essex Powerlines' risk exposure is accounted for and how it is used to facilitate development of an optimal Asset Investment Plan.

a) Since these are all qualitative scores how does Essex Powerlines ensure that the evaluation of each objective for each project/program is consistent?

b) Does Essex Powerlines change the optimal Asset Investment Plan developed from the Asset Optimization Tool? If yes, please identify all changes that deviated from the optimal plan and an explanation as to why.

> I. For bullet 5 "Financial returns" please provide details on how the net present value is determined. This should include the calculation used, underlying assumptions, and quantified examples of actual calculations.

c) How are the numerical weights assigned to Essex Powerlines' asset management objectives determined?

d) How does Essex Powerlines assign the numerical weights for each objective? Does Essex Powerlines plan to change these weights from application to application?

e) How does Essex Powerlines assess whether the Asset Investment Plan is economically optimal?

f) What metric is being optimized (e.g.: risk adjusted minimization of costs to ratepayers) and is the current plan optimal?

Response

a) While the scores are qualitative in nature, EPLC uses a consistent approach in the allocation of scores. For each new project type, EPLC carefully reviews similar projects and ranks the new

project against already established entries, while also reviewing existing entries for accuracy and overall appropriateness.

b) EPLC has not changed the optimal Asset Investment Plan from the Asset Optimization Tool.

I) Modified Internal Rate of Return ("MIRR") and NPV are calculated as follows:

$$MIRR = \sqrt[n]{\frac{FV(PositiveCashFlows, costofcapital)}{PV\ (InitialOutlays, FinancingCost)}} - 1$$

$$NPV = \sum_{t=1}^{T} \frac{C_t}{(1+r)^t} - C_o$$

Where

C_t = net cash inflow during the period t

C_o = total initial investment costs

r = discount rate, and

t = number of time periods

For the purpose of these calculations, the re-investment rate is assumed at 3% and the annual loan rate is assumed at 6%. For each project, the initial capital cost is input along with year over year cost savings, cost claims, revenue and other costs over a 10 year horizon. This process is completed for each project. The formal financial calculations are done within the Asset Optimization Tool itself therefore a demonstration of an actual calculation cannot be provided as EPLC is only provided with the outputs.

c) In conjunction with 3rd party experts, EPLC set its numerical weights for the seven asset management objectives as follows:

i) Financial Returns – 11%

ii) Service Quality – 13%

iii) Safety – 26%

iv) Environmental – 20%

v) Regulatory – 18%

vi) Legal – 8%

vii) Company Image – 6%

d) The weights are based on best utility practice and are subject to annual review.

e) EPLC assesses whether or not the Asset Investment Plan is economically optimal by setting a spending threshold (in EPLC's case, approximately $6M per year). EPLC's Asset Optimization Tool then ranks OEB mandated projects (ie. Customer Connections) and considers the highest non-essential scores. The Tool also defers projects with lower scores (financial considerations being one of the drivers) for future consideration.

f) EPLC confirms that the current plan is optimal, based on the output of EPLC's Asset Optimization Tool.

Exhibit 2: 2-Staff-28

Primary Underground Cable

Ref: Attachment 2-C – EPL Distribution System Plan – Table 3-4: Primary Underground cable service age relative to TUL

A large amount of the budget planned for system renewal is related to the replacement of underground cables. Essex Powerlines justifies this with approximately 19% of the cables reaching typical useful life. This is approximately 48.9km of underground cables that need replacement.

a) Over the last 8 years how many outages and outage hours are related to the failure of an underground cable?

b) Has Essex Powerlines tried to do cable testing for areas where it expects cable failure? If not, why?

c) What is the typical cost per kilometer of proactive direct buried cable replacement? What is the typical cost of reactive direct buried cable replacement?

d) What percentage of underground cable are laterals (no loop feed) and what percentage of underground cable are loop fed?

e) For each underground cable that are lateral identified in d) what is the average number of customers on that lateral?

Response

a) The following table outlines the outages and outage hours related to failure of underground cable:

Year	Restore Code	Frequency	Customer Hours	Customers	Outage Length (Hours)
2010	5.4	3	225	80	2.8
2011	5.4	8	2249	568	4
2012	5.4	8	1159	356	3.3
2013	5.4	4	4879	839	5.8
2014	5.4	2	149	77	1.9
2015	5.4	2	216	106	2
2016	5.4	2	282	124	2.3
2017	5.4	2	1041	289	3.6

b) EPLC has tried the two primary means of cable testing (TDR and High pot) however neither have been able to accurately or reliability predict cable failure, the methods can be costly and can also diminish the useful life of cable if used too frequently.

c) The following outlines the typical cost of replacing direct buried cable:

- Cost of conduit ($70/meter);
- Cost of cable ($14.30/meter);
- Cost of pulling cable ($7.20/meter);
- Total cost $170/meter or $170,000/kilometer

d) EPLC estimates that approximately 90% of underground cables are loop fed and 10% are laterals (no loop feed).

e) EPLC estimates that there would be approximately 6-8 customers per lateral.

Exhibit 2: 2-Staff-29

Reliability-Centered Maintenance

Ref: Attachment 2-C – EPL Distribution System Plan – Reliability-Centered Maintenance (page 69)

"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."

a) How does Essex Powerlines forecast the probability of failure?

b) Essex Powerlines has five categories for each qualitative score but since they are qualitative in nature the distinction between neighbouring categories can be subject to bias. How does Essex Powerlines ensure a consistent approach to the qualitative scores between evaluators?

c) Given that Essex Powerlines has been using this methodology for the past 10 years and the assets are generally in good to very good condition, is it possible that Essex Powerlines is setting the Risk scores too high and replacing instead of repairing/maintaining assets?

d) Does Essex Powerlines assess the tradeoffs between O&M costs and system renewal investments? If so, please provide that analysis.

e) Has the implementation of RCM led to a noticeable improvement in productivity (e.g. using a multi-factor productivity model)? If yes, please provide evidence.

f) Has the implementation of RCM led to higher annual CAPEX when compared to pre-RCM capital investment levels?

g) Does Essex Powerlines predict the reliability results associated with different capital investment portfolios?
I. If yes, please provide the forecasted reliability for each capital and OM&A investment.
II. Does Essex Powerlines compare predicted performance with actual performance? If yes, please provide details.

Response

a) Each reviewed project was scored in the risk matrix using all of the strategic business objectives (Exhibit 2, Attachment 2-C, Section 3) assuming the following formulations:

- Expected Return = Re
- Risk Free Rate of Return = Rf
- Average Market Return = Rm
- Re = Rf + Beta (Rm – Rf)

The resulting calculation is assessed against the chart below to determine probability of failure.

Risk Map

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

Probability

Consequence

b) Please refer to EPLC response to 2-Staff-27.

c) EPLC performs yearly risk scores reviews to ensure that EPLC is not replacing instead of repairing/maintaining assets. EPLC accredits its overall system asset condition to the RCM process and prudent investment over time.

d) EPLC is constantly balancing O&M costs with system renewal projects and is striving to keep these investments flat and consistent, year over year with reasonable adjustments for inflation and other factors beyond the control of EPLC (ie Extraordinary events, etc.). EPLC has historically been successful in keeping these costs in-line.

Cateogry	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
System Renewal	$ 3,113	$ 3,012	$ 2,695	$ 2,125	$ 2,655	$ 2,693	$ 1,362	$ 2,304	$ 2,248	$ 2,195
System O&M	$ 2,722	$ 2,994	$ 3,141	$ 3,171	$ 2,794	$ 3,067	$ 3,116	$ 3,162	$ 3,213	$ 3,264

e) The implementation of RCM has led to productivity improvements in the use of lineman staff as well engineering and planning staff as their projects and objectives have been clearly outlined and prioritized, ensuring that relevant staff are focussed on what is best for system reliability and EPLC electricity customers.

f) EPLC has been using RCM for over 10 years. Over that period of time, EPLC has been able to consistently manage its capital spending within desired ranges every year. EPLC has not made incremental capital spend as a result of RCM as compared to pre-RCM. Instead, RCM has allowed EPLC to make better, more targeted capital investments to ensure customer value and system reliability.

g) I) EPLC does not currently formally forecast reliability results for various capital investment portfolios.

II) EPLC is not currently comparing predicted performance with actual performance however is currently considering this as a future asset management continuous improvement opportunity.

Exhibit 2: 2-Staff-30

Asset Life Cycle Risk Management

Ref: Attachment 2-C – EPL Distribution System Plan – Asset Lifecycle Risk Management Policies and Practices

Ref: Attachment 2-C – EPL Distribution System Plan – Figure 3-23: Risk matrix to select and prioritize capital expenditures

Ref: Attachment 2-C – EPL Distribution System Plan – Table 3-6: Overall asset risk rating

"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.

$$R_e = R_f + \beta(R_m - R_f)$$

- Re is the expected rate of return.
- Rf is the risk-free rate of return
- Rm 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"

a) Please explain how Essex Powerlines uses the Capital Asset Pricing Model to prioritize projects.

b) What is used as the risk-free rate of return? Please provide an example.

c) What is used as the average market rate of return? Please provide an example.

d) Please provide how beta is calculated and examples of the calculation.

e) Is rate of return a measure of the economic value of an investment to Essex Powerlines as an asset owner, or to Essex Powerlines' ratepayers? Please provide details.

f) Is the purpose of this formula to maximize the expected rate of return?

g) Table 3-6 appears to drive the timing of projects, which is based on risk alone. How does table 3-6 and the Capital Asset Pricing Model relate to each other in terms of project prioritization?

Response

a) The 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. Also included in this process are service orders, minor field maintenance (non-program work where no system reconfiguration is required), and any minor load additions. 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.

All projects/programs on the system, as described above, are modeled and analyzed according to a consistent framework. For every request, multiple solutions are identified and compared to define the optimal path forward. Technical, financial and socio-political factors are analyzed for every project/program.

Risk is factored into all decisions to estimate and understand the degree of exposure between different courses of action. Risk is defined as the product of consequence and probability. Consequences are analyzed for technical, financial and socio-political considerations.

All projects are defined with enough information to initiate work. What, when, who, where, and why must be addressed for all work. In addition any funding requirements/approvals are achieved in this process.

Once defined all potential projects is integrated into a Project Information Policy (PIP) asset plan containing all work on the system; maintenance, construction, programs, etc. The AIP is a rolling plan with a horizon of one to five years for active planning, but does include known events beyond the planning horizon. The asset plan is very dynamic and should be continuously monitored and analyzed for synergies, issues and opportunities.

The development, refinement, and identification of “Standards” requirements are analyzed in the process. All standards are also monitored and assessed according to set goals and objectives. Likewise, all maintenance programs, mandated and internally driven, are developed and managed in the process.

Potential projects to be input in Project Information Plan (PIP) are gathered and assessed. Input and analysis is done using tools, statistics, databases, customer/developer input, assessments, and nondestructive examination (NDE).

Maximizing the Use of On-Line Systems allow recording and monitoring the distribution line operation through faults, operational counts, age, and loading using information technology 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 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 condition using on 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 oils levels can be identified using these nondestructive techniques and planned repairs or replacement can be schedule before failure.

The frequency and timing of distribution system maintenance is an important factor in balancing the costs and unplanned outages. Using nondestructive techniques, oil analysis, or statistical service lifetimes in service failures can be prevented and the lifetime of equipment extended. Equipment inventory is kept to a minimum using this approach.

Risk Assessments are currently complete on all assets. Risk Assessments identify from a lineman and operations manager perspective Risks associated with operating and maintaining EPL's oldest plant in the system. Any potential additional risks identified are required to fill in the Risk Assessment forms. These inputs come from the operating personnel, shareholder personnel customer calls, emergency personnel (Police, Fire), regular Health and Safety Meetings, or other LDCs and joint use partners.

Risk Assessments are also done on each task an operations person performs. Assessment Rating Scales were adopted by JH&SC and are used as inputs in projects that require these activities be carried out.

ASSIGN SEVERITY

Severity is the expected consequence of an event in terms of degree of injury.

Risk severity is rated according to the following scale:

- 0 - No Injury
- 1 - Bumps and bruises
- 2 - Requires first aid
- 3 - Requires medical attention
- 4 - Critical injury – Recoverable injury
- 5 - Death or Non-Recoverable injury

ASSIGN PROBABILITY

Probability is the likelihood that an event causing injury will occur.

Risk probability is rated according to the following scale:

- 0 - Not applicable
- 1 - Very remote
- 2 - Remote – unlikely to occur
- 3 - Uncommon – possible to occur
- 4 - Occasional – probably could occur occasionally
- 5 - Common – likely could occur regularly

ASSIGN FREQUENCY

Frequency is the portion of the workers' time per year that is spent doing this Task, regardless of type of work.

Risk frequency is rated according to the following scale:

- 0 - 0%
- 1 - 1 to 9% of total hours
- 2 - 10 to 19% of total hours
- 3 - 20 to 29% of total hours
- 4 - 30 to 39% of total hours
- 5 - 40% or more of total hours

The need to deliver high quality reliable power while not overspending is required in this current market condition. The frequency and timing of distribution system equipment maintenance is an important factor in this balance. Predictive maintenance or sometimes called value based maintenance relies on organized statistical data in order to identify distribution system components most subject to in service failure. Analysis of databases characterizes the number and severity of service interruptions.

Analyzing this data shows a distinction in terms of outage duration and customer minutes off. RCM preserves system function, failure probabilities, and methods of reducing failure, economic or other measures. This translates into statistical data by distribution system components (i.e. underground secondary services). A number of methods can be used for facilitating planning.

RCM provides the follow benefits to planning:

- Prevents failures whose consequences are most serious
- Schedule Maintenance to avoid unnecessary maintenance
- Produces severity and importance for each component that has the most detrimental effect to reliability
- Answers the question "What is the consequence of a single event on the Distribution System?"

The cost associated with each failure is used to predict future costs using failure trends. RCM focuses on preventing failures whose consequences are most serious while Predictive Maintenance uses diagnostic methods to schedule maintenance in a timely manner. Integrating two streams of information along with Risk and Value produces an optimal strategy for spending.

RCM has been used for at least 10 years for asset category focus to assist and monitor the health of the distribution system asset in performing the design function. It is divided into 45 categories for reporting purposes. Each outage is entered and the asset group that under performs can be monitored.

b) The risk free rate of return generally represents the rate of return on an investment with zero risk. For EPLC's evaluations, EPLC has used values that are closely aligned with Government of Canada 10 Year Bond Yields which have historically been close to 2.50%.

c) EPLC used the current Board Approved ROE as the market rate of return. For 2017, EPLC has used 8.78%.

d) EPLC uses qualitative analysis to determine an optimal value for beta based on the following criteria and also measured against other historical projects:

- Operational β less than 1 is low risk.
- Operational β equal to 1 is average risk
- Operational β greater than 1 is higher risk

e) The rate of return is designed as a measure to protect both EPLC and its customers by preventing EPLC from undertaking significantly risky projects. Where a project is identified as inherently risky to both EPLC and/or its customers and is considered mandatory capital work, EPLC would flag this project and determine suitable remediation/contingency strategies prior to commencement of the project. This process allows EPLC to pre-emptively identify inherently risky projects and to plan around them proactively. As a result, this process protects both EPLC and its customers.

f) No, the purpose of the formula is to further aid in the prioritization of projects using various and different evaluation criteria. In this case, the metrics are risk and financial in nature.

g) Where both analysis are completed and there are material differences between the two, they are then both compared by our Engineering & Asset Manager to ensure optimal implementation and timing.

Exhibit 2: 2-Staff-31

Pole Replacement Program

Ref: Attachment 2-C – EPL Distribution System Plan – System Renewal

"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."

a) Can a pole with 60% remaining strength be considered adequate for its application?
I. If no, please explain why not.
II. If yes, please explain why Essex Powerlines uses a 60% threshold for pole replacements.

b) How does Essex Powerlines ensure that poles are not being prematurely replaced and that Essex Powerlines is not overinvesting in pole replacement programs? Please provide a detailed explanation.

Response

a) No, a pole with 60% remaining strength cannot be considered adequate for its application. The requirement is defined by CAN/CSA C22.3 No. 1-15, *Overhead Systems*, one of a series of Standards issued under the *Canadian Electrical Code, Part III*. Clause 8.3.1.3 of the Standard reads "when the strength of a wood pole structure has deteriorated to 60% of the required design capacity, the structure shall be reinforced or replaced." Reinforcement is a temporary solution to maintain power until a replacement can be scheduled and is not a practical long-term solution.

b) To ensure it is not overinvesting in pole replacement programs, EPLC uses the results of its Asset Condition Assessment (ACA) to guide investments into pole replacement. As noted on page 61 of the Distribution System Plan, "The [ACA] results suggest a pole replacement rate of 1.5-2% per year, depending on the final results of the risk analysis."

To ensure that poles are not being prematurely replaced, Essex Powerlines uses pole testing (drilling) results to prioritize poles for replacement. As noted in the Reference above, "through its thorough preventative maintenance program, [Essex Powerlines] reviews the condition of its poles continuously to limit failure and maximize safety via non-destructive testing methods

such as drilling." Page 14 of the ACA report (attached as Appendix J to the DSP) provides a detailed explanation:

> 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.

Exhibit 2: 2-Staff-32

Risk Consequences

Ref: Attachment 2-C – EPL Distribution System Plan – Table 4-12: Definitions of numeric scores describing the consequence of project deferral

a) In the reference Table 4-12, Financial Risk is defined as a measure of lost revenue or avoided cost.

I. How does Essex Powerlines ensure that its measure of lost revenue does not overlap with other items in this table, such as reliability?
II. Please provide an example of how Essex Powerlines calculates avoided cost as referenced in this table.

b) What is the measure and medium for collecting information for the Company Image metric?

c) Please confirm if the order of definitions in Table 4-12 under Legal Risk, Regulatory Risk, Safety Risk and Environmental Risk should be reversed.

d) Under Environmental Risk, please provide an example of an asset that scores, or is able to score, a consequence score of 5.

e) Has Essex Powerlines considered the correlation between various items in Table 4-12 above? For example, is a high consequence Environmental Risk likely to trigger high consequence Regulatory, Legal, Company Image, Safety and/or Financial Risks? How does Essex Powerlines ensure that risks are not being exaggerated as a result of the various correlations and interdependencies?

Response

a) I) EPLC reviews scores yearly and also assesses long standing projects against each other for reasonableness to ensure that projects are not inherently positively or negatively impacted. Further, lost revenue and avoided costs require separate impacts into the model.

II) For 2018 Test Year, EPLC did not estimate any avoided costs as a part of its asset optimization strategy. In the past EPLC has calculated avoided cost for projects that facilitated the need for less overtime, less lineman hours, etc. In these cases, EPLC would have estimated the average value for items such as avoided overtime, avoided hours and inputted them into the project financials of the system.

b) EPLC's Company Image metric is based on the projected number of customer complaints received as a result of completing or not completing a particular capital project along with the potential consequences. These consequences are as follows:

I. None
II. Individual concerns made to Company.
III. Multiple concerns made to Company.
IV. Concerns raised to local government/board of directors plus local media coverage.
V. Concerns raised to regulator. Media coverage by regional media.
VI. General public outcry. Coverage by national media.

The consequences listed above are weighted against the probability of occurrence:

i. None.
ii. One event every 10 years.
iii. One event every 3 years.
iv. One event per year.
v. Quarterly, 2-4 events per year.
vi. More than 4 events per year.

c) Confirmed.

d) EPLC does not have any assets that would qualify a consequence score of 5 for Environmental Risk. An example of an asset or that could reach a 5 would be a property that has had significant ground contamination as a result of leakage of oil. The resulting cleanup/mitigation strategy would likely involve the Ministry of the Environment for cleanup solutions and this situation could be assessed an Environmental Risk score of 5.

e) EPLC has considered the correlation between various metrics identified in Table 4-12. EPLC reviews scores yearly and also assesses long standing projects against each other for reasonableness to ensure that projects are not inherently positively or negatively impacted.

Exhibit 2: 2-Staff-33

Project Prioritization

Ref: Attachment 2-C – EPL Distribution System Plan – Table 4-14: 2018 Test Year project prioritization

Essex provided a list of projects for 2018 prioritized based on the risk/strategic objective score.

a) Please provide a breakdown of the components that compose the risk/strategic objective score for each project.

b) Were there other projects that have been removed from this list as a result of pacing the five year capital spending?

c) If the total capital envelope was reduced would Essex Powerlines cut projects from the bottom of this list upwards until the envelope is reached?

Response

a) The components that compose the risk/strategic objective score are included below. Each metric has one or more different consequences and resulting probability of occurrence that is evaluated per project:

- 1.1. Financial
  - 1.1.1. MIRR Calculation
  - 1.1.2. Lost revenue
  - 1.1.3. Cost avoidance
- 1.2. Service Quality
  - 1.2.1. SAIFI
  - 1.2.2. SAIDI
- 1.3. Company Image
  - 1.3.1. Customer complaints
- 1.4. Legal
  - 1.4.1. Claims
- 1.5. Regulatory
  - 1.5.1. Regulatory compliance
- 1.6. Safety
  - 1.6.1. Employee safety

1.6.2. Public safety
1.7. Environmental
1.7.1. Disturbance considerations

b) Yes, please refer to EPLC response to 2-SEC-18 for an example.

c) Confirmed so long as they were not mandated/forced projects.

Exhibit 2: 2-Staff-34

Investment Drivers

Ref: Attachment 2-C – EPL Distribution System Plan – Table 4-1: List of material capital expenditure – System Access

Ref: Attachment 2-C – EPL Distribution System Plan – System Service (Page 118)

Essex Powerlines stated that "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."

In Table 4-1 it appears the budget for the Metering Upgrade & Replacement Program is trending upwards.

a) Please confirm that the evidence seems contradictory and if so please reconcile the statement or Table 4-1.

Response

a) EPLC's statement on Page 118 of Exhibit 2, Attachment 2-C is reconciled to state that there is an upward trend for metering investments required as a result of meter seal expiries, communication issues with new technologies and its integration with SmartMAP and EPLC's various systems like OMS, billing system, etc.

Exhibit 2: 2-Staff-35

Municipal Requests

Ref: Attachment 2-C – EPL Distribution System Plan, Appendix A: Project Narratives – Municipal Requests (Page 7)

a) What is Essex Powerlines level of confidence in the projected expenditure requests for 2018 and beyond?

I. What is the basis of Essex Powerlines' confidence in the request quantum for each of these future years?

b) What are expenditures for the 2017 bridge year to-date?

Response

a) EPLC is confident in the projected expenditure requests for 2018 and beyond. EPLC's budget is largely based on historical expenditures and supported by ongoing discussions with local municipalities and known major provincial capital projects (ie Gordie Howe bridge). EPLC's historical spending is outlined below:

Description	2010	2011	2012	2013	2014	2015	2016	2017	2018
Municipal Requests	$1,367,880	$721,963	$140,953	$1,048,671	$1,577,009	$311,344	$12,336	$600,000	$612,000

b) The estimated 2017 bridge year to-date Municipal Request spending is $371,598.

Exhibit 2: 2-Staff-36

Municipal Requests

Ref: Attachment 2-C – EPL Distribution System Plan, Appendix A: Project Narratives – New Service Upgrades C&I (Page 10)

Ref: Attachment 2-C – EPL Distribution System Plan, Appendix A: Project Narratives – Metering Upgrade & Replacement Program (Page 13)

Ref: Attachment 2-C – EPL Distribution System Plan, Appendix A: Project Narratives – Overhead Reactive Replacement (Page 21)

Ref: Attachment 2-C – EPL Distribution System Plan, Appendix A: Project Narratives – Underground Reactive Replacement (Page 25)

Ref: Attachment 2-C – EPL Distribution System Plan, Appendix A: Project Narratives – Install/Replace Load Breaks (Page 29)

a) For each of the Material Investments listed above, please explain why Essex Powerlines forecasts expenditures to be significantly greater than the historic 2013-2016 average annual expenditures?

b) As part of Essex Powerlines' Overhead Reactive Replacement projects, it is mentioned that "EPL relies on a combination of proactive replacements, Reliability-Centered Maintenance ("RCM"), predictive maintenance, preventative maintenance, and cyclical inspections to manage its distribution assets and reduce the amount of reactive work required." Please explain why Essex Powerlines has forecasted an increase in reactive replacement when RCM is supposed to help minimize the need for reactive replacement and there has not been a historical trend to the proposed level of spending.

Response

a) Forecasted expenditures are largely comprised of the following elements:

- New Service Upgrades C&I: Please refer to EPLC response to 2-Staff-37 below.
- Metering Upgrade & Replacement Program: EPLC is planning on replacing meters with forthcoming seal expiry and to resolve several communication related issues with existing smart meters.
- Overhead Reactive Replacement: Please refer to EPLC response to b) below.

- Underground Reactive Replacement: Please refer to EPLC response to b) below.
- Install/Replace Load Breaks: EPLC has experienced several failures relating from various Load Breaks from a specific manufacturer. EPLC is currently replacing these specific Load Breaks over time given the impact of failure can be significant for impacted EPLC electricity customers.

b) RCM has resulted in reductions to reactive maintenance spending, historically. ELPC has forecasted an increase in reactive replacements to account for better than anticipated performance over the past several years and to ensure that EPLC has sufficient ability to respond to reactive events, as they occur.

Exhibit 2: 2-Staff-37

New Service Upgrades C&I

Ref: Attachment 2-C – EPL Distribution System Plan, Appendix A: Project Narratives – New Service Upgrades C&I (Page 10)

Essex Powerlines stated that it deals with a variety of requests that are not known at the time of budgeting and forecast costs are driven by historical trends and increased by inflation

a) Please provide a breakdown of the projects that make up the 2017 and 2018 capital expenditures for new service upgrades. Please provide the scope of the project and alternatives considered, if possible.

b) Please provide an explanation for the abrupt increase in capital spending in 2017 compared to historical years.

c) To the best of Essex Powerlines' abilities, please provide all known/planned projects for the five year periods. Please provide the scope of the project and alternatives considered, if possible.

Response

a) EPLC forecasted 8 (6 overhead, 2 underground) new C&I connections and 10 service upgrades in both 2017 and 2018 consistent with speculated growth and based on discussions with existing customers and developers.

b) EPLC has had discussions with various developers, existing customers looking for expansion opportunities along with potential new C&I customers which has substantiated the need for EPLC to increase its New Service Upgrades – C&I category. 2017 estimate for New Service Upgrades – C&I is $229,183 which represents a sharp increase from 2016 and is expected to continue growing into 2018 and beyond.

c) EPLC's 2018 forecast includes the following projects (names were removed for confidentiality purposes however EPLC listed the type of service planned):

- LAS Industrial – new primary/pad mount $79,098 - Contract signed Phase
- AMH Industrial – new primary/pad mount $100,877 - Contract review Phase
- TEC Commercial - new primary/pad mount –$84,018 (1 large grocery store, 1 drive thru restaurant, 1 larger retail) - Contract Draft Phase

- LAS Restaurant Malden increase padmount size to accommodate – Design Phase
- LEA Office Warehouse – Design Phase
- LEA Restaurant – Design Phase
- LAS School – Design Phase
- LEA Government Load – Design Phase

EPLC does not have a formal forecast of specific projects beyond 2018 however there are discussions surrounding 5 new general service apartment buildings which would require significant resources in 2019 and beyond. EPLC expects continued C&I growth given recent modest growth trends locally. Alternatives are considered where available and a discussion is generally made with the customer to select the most appropriate solution.

Exhibit 2: 2-Staff-38

Metering Upgrade Replacement Program

Ref: Attachment 2-C – EPL Distribution System Plan, Appendix A: Project Narratives – Metering Upgrade Replacement Program (Page 13)

Essex Powerlines forecasted the 2018 Test Year expenditure includes 351 interval meters, 672 smart meters, and 4 gatekeepers.

a) Please provide the total number of interval meters, smart meters, and gatekeepers in Essex Powerlines service territory.

b) Please provide a break down of the age demographic for the interval meters, smart meters, and gatekeepers. Also provide the typical useful life of each piece of equipment.

Response

a) Interval Meters: 398

Smart Meters: 29,578

Gatekeepers: 39

b) The following three tables outline the age demographic for interval meters, smart meters and gatekeepers. EPLC assumes that the useful lives on these assets is 15 years.

Interval Meter	
Manufacturing Date	TOTAL
2009	0
2010	2
2011	158
2012	90
2013	21
2014	2
2015	40
2016	83
2017	2
TOTAL:	398

Smart Meter Type	
Manufacturing Date	TOTAL
2007	909
2008	5,508
2009	10,449
2010	7,540
2011	151
2012	413
2013	1,177
2014	725
2015	916
2016	1,075
2017	713
2018	2
TOTAL:	29,578

Gate Keeper	
Manufacturing Date	TOTAL
2007	35
2008	0
2009	0
2010	0
2011	0
2012	0
2013	0
2014	0
2015	0
2016	0
2017	4
TOTAL:	39

Exhibit 2: 2-Staff-40

Overhead Reactive Maintenance

Ref: Attachment 2-C – EPL Distribution System Plan, Appendix A: Project Narratives – Overhead Reactive Replacement (Page 21)

Essex Powerlines has trended the overhead reactive replacement budget to reflect 2017 forecasted actuals for the five years following. Over the last ten years Essex Powerlines has been completing voltage conversion projects, which presumably involves replacement of overhead assets.

a) Please provide a cost break down of the 2017 forecasted actual. This should be broken down by project, cost of project, scope, and the event that caused the replacement.

b) Part of the driver for this program is assets at the end of their service life. Please explain how the line work done as part of the voltage conversion projects did not help reduce the probability of asset failure.

Response

a) The 2017 forecasted actual is $63,920. The breakdown by project, cost of project, scope and the event that caused the replacement is as follows:

Description	Cost
LEA 50 Peter replace Transformer - TX3B120	$ 8,139
TEC 11918 Tec Rd Replace Transformer TX10620	$ 11,651
LAS 9045 Broderick Replace Transformer TX70D88	$ 5,003
Various - Porcelain Switch Replacement/Failure	$ 31,287
LAS 10 Senator 75KVA Replace Transformer	$ 7,840
Total	**$ 63,920**

b) EPLC forecasts that Overhead Reactive Replacements would be substantially higher without the implementation of historical voltage conversion projects and line work done as a part of voltage conversion work has helped to reduce the probability of asset failure. Further, EPLC's overhead equipment related outages have been steadily decreasing over the past 5 years:

Description	2013	2014	2015	2016	2017
Defective Equipment	47	36	45	19	15

Exhibit 2: 2-Staff-41

Underground Reactive Maintenance

Ref: Attachment 2-C – EPL Distribution System Plan, Appendix A: Project Narratives – Underground Reactive Replacement (Page 25)

Essex Powerlines has trended the underground reactive replacement budget to reflect 2017 forecasted actuals for the five years following. In 2018, Essex Powerlines has budgeted a significant amount to the direct buried cable replacement program.

a) Please provide a cost break down of the 2017 forecasted actual. This should be broken down by project, cost of project, scope, and the event that caused the replacement.

b) Part of the driver for this program is assets at the end of their service life. Please explain how the additional capital expenditure in the replacement of direct buried cables would not help reduce the probability of asset failure.

Response

a) The 2017 forecasted actual is $55,133. The breakdown by project, cost of project, scope and the event that caused the replacement is as follows:

Description	Cost
LEA 28 Garrison Motor Vehicle Accident	$ 7,974
AMH Nomenclature inspection and replacement - Failed equipment	$ 12,091
AMH 228 George Replace Failed UG Transformer TX50116	$ 8,202
Various - Porcelain Switch Replacement/Failure UG	$ 26,866
Total	**$ 55,133**

b) The replacement of direct buried cable and the Infrastructure Rebuild project will help to control underground asset failure now and into the immediate future by specifically targeting known problem areas and renewing assets that have a history of reliability concerns or are at or near end of useful life.

Exhibit 2: 2-Staff-42

Install/Replace Load Breaks

Ref: Attachment 2-C – EPL Distribution System Plan, Appendix A: Project Narratives – Install/replace Load Breaks (Page 29)

Essex Powerlines has trended the Install/replace load break budget to reflect 2017 forecasted actuals for the five years following.

a) Is there an asset condition assessment of load break switches? If not, please provide the age demographics of all load break switches.

b) Please provide a cost break down of the 2017 forecasted actual. Are these replacements due to the condition of the load break switch, to meet the needs of the self-healing grid, or a combination of both?

Response

a) Load Break Switches were not part of the scope of EPLC's Asset Condition Assessment. EPLC's historical records related to asset information on Load Break Switches is currently minimal and was not included as a result.

b) The cost break down for the 2017 forecasted actual Load Break Switch replacements are shown below. These replacements are largely the result of the condition of the switch which have failed and required replacement. These replacements can be used to enhance and fast track upgrades required as part of EPLC's Self-Healing Grid Initiative.

Description	Cost
AMH 419 Alma Replace Defective LB Switch	$ 61,173
AMH 157 Park Replace Defective Switch	$ 52,685
LE Sherk Oak Install LB Switch	$ 31,329
Total	**$ 145,186**

Exhibit 2: 2-Staff-43

Switchgear Replacement Program

Ref: Attachment 2-C – EPL Distribution System Plan, Appendix A: Project Narratives – Switchgear Replacement Program (Page 40)

Essex Powerlines plans to replace two live-front switchgears per year over the next five years. Essex Powerlines also provided an age profile and asset condition assessment for all its switchgears. The age profile show that there are only five switchgears with service age greater than 21 years. Furthermore, there was only two switchgears in fair condition, the remaining are either in very good or good condition.

a) Please provide Essex Powerlines' justification for replacing switchgears that are in either good or very good condition.

b) If it is anticipated that the age or condition of the transformer will move over the next five years to a lower echelon, please provide evidence justifying the move.

Response

a) EPLC has recently had a history of a specific name-brand of Switchgear devices prematurely failing. Given the customer and safety impacts associated with these devices failing, EPLC is slowly working towards replacing them with more reliable units, over a period of time to limit exposure and reliability concerns and minimize financial impacts.

b) See response to a) above. The age or condition of these replacements is not currently the primary driver for replacement.

Exhibit 2: 2-Staff-44

HONI Asset Purchase - Leamington

Ref: Attachment 2-C – EPL Distribution System Plan, Appendix A: Project Narratives – HONI Asset Purchase - Leamington (Page 45)

Essex Powerlines intends to transfer assets between Essex Powerlines and Hydro One through the purchase and sales of assets.

a) Does Essex Powerlines have plans or anticipate any other possible transfer of assets in its service territory over the next five years?

Response

a) The transfer of assets between EPLC and Hydro One, for a variety of reasons such as elimination of Load Transfers, system optimization and customer connections occurs frequently. EPLC does anticipate the transferring and/or purchase/sale of assets in the Leamington area as a result of the commissioning of Leamington TS, which is anticipated mid 2018. While specific details are not currently known beyond 2018, significant distribution related work downstream needs to occur to re-configure the Kingsville/Leamington area, which is currently solely serviced by Kingsville TS. With the implementation of Leamington TS, EPLC is working jointly with Hydro One to optimize distribution assets in the area. EPLC forecasts that for 2018, asset transfers will include:

- Purchase of 5.9km of poles, conductor and insulators in locations where Hydro One does not have another feeder (e.g. 3M6 and 3M4) within EPLC's service territory;
- Sale of 1.1km of conductor and insulators (related to the 3M9 circuit);
- Sale of poles along the east side of an arterial road, on which EPLC has no current asset;

Exhibit 2: 2-Staff-45

Self-Healing Grid - Reclosers

Ref: Attachment 2-C – EPL Distribution System Plan, Appendix A: Project Narratives – Self-Healing Grid (Page 51)

Essex Powerlines intends to reduce the duration of outages caused by loss of supply by installing reclosers that can facilitate automatic switching and service restoration.

a) Please provide the business case supporting the Self-Healing Grid. This should include the scope of the whole project, alternatives considered, expected savings, and implementation plan.

b) Does Essex Powerlines need to communicate with Hydro One before automatic switching? Please provide the steps that are taken starting from the moment the outage is detected till a final load transfer is completed.

c) For interoperability Essex Powerlines stated that there is substantial work on Hydro One's end to update their systems, processes, and protocols to accommodate the request.

I. Does that mean that there won't be full automation until this is completed?

II. What is the expected timeline from Hydro One to have a fully functional system?

d) For each of the figures 9 through 11 please provide the electronic single line diagram for the distribution system that are legible.

Response

a) The primary driver for the need of EPLC's Self-Healing Grid Initiative remains that approximately 75% of EPLC Customer Hours relating to outage are caused by incidents outside of EPLC's service territory and therefore out of EPLC control.

Project Scope

There are three primary capital components to EPLC's Self-Healing Grid initiative:

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.

EPLC expects to have the necessary capital work completed for this initiative over the course of the next 5 years. In addition, EPLC will need to work on the integration and control of these assets for the eventual automation that EPLC requires.

Risk 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. There are limited alternatives to address EPLC's significant Loss of Supply issue in the area as it has been cost effectively trying to manage this issue for close to 20 years.

Efficiency, Customer Value, Reliability

I) 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 vend*ors, good utility practice and regulation as metrics to justify the investment.

II) 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.

b) Yes, EPLC is currently in ongoing discussions with Hydro One to facilitate automatic switching. For clarity, EPLC has not yet implemented automatic switching therefore the steps taken to switch load and resolve an outage are still unknown at this point in time.

c) I) Confirmed.

II) EPLC is working closely with Hydro One to be able to have a fully functional system, including all EPLC installation work prior to our next Cost of Service Application.

d) Please refer to Attachment 1-N for the electronic single line diagrams.

Exhibit 2: 2-Staff-46

Buildings & Fixtures

Ref: Attachment 2-C – EPL Distribution System Plan, Appendix A: Project Narratives – Building & Fixtures (Page 60)

Ref: Attachment 2-C – EPL Distribution System Plan, Appendix H: Building Condition Review

Essex Powerlines budgeted approximately $1.5M in building & fixture projects over the five year period. This is supported by the building condition review report in appendix H. In the report, the total estimated costs were approximately $750k and it also noted that over the next five years there were only concerns on the parking asphalt, roofing/skylight, and the Heating Ventilation and Air Condition (HVAC) system.

a) Please explain what Essex Powerlines plans to spend the additional $750k requested in the budget.

b) Please provide the list of projects planned between 2020-2022.

Response

a) The incremental spend relates to the following projects:

- Storage Pole Barn (storage for RBDs, Forklift and front loader) - $300k
- General Upkeep and maintenance of EPLC properties (including work described in b) below) - $450k

b) The following projects are planned during the 2020-2022 time period:

- Drainage for the fleet garage. This is a specific item, and local bylaws and building requirements have been difficult to pin down. Without any detail this amount was listed under miscellaneous with details to follow.
- Seasonal repairs to the paved areas, e.g. concrete and asphalt repair/restoration.
- Building structure enhancements such as new windows, doors, insulation, and lighting. This would also include interior changes to reconfigure for new employees or departmental changes and improvements.
- Improvements or major repairs to the inventory area including, shelving, racking, covered storage.

Exhibit 2: 2-Staff-47

Computer Software

Ref: Attachment 2-C – EPL Distribution System Plan, Appendix A: Project Narratives – Computer Software (Page 63)

Essex Powerlines budgeted a consistent expenditure of $80k a year for 2019 to 2022.

a) Please provide a breakdown of the planned projects for each of the four years.

Response

a) Between 2019 to 2022, EPLC plans on upgrading and updating several key systems. While software updates and upgrades can be hard to forecast, EPLC is planning to upgrade the following systems:

- GIS (Estimated 2019);
- Customer Portal (Online experience upgrade, Estimated 2019);
- Work Management System upgrade (Estimated 2020);
- Work Estimate System upgrade (Estimated 2020);
- Utility Dashboard (EPLC management upgrade, Estimated 2021);
- CIS upgrade (Estimated 2021);
- Finance (GP) upgrade (Estimated 2022);
- Website updates (Estimated 2022);

Exhibit 2: 2-Staff-48

Transportation Equipment

Ref: Attachment 2-C – EPL Distribution System Plan, Appendix A: Project Narratives – Transportation Equipment (Page 66)

Ref: Attachment 2-C – EPL Distribution System Plan, Appendix I: Fleet Purchasing Policy

Essex Powerlines forecasted a growth in expenditure over the next five years, doubling by 2022.

a) For each vehicle planned for replacement please also provide the number of kilometers driven, and a condition assessment, if available.

b) Please explain why there does not appear to be any planned vehicle replacements for 2019 and 2021 but Essex Powerlines has budgeted $275k and $445k for the respective years.

Response

a) There is only 1 vehicle planned for replacement in 2018. It has a current mileage of 155,000 kilometers, it is 8 years old and logs approximately 15,000 kilometers per year. It is reviewed and assessed internally and is rated in poor condition with aggressive rust in some locations, it also has a damaged rear bumper.

Also scheduled for 2018 is:

- The purchase of 2nd UG Truck. The current UG truck is heavily utilized and with our increasing capital replacement program to UG infrastructure, a second UG truck is required to ease some of the workload.
- The replacement of reel tensioner/stringer. The current reel trailer is aging and has varying degrees of maintenance related issues and is rated in poor condition.
- The replacement of wood chipper. The existing unit is aging and parts for that model are increasingly unavailable.

b) The 2019 and 2021 budgets have a number of planned replacements and purchases:

- Replacement of Unit 67 (UG Truck) - $95K budgeted in 2019 from capital budget forecast
- Replacement of 2 Engineering vehicles - $90K budgeted in 2019 from capital budget forecast

- Replacement of Unit 72 (Sub-Foreman vehicle) - $55K budgeted in 2019 from capital budget forecast
- Purchase of a general use Office vehicle - $45K budgeted in 2019 from capital budget forecast
- Refurbishment of Unit 103 - $50K budgeted in 2019 from capital budget forecast

Additionally, the 2021 budget includes the replacement of Unit 351 (a 55' Double Bucket) at an estimated cost of $445K.

Exhibit 2: 2-SEC-13

[Appendix 2-AB] Please revise Appendix 2-AB to include, under the 'plan' columns, the annual internally budgeted amounts, and provide basis for the budgeted number. Please explain all material variances between actuals and budgeted amounts.

Response

Please review revised Appendix 2-AB below with budgeted numbers for each year.

Category	2010		2011		2012		2013		2014		2015		2016		2017	
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual
	$ '000		$ '000		$ '000		$ '000		$ '000		$ '000		$ '000		$ '000	
System Access	$ 4,092	$ 1,928	$ 1,791	$ 1,502	$ 3,224	$ 1,717	$ 3,193	$ 1,766	$ 2,150	$ 2,532	$ 1,592	$ 2,341	$ 1,396	$ 1,759	$ 1,712	$ 1,294
System Renewal	$ 2,200	$ 1,675	$ 3,097	$ 1,833	$ 2,921	$ 2,698	$ 3,828	$ 3,113	$ 2,865	$ 3,012	$ 2,751	$ 2,695	$ 2,205	$ 2,125	$ 2,655	$ 3,086
System Service	$ 147	$ 693	$ 172	$ 940	$ 100	$ 885	$ 67	$ 185	$ 92	$ 177	$ 579	$ 2,196	$ 1,025	$ 1,005	$ 787	$ 734
General Plant	$ 370	$ 960	$ 937	$ 251	$ 1,113	$ 1,272	$ 863	$ 450	$ 885	$ 487	$ 845	$ 547	$ 595	$ 384	$ 1,504	$ 1,249
Total Expenditure	**$ 6,809**	**$ 5,256**	**$ 5,997**	**$ 4,526**	**$ 7,358**	**$ 6,572**	**$ 7,951**	**$ 5,513**	**$ 5,992**	**$ 6,208**	**$ 5,767**	**$ 7,779**	**$ 5,221**	**$ 5,274**	**$ 6,658**	**$ 6,362**
System O&M	$ 2,170	$ 2,264	$ 2,846	$ 2,618	$ 2,860	$ 3,203	$ 2,720	$ 2,722	$ 2,745	$ 2,994	$ 2,980	$ 3,141	$ 3,193	$ 3,171	$ 2,794	$ 2,792

Material variance explanations:

- 2010/2013 System Access - EPLC overbudgeted due to a planned Municipal Request project that never materialized.
- General Plant 2010/2011 – Planned consolidation for EPLC's operations from the Essex Civic Centre to the Operations Centre was planned in 2010 but realized in 2011.
- 2011 System Renewal – EPLC planned significant System Renewal projects in 2011 that were later deferred due to constraints in labour.
- 2012 System Access – EPLC planned a significant Municipal Request project that never materialized.
- General Plant 2013/2014 – EPLC deferred the planned purchase of transportation equipment.
- 2015/2016 System Access – EPLC realized higher than expected residential connections and Municipal Request related work.
- 2010-2015 System Service – EPLC has consistently underbudgeted System Service projects that were captured in System Renewal. This was addressed in 2016.

Exhibit 2: 2-SEC-14

[Ex., p.25] With respect to the Leamington TS:

a. Please provide the Applicant's most recent forecast for the capital contribution it will be required to pay for the Leamington TS.

b. When is the Leamington TS expected to go in-service?

c. Please explain how the Applicant has adjusted its capital budget during the DSP period to account for the fact it will be required to pay a capital contribution to Hydro One for the Leamington TS.

Response

a) EPLC has not forecasted or budgeted for a capital contribution to HONI required for Leamington TS. As stated in Exhibit 2, Section 2.3, EPLC is planning to file an ICM when further information is available.

b) Mid 2018.

c) EPLC has not adjusted its capital budget during the DSP period to account for the fact it will be required to pay a capital contribution to Hydro One for Leamington TS. The cost allocation principles are currently being reviewed and discussed as part of EB-2016-0003. EPLC, through the E3 Coalition, has been an active participant in these proceedings.

Exhibit 2: 2-SEC-15

[Ex.2, DSP, p.39] Please provide a table that shows the number of customer interruptions by cause code for each year between 2013 and 2017.

Response

Please refer to the table below for interruptions by cause code for each year between 2013 and 2017:

Outage Code	Description	Number of Outages				
		2013	2014	2015	2016	2017
0	Unknown	5	2	2	1	1
1	Scheduled Outage	168	158	185	68	116
2	Loss of Supply	33	26	19	12	8
3	Tree Contact	8	9	8	1	5
4	Lightning	14	7	11	0	6
5	Defective Equipment	47	36	45	19	15
6	Adverse Weather	9	4	2	2	6
7	Adverse Environment	2	0	1	0	2
8	Human Element	0	1	1	2	0
9	Foreign Interference	35	39	32	21	41

Exhibit 2: 2-SEC-16

[Ex.2, DSP, p.54-55] With respect to the Applicant's 7 Strategic Objectives:

a. Using multiple examples of actual projects, please break down the calculations for each objective including detailed explanations for those with qualitative scores.

b. Please explain how the Applicant determined the weights to be given to each Strategic Business Objective.

Response

a) The following table shows the scores and breakdown of results for each objective. A detailed description of the calculations is available as part of EPLC response to 2-Staff-27.

Name	New C & I Expansion - 2018	New Subdivision Residential - 2018
Mandatory	Yes	Yes
Investment ID	1239	1230
Year	2018	2018
Company	Essex	Essex
Process Area	Process 2 - Capital	Process 2 - Capital
System Type	Distribution	Distribution
Responsibility Center	Essex1	Essex1
Project Classification	Serve New Customers	Serve New Customers
Project Type	Commercial Connections	Residential Connections
Cost Category	Capital	Capital
Project Initiator	Kris Taylor	Kris Taylor
Project Manager	Mark Alzner	Mark Alzner
Total Investment Cost	$ 356,959	$ 382,500
Total Expense Cost	$ -	$ -
Expense Costs	$ -	$ -
Total Capital Cost	$ 356,959	$ 382,500
Capital Costs	$ 356,959	$ 382,500
Units	4	3
Dependency ID	0	0
Strategic Objective Score	3.571428571	3.428571429
Financial	5	4
NPV	5	4
Service Quality	1	1
SAIFI	1	1
SAIDI	1	1
Community Image	6	6
Customer Complaints	6	6
Legal	5	5
Claims	5	5
Regulatory	6	6
OEB	6	6
Safety	1	1
Employee	1	1
Public	1	1
Highest Risk of Deferral	25	25
Consequence of Highest Risk	5	5
Financial Consequence	5	4
Technical Consequence	0	0
Socio-Political Consequence	5	5
Probability of Highest Risk	5	5
Financial Probability	4	4
Technical Probability	0	0
Socio-Political Probability	5	5
Risk/Strategic Objective Score	**28.57142857**	**28.42857143**

b) Please refer to EPLC response to 2-Staff-27.

Exhibit 2: 2-SEC-17

[Ex.2, DSP, p.60, Table 3-3] Please provide a table showing for each of the listed asset types, the number that the Applicant has replaced or is forecast to be replaced, in each year between 2010 and 2022.

Response

a) Please review the table below:

Asset Class	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Wood Poles	109	35	123	84	128	165	121	162	70	118	105	61	141
Concrete Poles	-	-	-	-	-	1	2	-	-	-	-	-	-
Steel Poles	-	-	-	-	-	-	-	-	-	-	-	-	-
Pad-mounted Distribution Transformers	34	27	28	36	25	22	6	21	78	21	44	56	47
Pole-mounted Distribution Transformers	30	15	41	38	47	43	26	9	25	38	24	25	29
Pad-mounted Switchgear	2	3	2	1	1	2	2	2	1	2	2	2	1
Dip Poles (Primary Risers)	14	14	25	10	10	3	16	19	15	15	14	14	14
Direct-Buried Primary Underground Cable (km)	4.3	2.4	9.0	2.9	4.2	1.5	0.7	6.6	7.6	3.2	3.9	5.7	3.4
Primary Underground Cables in Conduit (km)	-	-	-	-	-	-	-	-	-	-	-	-	-

Exhibit 2: 2-SEC-18

[Ex.2, DSP, p.108, Table 4-14] For the 2018 projects prioritization:

a. Please provide a breakdown of the risk/strategic score into its 7 specific strategic business objectives.

b. Please provide on a similar basis to Table 4-14, as well as part (a), the next 5 highest score projects for 2018 that were ultimately not selected to be completed in the year.

c. Please provide on a similar basis to Table 4-14, as well as part (a), the 2017 material capital projects.

Response

a) Please refer to EPLC response to 2-Staff-27.

b) The highest rated projects that were deferred as part of planned projects for 2018 include the following:

1) LaSalle Front Road Conversion - constrained as a result of easement/access issues ($80,000);
2) HONI Asset Purchase – 24M7 in Amhestburg area including 2.6km of poles, conductor and insulators. Constrained as a result of unwillingness of Hydro One to sell assets at this time. (Estimated purchase price of $265,200).
3) HONI Asset Sale – 24M7 in Amherstburg area including 3.8km of poles, conductor and insulators. Constrained as a result of unwillingness of Hydro One to sell assets related to 2) above. (Sale price $232,560).
4) 8kV Gore to Dalhousie Conversion – Constrained as a result of easement/access issues ($425,000);
5) 4kV Main Street North West conversion ($160,000)

c) Please review the following chart using 2017 budget values:

Project Name	Project Classification	Project Type	Net Capital Expenditures	Risk/Strategic Objective Score
Residential Connection/Expansion	Serve New Customers - Residential	Residential Connections	$ 375,000	28.57
New Service Upgrades - C&I	Serve New Customers - C&I	Commercial Connections	$ 349,960	28.57
New Residential Subdivisions	Serve New Customers - Residential	Residential Connections	$ 375,000	28.45
Overhead Reactive Replacements	None	Reactive	$ 80,784	21.38
Underground Reactive Replacements	None	Reactive	$ 63,690	21.29
Municipal Requests	Increase System Capacity - Improvements	Expansions	$ 600,000	14.69
FIT & Generation Connections	Increase System Capacity - Improvements	Expansions	$ 188,892	14.00
Install/Replace Load Breaks	Increase System Capacity - Improvements	Preventative	$ 58,752	13.57
Switchgear Replacement Program	Increase System Capacity - Improvements	Preventative	$ 144,432	13.55
Metering Upgrade & Replacement Program	None	Metering	$ 163,037	13.42
Computer Hardware	None	General Plant	$ 356,150	11.21
Single Voltage Utility - Conversion	Increase System Capacity - Improvements	Enhancements	$ 617,735	11.15
Self-Healing Grid Reclosers	Increase System Capacity - Improvements	Preventative	$ 264,843	11.03
Infrastructure Rebuild Program	Increase System Capacity - Improvements	Enhancements	$ 1,229,416	10.78
Computer Software	None	General Plant	$ 254,500	10.22
Purchase/Sell HONI Leamington Assets	None	Expansions	$ 170,360	9.83
Pole Replacement Program	None	Reactive	$ 460,478	9.40
Transportation Equipment	None	General Plant	$ 487,000	7.32
Tools & Equipment	None	General Plant	$ 110,000	7.08
Building & Fixtures	None	General Plant	$ 286,800	5.51

Exhibit 2: 2-SEC-19

[Ex.2, DSP, p.116] Please explain the significant reduction in 2017 O&M costs.

Response

The reduction in 2017 O&M costs are largely the result of the elimination of one superintendent along with a planned low year in field services and overhead right of way conversion work consistent with Exhibit 4, Section 4.2.3 of EPLC's Initial Application.

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	$ 237,959
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)	$ (150,702)
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)**

Exhibit 2: 2-SEC-20

[Ex.2, DSP, p. Appendix A]With respect to capital projects in-service between 2011 and 2017:

a. Please provide a similar project narrative for all material capital projects between 2011 and 2017.

b. For all material capital projects, please provide the annual budgeted amounts and the final actual amount. Please explain any variances over +/-10%.

Response

a) As part of the DSP, EPLC has provided project narratives for the following material capital projects:

- New Residential Subdivisions;
- Residential Connections/Expansion;
- Municipal Requests
- New Service Upgrades – C&I;
- Metering Upgrade & Replacement Program;
- Pole Replacement Program;
- Overhead Reactive Replacements;
- Underground Reactive Replacements;
- Install/Replace Load Breaks;
- Infrastructure Rebuild Program;
- Switchgear Replacement Program;
- HONI Asset Purchase – Leamington;
- FIT & Generation Connections;
- Self-Healing Grid – Reclosers;
- Building & Fixtures;
- Computer Software;
- Computer Hardware;
- Transportation Equipment;
- Tools & Equipment;

These programs are reasonably consistent and predictable in terms of their usage and detailed summaries of spending are provided in the project narratives and in Exhibit 2, Section 2.6.4 of EPLC's initial Application.

The following programs, not included as Appendix A of EPLC's DSP are briefly described below:

- **Single Voltage Utility Initiative:**
  - General Description: 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.
  - Historical Spending: 2010 - $633,783, 2011 - $423,196, 2012 - $929,490, 2013 – $935,091, 2014 – $852,182, 2015 – $547,174, 2016 – $85,942, 2017 – $673,901
  - Project Drivers: Reduction of inventory, reduction in distribution losses, customer bill reductions, reduced complexity of distribution system.
  - Customer Benefits: Reduced distribution losses, renewed distribution assets and more efficiencies passed on.
  - Impact on Reliability: EPLC expects to see enhanced reliability as a result of renewed assets.
  - Safety: As EPLC works towards implementing a variety of smart grid related initiatives, it is continuously updating its operating procedures and protocols to ensure staff safety.
  - CyberSecurity/Privacy: This program does not raise any CyberSecurity/Privacy concerns.

- **Replacement – Lithgow Livefront Transformers:**
  - General Description: Removal of known problematic livefront transformers on Lithgow Avenue in Leamington at or near end of life.
  - Historical Spending: 2013 – $389,704
  - Project Drivers: Elimination of livefront transformers, employee safety, replacement of assets at or near end of life.
  - Customer Benefits: Customer safety, enhanced reliability.
  - Impact on Reliability: EPLC expects to see enhanced reliability as a result of renewed assets.

- Safety: The elimination of livefront transformers from EPLC's distribution system enhances and improves EPLC staff safety as livefront transformers pose incremental risk to operating staff.
- CyberSecurity/Privacy: This program does not raise any CyberSecurity/Privacy concerns.

- **Conversion – Monopoly Subdivisions:**
  - General Description: The Monopoly Subdivision conversion was a large scale Livefront and direct buried cable replacement initiative.
  - Historical Spending: 2014 – $675,210, 2015 – $259,837, 2016 – $312,264
  - Project Drivers
  - Customer Benefits
  - Impact on Reliability: EPLC expects to see enhanced reliability as a result of renewed assets.
  - Safety: Proper asset management of old and deteriorating equipment in the field mitigates safety concerns to EPLC staff and customers. All new construction meets the latest distribution standards for safety.
  - CyberSecurity/Privacy: This program does not raise any CyberSecurity/Privacy concerns.

- **Insulator Replacement:**
  - General Description: Replacement of problematic porcelain insulators.
  - Historical Spending: 2010 - $94,700, 2015 – $132,486, 2016 - $145,399
  - Project Drivers: Customer restoration, asset renewal, preventative investments.
  - Customer Benefits: Enhanced reliability.
  - Impact on Reliability: EPLC expects to see enhanced reliability as a result of renewed assets.
  - Safety: Proper asset management of old and deteriorating equipment in the field mitigates safety concerns to EPLC staff and customers. All new construction meets the latest distribution standards for safety.
  - CyberSecurity/Privacy: This program does not raise any CyberSecurity/Privacy concerns.

- **Conversion – Howard/6th Concession:**
  - General Description: The Howard/6th Concession conversion project was a large-scale voltage conversion project to help facilitate the Single Voltage Utility initiative.
  - Historical Spending: 2015 - $744,587
  - Project Drivers
  - Customer Benefits
  - Impact on Reliability: EPLC expects to see enhanced reliability as a result of renewed assets.
  - Safety: Proper asset management of old and deteriorating equipment in the field mitigates safety concerns to EPLC staff and customers. All new construction meets the latest distribution standards for safety.
  - CyberSecurity/Privacy: This program does not raise any CyberSecurity/Privacy concerns.

- **Primary Cable Replacement:**
  - General Description: Replacement of Primary Cable relating to known problem areas consisting with failed, damaged or forecasted cable failure.
  - Historical Spending: 2011 - $522,882, 2012 - $24,495, 2014 - $713,295, 2015 - $113,618, 2016 - $93,316
  - Project Drivers: Customer restoration, asset renewal, preventative investments.
  - Customer Benefits: Enhanced reliability.
  - Impact on Reliability: EPLC expects to see enhanced reliability as a result of renewed assets.
  - Safety: Proper asset management of old and deteriorating equipment in the field mitigates safety concerns to EPLC staff and customers. All new construction meets the latest distribution standards for safety.
  - CyberSecurity/Privacy: This program does not raise any CyberSecurity/Privacy concerns.

- **Transformer Replacement Program:**
  - General Description: Initiative to replace known problem areas relating specifically from transformers, mainly livefronts.
  - Historical Spending: 2010 - $254,532, 2011 – $57,308, 2012 - $47,978, 2013 - $108,721, 2014 - $143,405, 2015 - $178,078, 2016 – $424,720

- Project Drivers: Replace old, failed or deteriorating assets at or near end of life.
- Customer Benefits: Enhanced reliability.
- Impact on Reliability: EPLC expects to see enhanced reliability as a result of renewed assets.
- Safety: Proper asset management of old and deteriorating equipment in the field mitigates safety concerns to EPLC staff and customers. All new construction meets the latest distribution standards for safety.
- CyberSecurity/Privacy: This program does not raise any CyberSecurity/Privacy concerns.

- **Leamington Tornado:**
  - General Description: One of EPLC's 4 shareholder municipalities were affected by a tornado on June 6th, 2010.
  - Historical Spending: 2010 – $135,278
  - Project Drivers: Mandatory restoration of EPLC distribution customers.
  - Customer Benefits: Restored power, renewed assets.
  - Impact on Reliability: Improved reliability through renewed assets.
  - Safety: Proper asset management of old and deteriorating equipment in the field mitigates safety concerns to EPLC staff and customers. All new construction meets the latest distribution standards for safety.
  - CyberSecurity/Privacy: This program does not raise any CyberSecurity/Privacy concerns.

- **Smart Metering Initiative:**
  - General Description: Provincially mandated initiative to replace all residential meters in Ontario with Smart Meters and Smart Metering Infrastructure.
  - Historical Spending: 2010 - $337,747, 2012 - $515,559, 2015 - $2,051,075, 2016 - $87,921
  - Project Drivers: Provincially mandated initiative.
  - Customer Benefits: Enhanced electricity consumption data, accurate billing.
  - Impact on Reliability: Not applicable.
  - Safety: EPLC predicted no major safety concerns with this project.
  - CyberSecurity/Privacy: EPLC is working towards compliance with the Board's CyberSecurity Framework to ensure smart metering infrastructure related customer data and information is protected.

b) Please refer to the chart below which outlines budget and actual values for all material projects listed in Appendix A of EPLC's DSP.

Description	2011		2012		2013		2014		2015		2016		2017	
	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual
New Residential Subdivisions	$ 389,955	$ 540,677	$ 559,050	$ 728,506	$ 849,000	$ 240,014	$ 375,000	$ 150,424	$ 375,000	$ 1,020,249	$ 375,000	$ 446,196	$ 375,000	$ 224,992
Residential Connections/Expansion	$ 183,499	$ 188,901	$ 133,208	$ 471,954	$ 242,186	$ 429,496	$ 230,764	$ 677,866	$ 512,311	$ 872,062	$ 410,855	$ 1,050,696	$ 386,636	$ 449,096
Municipal Requests	$ 400,000	$ 721,963	$ 466,399	$ 140,953	$ 1,822,000	$ 1,048,671	$ 1,300,000	$ 1,577,009	$ 350,000	$ 311,344	$ 350,000	$ 12,336	$ 600,000	$ 371,598
New Service Upgrades – C&I	$ 519,222	$ 120,392	$ 570,000	$ 226,150	$ 250,000	$ 100,871	$ 50,000	$ 21,124	$ 300,000	$ 3,767	$ 250,000	$ 99,080	$ 349,960	$ 229,183
Metering Upgrade & Replacement Program	$ -	$ -	$ 61,980	$ 56,878	$ 85,979	$ 100,139	$ 18,000	$ 7,712	$ 89,516	$ 8,460	$ 150,918	$ 156,282	$ 163,037	$ 202,752
Pole Replacement Program	$ 162,000	$ 115,417	$ 102,360	$ 194,333	$ 102,360	$ 478,275	$ 113,580	$ 193,281	$ 113,580	$ 335,898	$ 518,377	$ 513,973	$ 460,478	$ 745,231
Overhead Reactive Replacements	$ 66,000	$ 110,554	$ 79,200	$ 6,908	$ 79,200	$ -	$ 79,200	$ 6,145	$ 79,200	$ -	$ 79,200	$ 104,563	$ 80,784	$ 63,920
Underground Reactive Replacements	$ 124,000	$ 8,785	$ 98,848	$ 53,159	$ 98,848	$ 10,765	$ 62,441	$ -	$ 62,441	$ 6,890	$ 62,441	$ -	$ 63,690	$ 55,133
Install/Replace Load Breaks	$ 34,236	$ 34,236	$ 25,000	$ 3,612	$ -	$ -	$ -	$ -	$ 42,000	$ -	$ 42,000	$ 64,119	$ 58,752	$ 145,186
Infrastructure Rebuild Program	$ 320,000	$ 346,712	$ 946,000	$ 1,100,768	$ 1,073,000	$ 851,290	$ 525,000	$ 299,670	$ 75,000	$ 88,733	$ 75,000	$ 43,582	$ 1,229,416	$ 1,183,220
Switchgear Replacement Program	$ 107,200	$ 162,024	$ 107,200	$ 27,180	$ 107,200	$ 122,012	$ 107,200	$ 63,630	$ 107,200	$ 55,209	$ 129,300	$ 135,236	$ 144,432	$ 152,390
HONI Asset Purchase – Leamington	$ 464,828	$ 468,859	$ 232,123	$ 232,123	$ 23,422	$ 13,222	$ 390,000	$ 89,077	$ 200,000	$ 21,142	$ -	$ -	$ 170,360	$ 12,188
FIT & Generation Connections	$ 50,747	$ 463,599	$ 141,700	$ 30,227	$ 119,710	$ 91,689	$ 119,710	$ 25,824	$ 119,710	$ 67,577	$ 119,709	$ 80,085	$ 188,892	$ 142,411
Self-Healing Grid – Reclosers	$ -	$ -	$ -	$ -	$ -	$ -	$ 61,552	$ 61,005	$ -	$ -	$ 503,293	$ 633,057	$ 264,843	$ 376,219
Building & Fixtures	$ 52,000	$ 13,214	$ 552,000	$ 844,622	$ 165,000	$ 21,981	$ 60,000	$ -	$ 120,000	$ 48,914	$ 80,000	$ 42,469	$ 286,000	$ 150,040
Computer Hardware	$ 85,182	$ 27,112	$ 66,879	$ -	$ 53,250	$ 13,501	$ 53,250	$ 25,333	$ 70,000	$ 5,837	$ 225,226	$ 117,329	$ 356,150	$ 277,378
Computer Software	$ 194,134	$ 17,981	$ 11,618	$ 34,572	$ 20,000	$ 52,989	$ 22,600	$ 166,960	$ 10,000	$ 17,043	$ 15,000	$ 4,632	$ 254,500	$ 252,780
Transportation Equipment	$ 401,000	$ 156,970	$ 405,700	$ 198,529	$ 510,000	$ 307,516	$ 430,000	$ 248,438	$ 470,000	$ 401,244	$ 400,000	$ 136,662	$ 487,000	$ 418,931
Tools & Equipment	$ 39,350	$ 35,577	$ 47,450	$ 163,983	$ 85,000	$ 47,415	$ 165,000	$ 45,486	$ 60,000	$ 68,451	$ 50,000	$ 62,365	$ 110,000	$ 124,012

Variances arising from the following capital projects are the result of EPLC's forecast of customer connections. Variances above or below budget are the result of greater than or less than expected connections in a given year:

- New Residential Subdivisions;
- Residential Connections/Expansion;
- Municipal Requests;
- New Service Upgrades – C&I;
- FIT & Generation Connections;

Pole Replacement Program: Variances in 2011 and 2012 are the result of EPLC deferring planned pole replacements from 2011 to 2012. Variances in 2014, 2015 and 2017 are the result of EPLC pushing forward various pole replacement work in conjunction with the Single Voltage Utility initiative and based on EPLC's Asset Condition Assessment.

Overhead/Underground Reactive Replacements: EPLC has budgeted consistently between 2011-2017 to ensure that sufficient capital resources are available in the case that reactive replacements (both overhead and underground) are required.

Install/Replace Load Breaks: Variances in 2012 and 2015 are the result of budgeted load break replacements not being completed and not needed during the given year.

Infrastructure Rebuild Program: EPLC has been reasonably in line with budget for the Infrastructure Rebuild Program. Any minor variances are immaterial.

Switchgear Replacement Program: Variance in year 2011 is the result of an incremental switch being replaced compared to budget. Years 2012, 2014 and 2015 resulted in one less switch being replaced compared to budget.

HONI Asset Purchase – Leamington: Variances in years 2014, 2015 and 2017 are a result of EPLC budgeted asset purchases not being accepted or the result in delays in negotiations with Hydro One.

Self-Healing Grid – Reclosers: The variance in 2016 is the result of EPLC installing more 2 more reclosers than budgeted.

Building & Fixtures: EPLC consolidated offices from the Essex Civic Centre to the Oldcastle Service station in 2012. EPLC budgeted to complete the renovation through 2012/2013 however most capital expenditure was completed in 2012. The variance in 2014 relates to a budgeted amount that was not needed as a result of consolidation.

Computer Hardware: From 2011-2015, EPLC has deferred Network and Security IT infrastructure that was largely implemented in 2016 and 2017. In 2016 and 2017, EPLC has budgeted increases in Computer Hardware to upgrade servers and to prepare for compliance with the Board's CyberSecurity framework. EPLC has deferred some hardware costs (approximately $75k) until such time that the Cybersecurity framework is finalized.

Computer Software: EPLC budgeted an upgrade to its financial system that was subsequently deferred in 2011 which represents approximately $120k of the variance. This upgrade was deferred until 2014.

Transportation Equipment: EPLC deferred the need for an RBD truck in 2011 through 2014 which resulted in a variance of approximately $200k per year.

Tools & Equipment: The variance in 2012 is the result of EPLC moving up a future planned need to replace various lineman tools and not reflecting this change in years 2013 and 2014.

Exhibit 2: 2-SEC-21

[Ex.2, DSP, Appendix A, p.1] With respect to New Residential Sub-Divisions:

a. The Applicant states, "New subdivision plans for the 2018 Test Year are not known at this time." Please provide an update on the new subdivisions plans for 2018.

b. Please provide the forecast capital contributions for new residential sub-divisions.

Response

a) Currently connected in 2018:

MZM - 24 single family homes;

Currently planned (awaiting approval):

Richmond Court - 12 large single-family homes;
Head D'Amore phase 9 – 32 single family, 60 semi-detached, 24 triplexes;
Head D'Amore phase 8 – 36 single family;
Forest Trails phase 3A – 79 single family homes;
Donato – 84 large single-family homes;

b) EPLC currently estimates between $2,000-$3,000 per lot.

Exhibit 2: 2-SEC-22

[Ex.2, DSP, Appendix A, p.7] Please provide an update to planned Municipal Request projects for 2018, and the impact on forecast costs.

Response

EPLC currently has approximately $100,00 of planned Municipal Request projects underway in 2018 (related to the Erie Street South overhead to underground conversion in Leamington). EPLC is currently in discussions with the Town of Tecumseh for a major three phase conversion project planned for 2018 and beyond. EPLC's current budget is well positioned to address these forthcoming projects.

Exhibit 2: 2-SEC-23

[Ex.2, DSP, Appendix A, p.69] With respect to Computer Hardware:

a. Please provide a breakdown of planned 2018 spending.

b. Please explain the significant 2017 spending in this category.

Response

a) EPLC is currently focused on upgrading the mobile workforce and office connectivity. Many of the devices that EPLC staff are using in the field are nearing end of life and require updating and/or replacement. Further, most existing hardware that is not at end of life requires upgrading to ensure cybersecurity compliance and to support various mobile security measures. These upgrades represent approximately 45% of the total budget.

The remaining 2018 spending relates to a network segregation project to support business continuity and other cybersecurity related upgrades along with EPLC's typical yearly Computer Hardware upgrades (computers and other miscellaneous, non-material hardware). The business continuity and cybersecurity upgrades will allow EPLC to easily and securely re-route traffic to support its business should EPLC experience an upstream network outage.

b) EPLC had significant IT infrastructure nearing end of life that required replacement, largely a new server along with the necessary 3rd party costs to install and commission the unit. These upgrades were also driven by ERP software system upgrades that required additional server space and cybersecurity framework compliance.

EPLC also implemented office wireless infrastructure and new access points throughout its business to improve IT security. Finally, EPLC deployed a new Virtual Private Network and new firewall appliances across the company along with the implementation of a new back-up disaster recovery solution which also help improve reliability, security and overall IT systems risk.

Exhibit 2: 2-SEC-24

[[Appendix 2-AA] Please provide a table showing the annual capital contributions received by the Applicant from 2011 to 2017, and the forecast amount in 2018. Please explain where the Applicant has included these amounts in its Appendix 2-AA.

Response

Please refer to the table below detailing the total capital contributions recognized in the fiscal years 2011-2017 and the forecasted capital contributions for 2018.

	2011	2012	2013	2014	2015	2016	2017	2018 (forecasted)
Capital Contributions								
	$ 1,939,671.87	$ 869,852.74	$ 2,191,898.38	$ 1,122,171.09	$ 1,448,183.28	$ 931,021.46	$ 921,652.31	$ 1,224,757.00

The figures listed in Appendix 2-AA do not include contributions received by EPLC.

Exhibit 2: 2-SEC-25

[Ex. 2] For each year between 2011 and 2018, please provide the percentage of work (measured in percentage of capital expenditures) being undertaken by third-party contractors.

Response

Please see the table below which illustrates the percentage of work being undertaken by third-party contractors.

