Exhibit 2:

Rate Base

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2.1 Rate Base

2.1.1 Overview

This Exhibit provides detailed explanations of Essex Powerlines Corporation's ("EPLC") historical and projected Rate Base from 2010 Board Approved ("BAP") amounts to 2017 Bridge Year and 2018 Test Year. Further, detailed variance analysis is provided for any year over year variance over EPLC's materiality threshold. EPLC has prepared this Exhibit in accordance with Chapter 2 of the "Filing Requirements for Electricity Distribution Rate Applications – 2017 Edition for 2018 Rate Applications" issued July 20th, 2017.

EPLC has calculated its 2018 Test Year Rate Base by using the average of the projected opening and closing 2018 Test Year Gross Fixed Assets and Accumulated Depreciation and adding a Working Capital Allowance ("WCA") which is determined by taking the sum of EPLC's cost of power and controllable costs; multiplied by an allowance factor. For the purposes of this Application, EPLC has used the deemed rate of 7.5% for the WCA factor which represents a 7.5% decrease from the 2010 BAP. Further information regarding EPLC's WCA calculation can be found in Section 2.4 of this Exhibit.

For the purpose of this Application, capital assets include Property, Plant and Equipment ("PP&E") and intangible assets that enable EPLC to distribute electricity to its customers. EPLC's proposed 2018 Rate Base does not include any non-distribution assets. EPLC's controllable expenses include operations, maintenance, billing and collecting and administrative expenses.

Figure 1 below outlines EPLC's historical Rate Base calculation from 2010 BAP to the proposed 2018 Test Year. 2017 and 2018 reflect projected amounts whereas 2010 to 2016 reflect actual results. EPLC's proposed 2018 Test Year Rate Base is $59,927,210 which represents a 45.7% increase (or a 5.71% yearly average increase) from the 2010 BAP Rate Base. Detailed explanations for the increases to Rate Base are described in Section 2.2 of this Exhibit.

Figure 1 – Rate Base Continuity Schedule

Description	2010 BAP	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Accounting Standard	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Gross Fixed Assets	$ 50,352,174	$ 49,083,253	$ 51,669,129	$ 57,371,668	$ 60,692,887	$ 65,778,217	$ 72,109,471	$ 76,452,554	$ 81,886,262	$ 86,844,505
Accumulated Depreciation	$ (16,335,848)	$ (16,290,184)	$ (18,356,056)	$ (20,735,930)	$ (22,530,327)	$ (23,960,237)	$ (26,444,102)	$ (27,550,954)	$ (29,220,079)	$ (31,068,083)
Net Book Value	$ 34,016,326	$ 32,793,069	$ 33,313,073	$ 36,635,738	$ 38,162,560	$ 41,817,980	$ 45,665,369	$ 48,901,600	$ 52,666,183	$ 55,776,422
Average Net Book Value	**$ 33,009,250**	**$ 32,138,850**	**$ 33,053,071**	**$ 34,974,405**	**$ 37,399,149**	**$ 39,990,270**	**$ 43,741,674**	**$ 47,283,484**	**$ 50,783,891**	**$ 54,221,302**
Total Working Capital	$ 54,069,758	$ 54,778,916	$ 56,734,399	$ 58,590,963	$ 57,589,775	$ 64,252,177	$ 69,042,180	$ 78,624,142	$ 74,975,367	$ 76,078,771
Allowance Factor	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	7.50%
Working Capital Allowance	**$ 8,110,464**	**$ 8,216,837**	**$ 8,510,160**	**$ 8,788,644**	**$ 8,638,466**	**$ 9,637,827**	**$ 10,356,327**	**$ 11,793,621**	**$ 11,246,305**	**$ 5,705,908**

Figure 2 below summarizes EPLC's historical WCA for years 2010 through 2016 and calculated for years 2017 and 2018. EPLC's proposed 2018 Test Year WCA is $5,705,908 which represents a 29.6% reduction from the 2010 BAP WCA. Further details about EPLC's WCA calculation are provided in Section 2.4 of this Exhibit.