	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**
Total Gross Capital Expenditures - from Appendix 2-AA	$4,525,547	$6,572,392	$5,513,117	$6,207,502	$7,779,437	$5,274,104	$6,658,465	$6,183,000
Third-Party Contractors ($)	$1,881,323	$1,657,098	$2,175,037	$2,739,771	$1,782,021	$1,284,077	$1,735,197	$1,545,750
Percentage of Gross Capital Expenditures	42%	25%	39%	44%	23%	24%	26%	25%

Exhibit 2: 2-SEC-26

[Ex.4, p.6] Please provide a revised version of Figure 2, including additional columns for each year between 2011 and 2017 showing annual budgeted amounts. Please also provide the basis for the budgeted number.

Response

Please refer to the revised version of Figure 2, including additional columns for each year between 2011 and 2017 showing annual budgeted amounts. The basis for the budgeted number is based on EPLC's budgeting process described in Exhibit 4, Section 4.2.1.

Description	2011 Budget	2011 Actual	2012 Budget	2012 Actual	2013 Budget	2013 Actual
Operations	$1,070,238	$1,003,987	$1,120,226	$1,190,375	$1,331,607	$1,207,057
Maintenance	$1,775,670	$1,614,034	$1,739,380	$2,013,059	$1,388,862	$1,515,425
Subtotal	**$2,845,908**	**$2,618,021**	**$2,859,606**	**$3,203,433**	**$2,720,469**	**$2,722,482**
Billing & Collecting	$1,321,319	$1,131,257	$1,209,185	$1,174,568	$1,268,314	$1,329,771
Community Relations	$ 20,000	$ 11,394	$ 20,000	$ 8,539	$ 20,000	$ 8,451
Admin & General	$1,784,910	$1,786,257	$2,191,257	$1,806,757	$2,117,572	$1,966,590
Subtotal	**$3,126,229**	**$2,928,908**	**$3,420,442**	**$2,989,863**	**$3,405,886**	**$3,304,813**
Total OM&A	**$5,972,137**	**$5,546,929**	**$6,280,048**	**$6,193,296**	**$6,126,355**	**$6,027,295**

2014 Budget	2014 Actual	2015 Budget	2015 Actual	2016 Budget	2016 Actual	2017 Budget	2017 Actual (Prelim)
$1,375,774	$1,545,489	$1,436,963	$1,332,350	$1,298,304	$1,337,677	$1,221,419	$1,358,260
$1,368,825	$1,448,980	$1,542,619	$1,808,438	$1,895,110	$1,833,650	$1,572,404	$1,433,999
$2,744,599	**$2,994,470**	**$2,979,582**	**$3,140,788**	**$3,193,414**	**$3,171,328**	**$2,793,823**	**$2,792,258**
$1,240,324	$1,158,128	$1,386,560	$1,229,676	$1,232,682	$1,348,249	$1,499,880	$1,368,077
$ 20,000	$ 10,016	$ 20,000	$ 12,013	$ 20,000	$ 6,482	$ 23,442	$ 14,940
$2,347,656	$2,541,606	$2,248,851	$2,381,742	$2,978,771	$2,455,564	$2,950,224	$2,914,238
$3,607,980	**$3,709,749**	**$3,655,411**	**$3,623,431**	**$4,231,453**	**$3,810,295**	**$4,473,546**	**$4,297,255**
$6,352,579	**$6,704,219**	**$6,634,993**	**$6,764,218**	**$7,424,866**	**$6,981,623**	**$7,267,369**	**$7,089,513**

Exhibit 2: 2-VECC-11

Reference: Exhibit 2, page 8, Figure 4

a) Please describe and explain the source of the "intangible assets" beginning in 2016 ($1,556,875).

Response

The intangible assets listed on Figure 4 in Exhibit 2 are comprised of the following values: Land Rights $207,803 and Computer Software $1,349,072.

Exhibit 2: 2-VECC-12

Reference: Exhibit 2, page 52, Figure 12. /page 59 Figure 14

a) Please update Figures 12 through 14 for 2017 actual amounts.

Response

Revised Figure 12 through 14 are included below with revised preliminary 2017 amounts.

USoA	Description	2016 Actual	2017 Bridge	Variance
	Intangible Plant			
1611	Computer Software	$ 1,349,073	$ 1,601,853	$ 252,780
1612	Land Rights	$ 207,803	$ 224,734	$ 16,931
	Subtotal	**$ 1,556,875**	**$ 1,826,587**	**$ 269,712**
	Distribution Plant			
1805	Land	$ 35,899	$ 35,899	$ -
1806	Land Rights	$ -	$ -	$ -
1820	Distribution Station Equipment < 50 kV	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 8,897,418	$ 9,891,875	$ 994,457
1835	Overhead Conductors & Devices	$ 9,205,503	$ 10,020,214	$ 814,711
1840	Underground Conduit	$ 13,230,112	$ 13,698,335	$ 468,223
1845	Underground Conduit & Devices	$ 14,457,773	$ 15,377,206	$ 919,433
1850	Line Transformers	$ 19,300,481	$ 19,775,476	$ 474,995
1855	Services	$ 12,154,283	$ 13,184,943	$ 1,030,660
1860	Meters	$ 9,412,656	$ 9,835,349	$ 422,693
1860	Meters - Smart Meter Sub-Account	$ -	$ -	$ -
	Subtotal	**$ 86,694,126**	**$ 91,819,297**	**$ 5,125,171**
	General Plant			
1905	Land	$ 190,119	$ 190,119	$ -
1908	Building & Fixtures	$ 2,513,740	$ 2,663,780	$ 150,040
1915	Office Furniture & Equipment	$ 216,760	$ 225,732	$ 8,972
1920	Computer Equipment - Hardware	$ 488,700	$ 766,079	$ 277,379
1925	Computer Software	$ 585	$ 585	$ -
1930	Transportation Equipment	$ 2,381,417	$ 2,800,348	$ 418,931
1935	Stores Equipment	$ 47,367	$ 89,916	$ 42,549
1940	Tools, Shop & Garage Equipment	$ 564,329	$ 645,792	$ 81,463
1945	Measurement & Testing Equipment	$ 70,248	$ 70,247	$ (1)
1955	Communication Equipment	$ 294,423	$ 294,423	$ -
	Subtotal	**$ 6,767,688**	**$ 7,747,021**	**$ 979,333**
	Contributions & Grants			
1995	Contributions & Grants	$ (18,566,136)	$ (19,487,788)	$ (921,652)
	Subtotal	**$ (18,566,136)**	**$ (19,487,788)**	**$ (921,652)**
	Grand Total	**$ 76,452,553**	**$ 81,905,117**	**$ 5,452,564**

USoA	Description	2017 Bridge	2018 Test	Variance
	Intangible Plant			
1611	Computer Software	$ 1,601,853	$ 1,718,573	$ 116,720
1612	Land Rights	$ 224,734	$ 298,936	$ 74,202
	Subtotal	**$ 1,826,587**	**$ 2,017,508**	**$ 190,921**
	Distribution Plant			
1805	Land	$ 35,899	$ 35,899	$ -
1806	Land Rights	$ -	$ -	$ -
1820	Distribution Station Equipment < 50 kV	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 9,891,875	$ 10,262,670	$ 370,795
1835	Overhead Conductors & Devices	$ 10,020,214	$ 10,586,627	$ 566,413
1840	Underground Conduit	$ 13,698,335	$ 14,829,081	$ 1,130,746
1845	Underground Conduit & Devices	$ 15,377,206	$ 16,099,450	$ 722,244
1850	Line Transformers	$ 19,775,476	$ 21,366,845	$ 1,591,369
1855	Services	$ 13,184,943	$ 13,777,367	$ 592,424
1860	Meters	$ 9,835,349	$ 9,945,259	$ 109,910
1860	Meters - Smart Meter Sub-Account	$ -	$ -	$ -
	Subtotal	**$ 91,819,297**	**$ 96,903,199**	**$ 5,083,902**
	General Plant			
1905	Land	$ 190,119	$ 190,119	$ -
1908	Building & Fixtures	$ 2,663,780	$ 3,170,540	$ 506,760
1915	Office Furniture & Equipment	$ 225,732	$ 236,760	$ 11,028
1920	Computer Equipment - Hardware	$ 766,079	$ 1,006,660	$ 240,581
1925	Computer Software	$ 585	$ 585	$ -
1930	Transportation Equipment	$ 2,800,348	$ 3,138,417	$ 338,069
1935	Stores Equipment	$ 89,916	$ 147,367	$ 57,451
1940	Tools, Shop & Garage Equipment	$ 645,792	$ 684,329	$ 38,537
1945	Measurement & Testing Equipment	$ 70,247	$ 70,247	$ -
1955	Communication Equipment	$ 294,423	$ 294,423	$ -
	Subtotal	**$ 7,747,021**	**$ 8,939,447**	**$ 1,192,426**
	Contributions & Grants			
1995	Contributions & Grants	$ (19,487,788)	$ (21,015,650)	$ (1,527,862)
	Subtotal	**$ (19,487,788)**	**$ (21,015,650)**	**$ (1,527,862)**
	Grand Total	**$ 81,905,117**	**$ 86,844,505**	**$ 4,958,239**

Description	2017 Bridge
Residential Connections	$ 693,067
C&I Connections	$ 229,183
Conversions	$ 1,923,995
Municipal Requests & Asset Purchases	$ 383,786
FIT & Generation Connections	$ 142,411
Smart Grid/Self Healing Grid	$ 376,219
Replacements	$ 1,042,807
Emergencies	$ 119,053
Distribution Plant Total	**$ 5,154,015**

Exhibit 2: 2-VECC-13

Reference: Exhibit 2, page 56, 63

a) What was the actual reactive (emergency) capital spending on overhead and underground replacements in 2011 through 2017?

b) How was the forecast amount for 2018 of $147,363 derived?

Response

a) The actual reactive (emergency) capital spending on overhead and underground replacements in 2011 through 2018 is summarized below:

Category	2011	2012	2013	2014	2015	2016	2017 Bridge Year	2018 Test Year
O/H Reactive Replacements	$ 110,554	$ 6,908	$ -	$ 6,145	$ -	$ 104,563	$ 63,920	$ 82,400
U/G Reactive Replacements	$ 8,785	$ 53,159	$ 10,765	$ -	$ 6,890	$ -	$ 55,133	$ 64,964

It should be noted that some historical reactive replacement work has been allocated to other smaller, immaterial jobs which explains some of the lower years.

b) The forecasted 2018 value of $147,363 was derived through the use of historical analysis and forecasting to ensure that EPLC can support the anticipated reactive workload where required.

Exhibit 2: 2-VECC-14

Reference: Exhibit 2, page 58, 61

a) Please explain how the $1.22 million in capital contributions for the test year was derived.

b) Please provide a table showing the actual capital contributions in years 2010 through 2017 and separately for each year the gross capital spending related to those contributions. Please specifically identify Municipal Request capital expenditure and associated capital contributions amounts separately.

Response

a) The $1.22 million in capital contributions for the test year were forecasted based historical trending and current known projects scheduled for 2018.

b) Please see the table below identifying capital contributions for years 2010-2017 and the associated gross capital spend.

Total Contributions (inc. Municipal)	2010	2011	2012	2013	2014	2015	2016	2017
Capitalized Value	$ 2,834,320	$ 2,017,603	$ 1,661,309	$ 1,982,339	$ 2,551,040	$ 2,174,667	$ 1,741,321	$ 1,599,369
Capital Contributions	$ 1,667,247	$ 1,939,672	$ 869,853	$ 2,191,898	$ 1,122,171	$ 1,448,183	$ 931,021	$ 921,652
	2010	2011	2012	2013	2014	2015	2016	2017
Municipal Requests - from Appendix 2-AA	$ 1,148,566	$ 714,509	$ 140,953	$ 900,403	$ 1,562,124	$ 311,344	$ 12,336	$ 371,598
Municipal Capital Contributions	$ 803,996	$ 662,262	$ 141,013	$ 546,571	$ 1,110,747	$ 9,120	$ 11,713	$ 310,540

Exhibit 2: 2-VECC-15

Reference: Exhibit 2, page 78, 89 (Appendix 2-AA/2-AB)

a) Please update Figure 26 (Appendix 2-AB) and Figure 37 (Appendix 2-AA for 2017 actuals and for any necessary updates to the 2018 Test year.

b) Please add years 2010 (through 2018) to the tables above to show both Board approved and actuals in the last approved test year (i.e. cost of service proceeding EB-2009-0143).

c) Please explain how the Municipal Request forecast for 2018 (612k) was derived.

Response

a) EPLC has updated Figure 26 (Appendix 2-AB) and Figure 37 (Appendix 2-AA) for 2017 actuals. No updates were made to the 2018 Test Year.

b) The following charts have been updated to include 2010 as requested:

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	$ 596	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	$ 946	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	**$ -**	**$ 5,146**	**$ -**	**$ 4,526**	**$ -**	**$ 6,572**	**$ -**	**$ 5,513**	**$ -**	**$ 6,208**	**$ -**	**$ 7,779**	**$ -**	**$ 5,274**	**$ -**	**$ 6,658**
System O&M	Note 1	$ 2,264	Note 1	$ 2,618	Note 1	$ 3,203	Note 1	$ 2,722	Note 1	$ 2,994	Note 1	$ 3,141	Note 1	$ 3,171	Note 1	$ 2,794

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**
$ 3,067	$ 3,116	$ 3,162	$ 3,213	$ 3,264

Projects	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
System Access									
Subdivisions	$ 223,557	$ 540,677	$ 728,506	$ 240,014	$ 150,424	$1,020,249	$ 446,196	$ 375,000	$ 382,500
Residential Connection/Extension	$ 127,068	$ 188,901	$ 471,954	$ 429,496	$ 677,866	$ 872,062	$1,050,696	$ 386,636	$ 394,369
Municipal Requests	$1,367,880	$ 721,963	$ 140,953	$1,048,671	$1,577,009	$ 311,344	$ 12,336	$ 600,000	$ 612,000
New Service Upgrades - C&I	$ 125,733	$ 120,392	$ 226,150	$ 100,871	$ 21,124	$ 3,767	$ 99,080	$ 349,960	$ 356,959
Miscellaneous	$ 84,029	$ (69,558)	$ 149,705	$ (53,546)	$ 105,509	$ 133,539	$ 150,961	$ -	$ -
Subtotal - System Access	**$1,928,266**	**$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	$ 151,029	$ 115,417	$ 194,333	$ 478,275	$ 193,281	$ 335,898	$ 513,973	$ 460,478	$ 114,062
O/H Reactive Replacements	$ 83,374	$ 110,554	$ 6,908	$ -	$ 6,145	$ -	$ 104,563	$ 80,784	$ 82,400
U/G Reactive Replacements	$ 27,558	$ 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	$ 33,806	$ 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	$ 633,783	$ 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	$ 94,700	$ -	$ -	$ -	$ -	$ 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	$ 254,532	$ 57,308	$ 47,978	$ 108,721	$ 143,405	$ 178,078	$ 424,720	$ -	$ -
Leamington Tornado	$ 135,278								
Miscellaneous	$ 260,929	$ 51,431	$ 310,092	$ 216,870	$ 65,157	$ 232,675	$ 202,228	$ -	$ -
Subtotal - System Renewal	**$1,674,990**	**$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	$ 18,170	$ 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	$ 1,089	$ -	$ 56,878	$ 100,139	$ 7,712	$ 8,460	$ 156,282	$ 163,037	$ 166,297
Smart Metering Initiative	$ 337,747	$ -	$ 515,559	$ -	$ -	$2,051,075	$ 87,921	$ -	$ -
Self Healing Grid Reclosers	$ -	$ -	$ -	$ -	$ 61,005	$ -	$ 633,057	$ 264,843	$ 270,140
Miscellaneous	$ 239,396	$ 7,314	$ 50,649	$ (20,282)	$ (7,117)	$ 47,571	$ 48,019	$ -	$ -
Subtotal - System Service	**$ 596,402**	**$ 939,772**	**$ 885,435**	**$ 184,769**	**$ 176,502**	**$2,195,825**	**$1,005,363**	**$ 787,132**	**$ 707,281**
General Plant									
Bldgs & Fixtures	$ 1,080	$ 13,214	$ 844,622	$ 21,981	$ -	$ 48,914	$ 42,469	$ 286,800	$ 370,000
Office Furniture/Equip	$ 30,534	$ -	$ 29,967	$ 6,711	$ 876	$ 5,980	$ 20,672	$ 10,000	$ 10,000
Computer Equipment HW	$ 189,930	$ 27,112	$ -	$ 13,501	$ 25,333	$ 5,837	$ 117,329	$ 356,150	$ 161,809
Computer Software	$ 449,119	$ 17,981	$ 34,572	$ 52,989	$ 166,960	$ 17,043	$ 4,632	$ 254,500	$ 115,000
Transportation Equip	$ 223,803	$ 156,970	$ 198,529	$ 307,516	$ 248,438	$ 401,244	$ 136,662	$ 487,000	$ 270,000
Tools & Equipment	$ 51,986	$ 35,577	$ 163,983	$ 47,415	$ 45,486	$ 68,451	$ 62,365	$ 110,000	$ 110,000
Miscellaneous		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - General Plant	**$ 946,452**	**$ 250,855**	**$1,271,673**	**$ 450,112**	**$ 487,094**	**$ 547,468**	**$ 384,129**	**$1,504,450**	**$1,036,809**
Total	**$5,146,110**	**$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	**$5,146,110**	**$4,525,547**	**$6,572,392**	**$5,513,117**	**$6,207,502**	**$7,779,437**	**$5,274,104**	**$6,658,465**	**$6,183,000**

c) In conjunction to EPLC's evidence filed as part of Exhibit 2, Attachment 2-C, Appendix A, page 7-9, EPLC has significant planned Municipal Request work in 2018 and beyond resulting from community improvement projects in its shareholder territories. The 2018 forecast was derived based on discussions with its shareholder communities and based on historical trends.

Exhibit 2: 2-VECC-16

Reference: Exhibit 2, page 61

a) Please explain the difference between a "residential connection" and a "residential expansion"?

Response

a) Residential connections relates to new customer connections considered to be subdivisions which are connecting to the distribution system (previously un-serviced). A residential expansion refers to non-subdivision related residential connections.

Exhibit 2: 2-VECC-17

Reference: Exhibit 2, page 76

a) Why are their net additions to stranded meters costs between 2008 and 2011? That is, why does the gross value of the assets increase until 2011 if smart meters are being installed during this period?

Response

Smart Meter deployment was considered to be 100% complete by the end of 2011. Within 2011, some additional conventional meters were capitalized.

Exhibit 2: 2-VECC-18

Reference: Exhibit 2, page 92

a) Please update Figure 39 to include 2017 actual results.

Response

Please see revised Figure 39 below to include 2017 actual results. Please note that 2017 values are still preliminary and may not match final RRR submission.

Indicator	5 Year Historical Average	2012	2013	2014	2015	2016	2017
Including outages caused by loss of supply							
SAIDI	3.698	4.530	5.370	3.820	2.230	2.540	3.328
SAIFI	2.982	3.830	3.580	2.460	1.840	3.200	1.334
Excluding outages caused by loss of supply							
SAIDI	1.252	0.890	2.240	1.160	1.340	0.630	0.838
SAIFI	0.744	0.610	1.120	0.660	0.830	0.500	0.570
Excluding major event days							
SAIDI	1.252	0.890	2.240	1.160	1.340	0.630	0.838
SAIFI	0.744	0.610	1.120	0.660	0.830	0.500	0.570

Indicator	OEB Minimum Standard	2012	2013	2014	2015	2016	2017
Low Voltage Connections	90%	93.2%	92.7%	93.0%	92.3%	90.5%	90.3%
High Voltage Connections	90%	N/A	N/A	N/A	N/A	N/A	N/A
Telephone Accessibility	65%	68.5%	66.4%	78.0%	79.2%	73.6%	75.2%
Appointments Met	90%	95.7%	94.3%	94.7%	94.8%	97.0%	93.2%
Written Response to Enquires	80%	93.9%	91.2%	91.7%	84.7%	96.3%	99.1%
Emergency Urban Response	80%	91.2%	92.9%	96.3%	100.0%	97.7%	100.0%
Emergency Rural Response	80%	N/A	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%	0.8%
Appointment Scheduling	90%	96.8%	96.5%	95.5%	98.5%	98.8%	93.6%
Rescheduling a Missed Appointment	100%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Reconnection Performance Standard	85%	96.7%	93.3%	99.1%	92.3%	97.5%	97.7%

Exhibit 2: 2-VECC-19

Reference: Attachment 2-A

a) Please explain why it appears that the continuity schedules post inclusion of smart meters shows only partial disposals of the stranded meters in the 2015 through 2018 schedules.

b) Please reconcile Figure 25/Appendix 2-S (page 76) with the continuity schedules.

c) Please explain why there are additions to the non-smart meter account 1860 post installation of smart meters.

Response

a) The net book value of stranded meters has remained in account 1860 awaiting approved disposition.

b) Please refer to EPLC response to 9-Staff-98.

c) There are non-smart meter additions post account 1860 installation of smart meters as EPLC has added conventional style meters for larger customers. These assets have been added into the 1860 account which is not specifically related to Smart Meters.

Exhibit 2: 2-VECC-20

Reference: Exhibit 2, Attachment 2-C, DSP, page 35-43, page 47 Table 2-6

a) The above reference contains a table showing metrics and desired outcomes for the new Distribution System Plan (DSP). Is it Essex intention to report annually on these metrics?

b) How are the cost efficiency and effectiveness metrics linked to the compensation of Essex employees (specifically management).

c) Given the strong correlation between capital investment and outages due to defective equipment why did Essex not develop a metric which monitors improvement in outages due to defective equipment as part of the measure of the effectiveness of its DSP?

Response

a) EPLC does not plan on reporting these metrics annually. It is EPLC intention to continue tracking these metrics. Where requested, EPLC can provide updated metrics and progress in future rate applications.

b) Prudent, careful and calculated investment in local infrastructure has been a key driver for EPLC management since inception. Reasonable Rates is also one of EPLC Core Values. EPLC management staff are evaluated against their overall yearly performance and the Core Values of EPLC.

c) EPLC is constantly striving to improve its performance through various metrics and tracking mechanisms. EPLC had not previously considered this metric but will implement a similar metric for future consideration.

Exhibit 2: 2-VECC-21

Reference: Exhibit 2, Attachment 2-C (DSP), page 60 / Appendix J: Asset Condition Assessment Report

a) Asset condition for all the asset types listed in Table 3-3 (other than wood poles) appears to be ascertained solely through either visual inspection or age. What assets are subject to testing or invasive inspection in order to determine their condition? Please specify the percentage of assets of the total population that are subject to such testing.

b) What percentage of the wood pole population are subject to resistograph testing?

Response

a) Almost 100% of EPLC's asset base is subject to some form of testing. Transformers, switchgear/overhead & underground primary risers are subject to IR thermography and loading analysis. Underground primary cables are tested during fault conditions or splices to determine an estimated useful life.

b) Almost all wood poles have been subject to resistograph testing. The only outliers are subject to various access issues that EPLC is working to resolve with the applicable customer.

Exhibit 2: 2-VECC-22

Reference: Exhibit 2, Attachment 2-C (DSP), page 82

a) Please provide an update on the expected capital contribution to Hydro One for the new Leamington TS and the expected in-service date.

b) If the agreement with Hydro One has not yet been completed please provide Essex's current estimate of its initial capital contribution and the projected CCRA (true-up) anniversary dates.

c) Please also provide the load estimates for the new station that must be met so as to avoid future CCRA payments.

Response

Please refer to EPLC response to 2-SEC-14.

Exhibit 2: 2-VECC-23

Reference: Appendix 2-AA / Appendix J: Metsco Asset Condition Assessment, page 33

a) Please provide Essex's actual capital spending in 2017 on the Direct Buried Cable Replacement Program.

b) Essex has spent less than $500k on this program in 2014, 2015 and 2016 combined. In 2017 it estimates it will spend $1.22 million and $2.224 million in 2018. Please explain the large variation in spending on this program.

c) We are unable to locate in the DSP or evidence-in-chief a detailed business plan for the direct buried cable program. Please provide this plan if one has been developed.

d) A casual review of the Metsco Asset Condition assessment of buried cable as show on page 33 does not appear to support the elevated level of spending in this area. For example Table - 33 shows a levelized 10 year plan to replace 6.6 kilometers per year. How many kilometers were replaced in 2017 and how many kilometers are forecast to be replaced in 2018 for the forecast $2.224million?

e) Please provide both the kilometers forecast to be replaced and the forecast capital expenditure on this project for the period 2018 through 2022.

Response

a) EPLC's actual capital spending in 2017 on the Direct Buried Cable Replacement Program is $1,183,220.

b) Essex Powerlines 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 kilometers of line) and partly in response to an increased impact of direct-buried cable failures. These investments are supported by the Asset Condition Assessment (ACA) report.

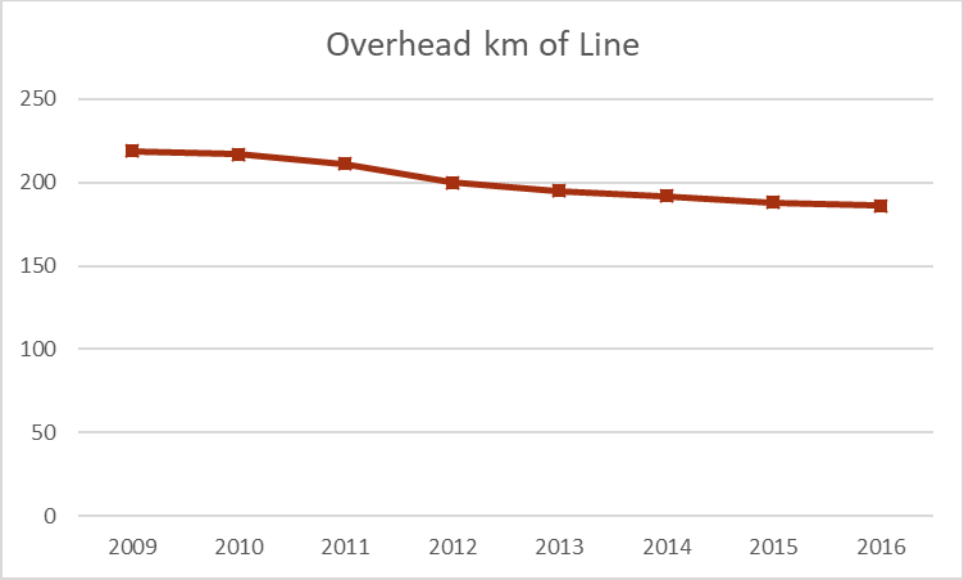
Essex Powerlines has been focusing on voltage conversions of primarily overhead lines over the historical period. Presently, Essex Powerlines owns less kilometers of overhead line that it did historically. As noted on page 24 of the Distribution System Plan (DSP):

> *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 kilometers of line under management while the number of customers has continued to increase.

The following figure, depicting the reduction in overhead line length, is provided on the same page:

Figure 2-1: Kilometres of overhead line owned by EPL



Essex Powerlines has seen an increased impact of direct-buried cables failures and is investing in cable replacements to address this issue. As noted on page 39 of the DSP:

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.

The following figures, excerpted from page 40 and 41 of the DSP, illustrate the changes in outage impacts for overhead and underground equipment. In these figures, the yellow lines indicate the linear trend in "Customer Minutes Out Importance" and the red lines indicate the linear trend in "Duration Importance".

Figure 2-2: Severity - Impacts of outages caused by defective overhead equipment

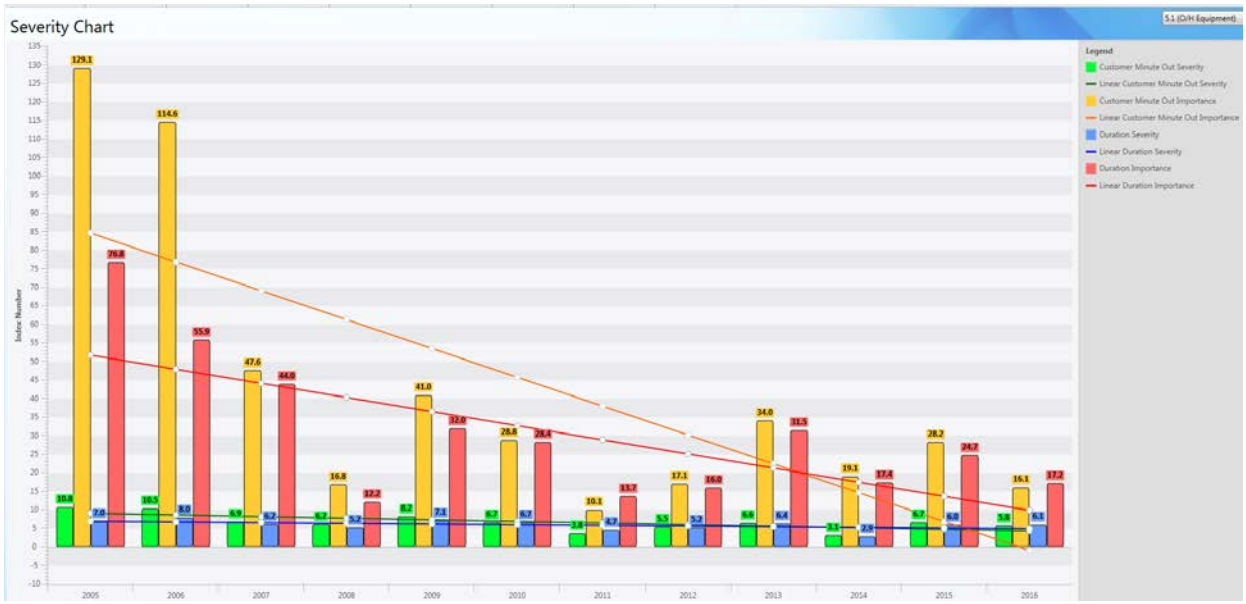
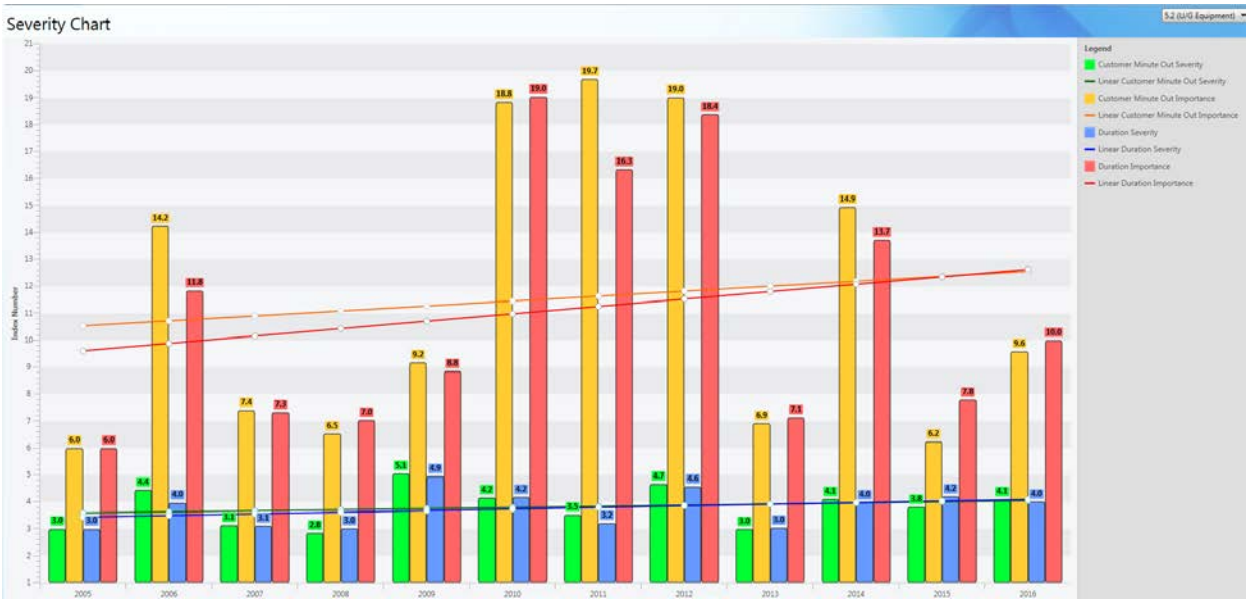


Figure 2-3: Severity - Impacts of outages caused by defective underground equipment



Direct-buried cable replacements are supported by the ACA. As summarized on page 3 of the ACA, underground cable assessments are based on age relative to Typical Useful Life (TUL) and reliability statistics. The combination of Age and Failure Statistics gives a quite robust Health

Index, however in addition, a cable testing program will be conducted to ensure that cable degradation is in line with projections.

With respect to age demographics, page 33 of the ACA:

> *[Essex Powerlines] 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 [tree-retardant cross-linked polyethylene] 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.*

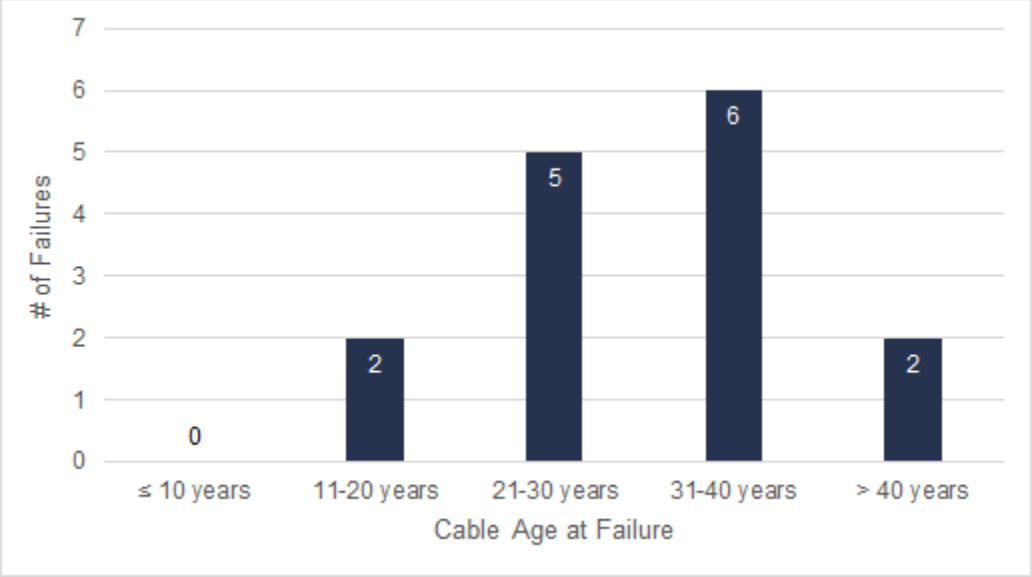
Furthermore, the summary on page 4 of the ACA reads: "A total of 48.9 km of cables are past their TUL and an additional 16.9 km will reach TUL by 2026."

With respect to underground cable reliability, the ACA looks at failure statistics for underground cables. Page 34 of the ACA report states:

> 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.

The following figure is excerpted from the same page of the ACA report:

Figure 3-4: Age of Primary Underground Cable at Failure



With respect to Testing, Cable testing is an emerging tool and results are under investigation. It appears at this time that the information collected is worth the expense, however where

demographics, age or cable fault data is well correlated with tested condition, some degree of extrapolation of results is expect. That is, not every replaced section of cable will necessarily be tested.

The proposed increase in spending from 2017 onwards is then summarized at the bottom of page 34 of the ACA:

> *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 [Essex Powerlines] 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.*

c) The Infrastructure Rebuild Program (Appendix A of the DSP, pages 33-39) encompasses the Direct-buried Cable Replacement Program along with the Overhead Line Rebuild Program.

d) EPLC replaced 6.68 km of line in 2017 and is forecasting the replacement of 7.39 km of line in 2018. It should be noted that the Direct Buried Cable Replacement/Infrastructure Renewal Program involves the replacement of other assets in addition to cable.

e) Please refer to Exhibit 2, Attachment 2-C, Appendix A, pages 33-39.

Exhibit 3: 3-Staff-49

Load Forecast

Ref: Attachment 3-A – EPLC Load Forecast

In section 2.2 GS<50 of the load forecast, Essex Powerlines used March and December as variables for the load forecast. Essex Powerlines also used a shoulder variable which represent the months of March, April, May, September, October, and November.

a) Please explain the statistical significance to have both a shoulder variable and a March variable.

b) The December variable results in a negative coefficient. Please comment on why Essex Powerlines expect load to decrease in one of the colder months of the year.

Response

a) Including both the shoulder and March dummy variables indicates that expected consumption in March is sufficiently different than expected consumption in the other shoulder months. GS<50 kW consumption is typically lower in the shoulder months as indicated by the negative shoulder variable coefficient. The lower positive March coefficient shows that consumption in March isn't lower to the same degree as the other shoulder months.

The results would not change in a hypothetical regression that used a shoulder variable that excluded the month of March. In this hypothetical regression, the shoulder coefficient would remain the same and the March coefficient would be the sum of the filed load forecast's shoulder and March coefficients.

b) From 2009 to 2016, the GS<50 kW class' December load has been lower than the average monthly load. The December load may be lower as a result of fewer work days in that month due to more holiday days. Additionally, impacts of colder weather in December are captured by the Heating Degree Day variable.

Exhibit 3: 3-Staff-50

Load Forecast

Ref: Attachment 3-A – EPLC Load Forecast

In section 4.4 Embedded Distributor of the load forecast, Essex Powerlines forecasted the 2017 and 2018 kWh through linear trending. Essex Powerlines also stated that the embedded distributor class is fed through three connection points. There were historically seven connection points and reduced to three in 2016.

a) Please confirm if the reduction in connection points is due to the transfer of assets through purchase/sales with Hydro One

b) If assets were transferred how was linear trending used to forecast future loads when discrete customers were either added/removed from Essex Powerlines system.

Response

a) The reduction in connection points is due to conversion work completed by both EPLC and Hydro One and the permanent transferring of load to different HONI owned feeders.

b) Not applicable.

Exhibit 3: 3-Staff-51

Load Forecast

Ref: Attachment 3-A – EPLC Load Forecast – CDM Adjustments

Ref: EPLC Chp2Appendice 20170828 – App.2-I LF CDM

Essex Powerlines calculated the total LRAMVA target of 16,566,174kWh in the load forecasting model. In the chapter 2 appendix reference above the total LRAMVA threshold is 20,385,844.

a) Please confirm if Essex Powerlines intends to use the amounts in appendix 2 for future LRAMVA claims. If yes, please update the load forecast model.

Response

a) The difference between the LRAMVA target in the chapter 2 appendix and the load forecast model is the amount of CDM in 2015, which is 3,819,710 kWh. LRAMVA claims are based on annual LRAMVA thresholds which are the same for the years 2016-2018 in both the chapter 2 appendix and load forecast model. CDM in 2015 is historic, verified, and will require no further true-up so it will not need to be claimed in future LRAMVA dispositions. Please note that the LRAMVA figures in the load forecast model are presented for illustrative purposes and do not impact the load forecast results.

Exhibit 3: 3-Staff-52

Other Revenues

Essex Powerlines stated that most variances in Account 4375 and 4380 are due to Conservation & Demand Management (CDM) items.

a) Please provide a breakdown of what CDM items are included in the revenue and expense accounts.

Response

a) The revenue account (4375) reflects all revenue associated with IESO payments for CDM activities rendered. The expense account (4380) reflects all program delivery costs provided by Essex Energy Corporation. In 2016, 4375 had $1,703,389 in revenue related to CDM and 4380 had $1,703,389 in expenses related to CDM.

Exhibit 3: 3-SEC-27

[Ex.3, Appendix 2-H] Please explain the -$799,973 for 'Other Income and Deductions' in 2016.

Response

$781,899.77 of the value above relates to the difference in accounting standards between IFRS (audited statements) and MIRFS (OEB reported statements). The offset to this entry is a credit to Account 1576.

Exhibit 3: 3-VECC-24

Reference: Exhibit 3, pages 6 and 9
Exhibit 3, Attachment 3-A, Section 5
Load Forecast Excel Model, Connection Count Tab

a) Please reconcile the total customer counts shown in Figures 4 and 10 for 2018 (i.e., 32,736 and 32,739 respectively).

b) Are the customer counts shown in Figure 10 year-end or average annual values?

c) For each customer class please provide the actual customer count as of the end of 2016 and as of the end of each month in 2017.

d) Section 5 of Attachment 3-A states that the connection counts for Street Light, Sentinel Light and USL are forecasted based on the historic geometric mean growth rate. However, in the Excel Model the 2017 and 2018 counts are based on the 2016 values (November and December in the case of Street Light). Please reconcile and confirm which approach Essex is proposing.

Response

a) Figure 4 is correct. Total customers should be 32,736.

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

b) Customer counts in Figure 10 are average annual values.

c) Please see the table below for the requested data.

Month	Residential	GS<50	GS>50	USL	Street Lights	Sentinel Lights	Embedded Distributor
16-Dec	27,309	1958	46	139	2,740	172	3
17-Jan	27,334	1974	213	142	2,740	173	3
17-Feb	27,352	1977	213	141	2,746	173	3
17-Mar	27,415	1988	213	141	2,746	173	3
17-Apr	27,482	1977	213	141	2,746	173	3
17-May	27,548	1979	215	141	2,757	173	3
17-Jun	27,587	1969	216	141	2,757	172	3
17-Jul	27,611	1973	217	141	2,757	172	3
17-Aug	27,677	1990	220	141	2,757	172	3
17-Sep	27,775	1989	218	141	2,757	172	3
17-Oct	27,681	1982	218	141	2,757	171	3
17-Nov	27,692	1991	221	141	2,757	171	3
17-Dec	27,746	2000	222	141	2,758	173	3

d) EPLC proposes to use the 2016 (November and December) customer counts as the forecast Street Light, Sentinel, and USL classes. The reference in the revised load forecast report has been updated: “Forecast connection counts are 2016 end of year customer counts for each of these classes.”

Exhibit 3: 3-VECC-25

Reference: Exhibit 3, pages 5-6 and 9

a) The 2018 forecasted kWh by rate class in Figures 2 and 3 do not match those in Figure 9. Please explain the difference.

Response

a) EPLC previously adjusted Figures 2 and 3 to account for Wholesale Market Participant load outlined in Figure 9 in EPLC's pre-filed evidence. As a result, there is no difference to explain.

Exhibit 3: 3-VECC-26

Reference: Exhibit 3, page 7, lines 4-8
Exhibit 3, Attachment 3-A, page 1
Exhibit 3, Attachment 3-C
Load Forecast Model, Historic CDM Tab
Exhibit 4, Tab 1, Schedule 4

a) The Historic CDM Tab sets out program savings from 2009 and 2010 CDM programs (Rows 3-5). Please provide a copy of the OPA/IESO reports that support the persisting savings set out through to 2018 for each of the two year's programs.

b) It appears that for each year (2009 and 2010) the program savings were allocated to the Residential, GS<50 and GS>50 customer classes based on each class' share of total energy use for the three over the period 2009-2016. Please confirm if this was the case and, if not, explain how the allocation was done.

c) Please explain why the calculation of the allocation base for the 2009-2010 programs did not include Intermediate class' usage.

d) Please explain why the allocation of 2009 and 2010 program savings wasn't based on either i) the actual reported programs results from the OPA/IESO using assumptions similar to those used in Exhibit 4 or ii) each class' share of energy use for the 2009-2010 period.

e) Please provide the OPA/IESO reports supporting the persisting savings through to 2018 by customer class from 2011-2014 programs as used in the Historic CDM Tab (Rows 14-45).

f) It appears that for each year (2011 to 2014) the Business and Industrial program savings were allocated to the GS<50 and GS>50 customer classes based on each class' share of total energy use for the two classes over the period 2009-2016. Please confirm if this was the case and, if not, explain how the allocation was done.

g) Please explain why the calculation of the allocation base for the 2011-2014 programs did not include Intermediate class' usage.

h) Please explain why the allocation of 2011-2014 program savings wasn't based on either i) the actual reported programs results from the OPA/IESO using assumptions similar to those used in Exhibit 4 or ii) each class' share of energy use for the 2011-2014 period.

i) Please provide the IESO reports that verify the 2015 and 2016 programs results and set out the persisting impacts through to 2018 for each year's programs.

j) If the 2015 and 2016 total program impacts set out in the Historic CDM Tab (Rows 19-20, 31-32 and 43-44) are not based on the IESO Reports provided in response to part (i), please re-calculate the 2015 and 2016 values used in the Historic CDM Tab based on the IESO verified results.

k) It appears that for each year (2015 to 2016) the Business and Industrial program savings were allocated to the GS<50 and GS>50 customer classes based on each class' share of total energy use for the two classes over the period 2009-2016. Please confirm if this was the case and, if not, explain how the allocation was done.

l) Please explain why the allocation of 2015&2016 program savings wasn't based on either i) the actual reported programs results from the OPA/IESO using assumptions similar to those used in Exhibit 4 or ii) each class' share of energy use for the 2015-2016 period.

Response

a) A report supporting persistence of 2009-2010 programs is provided as Attachment 1-O.

b) Confirmed.

c) EPLC is proposing to eliminate the Intermediate class as part of its Application. Though the class no longer exists, the customers that were in that class remain as EPLC customers, now in the GS > 50 kW class, therefore the CDM associated with those customers persists within the current classes.

d) Elenchus considers consumption to be an appropriate proxy to apportion CDM program savings by class. Programs often target multiple classes so program savings need to be allocated with another measure. Elenchus elected to use average consumption from 2007 to 2016 as a clear and consistent method of allocating savings to each class. Additionally, this method allows savings that would be attributable to Essex's previous rate classes (including Intermediate) to be allocated among Essex's current rate classes. Proportional consumption by class has been fairly consistent so using energy use by class in a specific period would not materially impact the load forecast results.

e) A report supporting persistence of 2011-2014 activities is provided as Attachment 1-O.

f) Confirmed.

g) See response to part (c) above.

h) See response to part (d) above.

i) The 2015 results are provided as Attachment 1-O.

j) The 2015 results are based on the IESO report provided in response to part (i). Persistence results for 2016 were not available when the Load Forecast was produced. The 2016 target is used in its place.

k) Confirmed.

l) See response to part (d).

Exhibit 3: 3-VECC-27

Reference: Exhibit 3, Attachment 3-A, Section 2.3 (GS>50 Class)
Load Forecast Excel Model, Monthly Data Tab

a) It is noted that Essex reported on Intermediate customer for the period 2009-2014. After 2014 did the customer go out of business such that the premise is now vacant or was the customer location re-classified to the GS>50 class?

b) If the customer was reclassified, please explain why the usage for the Intermediate class customer class was not combined with the GS>50 class use for purpose of developing the GS>50 class forecast model.

Response

a) Yes, EPLC's sole Intermediate customer closed. The site was briefly vacant however a new business has since moved in. Their load would not qualify for the Intermediate Use rate class as of 2017 and currently resides in the GS>50 rate class.

b) Not applicable.

Exhibit 3: 3-VECC-28

Reference: Exhibit 3, Attachment 3-A, Section 3

a) What was the basis for the 2017 and 2018 forecast values used for Windsor Full Time Employment?

b) .Are more recent forecast values now available from the same source(s) and, if so please provide a table comparing these more recent values with those used to prepare the load forecast.

c) Please provide a load forecast for 2018 using the 20-year trend values for HDD and CDD and compare the results with those prepared using the 10-year average values.

Response

a) Monthly forecast Windsor FTEs are based on the number of FTEs from the same month of the previous year times the forecast FTE growth rate. The forecast FTE growth rate is the average Ontario Employment growth rates forecasted by BMO, TD, Scotiabank, and RBC at the time the load forecast was prepared, March 2017. Different growth rates are used for 2017 and 2018.

b) The requested information is provided in the following table:

	BMO	TD	Scotiabank	RBC	Average
Used in Load Forecast (March 2017)					
2017	1.40%	1.30%	1.40%	1.30%	1.35%
2018	1.20%	0.70%	0.70%	0.90%	0.88%
Current Employment Forecasts (February 2018)					
2017	1.80%	1.70%	1.80%	1.80%	1.78%
2018	1.90%	1.20%	1.60%	1.40%	1.53%

c) The tables below show the weather-normalized 2018 load forecasts using both the 10-year average method and 20-year trend method in the revised load forecast model. The 20-year trend HDD and CDD are slightly higher than the 10-year average HDD and CDD and, as a result, forecast consumption is also higher.

10-Year Average

CDM Adjusted

kWh	2018 Weather Normal Forecast	CDM Adjustment	2018 CDM Adjusted Forecast
Residential	246,572,980	1,169,888	245,403,092
GS < 50	65,548,484	2,780,199	62,768,285
GS > 50	185,139,694	7,094,029	178,045,665
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	531,816,720	11,044,116	520,772,604

20-Year Trend

CDM Adjusted

kWh	2018 Weather Normal Forecast	CDM Adjustment	2018 CDM Adjusted Forecast
Residential	248,338,294	1,169,888	247,168,406
GS < 50	65,755,321	2,780,199	62,975,122
GS > 50	185,556,751	7,094,029	178,462,722
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	534,205,927	11,044,116	523,161,811

Exhibit 3: 3-VECC-29

Reference: Exhibit 3, Attachment 3-A, Section 4.1

a) With respect to the Residential Class (Section 4.1), please explain how the actual normalized values for 2009-2016 were determined (Column D).

b) If a different approach was used to determine the actual "normalized" values in Section 4.1, please re-calculate the normalized values for 2015 and 2016 as follows:

i. For each month calculate the difference the actual HDD and CDD values and the corresponding weather normal values.
ii. Multiply the differences determined in (i) respectively by the HDD and CDD coefficients determined per the regression model.
iii. Provide an alternative estimate of normalized Residential use for 2015 and 2016 by summing the results from part (ii) over the 12 months in each year and adding the result to the annual actual usage with no CDM (Column C) for the Residential class for the year.

c) Please provide the actual Residential class usage by month for 2017 and the total 2017 actual use.

d) Please provide the actual 2017 HDD and CDD values by month.

e) Please calculate the weather normalized Residential use for 2017 as follows:

i. For each month calculate the difference the actual HDD and CDD values and the corresponding weather normal values.
ii. Multiply the differences determined in (i) respectively by the HDD and CDD coefficients determined per the regression model.
iii. Provide an estimate of normalized Residential use for 2017 by summing the results from part (ii) over the 12 months in and adding the result to the annual actual usage for the Residential class for the year.

Response

a) Actual normalized values for 2009-2016 were determined with forecast values for explanatory variables and coefficients from an ordinary least squares (OLS) regression. The coefficients were determined with an OLS regression using actual consumption, economic, weather, and calendar data from 2009 to 2016. Various regressions were run to determine the statistically significant explanatory variables. Variables that were tested but not used include customer count and a dummy variable for each month. Forecasts of the explanatory variables were determined by various methods. As described in the report, 10-year averages were used

for weather variables. Windsor FTEs were increased by the average Ontario employment growth forecast as reported by four major Canadian banks (see 3-VECC-28 part b).

The forecasts of explanatory variable were then multiplied by the associated coefficient from the regression results in Section 2.1. The sums of the resulting values are the normalized value in each month. The values in Section 4.1 are the sums of monthly normalized consumption for each year.

b) The results of the described weather-normalizing method are presented below with the normalized values from section 4.1.

	Section 4.1, Column D	3-VECC-29 (b)
2015	253,080,867	252,384,886
2016	255,142,798	253,714,730

c) Monthly and total 2017 Residential consumption is provided in the following table.

	Monthly kWh
Jan-17	19,577,899
Feb-17	16,130,962
Mar-17	17,096,864
Apr-17	15,205,151
May-17	17,118,677
Jun-17	22,734,884
Jul-17	29,587,934
Aug-17	25,854,116
Sep-17	21,157,398
Oct-17	18,237,883
Nov-17	11,085,787
Dec-17	16,820,963
2017 Total	**230,608,518**

d) Actual 2017 HDD and CDD data is provided in the following table.

	HDD	CDD
Jan-17	570.4	0
Feb-17	411.8	0
Mar-17	469.7	0
Apr-17	177.1	6.1
May-17	124.4	28.5
Jun-17	2.9	128.1
Jul-17	0	179.5
Aug-17	1.9	121.4
Sep-17	27.4	80.7
Oct-17	124.6	24.9
Nov-17	379.5	0
Dec-17	634.4	0
Total 2017	**2,924.1**	**569.2**
10-year average	3,196.8	579.9
20-year trend	3,223.6	603.3

e) Normalized 2017 consumption using the described methodology for the Residential class is 239,230,919 kWh.

Exhibit 3: 3-VECC-30

Reference: Exhibit 3, Attachment 3-A, Section 4.2

a) With respect to the GS<50 Class (Section 4.2), please explain how the actual normalized values for 2009-2016 were determined (Column D).

b) If a different approach was used to determine the actual "normalized" values in Section 4.2, please re-calculate the normalized values for 2015 and 2016 as follows:

i. For each month calculate the difference the actual HDD and CDD values and the corresponding weather normal values.
ii. Multiply the differences determined in (i) respectively by the HDD and CDD coefficients determined per the regression model.
iii. Sum the results from part (ii) over the 12 months in each year and add the result to the annual actual usage with no CDM (Column C) for the GS<50 class for the year.

c) Please provide the actual GS<50 class usage by month for 2017 and the total 2017 actual use.

d) Please calculate the weather normalized GS<50 use for 2017 as follows:

i. For each month calculate the difference the actual HDD and CDD values and the corresponding weather normal values.
ii. Multiply the differences determined in (i) respectively by the HDD and CDD coefficients determined per the regression model.
iii. Provide an estimate of normalized GS<50 use for 2017 by summing the results from part (ii) over the 12 months in and adding the result to the annual actual usage for the GS<50 class for the year.

Response

a) Please see EPLC response to 3-VECC-29 part (a).

b) The results of the described weather-normalizing method are presented below with the normalized values from section 4.2.

	Section 4.2, Column D	3-VECC-30 (b)
2015	69,797,386	69,725,739
2016	70,791,210	72,494,929

c) Monthly and total 2017 GS<50 consumption is provided in the following table.

	Monthly kWh
Jan-17	5,596,505
Feb-17	4,876,383
Mar-17	5,262,257
Apr-17	4,768,353
May-17	5,142,884
Jun-17	5,706,443
Jul-17	6,298,857
Aug-17	5,961,455
Sep-17	5,568,832
Oct-17	5,156,377
Nov-17	2,547,514
Dec-17	4,208,878
2017 Total	**61,094,739**

d) Normalized 2017 consumption using the described methodology for the GS<50 kW class is 71,206,099 kWh.

Exhibit 3: 3-VECC-31

Reference: Exhibit 3, Attachment 3-A, Section 4.3

a) With respect to the GS>50 Class (Section 4.3), please explain how the actual normalized values for 2009-2016 were determined (Column D).

b) If a different approach was used to determine the actual "normalized" values in Section 4.3, please re-calculate the normalized values for 2015 and 2016 as follows:

i. For each month calculate the difference the actual HDD and CDD values and the corresponding weather normal values.
ii. Multiply the differences determined in (i) respectively by the HDD and CDD coefficients determined per the regression model.
iii. Sum the results from part (ii) over the 12 months in each year and add the result to the annual actual usage with no CDM (Column C) for the GS>50 class for the year.

c) Please provide the actual GS<50 class usage by month for 2017 and the total 2017 actual use.

d) Please calculate the weather normalized GS<50 use for 2017 as follows:

i. For each month calculate the difference the actual HDD and CDD values and the corresponding weather normal values.
ii. Multiply the differences determined in (i) respectively by the HDD and CDD coefficients determined per the regression model.
iii. Provide an estimate of normalized GS<50 use for 2017 by summing the results from part (ii) over the 12 months in and adding the result to the annual actual usage for the GS<50 class for the year.

Response

This response assumes that GS<50 should be replaced with GS>50 in parts (c) and (d) as responses relevant to the GS<50 class are provided in 3-VECC-30.

a) See response to 3-VECC-29 part (a).

b) The results of the described weather-normalizing method are presented below with the normalized values from section 4.3.

	Section 4.3, Column D	3-VECC-31 (b)
2015	181,778,601	182,840,667
2016	193,615,532	216,433,466

c) Monthly and total 2017 GS>50 consumption is provided in the following table.

	Monthly kWh
Jan-17	14,187,165
Feb-17	12,905,462
Mar-17	14,400,959
Apr-17	13,028,817
May-17	13,988,943
Jun-17	15,398,487
Jul-17	17,180,519
Aug-17	16,940,697
Sep-17	16,785,056
Oct-17	15,540,522
Nov-17	12,954,573
Dec-17	13,129,852
2017 Total	**176,441,054**

d) Normalized 2017 consumption using the described methodology for the GS>50 kW class is 197,839,004 kWh.

Exhibit 3: 3-VECC-32

Reference: Exhibit 3, Attachment 3-A, Section 4.4

a) With respect to Section 4.4, please provide the actual Embedded Distributor usage (kWh and kW) for 2017.

Response

a) Please see Embedded Distributor usage (kWh and kW) for 2017:

Month	kWh	kW
January	2,922,799	6,572
February	2,546,797	6,224
March	2,824,564	6,315
April	2,380,301	5,850
May	2,572,689	5,940
June	2,838,910	6,856
July	2,885,786	6,854
August	3,017,009	7,278
September	2,712,860	7,209
October	2,654,940	6,345
November	2,719,814	6,016
December	2,610,461	6,326
Total	**32,686,929**	**77,782**

Exhibit 3: 3-VECC-33

Reference: Exhibit 3, Attachment 3-A, Section 6
Exhibit 3, Attachment 3-C

a) It is understood that LDCs periodically update their 2015-2020 CDM Plans and the revised Plans are subsequently approved by the IESO. Does Attachment 3-C represent the Essex's most recently approved 2015-2020 CDM Plan? If not please provide the most recently approved Plan.

b) For purposes of the load forecast, why aren't the CDM savings from 2017 and 2018 programs based on savings set out in the 2015-2020 CDM Plan for those years?

Response

a) EPLC confirms that Attachment 3-C is not the most up to date 2015-2020 CDM Plan. Please refer to Attachment 1-P for EPLC's most up to date CDM Plan approved December 15th, 2017.

b) EPLC utilized a straight-line approach to the application of CDM to its load forecast. EPLC currently projects that it will meet its 2020 target in 2018 as a result of the completion of a single large project. In order to minimize the risk of this project not materializing and to avoid a large load drop in the 2018 Test Year, EPLC opted to normalize CDM related savings over the course of the 2015-2020 program years.

Exhibit 3: 3-VECC-34

Reference: Exhibit 3, page 35

a) Please provide a schedule with a similar level of detail as Figure 39 that compares the forecast 2017 Other Revenue with the Actual 2017 Other Revenue.

Response

Please refer to the schedule below which has been updated for 2017 actuals.

USoA #	Description	2017 Forecast	2017 Actual	Difference
	Reporting Basis	MIFRS	MIFRS	MIFRS
4235	Specific Service Charges	$ (166,480)	$ (94,607)	$ (71,873)
4225	Late Payment Charges	$ (260,400)	$ (202,219)	$ (58,181)
4080	SSS Revenue	$ (80,000)	$ (88,894)	$ 8,894
4082	Retail Services Revenues	$ (28,000)	$ (18,435)	$ (9,565)
4084	Service Tax Requests	$ (7,640)	$ (7,000)	$ (640)
4090	Electric Services Incidental to Energy Sales	$ -	$ -	$ -
4205	Interdepartmental Rents	$ -	$ -	$ -
4210	Rent from Electric Property	$ (109,515)	$ (115,364)	$ 5,849
4215	Other Utility Operating Income	$ -	$ -	$ -
4220	Other Electric Revenues	$ -	$ -	$ -
4240	Provision for Rate Refunds	$ -	$ -	$ -
4245	Government Assistance Directly Credited to Income	$ -	$ -	$ -
4305	Regulatory Debits	$ -	$ 342,323	$ (342,323)
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	$ -	$ (48,078)	$ 48,078
4360	Loss on Disposition of Utility and Other Property	$ -	$ 39,105	$ (39,105)
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)	$(2,204,120)	$ 338,867
4375	Generation Facility Revenues - Sub-Account	$ (369,700)	$ (378,899)	$ 9,199
4380	Expenses from Non-Utility Operations	$ 1,784,228	$ 2,222,908	$ (438,680)
4380	Generation Facility Expenses - Sub-Account	$ 212,000	$ 264,966	$ (52,966)
4385	Expenses of Non-Utility Operations	$ -	$ -	$ -
4390	Miscellaneous Non-Operating Income	$ (14,000)	$ (22,161)	$ 8,161
4395	Rate-Payer Benefit Including Interest	$ -	$ -	$ -
4398	Foreign Exchange Gains and Losses, Including Amortization	$ -	$ 10,428	$ (10,428)
4405	Interest and Dividend Income	$ (101,310)	$ (141,249)	$ 39,939
4415	Equity in Earnings of Subsidiary Companies	$ -	$ -	$ -
Specific Service Charges		$ (166,480)	$ (94,607)	$ (71,873)
Late Payment Charges		$ (260,400)	$ (202,219)	$ (58,181)
Other Operating Revenue		$ (225,155)	$ (229,693)	$ 4,538
Other Income or Deductions		$ (354,035)	$ 85,224	$ (439,259)
Total		**$ (1,006,070)**	**$ (441,296)**	**$ (564,774)**

Exhibit 4: 4-Staff-53

OM&A Summary

Ref: EPLC Chp2Appendice 20170828 – App.2 – JA OM&A Summary Analysis

a) Please identify what improvements in services and outcomes the Applicant's customers will experience in 2018 and during the subsequent IRM term as a result of increasing the provision for OM&A in 2018 at about 44% times since the last rebasing eight years ago.

b) How has the Applicant communicated these benefits and the associated costs to its customers, and how did customers respond? Please provide some examples, including a synopsis of any customer feedback. If no communications took place, please explain why not.

Response

a) EPLC has heard from its customers, on multiple occasions, that their three primary concerns are affordability, reliability and communication.

EPLC is proposing to enhance customer communication through investment in a 24/7 Control Room. This investment will improve communication to customers and key stakeholders calling after hours and will convey near real-time information about outage restoration and other potential issues. Further, EPLC has implemented various social media communication throughout its operation to better communicate with its customers.

As it relates to reliability, EPLC is continuing its investment in the Self-Healing Grid to reduce Loss of Supply incidents that occur outside of EPLC's service territory. In addition, the Control Room services will introduce efficiencies in the outage response process that will lead to reliability improvements.

Lastly, to address EPLC's customer concerns related to affordability, as part of this Application EPLC is proposing to reduce the cost of the total bill across all customer classes.

It should also be noted that the 44% increase relates to 2010 Actual vs. 2018 Test Year. Comparing 2010 Board Approved figures to the projected 2018 Test Year, the increase is 24% (or 3% per year).

b) Through the Innovative Survey (Exhibit 2, Attachment 2-C, Appendix D), EPLC asked customers for social permission to modernize the grid which includes initiatives like the Self-Healing Grid to improve overall system reliability. A summary of the studies findings can be

found in Exhibit 2, Attachment 2-C, Appendix D, pages 2-3. EPLC also communicated these benefits at the 4 open house meetings held prior to the application and customers were given the opportunity to discuss and provide feedback.

Exhibit 4: 4-Staff-54

Cost Drivers

EPLC Chp2Appendice 20170828 – App.2 JB OM&A Cost Drivers

Essex Powerlines provided the drivers for the year-to-year changes in OM&A.

a) Please reconcile the sum of the operations sub-total for the 2018 test year and the drivers that sum up to it.

b) The cumulative increase for OM&A expenses related to O/H Right of Way – Conversion since 2010 is $321,703, which represent approximately 21% of the changes to OM&A. Please explain why the expenses related to conversion did not decrease as the voltage conversion initiative concluded.

c) The cumulative increase for OM&A expenses related to Customer Billing since 2010 is $333,432, which represent approximately 22% of the changes to OM&A. Please explain what has changed in they way customers are billed to warrant this increase.

d) The cumulative increase for OM&A expenses related to Change in Employee Pensions & Benefits since 2010 is $362,363, which represent approximately 24% of the changes to OM&A. Please provide an explanation for this increase.

Response

a) A revised Appendix 2-JB has been provided as Attachment 1-J.

b) EPLC has ongoing overhead conversion work to be completed in 2018 and beyond. EPLC expects that expenses related to conversion will indeed decrease upon conclusion of the initiative.

c) Customer billing costs have risen steadily since 2010 by $333,432 (22% or 2.75% per year). EPLC has experienced a variety of 3rd party costs that have risen beyond the rate of inflation however these costs are largely out of the direct control of EPLC. Increases in the cost of postage and 3rd party printer are the largest contributors to this increase.

d) Employee Pensions & Benefits has increased by $362,363 between 2010 and 2018. This represents an increase of approximately 24% or 3% per year. This change is the result of an

Actuarial report that re-evaluated EPLC's Pension & Benefit expense and changes in updated collective bargaining agreements.

Exhibit 4: 4-Staff-55

Control Room Support

Ref: Exhibit 4: Operating Expense – Control Room Support (Page 7)

Essex Powerlines plans to use a 3rd party Control Room support service to provide monitoring and control for its distribution system as part of the Self-Healing Grid initiative.

a) Please provide the scope used for Essex Powerlines' Request for Quotation (RFQ).

b) How many competitive bids were there for this RFQ? What was the selection criteria?

c) Does the 3rd party control room vendor provide 24 hour service?

d) Does Essex Powerlines expect to reduce the number of staff required during off hours with the 3rd party control room?

e) Does the 3rd party control room vendor provide data acquisition services as part of the contract? If so, how does Essex Powerlines plan to use this data?

Response

a) EPLC has not issued a Request for Quotation for this service. EPLC plans to select a successful vendor in 2018.

b) Not applicable.

c) EPLC's intention is for the eventual successful vendor to provide 24 hour service.

d) EPLC currently contracts after hour calls to a 3rd party. EPLC will still have superintendents on-call to respond to after hour incidents, as needed.

e) Not applicable.

Exhibit 4: 4-Staff-56

Cybersecurity Maintenance

Ref: Exhibit 4: Operating Expense – Cybersecurity Maintenance (Page 8)

Essex Powerlines plans to use 3rd party IT experts to provide cybersecurity services in order to be compliant with the OEB's proposed Cybersecurity Framework.

a) Please provide the scope used for Essex Powerlines' Request for Quotation (RFQ).

b) How many competitive bids were there for this RFQ? What was the selection criteria?

c) Has Essex Powerlines completed its Cyber Security self certification requirement.

d) Is the Cyber Security infrastructure on-site or cloud based?

Response

a) EPLC has not issued a Request for Quotation for this service. EPLC plans to select a successful vendor in 2018.

b) Not applicable.

c) EPLC has not completed a self-certification requirement however EPLC has completed a preliminary self-assessment using the Board's Cybersecurity framework risk profile tool.

d) EPLC's planned Cyber Security infrastructure will be both on-site and cloud based.

Exhibit 4: 4-Staff-57

Cost per Customer & FTE

Ref: EPLC Chp2Appendice 20170828 – App.2-K Employee Costs

Essex Powerlines stated in other areas of the application that increase in OM&A expense is due to inflationary pay increases.

a) Please explain the reason for the sudden decrease in full time employees between 2010 and 2011.

b) The average employee compensation increased more than 10% in 2012 and again between 2015-2016. Please explain the reasons for the step increase.

Response

a) The decrease in full time employees between 2010 and 2011 relates to a labour dispute in 2011.

b) The average employee compensation increased in 2012 and again in 2015-2016 as a result of new bargaining unit increases in 2012 and revised EPC allocations (please refer to 4-Staff-67 below) in 2016.

Exhibit 4: 4-Staff-58

General Building Expense

Ref: Exhibit 4: Operating Expense – General Building Expenses (Page 20)

Essex Powerlines chose to consolidate all its regulated activities to its Oldcastle Service Station to reduce its rent expense.

a) Please provide the yearly rent Essex Powerlines was paying at the Essex Civic Centre.

b) What incremental building expenses were incurred as a result of consolidation?

Response

a) EPLC paid $48,661.67 for rent in 2011 and $29,520.56 (moved out in September 2012).

b) EPLC had to make some incremental changes to its operations center in 2012 to accommodate the incremental employees arriving from the Essex Civic Centre. Over time, this move will result in a net benefit of approximately $50,000 per year in avoided rent expense.

Exhibit 4: 4-Staff-59

Regulatory Affairs

Ref: Exhibit 4: Operating Expense – Regulatory Affairs (Page 21)

Essex Powerlines created two new positions in regulatory affairs, a Manager of Regulatory Accounting and a Regulatory Accounting Analyst.

a) Please explain the need for the two new positions.

b) The regulatory affairs costs increased approximately by $237k from 2016 to 2017. Is this cost increase fully due to the salary of the two new positions?

Response

a) The need is the result of a retirement of the Vice President, Regulatory Affairs and the departure of the Operations & Regulatory Accounting Analyst. Previously, these two positions made up EPLC's entire regulatory FTEs at approximately 1.5 per year (The VP, Regulatory Affairs was fully dedicated and the Operations & Regulatory Accounting Analyst was 0.5 to regulatory matters). EPLC re-structured the Operations & Regulatory Accounting Analyst position, moving its operations related functions to the Corporate Procurement & Financial Analyst and creating two new regulatory positions: Manager of Regulatory Accounting and the Regulatory Accounting Analyst. Both of these new positions are totally dedicated to Regulatory matters across EPLC. This need was identified by EPLC to address risk mitigation across a variety of new and growing regulatory challenges facing LDCs such as the Fair Hydro Plan, the revised Long Term Energy Plan, the RRFE, Green Energy Act, etc.

b) Confirmed however it should be noted that Regulatory labour costs were not previously accounted for in Account 5655 and that the true incremental regulatory costs are to reflect an additional 0.5 FTE.

Exhibit 4: 4-Staff-60

Customer Collection

Ref: Exhibit 4: Operating Expense – Customer Collections (Page 22)

Essex Powerlines stated that the increase in Customer Collection expenses were due to the loss of a water billing customer which provided cost offset of $70,000 and inflationary increases to wages.

a) Please provide the cost allocation method used for the Customer Collection expenses to bill the water billing customer.

b) The cost offset from the water billing customer is approximately 1/3 of the total expense. Please explain why the loss of this customer does not reduce the amount of work required for customer collection.

c) Offsetting the 2018 Customer Collection expense by $70,000 and comparing it with the 2010 actuals still shows an increase of 70%, an average increase of 8.7% per year, which is above inflation. Please explain what other costs have increased in this expense.

Response

a) The cost allocation methodology is based on customer account and consistent with the water billing agreements included as Attachment 1-U.

b) EPLC bills both hydro and water charges on the same bill. Despite losing a water billing customer, the amount of total bills issued remains immateriality different. EPLC does not focus any direct collection effort towards the payment of water bills. The total number of payments received would also remain immaterially different.

c) Please refer to EPLC response to 4-Staff-54.

Exhibit 4: 4-Staff-61

Vegetation Control

Ref: Exhibit 4: Operating Expense – Vegetation Control (Page 23)

Essex Powerlines stated that it does not believe that it will be required to continue spending at historical spending levels but believes rigorous vegetation control can significantly improve reliability.

a) Please provide the tree related outages between 2010 to 2016.

b) What is Essex Powerlines tree trimming cycle? Does Essex Powerlines have a vegetation management policy? If so, please provide.

Response

a) The following table outlines the tree related outages between 2010-2016:

Outage Code & Description		2010	2011	2012	2013	2014	2015	2016	2017
3	Tree Contact	16	29	6	8	9	8	1	5

b) EPLC does not currently have a formal vegetation management policy. EPLC's tree trimming cycle is 3 years for primary cable and 8 years for secondary.

Exhibit 4: 4-Staff-62

Meter Operations

Ref: Exhibit 4: Operating Expense – Meter Operations (Page 23)

Essex Powerlines stated that most of the increase in this expense is due to the reallocation of Meter Maintenance expense and inflationary pay.

a) Comparing the 2010 OEB approved to the 2010 actual expense for both these expense accounts show an approximate underspending of 50%. Please explain the underspending in 2010.

b) The spending in the Meter Operations expense were particularly high between 2012 to 2014. Please provide an explanation to the costs incurred during that period.

Response

a) EPLC did not experience the expected level of metering related troubleshooting and maintenance occurrences in 2010.

b) The variance in Meter Operations spending is largely the result of cost allocation inconsistency between 2012 and 2014 within the Meter Operations and Meter Maintenance accounts. This was resolved in 2015 and beyond as demonstrated in the table below:

Description	2010 BAP	2010	2011	2012	2013	2014	2015	2016	2017	2018
Meter Operations	135,439	58,051	79,937	303,051	408,908	591,129	220,528	213,180	222,133	216,785

Exhibit 4: 4-Staff-63

Operations Management

Ref: Exhibit 4: Operating Expense – Operations Management (Page 24)

Essex Powerlines stated that most of the increase in Operations Management expense is due to 3rd party control room support as part of the Self-Healing Grid initiative.

a) Please breakout the costs related to the 3rd party control room support.

Response

a) While a vendor has not yet been selected, these costs reflect the ongoing, year over year cost of engaging 3rd party control room industry experts. The services are proposed to be offsite and would solely use 3rd party labour. The expense identified is considered to be an "all-in" expense. The Control Room 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. EPLC budgeted the all-in 3rd party Control Room support figures based on detailed discussions with various 3rd party vendors.

Exhibit 4: 4-Staff-64

Overhead Operations

Ref: Exhibit 4: Operating Expense – Overhead Operations (Page 24)

Essex Powerlines stated that the increase in Overhead Operations expense is due to focusing on overhead plant as Essex Powerlines begins more overhead related conversion work. Essex Powerlines also stated that it is complete the voltage conversion work on its distribution system.

a) Please explain why there is still more voltage conversion work if Essex Powerlines is apparently complete.

b) Please provide an estimation of kilometers of line that still require voltage conversion.

Response

a) EPLC is still not 100% complete. There are currently still small pockets remaining that EPLC is actively working on converting.

b) Some are EPLC lines connected to private lines where customer would have to agree to convert as well or we would just put step downs. In some case EPLC owns the transformers on the private lines.

As of today 1.3km of conversion work remains in a backyard, heavily treed areas. We do not want to or cannot rebuild in the same area as it is difficult work that would require significant restoration work. EPLC also requires some land rights to be able to move the high voltage to an accessible road area to reduce risk to public of falling lines and employees that may have to climb. EPLC is working to eliminate all 4/8kV as expeditiously as possible.

Exhibit 4: 4-Staff-65

Transformer Operations and Underground Operations

Ref: Exhibit 4: Operating Expense (Page 24)

Essex Powerlines did not provide a variance analysis for the Transformer Operations and Underground Operations expense.

a) Please provide the variance analysis for both of these expenses.

b) Comparing the 2010 OEB approved to the 2010 actual expense for Transformer Operations show an approximate underspending of 70%. Please explain the underspending in 2010.

Response

a) Please review the table below which shows year over year variances for both the Transformer Operations and Underground Operations expense items.

Description	2010 BAP	2010		2011		2012		2013		2014		2015		2016		2017		2018	
Transformer Operations	122,523	40,324	-67%	82,151	104%	49,935	-39%	46,145	-8%	39,021	-15%	63,883	64%	52,888	-17%	43,444	-18%	86,805	100%
Underground Operations	32,108	19,692	-39%	9,330	-53%	11,838	27%	27,514	132%	11,552	-58%	46,040	299%	111,261	142%	51,703	-54%	58,040	12%
Total	**154,631**	**60,016**	**-61%**	**91,481**	**52%**	**61,773**	**-32%**	**73,659**	**19%**	**50,573**	**-31%**	**109,923**	**117%**	**164,149**	**49%**	**95,147**	**-42%**	**144,845**	**52%**

The nature of these expenses are largely related reactive in nature and can vary dramatically. EPLC used trend analysis and forecasting in order to assess and create its 2017/2018 budgets.

b) EPLC did not experience the expected level of transformer related troubleshooting, replacement and maintenance related occurrences in 2010.

Exhibit 4: 4-Staff-66

Age Demographics

Ref: Exhibit 4: Operating Expense – Aging Demographics (Page 28)

Approximately 60% of union staff are near retirement age.

a) What are Essex Powerlines plans for the transition with the retirement of so many staff?

Response

a) EPLC acknowledges and understands that retirements will create upcoming staffing and HR challenges for the coming years. As a result, EPLC is currently in the process of working on a succession plan that will formally address many of these potential hurdles.

One of EPLC's biggest concerns was attracting linemen from neighboring jurisdictions (and vice versa). As a result, EPLC, along with other local LDCs are investing in local education with the intent of hiring apprentices that were trained locally. EPLC is a proud partner of St. Clair College's Powerline Technician Program in Chatham, Ontario which has already resulted in EPLC acquiring locally trained talent.

Exhibit 4: 4-Staff-67

Shared Services

Ref: Exhibit 4: Operating Expense – Shared Services from Affiliates (Page 43)

Essex Powerlines purchases services from Essex Energy Corporation and Essex Power Corporation to provide CDM, HR, IT, Procurement, and Executive services.

a) Has Essex Powerlines tried to procure the same services it receives from Essex Energy Corporation through a competitive bidding process?

b) How does Essex Energy Corporation and Essex Power Corporation allocate the costs it charges Essex Powerlines for the services provided?

c) Please provide the total number of man hours charged yearly to Essex Powerlines by Essex Energy Corporation and Essex Power Corporation.

d) Are the employees from these affiliates included in Essex Powerlines full-time employee?

Response

a) EPLC initially requested quotes from various vendors when the decision was made to outsource CDM related services prior to the 2010-2014 CDM Framework. Essex Energy Corporation was selected as the lowest-cost option and the sole entity that could truly turn-ley the service on behalf of EPLC.

Essex Energy Corporation has a track record of meeting and/or exceeding EPLC's conservation goals which is why they were selected as the successful applicant for the 2015-2020 Conservation First Framework. EEC also provides a variety of technical CDM services for other LDCs in southwestern Ontario.

In addition to the turn-key services provided within the allocated budgets provided by the IESO, EEC is also committed to remitting any performance incentives it receives for goal achievement back to EPLC. EPLC views this engagement as a low risk investment with potential upside.

b) There are no direct allocations to EPLC from Essex Energy Corporation. Any/all work completed by Essex Energy Corporation on behalf of EPLC is done through a quote/tender process and approved by the appropriate EPLC manager.

Essex Power Corporation allocations are consistent with the chart below:

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**

c) See response to b) above for EPC hours. Essex Energy Corporation hours directly billed to EPLC totalled 2,363 in 2016.

d) The adjusted FTEs with EPC allocations are consistent with the chart below:

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**

Exhibit 4: 4-Staff-68

Non-Affiliate Services

Ref: Exhibit 4: Operating Expense – Purchase of Non-Affiliate Services (Page 46)

The services procured for Billing Services from ERTH Holdings Inc. have increased significantly since 2011 to 2016.

a) Please provide an explanation for the costs increase and more specifically explain why it almost doubled between 2015 and 2016.

b) Please provide the competitive bidding process used to select the vendor for billing services, the number of bidders, the number of evaluators, and the selection process.

Response

a) EPLC provided incremental back-office billing functions to ERTH in 2016 as a result of internal retirements that were not replaced. These incremental ERTH costs were lower than the cost of the internal staff member.

b) EPLC consulted with various billing agents at the time of selection. Submissions were reviewed and evaluated by EPLC's senior management team and billing department managers. EPLC weighed factors such as history, experience, qualifications, scope of work, risk and price in order to select a successful candidate.

Exhibit 4: 4-Staff-69

LRAMVA

Ref: Exhibit 4: Operating Expense – Conservation and Demand Management (Page 79-80)

Ref: EPLC LRAMVA 20170828 – Tab 1 – Table 1.b

The application indicates that Essex is seeking disposition of a debit balance of $513,500 in lost revenues associated with new CDM program savings between 2013 and 2015. However, the LRAMVA work form indicates a disposition of lost revenues from 2013 to 2016. There are no forecast savings used as a comparator against actual savings over this period, as there was no CDM adjustment and LRAMVA threshold approved from the distributor's 2010 COS application.

a) Please confirm whether Essex is seeking disposition of lost revenues between 2013 and 2016, as indicated in Table 1-b of the LRAMVA work form.

b) If yes, please ensure all evidence reflects the disposition of lost revenues between 2013 and 2016.

Response

a) Confirmed.

b) All Chapter 2 Appendices and the LRAMVA Work Form reflect the disposition of lost revenues between 2013 and 2016.

Exhibit 4: 4-Staff-70

LRAMVA

Ref: EPLC LRAMVA 20170828 – Tab 3 – Table 3

Ref: EB-2012-0123 Tariff of Rates and Charges

Essex Powerlines included the distribution volumetric rate for each year 2013-2016. The model also requires the rate rider for tax sharing, foregone revenue, or other rate riders. In Essex Powerlines tariff sheet for 2013-2016 there is a rate rider for Tax Changes.

a) Please explain why Essex Powerlines did not include the Tax Change rate rider for the years 2013-2016.

b) Please provide the account number that records the amount credited to customers for tax sharing.

Response

a) EPLC has included a revised LRAMVA Work Form as Attachment 1-Q that includes the Tax Change rate rider for years 2013-2016.

b) The account number that records the amount credited to customers for tax sharing is 4080.

Exhibit 4: 4-Staff-71

LRAMVA

Ref: EPLC LRAMVA 20170828 – Tab 5 – Table 5-b 2016 Lost Revenue Work Form

Table 5-b provides a template for distributors to input 2016 energy and demand savings by program that were verified by the IESO.

a) Please confirm that there were no energy or demand savings from Conservation First Programs that were verified by the IESO in the 2016 program year.

Response

a) Confirmed.

Exhibit 4: 4-Staff-72

LRAMVA

a) Please file an excel copy of the IESO CDM Final Verified Results Reports for the 2013, 2014, 2015 and 2016 program years.

b) Please file a copy of the IESO persistence savings reports for 2013, 2014 and 2015.

Response

a) Please see IESO CDM Final Verified Results Reports for 2013, 2014, 2015 and 2016 program years attached as Attachment 1-R respectively.

b) Please see IESO persistence savings reports for 2013, 2014 and 2015 program years attached as Attachment 1-O respectively.

Exhibit 4: 4-Staff-73

LRAMVA

Ref: EPLC LRAMVA 20170828

If Essex has made any changes to the LRAMVA work form as a result of its responses to interrogatories, please file an updated LRAMVA work form.

Response

A revised LRAMVA work form is included as Attachment 1-Q.

Exhibit 4: 4-SEC-28

Ex.4, p.7] With respect to the 3rd party control room support:

a. Please provide a copy of the "preliminary analysis" the Applicant undertook.

b. Has a formal business case been undertaken? If so, please provide a copy.

c. What is the basis for the 2018 test year budget of $186,000? Please provide supporting documentation.

Response

a)

Essex Powerlines Background Information

Current Process

EPL does not currently have a centralized Control Room or SCADA system. All work protection is self-administered by the Supervisor of Operations, sub-foremen or on-call linemen depending on the nature of the work and the time of day. Work protection is documented, principally through the use of PC17B's, as a self-administered work permit.

Work protection documentation is a manual paper-based process. EPL has not adopted any electronic form filling for any UWPC forms.

Current Maps and Technology

Crews have access to GIS maps via field laptops, as well as copies of paper maps. There are large operating maps in the main operations area that depict the status of all switches and any work protection in effect at any one time. The operations paper maps derive their data, in part, from GIS but are a derivative produced with CAD software.

SmartMap and GIS

SmartMap is automatically updated, via a scheduled batch process, when changes are made to GIS. The use of SmartMap data is growing within the company but is not yet ubiquitous. EPL's goal is to transition to using SmartMap data and representations for all operation functions and abandon the use of paper representations (except for backup purposes) and all other digital

representations of the distribution system. GIS data will remain as the comprehensive repository of EPL's distribution data with SmartMap data and maps becoming the operational and planning tool of choice for all other uses.

Utility Work Protection Code – Roles & Responsibilities

- Controlling Authority – Essex Powerlines will authorize 3rd Party Provider as the Controlling Authority. This will enable 3rd Party Provider to issue supporting guarantees on behalf of Essex Powerlines, as well as operate Essex Powerlines equipment after hours in line with established procedures.

- Issuing Authority – Essex Powerlines will authorize 3rd Party Provider as their issuing authority. 3rd Party Provider will ensure that the condition requested by Essex Powerlines applicant has been established. 3rd Party Provider is then responsible for making effective and terminating the PC2 Work Permit or Supporting Guarantee and keeping a written log of all such events.

- Establishing Authority – this authority will be shared between 3rd Party Provider and Essex Powerlines. 3rd Party Provider will be the authority to prepare the conditions for a Work Permit or Supporting Guarantee by filling out the "PC2" and "PC17A" forms. Essex Powerlines will then check and establish the conditions for said Work Permit or Supporting Guarantee.

Assumptions

1. Essex Powerlines will be contacting the 3rd Party Provider Control Room Operator via phone, IP radio, or email.

Essex Powerlines envisions all three forms of communication being used. EPL's current radio system will be connected via an IP bridge to permit 2-way communication between local field crews and the system operators at 3rd Party Provider.

2. Essex Powerlines will collaborate with 3rd Party Provider to establish Hydro One ICCP access to Essex Powerlines data, including provisions to block breaker reclose remotely from SCADA. 3rd Party Provider will configure dedicated screens in their existing SCADA system to enable this functionality.

EPL will work 3rd Party Provider to access all relevant EPL SCADA status information from HONI. HONI has already been contacted in this regard and stands ready to assist. 3rd Party Provider will have to create the SCADA schematics and screens that mirror the existing station layout and feeder configuration that currently services EPL's 4 service areas. EPL can assist to gather

information but any SCADA reconfiguration will be up to 3rd Party Provider. EPL will assume and depend on 3rd Party Provider's SCADA system to provide all the services 3rd Party Provider will require.

3. The 3rd Party Provider Control Room will have an up to date physical paper copy of Essex Powerlines distribution system maps for backup purposes only.

As stated earlier, EPL's goal is to use its SmartMap system as the primary means with which 3rd Party Provider system operators can monitor, and oversee the distribution system. Paper maps will be provided for backup purposes but the main goal is that SmartMap will be used exclusively for all control room services.

4. Essex Powerlines will deploy their Smart Map in the 3rd Party Provider control room in addition to a communication link to support ongoing Smart Map operations.

EPL also envisions considerable training and support will be required. EPL will make arrangements to provide this support and any continuing support that may be required.

5. Alarm enunciation will be configured from the Essex Powerlines Smart Map directly to the 3rd Party Provider Operator via email.

Also included are a list of draft Control Room processes as Attachment 1-S.

b) A formal business case has not yet been completed. EPLC intends to complete a formal business case as it gathers final quotes, prior to project kick-off.

c) EPLC research other Ontario LDCs that have 3rd party control room support and adjusted for customer count and system complexity to determine its budgeted amount. In addition, EPLC received preliminary estimate information from vendors.

Exhibit 4: 4-SEC-29

[Ex.4, p.12] Please explain what the Applicant means by "Regulatory Re-Alignment". Please provide a breakdown of those incremental costs.

Response

Please refer to EPLC response to 4-Staff-59.

Exhibit 4: 4-SEC-30

[Ex.4, p.12, p.21] Please provide a detailed breakdown of the 'Outside Services/Cybersecurity' costs in 2017 and 2018.

Response

Consistent with EPLC's response to 4-Staff-56, EPLC has not yet committed to the anticipated ongoing maintenance and monitoring costs associated with cybersecurity. Based on discussions with various third party providers, EPLC expects the following breakdown to closely resemble the scope of services to be provided in order to maintain compliance with the Cybersecurity framework (note that all services would be provided by various 3rd party providers (note that dollar values are budgetary estimates and that the vast majority of the proposed costs reside in item i) below):

i) Network Services – Managed IT Services & Outsourced Network Security Services ($250k)

Managed Detection & Response Services:

This service is delivered as a managed service combining proprietary technology that detects suspicious behaviors, a suite of tools that capture and analyze rich forensic data, and human experts who engage to resolve threats. Technology alone cannot accomplish what Managed Detection and Response can. It differs from traditional cybersecurity in several crucial ways:

Active Analytics operates in real-time, going deeper to detect threatening behaviors traditional cybersecurity offerings miss because they don't look for them. This provides more comprehensive protection than solutions that rely on system and device logs to aggregate security event information after-the-fact.
Active Forensics intelligently interprets events, sifting true attacks from false alerts and providing advanced tools that make event information immediately actionable. This differs from security systems that simply create a flood of alerts, leaving it to the user to discern which ones need deeper investigation.
Active Correlation integrates data gathered by other security systems into the Active Forensics database, yielding a far richer set of event information that vastly improves mitigation efforts.
Active Intervention is managed by certified security specialists who monitor client networks on a 24x7x365 basis. They leverage Active Forensics to identify and resolve security issues before they become unmanageable. Unlike legacy Managed Security Services Providers, 3rd party will actively assist in resolving them and stay engaged until systems are restored to normal.

Intelligent Threat Interpreter applies proprietary software algorithms to the Active Forensics Database, eliminating false positives and highlighting events that truly need attention.

Cybersecurity is challenging because the threat landscape is constantly changing. That's why solutions built to face outward and detect yesterday's threats are not equipped to handle today's new, previously unknown attacks. Cyber criminals have proven that they can learn new ways to deliver a nefarious payload that lodges inside the corporate network. Once ensconced, this threat silently gathers information to exploit, while security systems continue to look outward, unaware of the enemy behind the lines.

Active Protection – Maximized Safety Many companies that are high value targets of cyber criminals rely on Network Interceptor. Network Interceptor maximizes safety through an Managed Detection and Response approach. Highlights include:

- Active defense against data and intellectual property loss
- Intrusion detection and prevention of Active Persistent Threats (APTs), even "zero day" attacks
- Real-time inspection of every packet, stopping threats that others miss
- Behavior-based detection of suspicious activities
- Client-specific security interaction and ongoing consultation
- Seamless escalation to active engagement by certified security analysts, 24x7x365

Network Interceptor Capabilities:

The Network Interceptor is a service delivery platform equipped with many capabilities, embodied in software applications that are used by the SOC to deliver the Network Interceptor Service. The following sections describe the Network Interceptor capabilities.

Remanence

Remanence provides URL capture that is used by the SOC for threat qualification and forensic analysis. Remanence captures HTTP traffic and provides a full forensics view complete with referrer and user agent. Remanence uses a proprietary Deep Packet Inspection (DPI) engine to detect and capture URLs.

Sniper

Sniper provides rule based detection and mitigation, blocking threats in real time. Sniper combines rules from emerging threat feeds with custom rules configured by the SOC and the Systems Team. Sniper has the capability to handle thousands of rules. Rules can be configured to automatically "kill" TCP connections in real-time or to notify the SOC. The SOC can also manually "kill" TCP connections.

Bandwidth Profiler

The Bandwidth Profiler notifies the client and the SOC of abnormal bandwidth usage. The SOC provides further analysis and alerts the client if there is a suspected breach of the client's Acceptable Use Policies, a suspected internal threat (exfiltration or otherwise) or a Distributed Denial of Service (DDOS) attack. The SOC must acquire a baseline to understand normal

bandwidth patterns as well as acquire very specific knowledge of the client's network and policies for this capability to be effective.

Packet Analyzer

Packet Analyzer detects suspicious behaviour such as unusual ports scans, sequential scans and "spamming" machines. Once detected, the SOC is notified and provides further analysis and alerts the client of the suspicious behaviour.

TCP Archive

TCP Archive uses a buffer to provide continuous full packet capture of TCP traffic for later forensic analysis by the SOC.

Executioner

Executioner provides whitelist-based executable download detection and mitigation. Executioner uses a proprietary Deep Packet inspection (DPI) engine to detect executables in HTTP traffic, even if they are disguised, for example as .txt, or .jpeg. If a file is not in the whitelist, Executioner intervenes and can block the download by killing the connection in real-time. It then notifies the SOC and the user that attempted to download the executable. The SOC controls the whitelist that is client specific. Executables are also captured and stored for later forensic analysis.

Captive Portal Redirection (User Communication)

Executioner has the ability to perform a policy-based redirection (AKA "http redirect" or "hotlining") of network users, to a web page where a notification or educational message is served. Users may be notified of AUP or Security Policy violations (e.g. prohibited file download). Based on client preference, the page may be configured to facilitate a password exchange to allow select users to proceed with file download.

Data Loss Analysis

Data Loss Analysis (DLA) provides outbound file capture, such as email attachments, for threat qualification and forensic analysis. All unencrypted documents leaving the network through SMTP are logged, captured and can be viewed by the SOC for forensic analysis purposes. DLA can also be configured to deal with additional exfiltration activities resulting from cloud storage, FTP transfers, etc. DLA uses a proprietary Deep Packet Inspection (DPI) engine to detect and capture the file traffic.

Asset Manager Protect

Asset Manager Protect (AMP) provides global IP blacklist based detection and mitigation. A global IP blacklist is maintained by the SOC and is published to all Network Interceptors in the field. AMP uses a proprietary Deep Packet inspection (DPI) engine to detect traffic from the blacklisted IPs.

Monitoring

Network Interceptor sensor establishes 4 reverse VPN connections to communicate with the 3rd Parties' data centers in Canada and overseas.

ii) Network Penetration Testing ($16k)

iii) Establishing & Updating Cybersecurity protocols and policies ($20k)

Exhibit 4: 4-SEC-31

[Appendix 2M; Ex.4, p.16] Please confirm that the Applicant has included certain one-time regulatory costs related to this application in the 2017 OM&A and then is seeking to recover the same amount amortized over 5 years including 2018. If this is correct, please remove the one-time costs in 2017 from the various OM&A Appendices.

Response

EPLC is requesting a total of $405,869 in 2018 as identified on Appendix 2M and Figure 7 within Exhibit 4. EPLC has recognized in Account 5655 one-time costs associated with completing the application in the year which these costs are incurred. In 2018, one-time costs incurred during 2018 related to the application have been removed and have been replaced with the annual amortized value for the application.

Exhibit 4: 4-SEC-32

[Ex.4, p.22] The Applicant states: "EPLC is currently evaluating the cost structure of its Customer Service & Billing department to ensure optimization of cost and customer benefit."

a. Please provide further details of this evaluation and When does the Applicant expect this evaluation to be completed.

b. Please provide preliminary findings and/or evaluations that the Applicant undertaken so far.

Response

a) EPLC expects to complete this evaluation over the course of the next 1-2 years. The evaluation will consider a variety of issues such as the potential loss of water billing customers and its associated impacts, union negotiations and 3rd party service costs and performance.

b) EPLC has no current information to share at the time of this filing.

Exhibit 4: 4-SEC-33

[Ex.4, p.30] With respect to affiliate allocations, please explain the decrease in 2016 and 2017.

Response

EPLC made changes to its affiliate allocations in 2016 and 2017 in order to better align staffing needs and to account for employee retirements and departures over this same time.

In 2016, the Manager of Accounting, which was previously allocated 50%, was dedicated to EPLC in order to address a recent retirement and departure. Further, the Manager of Technology and Corporate Services, previously allocated at 20%, was fully dedicated to EPLC in order to begin addressing Cyber Security.

An IT Administrator, which was previously allocated 80% to EPLC, was fully allocated as an EPLC employee in 2017 in order to address Cyber Security readiness. EPLC also reduced the allocation of a separate IT Administrator by 0.2 to offset this increase. Further, a corporate procurement & financial analyst, which was previously allocated 75% to EPLC in 2016, was dedicated in 2017.

Figure 1 – EPLC Allocations from EPC

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**

Figure 2 below shows the EPLC FTE count, adjusted for EPC allocations. Figure 2 also demonstrates that it is EPLC's priority to maintain a consistent FTE count, year over year.

Figure 2 – EPLC FTEs – Adjusted for 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	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**

Exhibit 4: 4-SEC-34

[Ex.4, p.30] Please explain the significant increase in 2016 (10.53%) and 2017 (5.73%) in total management salaries and wages per employee.

Response

The increase in 2016 and 2017 management salaries and wages per employee are largely due to an increase of dedicated EPLC staff resulting from a decrease in corporate allocations. For further information, please see EPLC response to 4-SEC-33.

Exhibit 4: 4-SEC-35

[Ex.4, p.30] The Applicant states: "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." Please provide details regarding the labour dispute and explain what the Applicant means by it has re-structured its staffing requirements to operate more efficiently.

Response

EPLC had a labour dispute lasting approximately 3 months in 2011. Through this labour dispute, EPLC management and non-management employees were able to effectively and professionally resolve their differences and come to a mutually agreeable new contract that was positive for both sides. Given the length of the labour dispute, EPLC management took deeper, more detailed reviews of various operational items and implemented various improvements to its operations department and entire regulated operations. The learnings from this event largely related to EPLC's current decision to move away from two superintendents, re-structure its inventory/stores, move to improve our overall health & safety policies and procedures and streamline the Corporate Procurement & Financial Analyst position to enhance workflow through the operations department.

Exhibit 4: 4-SEC-36

[Ex.4, p.39] Please provide a copy of any shared service agreements between the Applicant and its affiliates.

Response

The Shared Service Agreement between EPLC and Essex Power Services Corporation is included as Attachment 1-T.

Exhibit 4: 4-SEC-37

[Ex.4, p.46] Please revise Figure 28 to include 2017 actual information.

Response

Please refer to the revised Figure 28 below which includes 2017 preliminary information.

Vendor	Product/Service	Method of Selection	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Prelim
1307749 ONTARIO LTD.	Tree Trimming	Quote	$ 285,412	$ 601,856	$ 517,789	$ 506,965	$ 493,452	$ 537,662	$ 365,246
AFI INTERNATIONAL GROUP INC.	Security	Quote	$ 61,140	$ -	$ -	$ -	$ -	$ -	
ANIXTER CANADA INC.	Inventory	Quote	$ 117,481	$ 221,459	$ -	$ 367,727	$ 414,090	$ -	$ 592,195
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	$ 382,753
CANADIAN ELECTRICAL SERVICES	Transformers	Quote	$ 199,185	$ 432,706	$ 666,389	$ 438,726	$ 358,329	$ 313,269	$ 294,592
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	$ 566,795
G&W CANADA	Inventory	Quote	$ -	$ -	$ -	$ -	$ 144,866	$ 148,160	$ 155,177
GREEN SHIELD	Employee Benefits	Quote	$ 112,613	$ 172,374	$ 122,809	$ 110,968	$ 150,483	$ 171,383	$ 203,384
G-TEL	Locate Services	Quote	$ 214,120	$ 239,463	$ 235,192	$ 321,620	$ 430,339	$ 232,500	$ 297,844
J FORTIER & SON EXCAVAT.	Construction Services	Quote	$ 78,886	$ 152,652	$ 130,688	$ 129,469	$ 167,418	$ 211,840	$ 212,128
KEN LAPAIN & SONS LTD.	Vehicle Repairs	Quote	$ 161,619	$ 121,384	$ 102,078	$ -	$ 110,035	$ 67,366	$ 65,261
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	$ 115,916
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	$ 111,449
POSI PLUS TECHNOLOGIES INC	Vehicles	Quote	$ 290,527	$ 251,785		$ 325,835			
PRICEWATERHOUSECOOPERS LLP	Accounting Services	Quote	$ -	$ -	$ 99,101	$ -	$ -	$ 83,514	
REAUME CHEVROLET	Vehicles	Quote							$ 213,460
STELLA JONES INC (DBA-GUELPH UTILILITY POLE)	Poles	Quote	$ 62,965	$ 111,519	$ 84,570	$ 92,029	$ 96,145	$ 81,670	$ 95,705
THE MEARIE GROUP	Insurance, Employee Benefits	Sole Source	$ 205,492	$ 250,871	$ 252,794	$ 200,672	$ 160,034	$ 158,797	$ 137,880
THOMAS & BETTS LIMITED	Inventory	Quote	$ 174,111	$ 419,903	$ 287,985	$ -	$ 178,241	$ 116,983	$ 365,473

Exhibit 4: 4-VECC-35

Reference:

a) Please update Appendix 2-JA and 2-JC to show 2017 (unaudited) actuals)

Response

Please refer to revised Appendices 2-JA and 2-JC which now show 2017 (unaudited and preliminary) actuals as Attachment 1-J.

Exhibit 4: 4-VECC-36

Reference: Exhibit 4, page 8 / Exhibit 1, Attachment 1-D, Green Energy Plan, page 16

a) Essex has included $186,000 for 3rd party control room support. Please describe the nature of these costs (e.g. labour, facilities etc.).

b) Who is the 3rd party being referred to?

c) Please explain how these costs relate to the proposed booking of $102,917 in OM&A costs for smart grid OM&A deferral account

Response

a) These costs reflect the ongoing, year over year cost of engaging 3rd party control room industry experts. The services are proposed to be offsite and would solely use 3rd party labour. The expense identified is considered to be an "all-in" expense. The Control Room 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.

b) The 3rd party has yet to be determined.

c) These costs do not relate to the proposed booking of $102,917 in OM&A costs for smart grid OM&A deferral account.

Exhibit 4: 4-VECC-37

Reference: Exhibit 4, page 9/page 16

a) Please explain how the $286,463 in incremental cyber security costs was estimated.

b) Please identify which of these costs are one-time in nature and which costs will be ongoing.

c) Please confirm (or clarify) that all the cyber security costs are captured in the category of "Audit, Legal and Consulting" in Appendix 2-JC (Figure 7 Section 4.3.1). If this is incorrect please clarify where these costs are shown in that exhibit.

Response

a) Please refer to EPLC response to 4-SEC-30.

b) These costs are planned to be ongoing costs to assist with Cybersecurity compliance using 3rd party support.

c) Confirmed.

Exhibit 4: 4-VECC-38

Reference: Exhibit 4, page 14

a) Essex explains that the loss of a water billing customer increased net costs. Please confirm that in comparing 2010 OM&A costs to 2018 this would not make a difference since the gross costs are comparable (that is, other revenues have decreased).

b) Please explain why Essex only spends an average one half of the amount for community relations of $22.5k the Board approved in 2010 and now requires an increased amount.

Response

a) Confirmed.

b) The increase is related to anticipated LEAP funding adjustments, ESA and customer satisfaction surveys along with forecasted increases to overall community relations spending.

Exhibit 4: 4-VECC-39

Reference: Exhibit 4, page 46

a) Please provide the fees paid to the EDA for each of the years 2010 through 2018 (forecast)

Response

The following table provides the fees paid to the EDA for each of the years 2010 through 2018 (forecast):

Description	2010	2011	2012	2013	2014	2015	2016	2017	2018
EDA Membership Fees	$ 38,800	$ 40,000	$ 42,200	$ 44,300	$ 46,200	$ 47,800	$ 48,300	$ 48,800	$ 49,800

Exhibit 4: 4-VECC-40

Reference: Exhibit 4, page 20

a) With respect to the increase in General Building expenses of $101k as compared to 2018 please explain why consolidating locations led to an increase in costs. Specifically explain the increase in the Tecumseh service station costs and whether this is an annual reoccurring increase.

Response

a) The increased costs related to General Building expenses have increased primarily as a result of known costs that would have had to be spend regardless of the consolidation of office space with the Essex Civic Centre. There were various upkeep and related expenses required to upgrade the Tecumseh/Oldcastle service station to accommodate the increased staff and the ongoing maintenance to the overall facility has increased as a result. Some of these costs include increased utilities, maintenance of incremental parking, ongoing upkeep of additional office space and increased costs relating to aging infrastructure.

Exhibit 4: 4-VECC-41

Reference: Exhibit 4, page 20

a) Please provide a breakdown of the office and supplies costs increase (2010-2018) of $209k as between the increase for software & IT and other non-IT related costs.

Response

A breakdown of the office and supplies costs between 2010 and 2018 Test Year is provided below:

Description		2010	2011	2012	2013	2014	2015	2016	2017	2018
Office Supplies Expense	IT Related	$ 179,342	$ 219,828	$ 207,337	$ 228,008	$ 224,322	$ 235,187	$ 223,500	$ 56,758	$ 254,801
	Non-IT Related	$ 154,457	$ 148,762	$ 164,345	$ 168,377	$ 177,711	$ 207,953	$ 179,058	$ 182,679	$ 223,896
	Total	$ 333,799	$ 368,589	$ 371,682	$ 396,385	$ 402,033	$ 443,140	$ 402,558	$ 239,436	$ 478,697

Exhibit 4: 4-VECC-42

Reference: Exhibit 4, page 14

a) Please provide all third-party consulting costs in each year 2010 through 2018. Please identify separately any consulting costs above Essex's materiality threshold (66k).

Response

Please refer to the table below which outlines all third-party consulting costs in each year 2010 through 2018. Note that EPLC did not have any consulting costs above EPLC's materiality threshold.

Year	2010	2011	2012	2013	2014	2015	2016	2017	Total
3rd Party Consulting Costs	$ 45,816	$ 54,187	$ 53,481	$ 69,016	$ 91,550	$ 88,010	$ 79,745	$ 115,800	$ 597,606

Exhibit 4: 4-VECC-43

Reference: Exhibit 4, page 30

a) There is a significant variance between the 2010 Board approved FTEs (57) and the subsequent actuals (between 44 and 53 FTEs). Please provide a table which shows by job category/classification the positions sought for funding in 2010 and, in accompanying columns the actual positions employed in 2016, 2017 and 2018. (The purpose of the table is to be able to compare job categories and fills – i.e. lineman- in 2010 and the listed 3 years).

b) Please provide an explanation as to the nature of the labour dispute in 2011 and its impact on staffing and labour costs at Essex.

c) In 2010 the Board approved rates supported an average cost per FTE of $86,820 ($4,948,729/57). In 2018 the equivalent figure is $107,432 ($4,941,897/46). This nearly 24% increase in total compensation per employee is double inflation for the equivalent period. Please explain what productivity offsetting Essex has undertaken to justify this increase this large increase in average salaries.

Response

a) Please refer to the table below which demonstrates the number of FTEs by category:

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**

b) Please refer to EPLC's response to 4-SEC-35.

c) Consistent with Exhibit 4, Attachment 4-G, EPLC's actual total compensation to staff from 2010 BAP to 2018 Test Year has actually decreased slightly ($6,832) and EPLC has also decreased the total number of FTEs employed by 11.3 through retirements and attrition over an 8 year horizon. EPLC has been actively optimizing the deployment of its staff in efforts to manage costs. The average salary cost per FTE has increased as EPLC is now employing staff

with increased workloads, responsibilities, scope and requiring a more diverse skillset given the significant reduction in staff. Another driver of cost is the result of revised collective bargaining agreements.

Exhibit 4: 4-VECC-44

Reference: Exhibit 4, page 43-

a) Please provide the water billing agreement(s) with the parties that Essex serves.

b) What was the per-bill rate in 2010 and what is it in 2018?

Response

a) Please refer to Attachment 1-U for water billing agreements with the parties that EPLC serves. Please note that market sensitive fees have been redacted.

b) Please see the table below summarizing the total cost per bill in 2010 and 2018 (forecasted).

Review of Cost per Bill - 2010 and 2018	2010	2018 (forecasted)
Revenues Received	907,509.25	765,456.00
Bills Issued	358,272	252,840
Cost per Bill	2.53	3.03

Exhibit 4: 4-VECC-45

Reference: Exhibit 4, page 43

a) Please confirm that the $914,911 in CDM costs noted as a service from EEC is not included in the 2018 Revenue Requirement of EPLC.

b) Please explain why EPLC pays $71,497 for maintenance of streetlights to EPS. Are these streetlights owned by EPLC or the municipality/townships?

c) What engineering support services does EEC provide EPLC ($90,817 in 2018)?

Response

a) Confirmed.

b) This $71,497 relates to EPS staff that charges time to manage streetlight repairs, replacements and inquiries. The streetlights are owned by local municipalities and other private owners.

c) Engineering support services include distribution system modelling, distribution system engineering, connection impact assessments, software engineering and various other engineering work, as required.

Exhibit 4: 4-VECC-46

Reference: Exhibit 4, page 47

a) Please explain why in Figure 29 the Applications costs for 2018 are listed as $35,000, whereas in Figure 30 below the amortized costs is listed as $39,386?

b) Please reconcile the regulatory costs shown in Figures 29/30 with the amounts shown for 2018 Regulatory Affairs of $393,533 in Figure 7 (Section 4.3.1, page 16)

c) Please update Figure 30 to show actual costs spent to date on this application.

Response

a) Figure 29 shows that forecasted intervenor costs specific to this application are $35,000. The gross costs for this application as shown in Figure 30 are amortized over five years. The annualized value of amortized costs is $39,386.23. Please refer to Chapter 2 appendices schedule 2-M, where the forecasted one-time costs incurred in the test year related to the application ($95,000) are removed and the annualized amortized portion is included.

b) Please refer to the Chapter 2 Appendices Schedule 2-M for this reconciliation.

c) Please see Figure 30 below which has been updated to include 2017 preliminary results.

Regulatory Cost Category	Historical Year(s)	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	$ 43,544	$ 101,931	$ 10,000	$ 155,476	$ 31,095
Incremental operating expenses associated with staff resources allocated to this application.	$ 36,961			$ 36,961	$ 7,392
Incremental operating expenses associated with other resources allocated to this application. 1	$ 2,191			$ 2,191	$ 438
Intervenor costs			$ 35,000	$ 35,000	$ 7,000
Total	**$ 82,697**	**$ 101,931**	**$ 85,000**	**$ 279,628**	**$ 55,926**

Exhibit 4: 4-VECC-47

Reference: Exhibit 4, page 75

a) Please provide the actual PILs paid in each year 2010 through 2017 (estimate).

Response

Please refer to the table below for actual PILs paid in each year 2010 through 2017 (estimate).

2010	2011	2012	2013	2014	2015	2016	2017
$ 300,056	$ 901,838	$ 328,331	$ 648,727	$ 352,156	$ 447,265	$ 543,908	$ 360,000

Exhibit 4: 4-VECC-48

Reference: Exhibit 4, page 79 and Attachment P
LRAMVA Work Form

a) At page 79 Essex states that it is seeking recovery from conservation & demand management activities for years 2013, 2014 and 2015. However, the LRAMVA Work Form also includes lost revenues in 2016 from 2011-2016 program activities. Please clarify and confirm the years for which Essex is seeking recovery of lost revenues and the program years impacts it is seeking recovery for in each of these years. If necessary, please provide a revised LRAMVA Work Form.

b) At page 79 Essex states that Attachment P provides the IESO verified results supporting its LRAMVA claim. However, Attachment P only provides verified results for 2011 and 2012 CDM programs. Please provide the IESO reports that document the verified results from 2011-2016 programs with persisting impacts through to 2016.

Response

a) EPLC is seeking recovery for program activities from 2011-2016.

b) The persistence reports for 2011-2016 are included as Attachment 1-O.

Exhibit 4: 4-VECC-49

Reference: Exhibit 4, page 80
Exhibit 9, page 36

a) At Exhibit 4, page 80 Essex states that it is seeking recovery of the LRAMVA balance over one year. However, in Exhibit 9, page Essex indicates it is seeking recovery over a two year period. Please clarify the proposed recovery period.

Response

EPLC is proposing to recover the LRAMVA balance over a two year period.

Exhibit 5: 5-Staff-74

Debt Instruments

Ref: Attachment 5-C Debt Instruments

Essex Powerlines stated it is currently renegotiating the two municipal loans.

a) Please provide an update on the status of the renegotiation.

Response

a) EPLC has successfully renegotiated lower municipal loans in both cases. Please review Attachment 1-V for a copy of both new draft agreements. Please note that EPLC is in the process of having the attached agreements executed.

Exhibit 5: 5-SEC-38

[Ex.5, Attach 5-C, p.2] The Applicant has a debt instrument from TD Bank that has a principle of $2,784,658 at a rate of 5.03% and will be due in November 2018. What are the Applicant's plans with respect to replacing that debt instrument in November 2018, and what is the forecast interest rate for that replacement?

Response

EPLC is planning on borrowing from TD Bank in the amount of approximately $3.0M. EPLC's forecasted interest rate is 4.0% with a 10 year term.

Exhibit 5: 5-SEC-39

[EB-2014-0072 Decision and Order, June 9 2015, p.15-16] In its EB-2014-0072 Decision and Order, the Board sated:

The OEB is very concerned with the apparent risks assumed by Essex Powerlines in structuring its debt arrangements and the subsequent, thin margin of risk it can absorb. Even normal business risks associated with changes in weather and customer demand could represent a high risk to Essex Powerlines and expose it to risk of default.
…..
As a result, consistent with the OEB's statutory objective, the OEB recommends that at its next cost of service application, Essex Powerlines file sufficient information to enable the OEB to fully review the inherent risks of its financing arrangements.

a. Please provide such evidence to address the concerns of intervenors and the Board in the EB-2014-0072 proceeding.

b. What is the largest annual loss (in dollars and return on equity) that the Applicant can handle without it being in a risk of default under any of its debt agreements? Please include citations to specific provisions of its debt instruments.

Response

a) Please refer to EPLC response to 1-Staff-10.

b) Please refer to EPLC response to 1-Staff-10.

Exhibit 5: 5-SEC-40

[Ex.5, Attach 5-C] Please provide a copies of the Applicant's current debt instruments not already included in the application.

Response

Please refer to the attached debt instruments not already included in the application as Attachment 1-J.

Exhibit 5: 5-VECC-50

Reference: E5

a) Please update Appendix 2-OA for the Board's updated cost of capital parameters (November 23, 2017).

Response

Please refer to Attachment 1-J which includes revisions to Appendix 2-OA for the Board's updated cost of capital parameters.

Exhibit 5: 5-VECC-51

a) Please update Appendix 2-OB for the Board November 23, 2017 affiliated debt long-term rates (or lesser of the negotiated rate).

b) Please explain why both line 5 and line 10 showing the original and the replacement BA swap loan as a cost in the 2018 Appendix 2-OB .

c) For the 2018 table please explain why in lines 11 and 12 the noted loan amounts ($5.15m and $2.40m respectively) are different than the associated principle amounts ($4.957m and $1.98 million respectively).

Response

a) An updated Appendix 2-OB has been included as Attachment 1-J.

b) Year 2017 table line 5 represents the BA swap due on November 4, 2018 and is unrelated to EPLC's originally estimated July 1, 2017 $5.15M new borrowing on Line 10. The 2017 table has been updated with more current information to demonstrate that EPLC only borrowed an additional $3.0M in year 2017 for new capital purposes.

c) EPLC has updated the table for year 2018 has now been updated with more current information. Please refer to EPLC response to 5-VECC-52 b) for more information on the change.

Exhibit 5: 5-VECC-52

a) Please confirm that the July 1, 2017 loan for 5.15 was executed at the rate of 2.91%.

b) Please update the status of the anticipated July 1, 2018 loan for $2.4 million. Has a loan agreement been negotiated for this principle?

Response

a) This is not confirmed. On August 18, 2017, EPLC borrowed $3,000,000 at 3.18% on a 10 year term, amortized over 20 years.

b) Precise timing is not known at this time for the proposed 2018 borrowing. EPLC has budgeted to borrow an additional new $3,000,000 sometime in 2018. The TD bank has agreed to fund this in principle but no terms have been negotiated at this time. Consistent with EPLC's response to 5-SEC-38, EPLC plans to refinance $3.0M of the expiring $3.3M.

Exhibit 5: 5-VECC-53

a) Please provide Essex's actual and deemed return of equity for the years 2010 through 2017 (unaudited).

Response

Please refer to EPLC response to 1-Staff-4.

Exhibit 7: 7-Staff-75

Weighing Factors

Ref: Exhibit 7 – Cost Allocation - Weighing Factors – Figure 3

Ref: Exhibit 7 – Cost Allocation - Weighing Factors – Figure 4

Essex Powerlines stated that the weighting for each class was based on assessment of work required to support each respective class in relation to the Residential Class

a) Please explain on what basis the assessment was made for each rate class.

b) Was the weighting calculated on a qualitative or quantitative basis? Please provide the metrics from either method.

Response

a) Please refer to Exhibit 7, Section 7.3.6 for EPLC's assessment of weighing factors for each rate class.

b) The Streetlight, Sentinel Light and USL customer classes were largely assessed based on a qualitative assessment by EPLC through discussion with various staff members in relation to the cost of servicing and billing/collecting residential accounts. For GS<50, GS>50 and Embedded Distributor customer classes, a more quantitative approach was taken as EPLC commits substantially more resources to service these customers. Major considerations that EPLC considered included number of site visits, customer calls, complexity of challenges presented by these customer classes, order of magnitude of potential errors and service quality needs.

Exhibit 7: 7-Staff-76

Bad Debt

Ref: EPLC Cost Allocation 20170828 – I6.2 Customer Data

Ref: EPLC Chp2Appendice 20170828 – App.2 – JC OMA Programs

Essex Powerlines provided the total bad debt between 2014-2016 in both tables in the above reference.

a) Please reconcile the total bad debt for each of these years.

Response

a) The remaining differences represent timing differences year over year as write-offs are completed in the following fiscal year. A monthly provision for bad debts is recorded and true-up in the following year based on actual write-offs recognized.

	2014	2015	2016	Total
Bad Debts per Appendix 2-JC	136,108	190,315	150,478	476,901
Bad Debts per I6.2 Customer Data	143,700	164,888	183,840	492,428
Difference	-7,592	25,427	-33,362	-15,527
DRIC write-offs included in I6.2	6,487.52	6,624.79	3,907.93	17,020.24
Remaining Difference	**-1,104.48**	**32,051.79**	**-29,454.07**	**1,493.24**

Exhibit 7: 7-Staff-77

Co-Incident Peak

Ref: EPLC Cost Allocation 20170828 – I8 Demand Data

Essex Powerlines provided four co-incident peak (4CP) for the embedded distributor rate class. It also provided the single co-incident peak (1CP) for the embedded distributor rate class.

a) Please explain how the 4CP value is larger than four times 1CP.

Response

a) The demand data was derived using 2016 hourly loads. The coincident peak in 2016 occurred in July and is driven by high consumption by the Residential and General Service classes. The Embedded load wasn't particularly high at that time, though it was during the June and August monthly coincident peaks. Though it is generally expected that the 4CP value is lower than four times the 1CP this isn't necessarily the case for each rate class, especially smaller rate classes such as the Embedded class.

Exhibit 7: 7-Staff-78

Direct Allocation

Ref: EPLC Cost Allocation 20170828 – I9 Direct Allocation

Essex Powerlines allocated $86k to the Embedded Distributor rate class for the cost of settlement as well as regulatory and senior management review.

a) Please explain what incremental work is required to bill Hydro One.

Response

Given the magnitude of Hydro One's Embedded Load in EPLC's distribution system and the complexity of its setup, EPLC requires substantial monthly review across most of its operation to ensure that Hydro One settlement is completed correctly and accurately.

One such example of a monthly complex settlement is on the 24M7 out of Windsor Malden TS. Hydro One has embedded load downstream of EPLC's wholesale meter between the LaSalle and Amherstburg (previously outside of Amherstburg as well creating a situation where HONI was embedded several times on the same circuit). Also embedded between Amhersburg and LaSalle is significant wind generators connected to Hydro One's distribution system. EPLC does not have access to the meters of these wind assets (as they are HONI customers) however this generation is significant enough that at times, can overtake the load of the entire feeder and backfeed through the IESO wholesale wholesale metering point and inject into the IESO controlled grid. EPLC is forced to complete detailed settlement at every 5 minute internal to determine if these generators are backfeeding into the IESO controlled grid for settlement purposes.

Exhibit 7: 7-SEC-41

[Ex.7, p.9-10] Please explain in detail how it determined the service and billing & collecting weighting factors.

Response

Please refer to EPLC response to 1-Staff-75.

Exhibit 7: 7-VECC-54

Reference: Exhibit 7, page 5 (Section 7.2.4)

a) What changes did Essex make 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?

Response

a) EPLC removed Hydro One embedded load for all connection points where Hydro One owned distribution assets in Sheet I8, (Demand Data), within the Board's Cost Allocation Tool. Co-incident and non-co-incident peaks were modified to reflect this change. This change was determined through ongoing discussions with Hydro One representatives in order to avoid the tool's allocation of EPLC distribution assets to the Embedded Distributor class given Hydro One's ownership of the majority of the distribution assets in question.

Exhibit 7: 7-VECC-55

Reference: Exhibit 7, page 8 (Section 7.3.4)
Cost Allocation Model, Tab I4 – BO Assets

a) Please explain how 30% of underground conductor can be at secondary voltages when 100% of the underground conduit is at primary voltages.

Response

a) EPLC has direct buried secondary cable that is not in conduit. All primary cable is in conduit.

Exhibit 7: 7-VECC-56

Reference: Exhibit 7, pages 9-10 (Section 7.3.6)

a) Please provide the supporting analysis setting out the derivation of the weighting factors for: i) Services and ii) Billing and Collecting.

Response

Please refer to EPLC response to 1-Staff-75.

Exhibit 7: 7-VECC-57

Reference: Exhibit 7, page 13 (Section 7.3.11)
Exhibit 7, Attachment 7-C
Cost Allocation Model, Tab I8 (Demand Data)

a) It is noted that Tab I8 indicates that the 4CP and 4NCP allocators are to be used for Essex's cost allocation. However, Tab I8 does not include any 4CP values for Street Light or Sentinel Light.

i. Is the 4CP allocator used at all in the cost allocation model for allocating costs?
ii. If so, please indicate what costs are allocated based on 4CP and how the lack of a value for these two customer classes impacts the allocation.

b) With respect to Tab I8, please explain how the 4CP value for embedded distributor can be more than 4 times the 1CP value.

c) It is noted that, per Tab I6.1, a portion of the GS>50 load receives the transformer ownership discount. Please explain why the GS>50 4NCP values for Primary, Line Transformer and Secondary are all the same.

Response

a) Please note that the 4CP values for the Street Light and Sentinel Light classes is zero because the 4 highest monthly coincident peaks occur during the daytime in the months of June to September when street lights and sentinel lights are not on.

i. Yes, the 4CP allocator is used to allocate one asset item.

ii. The Land Station<50 kV asset is allocated by 4CP. As a result, net fixed asset allocators (NFA and NFA ECC) are marginally lower for the Street Light and Sentinel Light classes and slightly higher for the remaining classes. Interest, net income, and property insurance are allocated by the net fixed asset allocator. This asset is 0.07% of net fixed assets so the impact is negligible.

b) See response to 7-Staff-77.

c) The 4NCP values should be lower for the Line Transformer and Secondary NCPs. The revised cost allocation model includes revised NCP figures for the GS > 50 kW class. Actual demand from the specific GS > 50 kW customers that receive the transformer ownership discount has been backed out from total GS > 50 kW demand to determine the revised LTNCPs and SNCPs.

Exhibit 7: 7-VECC-58

Reference: Exhibit 7, page 13 (Section 7.3.11)
Exhibit 7, Attachment 7-C
Load Forecast Model, GS>50 OLS Model Tab

a) According to Attachment 7-C the 2016 actual load profile for the GS>50 class was adjusted to account for changes in relative loads from 2016 to 2018. It is also noted that, based on the load forecast model, the GS>50 load is weather sensitive. Was the 2016 actual load profile for GS>50 weather normalized prior to using it to estimate the 2018 GS>50 load profile? If yes, how was this done?

Response

a) The 2016 GS>50 kW load profile was not weather normalized.

Exhibit 7: 7-VECC-59

Reference: Exhibit 7, page 13 (Section 7.3.11)
Exhibit 7, Attachment 7-C

a) How were the 2018 load profiles for the Street Light, Sentinel Light and USL classes determined?

b) If not based on the load profiles used in the Cost Allocation prepared for Essex's 2010 Rate Application, please calculate the CP and NCP values for these classes by scaling the load profiles used in that Application to match the 2018 load forecast and compare with the values used in the Tab I8 of the current Application.

Response

a) The Street Light, Sentinel Light, and USL load profiles were determined by the same method as the GS > 50 kW and Embedded Distributor classes. The 2016 London hourly loads of each class were scaled to Essex's 2018 load forecast.

b) The 2010 load profiles scaled to the 2018 load forecast is presented below.

	Scaled from 2010		
	Street Light	Sentinel	USL
1CP	-	-	207
4CP	-	-	830
12CP	2,873	315	2,480
1NCP	771	137	221
4NCP	3,076	509	866
12NCP	9,201	1,247	2,492

	Current Application		
	Street Light	Sentinel	USL
1CP	-	-	178
4CP	-	-	711
12CP	3,363	349	2,125
1NCP	713	117	189
4NCP	2,846	434	731
12NCP	8,513	1,059	2,125

Exhibit 7: 7-VECC-60

Reference: Exhibit 7, page 13 (Section 7.3.11)
Exhibit 7, Attachment 7-C

a) Has the methodology that Essex has employed to determine the weather normalized load profiles for the Residential and GS<50 been used elsewhere? If so, please provide the references.

b) VECC is finding it difficult to understand how the methodology works and why it produces "weather normalized: load profiles for Essex's Residential and GS<50 customer classes. Is there a more comprehensive description of the methodology available that could be provided?

c) How does the weather normalization process for Residential and GS<50 account for the fact that the Essex and London customer classes may have different sensitivities to weather due to different penetrations of electric space heating and electric space cooling?

d) Please re-do the Cost Allocation using the same load profiles for GS>50 and the Embedded Distributor classes but for all other classes use the load profile from the 2010 Rate Application adjusted to match the change in kWh between 2010 and 2018.

Response

a) The methodology used to determine weather normalized load profiles has also been used by Erie Thames. There are not many other examples as this methodology was developed to meet the Board's more recent requirement for LDCs to use updated weather normalized load profiles.

b) This response was produced to provide a more detailed description of the methodology.

First, daily London and Windsor weather data from 2007 to 2016 is collected. The days within each month are then ranked from 1 to 28-31 (depending on the month) from highest HDD to lowest HDD. Days are ranked again for CDD.

The average HDD for each ranked day for each month is determined for Windsor. For example, the HDD of the number 1 ranked HDD days in January of each year are averaged. In other words, the HDD of the coldest day in Windsor in January 2007, the coldest day in January 2008, etc. are averaged to determine the average coldest day in Windsor in January. This process is repeated for the 2nd ranked HDD day (second coldest day) of each January, the 3rd ranked HDD

day, and so on for each day of each month. The process is repeated for CDD. The process allows for the consideration of multiple years of data while maintaining weather peaks.

The average Windsor HDD and CDD as determined above are then assigned to the corresponding ranked day in London in 2016. Using the same January example, the HDD of the average coldest day in January in Windsor is assigned to the actual coldest day in London in January 2016. The difference between the average ranked Windsor HDD and actual 2016 ranked London HDD are then determined. The same is done for CDD.

Separately, OLS regressions are run for each of the residential and GS < 50 kW rate classes. The dependent variable is hourly load and there are three sets of independent variables: HDD in each hour, CDD in each hour, and a dummy variable for each hour. Additionally, there is a trend variable. The regression results show the impact of HDD and CDD in each hour of the day. The set of hour dummy variables captures the typical change in consumption throughout the day that is not influenced by weather.

For each hour in 2016, the difference between average ranked Windsor HDD (or CDD) and actual London HDD (or CDD) as described earlier is multiplied by the applicable coefficient determined in the OLS regression. For example, The HDD difference for the first hour of the coldest day in January is multiplied by the HDD Hour 1 coefficient, the CDD difference in that hour is multiplied by the CDD Hour 1 coefficient (which would be 0 in this example), and the trend figure is multiplied by the trend coefficient. The sum of the resulting values represents the adjustment to normalize London's hourly load in 2016 to typical Windsor weather. The sum is added to actual consumption in that hour of 2016 to determine the weather normalized consumption in that hour. This process is done for both the residential and GS < 50 kW classes.

The sum of the weather normalized consumption in each hour of 2016 is compared with Essex's 2018 load forecast to determine a load forecast adjustment factor. The adjustment factor is then applied to the weather normalized consumption in each hour. The resulting loads in each hour make up the weather-normalized load profile.

c) The weather normalization process does not consider these differences.

d) An updated Cost Allocation Model (Attachment 1-W) with alternate demand allocators is provided in an attachment to this response. For the purposes of this response, demand data of the previous Intermediate class has been merged with the GS>50 kW class. The Embedded Distributor class' demand data has not been changed.

Exhibit 7: 7-VECC-61

Reference: Exhibit 7, page 15

a) Please explain why the revenue to cost ratio for the Residential class was the only one increased in order to restore revenue neutrality when the status quo ratio of the GS>50 class is less than the status quo ratio for the Residential class.

b) What would be the resulting revenue to cost ratio for the Residential and GS>50 classes if revenue neutrality was maintained by increasing the ratios for both classes to same common value?

Response

a) The revenue to cost ratio for Residential was adjusted by a fraction of a percentage in order to restore revenue neutrality. Given that the required adjustment was small, EPLC allocated the adjustment to the largest portion of its rate base without affecting other rate classes.

b) The resulting revenue to cost ratio if revenue neutrality was maintained by increasing the ratios for both classes to the same common value:

	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%	96.52%	96.93%	85 - 115
2	General Service < 50 kW	49.56%	118.58%	118.58%	80 - 120
3	General Service > 50 kW	159.99%	96.07%	98.39%	80 - 120
4	Intermediate Use	336.93%	N/A	N/A	80 - 120
5	Street Lights	32.36%	112.62%	112.62%	80 - 120
6	Unmetered Scattered Load	132.66%	129.61%	120.00%	80 - 120
7	Sentinel Lights	38.09%	126.14%	120.00%	80 - 120
8	Embedded Distributor	N/A	193.59%	120.00%	80 - 120

Exhibit 8: 8-Staff-79

Loss Adjustment Factors

Ref: EPLC Chp2Appendice 20170828 – App.2-R Loss Factors

Essex Powerlines stated that it has realized significant reductions in distribution losses as a result of the Voltage Conversion Program.

a) Please explain why the 2012 distribution loss factor was lower than all the other historical years.

b) Please explain why the distribution loss factor appears to be trending upwards when Essex Powerlines stated that voltage conversion is supposed to reduce losses.

Response

a) The 2012 distribution loss factor was lower than all the other historical years largely as a result of a 23% increase in embedded generation kWhs.

b) EPLC's current Board-Approved secondary loss factor is 1.0602. EPLC is currently seeking to reduce it's loss factor to 1.0355 which represents significant savings to all EPLC electricity customers. While the loss factor can fluctuate nominally, year over year as a result of a variety of issues (in EPLC's case, closure of its largest Intermediate Load, some of the highest penetration of embedded generation in the province, etc.) the voltage conversion work that EPLC has completed over the course of the last several years has resulted in meaningful reductions to EPLC customers bills.

Exhibit 8: 8-VECC-62

Reference: Exhibit 8, page 22

a) How much did Essex pay HONI for Sub-Transmission service in 2017?

Response

The following summarizes EPLC payments to HONI for Sub-Transmission service in 2017.

Network Charges	20-4714-0000-000-00	$3,410,759.03
Connection Charges	20-4716-0000-000-00	$2,306,809.36
LV Charges	20-4750-0780-000-00	$1,701,643.10
Total		**$7,419,211.49**

Exhibit 9: 9-Staff-80

Accounting Audit

Ref: Exhibit 9 - Deferral and Variance – Overview (Page 5)

Essex Powerlines has stated that it has made adjustments to its Group 1 and Group 2 account balances, and that all adjustments, except one, were consistent with the OEB's recent audit findings.

a) Please indicate where these adjustments are shown in the application

b) Please disclose the results of the audit for Group 1 accounts (2015 IRM) and Group 2 accounts (2013 Audit Report).

c) Please explain the adjustment that was not made in accordance with the OEB's audit.
i. Please quantify the impact of the adjustment.

d) In EB-2014-0072, Group 1 balances as at December 31, 2013 was approved on an interim basis. Please indicate if Essex Powerlines is requesting final disposition of the balances.

Response

a) All adjustments are included in EPLC's DVA Continuity Schedule under 2015 Principal Adjustments (2) during 2015 and Interest Adjustments (2) during 2015.

b) Both the 2015 and 2013 Confidential Audit Reports have been successfully closed, with the exception of one item detailed in EPLC's initial application and clarified below, with all matters having been fully resolved and mutually agreed upon by both EPLC and OEB Auditors. The sole item remaining, as detailed in Exhibit 9, Section 9.1, is fully provided below and is the only item from either Audit Report that pertains directly to this Application:

10.1.1 Finding Group 1 DVAs

Essex Powerlines made adjustments to account balances that had previously been approved for disposition on a final basis. These adjustments, made as part of the 2015 IRM proceeding to recover a double refund of $1.8 million from customers, were not explained in a section of the application under a section titled "Adjustments to Deferral and Variance Accounts", and should therefore not be reflected in the reconstructed DVA continuity schedules.[55] Some of the Group 1 DVA balances are misstated. Essex Powerlines disagrees with this finding.

Table 9 below provides a summary of the impact to Essex Powerlines' customers as a result of the finding noted above, for the relevant Group 1 accounts.

		What happened	What should have happened	Difference
		$millions		
2012 IRM	Amount recovered from / (refunded to) all customers	1.5	1.5	0.0
EB-2011-0166	Amount recovered from / (refunded to) non-RPP customers	(3.3)	(3.3)	0.0
Final basis	**Net impact on customers - recovery / (refund)**	**(1.8)**	**(1.8)**	**0.0**
2014 IRM	Amount recovered from / (refunded to) all customers	5.7	4.2	1.5
EB-2013-0128	Amount recovered from / (refunded to) non-RPP customers	(8.8)	(5.5)	(3.3)
Final basis	**Net impact on customers - recovery / (refund)**	**(3.1)**	**(1.3)**	**(1.8)**
2015 IRM	Amount recovered from / (refunded to) all customers	(3.7)	(2.2)	(1.5)
EB-2014-0301 / EB-2014-0072	Amount recovered from / (refunded to) non-RPP customers	4.4	1.1	3.3
Interim basis	**Net impact on customers - recovery / (refund)**	**0.7**	**(1.1)**	**1.8**

Note: Accounts 1590 and 1595 have been excluded from these figures as they were not a factor in the double refund and recovery of $1.8M

"A" - Net refund to customers of $1.8 million as a result of amounts that were disposed on a **final basis** in 2012 IRM.

"B" - Net refund to customers of a duplicate $1.8 million as a result of amounts that were disposed on a **final basis** in 2014 IRM.
The "A" amount was cleared again in 2014 IRM as no journal entry was done in fiscal 2012 to transfer the 2012 IRM OEB approved DVA balances to Account 1595, the "holding account".

"C" - Net recovery from customers as a result of amounts that were disposed on an **interim basis** in 2015 IRM.
Adjustments were made to balances approved on a final basis in the 2014 IRM to "correct" the duplicate $1.8 million refund in "B".

10.1.2 Basis of Finding

As a result of accounting errors and adjustments made by Essex Powerlines in the accounts reviewed and approved for final disposition in the 2014 IRM proceeding, Essex Powerlines refunded a net amount of $1.8 million that had previously been refunded through approved rate riders in the 2012 IRM proceeding. The result was that $1.5 million was recovered twice from all customers and $3.3 million was refunded twice to non-RPP customers, for a net refund to customers twice of $1.8 million. These balances were approved for disposition on a final basis in both the 2012 and 2014 IRM proceedings, resulting in a net overstated refund of $1.8 million.

During the 2015 IRM proceeding, Essex Powerlines applied to recover the net $1.8 million from customers to correct for the double refund. In order to do this, Essex Powerlines made adjustments to account balances that had previously been approved for disposition on a final basis. Audit is of the view that the adjustments to the account balances, including the $1.8 million debit adjustment, should not be reflected in the Group 1 DVA balances as of December 31, 2015. Additional details are set out below.

In its 2012 IRM rate application, Essex Powerlines requested disposition of Group 1 DVA balances as at December 31, 2010[57]. A total credit balance of $3,452,443 was approved for disposition on a final basis. Excluding the balance in Account 1590 and 1595, the approved amount was a $1.5 million debit to be received from all customers and a $3.3 million credit to be refunded to non-RPP customers (for a net credit of $1.8 million).

Essex Powerlines did not transfer its Group 1 DVA balances which were approved for disposition into the applicable principal and carrying charge subaccounts of Account 1595 on a timely basis (generally the date the rate riders are effective or, in this case, May 1, 2012) as set out in the 2012 IRM Decision. Because the disposition amount was not transferred to Account 1595 until December 31, 2014[60], the amounts of $1.5 million to be recovered from all customers and $3.3 million to be refunded to non-RPP customers remained in the Group 1 balances on Essex Powerlines' books of accounts as at December 31, 2012.

Group 1 DVA balances as at December 31, 2012. A total credit balance of $4,592,942 was approved for disposition on a final basis. As noted above, the amount approved included the incorrect amounts. The previously approved amounts had not been transferred. Excluding the balance in Account 1590 and 1595, the amount approved for disposition was a $5.7 million debit to be received from all customers and a $8.8 million credit to be refunded to non-RPP customers. These amounts incorrectly included the $1.5 million debit to be received from all customers and the $3.3 million credit to non-RPP customers (for a net credit of $1.8 million)[63]. As a result, $1.5 million debit was recovered twice from all customers, and $3.3 million credit was refunded twice to non-RPP customers.

As part of the 2014 IRM proceeding, OEB staff noted that the Group 1 balances as of December 31, 2012 as shown on Essex Powerlines' IRM DVA continuity schedule reconciled with the RRR filings submitted by Essex Powerlines. Audit found that Essex Powerlines had achieved this reconciliation by making an adjustment of $1.8 million credit to the net transactions column in the continuity schedule.

As part of its 2015 IRM rate application, Essex Powerlines requested disposition of Group 1 DVA debit balance of $1,522,723 as at December 31, 2013. Excluding the balances in Account 1590 and 1595, the amount requested was a $4.5 million debit to be received from all customers and a $5.7 million credit to be refunded to non-RPP customers.

In its reply submission on January 19, 2015 Essex Powerlines stated:

Essex also realized during its review of all the variance accounts that the Board Approved disposition amounts for 2012 had not been moved to their respective 1595 accounts. The time period for the 2010 and 2012 disposition amounts has concluded and therefore they have been added to the model in their applicable 1595 accounts to ensure the correct amount is used for disposition in 2015, which explains the variance in the RRR vs 2013 balance column.

At the same time, Essex Powerlines submitted a revised rate generator model with changes to the 2015 IRM DVA continuity schedule[70]. Adjustments were made to the revised continuity schedule which impacted the opening principal and interest amounts for Group 1 DVAs as at January 1, 2013. The adjustments made by Essex Powerlines to the opening balances as at January 1, 2013 were equal and offsetting to the amounts approved for disposition on a final basis in the 2012 IRM proceeding, i.e., $1.5 million debit for all customers, $3.3 million credit for non-RPP customers, net $1.8 million credit[72]. As a result, the opening balances as at January 1,

2013 did not match the closing balances as at December 31, 2012 from the 2014 IRM DVA continuity schedule.

Essex Powerlines included a table in its reply submission demonstrating that the amounts "added to the model" resulted in the variance between the RRR filing and the ending balances as at December 31, 2013 on the adjusted 2015 IRM DVA continuity schedule. The Group 1 DVA balances included the adjustments for a refund of $1.5 million credit to all customers and a recovery of $3.3 million debit from non-RPP customers (net recovery of $1.8 million debit). These adjustments were made to rectify the double disposition that occurred in the 2014 IRM proceeding and the balances were subsequently approved for disposition on an interim basis in the 2015 IRM rate application proceeding. As a result, Essex Powerlines has recovered the net $1.8 million debit from its customers.

The OEB issued filing requirements for 2015 rate applications stating its expectation that no adjustments will be made to any DVA balances previously approved by the OEB on a final basis. The filing requirements go on to provide that distributors must make a statement in their application as to whether or not any such adjustments are made. If a distributor reports that any adjustments have taken place, the distributor must provide explanations in its application for the nature and amounts of the adjustments. Supporting documentation must be included under a section titled “Adjustments to Deferral and Variance Accounts”.

Audit is of the view that Essex Powerlines did not fully comply with the filing requirements. Audit is therefore of the view that the adjustments should not be reflected in Essex Powerlines’ DVA balances as of December 31, 2015.

10.1.3 Action Required

Essex Powerlines should bring forward Finding 10.1 in the future 2017 or 2018 rate application proceeding. The application must include Group 1 DVA balances. Essex Powerlines should provide a statement in its application as to whether or not any adjustments were made. If it reports that adjustments have taken place, it must provide a separate section entitled “Adjustments to Deferral and Variance Accounts” in which it provides explanations for the nature and amounts of the adjustments and includes supporting documentation.

To ensure accurate DVA balances going forward, Essex Powerlines’ reconstructed Group 1 DVA continuity schedules should reflect balances that have been approved on a final basis. The January 1, 2013 opening balances should equal the December 31, 2012 closing balances that were approved on a final basis in the 2014 IRM proceeding.

In addition, the reconstructed Group 1 DVA continuity schedules should not include the adjustments made by Essex Powerlines in the 2015 IRM to recover the $1.8 million that had been double refunded to customers. These adjustments consisted of the journal entry made on December 31, 2014 to transfer the 2012 IRM disposition amounts to Account 1595. This journal entry should have been made on May 1, 2012. Therefore, to include this adjustment in 2014

balances would be adjusting balances that had already been disposed on a final basis in a prior proceeding.

10.1.4 Management Response

Essex Powerlines does not agree with this finding. The Audit Finding is based on the position that "Essex Powerlines made adjustments to account balances that had previously been approved for disposition on a final basis." (see 10.1.1). It goes on to note that the Board's 2015 Distribution Rate Filing Requirements provide that "no adjustments will be made to any DVA balances previously approved by the OEB on a final basis" (see 10.1.2). However, the OEB Filing Requirements go on to state that the Board may consider requests for such adjustments and support such requests by evidence (see 2015 Distribution Rate Filing Requirements, s. 3.2.3)(the "DRFR").

That is what happened in this case.

As part of Essex Powerlines' Responses to Board Staff Supplemental Questions (EB-2014-0072, "Essex Powerlines_IRR_continuity schedules_20150407.pdf"), Essex Powerlines' both fully disclosed and clearly articulated the nature of this error as one of three key findings (see Essex Powerlines responses in section 2i and 3).

Board staff commented upon these issues in its Reply Argument.

Given the pass through nature of these market related charges and whereby the intent of Group 1 RSVAs are to keep both the LDC and the customer whole, Essex Powerlines made adjustments, which were fully disclosed and clearly articulated for review by Board staff and approved by the Board in a subsequent rate order, to correct the three key findings and keep customers whole. This approach is consistent with the Board's obligation to hold a hearing on and ultimately fix a just and reasonable rate.

However, Audit seems to be suggesting that Essex Powerlines' disclosure was non-compliant because the information was not "explained in a section of the application under a section titled 'Adjustments to Deferral and Variance Account'" in the DRFR. According to Audit, this is a mandatory requirement of the DRFR, and the consequences to Essex Powerlines of not providing its explanation in that section (as opposed to providing that explanation elsewhere in the record) is that there should be *a $1.8 million loss to the shareholder (and a corresponding $1.8 million windfall to customers)*.

This is an unreasonable position.

First, as indicated, this information was provided in the application process and was known by Board staff and the Board. As a result, if there was an error in the location of this information, it had no impact on the proceeding. Second, the DRFR is a non-binding guideline. As the Board

has stated, “We also issue non-binding guidelines to assist those we regulate in preparing their applications for approvals.” The Board has never suggested that a technical failure to provide information in a particular section of those non-binding guidelines was subject to a massive shareholder punishment as proposed by Audit. In this regard, it is clear, that the Board does not have power to impose sanctions for failure to meet the requirements of a non-binding guideline. Yet that is what Audit is proposing here.

10.1.5 Management Action Plan

No Management Action Plan included due to nature of Management Response above.

c) Please refer to EPLC response to b) above.

d) Confirmed.