Figure 2 – Historical Working Capital Analysis

Description	2010 BAP	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Accounting Standard	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Operations	$ 1,111,126	$ 767,608	$ 1,003,987	$ 1,190,375	$ 1,207,057	$ 1,545,489	$ 1,332,350	$ 1,337,677	$ 1,221,419	$ 1,518,208
Maintenance	$ 1,517,732	$ 1,496,651	$ 1,614,034	$ 2,013,059	$ 1,515,425	$ 1,448,980	$ 1,808,438	$ 1,833,650	$ 1,572,404	$ 1,548,463
Billing & Collecting	$ 1,480,565	$ 1,305,098	$ 1,131,257	$ 1,174,568	$ 1,329,771	$ 1,158,128	$ 1,229,676	$ 1,348,249	$ 1,499,880	$ 1,550,150
Community Relations	$ 22,500	$ 16,957	$ 11,394	$ 8,539	$ 8,451	$ 10,016	$ 12,013	$ 6,482	$ 23,442	$ 23,396
Admin & General	$ 2,068,443	$ 1,894,041	$ 1,786,257	$ 1,806,757	$ 1,966,590	$ 2,541,606	$ 2,381,742	$ 2,455,564	$ 2,950,224	$ 3,070,058
Property Taxes	$ 85,824	$ 68,136	$ 43,471	$ 43,122	$ 45,301	$ 44,568	$ 41,843	$ 41,042	$ 42,621	$ 42,538
Total Controllable Costs	**$ 6,286,190**	**$ 5,548,490**	**$ 5,590,400**	**$ 6,236,418**	**$ 6,072,596**	**$ 6,748,787**	**$ 6,806,061**	**$ 7,022,665**	**$ 7,309,990**	**$ 7,752,813**
Cost of Power	$ 47,783,568	$ 49,232,444	$ 51,143,998	$ 52,354,545	$ 51,542,202	$ 57,503,389	$ 62,236,119	$ 71,601,477	$ 67,716,983	$ 68,325,958
Total Working Capital	**$ 54,069,758**	**$ 54,780,934**	**$ 56,734,399**	**$ 58,590,963**	**$ 57,614,798**	**$ 64,252,177**	**$ 69,042,180**	**$ 78,624,142**	**$ 75,026,973**	**$ 76,078,771**
Allowance Factor	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	7.50%
Working Capital Allowance	**$ 8,110,464**	**$ 8,217,140**	**$ 8,510,160**	**$ 8,788,644**	**$ 8,642,220**	**$ 9,637,826**	**$ 10,356,327**	**$ 11,793,621**	**$ 11,254,046**	**$ 5,705,908**

EPLC currently owns four separate non-distribution solar photovoltaic assets:

i) 500 kW DC, 12021 McNorton Street, Tecumseh, Ontario;
ii) 10 kW DC, Erie Street North, Leamington, Ontario;
iii) 10 kW DC, William Street, Amhestburg, Ontario;
iv) 10 kW DC, 50 Victoria Avenue North, Leamington, Ontario;

EPLC has not included any of these assets, or any of their associated revenues and expenses, in Rate Base or anywhere in this Application.

EPLC has included Attachment 2-A (Fixed Asset Continuity Schedules), consistent with Board Appendix 2-BA. It should be noted that EPLC will be proposing an adjustment to Net Book Value in 2017 that will reduce Rate Base. For the purpose of this Application, this adjustment has been used to calculate the change in Accounting Standards however all Rate Base calculations within this Exhibit are consistent with EPLC's RRR filings.

For the purpose of capital planning, EPLC considers Conservation & Demand Management initiatives as a means of deferring or avoiding future infrastructure projects as part of its distribution system planning process.

EPLC has also realized operating efficiencies as a result of the deployment and operationalization of smart meters and related technologies, mainly through the deployment of SmartMAP. Further information about SmartMAP and its functionality can be found in EPLC's DSP which is included as Attachment 2-C of this Exhibit.

2.1.2 Rate Base Variance Analysis

EPLC has created Figure 3 below which demonstrates Rate Base variances from 2010 BAP to the 2018 Test Year.