Exhibit 9: 9-Staff-81

Cost of Power reconciliation

Ref: Exhibit 9 - Deferral and Variance – 9.2.2 Cost of Power Reconciliation (Page 8)

It is indicated that figure 3 shows the revenues and expenses net to zero. However, for 2010, 2012, 2015, these revenues and expenses do not net to zero.

a) Please explain the differences for each of the years.

Response

a) Please see the revised Cost of Power Reconciliation and variance explanations below.

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)
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	**$ (49,128,678.60)**	**$ (51,143,998.38)**	**$ (52,354,544.57)**	**$ (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	**$ 103,765.83**	**$ -**	**$ (0.02)**	**$ (0.23)**	**$ 0.14**	**$ (26,298.89)**	**$ -**

1) Account 4050 was originally included in this reconciliation and should not have been included as the adjustment amounts contained within that account were not directly related to the cost to purchase power. This account has been removed from the schedule impacting balances for 2010-2012.
2) The remaining variance showing in 2010 relates to an adjusting year-end RSVA entry that was recorded backwards and not corrected.

3) The remaining variance showing in 2015 relates to an adjusting entry made to Account 4705 that was not included in the RSVA journal entry.

Exhibit 9: 9-Staff-82

Deferral and Variance Account

Ref: Exhibit 9 - Deferral and Variance – 9.3 Proposed Disposition (Page 10)

Essex Powerlines is requesting disposition of $166,920 in Account 1518 RCVA Retail. According to Article 490 of the APH:

This variance account is established to record the difference between the amount billed in relation to an STR and the incremental costs of providing the initial screening and actual processing services for the STR.

a) Please provide a description of the costs incurred and in which USoA were they recorded in.

OEB staff notes that Essex Powerlines' 2.1.7 filing for 2016 does not show any amount recorded in Account 4082.

b) Please explain why there are no revenues associated with this variance account. Essex Powerlines is requesting disposition of ($3.5M) net of any timing related adjustments.

c) What do "net of any timing related adjustments" mean?

Response

a) The incremental costs associated with processing services for STR's are recorded in the accounts 5610 Management Salaries and Expenses and 5315 General Administrative Salaries and Expenses. These costs are both related to labour hours spent handling and processing customer retailer requests.

b) EPLC has determined the net difference between the revenues and costs associated with processing services for STR's to be incremental and were not included in the revenue requirement in the 2010 COS therefore the difference has been recorded in the 1518 account monthly.

c) "Net of timing adjustments" is specifically in reference to Account 1576. Please refer to Figure 27 in Exhibit 9 (page 25) for further details.

Exhibit 9: 9-Staff-83

Deferral and Variance Account

Ref: Exhibit 9 - Deferral and Variance – 9.4.8 Account 1588: cost of Power Variance Account (Page 15)

Ref: EPLC_DVAContinuity_20170828 – Tab 2. 2016 Continuity Schedule

Ref: EPLC_DVAContinuity_20170828 – Tab 7.a GA Analysis Workform

Essex Powerlines has stated that it is "currently following the guidance of the Board's May 23, 2017 letter pertaining to the period that is being requested for 1588". Please indicate:

a) Does Essex Powerlines reflect true-up adjustments in the books prior to closing them at year-end?

b) Did Essex Powerlines settle a true-up adjustment related to 2016 consumption with the IESO subsequent to year-end?
i. If yes, please indicate, under which column is the true-up adjustment is shown on the DVA Continuity Schedule and the amount.

c) Did Essex Powerline make an adjustment related to RPP and Non-RPP trueup related to actual proportions for GA costs for 2016 consumption subsequent to year-end?
i. If yes, please indicate under which column is this adjustment shown on the DVA Continuity Schedule, and the amount.

Response

a) EPLC accrued a true-up adjustment with the IESO in 2016.

b) EPLC settled a true-up adjustment with the IESO in 2017 related to 2016.

i) This amount is shown under the activity for 2016 as the amount settled with the IESO was financial accrued in 2016.

c) EPLC accrued a true-up for GA rate and consumption for 2016.

i) This amount is shown under the activity for 2016 as the amount settled with the IESO was financial accrued in 2016.

Exhibit 9: 9-Staff-84

Deferral and Variance Account

Ref: EPLC_DVAContinuity_20170828 – Tab 2. 2016 Continuity Schedule

Ref: EPLC_DVAContinuity_20170828 – Tab 7.a GA Analysis Workform

In booking expense journal entries for Charge Type 1142 (formerly 142), and Charge Type 148 from the IESO invoice, please confirm which of the following approaches is used:

a) Charge Type 1142 is booked into Account 1588. Charge Type 148 is pro-rated based on RPP/non-RPP consumption and then booked into Account 1588 and 1589, respectively.

b) Charge Type 1142 is booked into Account 1588. In relation to Charge Type 148, the non-RPP quantities multiplied by the GA rate is booked to account 1589 and the remainder of Charge Type 148 is booked to account 1588.

c) Charge Type 148 is booked into Account 1589. The portion of Charge Type 1142 equaling RPP-HOEP for RPP consumption is booked into Account 1588. The portion of Charge Type 1142 equaling GA RPP is credited into Account 1589.

d) If another approach is used, please explain in detail

Response

The method used by EPLC to record Charge Type 1142 and Charge Type 148 is not listed in options a-c above. EPLC records Charge Type 1142 and Charge Type 148 as follows:

i) Charge Type 1142 is recorded into account 1588.
ii) Charge Type 148 is recorded into account 1589 in full. A subsequent journal entry is recorded to credit account 1589 and debit account 1588 for the RPP portion of Charge Type 148. The RPP portion of Charge Type 148 is determined by using the kWh consumption used to calculate Charge Type 1142 multiplied by the Global Adjustment second estimate. This calculation is trued-up for both actual kWh consumption and the Global Adjustment final rate

Exhibit 9: 9-Staff-85

Deferral and Variance Account

Ref: EPLC_DVAContinuity_20170828 – Tab 2. 2016 Continuity Schedule

Ref: EPLC_DVAContinuity_20170828 – Tab 7.a GA Analysis Workform

With regards to the amount being requested for disposition of USoA 1589 account balance as at Dec. 31, 2016, all components that flow into Account 1589 (i to iv in table below) should be based on actuals in the DVA Continuity Schedule Tab 2. Please complete the following table to:

a) Indicate whether each of the components are based on estimates or actuals at year end, and

b) Quantify the adjustment amount pertaining to each component that is trueup from estimate to actual.

	Component	Estimate or Actual	Notes/Comments	Quantity True Up Adjustment $ Amount
i	Revenue (i.e. is an unbilled revenue trueup adjustment reflected in the balances being requested for disposition?)			
Ii	Expenses - GA non-RPP: Charge Type 148 with respect to the quantum dollar amount (ie is expense based on IESO invoice at year end)			
Iii	Expenses – GA non-RPP: Charge Type 148 with respect to the RPP/Non-RPP kWh volume proportions			
iv	Credit of GA RPP: Charge Type 142 if the approach under Staff Question 1c is used			

c) Please confirm that the GA Analysis Workform for 2016 and the DVA Continuity Schedule Tab 2 for 2016 have been adjusted for settlement trueups where settlement was originally based on estimate and trued up to actuals subsequent to 2016 per the table above.

Response

a) Please refer to the completed table below:

	Component	Estimate or Actual	Notes/Comments	Quantity True Up Adjustment $ Amount
i	Revenue (i.e. is an unbilled revenue trueup adjustment reflected in the balances being requested for disposition?)	Actual	Unbilled revenue accrued at the end of the year is based on actual billings. The portion of billings related to the prior year are prorated based on days to split usage between the two years.	$0.00
Ii	Expenses - GA non-RPP: Charge Type 148 with respect to the quantum dollar amount (ie is expense based on IESO invoice at year end)	Actual	IESO charges are accrued to actual at the end of the year.	$0.00
Iii	Expenses – GA non-RPP: Charge Type 148 with respect to the RPP/Non-RPP kWh volume proportions	Actual	The split for Charge Type 148 is trued-up subsequent to year end and a year-end accrual entry is recorded. The accrual is based on actual kWh consumption and Global Adjustment rate to determine the RPP and Non-RPP portions. The Non-RPP portion	$0.00

			of CT148 is what remains in account 1589.	
iv	Credit of GA RPP: Charge Type 142 if the approach under Staff Question 1c is used	N/A	N/A	N/A

b) Please refer to EPLC response to a) above.

c) Please refer to the GA Analysis Workform that has been resubmitted as Appendix 1-X.

Exhibit 9: 9-Staff-86

Deferral and Variance Account

Ref: EPLC_DVAContinuity_20170828 – Tab 2. 2016 Continuity Schedule

With regards to the amount being requested for disposition of USoA 1588 account balance as at Dec. 31, 2016, all components that flow into Account 1588 (i to iv in table below) should be all based on actuals at year end. Please complete the following table to:

a) Indicate whether the component is based on estimates or actuals at year end, and

b) Quantify the adjustment pertaining to each component that is trued-up from estimate to actual

	Component	Estimate or Actual	Notes/Comments	Quantity True Up Adjustment $ Amount
i	Revenue (i.e. is an unbilled revenue trueup adjustment reflected in the balances being requested for disposition?)			
Ii	Expenses – Commodity Charge Type 101 (i.e. is expense based on IESO invoice at year end)			
Iii	Expenses – GA RPP: Charge Type 148 with respect to the RPP/Non-RPP kWh volume proportions			
iv	Expenses – GA RPP: Charge Type 148 with respect to the RPP/non-RPP kWh volume proportions.			
v	RPP Settlement: Charge Type 142 including any data used for determining the RPP/HOEP/RPP GA components of the charge type			

c) Please confirm that the DVA Continuity Schedule Tab 2 for 2016 has been adjusted for settlement true-ups where settlement was originally based on estimate and trued up to actuals subsequent to 2016 per the table above.

Response

a) Please refer to the table below:

	Component	Estimate or Actual	Notes/Comments	Quantity True Up Adjustment $ Amount
i	Revenue (i.e. is an unbilled revenue trueup adjustment reflected in the balances being requested for disposition?)	Actual	Unbilled revenue accrued at the end of the year is based on actual billings. The portion of billings related to the prior year are prorated based on days to split usage between the two years.	$0.00
Ii	Expenses – Commodity Charge Type 101 (i.e. is expense based on IESO invoice at year end)	Actual	IESO charges are accrued to actual at the end of the year.	$0.00
Iii	Expenses – GA RPP: Charge Type 148 with respect to the RPP/Non-RPP kWh volume proportions	Actual	The split for Charge Type 148 is trued-up subsequent to year-end and a year-end accrual entry is recorded. The accrual is based on actual kWh consumption and Global Adjustment rate to determine the	$0.00

			RPP and Non-RPP portions. The RPP portion of CT148 is what remains in account 1588.	
iv	Expenses – GA RPP: Charge Type 148 with respect to the RPP/non-RPP kWh volume proportions.	See above	See above	See above
v	RPP Settlement: Charge Type 142 including any data used for determining the RPP/HOEP/RPP GA components of the charge type	Actual	IESO charges are accrued to actual at the end of the year. In addition, a true-up for consumption and Global Adjustment final estimate are accrued.	$0.00

b) Please refer to EPLC response to a) above.

c) Please refer to the GA Analysis Workform that has been resubmitted as Attachment 1-X.

Exhibit 9: 9-Staff-87

Global Adjustment

Ref: EPLC_DVAContinuity_20170828 – Tab 2. 2016 Continuity Schedule

Ref: EPLC_DVAContinuity_20170828 – Tab 7.a GA Analysis Workform – Reconciliation items 2a and 2b

a) No amounts have been included in the GA Analysis Workform for reconciliation items 2a and 2b, please explain why not.

Response

A revised GA Analysis Workform has been included as Attachment 1-X. This re-submission includes reconciling items.

Exhibit 9: 9-Staff-88

Global Adjustment

Ref: EPLC_DVAContinuity_20170828 – Tab 7.a GA Analysis Workform – Consumption Data Excluding for Loss Factor – Box E

Ref: EPLC_DVAContinuity_20170828 – Tab 7.a GA Analysis Workform – Analysis of Expected GA Amount

a) The calculated value from the GA Analysis Tab for "F59/D26" = 1. 2362 and Essex Powerline's, OEB approved total loss factor is 1.0602. Please reconcile this difference.

b) Please confirm that the Non-RPP Class B kWh amounts entered in column F represent the kWh that was consumed by non-RPP Class B customers for each month.

Response

a) The GA Analysis Workform has been resubmitted as Attachment 1-X. This re-submission shows a difference for "F59/D26" of 1.061.

b) Confirmed.

Exhibit 9: 9-Staff-89

Global Adjustment

Ref: EPLC_DVAContinuity_20170828 – Tab 7.a GA Analysis Workform – GA Billing Rate

a) Essex Powerlines has not completed the GA Billing Rate Description under Note 3. Please provide a description as per the GA Analysis Instructions Tab 7. Of the DVA Continuity Schedule.

b) What GA rate is used to bill customers? Is the same GA rate used for unbilled revenue? If not what rate is used?

c) Explain how the GA billing rate is determined for billing cycles that span more than one load month.

d) Confirm that the GA rate that is used is applied consistently for all billing and unbilled revenue transactions for non-RPP Class B customers for each customer class.

e) Where the same GA rate is not used for non-RPP Class B customers in all customer classes, explain what GA rate is applied to each customer class.

Response

a) The GA Analysis Workform has been re-submitted as Attachment 1-X. This re-submission includes a completed GA Billing Rate Description.

b) The Global Adjustment first estimate is used to bill customers. The same rate is applied to unbilled revenue.

c) Please refer the re-submitted GA Analysis Workform in Attachment 1-X for an explanation of how Global Adjustment is determined for billing cycles that span more than one load month.

d) All Class B customers are charged using the first estimate of Global Adjustment.

Exhibit 9: 9-Staff-90

Global Adjustment

Ref: Exhibit 9 – Deferral and Variance – Account 1589: Global Adjustment Variance Account (Page 15)

Essex Powerline has stated that it does not have any Class A customers for the disposition period but does have them effective 2017. Please confirm that these new Class A customers who were Class B during the variance accumulation period of 2015 and 2016 would be charged:

a) The GA rate rider.

b) The CBR Class B rate rider.

Response

a) Confirmed.

b) Confirmed.

Exhibit 9: 9-Staff-91

Deferral and Variance Account

Ref: Exhibit 9 – Deferral and Variance – Account 1595 (Page 17-19)

Ref: EPLC_DVAContinuity_20170828

a) Accounts 1590 (2010), 1595 (2012) and 1595 (2014) were disposed on an interim basis in Essex Powerlines 2015 IRM. Accounts 1590 and 1595 are only expected to be disposed once. Please explain why Essex Powerlines is requesting to dispose these sub-accounts again and what the balances being requested for disposition pertain to.

b) Essex Powerlines is requesting disposition of Account 1590. Essex Powerlines previously disposed this account balance. This account was discontinued by the OEB in 2008. As per the EDDVAR policy, once the residual balance in the recoveries account is disposed, it should be transferred to the vintage rate year in which the residual balance was approved.
i. Why does Essex continue to record balances in account 1590?
ii. Please provide a detailed analysis of this account from 2014
iii. Please describe Essex Powerlines accounting procedures with respect to recording of approved dispositions.

c) OEB staff is unable to verify the principal and interest dispositions columns for Account 1595 for 2015. Please reconcile to the approved interim dispositions.

d) According to the 2015 Essex Decision and Order interim dispositions were as follows:
i. Rate Rider 1 Credit $3,202,317
ii. Rate Rider 2 Credit $1,089,506
iii. Rate Rider 3 Credit $2,151,441
iv. Rate Rider 4 Debit $4,382,923

Please reconcile the above amounts to the dispositions columns for 2015 in the DVA Continuity Schedule.

e) Please explain the Principal Adjustments and Interest Adjustments shown in 2015 for all accounts.

Response

a) The account balances for Account 1595 were reconstructed and reviewed by OEB Audit and subsequently agreed by EPLC. The reconstructed residual balances are as requested on the DVA continuity schedule.

b) i) EPLC has not recorded balances in Account 1590. Figure 5 in Exhibit 9 should have stated the request for disposition was in Account 1595, not 1590.

ii) Please refer to EPLC response to c) below.

iii) Accounting dispositions are to be recorded within the month in which the OEB rate order is effective. This entry would be recorded by the Regulatory Accounting Analyst and reviewed by the Regulatory Accounting Manager.

c) Please refer to the reconciliation below.

Reconciliation for IRM Approved Balances

Rate Rider Number	Balance	Duration for recovery/refund	Approved Amount
Rate Rider 1	Credit	1	-3,202,317.00
Rate Rider 2	Credit	1	-1,089,506.00
Rate Rider 3	Credit	2	-2,151,441.00
Rate Rider 4	Debit	3	4,382,923.00

DVA Contintuity Schedule mapping

	Principal
OEB Approved Dispositions	970,837.00
Rate Riders Included as OEB Approved Dispositions [1]	970,835.00
Unreconciled Variance	2.00

1. The approved balance for rate rider 2 from above was not moved from Account 1595(2014) to 1595 (2015) upon approval for disposition. The residual amount remaining as at Dec 31/15 was moved as an Audit Adjustment. This amount is shown under the Principal Adjustments(2) during 2015.

d) Please refer to EPLC's response to c) above.

e) The Principal and Interest Adjustments shown in 2015 for all accounts are related to the OEB Audit adjustments as proposed by Essex Powerlines.

Exhibit 9: 9-Staff-92

Deferral and Variance Account

Ref: Exhibit 9 – Deferral and Variance – 9.5.3 Account 1525 Misc. deferred Debits (Page 21)

Essex Powerlines stated that it is using Account 1525 to record costs of previous rate rebasing applications that were subsequently deferred, that added value to this Application and were not counted as part of regulatory costs.

a) Please provide further details showing how the balance in the account was accumulated and provide a discussion on the prudency of these costs.

b) Per the APH, Article 220, "Amounts of regulatory expenses that by approval or direction of the Board are to be spread over future periods shall be charged to Account 1525, Miscellaneous Deferred Debits, and amortized by charges to this account.". Please provide reference to the OEB's approval or direction to record the amounts in Account 1525.

Response

a) EPLC has discontinued the practice of accumulating costs in account 1525 that pertain to rate rebasing applications that have not yet been filed with the Ontario Energy Board. The current balance in account 1525 related to charges for rate rebasing activities is $84,226. These costs include consultant costs and other immaterial miscellaneous costs that, despite deferring the filing of EPLC's rate rebasing application, still added value and would have otherwise been recorded in regulatory costs following new procedures.

b) EPLC is unable to provide OEB approval or direction to have historically recorded these amounts in Account 1525.

Exhibit 9: 9-Staff-93

Deferral and Variance Account

Ref: Exhibit 9 – Deferral and Variance – 9.5.4 Account 1531 Renewable Generation Connection Capital (Page 21-23)

Account 1531, 1534, and 1535 – renewable capital for disposition. It appears that Essex Powerlines has approximately $701K recorded in these accounts. However, Essex Powerlines has not provided Appendices 2FA to 2FC to request disposition and propose inclusion in rate base for the spending related to the direct benefits portion of the balances.

a) Please review Chapter 5 of the March 28, 2013 Filing Requirements for Electricity Distribution Applications, Consolidated Distribution System Filing Requirements, and APH accounting guidance issued in March 2015 and propose disposition of the balances in these accounts.

Response

a) Please refer to the revised DVA continuity schedule. As per the Board's Orientation Session held on July 25, 2017, year over year contributions in Account 1531 and 1535 are not material as such, EPLC is looking for approval to recover these balances in a rate rider, recovered over 2 years outlined in the table below.

EPLC is also seeking approval to recover balances in Accounts 1534 by rate rider, recovered over 2 years outlined in the table below.

Rate Class	Units	kW / kWh / # of Customers	Allocated Balance	Proposed Rate Rider
Residential	# Customers	27,484	$ 330,486	$ 0.5010
GS<50	kWh	62,768,285	$ 84,530	$ 0.0007
GS>50	kW	446,253	$ 239,775	$ 0.2687
Embedded Distributor	kW	80,869	$ 40,220	$ 0.2487
Street Light	kW	8,848	$ 3,771	$ 0.2131
Sentinel Light	kW	2,080	$ 452	$ 0.1087
USL	kWh	1,554,368	$ 2,093	$ 0.0007
Total			**$ 701,327**	

Exhibit 9: 9-Staff-94

Deferral and Variance Account

Ref: Exhibit 9 – Deferral and Variance – 9.5.4 Account 1531 Renewable Generation Connection Capital (Page 21-23)

Essex Powerlines is requesting disposition of Account 1572 relating to costs incurred from a tornado. Please provide a breakdown of these costs and reasons explaining why these costs were incurred. In particular, please discuss the prudency of these costs.

Response

The costs reflected in Account 1572 represents the cost of material, incremental labour and third-party contract labour directly related to the re-building efforts following a tornado in Leamington in 2010. These costs were prudently incurred as EPLC staff worked incremental hours in order to safely and efficiently re-store power for our rate payers.

These balances were reviewed as part of a 2013 OEB audit for Account balances. As a result of the audit, Essex Powerlines made an adjustment in the amount of $4,905.20 to reduce the balance in Account 1572. There were no further findings related to the causation, materiality or prudence of the charges recorded within this account.

Exhibit 9: 9-Staff-95

Deferral and Variance Account

Ref: Exhibit 9 – Deferral and Variance – 9.5.11 Account 1592: PILs & Tax Variances (Page 26)

Essex Powerlines is requesting disposition of Account 1592, Sub-account HST / OVAT Input Tax Credits (ITCs).

a) Please clarify whether the ($211k) represents 100% or 50% of the savings.

Response

a) This amount reflects 50% of the savings presently recorded in Account 1592.

Exhibit 9: 9-Staff-96

Account Status

Ref: Exhibit 9 – Deferral and Variance – 9.6 Account Status (Page 27-28)

a) Essex Powerlines plans to continue to use Account 1531 Renewable Generation Connection Capital. Per the March 2015 APH Guidance #8, the deferral accounts for renewable generation connection are to be discontinued following the approval of a rate order that is underpinned by a distributor's first consolidated DS plan. Please revise Essex Powerline's proposal to discontinue usage of these accounts.

b) Essex Powerlines plans to discontinue using Account 1576 Accounting Changes Under CGAAP, this account should continue to be used until the disposition period for the related rate rider expires as per March 2015 APH Guidance #6. Please clarify Essex Powerline's proposal as to when the discontinuation of this account will occur.

Response

a) EPLC plans to discontinue Account 1531 pending the approved disposition.

b) EPLC agrees that it will follow the accounting guidance documented within the March 2015 APH guidelines. This account will be discontinued once the rate rider has been fully settled with customers.

Exhibit 9: 9-Staff-97

Embedded Distributor

Ref: Exhibit 9 – Deferral and Variance – (Page 30)

Essex Powerlines has excluded embedded distributor volumes from billing determinants, and has stated that Essex Powerlines is not proposing to charge any RTSR charges as Embedded Distributor does not materially contribute to any Group 1 or Group 2 variance. OEB staff notes that as a distribution customer, the embedded distributor would be paying RTSR charges. In addition, all distribution customers use the distribution system and should be allocated the Group 2 rate riders.

a) Please discuss in more detail Essex Powerlines' justification for excluding the embedded distributor from the proposed dispositions calculations

Response

a) EPLC has included a revised DVA Continuity Schedule (included as Attachment 1-X) that includes the Embedded Distributor class for all rate riders.

Exhibit 9: 9-Staff-98

Stranded Meter

Ref: Exhibit 9 – Deferral and Variance – 9.5.8 Account 1555: Smart Meter Capital (Page 36)

Ref: EPLC Chp2Appendice 20170828 – App.2-S Stranded Meters

Ref: EPLC Chp2Appendice 20170828 – App.2BA Fixed Asset Cont

Essex Powerline is proposing disposition of $1,095,650 debit amount from its residential and GS <50 classes. OEB staff notes that Account 1555 is not on Essex Powelines' DVA Continuity Schedule, or in the 2.1.7 filings for 2016. In addition Essex Powerlines has not provided calculation of the rate rider as part of the rate rider calculations tab of the DVA Continuity Schedule.

a) Please update and refile the evidence as necessary.

b) Please explain why the total meter disposals in the fixed asset continuity from 2010 to 2018 does not match the asset value in Appendix 2-S

Response

a) The stranded meter balance remained in Account 1860 and therefore would not have been included within the DVA continuity schedule rate riders.

b) The values listed on the continuity schedule would include dispositions that are related to meter dispositions that are not considered stranded meters for the purpose of this application.

	Additions			
Fiscal Year	Opening Balance	Additions	Disposals	Closing Balance
2010	3,432,271.52	525,392.00		3,957,663.52
2011	3,957,663.52	220,177.00	22,310.00	4,200,150.52
2012	4,200,150.52	780,500.00	179,649.00	5,160,299.52
2013	5,160,299.52	174,407.00	-14,935.00	5,319,771.52
2014	5,319,771.52	94,907.00	237,709.00	5,652,387.52
2015	5,652,387.52	3,437,408.00	-770,147.00	8,319,648.52
2016	8,319,648.52	1,168,886.00	-75,877.00	9,412,657.52
2017	9,412,657.52	266,932.00		9,679,589.52
2018	9,679,589.52	365,671.00		10,045,260.52

Accumulated Depreciation					
Opening Balance	Additions	Disposals	Closing Balance	Net Book Value	NBV - remove Stranded
-805,475.26	-148,395.00		-953,870.26	3,003,793.26	1,371,430.71
-953,870.26	-155,889.00		-1,109,759.26	3,090,391.26	1,331,560.86
-1,109,759.26	-202,596.00		-1,312,355.26	3,847,944.26	2,193,826.58
-1,312,355.26	-198,723.00		-1,511,078.26	3,808,693.26	2,259,288.30
-1,511,078.26	-202,705.00		-1,713,783.26	3,938,604.26	2,493,912.02
-1,713,783.26	-383,646.00	-1,104,875.00	-3,202,304.26	5,117,344.26	3,777,364.74
-3,202,304.26	-374,594.00	-85,895.00	-3,662,793.26	5,749,864.26	4,514,597.46
-3,662,793.26	-384,378.00		-4,047,171.26	5,632,418.26	4,501,864.18
-4,047,171.26	-402,131.00		-4,449,302.26	5,595,958.26	4,500,308.42

Exhibit 9: 9-Staff-99

Ref: Exhibit 9 – Deferral and Variance – Appendix 9-D – IESO Self-Certification

Per section 2.9.5 of the Filing Requirements for 2018 Rate Applications, a certification must be provided to indicate that the distributor has robust processes and internal controls in place for the preparation, review, verification and oversight of the Account 1588 and 1589 balances being disposed, consistent with the certification requirements in Chapter 1 of the filing requirements. Essex provided Appendix 2-D, IESO's RPP Self-Certification which is not the same as the 2.9.5 Filing Requirement.

a) Please provide the certification requested on the Account 1588 and 1589 balances.

Response

a) Please refer to Attachment 1-Y for the certification requested on Account 1588 and 1589 balances.

Exhibit 9: 9-SEC-42

[Ex.9, p.5; EB-2014-0072 Decision and Order, June 9 2015, p.13] With respect to the Applicant's deferral and variance accounts:

a. Please provide a copy of the audit ordered by Board in its EB-2014-0072 Decision and Order.

b. Please provide details regarding the implementation of any recommendations made in the audit.

Response

a) Please refer to EPLC response to 9-Staff-80.

b) Please refer to EPLC response to 9-Staff-80.

Exhibit 9: 9-SEC-43

[Ex.9, p.5; EB-2014-0072 Decision and Order, June 9 2015, p.13] With respect to the Applicant's deferral and variance accounts:

a. Please provide a copy of the audit ordered by Board in its EB-2014-0072 Decision and Order.

b. Please provide details regarding the implementation of any recommendations made in the audit.

Response

a) Please refer to EPLC response to 9-Staff-80.

b) Please refer to EPLC response to 9-Staff-80.

Exhibit 9: 9-VECC-63

Reference: Exhibit 9, page 6, Figure 1

a) Please confirm the account noted at 1590 ($-174,821 principle balance) should read Account 1595. If this is not correct please describe what type of cost 1590 records.

Response

Confirmed.

Exhibit 9: 9-VECC-64

Reference: Exhibit 9, page 21

a) Please provide the Board reference allowing $83,197 in regulatory costs to be carried over from the last cost of service application.

Response

a) Please refer to 9-Staff-92.

Exhibit 9: 9-VECC-65

Reference: Exhibit 9, page 22-23

a) Please provide a breakdown the smart grid capital spending of $512,740 between 2012 and 2017 by category (e.g. reclosers, line monitoring, etc.)

b) Please provide the same for the smart grid OM&A spending of $91,626.

Response

a) Please see the breakdown below for smart grid capital spending from 2012 through 2017.

Description	Cost
Internal Labour	$ 50,114
Material	$ 86,374
Vehicle Charges	$ 8,093
Smart Map Software purchase & deployment	$238,856
Wholesale Meters installed	$127,000
Self-Healing Grid	$ 2,304
Total	$512,739

b) Please see the breakdown below for smart grid OM&A spending from 2012 through 2017.

Contracted Services	2013	2014	2015	2016	2017	Total
Staff Training and Travel	$ 221	-	-	-	$ -	$ 221
GEA Costs	$ 45,000	-	-	-	$ -	$ 45,000
Line Sensor Support and Data	-	-	$ 23,042	$ 21,590	$ -	$ 44,632
Total	**$ 45,221**	**$ -**	**$ 23,042**	**$ 21,590**	**$ -**	**$ 89,853**

Exhibit 9: 9-VECC-66

Reference: Exhibit 9, page 24

a) We are unable to find the proposed recovery of $1,095,690 in the DVA balances proposed for disposition as shown in Figure 1, page 6. Similarly, account 1508 in Figure 1 shows a balance of ($287,803) whereas Appendix 2-YA shows a balance of $291,829. Please update Figure 1 to show the actual balances that Essex is seeking for disposition.

b) For Group 2 accounts please calculate the interest accrued for all pre-2016 balances (i.e. interest on balances at year-end 2015).

Response

a) Appendix 2-YA shows a balance of ($291,829). The difference between Figure 1 and Appendix 2-YA is related to forecasted interest from January 1, 2017 through April 30, 2018. The forecasted interest has been included in Appendix-2YA but is not included in Figure 1 as the balances reflected in Figure 1 relate to Account balances as at December 31, 2016.

b) Please see chart below for interest calculated on all pre-2016 Group 2 Account balances.

Interest on Group 2 DVA Accounts - based on 2015 Closing Balances

Closing Principal Balance		Interest	Interest	Interest
Fiscal Year		2016	2017 [1]	2018
Interest Rate		1.10%	1.20%	1.50%
1508	-268,859.00	-2,957.45	-3,226.31	-1,325.88
1518	129,384.00	1,423.22	1,552.61	638.06
1525	47,811.00	525.92	573.73	235.78
1548	-2,182.00	-24.00	-26.18	-10.76
1572	80,414.00	884.55	964.97	396.56
1531	35,234.00	387.57	422.81	173.76
1534	459,028.00	5,049.31	5,508.34	2,263.70
1535	69,920.00	769.12	839.04	344.81
1568	315,318.75	3,468.51	3,783.83	1,555.00
	Total	**9,526.76**	**10,392.83**	**4,271.03**

1. Prescribed OEB Interest Rate increased in Q4 2017 from 1.1% to 1.5%

Exhibit 9: 9-VECC-67

Reference: Exhibit 9, page 6 / Attachment 9-E

a) Please reconcile the amount shown for recovery of $4,394,961 in Appendix 2-EC (Attachment 9-E) with the amount of $2,558,929 shown as the account 1576 IFRS-CGAAP change adjustment in Figure 1.

Response

a) Please see tables below outlining the requested reconciliation below. Appendix 2-EC has been re-filed and is included as Attachment 1-J. The adjustments number presented below represent a life-to-date true-up to originally recorded annual amounts.

Figure 27 - as filed

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 Balance	**$ (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)**

Figure 27 - Based on revised 2-EC

Description	Principle Balance	Interest	Total
December 31st, 2016 Balance	$ (2,558,929)	$ -	$ (2,558,929)
Adjustments	$ (651,112)	$ -	$ (651,112)
Revised December 31st, 2016 Balance	**$ (3,210,041)**	**$ -**	**$ (3,210,041)**
2017 Actuals	$ (523,907)	$ -	$ (523,907)
Forecasted December 31st, 2017 Balance	**$ (3,733,948)**	**$ -**	**$ (3,733,948)**
WACC			5.56%
Number of Years for Disposition			2
Return on Rate Base			$ (415,215)
Total Claim			**$ (4,149,163)**

The difference between the revised Appendix 2-EC and the original Appendix 2-EC are primarily due to an increase in CGAAP net book value (NBV). Please tables below for a summary per year that has been re-stated.

Appendix 2-EC Net Additions Difference

Fiscal Year	Revised	Original	Differnce
2015	$7,243,996	$7,020,363	$223,633
2016	$4,833,945	$4,570,662	$263,283

Change to Account 1576: 2015

Fiscal Year	Revised	Original	Difference
2015 CGAAP NBV	$43,885,981	$43,685,630	$200,351
2015 MIFRS NBV	$45,665,369	$45,665,369	$0
2016	-$1,779,388	-$1,979,739	$200,351

Change to Account 1576: 2016

Fiscal Year	Revised	Original	Difference
2016 CGAAP NBV	$45,691,588	$45,475,379	$216,209
2016 MIFRS NBV	$48,901,599	$48,901,599	$0
2016	-$3,210,011	-$3,426,220	$216,209

Attachment 1-A

Response to Letter of Comment - LaRose

March 2nd, 2018

Gordon Larose

RE: Larose Letter of Comment – 2018 Cost of Service Application

Dear Mr. Larose,

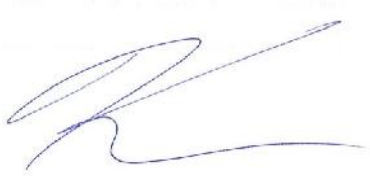
Thank you for your letter of comment submitted to the Ontario Energy Board ("OEB") related to Essex Powerlines Corporation's ("EPLC") 2018 Cost of Service Application. The time you took to submit comments is appreciated and we thank you for your interest in this proceeding.

EPLC understands your concerns about electricity rates and I would be happy to discuss this application or matters related to your electricity bill with you directly at your convenience. For more information about EPLC's rate application, please visit:

http://essexpowerlines.ca/downloads/cos/EPL_COS_DEC_2017.pdf

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

Yours truly,



Kristopher Taylor
Director of Corporate Strategy
Essex Powerlines Corporation

Cc: Board Secretary, OEB
Joe Barile, General Manager, EPLC
Lindsay Thiessen, Manager of Regulatory Accounting, EPLC

2730 Highway 3 | Oldcastle, ON | N0R 1L0
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Attachment 1-B

Response to Letter of Comment - Burford

March 2nd, 2018

Christopher Burford

RE: Larose Letter of Comment – 2018 Cost of Service Application

Dear Mr. Burford,

Thank you for your letter of comment submitted to the Ontario Energy Board ("OEB") related to Essex Powerlines Corporation's ("EPLC") 2018 Cost of Service Application. The time you took to submit comments is appreciated and we thank you for your interest in this proceeding.

EPLC understands your concerns about the length of electricity rate applications and I would be happy to discuss this application or matters related to your electricity bill with you directly at your convenience. For more information about EPLC's rate application, please visit:

http://essexpowerlines.ca/downloads/cos/EPL_COS_DEC_2017.pdf

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

Yours truly,

Kristopher Taylor
Director of Corporate Strategy
Essex Powerlines Corporation

Cc: Board Secretary, OEB
Joe Barile, General Manager, EPLC
Lindsay Thiessen, Manager of Regulatory Accounting, EPLC

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Attachment 1-C

Revenue Requirement Work Form

Attachment 1-D

EPLC 2018 Business Plan

ESSEX POWERLINES 2018 BUSINESS PLAN

Executive Summary

Operational Overview – 2017

The primary focus in last year's Business Plan was to restructure the Operations and Finance departments while also looking at ways to improve the productivity of other departments to not only achieve but also sustain the level of efficiency required of a 21st Century utility. To this end, the restructuring of the Operations and Finance Departments was completed as planned and the tangible productivity and process efficiency gains required in order to become a 21st Century Utility have and will continue to be achieved in all departments.

Other highlights achieved in Operations in 2017 were:

- Cyber Security alignment with future OEB Guidelines;
- Major accounting software (Great Plains) upgrade;
- Implementation of Health and Safety software compliance tool for all employees;
- Filed comprehensive Cost of Service ("COS") Application with OEB;
- Completed OEB Audit (Phase 1 and 2) and achieved all required goals to date;
- Upgraded back end CIS (Customer Service) billing system; and
- Commenced new Customer portal upgrade; and
- Joined and participated in the Grid Smart City ("GSC") Consortium

Also in 2017 we continued to ensure our employees were provided a safe working environment (zero time lost due to work related injury) and maintained the public's safety and well-being as a priority. As always, we continued to mitigate upward cost pressures to OM&A and were reasonable and prudent with respect to expenses. Last but no less important, we continued to contribute in numerous different ways to the communities we service and the customers we serve though various charitable organizations and initiatives.

Operational Objectives for 2018

One of the main areas of focus in 2018 will be to sustain the level of efficiency required of a 21st Century utility by becoming a *Digital Utility* and taking advantage of the new opportunities while effectively dealing with the challenges associated with this new way of undertaking our business at our utility. Many utilities see the digital revolution as a threat to their business model, but massive opportunities await those able to transform themselves ahead of the curve. Essex Powerlines Corporation intends to be ahead of that curve.

The digital revolution is coming to the power industry. Renewables, distributed generation, and smart grids demand new capabilities and are triggering new business models and regulatory frameworks. Data collection and exchange are growing exponentially, creating digital threats but also valuable opportunities. Participants in the digital economy are disrupting the industrial landscape, while governments and regulatory bodies seek to encourage smarter measuring systems and greener standards for generation and consumption.

To thrive amid these challenges, the Essex Powerlines Corporation ("EPL") of the future will need to strive to become a fully digital system. This means that we will face a digital transformation of our organization and business. This can begin with quick moves to improve efficiency. As the transformation builds momentum, it should open deeper digital opportunities across a wide field.

The opportunities are present all along the power-industry value chain, from generation to customer relationship management. As utilities pursue these opportunities, the effects are already being felt by retail customers. Many utilities have launched mobile applications for bill notification, presentment, and payment, as well as for outage management. Before long, mobile applications will extend into smart homes and connected buildings. Digital management of distributed energy resources, from individual sites to entire systems, has already begun. Many projects within the utility will have a digital focus and will be using techniques of the digital economy.

EPL can start realizing most of its *Digital Utility* potential starting in 2018 by three means: smart meters and the smart grid, digital productivity tools for employees and automation of back-office processes.

Smart meters and the smart grid -- These innovations form the foundation of the digital utility, supplying the massive volumes of data that are its lifeblood. For utilities invested in the right analytics capabilities, they enable data-based analyses, planning, and diagnostics. Smart grids are more efficient and less capital intense, allowing for predictive maintenance and better asset health. The array of means used to better analyze existing information ranges from local diagnostic tools to highly complex planning instruments. With such tools, utilities can optimize staffing levels and manage the intricate energy terrain of renewable and conventional sources and patterns in demand.

Productivity tools for employees -- Mobile enablement for employees is quickly becoming a powerful productivity-boosting capability. Since smartphones provide the platform, utilities can now digitize the core process of work management to greater effect. This means better asset management, engineering, planning, scheduling and dispatch, as well as execution and job closeout. With the latest digital and mobile technology, utilities can more easily incorporate all work into a single view with universal access.

Automation of back-office processes -- Administrative processes in customer management and billing are proliferating. The rewards of process standardization and automation are therefore growing. Process-efficiency opportunities are also evident in the significant variation among utilities in cost per customer, the cost of resolving errors, and billing inquiries.

The Grid Smart City ("GSC") cooperative, which EPL is a member of, is made up of partner LDCs, smart grid innovators, government, academia and other electricity industry stakeholders. The focus of the group is on productivity and efficiency improvements; advancements in smart grids; piloting new technologies; and community energy planning, among other pursuits. To date, we have participated in the GSC purchasing group which has led to cost savings in relation to certain asset purchases.

GSC's cooperative partners, like EPL, could play a key role in delivering innovative solutions, assisting member LDCs in achieving productivity and efficiency improvements, and the integration and deployment of new technologies. Therefore, in 2018 and beyond, it is EPL's intention to leverage its membership in GSC in order to establish and expand its *Digital Utility* vision.

Also in 2018, another EPL main focus will be on completing its Cost of Service application regulatory process for rates effective May 1, 2018. Furthermore, we will continue to invest in distribution system capital that will provide increased reliability and quality for our customers. These plans will enable us to achieve our goals of maximizing shareholder value, improving customer satisfaction and maintaining (and exceeding) regulatory compliance.

Our EPL senior management team will continue developing both short and long term labour strategies that align with the needs of our assets for replacement and repair in line with the compliment of line and metering resources.

Other highlights that EPL will be focusing on in Operations for 2018 are:

- Implementing of Shared Operation Control Room services;
- Completion of OEB Audit – medium to long term Action Plans;
- Expanded Health and Safety compliance tool for all employees;
- New website;
- Full compliance of OEB Cyber Security Framework;
- Migration of local to cloud based hosted service (Office 365);
- Continued Integration of SmartMap technology into day-to-day EPL operations; a
- Optimization of process, systems and technology integration across all departments.

Operations Department

In 2017, EPL was able to install five (5) additional automatic reclosers throughout our distribution system (which now has a total of 15) while at the same time expanding our use of SmartMap technology at the operational manager and supervisor level. As previously noted, the automatic reclosure installation is another "piece of the puzzle" that is part of our *Digital Utility* and "self-healing" distribution system goal.

In 2017, EPL formalized the coordination of the day to day activity of our operation department through implementation of the operations manager, one operation supervisor and two working sub-foreman hierarchy model (as opposed to the previous manager and two supervisor model)

Establishing the operations department as part of a *Digital Utility* will also require a high degree of internal proactive work flow coordination in order to maximize efficiency gains. In 2018 EPL will utilize a resource with effective digital tools that will coordinate to ensure day to day job tasks in the operations department are being completed and planned in an efficient, fiscally prudent and forward thinking manner while at the same time making use of all available digital technology that could assist in achieving the aforementioned goals. This will not only establish EPL as an industry leader but it will also allow EPL to be a model with respect to the integration of process, systems and technology in all aspects of its operations.

FINANCE and REGULATORY DEPARTMENT

In 2017, the EPL Regulatory department was focused on, amongst other things, completing the OEB audit process and ensuring implementation of the Change Management action plan arising from the same. The corporate reorganization of both the Finance and Regulatory department was also completed in 2017.

In 2018, the focus in the Finance and Regulatory departments (separate and apart from the required COS filing completion) will be in regards to improving departmental controls and procedures through the lens of a *Digital Utility*. Manual accounting processes will be eliminated where possible and software (such the RSVA and URB tools) developed in conjunction and partnership with our affiliates will be utilized.

CIS/BILLING DEPARTMENT

In 2017, EPL commenced training of customer service staff in relation to SmartMap technology. This will result not only in operational efficiency gains but also a greater understanding and awareness from our customer service staff on operation of our distribution system as a whole.

Ensuring customer billing accuracy has been and will continue to be a key focus in 2018. The integration of the Manager of Regulatory Accounting into the CIS department will add another layer of due diligence that will ensure, amongst other things, customer billing accuracy. This will ensure regulatory compliance as well as incorporating reasonably prudent procedures, controls, and oversight.

ESSEX POWERLINES CORPORATION

ENGINEERING/METERING DEPARTMENT

In 2017, the engineering/metering department continued to ensure that all customer and EPL capital work was designed, managed, planned and scheduled for completion by the operations department on a priority schedule basis. The metering department continued the process of sampling smart meters for testing for recertification requirement.

Capital Investment Overview in 2018 and beyond

- Customer Expansion – commercial growth has been steady over the last number of years and is expected to remain relatively flat or increase slightly. Shareholder related expansions are also expected to be flat.

- Customer Expansion – residential growth has been increasing significantly over the last few years. In 2017 EPL continued to experience an active growth period with respect to pre-serviced lots. Historical Growth has been in LaSalle and in 2018 and we are forecasting continued growth levels mainly in Lasalle.

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018 (projected)
# of lots serviced	0	38	198	86	201	81	446	370	410	385

- Municipal Road Projects – Government Infrastructure injections are forecasted to be low in 2018 requiring little EPL infrastructure improvements. The Town of Tecumseh is undertaking a major Streetscape Improvement of their central business area. Details are being finalized and this may require a significant transition from overhead to underground.

- Conversion due to age and reducing the amount of EPL assets will continue where logical and necessary.

- Existing underground infrastructure – systematic replacement of underground assets based on troublesome assets, inspections and age. This is forecasted to continue year after year.

- Overhead replacements – inspection programs identify replacements of overhead assets some based on age others based on failure rates. This is forecasted to continue year after year.

- Continue to Identify/purchase/sell assets that do not create a rate of return or control issues for EPL. This started in 2010 and will continue.

- Continue with Risk based approach to capital, operations and maintenance expenditures

- Electrical Safety Authority (ESA) - Improve 2017 level of compliance with regulation 22/04 which resulted in only one minor finding that needs improvement (NI).

EPL has invested significant resources into Capital and Maintenance which has significantly reduced tree contacts and EPL Equipment Failures. EPL continues to work closely with Hydro One to encourage them to improve the reliability of supply.

FEEDERS

Customer Expansion and EPL Capital - at the current rate of expansion, feeders in the LaSalle/Amherstburg area will become overloaded in the future (2 to 3 years). EPL has requested Hydro One Transmission provide estimates and timelines for building one or two new feeder and breaker positions to supply expanding load and generation needs. EPL will monitor closely feeder loading with Hydro One and will request the expansion when required by loading. EPL is working closely with Hydro One to dedicate circuits by LDC and load all the feeders to reasonable levels. Some sale and purchase of assets will assist with this balance and dedication.

Each new feeder position will add 15-17 MW of new capacity which enables increased supply options and allows more of our load to be dedicated to EPL feeders versus shared feeders with Hydro One.

Mapping out and studying locations of new feeders and options for integration into existing systems has begun and will continue throughout 2018 and beyond.

This will have a significant impact to our future Capital budget as this represents an incremental increase to the budget of $1.5 million. At this time we are forecasting that this will begin in 2019-2020. EPL will seek to recover this incremental expenditure in our next rate case as well as other incremental expenditures required for feeder egress on these new feeders.

2018 EPL Capital Budget

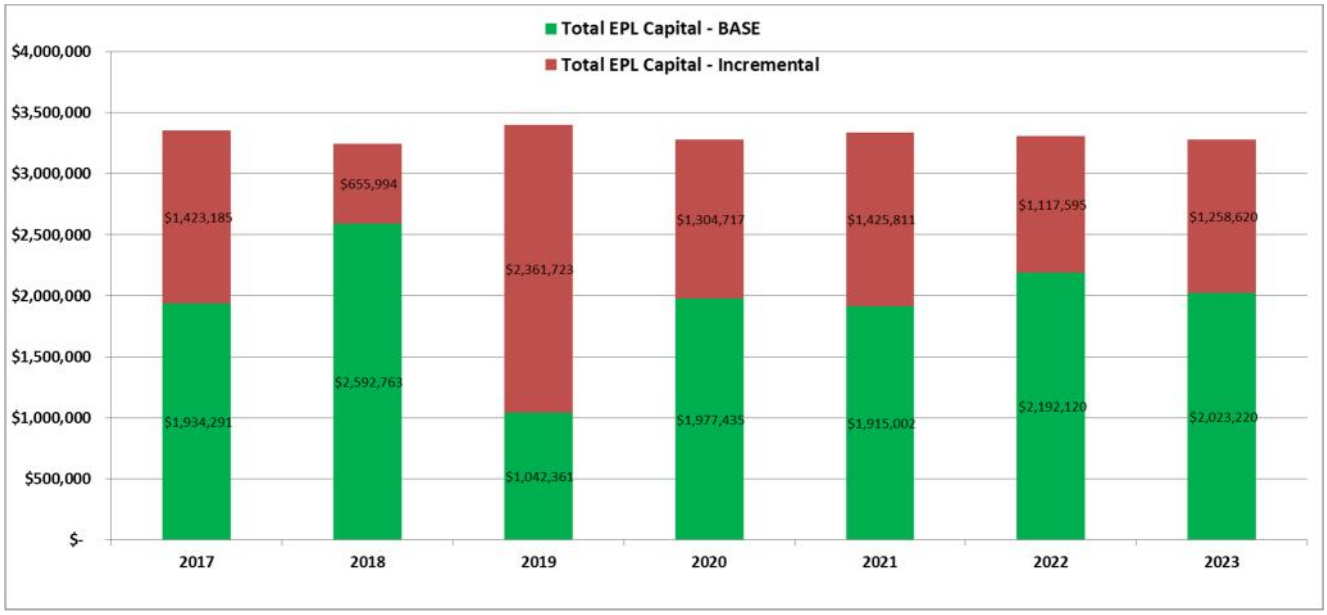
With customer work assumed to be flat and consistent from year to year below is a future look at distribution assets which includes the following:

EPL Capital Base

- replacement of individual assets that are no longer useful i.e. failed, strength low, overloaded, leaking, IR hot, from inspection, safety concerns
- includes groups of assets that are at the end of their useful lives.

EPL Capital Incremental

- programs that are not continuous year after year i.e. there is an end date
- live front equipment, conversion, metering, reclosers
- Purchase/Sale of assets (at current book value) to/from HONI, LTLT elimination
- Sale of EPL assets shows approximate book value credit to GL's
- Leamington TS – there are future capital requirements for the TS but nothing budgeted and will go after incremental funding to cover the known costs whenever we find out



Leamington TS

The Hydro One continues to move forward with the construction of a new Leamington TS. In 2015, the OPA and Hydro One obtained regulatory approval to construct the TS from the OEB. The remaining issue which still requires to be determined is with respect to the provincial/Hydro One cost allocation (currently at 22.5% and 77.5%) as well as the LDC cost allotment which currently exposes EPL to a cost allocation apportionment of approximately $6.55 million at this time. EPL has long supported the Leamington TS initiative and has sought intervenor status with respect to this proceeding in order to ensure that its rate-payers interests are reasonably and fairly represented. TS Construction is expected to be completed by 2018.

Fleet

In 2018, we will be acquiring the following vehicles to replace EPL vehicles that are past their useful life:

- Purchase of new pick-up truck (replacement of Unit 66)
- Replacement of stinging machine
- Addition of another UG truck (similar to unit 67)
- Replacement of chipper

We will also continue to investigate the purchase of an electric "smart technology" vehicle to be used by the Customer Service Supervisor. This vehicle will include vehicle wrapping to promote EPL's stance and green environment initiatives.

2017 Human Resources Outlook

There are one or possibly two eligible retirees in the foreseeable.

The plan is to continue to hire temporary or contract positions to fill voids for periods when we require help. This will result in reduced costs overall but still provide adequate resources to complete required tasks and remain compliant with our regulator.

In 2017, we continued the process of training a line maintainer apprentice (now in his 2nd year). The individual selected was a former student of the St. Clair College line maintainer program (2 years) and was a student employee at EPL for 2 years (summer). In 2018, we will continue his training to become a fully certified line maintainer. The line maintainer certification training will take 4-5 years at which time we expect to start experiencing some retirements within our current line maintainer employees.

As part of an outreach program with union and management employees, we continue to support a Wellness Committee comprised of both management and union members. The Committee will continue to bring programs to promote wellness in the work environment. The goal is to have ideas that will appeal to the entire company as a whole. Some of these initiatives included a flu shot clinic and fitness club reimbursement. We feel these activities will get all employees involved to build a more cohesive work environment. We have included funds in the business plan to cover expenses related to this initiative.

Health & Safety Business Plan

Health and Safety Training for 2018 includes but is not limited to the following:

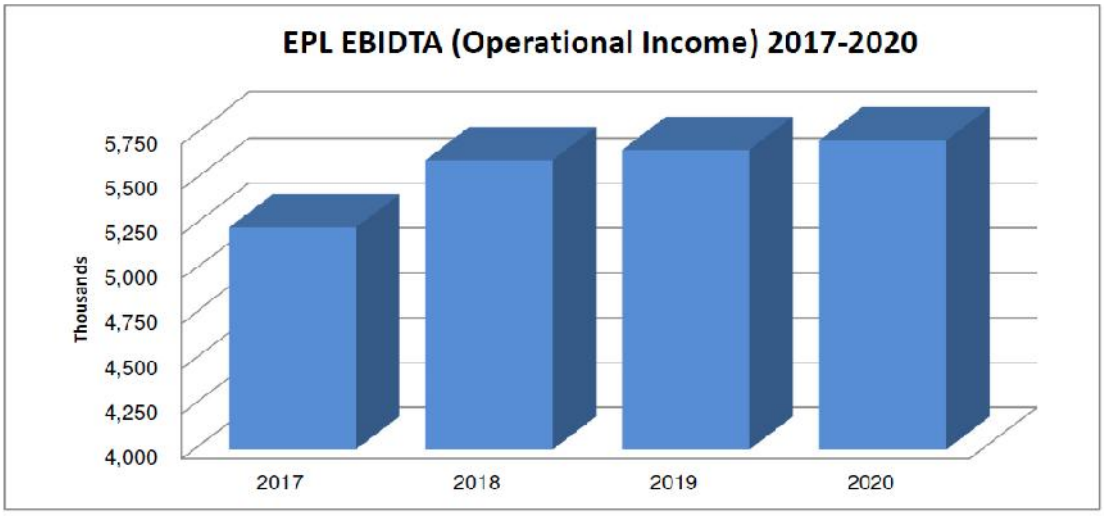
CPR/Defib
WHMIS
Working at Heights
Traffic Control Book 7
Pole Top/Bucket Rescue x2
Chainsaw Safety
Hours of Service/Pre-Trip
Fire Extinguisher
Defensive Driving

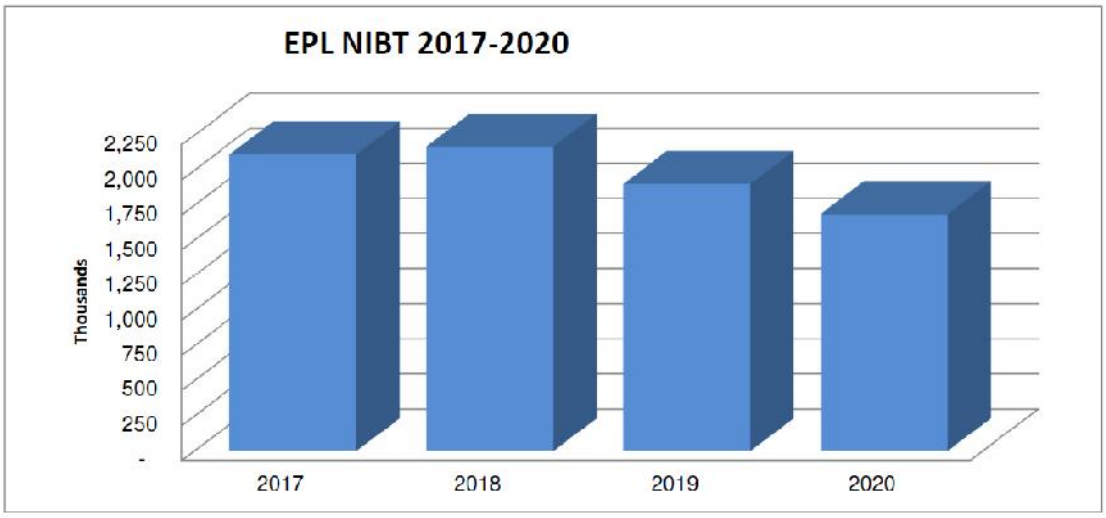
Regulatory Outlook for 2018

The Leamington Transformer Station is progressing through the OEB regulatory approval process and is expected to be completed in 2018. We will be asked to contribute to the cost of the station. We have included a total cost of $6.55 million in our capital plan to cover the cost of the transmission and distribution costs associated with the station.

We submitted our cost of service rate filing for rates effective May 1st, 2018. The capital expenditures outlined above and operations, maintenance and administrative expenses form the basis of the distribution revenue change. The smart meter variance account was be disposed of in 2015 following OEB approval to do so. This will increase our revenues for the rate adder revenue collected from customers during the period 2006 to 2012. We will also include the depreciation on the smart meter assets and O&M costs that will offset these revenues. The application process is very complex and requires considerable resources therefore we will be working on this application during the remainder of 2016 and into 2017 with a required filing date of April 2017.

Financial Budget Outlook for 2018




EPL NIBT 2017-2020
Thousands
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
-
2017
2018
2019
2020

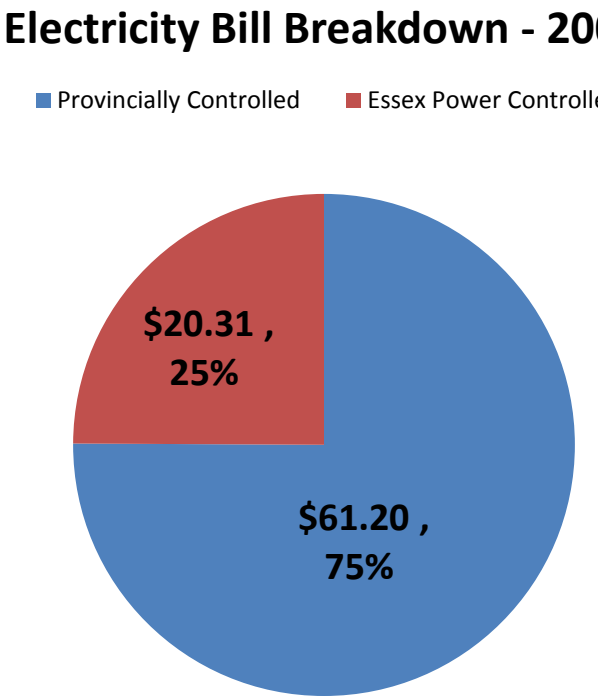
Attachment 1-E

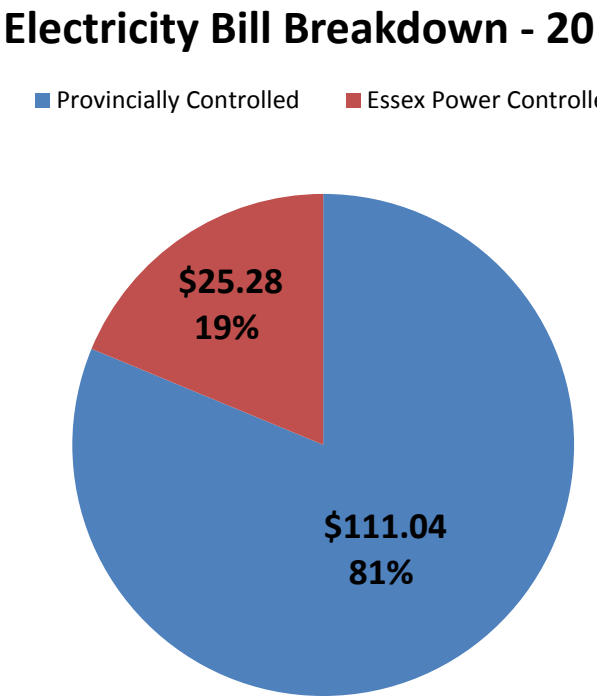
Council Presentation - Amherstburg

Essex Power Corporation
YOUR COMMUNITY PARTNER

February, 2017

What portion of the overall bill does EPL represent?





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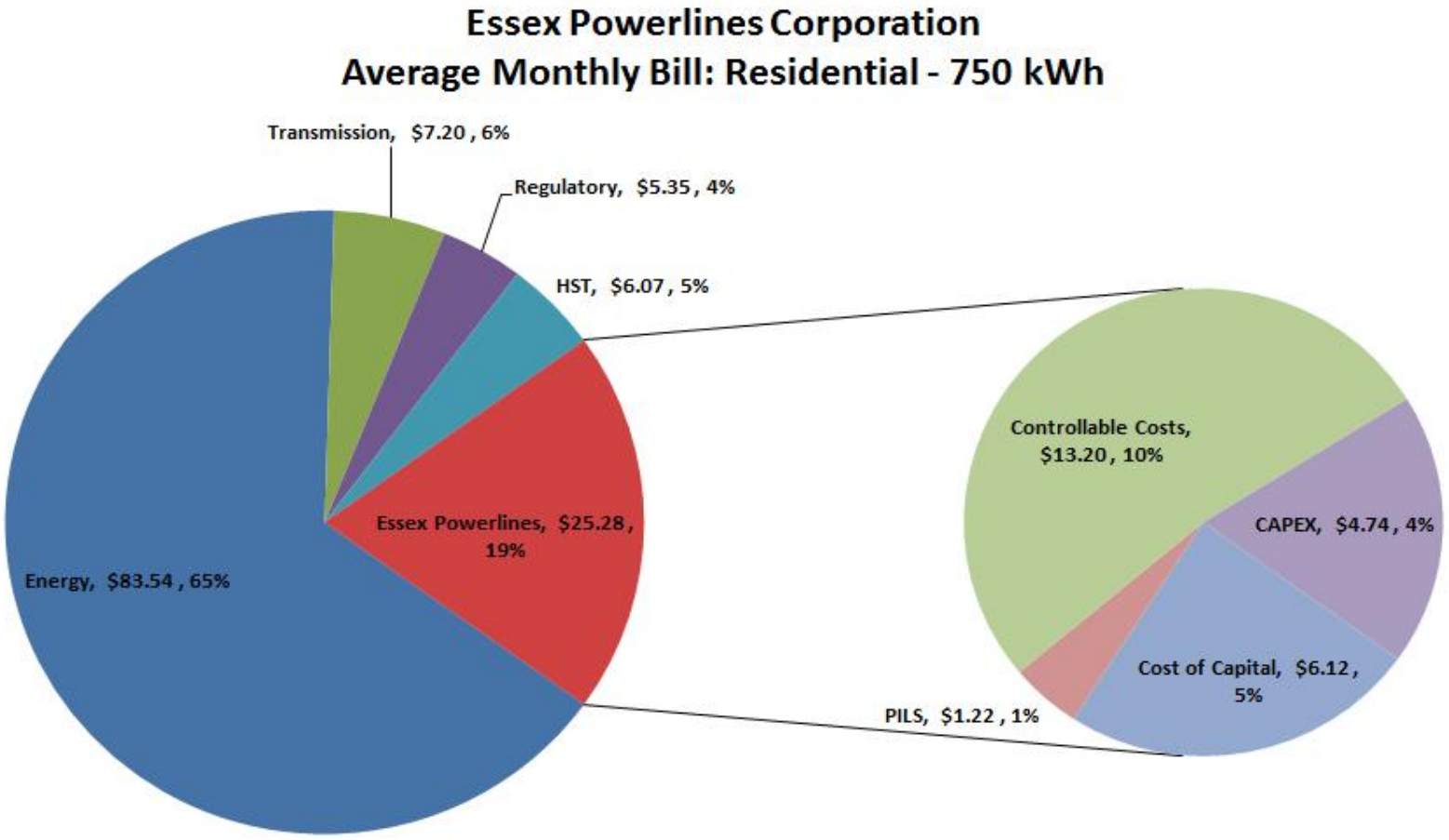

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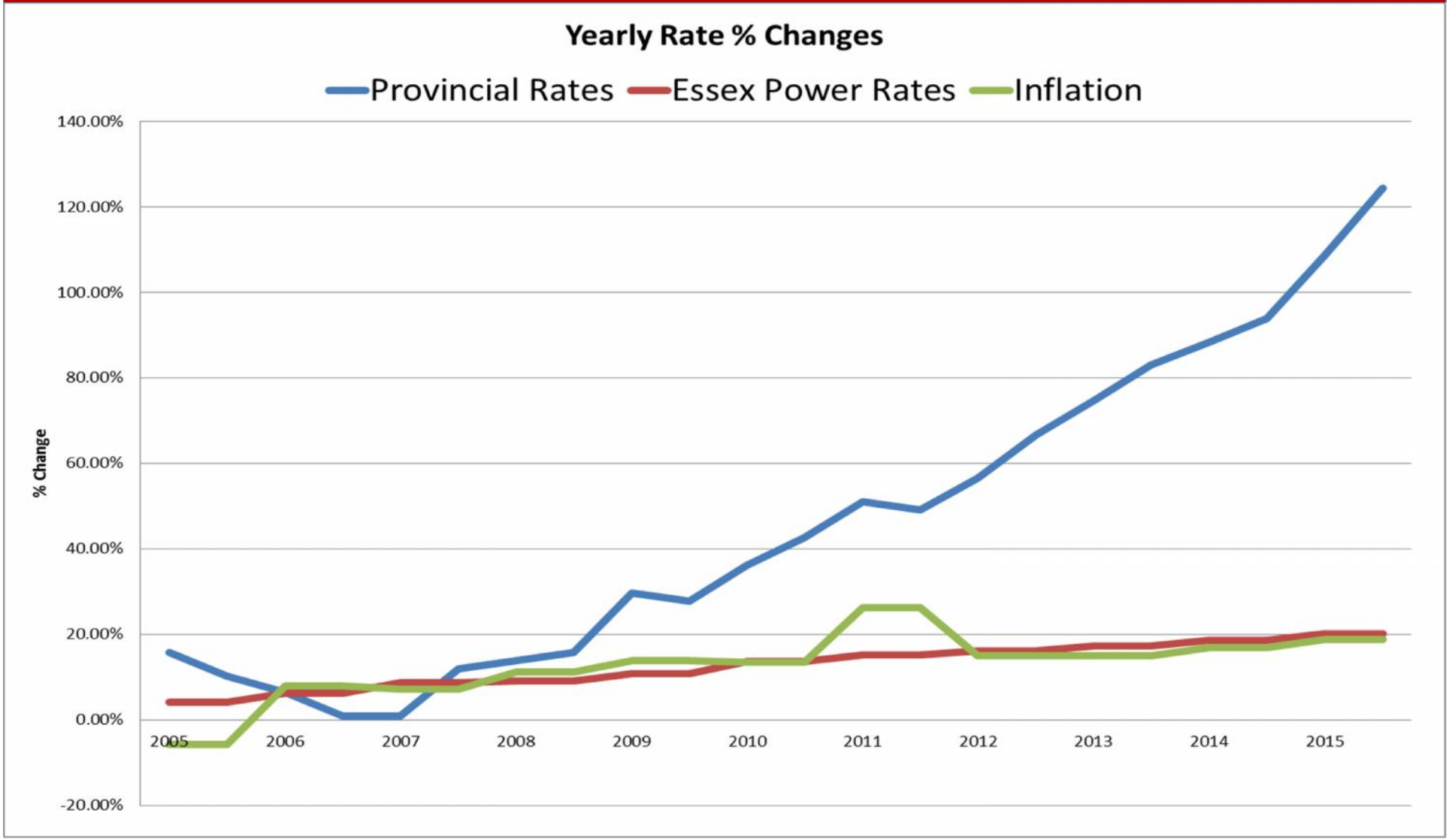

Conservation and Demand Management

Location	Municipality	Total $ Incentive	kWh Saved
Diageo	Amherstburg	$ 20,952.00	419,035 kWh
Centreline	LaSalle	$ 14,163.00	179,950 kWh
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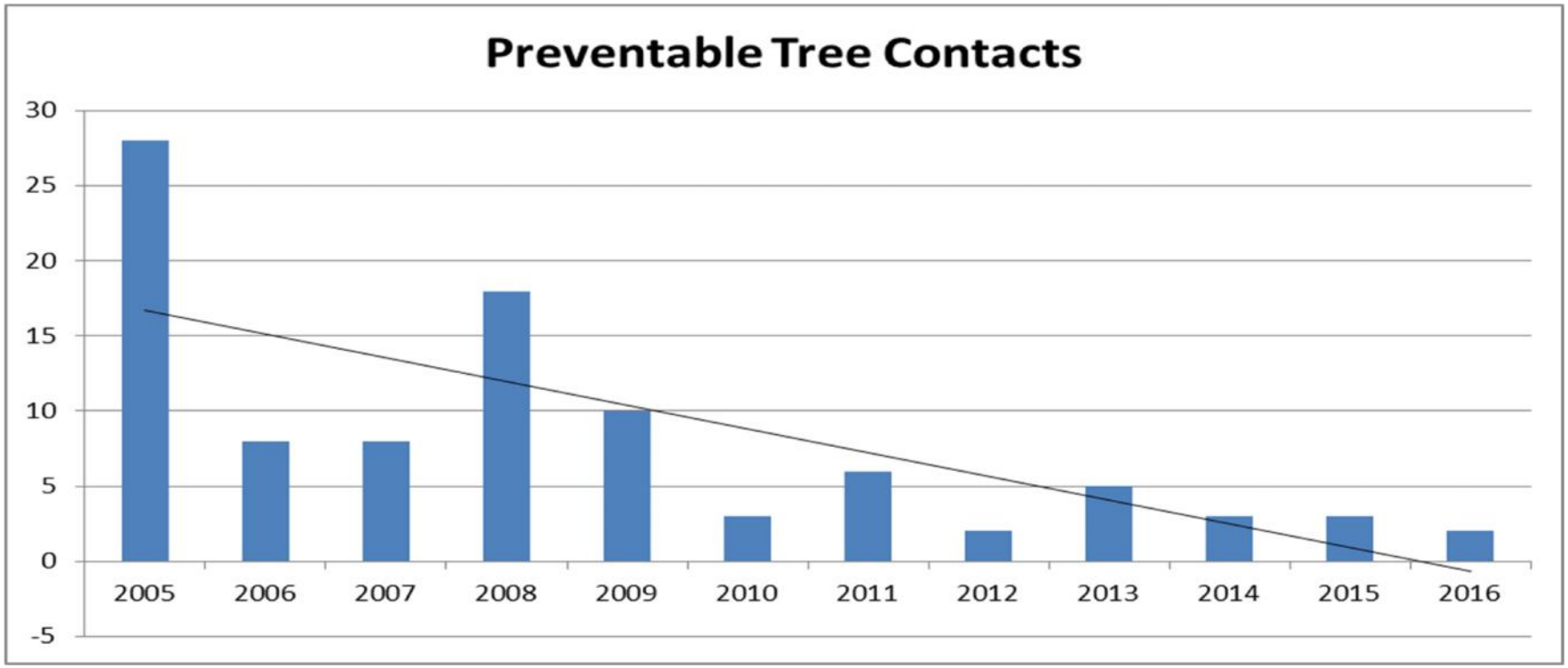

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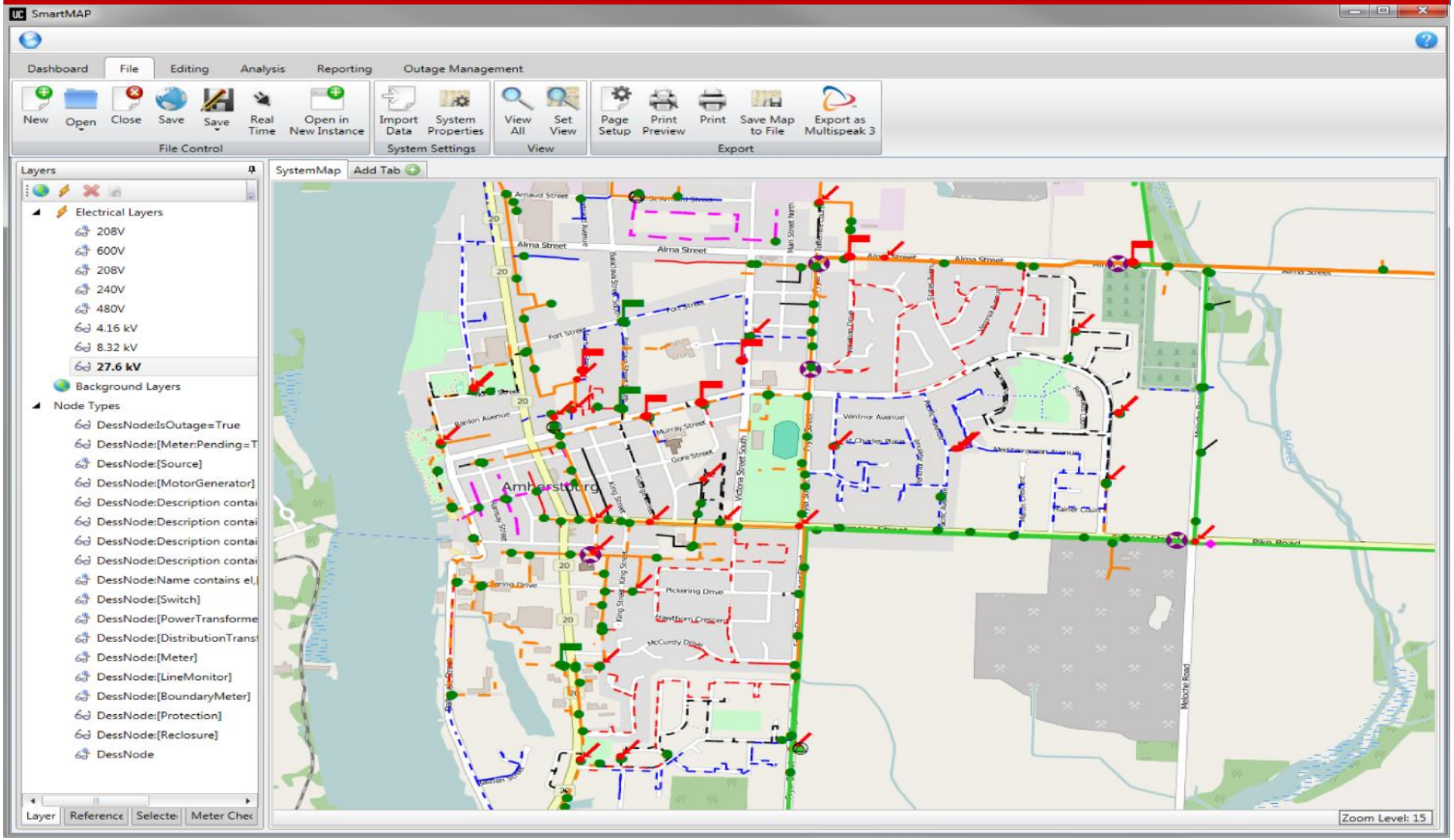

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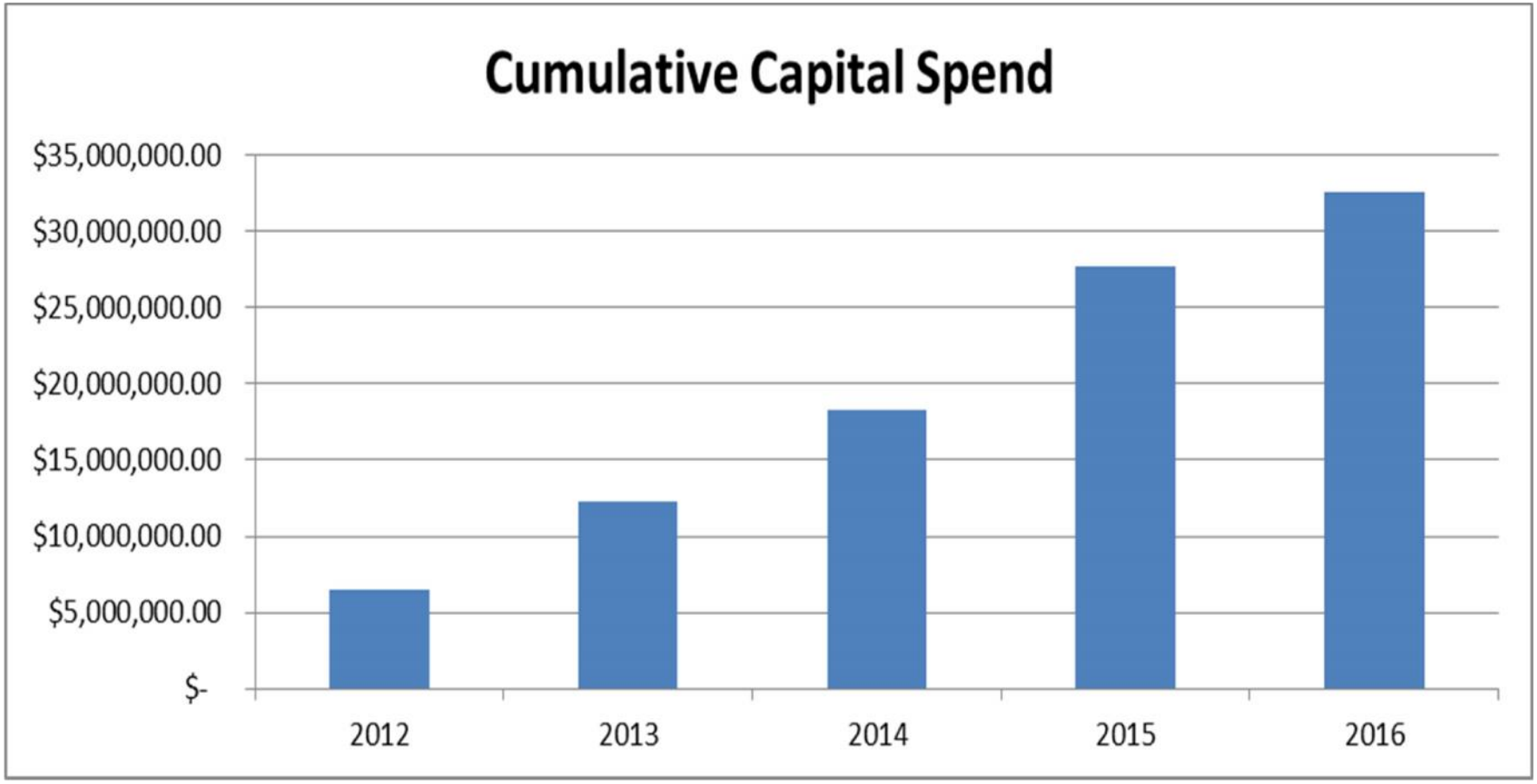
Re-Investing In Our Infrastructure



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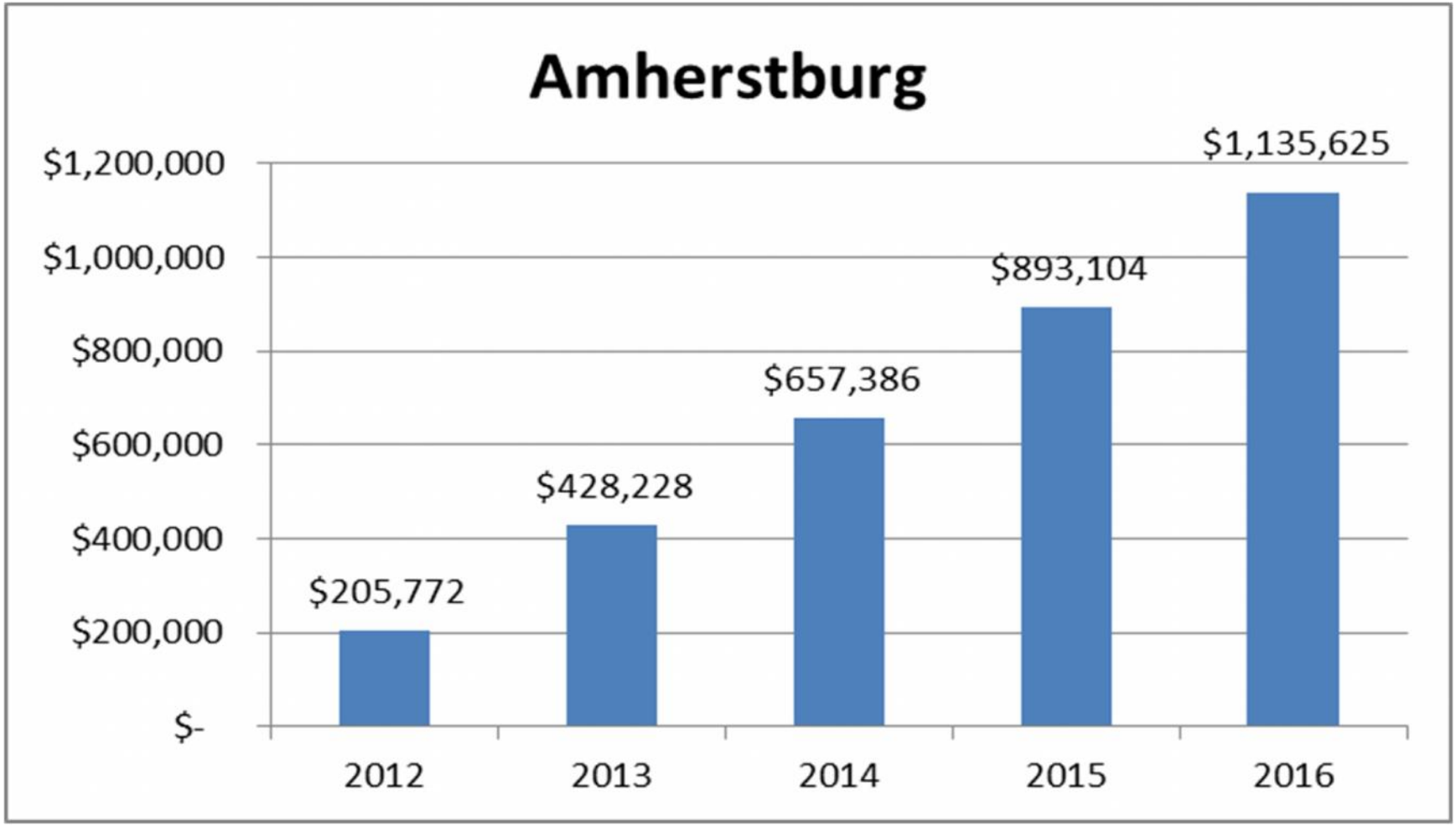

Youth in Community Fund

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- Essex Power Energy Zone
- Amherstburg Wildcats Gymnastics Program
- Jingle Bell Rock Youth Dance
- Free Youth swims and skates
- And the

ESSEX EMPOWERMENT CORPORATION Girls Group

Essex Power Helping Others in Our Communities

- Essex Power and staff have donated over $5000 to the Amherstburg Food and Fellowship Mission, along with other food banks in our service area.
- Essex Power has been a proud sponsor of Amherstburg’ s Community Festivals such as the annual Rib Fest, Harvest Fest and more

Recent Events – The Electricity Bill

- *Protecting Vulnerable Energy Consumers Act, 2017*
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  - Increased the amount of RRRP rate protection eligible to rural Ontarians

Thank You. Questions?

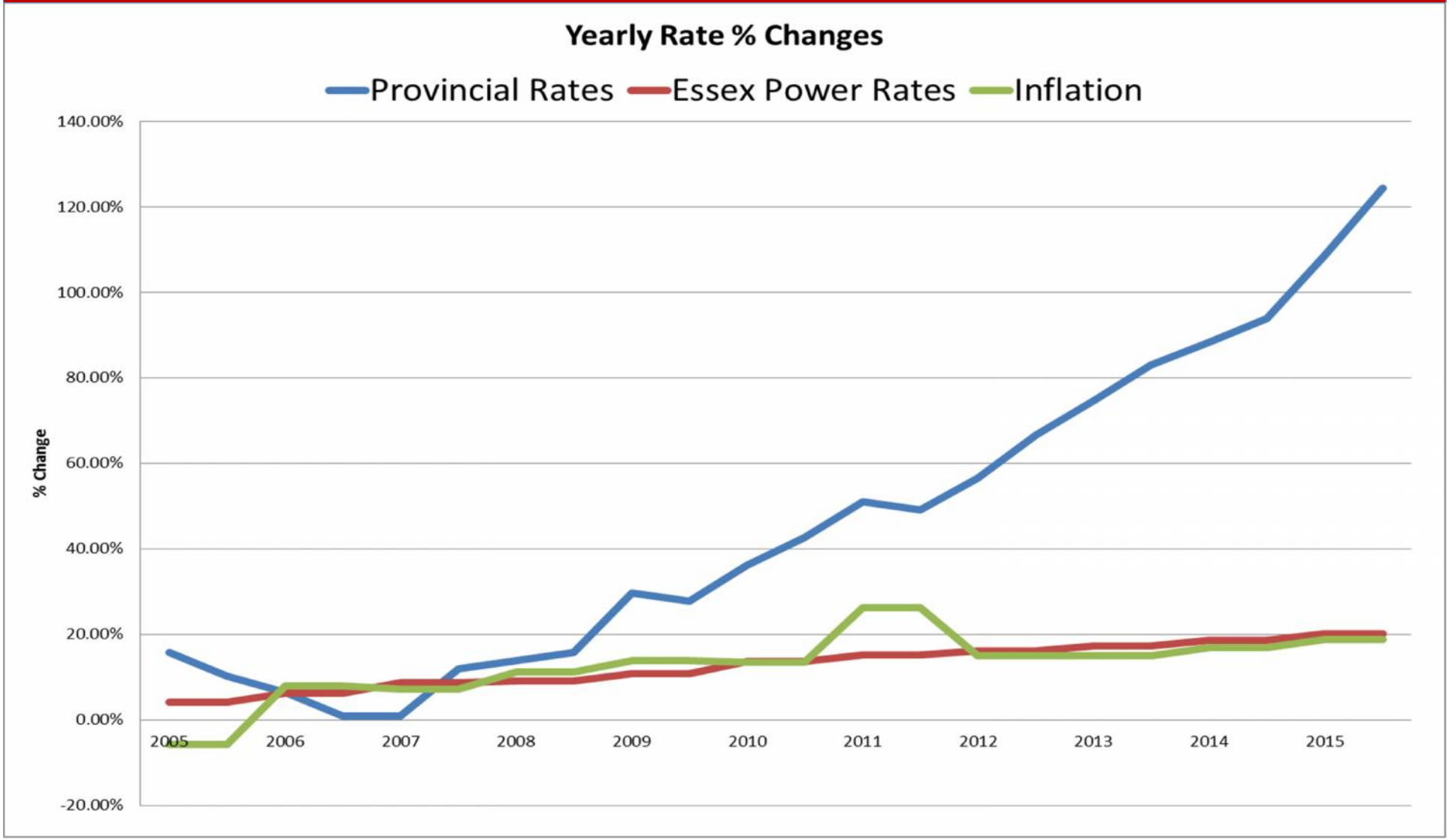
Attachment 1-F

Council Presentation - LaSalle

Essex Power Corporation
YOUR COMMUNITY PARTNER

March, 2017

Provincial Electricity Costs are a pivotal concern for our Customers



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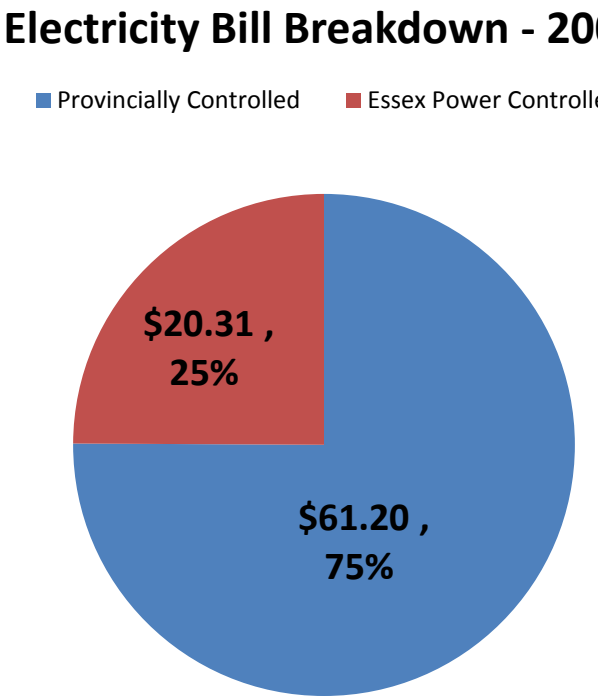

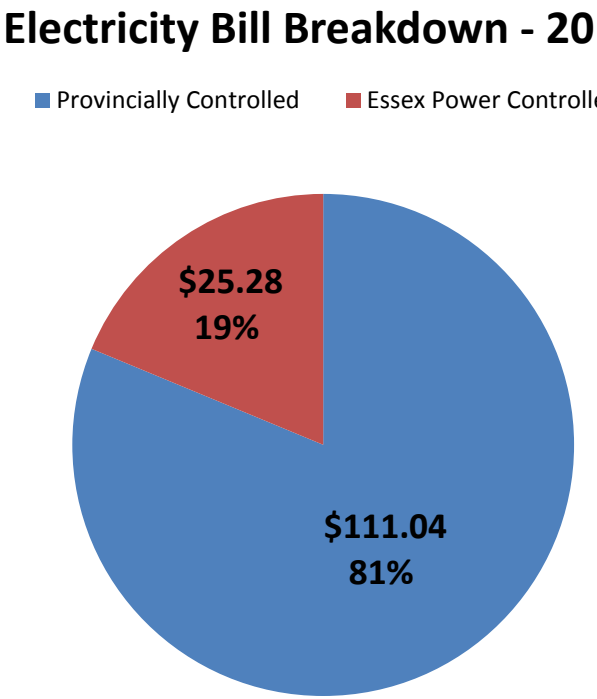

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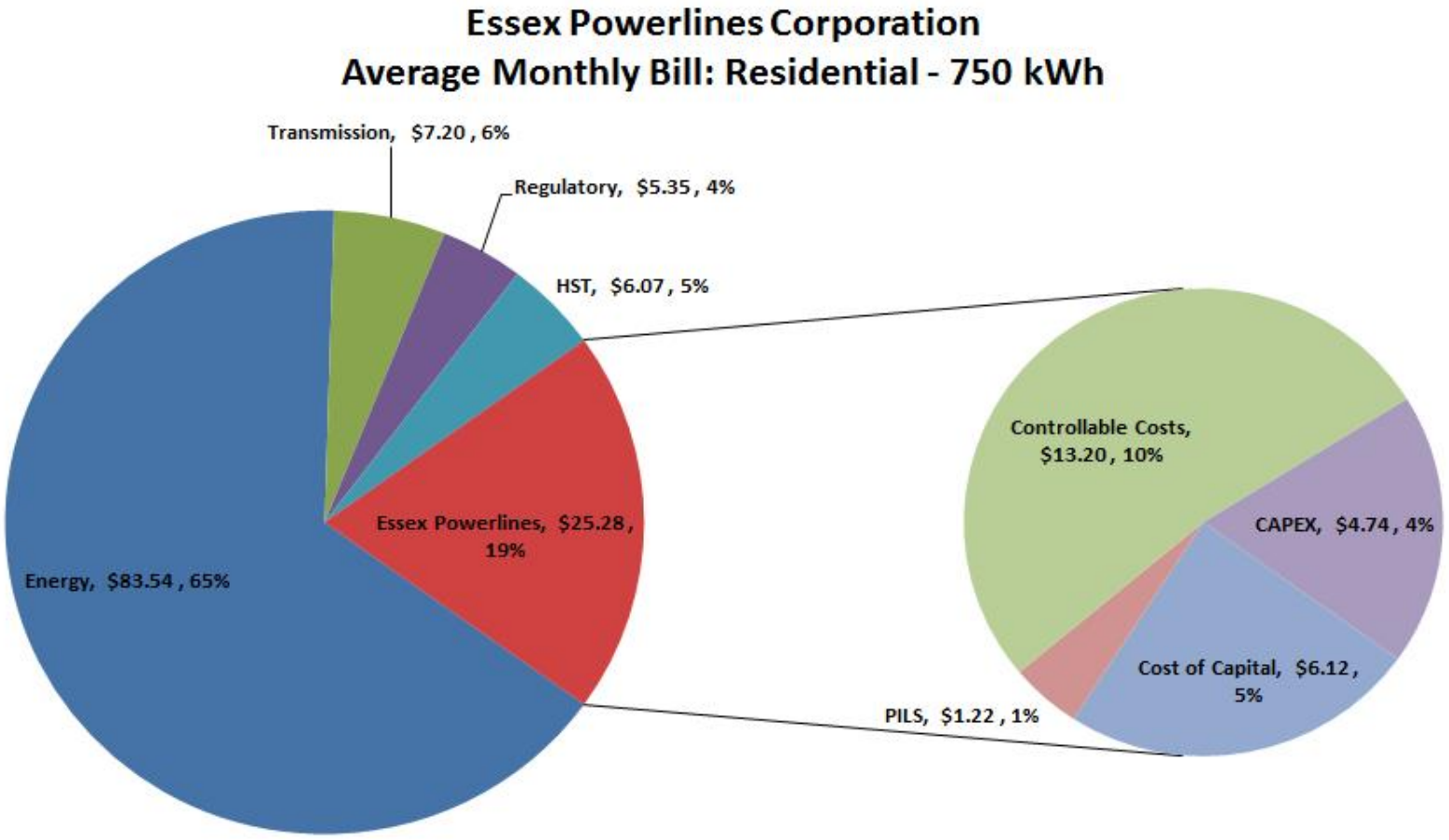
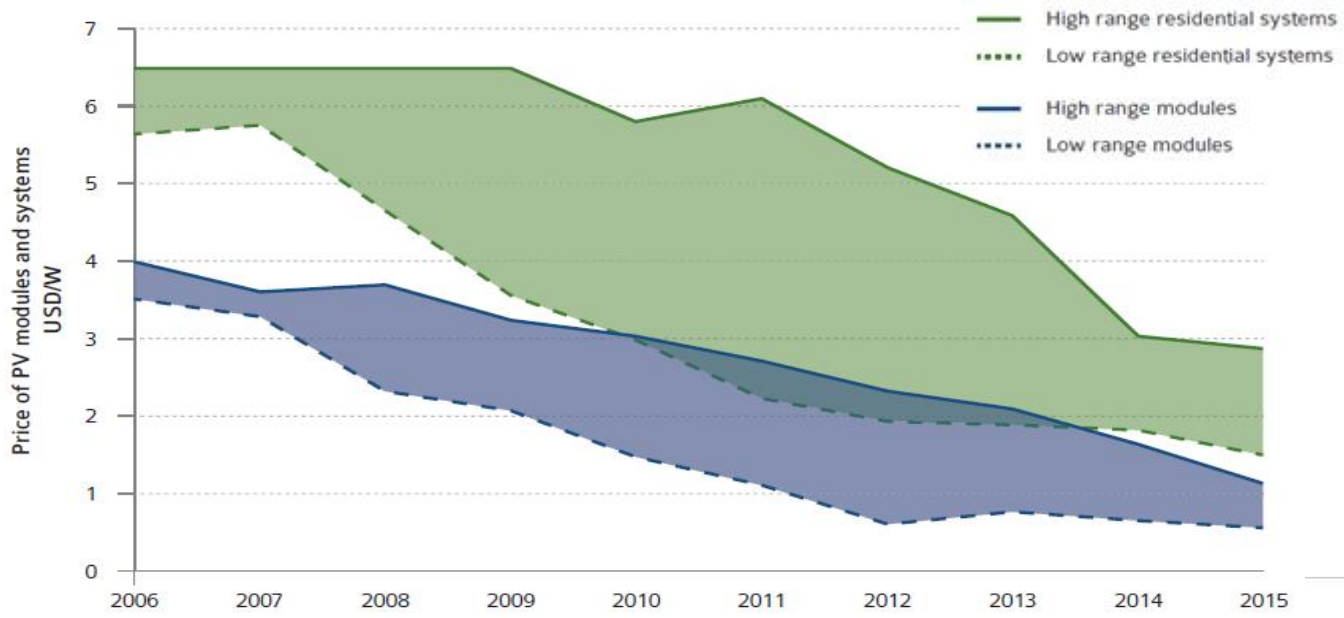


The Time for Zero Emission Communities Is NOW!



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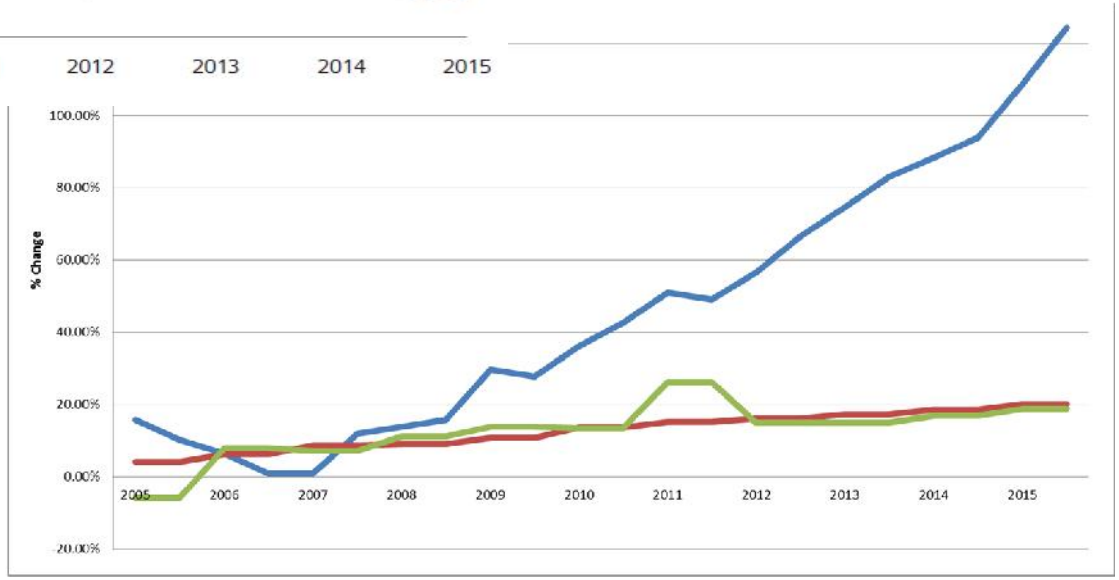

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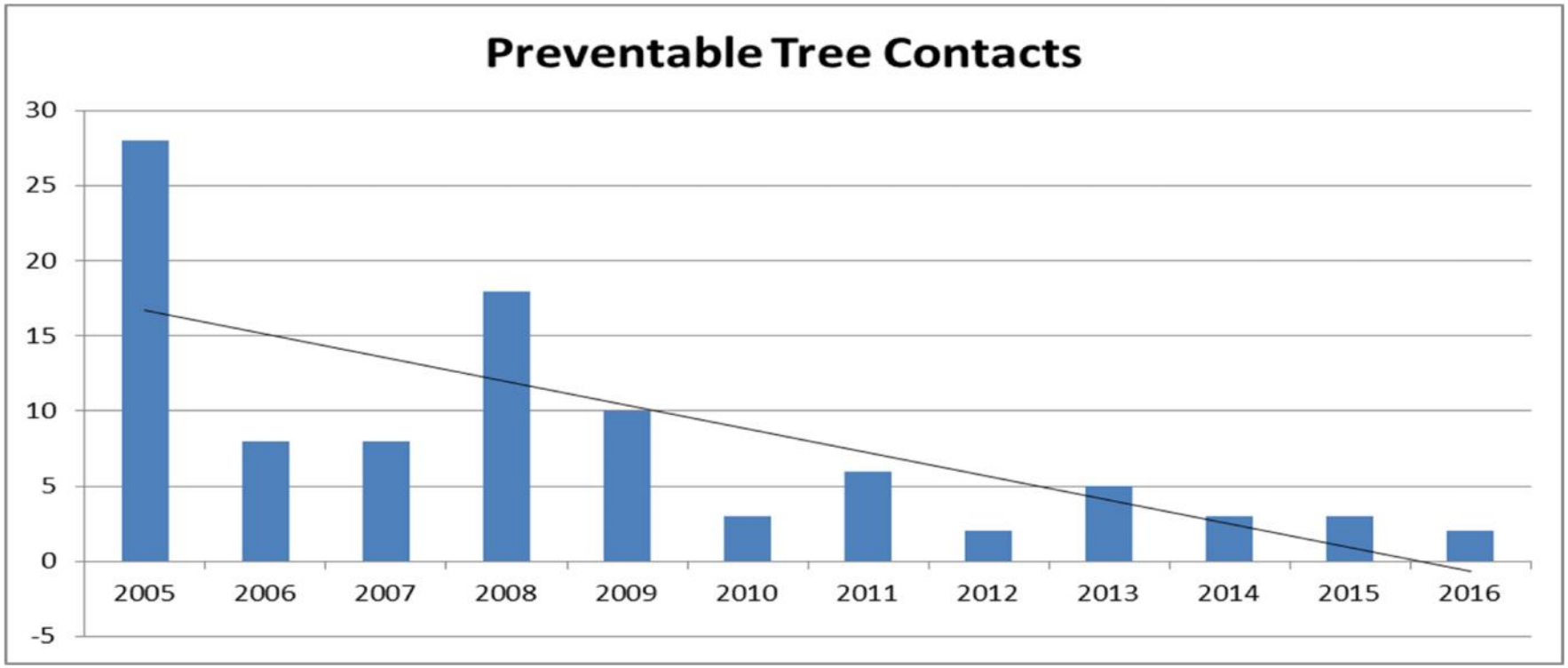

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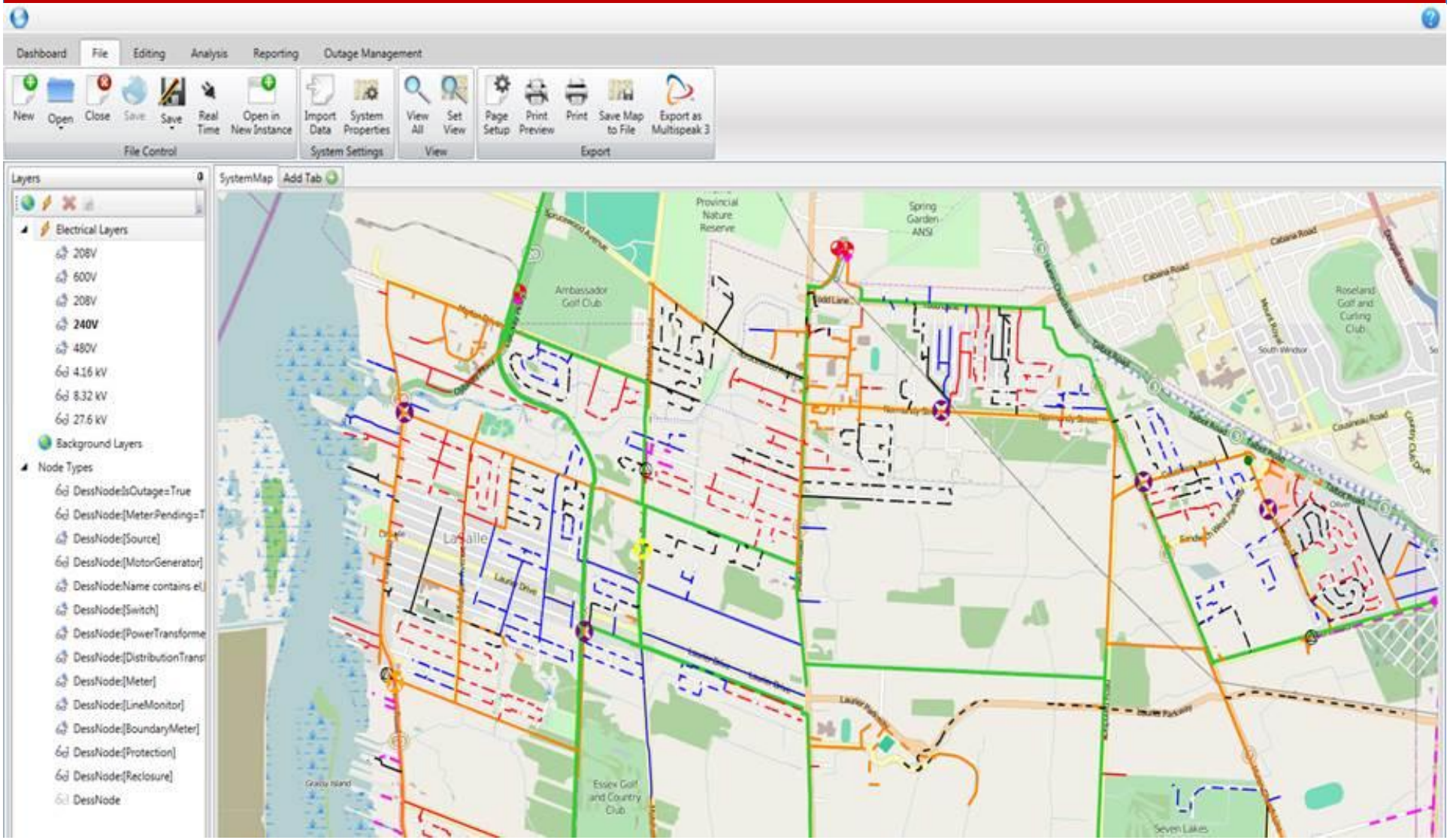

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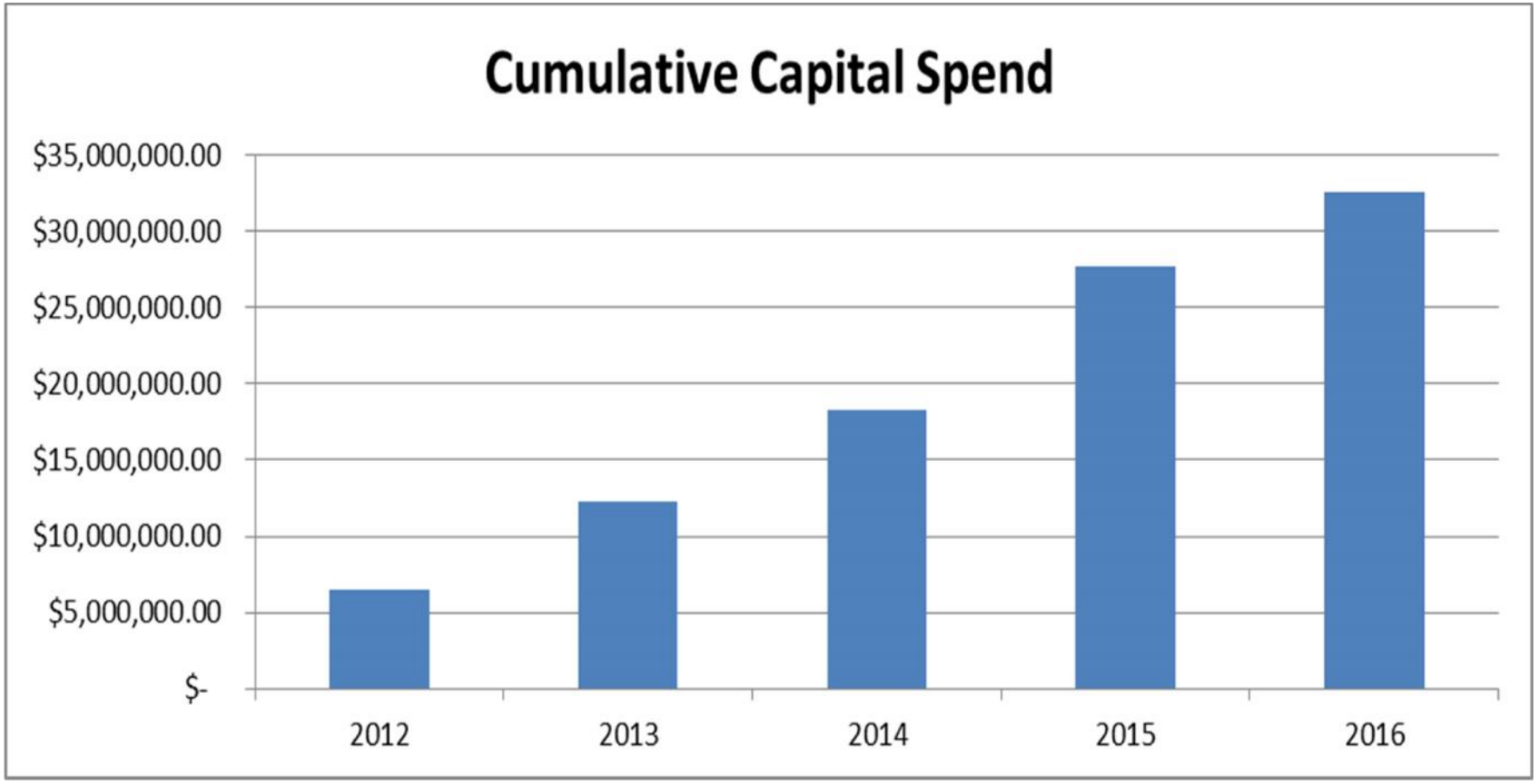
Re-Investing In Our Infrastructure



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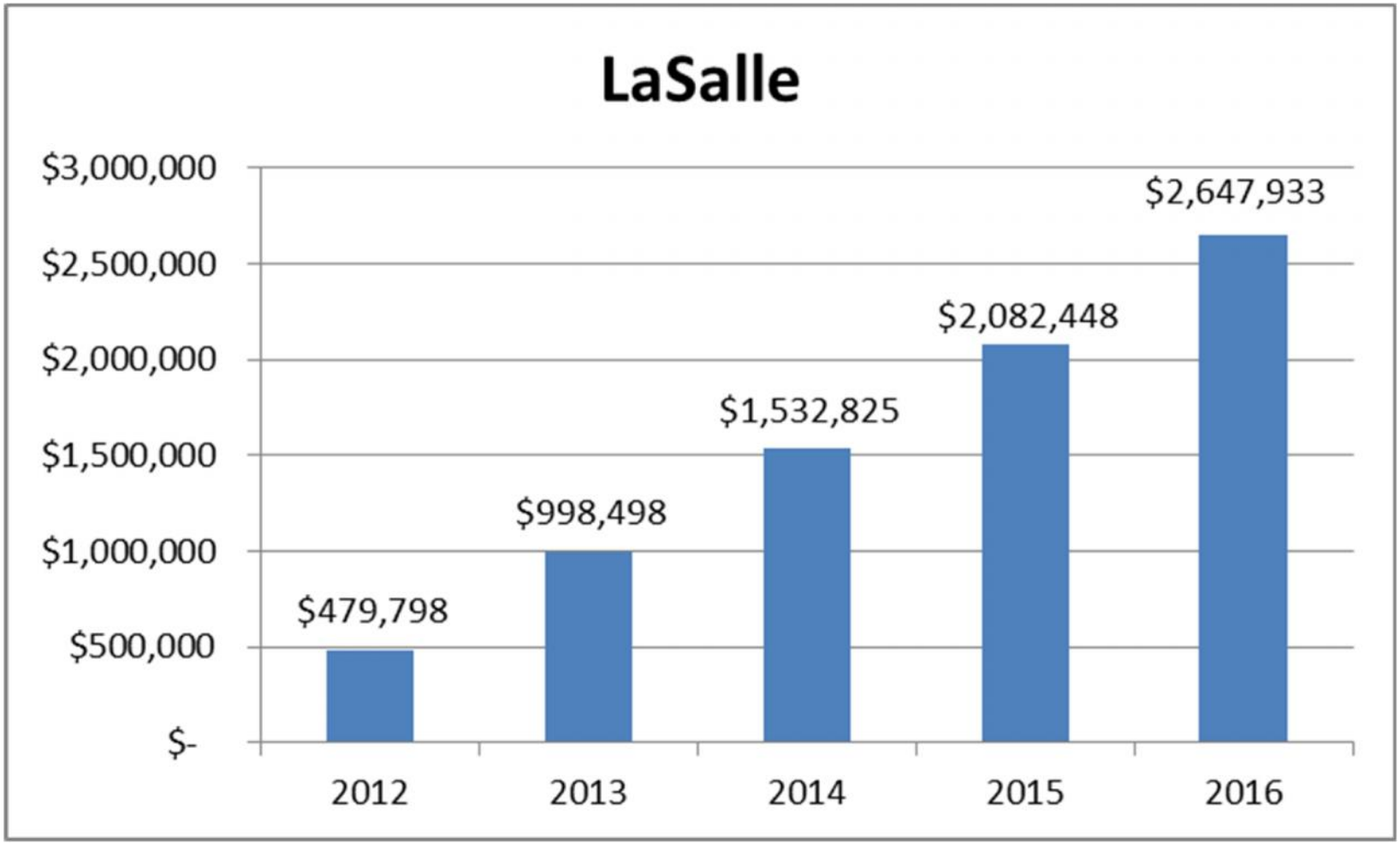

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- Pancake Breakfast with Santa and the Mayor
- Kids DJ Dance Party

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Council Presentation - Leamington

Essex Power Corporation
YOUR COMMUNITY PARTNER

April, 2017

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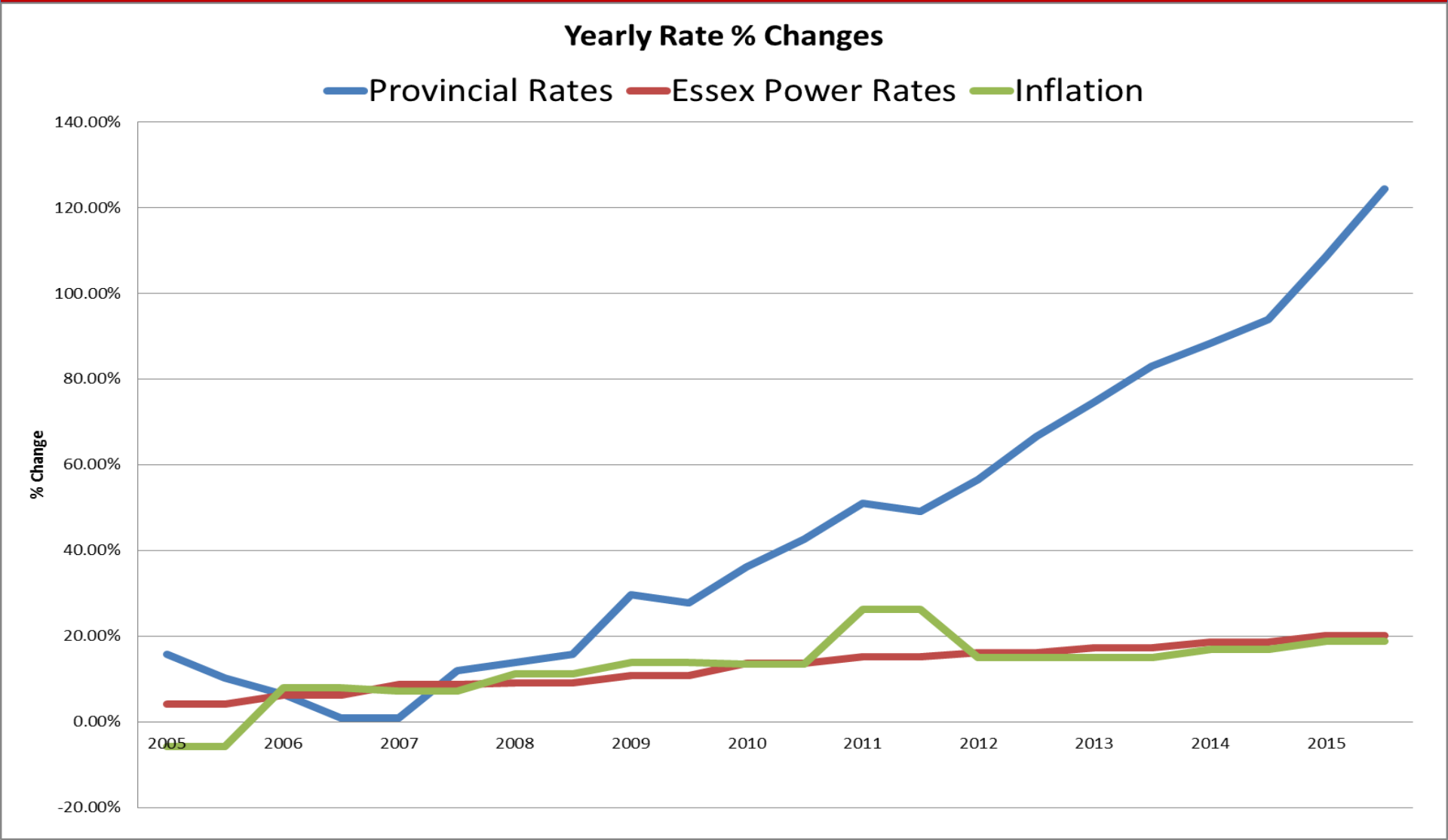

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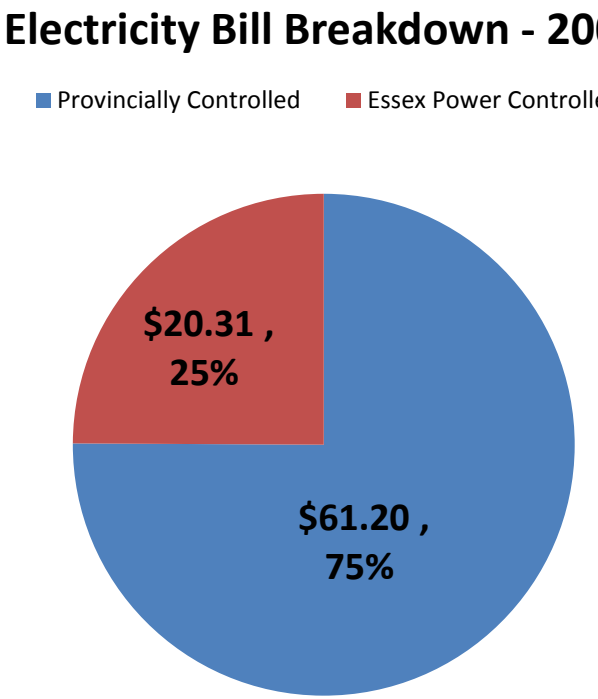

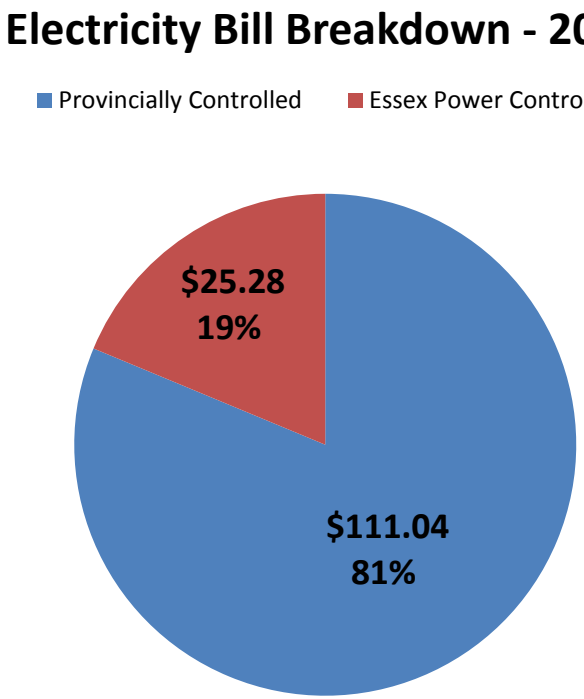

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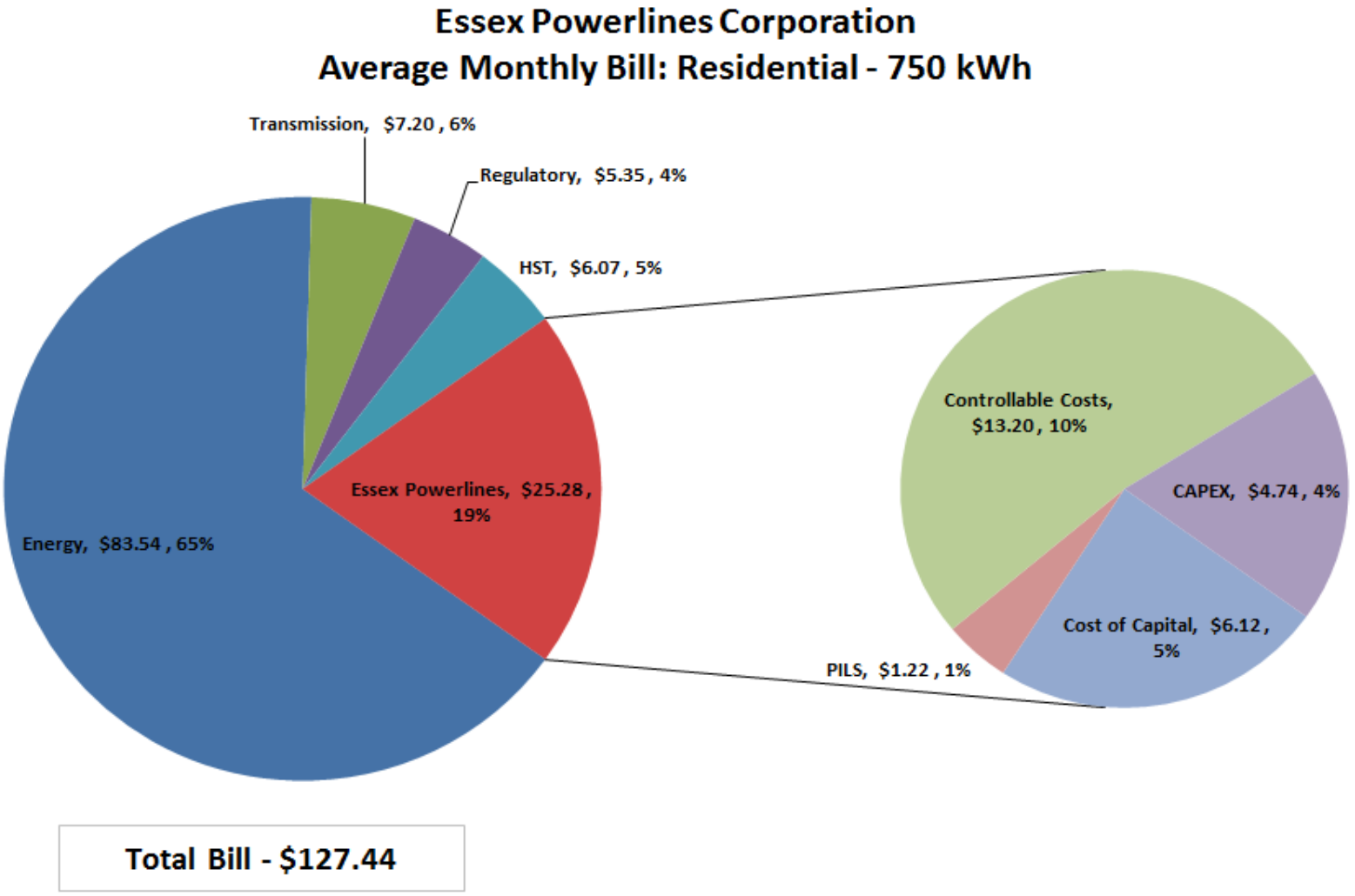

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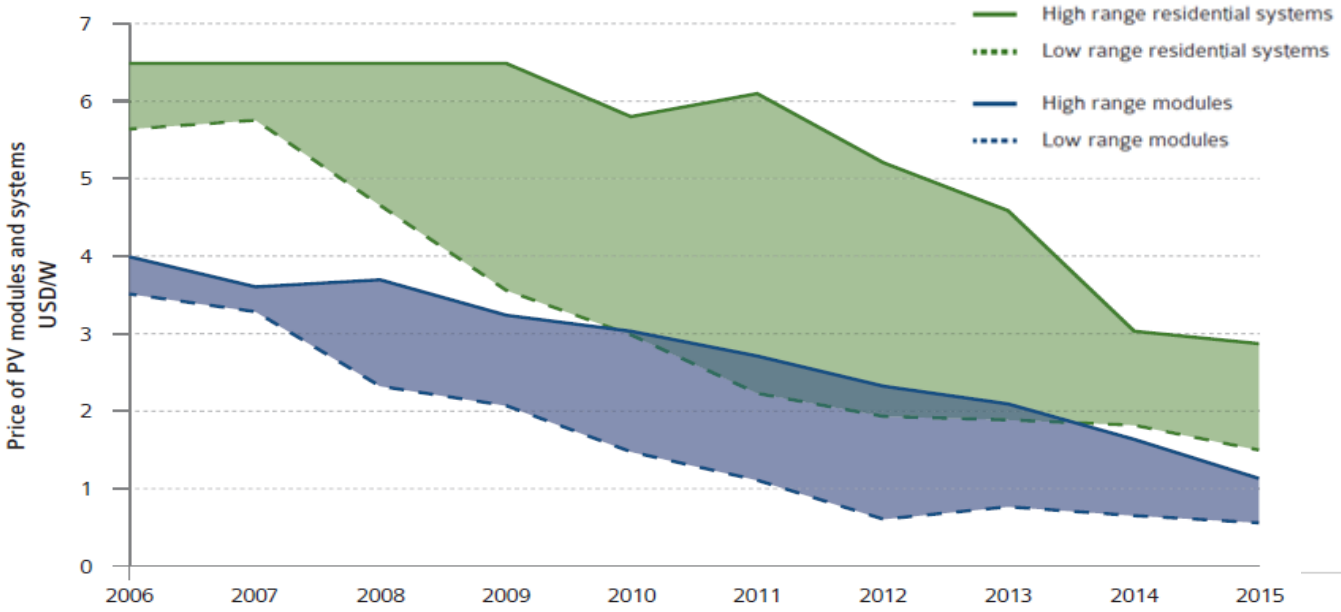

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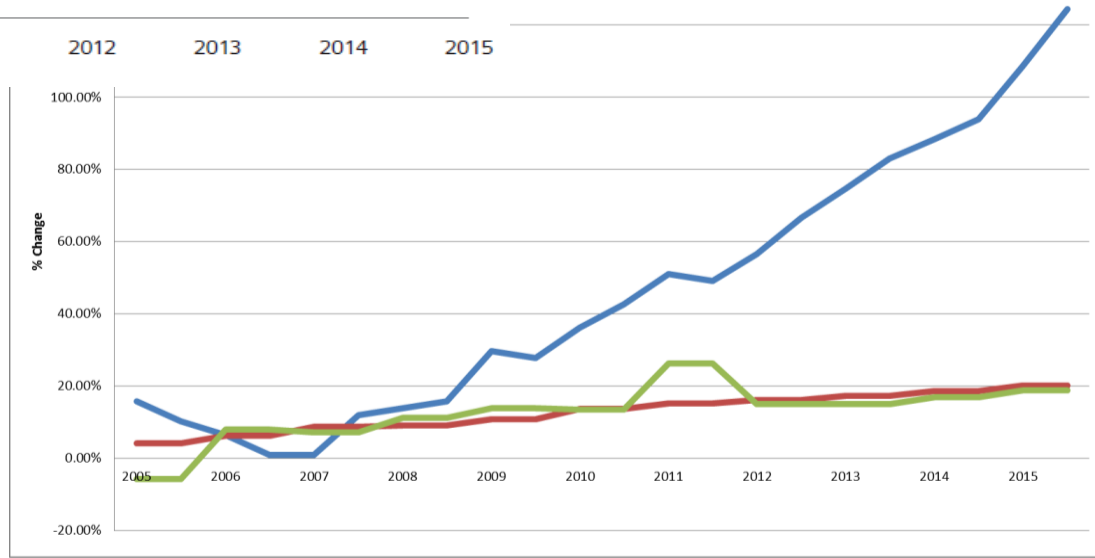

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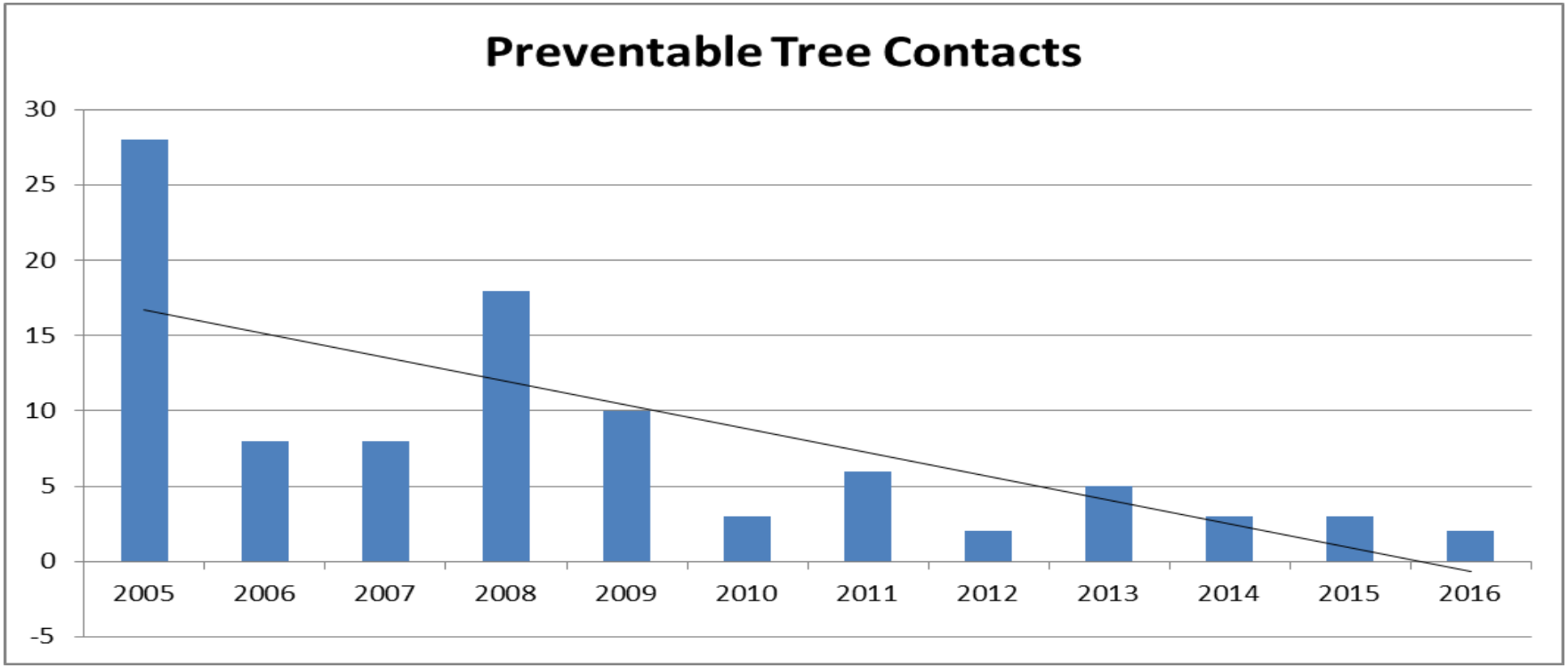

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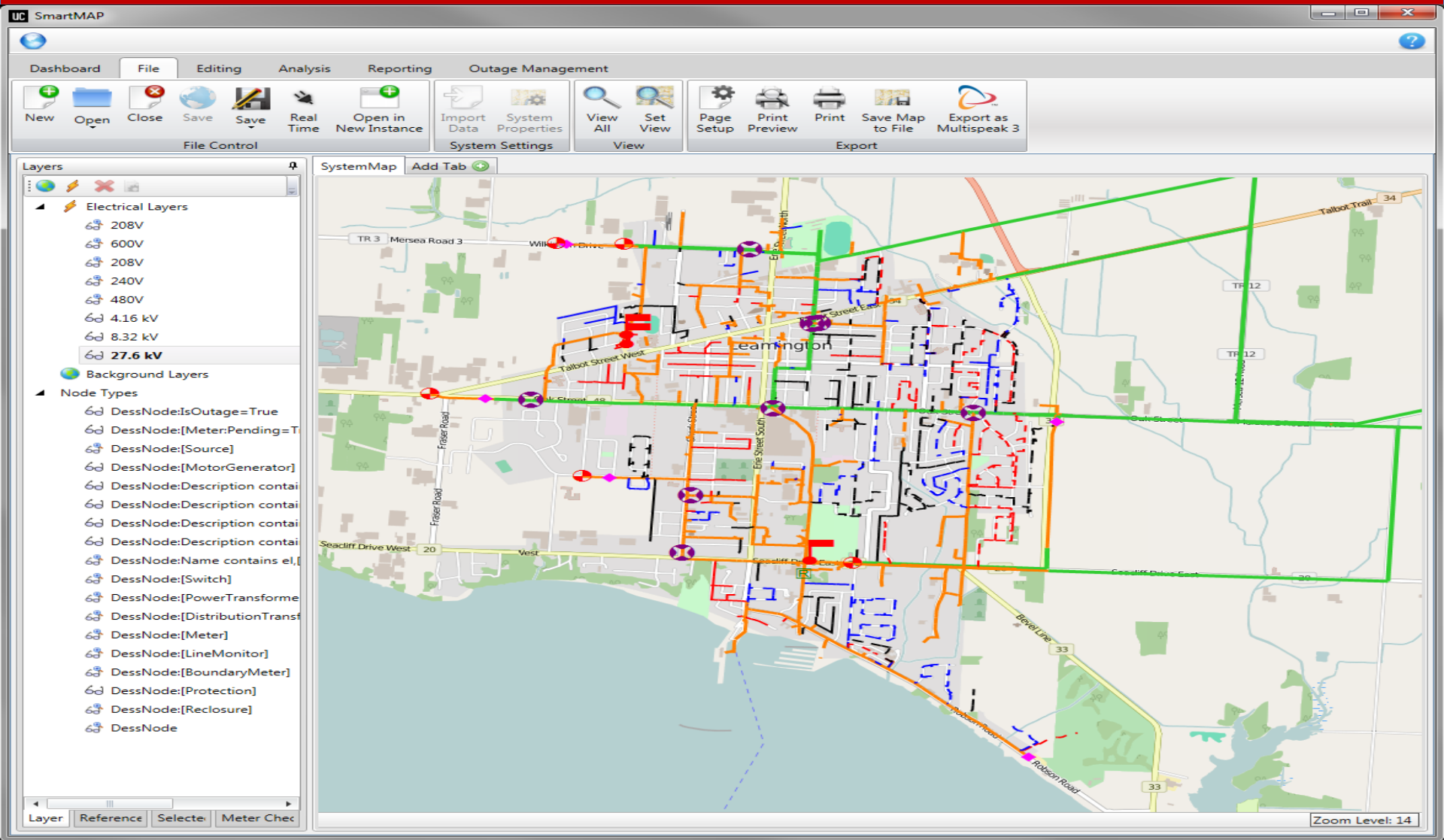

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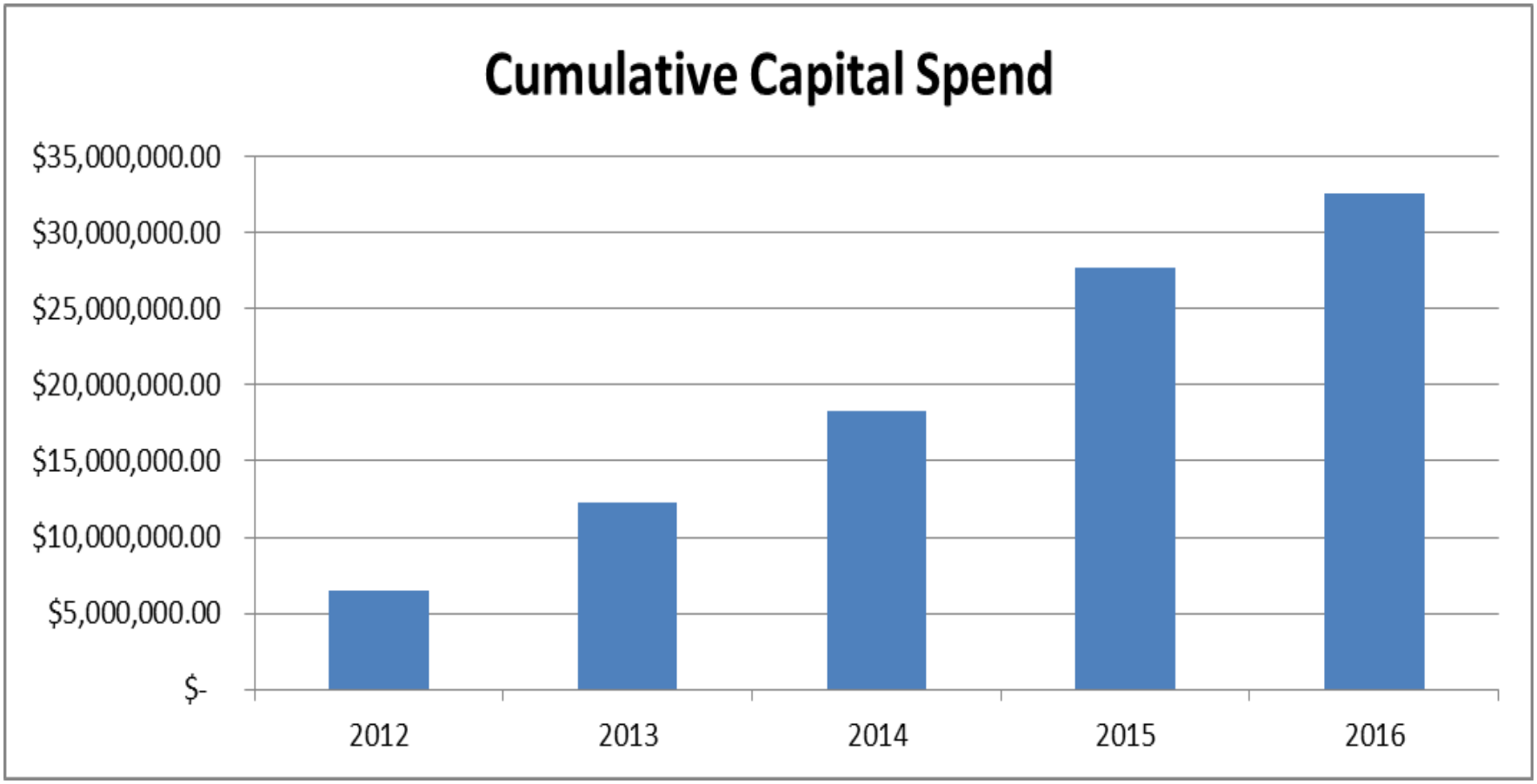
8	E.L.K. Energy Inc.	$ 223.38	11,704
9	Lakefront Utilities Inc.	$ 224.29	10,125
10	London Hydro Inc.	$ 225.29	153,947
11	Westario Power Inc.	$ 229.18	22,954
12	Peterborough Distribution Incorporated	$ 231.48	36,317
13	Entegrus Powerlines Inc.	$ 232.16	40,659
14	St. Thomas Energy Inc.	$ 232.60	17,072
15	Brantford Power Inc.	$ 232.85	39,127
16	Essex Powerlines Corporation	$ 235.45	28,892
17	Waterloo North Hydro Inc.	$ 239.32	55,416
18	Hydro Ottawa Limited	$ 248.05	323,919
19	Ottawa River Power Corporation	$ 255.33	10,892
20	PowerStream Inc.	$ 257.77	358,772

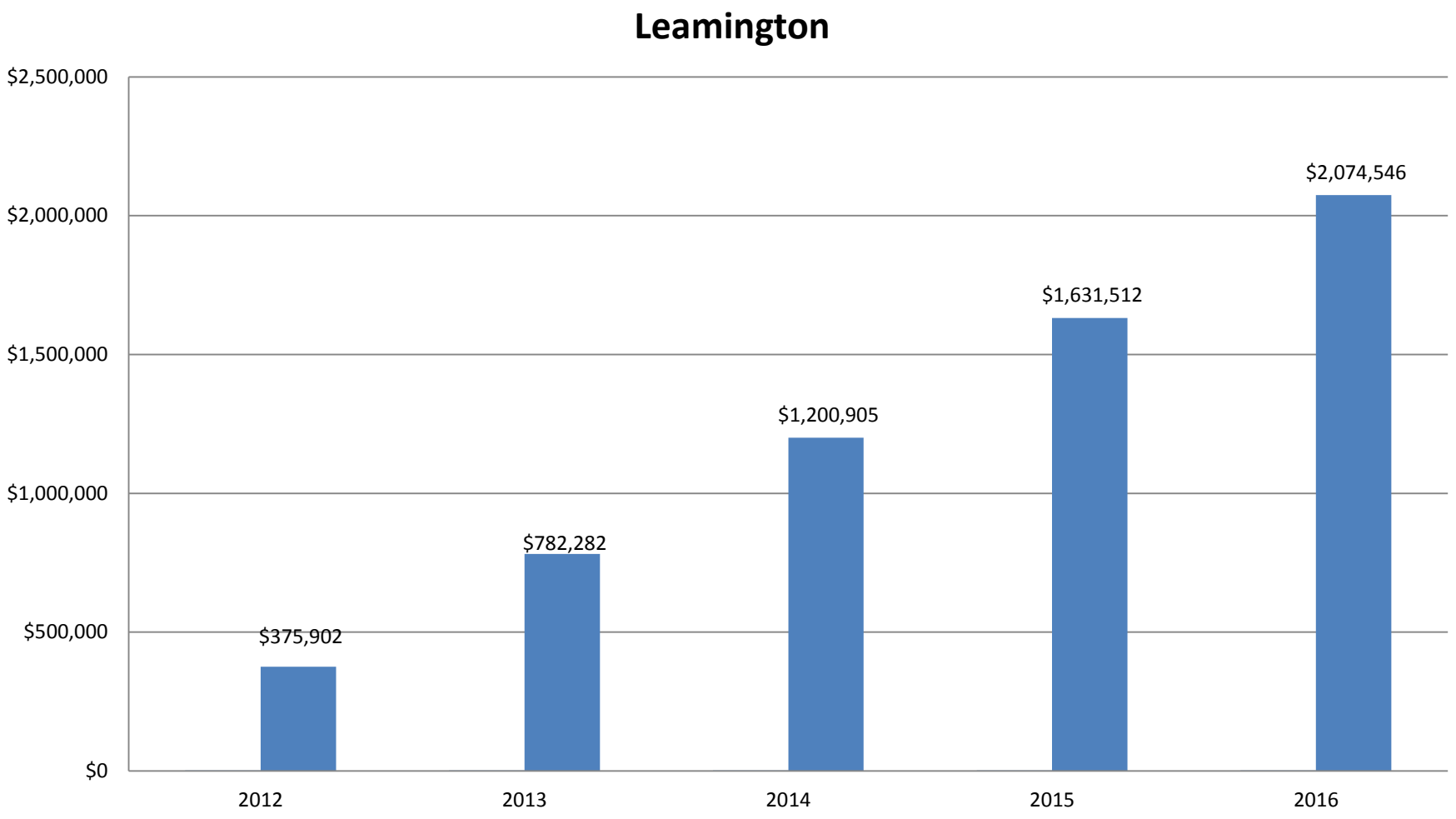
Worst Performers

	LDC Name	OM&A per Customer	Customer Count
60	Northern Ontario Wires Inc.	$ 393.99	6,075
61	Espanola Regional Hydro Distribution Corpora	$ 417.08	3,289
62	Kenora Hydro Electric Corporation Ltd.	$ 418.11	5,569
63	Fort Frances Power Corporation	$ 435.39	3,729
64	Wellington North Power Inc.	$ 447.52	3,725
65	Hearst Power Distribution Company Limited	$ 449.86	2,703
66	Hydro One Networks Inc.	$ 451.85	1,257,016
67	West Coast Huron Energy Inc.	$ 462.32	3,812
68	Sioux Lookout Hydro Inc.	$ 511.72	2,780
69	Chapleau Public Utilities Corporation	$ 599.82	1,229
70	Atikokan Hydro Inc.	$ 622.59	1,653
71	Algoma Power Inc.	$ 1,023.78	11,678

Re-Investing In Our Infrastructure



5 Year Cumulative Dividend Payment



Youth in Community Fund

Essex Power continues to invest in the
where we donate **$40,000** annually, divided equally amongst each municipality. **To date $160,000** has been given to the youth initiatives throughout EPL's distribution area.