Figure 3 – Historical Rate Base Variance

Description	2010 BAP	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Accounting Standard	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Gross Fixed Assets	$ 50,352,171	$ 49,083,254	$ 51,669,129	$ 57,371,669	$ 60,692,887	$ 65,778,218	$ 72,109,472	$ 76,452,554	$ 81,886,262	$ 86,844,505
Accumulated Depreciation	$ (16,335,848)	$ (16,290,184)	$ (18,356,056)	$ (20,735,930)	$ (22,530,327)	$ (23,960,238)	$ (26,444,103)	$ (27,550,955)	$ (29,220,080)	$ (31,068,084)
Net Book Value	$ 34,016,323	$ 32,793,070	$ 33,313,273	$ 36,635,739	$ 38,162,560	$ 41,817,980	$ 45,665,369	$ 48,901,599	$ 52,666,182	$ 55,776,421
Average Net Book Value	**$ 33,009,250**	**$ 32,138,850**	**$ 33,053,071**	**$ 34,974,405**	**$ 37,399,149**	**$ 39,990,270**	**$ 43,741,674**	**$ 47,283,484**	**$ 50,783,891**	**$ 54,221,302**
Total Working Capital	$ 54,069,758	$ 54,778,916	$ 56,734,399	$ 58,590,963	$ 57,589,775	$ 64,252,177	$ 69,042,180	$ 78,624,142	$ 74,975,367	$ 76,078,771
Allowance Factor	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	7.50%
Working Capital Allowance	**$ 8,110,464**	**$ 8,216,837**	**$ 8,510,160**	**$ 8,788,644**	**$ 8,638,466**	**$ 9,637,827**	**$ 10,356,327**	**$ 11,793,621**	**$ 11,246,305**	**$ 5,705,908**
Rate Base	**$ 41,119,714**	**$ 40,355,687**	**$ 41,563,231**	**$ 43,763,049**	**$ 46,037,615**	**$ 49,628,097**	**$ 54,098,001**	**$ 59,077,105**	**$ 62,030,196**	**$ 59,927,210**
Variances		**2010 BAP vs. 2010 Actual**	**2010 Actual vs. 2011 Actual**	**2011 Actual vs. 2012 Actual**	**2012 Actual vs. 2013 Actual**	**2013 Actual vs. 2014 Actual**	**2014 Actual vs. 2015 Actual**	**2015 Actual vs. 2016 Actual**	**2016 Actual vs. 2017 Bridge**	**2017 Bridge vs. 2018 Test**
Gross Fixed Assets		$ (1,268,917)	$ 2,585,875	$ 5,702,540	$ 3,321,218	$ 5,085,331	$ 6,331,254	$ 4,343,082	$ 5,433,708	$ 4,958,243
Accumulated Depreciation		$ 45,664	$ (2,065,872)	$ (2,379,874)	$ (1,794,397)	$ (1,429,911)	$ (2,483,865)	$ (1,106,852)	$ (1,669,125)	$ (1,848,004)
Net Book Value		$ (1,223,253)	$ 520,203	$ 3,322,466	$ 1,526,821	$ 3,655,420	$ 3,847,389	$ 3,236,230	$ 3,764,583	$ 3,110,239
Average Net Book Value		**$ (870,400)**	**$ 914,221**	**$ 1,921,334**	**$ 2,424,744**	**$ 2,591,121**	**$ 3,751,404**	**$ 3,541,810**	**$ 3,500,407**	**$ 3,437,411**
Total Working Capital		$ 709,158	$ 1,955,483	$ 1,856,564	$ (1,001,188)	$ 6,662,401	$ 4,790,003	$ 9,581,962	$ (3,648,775)	$ 1,103,404
Allowance Factor		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-7.50%
Working Capital Allowance		**$ 106,374**	**$ 293,322**	**$ 278,485**	**$ (150,178)**	**$ 999,360**	**$ 718,500**	**$ 1,437,294**	**$ (547,316)**	**$ (5,540,397)**
Rate Base		**$ (764,026)**	**$ 1,207,543**	**$ 2,199,819**	**$ 2,274,566**	**$ 3,590,481**	**$ 4,469,904**	**$ 4,979,104**	**$ 2,953,091**	**$ (2,102,986)**

Variances are a result of additions to Gross Assets and a decrease to Working Capital Allowance. Sections 2.2 and 2.4 below further detail these variances.

2.2 Gross Assets – Property, Plant & Equipment & Depreciation

2.2.1 Breakdown by Function

EPLC has categorized its gross assets into four primary categories, consistent with the Uniform System of Accounts ("USoA") as described below:

- **Intangible Plant:** Assets include USoA range of accounts 1606 to 1611 and generally include assets such as software;

- **Distribution Plant:** Assets include USoA range of accounts 1805 to 1860 and generally include assets such as poles, wires, meters, transformers, etc.;

- **General Plant:** Assets include USoA range of accounts 1905 to 1990 and generally include assets such as buildings, transportation equipment, computer hardware, tools, etc.;

- **Contribution & Grants:** Includes USoA account 1995 and captures contributions made towards capital either received or forecasted to be received consistent with the Distribution System Code. EPLC does not utilize Account 2440.

Figure 4 below outlines the breakdown described above. Year over year variances are summarized as part of Section 2.2.2 below.