Some of the Youth events and organizations the fund helped are

- Grade 9 Sherk Membership Program
- Grade 5 In Motion Swim Pass
- Mayor's Youth Advisory Committee activities
- Swim and Skates

Essex Power Helping Others in Our Communities

- Essex Power and Staff have donated nearly $6500 to the Leamington District & Ministerial Food Bank. EPC has also donated to other food banks in our service area.

- Essex Power has been a proud sponsor of Leamington's Community Festivals such as "Sip and Savour" and "Energy Forum for Agri. Business"

Recent Events – The Electricity Bill

- *Protecting Vulnerable Energy Consumers Act, 2017*
  - Prevents Distributors from disconnection or load limiters during the winter months
- *Ontario Rebate for Electricity Consumers Act, 2016*
  - Grants an 8% rebate (provincial portion of the HST)
- *Amendments to O. Reg. 442/01*
  - Increased the amount of RRRP rate protection eligible to rural Ontarians

Thank You. Questions?

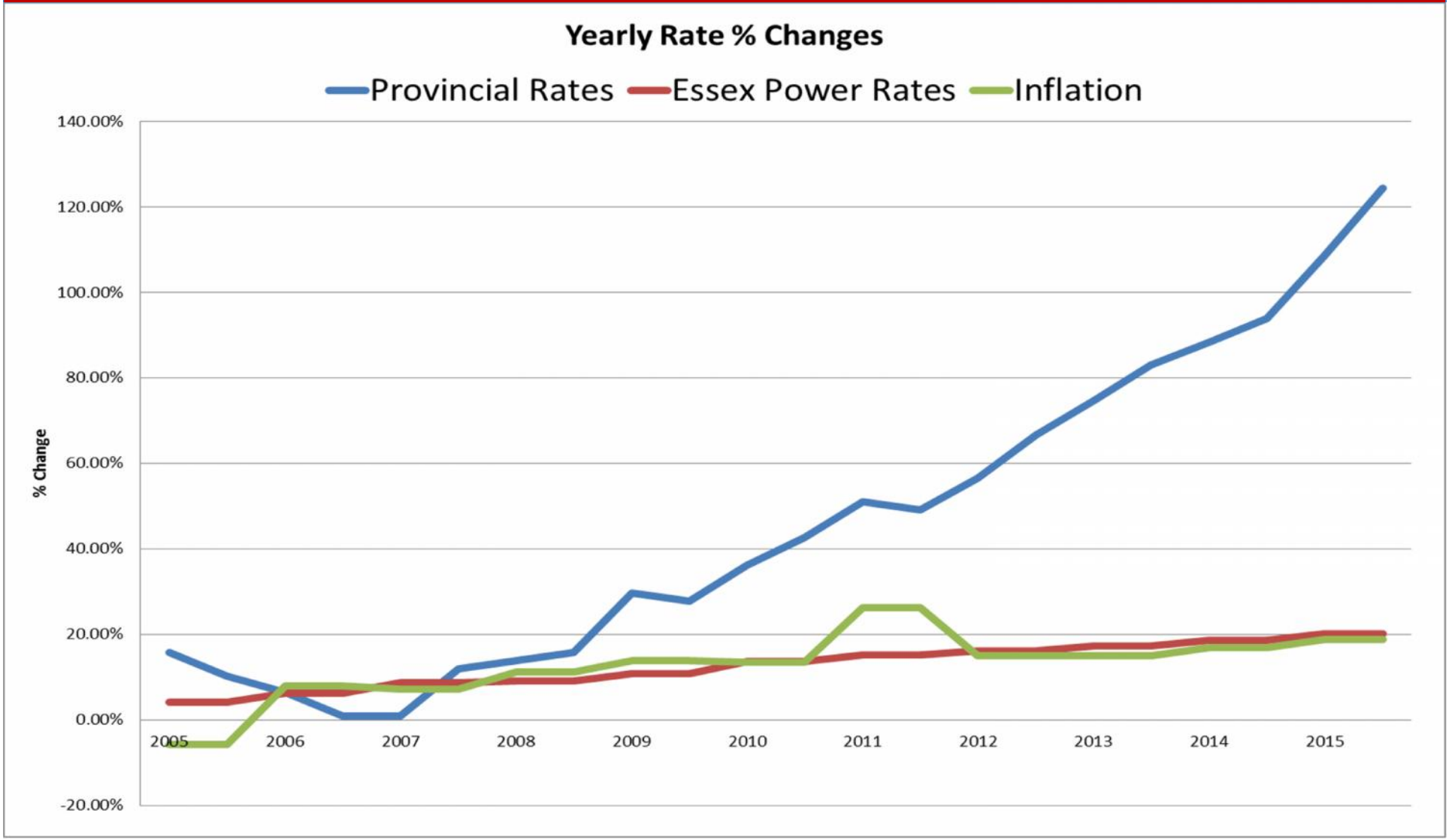
Attachment 1-H

Council Presentation - Tecumseh

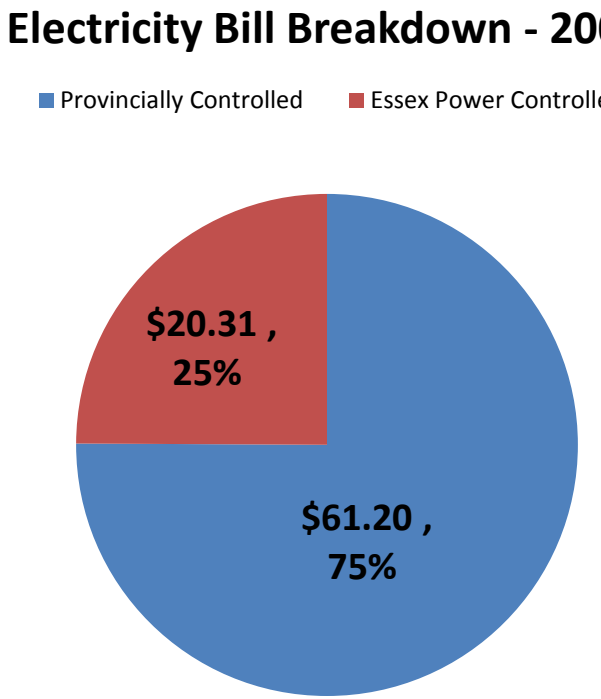
Essex Power Corporation
YOUR COMMUNITY PARTNER

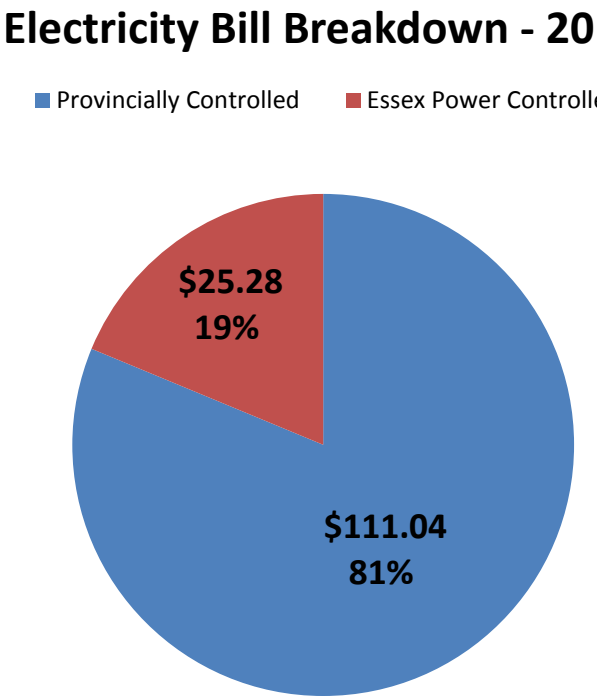
February, 2017

Provincial Electricity Costs are a pivotal concern for our Customers



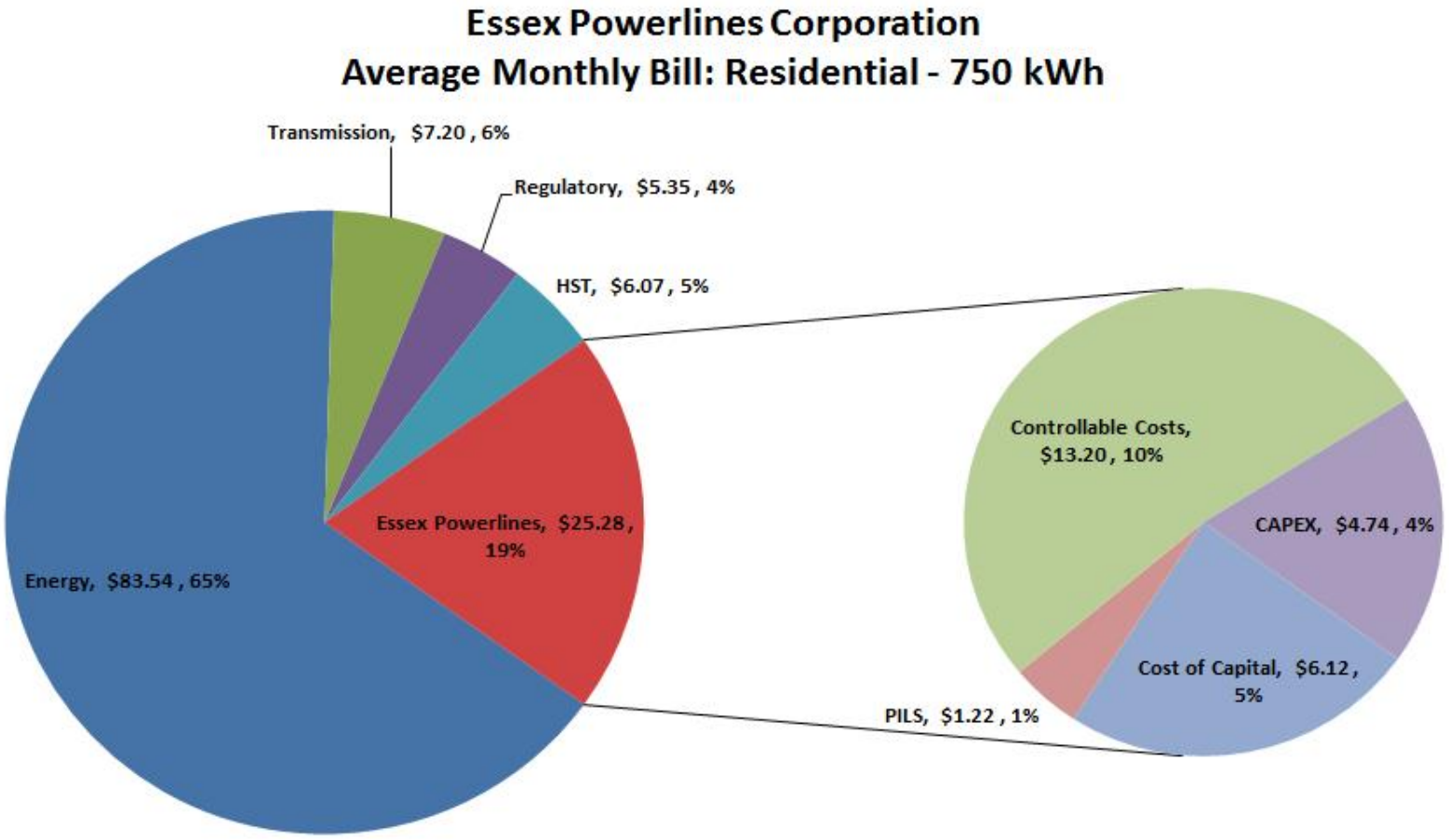
What portion of the overall bill does EPL represent?



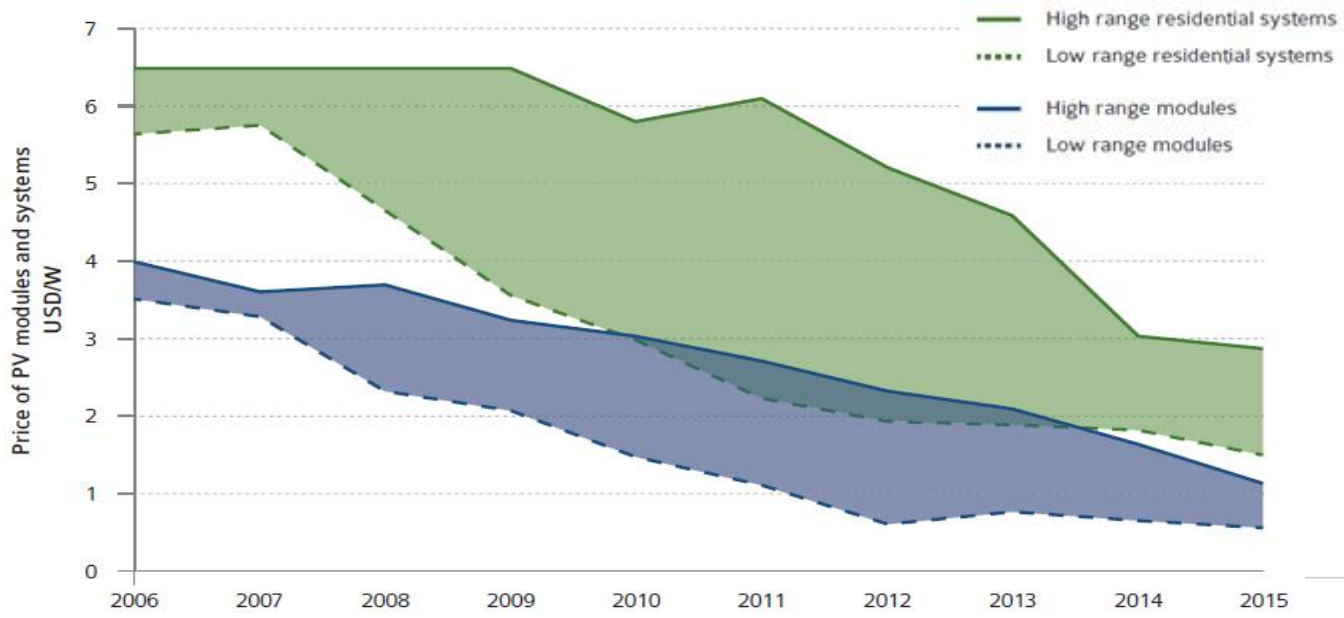


- For a typical Essex Powerlines residential electricity bill (800kWh/month), EPL's portion of the bill increased $5.29 while the provincial portion increased $49. 84 over the last 11 years.

What makes up EPL's portion of the bill

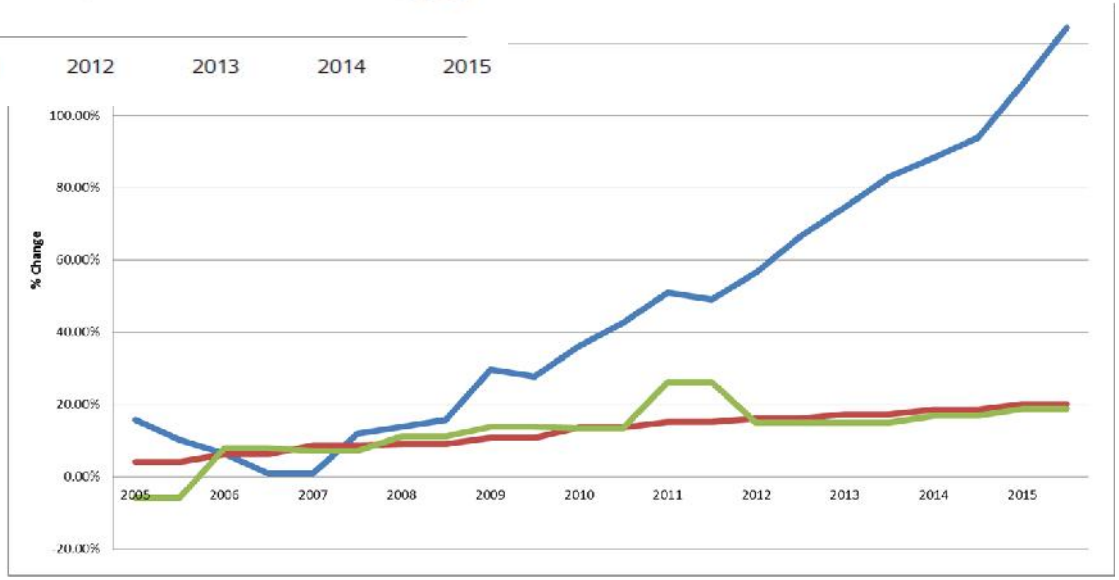


The Time for Zero Emission Communities Is NOW!



- Global costs of solar continue to fall;
- Provincial energy costs continue to rise well beyond the rate of inflation;

The time for zero emission communities is NOW!



Conservation and Demand Management

Essex Powerlines was one of 32 LDCs (out of 76) to accomplish their 2011-2014 targets;

Essex Powerlines is on pace to meet its conservation targets for the 2015-2020 framework;

Essex Powerlines on track to spend **$8.4M** between 2015-2020 to help its customers conserve energy and lower their electricity bills;

Conservation and Demand Management

Location	Municipality	Total $ Incentive	kWh Saved
Diageo	Amherstburg	$ 20,952.00	419,035 kWh
Centreline	LaSalle	$ 14,163.00	179,950 kWh
Highbury Canco	Leamington	$ 23,458.00	234,576 kWh
Bonduelle	Tecumseh	$ 32,882.00	328,822 kWh

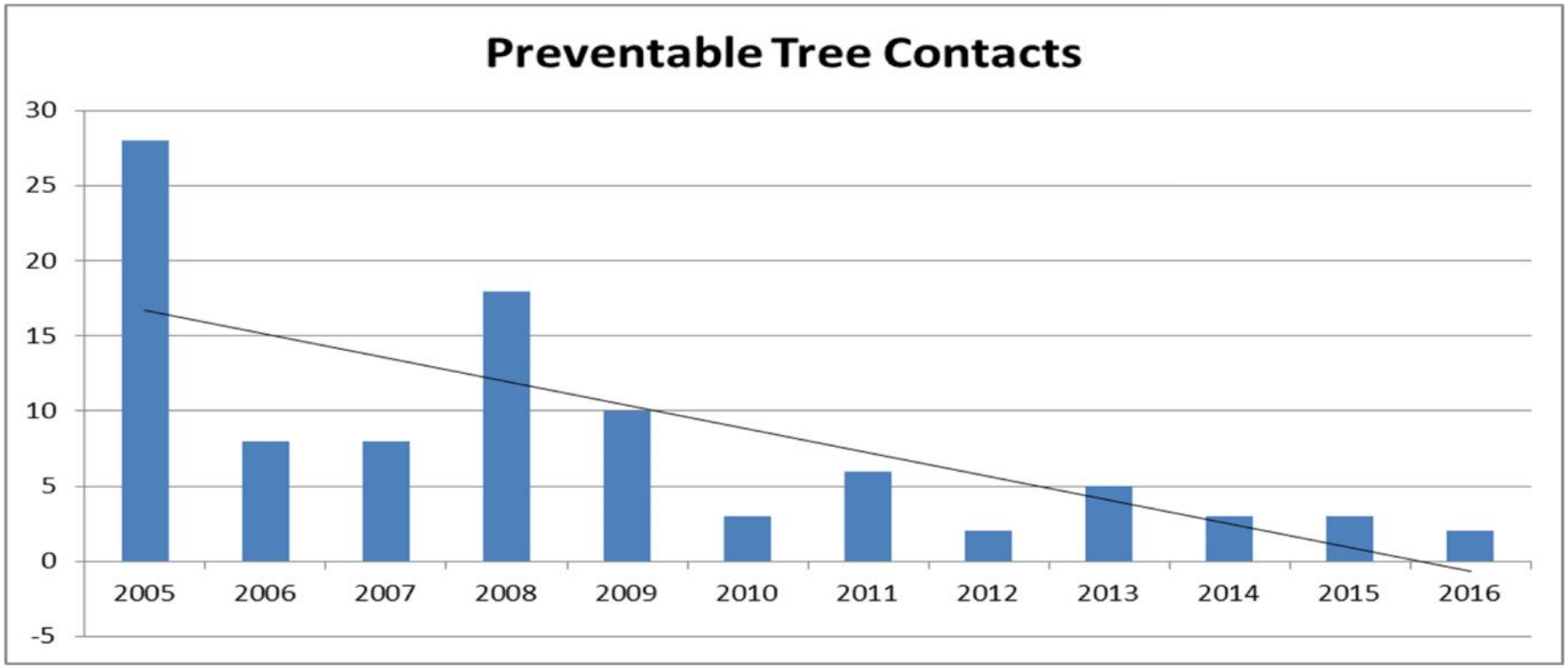
These retrofit projects alone will remove

1,170 cars off the road or shut off

11, 907 lightbulbs for a year!

Preventative Maintenance Results

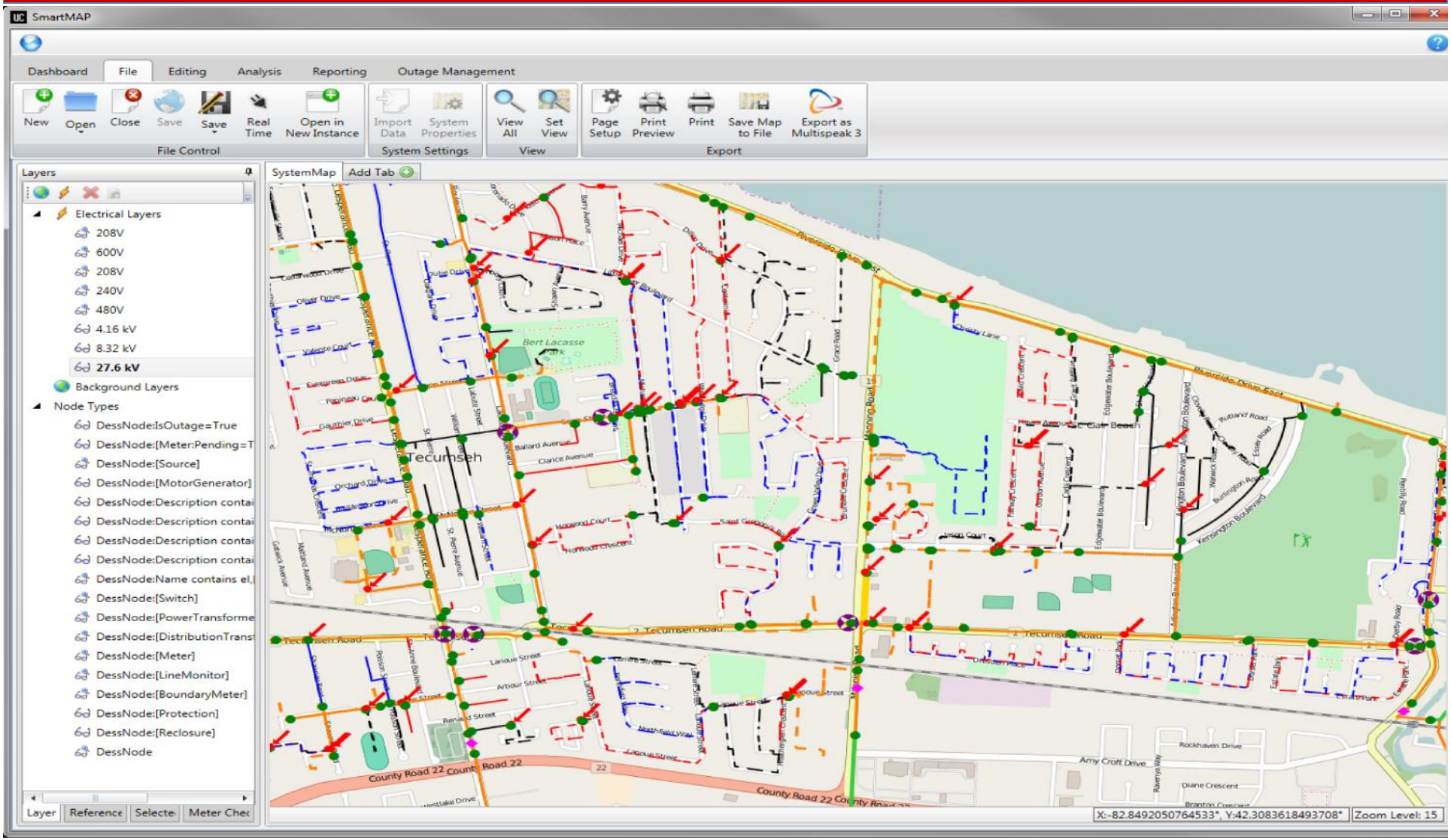
- EPL Preventative Maintenance Program has been successful in dramatically reducing outage frequency
- Infrared, ultrasonic, NDE, and visual
- Data is databased or geographical



Smart Grid – The 21st Utility

- Essex Power continues to CREATE and INVEST and new Smart Grid technologies
- Essex Powerlines has interactive “real time” modelling of it’s entire right up to the each customer’s meter
- This will allow us to immediately diagnose any system problem, improve restoration times or even prevent outages before they occur in the future

Smart Grid – The 21st Utility



OEB OM&A Provincial Ranking

Top Performers

	LDC Name	OM&A per Customer	Customer Count
1	Hydro Hawkesbury Inc.	$ 174.13	5,510
2	Kitchener-Wilmot Hydro Inc.	$ 178.78	92,404
3	Hydro One Brampton Networks Inc.	$ 180.72	154,105
4	Oshawa PUC Networks Inc.	$ 211.45	55,949
5	Newmarket-Tay Power Distribution Ltd.	$ 214.43	35,171
6	Wasaga Distribution Inc.	$ 217.42	13,172
7	Veridian Connections Inc.	$ 223.01	118,481
8	E.L.K. Energy Inc.	$ 223.38	11,704
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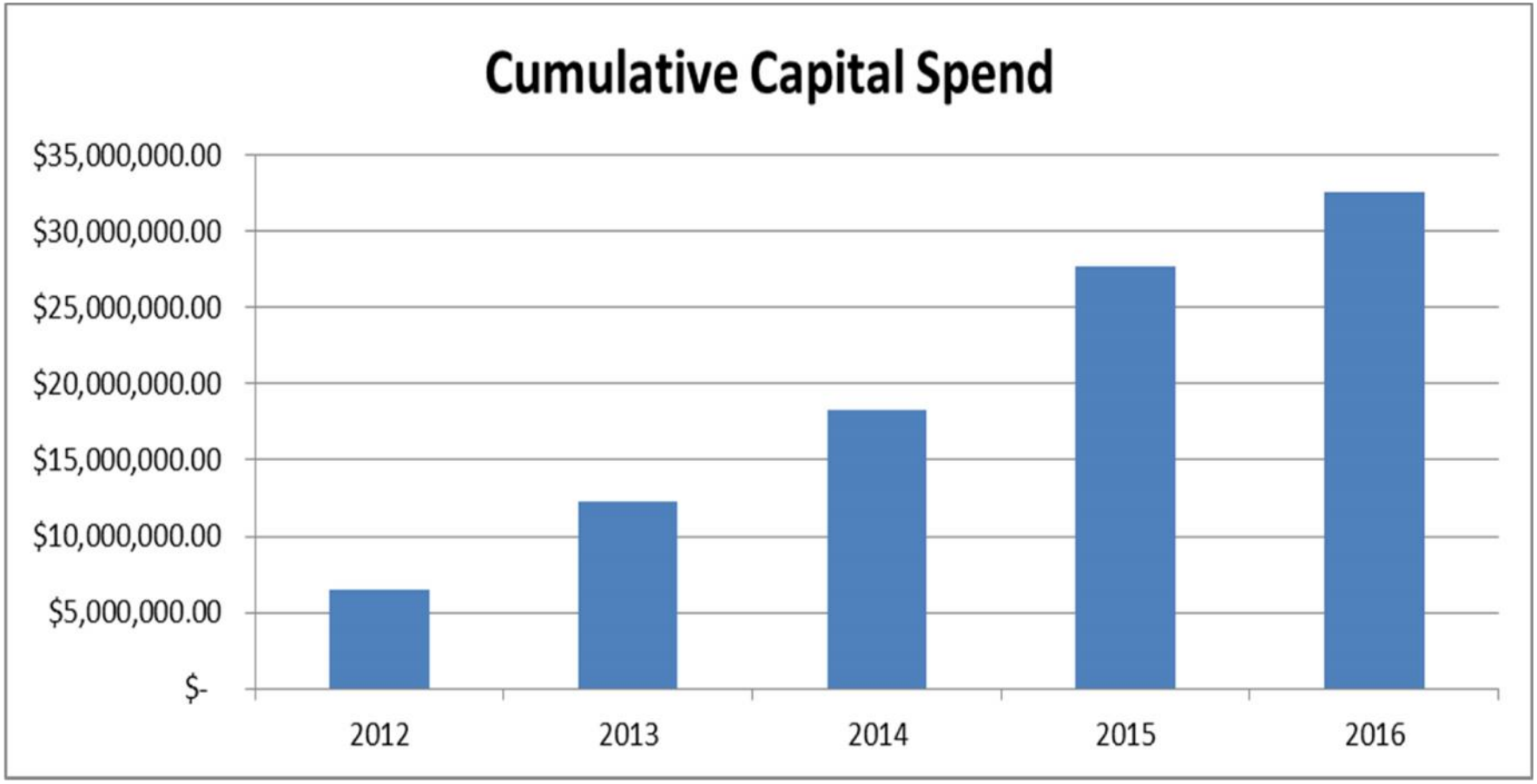
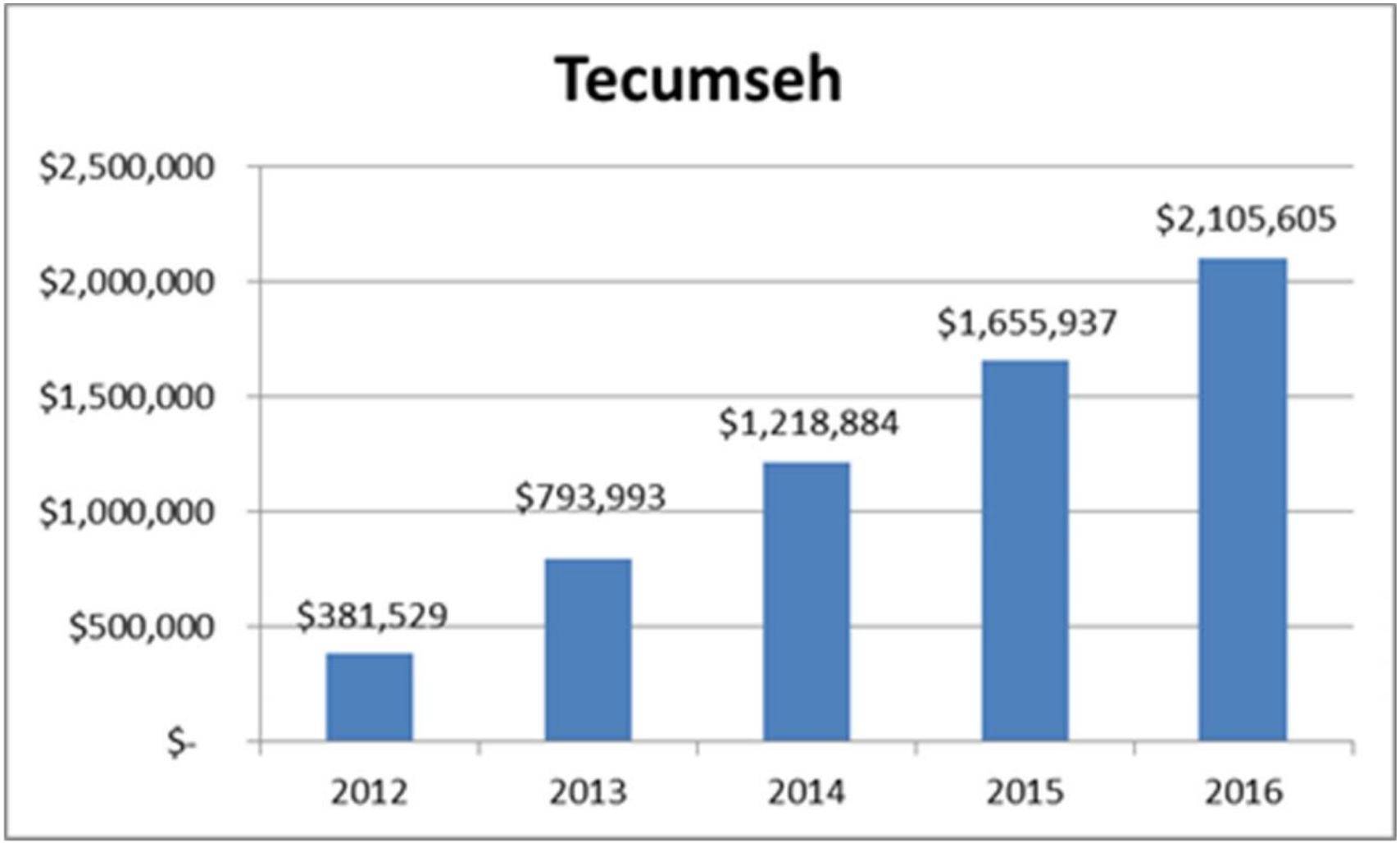
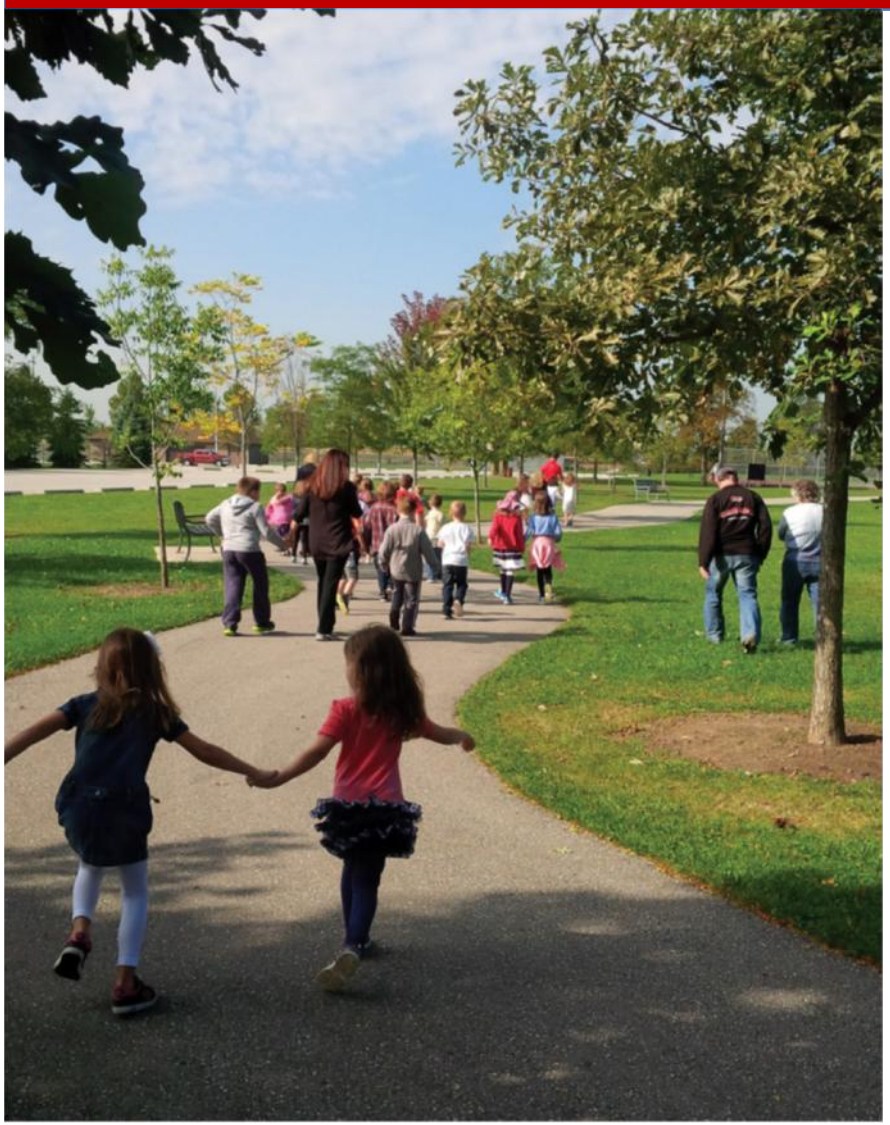
Re-Investing In Our Infrastructure



5 Year Cumulative Dividend Payment



Youth in Community Fund



Essex Power continues to invest in the where we donate **$40,000** annually, divided equally amongst each municipality. **To date $160,000** has been given to the youth initiatives throughout EPL's distribution area.

Some of the Youth events and organizations the fund helped are

- Tecumseh Soccer Club
- Tecumseh Minor Baseball
- Skateboard Competition
- In Motion Walk
- Christmas in Tecumseh

Essex Power Helping Others in Our Communities

- Essex Power and Staff have donated over $6000 to the Tecumseh Goodfellows, along with other food banks in our service area.

- Essex Power has been a proud sponsor of Tecumseh' s Community Festivals such as the annual Corn Fest, Taste of Tecumseh Fest and more

Tecumseh Corn Festival

TASTE of TECUMSEH
FOOD - BEER - WINE - MUSIC
LAKEWOOD PARK

Recent Events – The Electricity Bill

- *Protecting Vulnerable Energy Consumers Act, 2017*
  - Prevents Distributors from disconnection or load limiters during the winter months
- *Ontario Rebate for Electricity Consumers Act, 2016*
  - Grants an 8% rebate (provincial portion of the HST)
- *Amendments to O. Reg. 442/01*
  - Increased the amount of RRRP rate protection eligible to rural Ontarians

Thank You. Questions?

Attachment 1-I

AGM Presentation

ESSEX POWER CORPORATION

Welcome to our 2016 *Annual Shareholder Meeting*

July 26, 2017

Empowering Innovation

Welcome!

Essex Power is proud to present our 2016 Corporate results.

The results continue to demonstrate to our stakeholders the value of a "**local** and **accountable**" energy provider to the **communities** and customers we serve.

The ongoing and future success of Essex Power relies on **embracing** the evolving landscape of the Ontario electric distribution sector and **capturing** the ever growing **opportunities** in new **technologies**.

Essex Power remains committed to ensure our communities are served to the highest standards and that we ourselves are **leaders in sustainability**

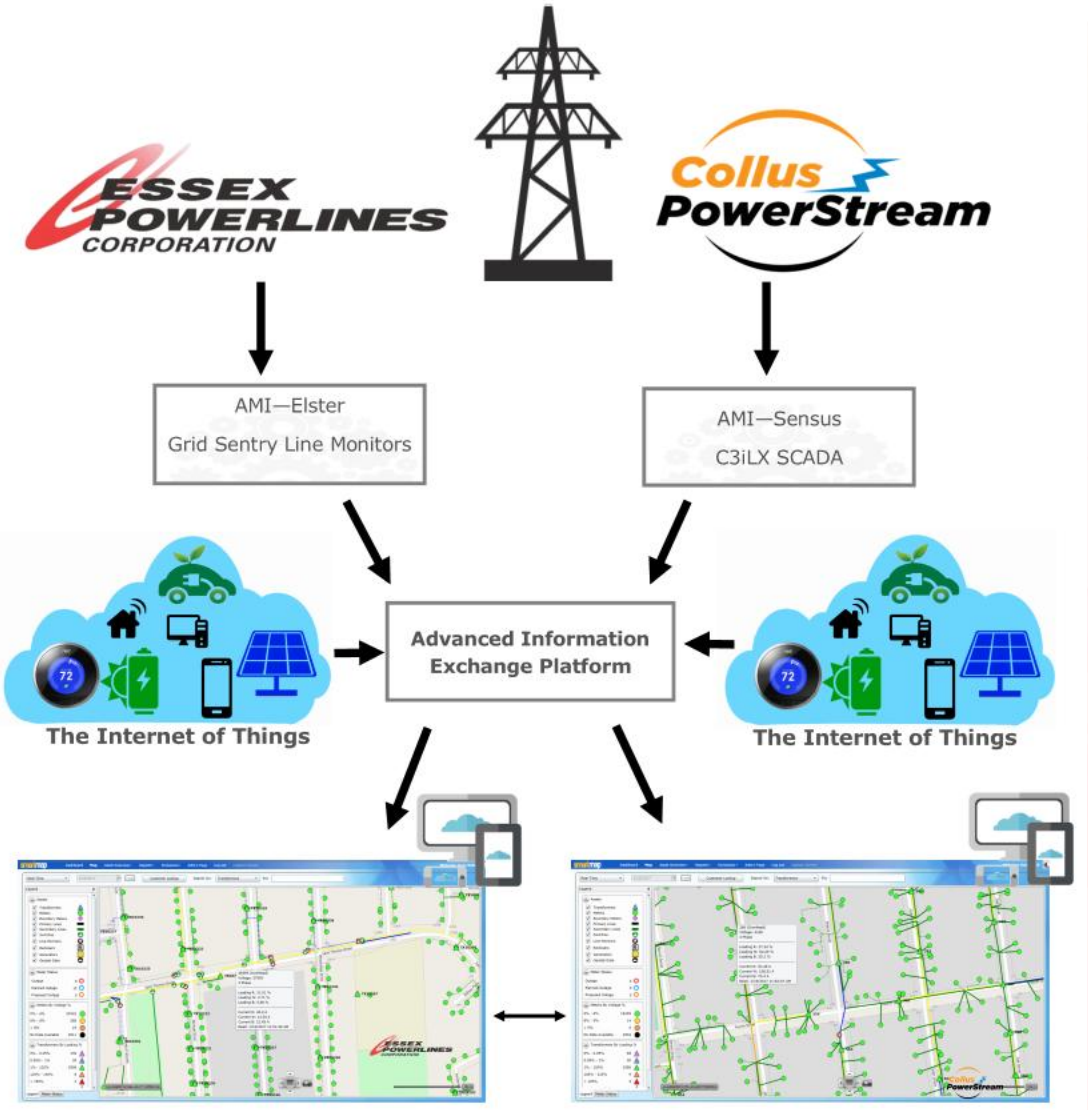
Sustainable Reporting

We are committed to evaluating our business against sustainability performance measures. ***Social, Economic*** *and* ***Environmental*** *performance* is **vital** for long term growth and future of the communities in which we serve. This is Essex Power's fourth filing within the Global Reporting Initiative

Excellence in Innovation Award

Essex Powerlines was the joint recipient of the Electricity Distributors Association 2016 “Excellence in Innovation” award.
Essex Powerlines implementation of “SmartGrid 2.0 was recognized as a unique business model focused on INNOVATIVE and ways of creating value while having meaningful impact on customer satisfaction

Excellence in Innovation Award SmartGrid 2.0



Financial Highlights 2016

- Gross Electricity Sales – $83,704,839
- Net Revenue from Sales- $22,525,631
- Net Income before tax & interest - $4,553,754
- Net Income for the year - $3,184,753
- Dividends (Common and Special GS) Paid - $1,700,709
- Return on Equity – 17.0%
- Total value returned to the shareholders to date:
  - $51.80 Million
  - 276% return on shares
  - 16.6% average return per year

Consolidated Income Statement, December 31, 2016

	2016	2015
Electricity Revenue	$83,704,839	$76,025,181
Cost of Power	71,601,477	62,236,119
Gross Margin	12,103,362	13,789,062
Other revenue	10,422,269	11,338,697
Total Revenues	22,525,631	25,127,759
Expenses		
Oper, Maint & Admin	13,974,970	15,508,573
Amortization	3,984,907	4,798,203
Interest	1,039,520	1,025,155
Total Expenses	18,999,397	21,331,931
Income from operations	3,526,234	3,795,828
Other Revenue and Expenses	118,036	(334,683)
Income before taxes	3,644,270	3,461,145
Income taxes	459,517	90,000
Net income for the year	3,184,753	3,371,145
Retained earnings (deficit) at beg of year	13,604,436	11,886,000
Regulatory adjustments	521,000	-
Net income	3,184,753	3,371,145
Dividends	(1,700,709)	(1,652,709)
Retained earnings (deficit) at end of year	$15,609,480	$13,604,436

2016 Highlights

- 2016 Capital expenditures $5.80M
  - EPL Capital expenditures $4.50M
- 2016 New Service connections 346 (2015- 254)

2016 Fast Facts
Essex Powerlines (Regulated)

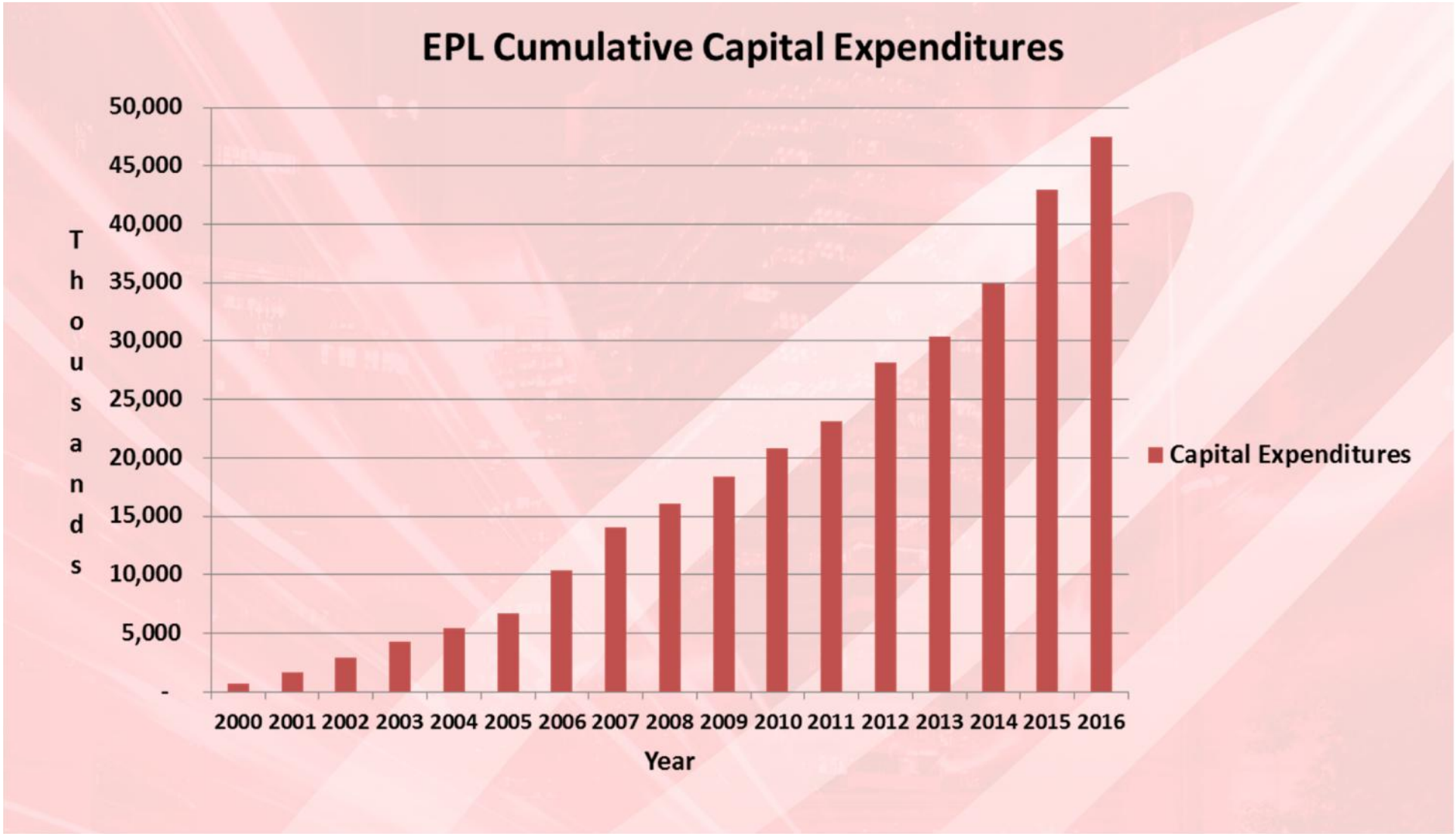
$53,773,779 Assets

- 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

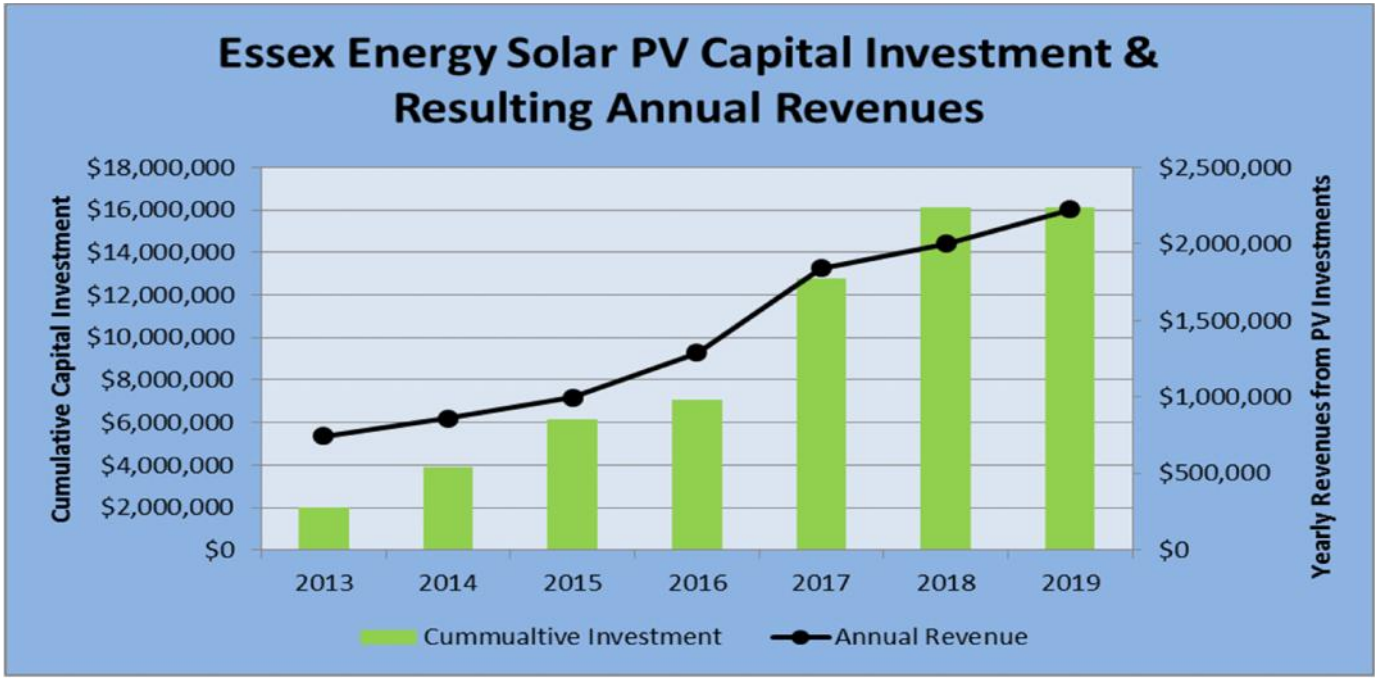
29,095 Customers

- Total Electricity Customers 29,095
- Total Electricity Consumed 505,521,588 kWh
- Number of Residential Customer Accounts 27,131
- Total Electricity Consumption 255,480,799 kWh
- Number of Commercial & Industrial Accounts 5,401
- Total Electricity Consumption 250,040,789 kWh

ESSEX POWER CORPORATION



Strategic Investment Leads to Consistent Growth



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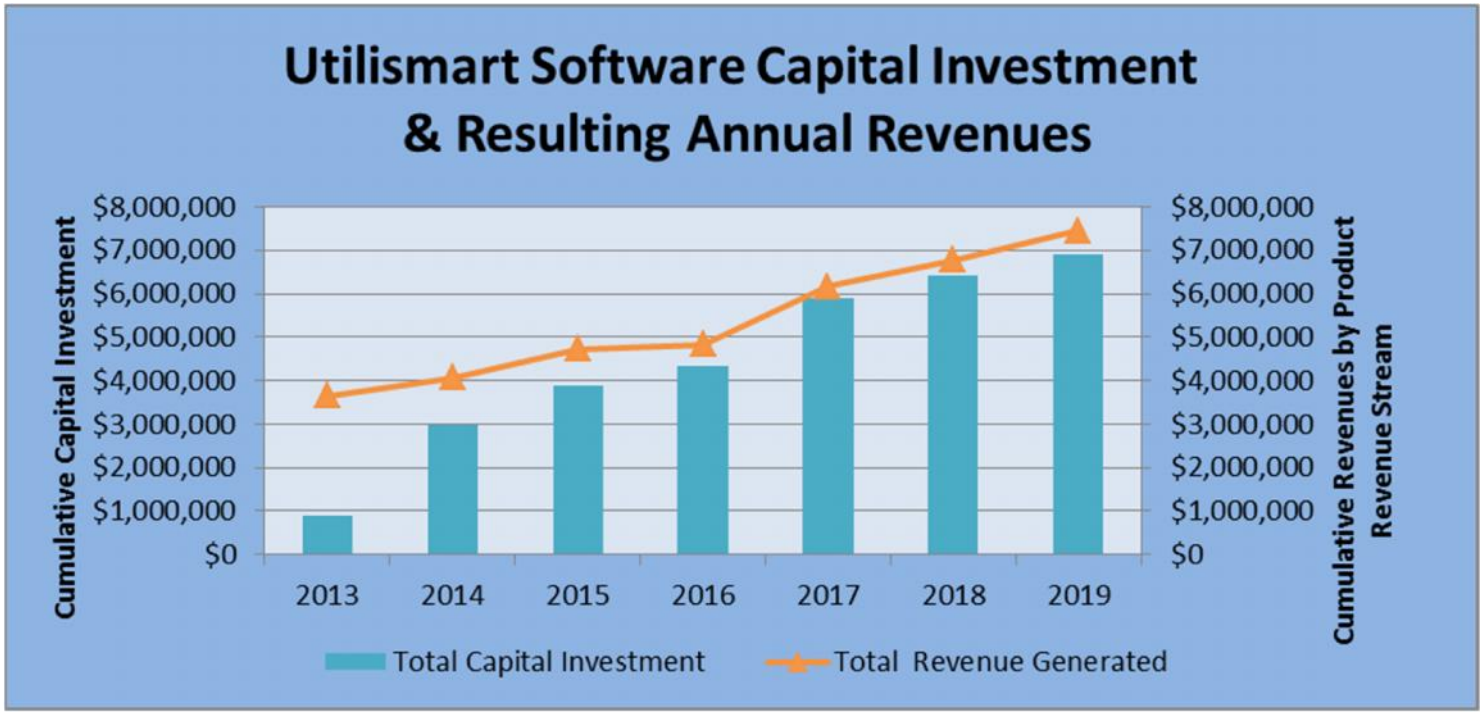
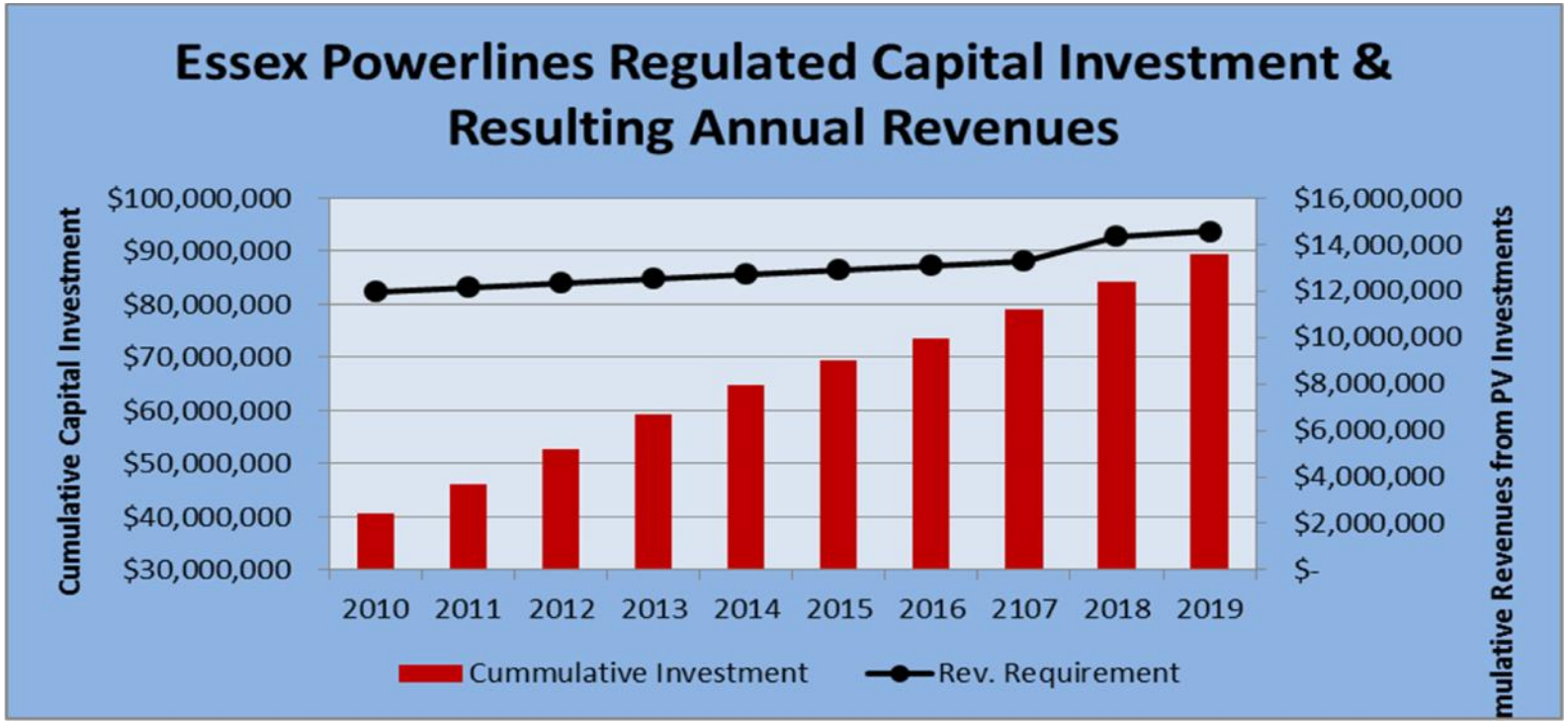
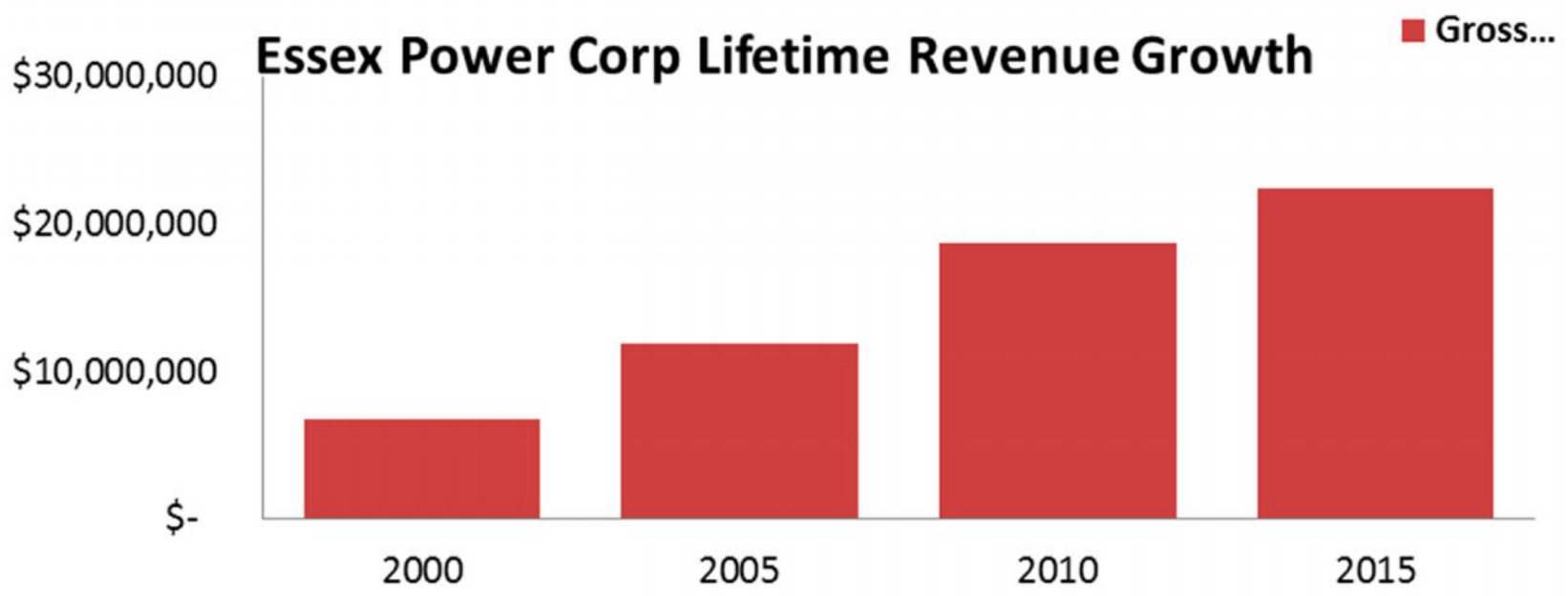


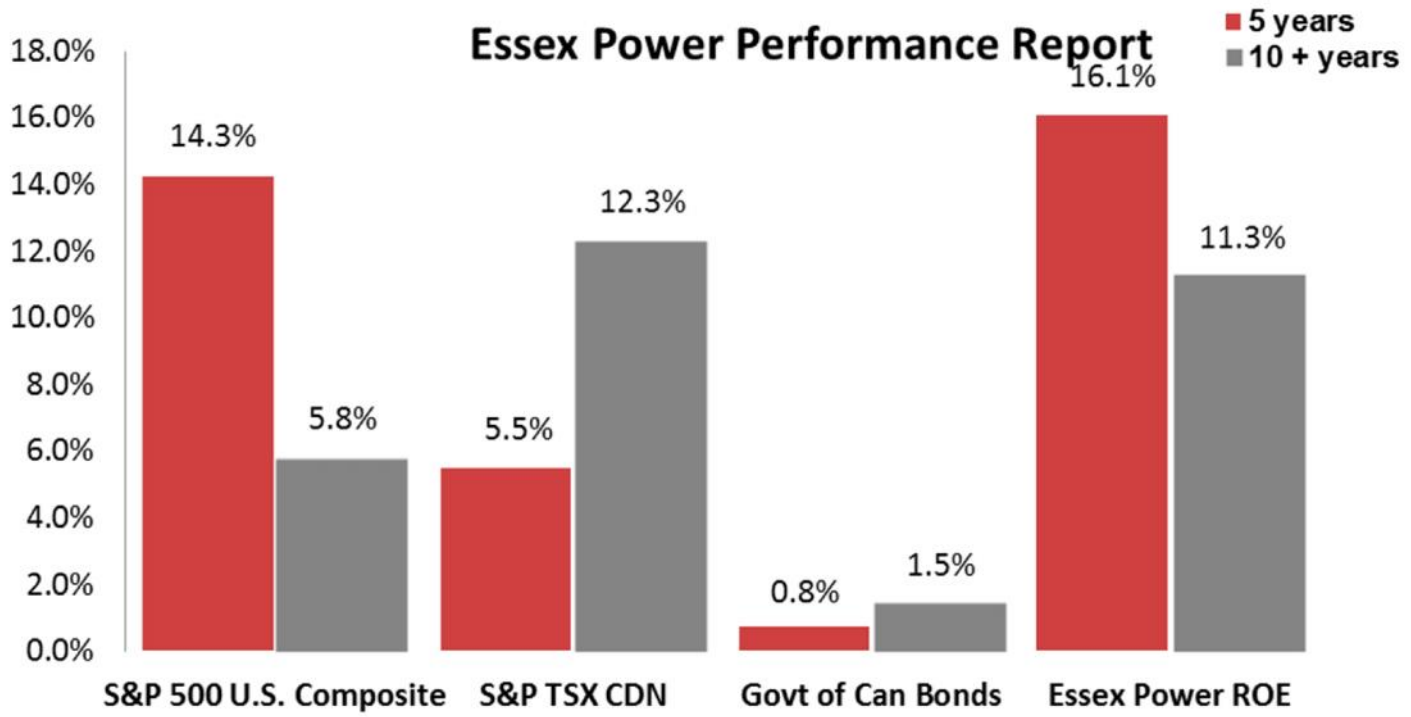
Strategic Investment Leads to Consistent Revenue Growth



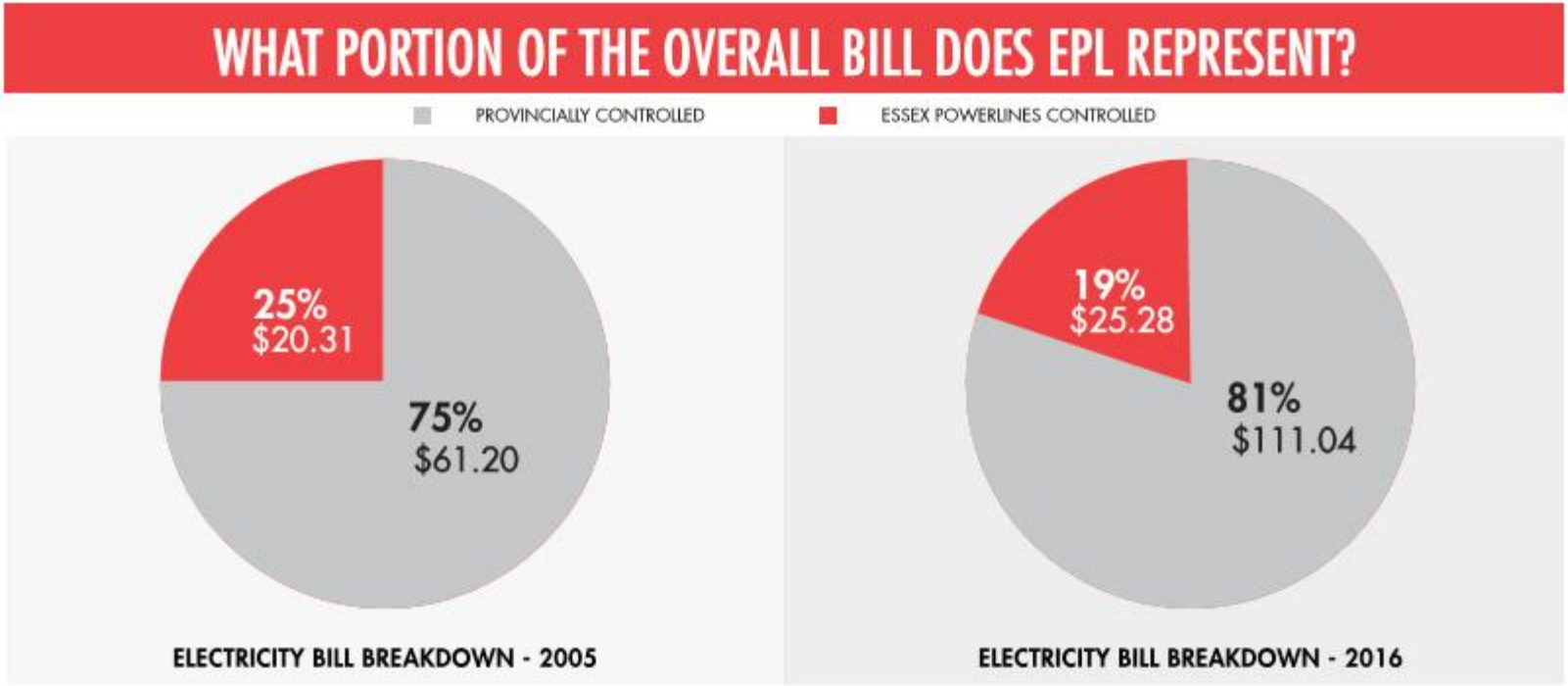
Proven Corporate Revenue Growth



Revenue Growth Drives Strong Corporate Performance and Shareholder Value

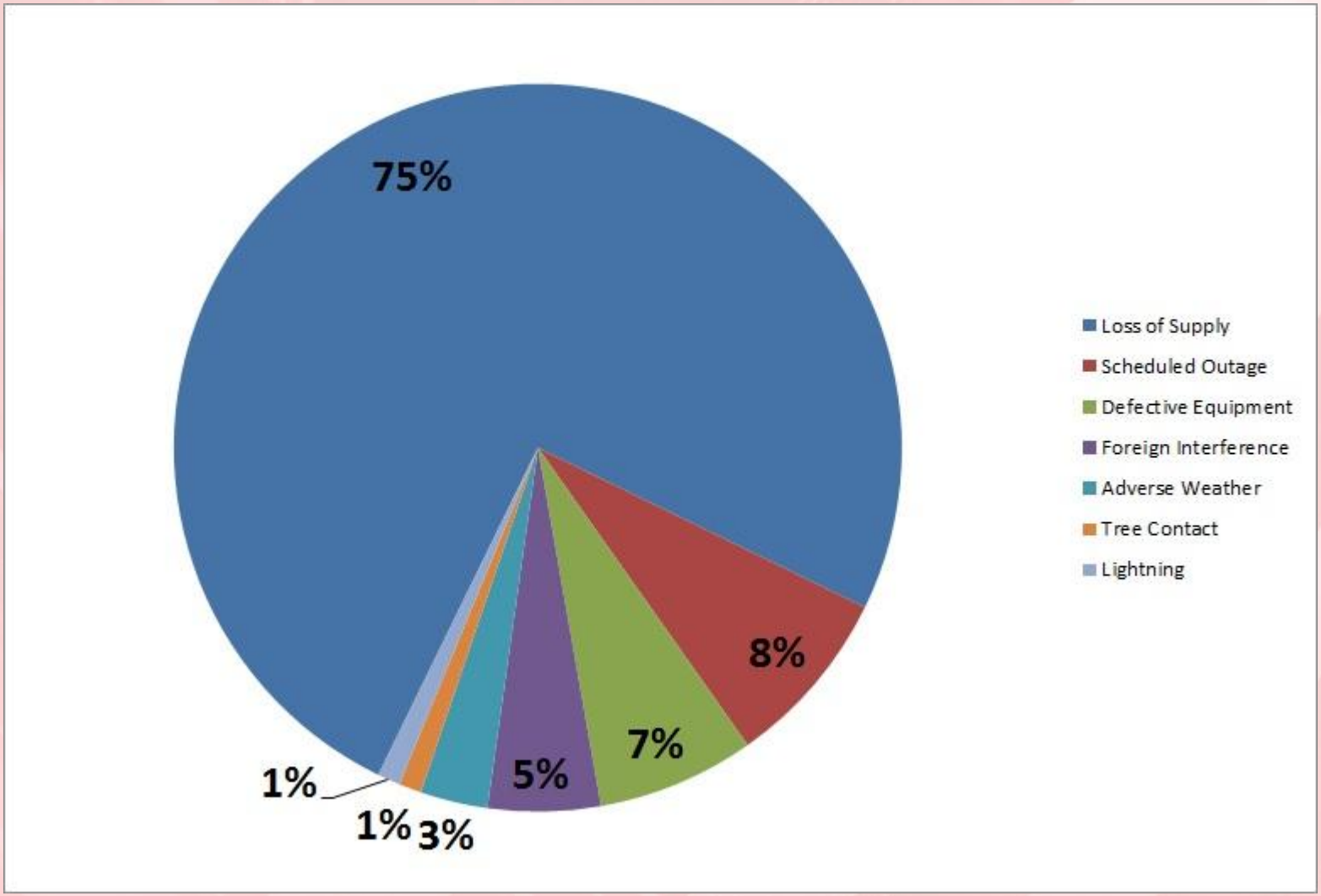


What are our customers really paying for?