Figure 4 – Historical Gross Plant Breakdown

Description	2010 BAP	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Accounting Standard	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,556,875	$ 1,853,567	$ 2,017,508
Distribution Plant	$ 55,778,952	$ 54,421,747	$ 58,696,440	$ 63,997,158	$ 69,060,163	$ 74,780,571	$ 82,012,540	$ 86,694,126	$ 91,805,950	$ 96,903,200
General Plant	$ 4,973,738	$ 4,724,845	$ 4,975,699	$ 6,247,373	$ 6,697,485	$ 7,184,579	$ 7,732,047	$ 6,767,688	$ 8,017,638	$ 8,939,447
Contribution & Grants	$ (10,400,516)	$ (10,063,338)	$ (12,003,010)	$ (12,872,862)	$ (15,064,761)	$ (16,186,932)	$ (17,635,115)	$ (18,566,136)	$ (19,790,893)	$ (21,015,650)
Total Gross Assets	**$ 50,352,174**	**$ 49,083,254**	**$ 51,669,129**	**$ 57,371,669**	**$ 60,692,887**	**$ 65,778,218**	**$ 72,109,471**	**$ 76,452,553**	**$ 81,886,262**	**$ 86,844,505**

2.2.2 Variance Analysis on Gross Asset Additions

This section was prepared by EPLC in order to explain year over year variance by USoA account. EPLC used a materiality threshold of $65,000 identified by cells highlighted in red in each of the figures within this section.

2010 BAP Vs. 2010 Actual

EPLC experienced a net decrease in Gross Assets of $1,268,920 between the 2010 BAP and 2010 Actual.

Figure 5 – 2010 BAP vs. 2010 Actual – By Account

USoA	Description	2010 BAP	2010 Actual	Variance
	Intangible Plant			
1611	Computer Software	$ -	$ -	$ -
1612	Land Rights	$ -	$ -	$ -
	Subtotal	**$ -**	**$ -**	**$ -**
	Distribution Plant			
1805	Land	$ 47,899	$ 47,899	$ 0
1806	Land Rights	$ 71,972	$ 97,579	$ 25,607
1820	Distribution Station Equipment < 50 kV	$ 95,292	$ 102,722	$ 7,430
1830	Poles, Towers & Fixtures	$ 5,954,727	$ 5,731,639	$ (223,088)
1835	Overhead Conductors & Devices	$ 6,262,137	$ 5,495,913	$ (766,224)
1840	Underground Conduit	$ 8,874,535	$ 8,523,236	$ (351,299)
1845	Underground Conduit & Devices	$ 10,420,429	$ 10,289,850	$ (130,579)
1850	Line Transformers	$ 13,622,935	$ 13,356,674	$ (266,261)
1855	Services	$ 7,264,023	$ 6,818,570	$ (445,453)
1860	Meters	$ 3,165,003	$ 3,957,664	$ 792,661
1860	Meters - Smart Meter Sub-Account	$ -	$ -	$ -
	Subtotal	**$ 55,778,952**	**$ 54,421,747**	**$(1,357,205)**
	General Plant			
1905	Land	$ 191,700	$ 190,119	$ (1,581)
1908	Building & Fixtures	$ 1,649,060	$ 1,607,140	$ (41,920)
1915	Office Furniture & Equipment	$ 142,501	$ 159,415	$ 16,914
1920	Computer Equipment - Hardware	$ 62,049	$ 251,403	$ 189,354
1925	Computer Software	$ 1,331,173	$ 1,037,697	$ (293,476)
1930	Transportation Equipment	$ 1,097,902	$ 982,829	$ (115,073)
1935	Stores Equipment	$ 24,040	$ 29,711	$ 5,671
1940	Tools, Shop & Garage Equipment	$ 200,751	$ 214,968	$ 14,217
1945	Measurement & Testing Equipment	$ 35,403	$ 54,338	$ 18,935
1955	Communication Equipment	$ 239,159	$ 197,224	$ (41,935)
	Subtotal	**$ 4,973,738**	**$ 4,724,845**	**$ (248,893)**
	Contributions & Grants			
1995	Contributions & Grants	$(10,400,516)	$(10,063,338)	$ 337,178
	Subtotal	**$(10,400,516)**	**$(10,063,338)**	**$ 337,178**
	Grand Total	**$ 50,352,174**	**$ 49,083,254**	**$(1,268,920)**

Intangible Plant

No material variance to explain.

Distribution Plant

Account 1830 – Poles, Towers & Fixtures

Typical projects that flow through Account 1830 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized a decrease of $223,088 in Account 1830 from 2010 BAP to 2010 Actual. This variance is largely made up of a one year deferral of the connection a large scale Renewable Energy Standard Offer Program ("RESOP") solar PV generator that occurs in 2011.

Significant projects in 2010 include:

- Malden Road rebuild from Todd Lane to Morton (Municipal request; job 750);
- Sunnyside 4kV Conversion F2 & F3 Phase 1 (Single Voltage Utility conversion; job 760);
- VIF3 Conversion on Elliot Street (Single Voltage Utility conversion; job 339);

Account 1835 – Overhead Conductors & Devices

Typical projects that flow through Account 1835 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized a decrease of $766,224 in Account 1835 from 2010 BAP to 2010 Actual. This variance is largely made up of a one year deferral of the connection of a planned subdivision which actually occurred in 2011.

Significant projects in 2010 include:

- Malden Road rebuild from Todd Lane to Morton (Municipal request; job 750);
- Porcelain Insulator Replacement (Insulator Replacement, job 955);

Account 1840 – Underground Conduit

Typical projects that flow through Account 1840 include:

- General engineering & operational support;
- Customer expansion requests;
- Cable Replacement projects;
- Conversion projects;
- Emergencies;

EPLC realized a decrease of $351,299 in Account 1840 from 2010 BAP to 2010 Actual. This variance is largely the result of lower than expected and budgeted cable replacement work completed in Amherstburg.

Significant projects in 2010 include:

- Lutsch to Orange Mill Conversion (Single Voltage Utility, job 658);
- Laurier Parkway Expansion (Municipal Request, job 773);
- Pacific Cable Replacement relating to Live Front removal (Cable Replacement job 696);

Account 1845 – Underground Conduit & Devices

Typical projects that flow through Account 1845 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Conversion projects;
- PMH Replacement projects;
- Emergencies;

EPLC realized a decrease of $130,579 in Account 1845 from 2010 BAP to 2010 Actual. This variance is largely the result of a delay in PMH replacement work originally planned in 2010.

Significant projects in 2010 include:

- Malden Road rebuild from Todd Lane to Morton (Municipal request; job 750);
- Vollmer Complex Expansion (Municipal Request, job 909);
- Laurier Parkway Expansion (Municipal Request, job 773);

Account 1850 – Line Transformers

Typical projects that flow through Account 1850 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Transformer Replacement program;
- PMH Replacement projects;
- Emergencies/reactive replacements;

EPLC realized a decrease of $266,261 in Account 1850 from 2010 BAP to 2010 Actual. This variance is largely the result of lower than expected transformer related work in 2010.

Significant projects in 2010 include:

- Malden Road rebuild from Todd Lane to Morton (Municipal request; job 750);
- Lutsch to Orange Mill Conversion (Single Voltage Utility, job 658);
- Leamington Pollution Control Plant Upgrade (Municipal Request, job 773);

Account 1855 – Services

Typical projects that flow through Account 1855 include:

- General engineering & operational support;
- Customer expansion requests;
- New service requests;
- Transformer Replacement program;
- Emergencies/reactive replacements;

EPLC realized a decrease of $445,453 in Account 1855 from 2010 BAP to 2010 Actual. This variance is largely the result of lower than expected services related work in 2010.

Significant projects in 2010 include:

- Leamington Pollution Control Plant Upgrade (Municipal Request, job 773);
- Oakridge Subdivision Phase 2 (Subdivision, job 848);
- Malden Road rebuild from Todd Lane to Morton (Municipal request; job 750);
- Tecumseh Road Bell Building Service (New Service Upgrade C&I, job 788);

Account 1860 – Meters

Typical projects that flow through Account 1860 include:

- Retail metering replacements;
- Commercial and industrial investments;
- Smart Metering Initiative;

EPLC realized an increase of $792,661 in Account 1860 from 2010 BAP to 2010 Actual. This variance is largely the result of the finalization of the Smart Metering Initiative installation along with various new C&I services.

General Plant

Account 1920 – Computer Equipment - Hardware

EPLC realized an increase of $189,354 in Account 1920 from 2010 BAP to 2010 Actual. This variance is largely made up of the following items:

- New Server, license and associated hardware $82k
- Two Toshiba Photocopiers $23k;
- Eleven Toughbooks for onsite information and communication for linemen and supervisors – $20k
- Hardware upgrade to facilitate Microsoft Dynamics (GP upgrade related) - $16k

Account 1925 – Computer Software

EPLC realized a decrease of $293,476 in Account 1925 from 2010 BAP to 2010 Actual. EPLC had initially planned to upgrade its financial system to Cayenta in 2010 as detailed in its previous

Cost of Service Application (EB-2009-0143). EPLC decided to move forward with Great Plains ("GP"), a different, more cost effective software platform that also provided additional functionality. GP was fully implemented in 2011 however EPLC realized approximately $341k in costs in 2010. EPLC was initially planning $795k for Cayenta. The resulting decrease in spending on GP in 2010 is the primary driver of the variance.