Approximately 81% of the charges on a EPL electricity bill are collected on behalf of other organizations. Only 19% of the total bill is kept by EPL to provide electricity distribution services

2016 Customer Hour Reliability



CENTRELINE WINDSOR LTD. | HIGH BAY CONVERSION
196,992 kWh total savings | $10,944 incentive | 202 Tonnes of CO_2 emissions prevented per year

Conservation and Demand Management $637,765 In total incentives

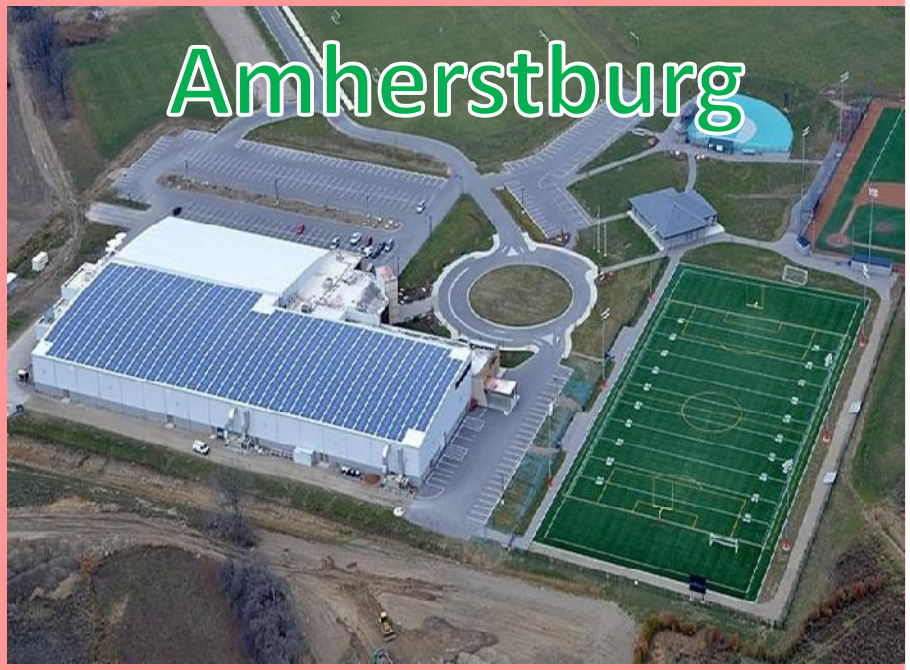
Essex Power offered energy retrofit programs to local businesses that injected over $1,709,211 into the economy, representing investments made by local residents, businesses and industry in conservation.

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

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

Green Share Solar PV Accomplishments

Project Name	Commissioned Date	Number of Days Running	kWh Savings	Homes Powered per Year
Tecumseh Arena	October 22, 2010	2468	3,736,841	420
Vollmer Arena	December 21, 2011	2043	2,268,270	255
Amherstburg Arena	November 19, 2012	1709	3,725,833	419

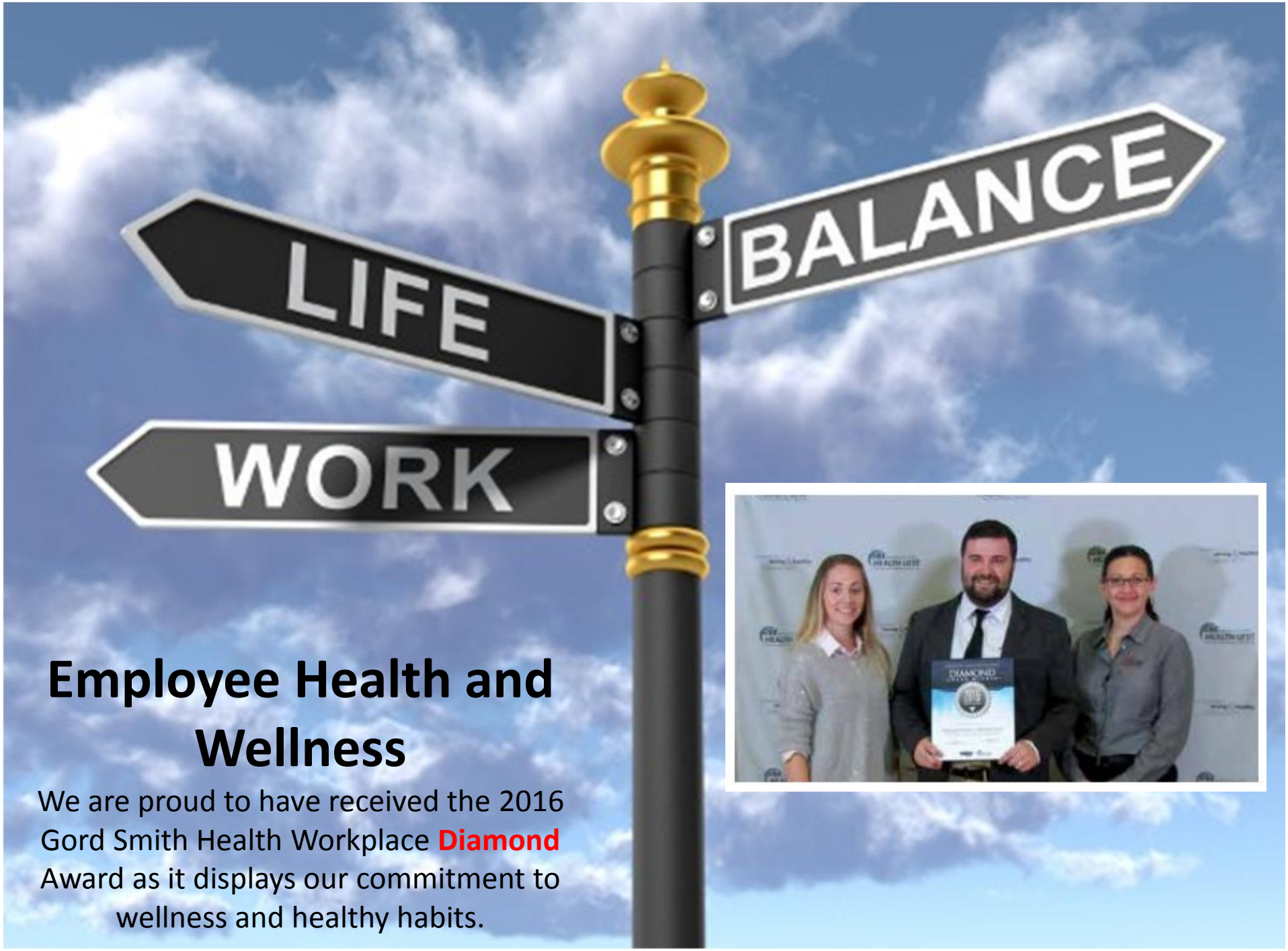


2016 Solar PV Accomplishments

Project Name	Commissioned Date	Number of Days Running	kWh Savings	Homes Powerered per Year
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

Mamora

Atlas Tube Centre



Employee Health and Wellness

We are proud to have received the 2016 Gord Smith Health Workplace **Diamond** Award as it displays our commitment to wellness and healthy habits.

Community Involvement!

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

Community Involvement!

EPL donated a used Radial Boom Derrick truck to St Clair College Powerline Technician Program – giving "hands on" practice to our industry's future members.

3rd Year Essex Power Youth In Community Fund

2017 Goals and Objectives

1. To continue to be a “best in class” electricity distributor in Ontario through state of the art business, technology and management practices.

2. To successfully submit and receive OEB approval on our 2017 “Cost of Service” which establishes the financial framework for LDC operations and Capital re-investment for 2018 through to 2022.

3. To increase corporate visibility within Essex County and our industry.

4. To establish Utilismart as a North America service provider of state of the art “Big Data and Utility Grid Intelligence Analytics”

5. To create a working environment that sustains employee motivation, innovation, customer responsiveness and that recognizes effective teamwork and maximizes employee participation in the delivery of the Company’s regulatory and non-regulatory services

2017 Themes and Objectives

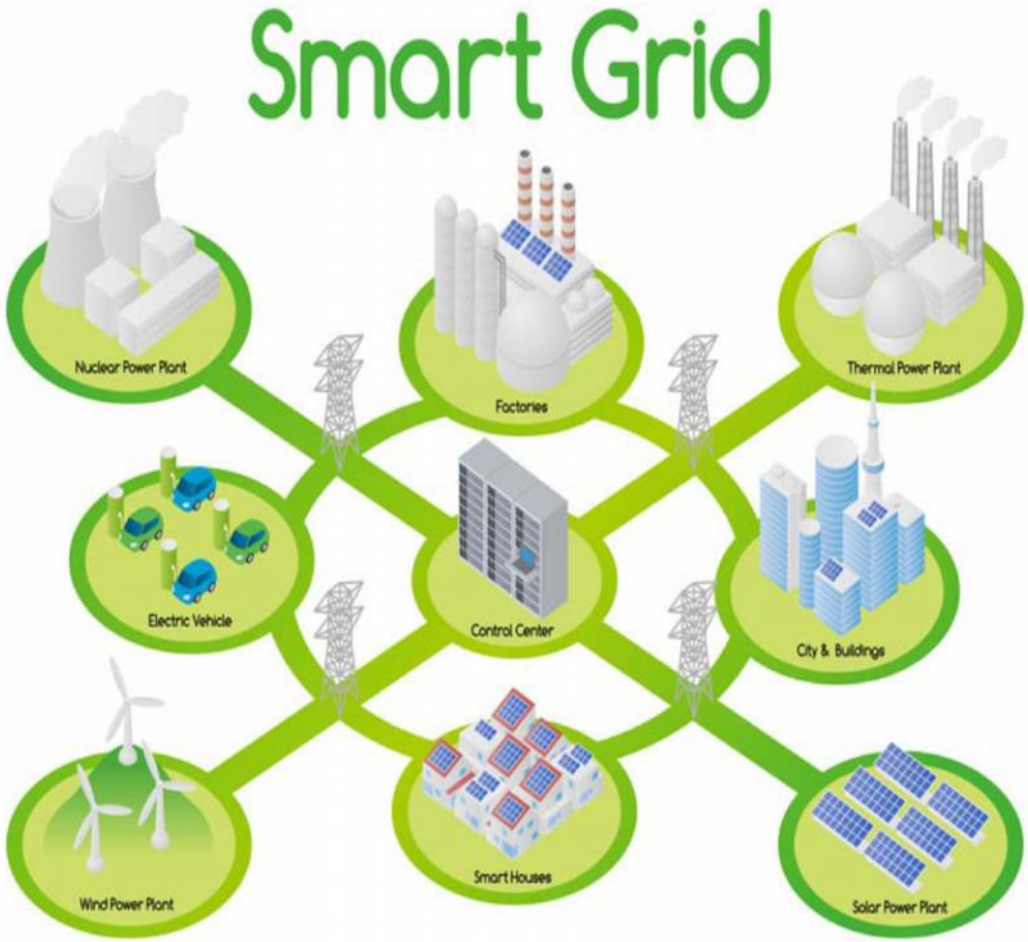
6. To maintain corporate profitability enabling cash dividend payments that meets and exceeds Shareholder expectations and grows the company's net value.

7. To establish Essex Energy as a first class leader in energy management, distributed generation and renewable energy and storage technologies by leveraging existing core competencies and internal expertise across Ontario, Canada and other jurisdictions.

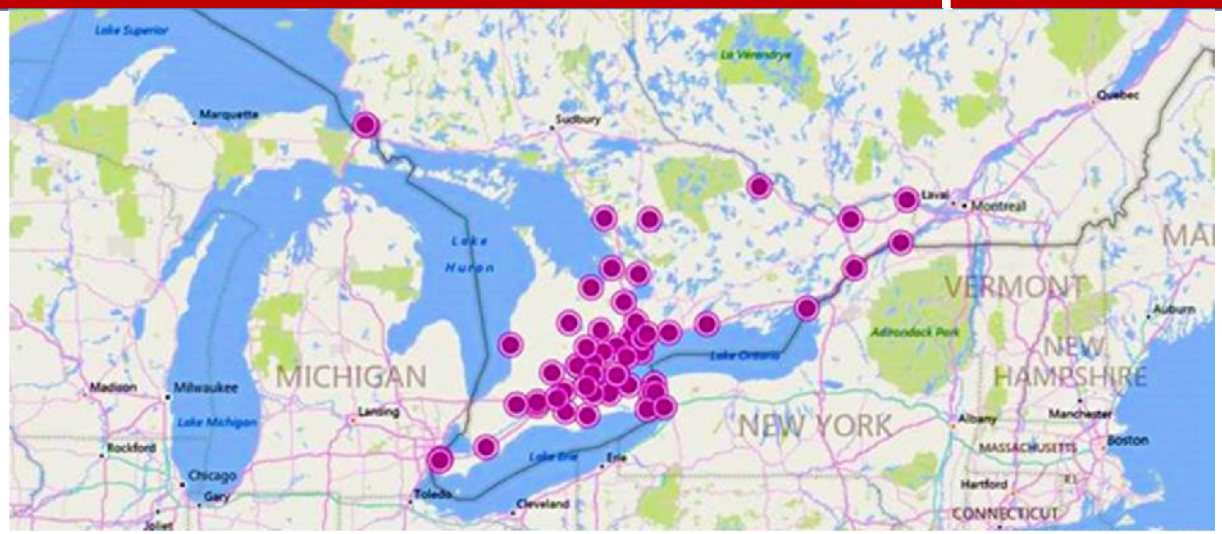
8. To establish Utilismart as a North American leader in meter data management and settlement services in the electric, water and gas industries.

9. To collaborate with our Municipal Shareholders to adopt new sustainability assets within their communities by creating "**Municipal Green Energy Cells**"

Sustainable Municipalities Powered by Local, Renewable and Innovative Energy Technologies



Our Market Place is Global
We Need to Think Big but Execute in Sustainable Steps



ESSEX POWER CORPORATION

Attachment 1-J

Chapter 2 Appendices

Attachment 1-K

PILS Workform

Attachment 1-L

Cost of Power Summary

Attachment 1-M

Service Territory Single Line Diagrams

KEITH
NA23

T22-H
T22SA1
T22
T22YNR
T22SA2
T22Y
R
-Y
SS10
SS10-X
SS10-Y
R1-Y
R1CA1
R1
R1-S
R1CA2
-R1
BR1
-B
Y BUS 28KV
M2 R -L
M4 R -L
M6 R -L
M1 R -B
M3 R -B
M5 R -B
M1-M2
M3-M4
M5-M6
ENWIN
-F1X
23M4RMCTVT
23M3RMCTVT
YVT
-F2X
SC2Y
SC2-GNG
SC2
Y-PT
YPT
-F1
-F2
B-PT
BPT
BVT
SC1B
SC1-GNG
SC1
T23-A
T23SA1
T23
T23BNR
T23SA2
T23B
B BUS 28KV
SS9-B
SS9-X
SS9
NA23 x GHIBM4-SB 1.3 km
NA23 x GHIBM3-SB 1.3 km
NA23 x GHIBM5-SB 1.3 km
LOAD
9148HVIL
30 Prospect Ave CGS
NC9148
3.1MW
9148LVI
9148HVI2
9148HVI
TX-G
23M4
GHIBM4-SB
23M3
GHIBM3-SB
23M5
GHIBM5-SB
GHIBM4-SB x GHIBM3-M4 0.9 km
GHIBM3-SB x GHIBM3-M4 0.9 km
GHIBM5-SB x RR Tracks 0.7 km
GHIBM3-M4 x WEV-M4 1.3 km
WEV-M4
M4-TEMP
MOR-3 x GHIBM3-M4 2.6 km
MOR3-S
MOR-3
GHIBM3-M4
GHIBM3-M4 x WEV-M3 1.3 km
M3-TEMP
WEV-M3
Maple Junction
KM3-KM5
MOR-3 x 7153-ILS 7.2 km
Amherstburg Solar #2
NC7153 10.0MW
7153HVI
7153-LBS
700722-S
700722
Essex Powerlines
7153-ILS
7153-LC
7153-ILS x MM8-KM4 0.4 km
MALDEN
M8
MM8-KM4
LLO-1
R1-1
-F1X
R1PT
R1
R1-S
R1-M3
La Salle RS
NW1534
40MVA@30C 50MVA@0C
1-9-17
R1-2
LLO-2
Station
Service
06959
Provincial
Lines
First Solar #1
NC7128 10.0MW
7128HVI
7128-L
700574-S
700574
7128-ILS
FS1-ILS
FS1-ILS x 7128-ILS 1.3 km
LA Salle RS x MID-7 5.8 km
MIDM3-M4-S
MIDM3-M4
MID-7 x MIDM3-M4 6.6 km
MID-7
THOM-ILS2
THOM-ILS1
MIDM3-M4 xILS-1 4.4 km
150 kVA
THMS-ILS
WM523M3
MALDEN
M7
ALM-M3
SIM-1
ILS-1
ILS-2
CAL-1
MALDEN
M7 &
KEITH
M5
Essex Powerlines
89-AM3
52AM3-A
Amherstburg Solar #3
NC7325 10.0MW
89-AM4
52AM4-A
Amherstburg Solar #4
NC7346 5.0MW
SEY-2
CALM5-M3
KEITH
M3
F
DET-1
MID-6 x DET-1 2.40 km
MID-6
RC-4 x MID-6 3.75 km
RC-4
0.2 km
RC-3
PET-1
MALDEN
M8
23M5-24M8
R1 x RC-3 6.6 km
NC8055
250 KW
Essex Powerlines
NC9053
112 KW
Essex Powerlines
Essex Powerlines
1.93 km
MAP-2
Amherstburg RS
NW1533
1-5-17
R1-1
R1-2
R1
R1-S
MOR-2 x R1 1.8 km
MOR-2
LAS-310
LAS-340
WM723M4
KEITH
M5
MALDEN
M8
MALDEN
M9
KEITH
M4
LAS-400
MALDEN
M8
MAT-M5
KM5-MM9 x MAT-M5 1.56 km
KM5-MM9
MALDEN
M9
LAS-460
ENWIN
24M2-23M5
LAS-450
MAP-ILS
KM5-MM9 x MAP-ILS 2.3 km
KM5-MM8
KM5-MM9 x KM5-MM8 3.7 km
MALDEN
M8
MAP-ILS x KM3-KM5 0.5 km
WM723M5
OJ-2
OJ-2 x MOR-2 2.0 km
MOR-1
NC8582
200KW
Essex Powerlines
LAS-430
KEITH
M4
GHIBM5-SB2
RR Tracks 0.2 km

LEGEND

- 500 KV
- 345 KV
- 230 KV
- 115 KV
- 69 KV
- 35 to 44 KV
- 22 to 28 KV
- 14 KV
- Auxiliary

This legend is for local plotting purposes only. It serves as a reference for the local print only and may not necessarily match that of the Hydro One Operating Drawing Convention Standard.

Rev. No.	Date	Revision	By	Appli
83.0	JAN 16 2018	Updated M5, M4 and M6 feeders exiting station. ISP-DX-17-22383, -22571 and -30080.	B/R	AMP
82.0	DEC 12 2017	Normal dated pins WM523M3 on the M3 feeder.	B/R	AMP
81.0	NOV 16 2017	Added pins WM723M to the M4 feeder and a pins to the M3 feeder post disconnect THOM -ILS1.	B/R	AMP
80.0	OCT 17 2017	Added voltage devices 23M3RMCTVT and 23M4RMCTVT.	B/R	DS
79.0	SEP 21 2017	Corrected overlap of property number for embedded generators.	MJ	DS
78.0	SEP 12 2017	Added 30 Prospect Ave CGS to the M1 feeder.	B/R	AMP
77.0	AUG 24 2017	Added disconnects THOM-ILS1 and THOM-ILS2 to the M3 feeder, ISP-DX-17-22416.	B/R	AMP
76.0	AUG 15 2017	Added M3-TEMP & M4-TEMP, ISP-DX-17-22381.	MJ	AMP
75.0	JUL 11 2017	Updated the M5 to enhance feeder tracing.	B/R	DS

Keith TS
NA23

OVERVIEW OPERATING DIAGRAM
(LOW TENSION)

hydro one Hydro One Networks Inc.
Integrated Transmission Operating Facilities

Date: DD/MM/YYYY: 23/01/2004
Drawn:
Checked:
Paper Size: 40x36

Note:
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NMI-2020 Process for New and Revised Operating Diagrams

DWG. NO. NA23 -2LT
REV NO. 83.0

KINGSVILLE
NW3
Y BUS 28KV
Y1 BUS 28KV
B1 BUS 28KV
B BUS 28KV
T4 T2 T1 T3
GT2.4
GT1.3
SC3SC
SC1.3Y
SC2.4B
SC4SC
3M1 3M2 3M3 3M4 3M5 3M6 3M7 3M8 3M9 3M10
KM10LEM28
3M10 393M28 RCS
LAUZON M24
LEAMINGTON M28
LEAMINGTON M25
LEAMINGTON M26
LEAMINGTON M24
LEAMINGTON M23
LEAMINGTON M22
LEAMINGTON M27
MALDEN M12
MALDEN M7
M3-SOAV-52-G
M3-SOAV-52-U
Soave Great NorthCGS NC7239 12.0MW
Mastron West CGS NC7249 600 KW
Ruthven DS NW340 8 MVA
Jem Farms CGS NC7248 600 KW
Leamington RS NW6511 25 MVA 1-7-23
8636LVI
500 EssexCt.R18.SOL NC8636 499 KW
Lakeside HothouseCGS NC7245 600 KW
Fair Jct
Victoria Jct
Essex Powerlines
Wheatley RS NW346 25 MVA 1-5-17
WHY1
KingsvilleM3 RCS
WHY2
KingsvilleM9 RCS
Leamington East RS NW738 25 MVA 1-5-17
Wheatley DS #2 NW350 5 MVA
Wheatley MS NW349 2 MVA
Entegrus Power Lines
Wheatley Harbor Jct
Fishermans Jct
Milo Fais NW328A 14 MVA
Sun Parlor Homes NC7299 1.0MW
Oak Jct
William Jct
Deer Run Jct
Oak St. Jct
8334LVIMB
8334LVITL
8334LVI
8334LVITG
8334LVIE
8334LVIG
LeamingtonGSet2.CGS NC8334 1.0MW
Hillman Bio NC7131 1.6MW
7131HVI
Leamington DS #2 NW339 5 MVA
1600Kratz.CGS NC8430 800 KW
8430LVI 8430CB
Agriville Farms 14 MVA
Pelee Island DS 01845 3 MVA
1814SeacliffDr.CGS NC8429 800 KW
8429LVI
8429CB2
8429CB
Mucci Farms 5 MVA
RUTHVEN JCT
SHERKJCT
55 TalbotStreetW SOL NC9105 390 KW
9105LVI3 9105LVI2 9105LVI
HghbryCanco Substn A NW315G 6 MVA
HghbryCanco Substn H NW315B 5 MVA
Highbury Canco CGS NCW2322 10.0MW
Cacciavillani & Family Farms CGS NC7244 325 KW
Mucci Farms West 2 MVA
Mucci Farms East 2 MVA
Agriville Farms Ltd. 8 MVA
KINGSVILLE M4 & KINGSVILLE M6
R67
KingsvilleM7 RCS
INV1
INV2
200ClarkSt.SOL NC8047 500 KW
2215RoseboroghRd.SOL NC8586 422 KW
8586LVI
Delta MS NWB313 2 MVA
SELLICK EQUIP 7.5 MVA
ATLAS TUBE 0.15 MVA
Ellenberger Jct
E.L.K Energy
Elk Energy Inc.
SMITH JCT
GREEN GIANT JCT
ERIEJCT
Elk Energy Inc NC7582 60 KW
R10
KingsvilleM1 RCS #2
OXLEYJCT
Oxley Wind Farm CGS NC7396 6.0MW
7396HVI
Oxley DS NW341 8 MVA
Comet DS NW358 5 MVA
M1RSJ KingsvilleM1 RSJ 3 x 480 kVA
McCormick RS NW359 1-5-17 25 MVA
R94
KingsvilleM1 RCS
Cedar Beach Acres CGS NC7247 600 KW
SPRUCEJCT
Kingsville Pulford DS NW342 4 MVA
KingsvillePlast2.SOL NC8318 450 KW
LEGEND
500 KV
345 KV
230 KV
115 KV
69 KV
35 to 44 KV
22 to 28 KV
14 KV
Auxiliary
179.0 FEB 22 2018 Added disconnects TEMP12-23, TEMP12-22 and bypass on the M3 feeder at the taps to Leamington M22 and M23. BR AMP
178.0 FEB 15 2018 Added construction points on the M3 feeder at the taps to the Leamington M22 and M23 feeders. BR AMP
177.0 FEB 13 2018 Moved km distance between disconnects 3M9ILS-2 and 3M9ILS-4 on the M9 feeder. BR AMP
176.0 JAN 16 2018 Moved equipment from the Kingsville M10 feeder to the Leamington M21 and M28 feeder, ISP-DX-17-3029. Renamed lineloops KM10-1, LEM28-1 to KM10LC-1 and LEM28LC-1. BR AMP
175.0 JAN 11 2018 Added M3-TEMP1 & M3-TEMP2. MJ DS
Rev. No. Date Revision By App'd
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Kingsville TS
NW3
OVERVIEW OPERATING DIAGRAM
(LOW TENSION)
hydro one
Hydro One Networks Inc.
Integrated Transmission Operating Facilities
Date: DD/MM/YYYY
23/01/2004
Drawn:
Checked:
Note:
All revisions to this diagram will require notification of the NMS Prints team, via email to NO Change Control Notification and follow up with a field marked paper copy. Refer to: OD-10-001: Operating Diagram Standard for Transmission NMI-2020: Process for New and Revised Operating Diagrams
Paper Size:
70x42
DWG. NO.
NW3 -2LT
REV. NO.
179.0

LEGEND

500 KV
345 KV
230 KV
115 KV
69 KV
35 to 44 KV
22 to 28 KV
14 KV
Auxiliary

This legend is for local plotting purposes only. It serves as a reference for the local print only and may not necessarily match that of the Hydro One Operating Drawing Convention Standard.

Rev. No.	Date	Revision	By	App'd
129.0	FEB 22 2018	Removed load interrupter MV10035 and disconnect SW10113 and added 7 reclosures and bypasses on the M25 and M26 feeders.	BR	AMP
128.0	JAN 18 2018	Moved R1 inline and removed bypass. Removed M27-TEMP1.	MJ	DS
127.0	DEC 12 2017	Removed recloser MANR4 and added Essex Powerlines recloser RE10400 on the M4 feeder.	BR	AMP
126.0	SEP 21 2017	Corrected overlap of property number for embedded generators.	MJ	DS
125.0	SEP 12 2017	Added 40kW generator, property number NC8169 to the M27 feeder, ISP-DX-17-23291.	BR	AMP
124.0	JUL 11 2017	Removed old nomenclature from JR1 and related equipment. Updated tap connection to R1 closer to the M27 breaker.	MJ	DS

Lauzon TS
NA56

OVERVIEW OPERATING DIAGRAM (LOW TENSION)

Hydro One Networks Inc.
Integrated Transmission Operating Facilities

Date: DD/MM/YYYY: 23/01/2004
Drawn:
Checked:
Paper Size: 70x42

Note:
All revisions to this diagram will require notification of the NMS Prints team, via email to NO Change Control Notification and follow up with a field marked paper copy. Refer to: OD-10-001: Operating Diagram Standard for Transmission NMI-2020: Process for New and Revised Operating Diagrams

DWG. NO. NA56 -2LT
REV NO. 129.0

LEGEND

- 500 KV
- 345 KV
- 230 KV
- 115 KV
- 69 KV
- 35 to 44 KV
- 22 to 28 KV
- 14 KV
- Auxiliary

Rev. No.	Date	Revision	By	App'd
160.0	FEB 13 2018	Added station nameplate for Harrow GDS on the M7 and M11 feeders.	BR	DS
159.0	JAN 16 2018	Added future Harrow GDS to the M7 and M11 feeders.	BR	AMP
158.0	DEC 01 2017	Added bolted opener T2B-TEMP.	MJ	DS
157.0	JUL 11 2017	Removed U symbol from Bois Blanc Island DS from the M12 feeder and removed Bob-Lo DS and associated equipment from the M7 feeder, ISP-DX-16-32387.	BR	AMP
156.0	FEB 14 2017	Added 250kW generator property number NC8760 on the M12 feeder, ISP-DX-16-32356.	BR	AMP
155.0	JAN 17 2017	Added 250kW generator property number NC8997 on the M12 feeder, ISP-DX-16-32193. Added embedded generators to the M4 feeder, ISP-DX-16-32326 and M5 feeder, ISP-DX-16-32327.	BR	AMP

This legend is for local plotting purposes only. It serves as a reference for the local print only and may not necessarily match that of the Hydro One Operating Drawing Convention Standard.

Malden TS
NAW24

OVERVIEW OPERATING DIAGRAM (LOW TENSION)

hydro one — Hydro One Networks Inc. Integrated Transmission Operating Facilities

Date: DD/MM/YYYY 05/03/2004 | Drawn: | Checked:

Note: All revisions to this diagram will require notification of the NMS Prints team, via email to NO Change Control Notification and follow up with a field marked paper copy. Refer to: OD-10-001: Operating Diagram Standard for Transmission NMI-2020: Process for New and Revised Operating Diagrams

Paper Size: 70x42

DWG. NO. NAW24 -2LT | REV. NO. 160.0

Attachment 1-N

Self-Healing Grid Single Line Diagrams

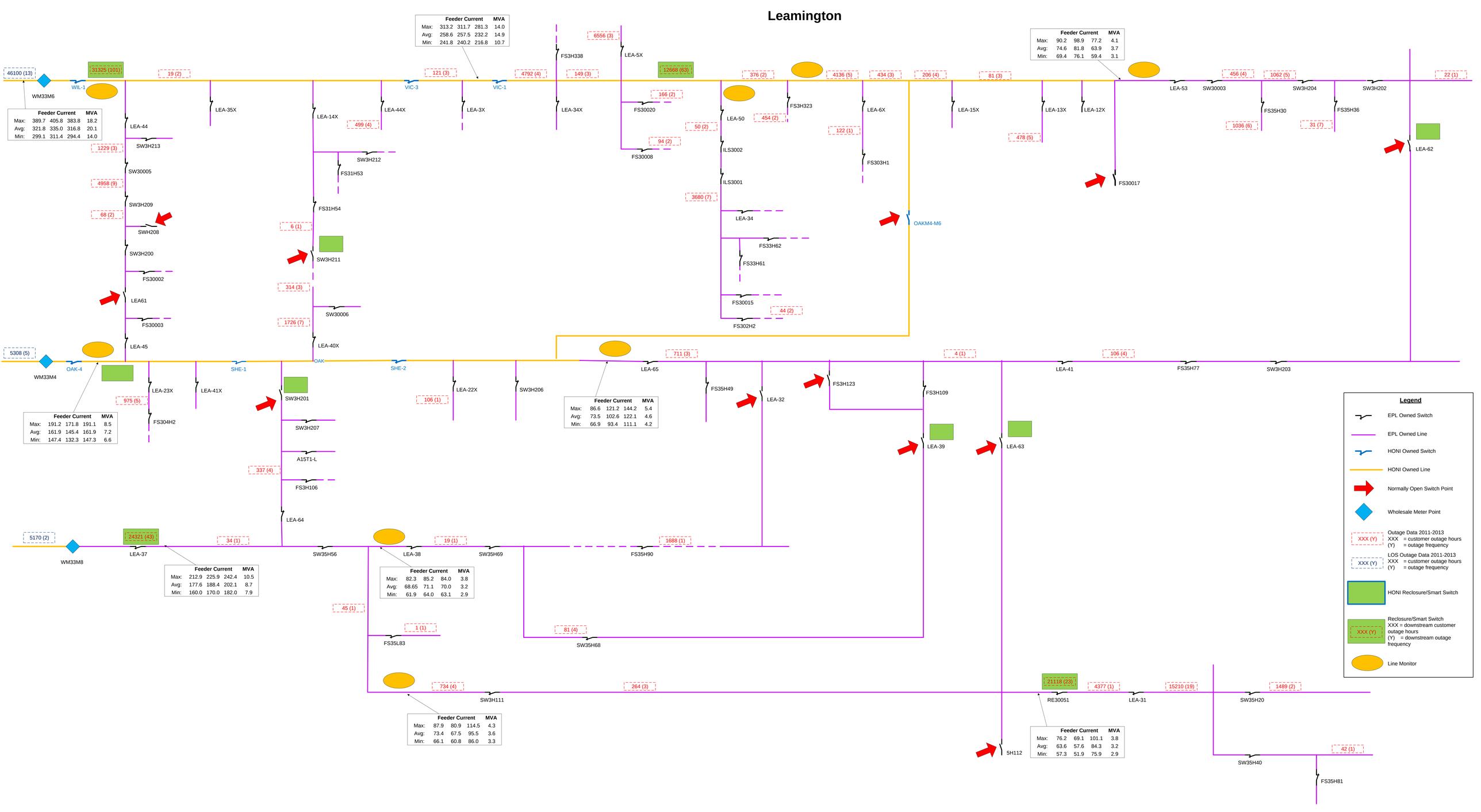
Lasalle and Amherstburg

61269 (9)
WM23M4
3384 (59)
39 (6)
LAS-340
SW7H103
Feeder Current MVA
Max: 455.5 311.2 395.2 18.0
Avg: 376.2 256.4 325.1 15.0
Min: 349.7 238.1 303.0 14.0
Feeder Current MVA
Max: 190.5 147.4 131.1 7.1
Avg: 157.6 121.6 108.4 6.0
Min: 146.6 112.9 100.8 5.6
902 (12)
527 (11)
SW7H106
SW70H29
SW70H61
1624 (27)
447 (4)
SW7H121
372 (10)
LAS-310
MID3-M4
SW7H172
Feeder Current MVA
Max: 45.7 42.4 65.8 2.4
Avg: 37.8 35.0 54.4 2.0
Min: 35.2 32.6 50.6 1.8
1035 (12)
778 (2)
DET-1
SW50345
SW70H62
Feeder Current MVA
Max: 100.2 52.8 58.2 3.3
Avg: 82.6 43.4 48.0 2.7
Min: 76.8 40.2 44.5 2.5
SW7H171
SW7H161
FS7H182
375 (1)
5119 (8)
WM723M5
OJ-2
5012 (46)
SW70754
306 (8)
1668 (5)
MOR-2
178 (3)
1533R1-S
52 (5)
19 (1)
Feeder Current MVA
Max: 205.2 181.1 223.2 9.6
Avg: 169.0 149.0 183.9 8.0
Min: 157.0 138.3 170.8 7.4
LAS-450
LAS-460
354 (2)
SW70H14
MATM5-M9
MAP-2
LAS-56X
FS7H220
91 (4)
LAS-45X
CAL-4
72 (1)
424 (2)
ILS-17
SW50200
18 (1)
17 (2)
FS50124
B12T2-A
FS50041
CALM5-M3
SEY-2
SW700H9
Feeder Current MVA
Max: 302.4 271.4 349.1 15.0
Avg: 258.8 232.4 299.3 12.9
Min: 229.9 206.5 266.1 11.5
19658 (7)
WM724M9
7600 (51)
36 (2)
MT3
2572 (12)
281 (3)
REA-1
150 (2)
MAP-1
15 (1)
LAS-430
56 (2)
SW70H48
43 (2)
SW7H150
479 (3)
213 (2)
FS50036
FS50027
783 (9)
LAS-320
3877 (22)
LAS-330
Feeder Current MVA
Max: 114.9 136.4 98.5 5.7
Avg: 98.5 116.8 84.4 4.9
Min: 87.6 103.8 75.1 4.4
119 (2)
SW7H108
91 (2)
847 (2)
SW7H114
70 (1)
MAPM3-M9
529 (7)
SW50335
REN-M3
15042 (10)
Feeder Current MVA
Max: 75.5 90.8 75.0 3.6
Avg: 65.3 78.6 64.8 3.2
Min: 54.6 65.8 54.1 2.7
FSS0101
1522 (4)
FS50001
SW50030
SW5G201
SW50031
SW5G210
AMH-42X
FS50133
547 (5)
Feeder Current MVA
Max: 86.8 87.7 98.6 4.1
Avg: 75.0 75.9 85.2 3.6
Min: 62.7 63.6 71.2 3.1
SIM-1
981 (13)
2686 (15)
SW70H45
155 (2)
LAS-420
Feeder Current MVA
Max: 38.4 28.9 16.6 1.4
Avg: 32.9 24.7 14.2 1.2
Min: 29.2 22.0 12.6 1.1
Feeder Current MVA
Max: 290.3 323.7 291.6 13.7
Avg: 250.8 280.0 251.9 12.1
Min: 209.5 234.4 210.5 10.2
62586 (15)
WM23M3
ILS-1
20453 (60)
CAL-1
LAS-480
ILS-2
4046 (33)
CAL-SEY
782 (8)
FS50035
54 (2)
ALM-M3
15 (3)
ILS-3
GEO-M7
90280 (18)
WM724M7
108 (2)
242 (3)
BOU-1
M7-HO
3865 (33)
LAS-490
11 (1)
29 (4)
Feeder Current MVA
Max: 425.2 323.2 322.9 16.6
Avg: 340.2 252.8 234.1 13.0
Min: 316.2 234.7 217.7 12.1
129 (6)
Feeder Current MVA
Max: 173.4 135.3 93.2 6.3
Avg: 143.2 111.4 76.9 5.2
Min: 133.1 103.4 71.5 4.9
LAS-410
246 (2)
FS70H96
LAS-500
SW7H193
SW70H37
56 (1)
FS70183
10614 (11)
WES_PME
Feeder Current MVA
Max: 53.5 58.3 14.0 2.0
Avg: 44.2 47.9 11.5 1.6
Min: 41.1 44.3 10.7 1.5
LAS-350
M7R
LAS-360
3523 (25)
LAS-390
LAS-370
169 (3)
FS7H210
LAS-470
Feeder Current MVA
Max: 261.1 135.7 242.9 9.8
Avg: 216.0 112.4 201.1 8.2
Min: 176.0 134.4 133.0 7.4
3199 (7)
348 (8)
WM724M10
LAS-72X
51 (2)
LAS-46X
179 (5)
Howard PME
Feeder Current MVA
Max: 51.5 52.3 103.6 3.3
Avg: 15.1 16.4 15.9 0.8
Min: 9.5 10.3 10.0 0.5
8732 (3)
AND-3
WM524M7
SW50330
4 (1)
SW50027
5 (1)
24M7ILS-1
PIK-1
D28A-L
AMH-30X
GEO-3
69 (2)
1414 (2)
PIKM7-M12
389 (2)
BOB-1
BOB-2
BOB-3
FS50042

Legend

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

Leamington


Feeder Current MVA
Max: 313.2 311.7 281.3 14.0
Avg: 258.6 257.5 232.2 14.9
Min: 241.8 240.2 216.8 10.7
Feeder Current MVA
Max: 90.2 98.9 77.2 4.1
Avg: 74.6 81.8 63.9 3.7
Min: 69.4 76.1 59.4 3.1
Feeder Current MVA
Max: 389.7 405.8 383.8 18.2
Avg: 321.8 335.0 316.8 20.1
Min: 299.1 311.4 294.4 14.0
Feeder Current MVA
Max: 191.2 171.8 191.1 8.5
Avg: 161.9 145.4 161.9 7.2
Min: 147.4 132.3 147.3 6.6
Feeder Current MVA
Max: 86.6 121.2 144.2 5.4
Avg: 73.5 102.6 122.1 4.6
Min: 66.9 93.4 111.1 4.2
Feeder Current MVA
Max: 212.9 225.9 242.4 10.5
Avg: 177.6 188.4 202.1 8.7
Min: 160.0 170.0 182.0 7.9
Feeder Current MVA
Max: 82.3 85.2 84.0 3.8
Avg: 68.65 71.1 70.0 3.2
Min: 61.9 64.0 63.1 2.9
Feeder Current MVA
Max: 87.9 80.9 114.5 4.3
Avg: 73.4 67.5 95.5 3.6
Min: 66.1 60.8 86.0 3.3
Feeder Current MVA
Max: 76.2 69.1 101.1 3.8
Avg: 63.6 57.6 84.3 3.2
Min: 57.3 51.9 75.9 2.9
46100 (13)
WM33M6
WIL-1
31325 (101)
19 (2)
LEA-44
SW3H213
1229 (3)
SW30005
4958 (9)
SW3H209
68 (2)
SWH208
SW3H200
FS30002
LEA61
FS30003
LEA-45
LEA-35X
121 (3)
VIC-3
VIC-1
4792 (4)
LEA-14X
499 (4)
LEA-44X
LEA-3X
SW3H212
FS31H53
FS31H54
6 (1)
SW3H211
314 (3)
SW30006
1726 (7)
LEA-40X
6556 (3)
FS3H338
LEA-5X
149 (3)
LEA-34X
12668 (63)
166 (2)
FS30020
94 (2)
FS30008
376 (2)
LEA-50
454 (2)
FS3H323
50 (2)
ILS3002
ILS3001
3680 (7)
LEA-34
FS33H62
FS33H61
FS30015
44 (2)
FS302H2
4136 (5)
434 (3)
LEA-6X
122 (1)
FS303H1
206 (4)
OAKM4-M6
81 (3)
LEA-15X
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LEA-13X
LEA-12X
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LEA-53
SW30003
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1062 (5)
SW3H204
SW3H202
22 (1)
FS35H30
1036 (6)
FS35H36
31 (7)
LEA-62
5308 (5)
WM33M4
OAK-4
OAK
SHE-1
SHE-2
LEA-23X
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FS304H2
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A15T1-L
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FS3H106
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LEA-22X
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LEA-65
711 (3)
FS35H49
LEA-32
FS3H123
FS3H109
LEA-39
4 (1)
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LEA-41
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WM33M8
24321 (43)
LEA-37
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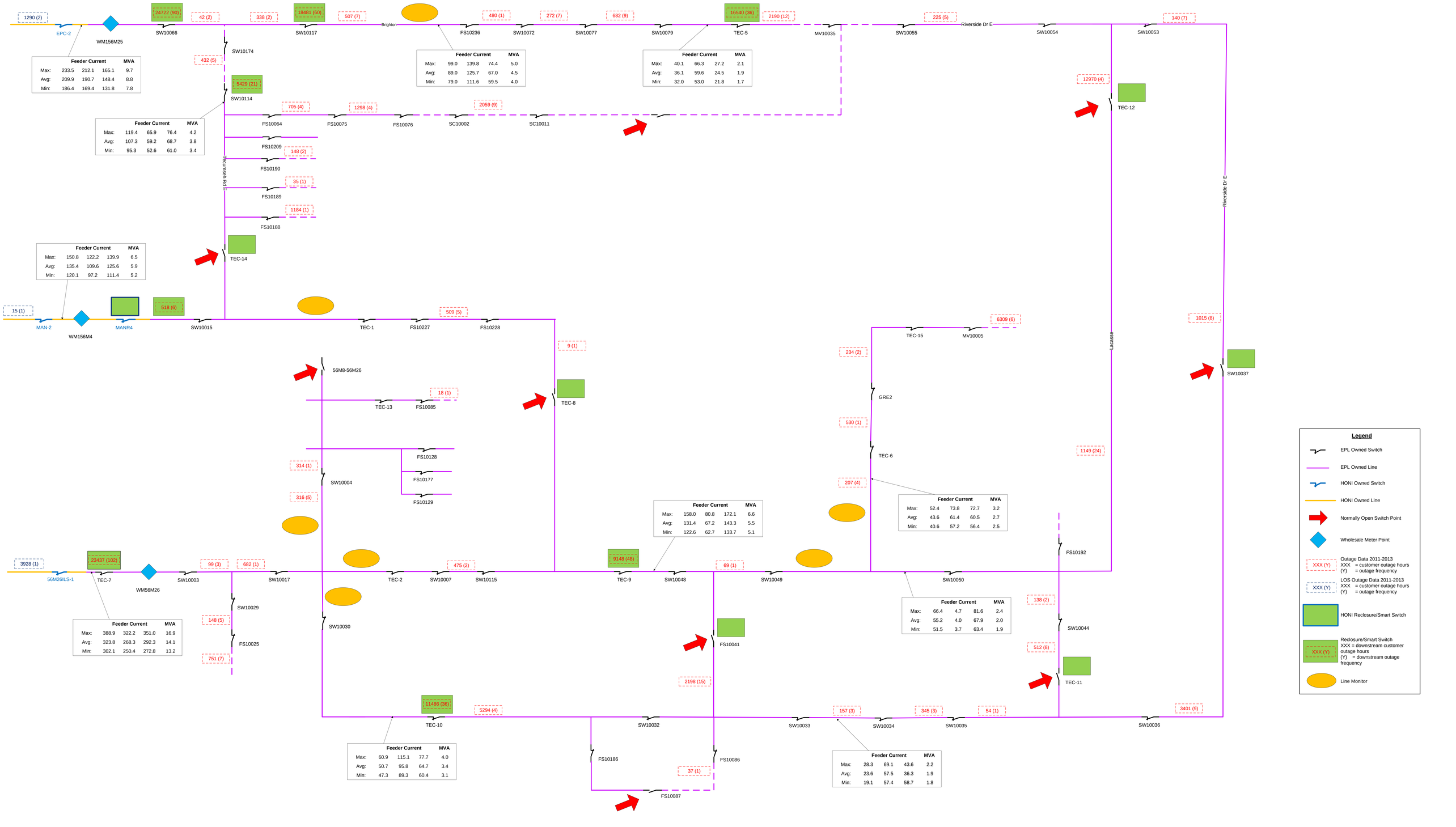
SW35H56
LEA-38
19 (1)
SW35H69
1688 (1)
FS35H90
45 (1)
1 (1)
FS35L83
81 (4)
SW35H68
734 (4)
SW3H111
264 (3)
21118 (23)
RE30051
4377 (1)
LEA-31
15210 (19)
1489 (2)
SW35H20
5H112
SW35H40
42 (1)
FS35H81
Legend
EPL Owned Switch
EPL Owned Line
HONI Owned Switch
HONI Owned Line
Normally Open Switch Point
Wholesale Meter Point
XXX (Y)
Outage Data 2011-2013
XXX = customer outage hours
(Y) = outage frequency
XXX (Y)
LOS Outage Data 2011-2013
XXX = customer outage hours
(Y) = outage frequency
HONI Reclosure/Smart Switch
XXX (Y)
Reclosure/Smart Switch
XXX = downstream customer outage hours
(Y) = downstream outage frequency
Line Monitor

Tecumseh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EPC-2
WM156M25
24722 (90)
SW10066
42 (2)
338 (2)
18481 (60)
SW10117
507 (7)
Brighton
480 (1)
FS10236
272 (7)
SW10072
682 (9)
SW10077
SW10079
16540 (36)
TEC-5
2190 (12)
MV10035
225 (5)
SW10055
Riverside Dr E
SW10054
140 (7)
SW10053
Feeder Current MVA
Max: 233.5 212.1 165.1 9.7
Avg: 209.9 190.7 148.4 8.8
Min: 186.4 169.4 131.8 7.8
Feeder Current MVA
Max: 99.0 139.8 74.4 5.0
Avg: 89.0 125.7 67.0 4.5
Min: 79.0 111.6 59.5 4.0
Feeder Current MVA
Max: 40.1 66.3 27.2 2.1
Avg: 36.1 59.6 24.5 1.9
Min: 32.0 53.0 21.8 1.7
SW10174
432 (5)
5429 (21)
SW10114
705 (4)
1298 (4)
2059 (9)
FS10064
FS10075
FS10076
SC10002
SC10011
12970 (4)
TEC-12
Feeder Current MVA
Max: 119.4 65.9 76.4 4.2
Avg: 107.3 59.2 68.7 3.8
Min: 95.3 52.6 61.0 3.4
FS10209
148 (2)
FS10190
35 (1)
FS10189
1184 (1)
FS10188
Tecumseh Rd E
Riverside Dr E
TEC-14
Feeder Current MVA
Max: 150.8 122.2 139.9 6.5
Avg: 135.4 109.6 125.6 5.9
Min: 120.1 97.2 111.4 5.2
15 (1)
MAN-2
WM156M4
MANR4
518 (6)
SW10015
TEC-1
FS10227
509 (5)
FS10228
9 (1)
TEC-15
MV10005
6309 (6)
234 (2)
Lakeside
1015 (8)
56M8-56M26
18 (1)
TEC-13
FS10085
TEC-8
GRE2
530 (1)
SW10037
FS10128
FS10177
FS10129
314 (1)
SW10004
316 (5)
TEC-6
207 (4)
1149 (24)
Feeder Current MVA
Max: 52.4 73.8 72.7 3.2
Avg: 43.6 61.4 60.5 2.7
Min: 40.6 57.2 56.4 2.5
Feeder Current MVA
Max: 158.0 80.8 172.1 6.6
Avg: 131.4 67.2 143.3 5.5
Min: 122.6 62.7 133.7 5.1
3928 (1)
56M26ILS-1
23437 (102)
TEC-7
WM56M26
99 (3)
682 (1)
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SW10017
TEC-2
475 (2)
SW10007
SW10115
9148 (48)
TEC-9
SW10048
69 (1)
SW10049
SW10050
FS10192
138 (2)
SW10044
512 (8)
TEC-11
Feeder Current MVA
Max: 66.4 4.7 81.6 2.4
Avg: 55.2 4.0 67.9 2.0
Min: 51.5 3.7 63.4 1.9
SW10029
148 (5)
FS10025
751 (7)
SW10030
FS10041
2198 (15)
11486 (36)
TEC-10
5294 (4)
SW10032
SW10033
157 (3)
SW10034
345 (3)
SW10035
54 (1)
3401 (9)
SW10036
Feeder Current MVA
Max: 60.9 115.1 77.7 4.0
Avg: 50.7 95.8 64.7 3.4
Min: 47.3 89.3 60.4 3.1
FS10186
FS10086
37 (1)
FS10087
Feeder Current MVA
Max: 28.3 69.1 43.6 2.2
Avg: 23.6 57.5 36.3 1.9
Min: 19.1 57.4 58.7 1.8
Legend
EPL Owned Switch
EPL Owned Line
HONI Owned Switch
HONI Owned Line
Normally Open Switch Point
Wholesale Meter Point
XXX (Y)
Outage Data 2011-2013
XXX = customer outage hours
(Y) = outage frequency
XXX (Y)
LOS Outage Data 2011-2013
XXX = customer outage hours
(Y) = outage frequency
HONI Reclosure/Smart Switch
XXX (Y)
Reclosure/Smart Switch
XXX = downstream customer outage hours
(Y) = downstream outage frequency
Line Monitor

Attachment 1-O

EPLC CDM Persistence Reports

Attachment 1-P

Current EPLC 2015-2020 CDM Plan

Attachment 1-Q

LRAM Workform

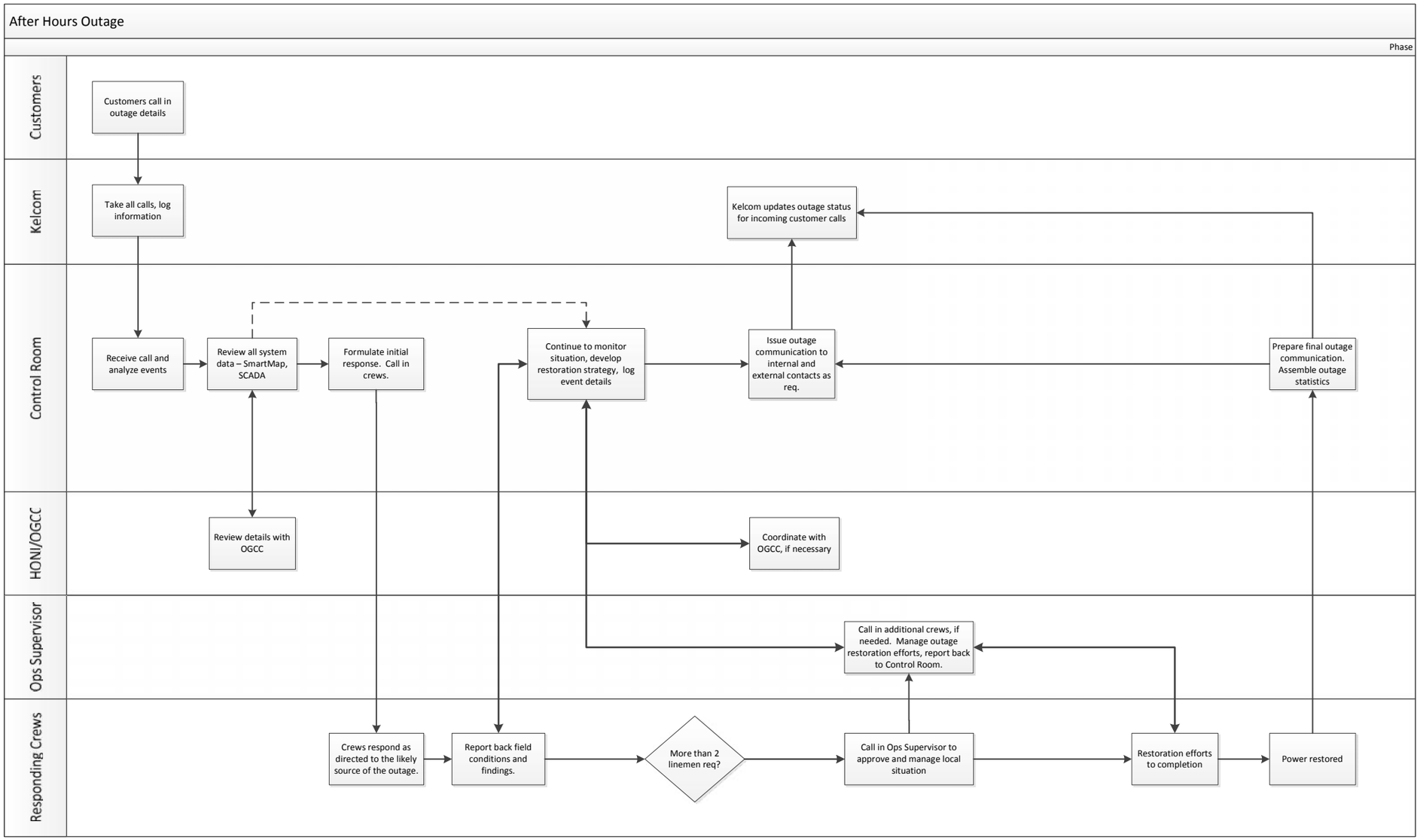
Attachment 1-R

EPLC CDM Final Reports 2011-2016

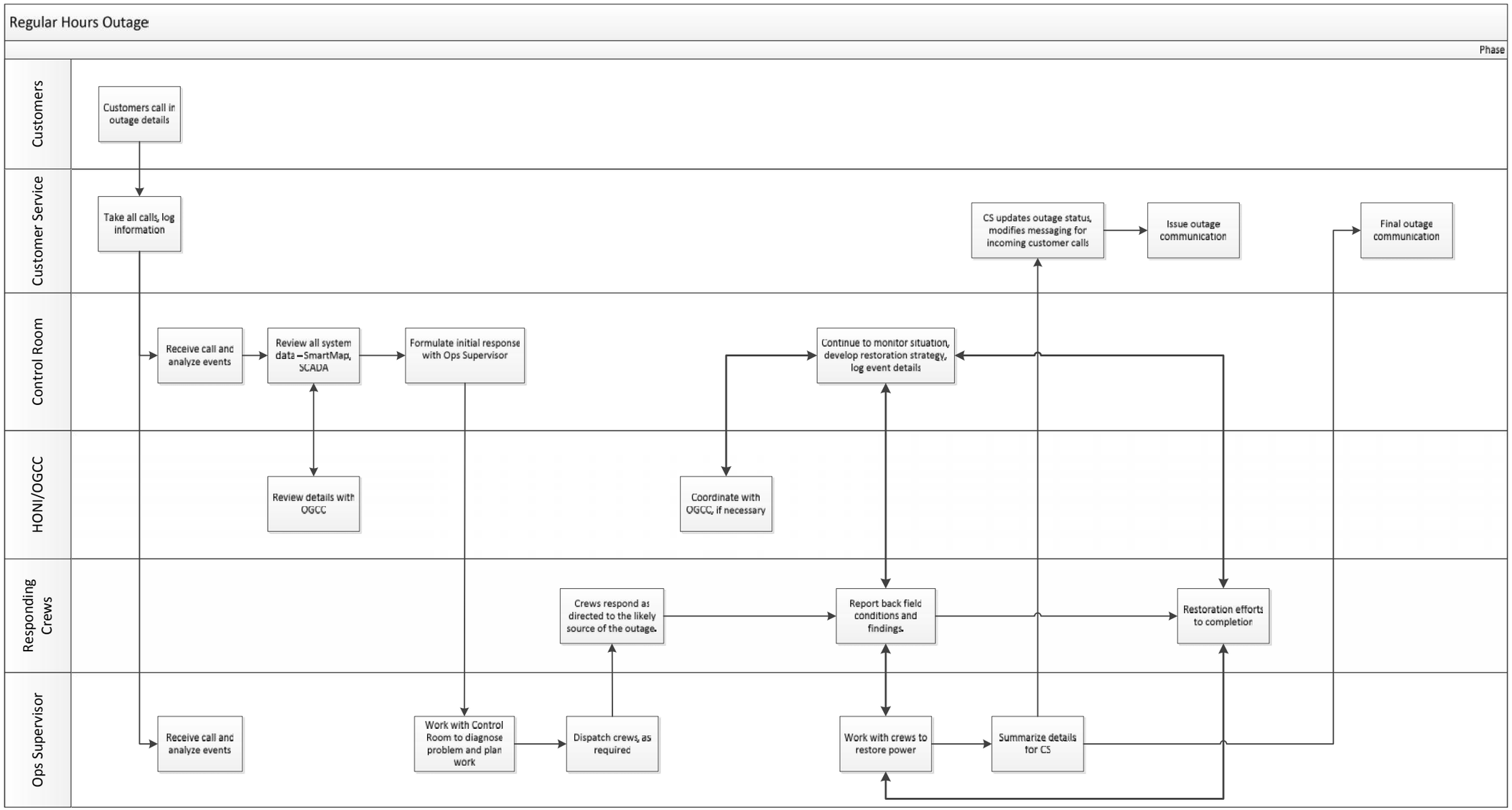
Attachment 1-S

Draft Control Room Processes

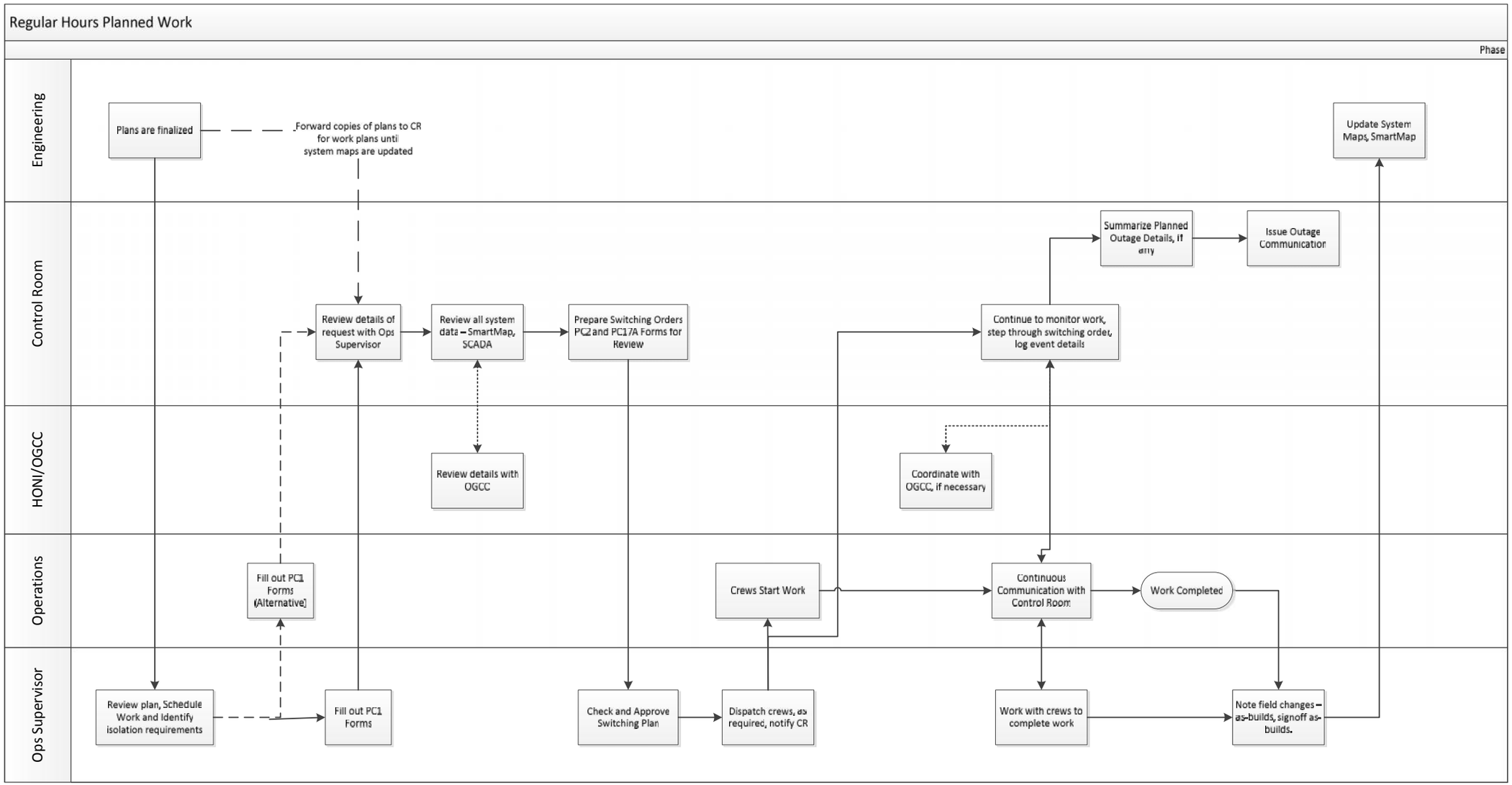
Appendix 1 – Control Room Processes



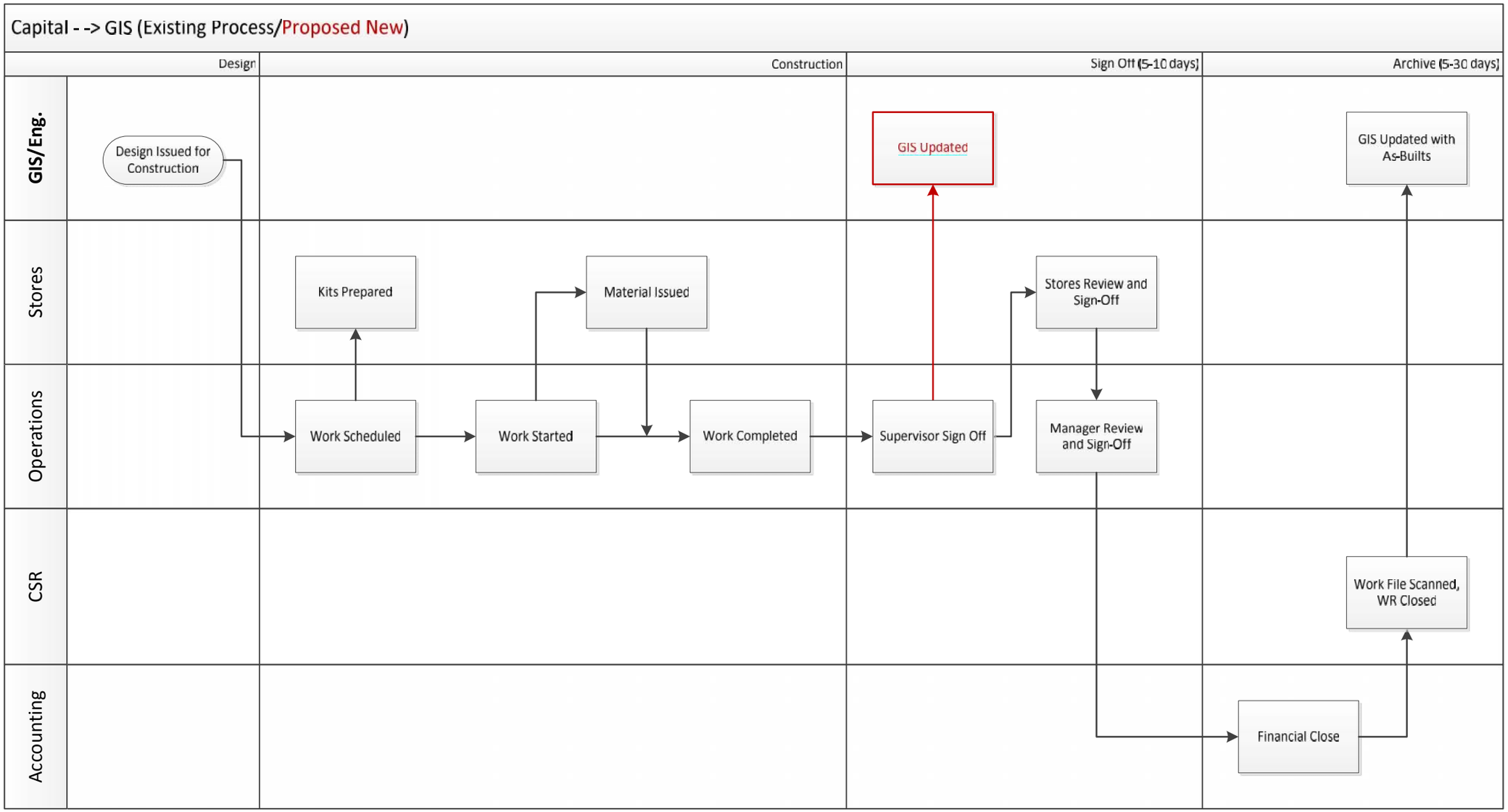
Appendix 1 – Control Room Processes



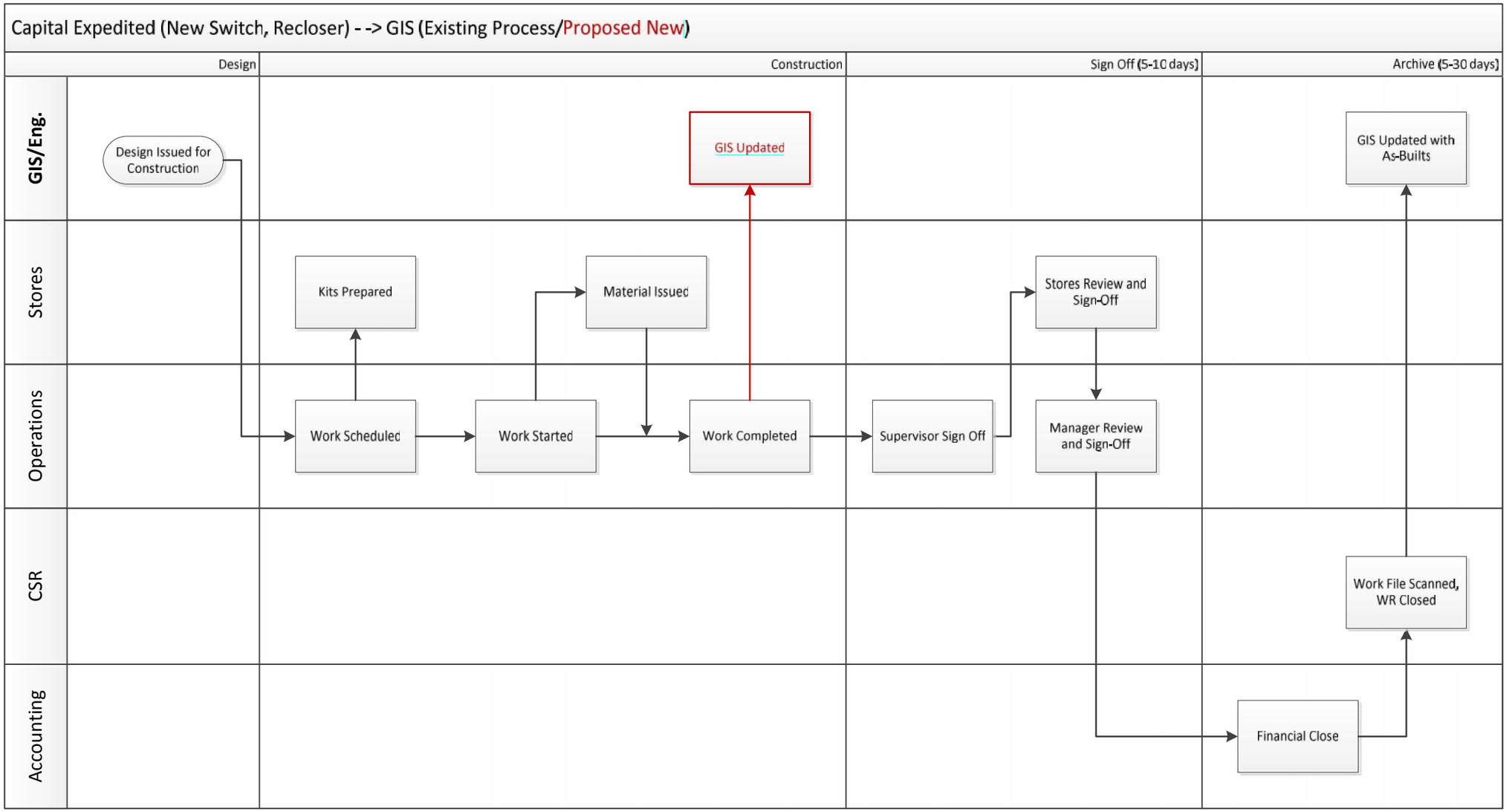
Appendix 1 – Control Room Processes



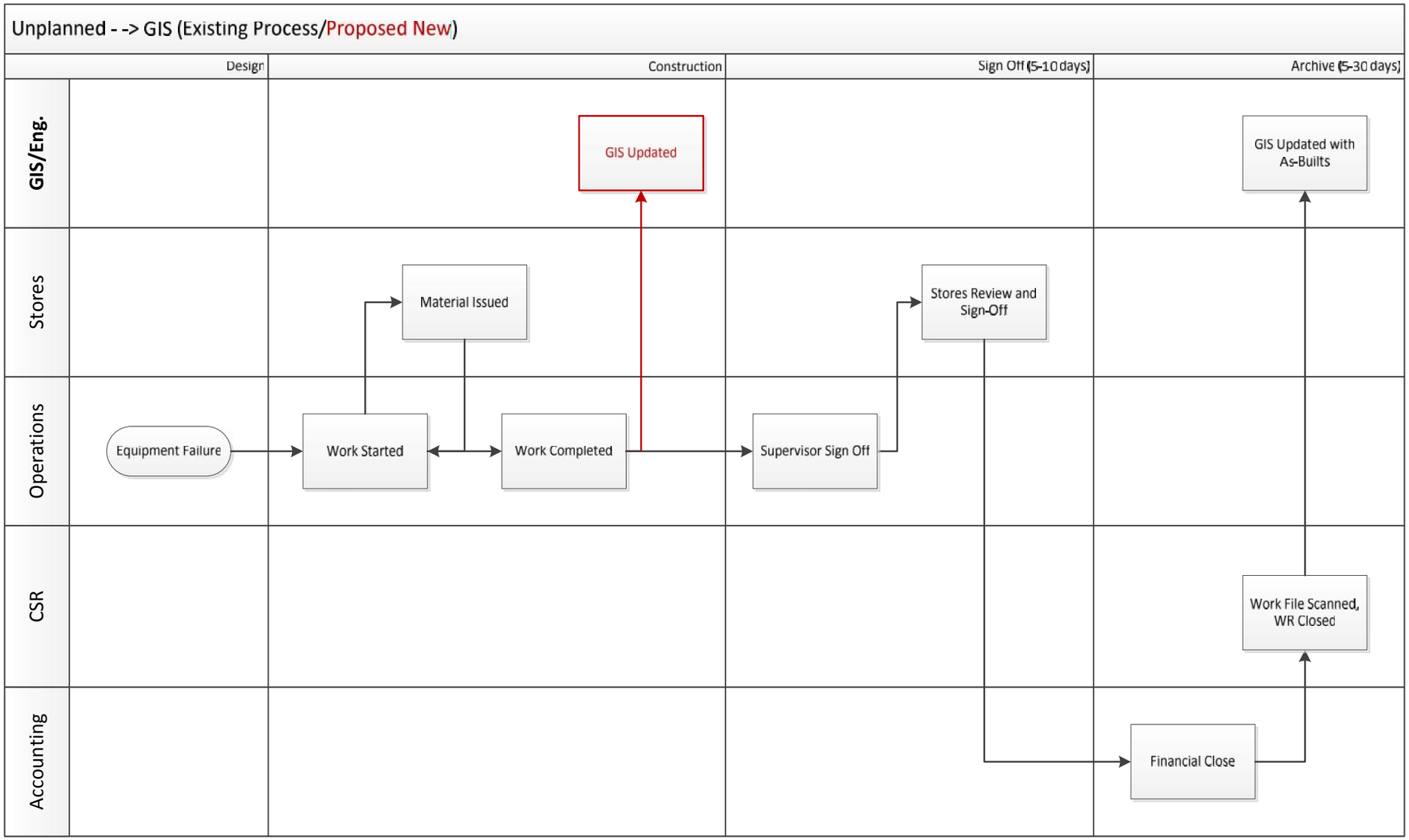
Appendix 2 – Map Update Process



Appendix 2 – Map Update Process



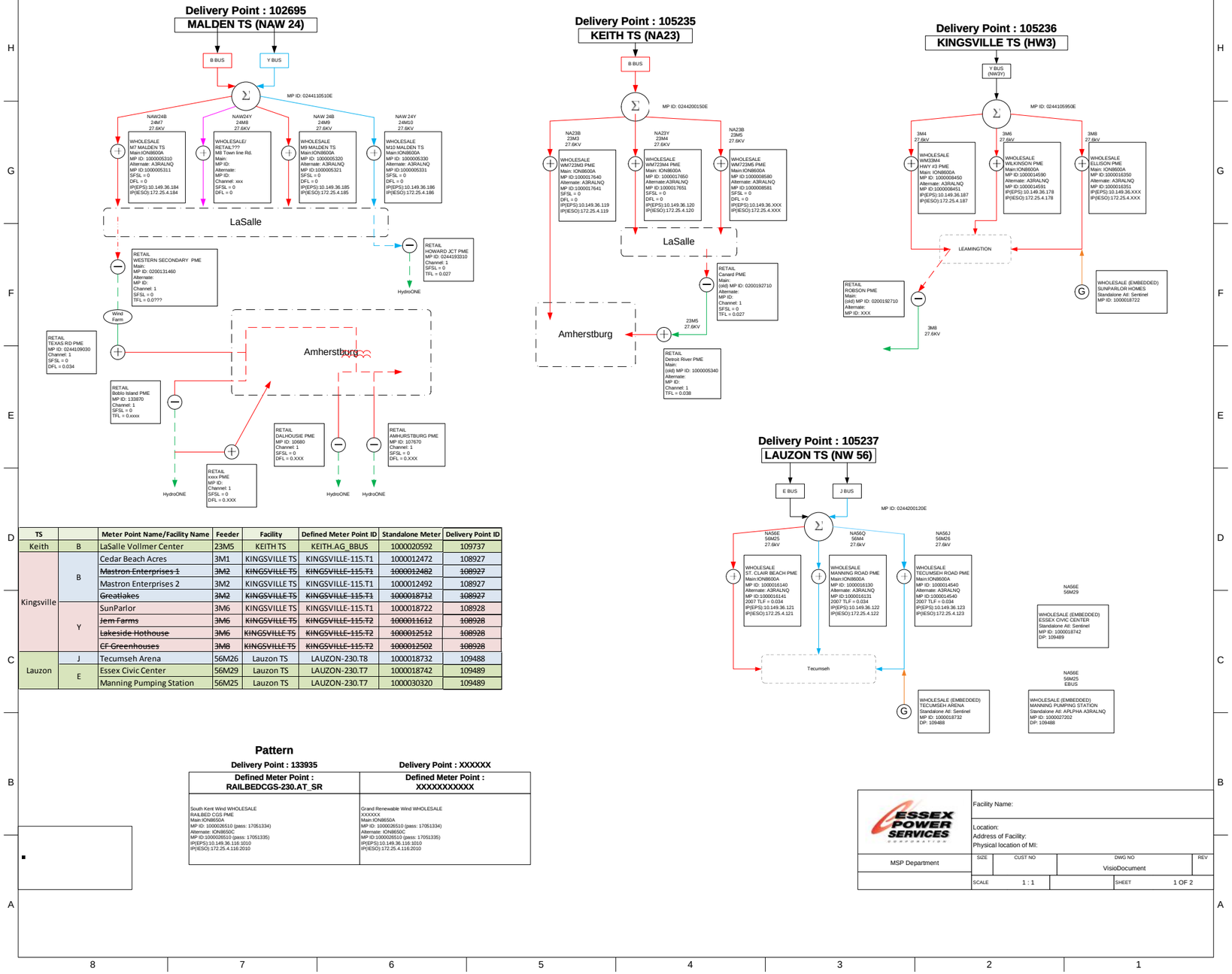
Appendix 2 – Map Update Process



Appendix 3 – Control Room Service Details and Data Access Requirements

Description of Service	- Use of Smartmap. - Use of other maps for information purposes only. - Interact with HONI for hold-offs and other services on EPL's behalf. - Responsible for all HONI operational interactions. - Responsible to keep maps and records updated with the current status of all switches and isolation points. - Full operational control of all EPL devices, via switching orders or remotely (future). - 24 hours crew dispatching for switching and emergency response.
Services	
HONI Interaction and Liaison	
First Point of contact with OGCC	Receive calls and emails from OGCC for all operational requests and issues. Filter requets and pass on to EPL main contact.
Manage all interactions with OGCC	Use information about EPL system and respond to HONI on EPL's behalf. Refer to EPL when appropriate.
Manage all Hold-Off Requests	Take and log all hold-off requests from crews and contractors. Communicate with HONI by phone or via SCADA to take hold-offs. Use EPL reclosers where appropriate.
Manage Hold-Offs Through Reclosers	Log and manage all hold-offs at each recloser. Dispatch crews depending on Service Level.
Manage outage calls	Liaise with Call-Center (Kelcom). Dispatch all necessary crews. Resolve outage.
Major Customer/DER Main Contact	Main contact for designated major customers and DER's requesting operational services from EPL.
Process and approve all switching orders	Prepare and execute (via crews, SCADA, Smartmap) all switching orders. Log all switching activity.
Recloser Control	Remotely operate reclosers (Future to be implemented) Suggest/recommend protection settings. Suggest/recommend new recloser/swtich locations.
Outage Management	
Dispatch On-Call employees	Liaise with crews responding to after hour emergencies. Guide crews to outage location and help restore power. Log any switching and work activity. Provide troubleshooting guidance.
Troubleshoot problem	Review maps, current conditions, and all system status data to troubleshoot problems, location of outages, and create remediation plans.
Ping meters and other field devices	Access AMI system and ping meters and devices as necessary.
Verify Proposed Outage	Verify proposed outage in Smartmap. Notify, via email, internal contacts as directed.
Device Status Alarm Response (Basic)	Respond to all EPL SCADA alarms. Forward alarms to EPL contacts.
Device Status Alarm Response (After Hours)	Troubleshoot cause Liaise with HONI, as required Dispatch crews as required. Monitor outage restoration progress, provide assistance until power is restored.
Other Operation Services	
Dispatch crews	Dispatch crews to outages. Execute switching orders. Communicate with crews 24 hours.
Liaise with DER's	1st point of operational contact. Dispatch DER ressources. Manage HONI - DER interaction.
Records Management	
Manage Smartmap System Model (After Hours)	Change switch status. Make corrections to the model. Record all temporary conditions.
Record outage stats	Record all outage data required for maintenance of outage statistics and records.
Communication	
Social Media notification	Issue all social media messaging about outages and emergencies.
Email - internal notification	Issue internal email notifications about outages and other emergencies. Include any relevant details.
Email - external notification	Issue email notifications to internal and external contacts about outages and other emergencies. Include any relevant details.
Information/Access Needed	
Systems	
Master to master SCADA connection of our feeders with HONI	ICCP connection to OGCC.
Operational Access to Smartmap	View and edit maps and system model. Save scenarios locally or offline.
Admin Access to Smartmap	Make permament changes to the system model.
Access to AMI	Ping meters, check loads and voltages.
AVL Data	Location of all trucks
Records	
Copies of maps (backup only)	Copies of paper-based maps and records for backup purposes.
On Call list, access to employee directory	Weekly on-call list.
Understand EPL contract and policies	Training on any labour contract or EPL corporate policy requirements that may effect after hours or on-call work and dispatching.
Access and understand customer contracts/arrangements	Copies of any customer specific information such as operational agreements and schematics.
Planned outage schedule	Access to all planned work and scheduled outage plans.
Boundary Maps	Copies of any special maps to precisely identify EPL boundaries and limits.
Disconnect List	Copies of the customer disconnect list to help manage outage calls.
Communications	
Interface with Kelcom	Receive emails and reports from Kelcom with respect to current otuages and emergencies reported by customers.
Access to Email	Access to corporate email system to issue internal and external notifications.
Access to Social Media	Access to social media credentials to issue notifications on EPL's behalf.
Access to field communcations (radios, phones, text, email)	Phones numbers, radio bridges (TBD), email addresses.
Access to Supervsiors and Designates (phone, email)	Phone numbers and emails for all main contacts at EPL.
Access to radio and phones (field personnel)	Ability to call or contact any crews in the field by radio, phone, text or email.