Account 1930 – Transportation Equipment

EPLC realized a decrease of $115,073 in Account 1930 from 2010 BAP to 2010 Actual. Additions in 2010 include:

- Purchase of trucks #66, #67, #68, #69, #70, #71 - $213k;
- Sale of small trucks #42, #48, #55 and car #57 – ($107k);
- Fleet refurbishment - $62k;
- GPS/Modems/Inverters for fleet – $55k

The primary reason for variance (decrease) from 2010 BAP and 2010 Actual is the sale of small trucks ($107k) listed above along with savings realized upon the completion of the transactions above from figures that were budgeted.

Contributions & Grants

Account 1995 – Contributions & Grants

This variance can be attributed to the following:

i) Variance in 2010 opening balance of $1,054,575;
ii) Variance in 2010 additions of $717,397;

EPLC traditionally receives approximately $1.4M per year in Capital Contributions & Grants. The 2010 Actual balance results in an increase of $267k from the average balance.

2010 Actual Vs. 2011 Actual

Figure 6 – 2010 Actual vs. 2011 Actual – By Account

USoA	Description	2010 Actual	2011 Actual	Variance
	Intangible Plant			
1611	Computer Software	$ -	$ -	$ -
1612	Land Rights	$ -	$ -	$ -
	Subtotal	**$ -**	**$ -**	**$ -**
	Distribution Plant			
1805	Land	$ 47,899	$ 47,899	$ -
1806	Land Rights	$ 97,579	$ 108,990	$ 11,410
1820	Distribution Station Equipment < 50 kV	$ 102,722	$ 103,107	$ 385
1830	Poles, Towers & Fixtures	$ 5,731,639	$ 6,006,615	$ 274,976
1835	Overhead Conductors & Devices	$ 5,495,913	$ 5,684,239	$ 188,326
1840	Underground Conduit	$ 8,523,236	$ 9,701,439	$ 1,178,203
1845	Underground Conduit & Devices	$ 10,289,850	$ 10,917,707	$ 627,858
1850	Line Transformers	$ 13,356,674	$ 14,233,655	$ 876,982
1855	Services	$ 6,818,570	$ 7,692,638	$ 874,068
1860	Meters	$ 3,957,664	$ 4,200,151	$ 242,487
1860	Meters - Smart Meter Sub-Account	$ -		$ -
	Subtotal	**$ 54,421,747**	**$ 58,696,440**	**$ 4,274,693**
	General Plant			
1905	Land	$ 190,119	$ 190,119	$ -
1908	Building & Fixtures	$ 1,607,140	$ 1,633,771	$ 26,631
1915	Office Furniture & Equipment	$ 159,415	$ 159,415	$ -
1920	Computer Equipment - Hardware	$ 251,403	$ 306,043	$ 54,640
1925	Computer Software	$ 1,037,697	$ 946,329	$ (91,368)
1930	Transportation Equipment	$ 982,829	$ 1,172,081	$ 189,253
1935	Stores Equipment	$ 29,711	$ 34,367	$ 4,656
1940	Tools, Shop & Garage Equipment	$ 214,968	$ 242,672	$ 27,703
1945	Measurement & Testing Equipment	$ 54,338	$ 63,987	$ 9,649
1955	Communication Equipment	$ 197,224	$ 226,916	$ 29,691
	Subtotal	**$ 4,724,845**	**$ 4,975,699**	**$ 250,855**
	Contributions & Grants			
1995	Contributions & Grants	$(10,063,338)	$(12,003,010)	$(1,939,672)
	Subtotal	**$(10,063,338)**	**$(12,003,010)**	**$(1,939,672)**
	Grand Total	**$ 49,083,254**	**$ 51,669,129**	**$ 2,585,876**

Intangible Plant

No material variance to explain.

Distribution Plant

Account 1830 – Poles, Towers & Fixtures

Typical projects that flow through Account 1830 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $274,976 in Account 1830 from 2010 Actual to 2011 Actual. This variance is largely made up of a one year deferral of the connection a RESOP solar PV generator that was originally planned in 2010, as described in the section above.

Significant projects in 2011 include:

- Helios RESOP Connection (FIT & Generation connection; job 124);
- Malden Road Conversion (Municipal request; job 750);
- Centennial primary replacement (Cable replacement; job 11-1293);

Account 1835 – Overhead Conductors & Devices

Typical projects that flow through Account 1835 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $188,326 in Account 1835 from 2010 Actual to 2011 Actual. This variance is largely made up of new connection requests that EPLC is required to facilitate.

Significant projects in 2011 include:

- Trillium Subdivision (Subdivision, job 1151);
- Sunnyside F2 Conversion Boismier to Maple (Single Voltage Utility, job 894);
- Victory Subdivision Phase 4 (Subdivision, job 11-1304);

Account 1840 – Underground Conduit

Typical projects that flow through Account 1840 include:

- General engineering & operational support;
- Customer expansion requests;
- Cable Replacement projects;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $1,178,203 in Account 1840 from 2010 Actual to 2011 Actual. This variance is largely a result of lower than expected cable replacement work completed in 2010 which was caught up in 2011.

Significant projects in 2011 include:

- End of Life Cable Replacement – Amherstburg (Cable Replacement program, job 696);

Account 1845 – Underground Conduit & Devices

Typical projects that flow through Account 1845 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Conversion projects;
- PMH Replacement projects;
- Emergencies;

EPLC realized an increase of $627,858 in Account 1845 from 2010 Actual to 2011 Actual. This variance is largely the result of a delay in PMH replacement work originally planned in 2010, moved to 2011 and beyond.

Significant projects in 2011 include:

- General Amherst Three Phase Loop Upgrade (New Service Upgrades C&I, job 883);
- Sandwich Street PMH Replacement (PMH Replacement Program, job 11-1321)
- MVI PMH224 Replacement (PMH Replacement Program, job 11-1255);
- Dillon Reactive Transformer & Line Replacement (Primary Cable Replacement, 1190);

Account 1850 – Line Transformers

Typical projects that flow through Account 1850 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Transformer Replacement program;
- PMH Replacement projects;
- Emergencies/reactive replacements;

EPLC realized an increase of $876,982 in Account 1850 from 2010 Actual to 2011 Actual. This variance is largely the result considerable storm damage that occurred in May and July of 2011.

Significant projects in 2011 include:

- July 2nd Storm Repairs (O/H Reactive Replacements; job 11-1217);
- May 29th Storm Repairs (O/H Reactive Replacements; job 11-1199);
- 6th Concession Transformer Replacement (Transformer Replacement program, job 11-1272);

Account 1855 – Services

Typical projects that flow through Account 1855 include:

- General engineering & operational support;
- Customer expansion requests;
- New service requests;

- Transformer Replacement program;
- Emergencies/reactive replacements;

EPLC realized an increase of $874,068 in Account 1855 from 2010 Actual to 2011 Actual. This variance is mainly the result of new residential secondary connections, ongoing Woodbridge Conversion as well as the installation of a retail point of supply at the Vollmer Complex in LaSalle in order to accommodate temporary switching conditions with Hydro One.

Significant projects in 2011 include:

- New Secondary Services/Connections (Residential Connection/Extension, job 12);
- Woodbridge Conversion (Single Voltage Utility Conversion, job 11-1287);
- Vollmer Complex Retail Supply Point (Municipal request; job 11-1341);

Account 1860 – Meters

Typical projects that flow through Account 1860 include:

- Retail metering replacements;
- Commercial and industrial investments;
- Smart Metering Initiative;

EPLC realized an increase of $242,487 in Account 1860 from 2010 Actual to 2011 Actual. This variance is primarily the result of the addition of new C&I services, Interval metering upgrades from A1R to A3R and the Vollmer Complex Retail Supply Point work required to accommodate temporary switching conditions with Hydro One.

General Plant

Account 1925 – Computer Software

EPLC realized a decrease of $91,368 in Account 1925 from 2010 Actual to 2011 Actual. EPLC spent approximately $36k on various software products including four GP licenses, payroll software customization and GP enhancements. EPLC also reallocated approximately $128k in GP costs to affiliated companies. This reallocation is the primary driver of the 2010 to 2011 variance.