Appendix 4 – Wholesale Metering Configuration



TS		Meter Point Name/Facility Name	Feeder	Facility	Defined Meter Point ID	Standalone Meter	Delivery Point ID
Keith	B	LaSalle Vollmer Center	23M5	KEITH TS	KEITH.AG_BBUS	1000020592	109737
Kingsville	B	Cedar Beach Acres	3M1	KINGSVILLE TS	KINGSVILLE-115.T1	1000012472	108927
		~~Mastron Enterprises 1~~	~~3M2~~	~~KINGSVILLE TS~~	~~KINGSVILLE-115.T1~~	~~1000012482~~	~~108927~~
		Mastron Enterprises 2	3M2	KINGSVILLE TS	KINGSVILLE-115.T1	1000012492	108927
		~~Greatlakes~~	~~3M2~~	~~KINGSVILLE TS~~	~~KINGSVILLE-115.T1~~	~~1000018712~~	~~108927~~
	Y	SunParlor	3M6	KINGSVILLE TS	KINGSVILLE-115.T1	1000018722	108928
		~~Jem Farms~~	~~3M6~~	~~KINGSVILLE TS~~	~~KINGSVILLE-115.T2~~	~~1000011612~~	~~108928~~
		~~Lakeside Hothouse~~	~~3M6~~	~~KINGSVILLE TS~~	~~KINGSVILLE-115.T2~~	~~1000012512~~	~~108928~~
		~~CF Greenhouses~~	~~3M8~~	~~KINGSVILLE TS~~	~~KINGSVILLE-115.T2~~	~~1000012502~~	~~108928~~
Lauzon	J	Tecumseh Arena	56M26	Lauzon TS	LAUZON-230.T8	1000018732	109488
	E	Essex Civic Center	56M29	Lauzon TS	LAUZON-230.T7	1000018742	109489
		Manning Pumping Station	56M25	Lauzon TS	LAUZON-230.T7	1000030320	109489

Pattern

Delivery Point : 133935	Delivery Point : XXXXXX
Defined Meter Point : RAILBEDCGS-230.AT_SR	Defined Meter Point : XXXXXXXXXX
South Kent Wind WHOLESALE RAILBED CGS PME Main:ION8650A MP ID: 1000026510 (pass: 17051334) Alternate: ION8650C MP ID:1000026510 (pass: 17051335) IP(EPS):10.149.36.116:1010 IP(IESO):172.25.4.116:2010	Grand Renewable Wind WHOLESALE XXXXXX Main:ION8650A MP ID: 1000026510 (pass: 17051334) Alternate: ION8650C MP ID:1000026510 (pass: 17051335) IP(EPS):10.149.36.116:1010 IP(IESO):172.25.4.116:2010

ESSEX POWER SERVICES CORPORATION	Facility Name:		
	Location: Address of Facility: Physical location of MI:		
MSP Department	SIZE	CUST NO	DWG NO: VisioDocument / REV
	SCALE 1 : 1		SHEET 1 OF 2

Attachment 1-T

Shared Service Agreement – Essex Power Services

MASTER SERVICES AGREEMENT

THIS AGREEMENT made this 1st day of March , 2009

BETWEEN:

(ESSEX POWER SERVICES CORPORATION)

(hereinafter referred to as **"EPSC"**)

OF THE FIRST PART

and

(ESSEX POWERLINES CORPORATION)

(hereinafter referred to as **"EPL"**)

OF THE SECOND PART

WHEREAS EPSC and EPL are duly incorporated pursuant to Section 142, Schedule A of the *Electricity Act, 1998.*

AND WHEREAS both EPSC and EPL will operate as separate corporate entities, notwithstanding the provisions of this Agreement;

AND WHEREAS the parties have agreed that EPL shall provide such and other products and services as may be agreed by the parties from time to time.

AND WHEREAS the parties acknowledge and agree that in providing goods and services EPSC acts as an independent contractor and not as an agent, partner, or servant;

NOW THEREFORE IN CONSIDERATION of the mutual covenants and agreements set forth, and for other good and valuable considerations for the sum of two ($2.00) dollars of lawful money of Canada now paid by each of the Parties to the other (the receipt and sufficiency of which is hereby expressly acknowledged), the Parties covenant and agree, with each other, as follows:

1. Definitions

1.01 **"Administration Costs"** means costs incurred by EPC to manage business, finances, and day to day operations.

1.02 **"Customer Service Costs"** means the cost incurred by a party to bill and collect and to provide related customer services.

1.03 **"Customer Services"** means all services related to customer services, which without limiting the generality of the foregoing shall include customer billing, collection of unpaid accounts, and customer relations, etc.

1.04 **"Extraordinary Costs"** means those unusual and unanticipated costs as more particularly described in Article 5.05.

1.05 **"Vehicle and Equipment Cost"** means the cost of trucks and other motorized vehicles, and equipment used in operations, maintenance, administration and capital works of EPL.

2. Term

2.01 Unless terminated in accordance with Article 11.01, the term of this Agreement shall be from January 1, 2008 to and including December 31, 2008 and renewed year by year thereafter, unless either party gives the other notice in writing not less than one hundred and eighty (180) days prior to the end of the term, or the end of renewal as the case may be that the Agreement is not to be extended.

3. Electrical Services

3.01 EPL agrees to perform in a good and workmanlike manner EPSC's request for electrical services which may include the installation and maintaining of street lights or any other high voltage electrical services that may be requested by EPSC that is not within EPL's distribution system, in the former Municipality of Leamington, former Towns of Tecumseh, LaSalle, and Amherstburg, and the former Village of St. Clair Beach hereinafter referred to as the "EPL Service Area".

3.02 In providing electrical services for EPSC, EPL shall maintain the minimum performance standards as required by EPSC and in conjunction with regulatory agencies such as the Electrical Safety Authority (ESA).

3.03 EPL shall follow good utility practice in providing services as requested by EPSC as to prevent exposure to EPSC for liability reasons.

4. Costs

4.01 **Administrative Costs**

4.02 EPSC shall reimburse EPL for its actual costs including overhead, which without limiting the generality of the foregoing shall include EPL direct labour, engineering design and review costs including overhead applicable to EPSC, plus labour overhead according to Schedule A.

4.03 Work may be progress billed or billed upon completion to EPSC and EPSC shall pay at least quarterly of receipt. Billing may include intercompany transfer and journal entries to record the transfer.

4.04 **Material/Accounts Payable/Inventory Costs**

EPSC shall pay EPL the fees and charges more particularly outlined in Schedule "A" for material used either from on hand inventory or specifically ordered and delivered for the required work. These costs may also include subcontractor or contracted services charges that are required to complete the work as requested by EPSC.

4.05 **Vehicle/Equipment Costs**

EPSC shall pay EPL the fees and charges more particularly outlined in Schedule "A" as EPSC's contribution towards the utilization of trucks, other motorized vehicles and equipment used by EPL to provide services as requested by EPSC.

4.06 **Direct Costs**

EPSC shall assume and be directly responsible for its Direct Costs. Direct costs may include EPSC specific training required by EPL's employees.

4.07 **Extraordinary Costs**

EPSC agrees to reimburse EPL for any extraordinary costs over and above normal service costs to which EPL may have resulting from extraordinary unanticipated events such as fires, major storms, tornadoes, equipment failures, and the like provided such equipment failures are not caused by negligence on the part of EPL.

4.08 **Renewal**

Upon renewal of the term of this Agreement and any subsequent renewals, EPL may adjust the Administrative costs, Vehicle/Equipment Costs, and Extraordinary Costs upon ninety (90) days prior notice in writing to EPSC provided that, if EPSC does not accept the adjusted costs and the parties are unable to agree after negotiating in good faith, the adjusted costs may be submitted to arbitration pursuant to Article 10 of this agreement.

5. Invoicing

5.01 EPL shall submit invoices to EPSC on a monthly basis, for costs in performing services under this agreement. All costs shall provide sufficient detail of the costs incurred and the description of the services undertaken by EPL. EPSC shall transfer payment to EPL via intercompany transfers or by cheque.

5.02 EPL will submit details of any extraordinary costs to EPSC for review prior to completion and EPSC will pay as per Article 6.01 at least quarterly.

6. Arbitration

6.01 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 Aricle10.02.

6.02 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.

6.03 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.

6.04 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.

6.05 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.

7. Termination

7.01 In the event of non-performance by either party of its obligations under this Agreement, the other party may at its sole option elect to terminate this Agreement provided that the defaulting party shall be given written notice of the default and shall be given sixty (60) days to cure the default, and then only upon failure to cure the default the Agreement may be terminated.

8. Insurance

8.01 EPL and EPSC shall jointly provide and keep in force an insurance policy in the amount of not less than $20 million in respect of the services performed by EPL under the terms of this Agreement.

8.02 EPSC agrees to endorse its insurance coverage with EPL as an additional named insured to cover any liability of EPL resulting or arising from any claims of injury, including injury resulting in death, loss of property, or damage due to the negligence of EPL, or to those for whom EPL is at law responsible.

8.03 All policies shall contain a clause requiring the insurer to give EPSC or EPL, as the case may be, two hundred (200) days written notice prior to canceling insurance coverage.

8.04 Both Parties will notify the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE) regarding liability insurance implications.

9. Warranty

9.01 EPL provides no warranty or guarantee for any defective or deficient equipment or materials supplied except for the manufacturer's or supplier's warranties or guarantees applicable to the defective or deficient equipment or materials.

10. Notices

10.01 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 President, EPSC at: 360 Fairview Avenue West, Suite 218, Essex, Ontario N8M 3G4

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.

11. Amendments

11.01 Amendments to this Agreement shall be in writing and executed by the Parties duly authorized signing officers.

12. Headings

12.01 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 test of this Agreement.

13. Governing Law

13.01. This Agreement shall be construed in accordance with the laws of the Province of Ontario.

14. Successors

14.01. This Agreement shall ensure to the benefit of and be binding upon the Parties and their successors and assigns, respectively.

14.02. 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 as required pursuant to the provisions of the Energy Competition Act, 1998.

14.03. For the purposes of this Agreement, whenever the term EPSC or EPL is used, the term shall be deemed to include all successor business corporations incorporated to whom assets and liabilities are transferred for the purpose of the installation, operation and maintenance of the Parties' electrical distribution systems.

15. Regulatory Changes

15.01. 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 10.

16. Relationship

16.01. The parties acknowledge and agree that EPL shall act as an independent contractor providing its services under this Agreement and the Parties further acknowledge and agree that nothing in this Agreement shall be deemed or construed to be the formation of a partnership between EPSC and EPL.

IN WITNESS WHEREOF the Parties have duly executed this Agreement on the date first above written:

EPSC

Per:

Chair JOHN PALINICH

President RAYMOND TRACEY

EPL

Per:

Chair WILLIAM VARGA.

General Manager RICHARD DIMMEL

Schedule A - Electrical Services Costs

Labour plus overhead calculated at 52% (41% payroll and non productive time related, 11% administrative) plus 7.64% mark up.

Material, Accounts Payable (contracted services charges) and inventory cost plus overhead at 15% (4% stores, 11% administrative) plus 7.64% mark up.

Trucks and Equipment at the following rates plus a 21% truck overhead (10% truck, 11% administrative) plus 7.64% mark-up:

Unit Class	Description	Rate
1	CARS, PICKUPS & VANS	12.00
2	SMALL DUMPS & SERVICE TRUCKS	18.00
3	SINGLE BUCKETS & LARGE DUMP	24.00
4	DOUBLE BUCKETS	36.00
5	RBD'S & LINE TRUCKS	36.00
6	BACKHOES	21.00
7	CHIPPERS	15.00
8	UTILITY - FLAT BED TRAILERS	15.00
9	POLE TRAILERS	15.00
10	REEL & BIG 'O' TRAILERS	15.00
11	PORTABLE TRANSFORMERS	15.00
12	TENSIONERS	15.00
13	MOBILE GENERATORS	120.00

All Administrative costs are included in the overhead amounts above and therefore will not be charged separately.

Attachment 1-U

Water Billing Agreements

BILLING, COLLECTING, METER READING AND CALL CENTRE AGREEMENT

BETWEEN

ESSEX POWERLINES CORPORATION

AND

THE CORPORATION OF THE TOWN OF AMHERSTBURG

TABLE OF CONTENTS

THIS AGREEMENT MADE IN TRIPLICATE THIS ___ DAY OF_____, 2007

BETWEEN:

ESSEX POWERLINES CORPORATION
(Hereinafter called "Essex Power")

OF THE FIRST PART;

AND:

THE CORPORATION OF THE TOWN OF AMHERSTBURG
(Hereinafter called "the Municipality")

OF THE SECOND PART;

WHEREAS Essex Power has been providing meter reading and billing and collecting and Call Centre functions for the water customers within the Municipality.

AND WHEREAS the Municipality desires that Essex Power continue to provide for the ongoing services and functions related to those activities,

NOW THEREFORE THIS AGREEMENT WITNESSETH THAT in consideration of the mutual covenants hereinafter expressed, it is agreed by and between the parties hereto as follows:

1.0 TERM

1.1 Subject to Section 2.9 the term of this agreement shall be for the period commencing on April 1, 2008 and ending March 31, 2009 (hereinafter referred to as the Initial Term) and thereafter be automatically renewed for a successive period of two (2) years upon the same terms and conditions herein provided that either party may terminate this agreement at any time after the expiry of the Initial Term by providing at least six (6) months written notice of termination to the other party, which notice may be given prior to the expiry of the Initial Term or the current renewal period.

2.0 SERVICES PROVIDED

2.1 GENERAL

The Municipality hereby retains the services of Essex Power in connection with the reading of meters and the billing and collecting of water and sewage charges and call centre activities and Essex Power hereby agrees to provide the services described herein under the general direction and control of the Municipality.

2.2 SERVICES

The services to be provided by Essex Power, as generally stated herein above, are set forth in Articles 3, 4 and 5 and such services as well as

services changed, altered or added to under Article 2 are hereinafter referred to as the "services".

2.3 METER READING SERSICES

In this agreement, unless there is something in the subject matter or context inconsistent therewith, meter reading shall mean all activities required to read all water meter installations located within buildings, meter pits, and such other locations that meters may be located within the area of the Municipality read by Essex Power. Meter installations which are owned by other agencies, private individuals or corporations, shall not be read unless designated by the Municipality.

2.4 BILLING AND COLLECTING SERVICES

In this agreement, unless there is something in the subject matter or context inconsistent therewith, billing and collecting shall mean all activities associated with the issuance of bills and the collection of related revenues for all water and sewage charges associated with the meters and areas within and designated by the Municipality.

2.5 COMPENSATION FOR SERVICES PROVIDED

The Municipality shall pay Essex Power in accordance with the provisions set forth in Article 6.

2.6 STAFF AND METHODS SERVICES

Essex Power shall use current principles and shall skillfully and competently perform the services and shall employ only skilled and competent staff who will be under the supervision of Essex Power.

2.7 DOCUMENTATION SERVICES

Documents or copies thereof required for meter reading and billing and collecting shall be exchanged between the parties on a reciprocal basis.

2.8 CHANGES AND ALTERATIONS AND ADDITIONAL SERVICES

With the written consent of Essex Power, the Municipality, in writing, may at any time after the execution of this agreement or the commencement of the services, delete, extend, increase, vary or otherwise alter the services forming the subject of this agreement. Where such action by the Municipality necessitates additional staff or services, Essex Power shall be paid for additional services and/or staff employed together with such actual expenses and disbursements as are necessary. Where such action by the Municipality necessitates a reduction in staff and/or equipment then six (6) months written notice shall be given to Essex Power by the Municipality.

2.9 SUSPENSION OR TERMINATION OF SERVICES

Upon execution of this agreement, The Municipality, or Essex Power shall have until December 31, 2008 to terminate the services of Essex Power upon 120 days notice in writing. Following December 31, 2008, the Municipality, or Essex Power may, giving three (3) months notice in writing to the other, suspend or terminate the services.

2.10 INVENTORY AND EQUIPMENT SERVICES

Upon termination of this agreement, the Municipality agrees to purchase any and all inventory and equipment on hand, at current book value, used exclusively for the meter reading, billing and collecting, that Essex Power maintained for the Municipality.

2.11 APPROVAL OF SERVICES BY OTHER AUTHORITIES

Unless otherwise provided in this agreement, where the services of Essex Power are subject to the approval or review of an authority, department or government, or agency other than the Municipality, such application for approval or review shall be the responsibility of Essex Power.

2.12 INSPECTION

The Municipality, or persons authorized by the Municipality, shall have the right at all reasonable times, to inspect or otherwise review the services performed or being performed, in respect of meter reading, billing and collecting, and the premises where they are being performed.

2.13 TIME

Essex Power shall perform the services expeditiously as is reasonable with regard to the circumstances to meet the requirements of the Municipality and shall complete any portion or portions of the services in such order as the Municipality may require.

The Municipality shall expeditiously give consideration to all plans, specifications, reports, proposals and other information submitted from Essex Power and shall make any decisions which it is required to make in connection therewith so as not to delay the work of Essex Power.

3.0 METER READING

3.1 Meter reading by Essex Power shall generally include the following:

- Record all water meter reads by electronic hand held device, or on paper document, at intervals as deemed appropriate by the Municipality or Essex Power. It is understood, that at the time of execution of this agreement, the Municipal Water Dept. Staff read all water only accounts (commonly known as cycles 28, 29 & 30) as well as water meters over 2" and provide reads to Essex Power for billing and collecting as required.
- Access and record meter reads from any and all locations which may include but not strictly limited to meter pits and building exteriors and interiors, that can be safely accessed by the reader.
- Re-read those meters for the purpose verifying abnormally high or low consumption.
- Final read those meters here occupancy or ownership will change.
- Record and report damage or repairs that may be required for water meter equipment.

3.2 METER READING SERVICES

Essex Power shall include the following services in conjunction with the reading of water meters:

(a) Preparation of service orders and/or advise to enable the Municipality to undertake repairs to metering equipment that has been identified to be in need of same due to physical damage or due to abnormal consumption.

(b) Advise Municipality where conflicts between meter equipment and other utility equipment has been identified.

(c) Guidance and advice to Municipal staff regarding current technology, materials and equipment as it relates to meter reading.

(d) When required, the preparation of estimates for meter reading as it related to additional or new meter routes that may added by the Municipality from time to time.

(e) When required, review and comment on meter change or additional programs prepared by consultants and submitted to Essex Power by the Municipality.

(f) Participate in a reasonable number of meetings for information, negotiations or presentation purposes with the Municipality in connection with design criteria or standards as it related to meters.

(g) Assist in the provision of tender documents for any work to be tendered as it relates to new meter installations.

(h) The keeping of complete and accurate records of time spent for all activities as they relate to water meter reading and related services by Essex Power staff in addition to the regular scope of work for which reimbursement is required.

(i) Provide the necessary labour and equipment to perform the work. Efforts shall be made to use the most inexpensive equipment but, where this is not feasible or acceptable, the Municipality shall pay for the actual equipment required.

(j) Review the physical work being undertaken to ensure compliance with the terms of this agreement.

(k) Provide any necessary field activity controls for all meter reading staff.

(l) Investigate, report and recommend on unusual circumstances which may be discovered during the provision of meter reading.

(m) Carry out periodic inspection of the work performed by the meter reading staff.

3.3 METER READING ADDITIONS

Essex Power will respond to notification from the Municipality regarding requests related to the following:

Read and bill new meters – next read and billing cycle as mutually agreed.
Read only additional meter routes – next read cycle as mutually agreed.
Bill only additional meter routes – next billing cycle as mutually agreed.
Read and bill additional meter routes – next read and bill cycles as mutually agreed.

3.4 OWNERSHIP OF WATER METERS

The Municipality owns and finances the design, construction maintenance and operation of the meter reading equipment at all locations within the Municipality and shall include, but not necessarily be limited to, the following items:

- main meters
- meter remotes and wire
- meter pits
- remote posts

No permits shall be required by Essex Power for the purpose of reading or accessing water meters during the term of this agreement.

4.0 BILLING AND COLLECTING SERVICES

4.1 BILLING SERVICES

Essex Power shall provide the following services in conjunction with the billing of all accounts for water meters read:

Water/Sewage Rates and Charges

- Maintain a billing system that will allow for the billing of all water and sewage charges as mutually agreed by both parties included but not limited to water and sewer rate changes and water meter changes.
- Receive and apply rates and charges for all customer accounts as designated by the Municipality from time to time.
- Input all meter reads as collected by Essex Power or the Municipality.
- Review and edit all consumption quantities for the purpose of identifying those quantities that may be abnormal for the respective customer class, or with respect to a specific customer consumption pattern.
- Display rates and charges for all customer accounts within the Essex Power bill format as mutually agreed.
- Provide one (1) water and sewer rate increase per calendar year.
- Additional water and or sewer rate increases in the same calendar year will be provided based on written estimate to perform the service

- Include a rates and charges information insert with the regularly scheduled billing once per calendar year coincident with the annual water or sewer rate increase.
- Include additional billing inserts as required at a rate of $ .03 per account provided the material meets specifications and the regular postage rate is not affected.
- Calculate billing quantities in accordance with formulae as required by the Municipality.
- Produce billing quantity records and reports for current and archive access.
- Print bills at intervals as mutually agreed.
- Mail bills at intervals as mutually agreed.
- Produce and mail final notices for all accounts not paid within acceptable schedules.
- Provide all necessary clerical support to perform all billing functions assigned to Essex Power by the Municipality.

4.2 COLLECTING SERVICES

Water/Sewage Rates and Charges

- Collect all revenues for all accounts that Essex Power bills on behalf of the Municipality with respect to water and sewage charges.
- Provide methods of payment for all billed accounts by means of cheque by mail, payments through financial institutions, pre-authorized payment plans, telebanking, etc.
- Produce and mail final notices for all accounts not paid within acceptable schedules
- Provide all necessary clerical support to perform all collecting functions assigned to Essex Power by the Municipality.
- Advise the Municipality of water only accounts that are not paid within acceptable schedules, in order that the Municipality may decide if disconnection of same is in order.
- Submit all revenues collected to the Municipality at intervals and in quantities as mutually agreed.
- Produce collection quantity records and reports for current and archive access.
- Contract the services of a Collection Agency for uncollectible and/or finalized accounts.

5.0 ADMINISTRATIVE SERVICES

5.1 Essex Power shall provide the following Administrative Services:

Ensure the quality of all work undertaken on behalf of the Municipality.

Review and advise on Municipal requests for additions or deletions to meter reading, billing and collecting activities, and to advise the Municipality of the estimate of cost to provide such additions or deletions if same are not within the scope of the services provided by this agreement. Refer Article 6.1.

Provide on a monthly basis, in a mutually acceptable format, statistics, summary's or reports as related to meter reading, billing and collecting.

Collect all revenues for water and sewage charges billed by Essex Power on behalf of the Municipality.

The review, modification and approval of meter reading and billing schedules as mutually agreed.

The processing of all payments for revenues billed and received on behalf of the municipality.

Invoicing of all costs related to all functions and services as described herein, and as provided by Essex Power, and same forwarded to the Municipality on a monthly basis or as otherwise required.

Provide the Municipality with monthly, quarterly, or annual reports as they may relate to the services described herein, and as mutually agreed.

Request, in writing, additional funds (preceded by an estimate) where services requested from time to time by the Municipality exceed the service levels described herein.

Provide staffing levels to accommodate the services described herein.

Maintain meter reading, billing and collecting hardware and software to fulfill the scope of this agreement.

Provide access to the Municipal Customers water and sewer only, Reading, Billing and Balance History information by means of a Virtual Private Network.

Provide a call centre for water related issues such as final reads relating to customer moves, general water and sewer rate inquires, high water consumption, leaking water meters.

6.0 PAYMENT OF ESSEX POWER METER READING, BILLING AND COLLECTING ACCOUNTS

6.1 Essex Power agrees to submit to the Municipality monthly charges for all accounts for meter reading, billing, collecting and administrative services as per the following:

Effective April 1, 2008 - [redacted] per month

7.0 INTEREST

All payments shall be payable without interest within 30 days after the billing date but, after 30 days, interest will be charged at the prime rate of interest charged by Essex Power's bank to its most creditworthy customers plus I % per month on the unpaid balance from the date of billing. Where a dispute arises, the Municipality shall pay the undisputed portion forthwith rather than withholding the entire payment.

8.0 PREVIOUS AGREEMENT

8.1 This agreement supersedes all previous agreements, arrangements, or understandings between the parties, whether written or oral, in connection with, or incidental to the meter reading, billing and collecting.

9.0 NOTICES

9.1 Any notice, document or other communication required or permitted to be given hereunder shall be in writing and shall be sufficiently given if delivered or sent by prepaid registered mail from a Post Office in Canada addressed in the case of the Municipality to:

The Corporation of the Town of Amherstburg
P.O. Box 159
271 Sandwich St. S.
Amherstburg, Ontario N9V 2Z3

Attention: Mr. Paul Beneteau
Treasurer

or addressed in the case of the Essex Power to:

Essex Powerlines Corporation
360 Fairview Ave West, Suite 218
Essex, Ontario N8M 3G4

Attention: Mr. Alan Parnell,
Manager, Customer Service

Each of the foregoing shall be entitled to specify a different address by giving written notice as aforesaid to the other. Any notice, if mailed, shall be deemed to have been given on the third business day following such mailing or if delivered by hand, shall be deemed to have been given on the day of delivery if a business day, or if not a business day, on the next business day following the day of delivery.

10.0 COUNTERPARTS

10.1 This agreement may be executed in several counterparts, each of which so executed shall be deemed to be an original and such counterparts together shall constitute one and the same instrument and notwithstanding their date of execution shall be deemed to bear date as of the date written above.

11.0 INTERPRETATION

11.1 In this agreement, words importing the singular number include the plural, and vice versa, and words importing the masculine gender include the feminine gender.

12.0 HEADINGS

12.1 Section headings are not to be considered part of this agreement but are included solely for convenience of reference and are not intended to be full or accurate descriptions of the contents thereof

13.0 BINDING EFFECT

13.1 This agreement shall extend to and be binding upon and endure to the benefit of the parties hereto and their respective successors and assigns.

14.0 INSURANCE AND INDEMNIFICATION

14.1 Essex Power hereby covenants and agrees to maintain at all times sufficient insurance as may be required by the Municipality.

14.2 Essex Power shall protect, defend, indemnify and save harmless the Municipality from and against all claims, actions, losses, expenses, costs or damages of every nature and kind whatsoever which the Municipality, its officers, employees or agents may suffer as a result of the negligence of Essex Power, its officers, employees, contractors or agents in the performance of this agreement.

Essex Power shall be responsible for all services, and potential affects, it undertakes with respect to services described herein during the term of this agreement and shall protect, defend and save the Municipality harmless in respect of any damage, defect or want of repair thereto, arising from any breach or default or from negligence by Essex Power, its officers, employees or agents and from all loss, charges, damages, liens, costs, legal fees, expenses and liabilities which the Municipality, its officers, employees, or agents may incur, provided however, that Essex Power shall not be responsible for any claim or demand arising from the negligence by any officer, employee, or agent of the Municipality while acting within the scope of his or her duties or employment.

15.0 ASSIGNMENT

15.1 Neither party may assign this agreement without the prior consent, in writing of the other.

16.0 REASONABLENESS:

16.1 Each party agrees that it shall at all times act reasonably in the performance of its obligations and the exercise of its rights under this License.

17.0 APPLICABLE LAW:

17.1 This agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein.

IN WITNESS WHEREOF THE PARTIES HERETO HAVE CAUSED THIS AGREEMENT TO BE EXECUTED BY THE SIGNATURES OF THEIR PROPER OFFICERS DULY AUTHOURIZED IN THAT BEHALF AS OF THE DATE AND YEAR FIRST ABOVE WRITTEN.

On behalf of **THE CORPORATION OF THE TOWN OF AMHERSTBURG**

Signature	Title	Date

Signature	Title	Date

On behalf of: **ESSEX POWERLINES CORPORATION**:

Signature	Title	Date

Signature	Title	Date

BILLING, COLLECTING, METER READING AND CALL CENTRE AGREEMENT

BETWEEN

ESSEX POWERLINES CORPORATION

AND

THE CORPORATION OF THE MUNICIPALITY OF LEAMINGTON

TABLE OF CONTENTS

THIS AGREEMENT MADE IN TRIPLICATE THIS ___ DAY OF_____, 2007

BETWEEN:

ESSEX POWERLINES CORPORATION
(Hereinafter called "Essex Power")

OF THE FIRST PART;

AND:

THE CORPORATION OF THE MUNICIPALITY OF LEAMINGTON
(Hereinafter called "the Municipality")

OF THE SECOND PART;

WHEREAS Essex Power has been providing meter reading and billing and collecting and Call Centre functions for the water customers within the Municipality.

AND WHEREAS the Municipality desires that Essex Power continue to provide for the ongoing services and functions related to those activities,

NOW THEREFORE THIS AGREEMENT WITNESSETH THAT in consideration of the mutual covenants hereinafter expressed, it is agreed by and between the parties hereto as follows:

1.0 TERM

1.1 Subject to Section 2.9 the term of this agreement shall be for the period commencing on April 1, 2008 and ending December 31, 2011 (hereinafter referred to as the Initial Term) and thereafter be automatically renewed for successive periods of three (3) years upon the same terms and conditions herein provided that either party may terminate this agreement at any time after the expiry of the Initial Term by providing at least six (6) months written notice of termination to the other party, which notice may be given prior to the expiry of the Initial Term or the current renewal period.

2.0 SERVICES PROVIDED

2.1 GENERAL

The Municipality hereby retains the services of Essex Power in connection with the reading of meters and the billing and collecting of water and sewage charges and call centre activities and Essex Power hereby agrees to provide the services described herein under the general direction and control of the Municipality.

2.2 SERVICES

The services to be provided by Essex Power, as generally stated herein above, are set forth in Articles 3, 4 and 5 and such services as well as

services changed, altered or added to under Article 2 are hereinafter referred to as the "services".

2.3 METER READING SERSICES

In this agreement, unless there is something in the subject matter or context inconsistent therewith, meter reading shall mean all activities required to read all water meter installations located within buildings, meter pits, and such other locations that meters may be located within the area of the Municipality read by Essex Power. Meter installations which are owned by other agencies, private individuals or corporations, shall not be read unless designated by the Municipality.

2.4 BILLING AND COLLECTING SERVICES

In this agreement, unless there is something in the subject matter or context inconsistent therewith, billing and collecting shall mean all activities associated with the issuance of bills and the collection of related revenues for all water and sewage charges associated with the meters and areas within and designated by the Municipality.

2.5 COMPENSATION FOR SERVICES PROVIDED

The Municipality shall pay Essex Power in accordance with the provisions set forth in Article 6.

2.6 STAFF AND METHODS SERVICES

Essex Power shall use current principles and shall skillfully and competently perform the services and shall employ only skilled and competent staff who will be under the supervision of Essex Power.

2.7 DOCUMENTATION SERVICES

Documents or copies thereof required for meter reading and billing and collecting shall be exchanged between the parties on a reciprocal basis.

2.8 CHANGES AND ALTERATIONS AND ADDITIONAL SERVICES

With the written consent of Essex Power, the Municipality, in writing, may at any time after the execution of this agreement or the commencement of the services, delete, extend, increase, vary or otherwise alter the services forming the subject of this agreement. Where such action by the Municipality necessitates additional staff or services, Essex Power shall be paid for additional services and/or staff employed together with such actual expenses and disbursements as are necessary. Where such action by the Municipality necessitates a reduction in staff and/or equipment then six (6) months written notice shall be given to Essex Power by the Municipality.

2.9 SUSPENSION OR TERMINATION OF SERVICES

Upon execution of this agreement, The Municipality, or Essex Power shall have until December 31, 2008 to terminate the services of Essex Power upon 120 days notice in writing. Following December 31, 2008, the Municipality, or Essex Power may, giving six (6) months notice in writing to the other, suspend or terminate the services.

Upon termination by the Municipality, the Municipality will pay Essex Power the following percentage of the Remaining Contract Amount:

a) Forty (40%) percent if terminated prior to December 31, 2009
b) Thirty (30%) percent if terminated prior to December 31, 2010
c) Twenty (20%) percent if terminated prior to December 31, 2011

2.10 INVENTORY AND EQUIPMENT SERVICES

Upon termination of this agreement, the Municipality agrees to purchase any and all inventory and equipment on hand, at current book value, used exclusively for the meter reading, billing and collecting, that Essex Power maintained for the Municipality.

2.11 APPROVAL OF SERVICES BY OTHER AUTHORITIES

Unless otherwise provided in this agreement, where the services of Essex Power are subject to the approval or review of an authority, department or government, or agency other than the Municipality, such application for approval or review shall be the responsibility of Essex Power.

2.12 INSPECTION

The Municipality, or persons authorized by the Municipality, shall have the right at all reasonable times, to inspect or otherwise review the services performed or being performed, in respect of meter reading, billing and collecting, and the premises where they are being performed.

2.13 TIME

Essex Power shall perform the services expeditiously as is reasonable with regard to the circumstances to meet the requirements of the Municipality and shall complete any portion or portions of the services in such order as the Municipality may require.

The Municipality shall expeditiously give consideration to all plans, specifications, reports, proposals and other information submitted from Essex Power and shall make any decisions which it is required to make in connection therewith so as not to delay the work of Essex Power.

3.0 METER READING

3.1 Meter reading by Essex Power shall generally include the following:

- Record all water meter reads by electronic hand held device, or on paper document, at intervals as deemed appropriate by the Municipality or Essex Power.
- Access and record meter reads from any and all locations which may include but not strictly limited to meter pits and building exteriors and interiors, that can be safely accessed by the reader.
- Re-read those meters for the purpose verifying abnormally high or low consumption.
- Final read those meters here occupancy or ownership will change.
- Record and report damage or repairs that may be required for water meter equipment.

3.2 METER READING SERVICES

Essex Power shall include the following services in conjunction with the reading of water meters:

(a) Preparation of service orders and/or advise to enable the Municipality to undertake repairs to metering equipment that has been identified to be in need of same due to physical damage or due to abnormal consumption.

(b) Advise Municipality where conflicts between meter equipment and other utility equipment has been identified.

(c) Guidance and advice to Municipal staff regarding current technology, materials and equipment as it relates to meter reading.

(d) When required, the preparation of estimates for meter reading as it related to additional or new meter routes that may added by the Municipality from time to time.

(e) When required, review and comment on meter change or additional programs prepared by consultants and submitted to Essex Power by the Municipality.

(f) Participate in a reasonable number of meetings for information, negotiations or presentation purposes with the Municipality in connection with design criteria or standards as it related to meters.

(g) Assist in the provision of tender documents for any work to be tendered as it relates to new meter installations.

(h) The keeping of complete and accurate records of time spent for all activities as they relate to water meter reading and related services by Essex Power staff in addition to the regular scope of work for which reimbursement is required.

(i) Provide the necessary labour and equipment to perform the work. Efforts shall be made to use the most inexpensive equipment but, where this is not feasible or acceptable, the Municipality shall pay for the actual equipment required.

(j) Review the physical work being undertaken to ensure compliance with the terms of this agreement.

(k) Provide any necessary field activity controls for all meter reading staff.

(l) Investigate, report and recommend on unusual circumstances which may be discovered during the provision of meter reading.

(m) Carry out periodic inspection of the work performed by the meter reading staff.

3.3 METER READING ADDITIONS

Essex Power will respond to notification from the Municipality regarding requests related to the following:

Read and bill new meters – next read and billing cycle as mutually agreed.
Read only additional meter routes – next read cycle as mutually agreed.
Bill only additional meter routes – next billing cycle as mutually agreed.
Read and bill additional meter routes – next read and bill cycles as mutually agreed.

3.4 OWNERSHIP OF WATER METERS

The Municipality owns and finances the design, construction maintenance and operation of the meter reading equipment at all locations within the Municipality and shall include, but not necessarily be limited to, the following items:

- main meters
- meter remotes and wire
- meter pits
- remote posts

No permits shall be required by Essex Power for the purpose of reading or accessing water meters during the term of this agreement.

4.0 BILLING AND COLLECTING SERVICES

4.1 BILLING SERVICES

Essex Power shall provide the following services in conjunction with the billing of all accounts for water meters read:

Water/Sewage Rates and Charges

- Maintain a billing system that will allow for the billing of all water and sewage charges as mutually agreed by both parties included but not limited to water and sewer rate changes and water meter changes.
- Receive and apply rates and charges for all customer accounts as designated by the Municipality from time to time.
- Input all meter reads as collected by Essex Power or the Municipality.
- Review and edit all consumption quantities for the purpose of identifying those quantities that may be abnormal for the respective customer class, or with respect to a specific customer consumption pattern.
- Display rates and charges for all customer accounts within the Essex Power bill format as mutually agreed.
- Provide one (1) water and sewer rate increase per calendar year.
- Additional water and or sewer rate increases in the same calendar year will be provided based on written estimate to perform the service

- Include a rates and charges information insert with the regularly scheduled billing once per calendar year coincident with the annual water or sewer rate increase.
- Include additional billing inserts as required at a rate of $ .03 per account provided the material meets specifications and the regular postage rate is not affected.
- Calculate billing quantities in accordance with formulae as required by the Municipality.
- Produce billing quantity records and reports for current and archive access.
- Print bills at intervals as mutually agreed.
- Mail bills at intervals as mutually agreed.
- Produce and mail final notices for all accounts not paid within acceptable schedules.
- Provide all necessary clerical support to perform all billing functions assigned to Essex Power by the Municipality.

4.2 COLLECTING SERVICES

Water/Sewage Rates and Charges

- Collect all revenues for all accounts that Essex Power bills on behalf of the Municipality with respect to water and sewage charges.
- Provide methods of payment for all billed accounts by means of cheque by mail, payments through financial institutions, pre-authorized payment plans, telebanking, etc.
- Produce and mail final notices for all accounts not paid within acceptable schedules
- Provide all necessary clerical support to perform all collecting functions assigned to Essex Power by the Municipality.
- Advise the Municipality of water only accounts that are not paid within acceptable schedules, in order that the Municipality may decide if disconnection of same is in order.
- Submit all revenues collected to the Municipality at intervals and in quantities as mutually agreed.
- Produce collection quantity records and reports for current and archive access.
- Contract the services of a Collection Agency for uncollectible and/or finalized accounts.

5.0 ADMINISTRATIVE SERVICES

5.1 Essex Power shall provide the following Administrative Services:

Ensure the quality of all work undertaken on behalf of the Municipality.

Review and advise on Municipal requests for additions or deletions to meter reading, billing and collecting activities, and to advise the Municipality of the estimate of cost to provide such additions or deletions if same are not within the scope of the services provided by this agreement. Refer Article 6.1.

Provide on a monthly basis, in a mutually acceptable format, statistics, summary's or reports as related to meter reading, billing and collecting.

Collect all revenues for water and sewage charges billed by Essex Power on behalf of the Municipality.

The review, modification and approval of meter reading and billing schedules as mutually agreed.

The processing of all payments for revenues billed and received on behalf of the municipality.

Invoicing of all costs related to all functions and services as described herein, and as provided by Essex Power, and same forwarded to the Municipality on a monthly basis or as otherwise required.

Provide the Municipality with monthly, quarterly, or annual reports as they may relate to the services described herein, and as mutually agreed.

Request, in writing, additional funds (preceded by an estimate) where services requested from time to time by the Municipality exceed the service levels described herein.

Provide staffing levels to accommodate the services described herein.

Maintain meter reading, billing and collecting hardware and software to fulfill the scope of this agreement.

Provide access to the Municipal Customers water and sewer only, Reading, Billing and Balance History information by means of a Virtual Private Network.

Provide a call centre for water related issues such as final reads relating to customer moves, general water and sewer rate inquires, high water consumption, leaking water meters.

6.0 PAYMENT OF ESSEX POWER METER READING, BILLING AND COLLECTING ACCOUNTS

6.1 Essex Power agrees to submit to the Municipality monthly charges for all accounts for meter reading, billing, collecting and administrative services as per the following:

Effective April 1, 2008 - [redacted] per month

Effective January 1, 2009 - [redacted] per month (subject to any adjustment required related to meter reading, billing & bill print costs and customer counts as of October 31, 2008)

Effective January 1, 2010 [redacted] per month (subject to any adjustment required related to meter reading, billing & bill print costs and customer counts as of October 31, 2009)

Effective January 1, 2011 - [redacted] per month (subject to any adjustment required related to meter reading, billing & bill print costs and customer counts as of October 31, 2010)

7.0 INTEREST

All payments shall be payable without interest within 30 days after the billing date but, after 30 days, interest will be charged at the prime rate of interest charged by Essex Power's bank to its most creditworthy customers plus I % per month on the unpaid balance from the date of billing. Where a dispute arises, the Municipality shall pay the undisputed portion forthwith rather than withholding the entire payment.

8.0 PREVIOUS AGREEMENT

8.1 This agreement supersedes all previous agreements, arrangements, or understandings between the parties, whether written or oral, in connection with, or incidental to the meter reading, billing and collecting.

9.0 NOTICES

9.1 Any notice, document or other communication required or permitted to be given hereunder shall be in writing and shall be sufficiently given if delivered or sent by prepaid registered mail from a Post Office in Canada addressed in the case of the Municipality to:

The Corporation of the Municipality of Leamington
38 Erie Street North
Leamington, Ontario N8H 2Z3

Attention: Ms. Cheryl Horrobon
Director of Financial Services

or addressed in the case of the Essex Power to:

Essex Powerlines Corporation
360 Fairview Ave West, Suite 218
Essex, Ontario N8M 3G4

Attention: Mr. Alan Parnell,
Manager, Customer Service

Each of the foregoing shall be entitled to specify a different address by giving written notice as aforesaid to the other. Any notice, if mailed, shall be deemed to have been given on the third business day following such mailing or if delivered by hand, shall be deemed to have been given on the day of delivery if a business day, or if not a business day, on the next business day following the day of delivery.

10.0 COUNTERPARTS

10.1 This agreement may be executed in several counterparts, each of which so executed shall be deemed to be an original and such counterparts together shall constitute one and the same instrument and notwithstanding their date of execution shall be deemed to bear date as of the date written above.

11.0 INTERPRETATION

11.1 In this agreement, words importing the singular number include the plural, and vice versa, and words importing the masculine gender include the feminine gender.

12.0 HEADINGS

12.1 Section headings are not to be considered part of this agreement but are included solely for convenience of reference and are not intended to be full or accurate descriptions of the contents thereof

13.0 BINDING EFFECT

13.1 This agreement shall extend to and be binding upon and endure to the benefit of the parties hereto and their respective successors and assigns.

14.0 INSURANCE AND INDEMNIFICATION

14.1 Essex Power hereby covenants and agrees to maintain at all times sufficient insurance as may be required by the Municipality.

14.2 Essex Power shall protect, defend, indemnify and save harmless the Municipality from and against all claims, actions, losses, expenses, costs or damages of every nature and kind whatsoever which the Municipality, its officers, employees or agents may suffer as a result of the negligence of Essex Power, its officers, employees, contractors or agents in the performance of this agreement.

Essex Power shall be responsible for all services, and potential affects, it undertakes with respect to services described herein during the term of this agreement and shall protect, defend and save the Municipality harmless in respect of any damage, defect or want of repair thereto, arising from any breach or default or from negligence by Essex Power, its officers, employees or agents and from all loss, charges, damages, liens, costs, legal fees, expenses and liabilities which the Municipality, its officers, employees, or agents may incur, provided however, that Essex Power shall not be responsible for any claim or demand arising from the negligence by any officer, employee, or agent of the Municipality while acting within the scope of his or her duties or employment.

15.0 ASSIGNMENT

15.1 Neither party may assign this agreement without the prior consent, in writing of the other.

16.0 REASONABLENESS:

16.1 Each party agrees that it shall at all times act reasonably in the performance of its obligations and the exercise of its rights under this License.

17.0 APPLICABLE LAW:

17.1 This agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein.

IN WITNESS WHEREOF THE PARTIES HERETO HAVE CAUSED THIS AGREEMENT TO BE EXECUTED BY THE SIGNATURES OF THEIR PROPER OFFICERS DULY AUTHOURIZED IN THAT BEHALF AS OF THE DATE AND YEAR FIRST ABOVE WRITTEN.

On behalf of **THE CORPORATION OF THE MUNICIPALITY OF LEAMINGTON**

Signature	Title	Date

Signature	Title	Date

On behalf of: **ESSEX POWERLINES CORPORATION**:

Signature	Title	Date

Signature	Title	Date

BILLING, COLLECTING, METER READING AND CALL CENTRE AGREEMENT

BETWEEN

ESSEX POWERLINES CORPORATION

AND

THE CORPORATION OF THE TOWN OF TECUMSEH

TABLE OF CONTENTS

THIS AGREEMENT MADE IN TRIPLICATE THIS ___ DAY OF_____, 2007

BETWEEN:

ESSEX POWERLINES CORPORATION
(Hereinafter called "Essex Power")

OF THE FIRST PART;

AND:

THE CORPORATION OF THE TOWN OF TECUMSEH
(Hereinafter called "the Municipality")

OF THE SECOND PART;

WHEREAS Essex Power has been providing meter reading and billing and collecting and Call Centre functions for the water customers within the Municipality.

AND WHEREAS the Municipality desires that Essex Power continue to provide for the ongoing services and functions related to those activities,

NOW THEREFORE THIS AGREEMENT WITNESSETH THAT in consideration of the mutual covenants hereinafter expressed, it is agreed by and between the parties hereto as follows:

1.0 TERM

1.1 Subject to Section 2.9 the term of this agreement shall be for the period commencing on April 1, 2008 and ending December 31, 2011 (hereinafter referred to as the Initial Term) and thereafter be automatically renewed for successive periods of three (3) years upon the same terms and conditions herein provided that either party may terminate this agreement at any time after the expiry of the Initial Term by providing at least six (6) months written notice of termination to the other party, which notice may be given prior to the expiry of the Initial Term or the current renewal period.

2.0 SERVICES PROVIDED

2.1 GENERAL
The Municipality hereby retains the services of Essex Power in connection with the reading of meters and the billing and collecting of water and sewage charges and call centre activities and Essex Power hereby agrees to provide the services described herein under the general direction and control of the Municipality.

2.2 SERVICES
The services to be provided by Essex Power, as generally stated herein above, are set forth in Articles 3, 4 and 5 and such services as well as

services changed, altered or added to under Article 2 are hereinafter referred to as the "services".

2.3 METER READING SERSICES

In this agreement, unless there is something in the subject matter or context inconsistent therewith, meter reading shall mean all activities required to read all water meter installations located within buildings, meter pits, and such other locations that meters may be located within the area of the Municipality read by Essex Power. Meter installations which are owned by other agencies, private individuals or corporations, shall not be read unless designated by the Municipality.

2.4 BILLING AND COLLECTING SERVICES

In this agreement, unless there is something in the subject matter or context inconsistent therewith, billing and collecting shall mean all activities associated with the issuance of bills and the collection of related revenues for all water and sewage charges associated with the meters and areas within and designated by the Municipality.

2.5 COMPENSATION FOR SERVICES PROVIDED

The Municipality shall pay Essex Power in accordance with the provisions set forth in Article 6.

2.6 STAFF AND METHODS SERVICES

Essex Power shall use current principles and shall skillfully and competently perform the services and shall employ only skilled and competent staff who will be under the supervision of Essex Power.

2.7 DOCUMENTATION SERVICES

Documents or copies thereof required for meter reading and billing and collecting shall be exchanged between the parties on a reciprocal basis.

2.8 CHANGES AND ALTERATIONS AND ADDITIONAL SERVICES

With the written consent of Essex Power, the Municipality, in writing, may at any time after the execution of this agreement or the commencement of the services, delete, extend, increase, vary or otherwise alter the services forming the subject of this agreement. Where such action by the Municipality necessitates additional staff or services, Essex Power shall be paid for additional services and/or staff employed together with such actual expenses and disbursements as are necessary. Where such action by the Municipality necessitates a reduction in staff and/or equipment then six (6) months written notice shall be given to Essex Power by the Municipality.

2.9 SUSPENSION OR TERMINATION OF SERVICES

Upon execution of this agreement, The Municipality, or Essex Power shall have until December 31, 2008 to terminate the services of Essex Power upon 120 days notice in writing. Following December 31, 2008, the Municipality, or Essex Power may, giving six (6) months notice in writing to the other, suspend or terminate the services.

Upon termination by the Municipality, the Municipality will pay Essex Power the following percentage of the Remaining Contract Amount:

a) Forty (40%) percent if terminated prior to December 31, 2009
b) Thirty (30%) percent if terminated prior to December 31, 2010
c) Twenty (20%) percent if terminated prior to December 31, 2011

2.10 INVENTORY AND EQUIPMENT SERVICES

Upon termination of this agreement, the Municipality agrees to purchase any and all inventory and equipment on hand, at current book value, used exclusively for the meter reading, billing and collecting, that Essex Power maintained for the Municipality.

2.11 APPROVAL OF SERVICES BY OTHER AUTHORITIES

Unless otherwise provided in this agreement, where the services of Essex Power are subject to the approval or review of an authority, department or government, or agency other than the Municipality, such application for approval or review shall be the responsibility of Essex Power.

2.12 INSPECTION

The Municipality, or persons authorized by the Municipality, shall have the right at all reasonable times, to inspect or otherwise review the services performed or being performed, in respect of meter reading, billing and collecting, and the premises where they are being performed.

2.13 TIME

Essex Power shall perform the services expeditiously as is reasonable with regard to the circumstances to meet the requirements of the Municipality and shall complete any portion or portions of the services in such order as the Municipality may require.

The Municipality shall expeditiously give consideration to all plans, specifications, reports, proposals and other information submitted from Essex Power and shall make any decisions which it is required to make in connection therewith so as not to delay the work of Essex Power.

3.0 METER READING

3.1 Meter reading by Essex Power shall generally include the following:

- Record all water meter reads by electronic hand held device, or on paper document, at intervals as deemed appropriate by the Municipality or Essex Power.
- Access and record meter reads from any and all locations which may include but not strictly limited to meter pits and building exteriors and interiors, that can be safely accessed by the reader.
- Re-read those meters for the purpose verifying abnormally high or low consumption.
- It is understood that during the term of this agreement, that the Municipality will perform all Final Reads (including Hydro reads where a hydro service is attached) where occupancy or ownership will change.
- Record and report damage or repairs that may be required for water meter equipment.

3.2 METER READING SERVICES

Essex Power shall include the following services in conjunction with the reading of water meters:

(a) Preparation of service orders and/or advise to enable the Municipality to undertake repairs to metering equipment that has been identified to be in need of same due to physical damage or due to abnormal consumption.

(b) Advise Municipality where conflicts between meter equipment and other utility equipment has been identified.

(c) Guidance and advice to Municipal staff regarding current technology, materials and equipment as it relates to meter reading.

(d) When required, the preparation of estimates for meter reading as it related to additional or new meter routes that may added by the Municipality from time to time.

(e) When required, review and comment on meter change or additional programs prepared by consultants and submitted to Essex Power by the Municipality.

(f) Participate in a reasonable number of meetings for information, negotiations or presentation purposes with the Municipality in connection with design criteria or standards as it related to meters.

(g) Assist in the provision of tender documents for any work to be tendered as it relates to new meter installations.

(h) The keeping of complete and accurate records of time spent for all activities as they relate to water meter reading and related services by Essex Power staff in addition to the regular scope of work for which reimbursement is required.

(i) Provide the necessary labour and equipment to perform the work. Efforts shall be made to use the most inexpensive equipment but, where this is not feasible or acceptable, the Municipality shall pay for the actual equipment required.

(j) Review the physical work being undertaken to ensure compliance with the terms of this agreement.

(k) Provide any necessary field activity controls for all meter reading staff.

(l) Investigate, report and recommend on unusual circumstances which may be discovered during the provision of meter reading.

(m) Carry out periodic inspection of the work performed by the meter reading staff.

3.3 METER READING ADDITIONS

Essex Power will respond to notification from the Municipality regarding requests related to the following:

Read and bill new meters – next read and billing cycle as mutually agreed.
Read only additional meter routes – next read cycle as mutually agreed.
Bill only additional meter routes – next billing cycle as mutually agreed.
Read and bill additional meter routes – next read and bill cycles as mutually agreed.

3.4 OWNERSHIP OF WATER METERS

The Municipality owns and finances the design, construction maintenance and operation of the meter reading equipment at all locations within the Municipality and shall include, but not necessarily be limited to, the following items:

- main meters
- meter remotes and wire
- meter pits
- remote posts

No permits shall be required by Essex Power for the purpose of reading or accessing water meters during the term of this agreement.

4.0 BILLING AND COLLECTING SERVICES

4.1 BILLING SERVICES

Essex Power shall provide the following services in conjunction with the billing of all accounts for water meters read:

Water/Sewage Rates and Charges

- Maintain a billing system that will allow for the billing of all water and sewage charges as mutually agreed by both parties included but not limited to water and sewer rate changes and water meter changes.
- Receive and apply rates and charges for all customer accounts as designated by the Municipality from time to time.
- Input all meter reads as collected by Essex Power or the Municipality.
- Review and edit all consumption quantities for the purpose of identifying those quantities that may be abnormal for the respective customer class, or with respect to a specific customer consumption pattern.
- Display rates and charges for all customer accounts within the Essex Power bill format as mutually agreed.
- Provide one (1) water and sewer rate increase per calendar year.
- Additional water and or sewer rate increases in the same calendar year will be provided based on written estimate to perform the service

- Include a rates and charges information insert with the regularly scheduled billing once per calendar year coincident with the annual water or sewer rate increase.
- Include additional billing inserts as required at a rate of $ .03 per account provided the material meets specifications and the regular postage rate is not affected.
- Calculate billing quantities in accordance with formulae as required by the Municipality.
- Produce billing quantity records and reports for current and archive access.
- Print bills at intervals as mutually agreed.
- Mail bills at intervals as mutually agreed.
- Produce and mail final notices for all accounts not paid within acceptable schedules.
- Provide all necessary clerical support to perform all billing functions assigned to Essex Power by the Municipality.

4.2 COLLECTING SERVICES

Water/Sewage Rates and Charges

- Collect all revenues for all accounts that Essex Power bills on behalf of the Municipality with respect to water and sewage charges.
- Provide methods of payment for all billed accounts by means of cheque by mail, payments through financial institutions, pre-authorized payment plans, telebanking, etc.
- Produce and mail final notices for all accounts not paid within acceptable schedules
- Provide all necessary clerical support to perform all collecting functions assigned to Essex Power by the Municipality.
- Advise the Municipality of water only accounts that are not paid within acceptable schedules, in order that the Municipality may decide if disconnection of same is in order.
- Submit all revenues collected to the Municipality at intervals and in quantities as mutually agreed.
- Produce collection quantity records and reports for current and archive access.
- Contract the services of a Collection Agency for uncollectible and/or finalized accounts.

5.0 ADMINISTRATIVE SERVICES

5.1 Essex Power shall provide the following Administrative Services:

Ensure the quality of all work undertaken on behalf of the Municipality.

Review and advise on Municipal requests for additions or deletions to meter reading, billing and collecting activities, and to advise the Municipality of the estimate of cost to provide such additions or deletions if same are not within the scope of the services provided by this agreement. Refer Article 6.1.

Provide on a monthly basis, in a mutually acceptable format, statistics, summary's or reports as related to meter reading, billing and collecting.

Collect all revenues for water and sewage charges billed by Essex Power on behalf of the Municipality.

The review, modification and approval of meter reading and billing schedules as mutually agreed.

The processing of all payments for revenues billed and received on behalf of the municipality.

Invoicing of all costs related to all functions and services as described herein, and as provided by Essex Power, and same forwarded to the Municipality on a monthly basis or as otherwise required.

Provide the Municipality with monthly, quarterly, or annual reports as they may relate to the services described herein, and as mutually agreed.

Request, in writing, additional funds (preceded by an estimate) where services requested from time to time by the Municipality exceed the service levels described herein.

Provide staffing levels to accommodate the services described herein.

Maintain meter reading, billing and collecting hardware and software to fulfill the scope of this agreement.

Provide access to the Municipal Customers water and sewer only, Reading, Billing and Balance History information by means of a Virtual Private Network.

Provide a call centre for water related issues such as final reads relating to customer moves, general water and sewer rate inquires, high water consumption, leaking water meters.

6.0 PAYMENT OF ESSEX POWER METER READING, BILLING AND COLLECTING ACCOUNTS

6.1 Essex Power agrees to submit to the Municipality monthly charges for all accounts for meter reading, billing, collecting and administrative services as per the following:

Effective April 1, 2008 - [redacted] per month

Effective January 1, 2009 - [redacted] per month (subject to any adjustment required related to meter reading, billing & bill print costs and customer counts as of October 31, 2008)

Effective January 1, 2010 - [redacted] per month (subject to any adjustment required related to meter reading, billing & bill print costs and customer counts as of October 31, 2009)

Effective January 1, 2011 - [redacted] per month (subject to any adjustment required related to meter reading, billing & bill print costs and customer counts as of October 31, 2010)

7.0 INTEREST

All payments shall be payable without interest within 30 days after the billing date but, after 30 days, interest will be charged at the prime rate of interest charged by Essex Power's bank to its most creditworthy customers plus I % per month on the unpaid balance from the date of billing. Where a dispute arises, the Municipality shall pay the undisputed portion forthwith rather than withholding the entire payment.

8.0 PREVIOUS AGREEMENT

8.1 This agreement supersedes all previous agreements, arrangements, or understandings between the parties, whether written or oral, in connection with, or incidental to the meter reading, billing and collecting.

9.0 NOTICES

9.1 Any notice, document or other communication required or permitted to be given hereunder shall be in writing and shall be sufficiently given if delivered or sent by prepaid registered mail from a Post Office in Canada addressed in the case of the Municipality to:

The Corporation of the Town of Tecumseh
917 Lesperance Road
Tecumseh, Ontario N8N 1W9

Attention: Mr. Luc Gagnon
Treasurer

or addressed in the case of the Essex Power to:

Essex Powerlines Corporation
360 Fairview Ave West, Suite 218
Essex, Ontario N8M 3G4

Attention: Mr. Alan Parnell,
Manager, Customer Service

Each of the foregoing shall be entitled to specify a different address by giving written notice as aforesaid to the other. Any notice, if mailed, shall be deemed to have been given on the third business day following such mailing or if delivered by hand, shall be deemed to have been given on the day of delivery if a business day, or if not a business day, on the next business day following the day of delivery.

10.0 COUNTERPARTS

10.1 This agreement may be executed in several counterparts, each of which so executed shall be deemed to be an original and such counterparts together shall constitute one and the same instrument and notwithstanding their date of execution shall be deemed to bear date as of the date written above.

11.0 INTERPRETATION

11.1 In this agreement, words importing the singular number include the plural, and vice versa, and words importing the masculine gender include the feminine gender.

12.0 HEADINGS

12.1 Section headings are not to be considered part of this agreement but are included solely for convenience of reference and are not intended to be full or accurate descriptions of the contents thereof

13.0 BINDING EFFECT

13.1 This agreement shall extend to and be binding upon and endure to the benefit of the parties hereto and their respective successors and assigns.

14.0 INSURANCE AND INDEMNIFICATION

14.1 Essex Power hereby covenants and agrees to maintain at all times sufficient insurance as may be required by the Municipality.

14.2 Essex Power shall protect, defend, indemnify and save harmless the Municipality from and against all claims, actions, losses, expenses, costs or damages of every nature and kind whatsoever which the Municipality, its officers, employees or agents may suffer as a result of the negligence of Essex Power, its officers, employees, contractors or agents in the performance of this agreement.

Essex Power shall be responsible for all services, and potential affects, it undertakes with respect to services described herein during the term of this agreement and shall protect, defend and save the Municipality harmless in respect of any damage, defect or want of repair thereto, arising from any breach or default or from negligence by Essex Power, its officers, employees or agents and from all loss, charges, damages, liens, costs, legal fees, expenses and liabilities which the Municipality, its officers, employees, or agents may incur, provided however, that Essex Power shall not be responsible for any claim or demand arising from the negligence by any officer, employee, or agent of the Municipality while acting within the scope of his or her duties or employment.

15.0 ASSIGNMENT

15.1 Neither party may assign this agreement without the prior consent, in writing of the other.

16.0 REASONABLENESS:

16.1 Each party agrees that it shall at all times act reasonably in the performance of its obligations and the exercise of its rights under this License.

17.0 APPLICABLE LAW:

17.1 This agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein.

IN WITNESS WHEREOF THE PARTIES HERETO HAVE CAUSED THIS AGREEMENT TO BE EXECUTED BY THE SIGNATURES OF THEIR PROPER OFFICERS DULY AUTHOURIZED IN THAT BEHALF AS OF THE DATE AND YEAR FIRST ABOVE WRITTEN.

On behalf of **THE CORPORATION OF THE TOWN OF TECUMSEH**

Signature	Title	Date

Signature	Title	Date

On behalf of: **ESSEX POWERLINES CORPORATION**:

Signature	Title	Date

Signature	Title	Date

Attachment 1-V

Municipal Loan Agreements

LONG TERM FINANCING AGREEMENT

THIS AGREEMENT made this day of December, 2017 **BETWEEN:**

THE CORPORATION OF THE MUNICPALITY 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 parties have agreed that The Municipality holds a promissory note dated June 1, 2000;

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 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. T e r m

The term of this Agreement shall be from January 1, 2018 to and including December 31, 2022 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 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, of 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 1s[t] 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 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 **3.80%** 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: 2730 Highway 3,Oldcastle, Ontario, NOR 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 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 Chances

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 Municipality of Leamington

Per:

_____

John Paterson, Mayor

_____

Ruth Orton, Clerk

Essex Powerlines Corporation

Per:

_____

Ken Antaya, Chair

_____

Joe Barile, General Manager

LONG TERM FINANCING AGREEMENT

THIS AGREEMENT made this day of December, 2017 **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. T e r m

The term of this Agreement shall be from January 1, 2018 to and including December 31, 2022 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 1s^{t} 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 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 **3.80%** 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, NOR 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 Chances

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:

_____

Ken Antaya, Chair

_____

Joe Barile, General Manager

Attachment 1-W

Cost Allocation Model

Attachment 1-X

DVA Continuity Schedule

Attachment 1-Y

Self-Certification – Account 1588 and 1589

March 1, 2018

Re: Certification of Account Balances being disposed – Accounts 1588 RSVA power and 1589 RSVA GA

I, GIUSEPPE (Joe) BARILE, General Manager of Essex Powerlines Corporation, hereby certify that Essex Powerlines Corporation has robust processes and internal controls in place for the preparation, review, verification and oversight of the above-noted account balances being disposed.

Joe Barile, General Manager
Essex Powerlines Corporation

2730 Highway 3 | Oldcastle, ON | N0R 1L0
Direct: 519-737-9811 | Fax: 519-737-9755