Account 1930 – Transportation Equipment

EPLC realized an increase of $189,253 in Account 1930 from 2010 Actual to 2011 Actual. Additions in 2011 include:

- New cab, chassis & aerial device, Truck #107 - $257k;
- Sale of Single Bucket Truck – ($127k);
- Fleet refurbishment - $47k;
- GPS System for Fleet - $10k;

Contributions & Grants

Account 1995 – Contributions & Grants

While this variance is above EPLC's materiality threshold, EPLC traditionally receives approximately $1.4M per year in Capital Contributions & Grants. This contribution can vary dramatically depending on the type of development that is ongoing at the time. The 2011 Actual balance results in an increase of $539k from the average balance which is above average. This increase is as a result of greater than expected contributions collected for new subdivision and service connections.

2011 Actual Vs. 2012 Actual

Figure 7 – 2011 Actual vs. 2012 Actual – By Account

USoA	Description	2011 Actual	2012 Actual	Variance
	Intangible Plant			
1611	Computer Software	$ -	$ -	$ -
1612	Land Rights	$ -	$ -	$ -
	Subtotal	**$ -**	**$ -**	**$ -**
	Distribution Plant			
1805	Land	$ 47,899	$ 47,899	$ -
1806	Land Rights	$ 108,990	$ 115,165	$ 6,175
1820	Distribution Station Equipment < 50 kV	$ 103,107	$ 114,073	$ 10,966
1830	Poles, Towers & Fixtures	$ 6,006,615	$ 6,463,571	$ 456,957
1835	Overhead Conductors & Devices	$ 5,684,239	$ 6,414,747	$ 730,509
1840	Underground Conduit	$ 9,701,439	$ 10,656,520	$ 955,081
1845	Underground Conduit & Devices	$ 10,917,707	$ 11,570,868	$ 653,161
1850	Line Transformers	$ 14,233,655	$ 15,077,416	$ 843,761
1855	Services	$ 7,692,638	$ 8,376,599	$ 683,961
1860	Meters	$ 4,200,151	$ 5,160,299	$ 960,149
1860	Meters - Smart Meter Sub-Account	$ -	$ -	$ -
	Subtotal	**$ 58,696,440**	**$ 63,997,158**	**$ 5,300,719**
	General Plant			
1905	Land	$ 190,119	$ 190,119	$ -
1908	Building & Fixtures	$ 1,633,771	$ 2,394,956	$ 761,185
1915	Office Furniture & Equipment	$ 159,415	$ 180,243	$ 20,829
1920	Computer Equipment - Hardware	$ 306,043	$ 306,043	$ -
1925	Computer Software	$ 946,329	$ 1,186,475	$ 240,146
1930	Transportation Equipment	$ 1,172,081	$ 1,282,473	$ 110,392
1935	Stores Equipment	$ 34,367	$ 37,075	$ 2,708
1940	Tools, Shop & Garage Equipment	$ 242,672	$ 329,469	$ 86,797
1945	Measurement & Testing Equipment	$ 63,987	$ 63,987	$ -
1955	Communication Equipment	$ 226,916	$ 276,532	$ 49,617
	Subtotal	**$ 4,975,699**	**$ 6,247,373**	**$ 1,271,673**
	Contributions & Grants			
1995	Contributions & Grants	$ (12,003,010)	$ (12,872,862)	$ (869,853)
	Subtotal	**$ (12,003,010)**	**$ (12,872,862)**	**$ (869,853)**
	Grand Total	**$ 51,669,129**	**$ 57,371,669**	**$ 5,702,540**

Intangible Plant

No material variance to explain.

Distribution Plant

Account 1830 – Poles, Towers & Fixtures

Typical projects that flow through Account 1830 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $456,957 in Account 1830 from 2011 Actual to 2012 Actual. This variance is mainly attributed to increased spending on System Renewal projects and an increase in System Access spending for new connections.

Significant projects in 2012 include:

- Direct Buried Cable Replacement in Tecumseh (Direct Buried Cable Replacement program, job 1194)
- Sunnyside F1 SW70007 Conversion (Single Voltage Utility, job 12-1183)
- Underground Conversion – Franklin to Rickway (Conversion; job 12-1014);
- Laurier Parkway Phase 2 (Residential connection/extension; job 12-1191);
- Georgia F1 Conversion - Oak to Marlborough (Conversion; job 1115);

Account 1835 – Overhead Conductors & Devices

Typical projects that flow through Account 1835 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;

- Conversion projects;
- Emergencies;

EPLC realized an increase of $730,509 in Account 1835 from 2011 Actual to 2012 Actual. This variance is largely made up of new connection requests that EPLC is required to facilitate, ongoing system conversion and a large commercial renewal project.

Significant projects in 2012 include:

- HPAC Subdivision Phase 6A (Subdivision, job 12-1277);
- Beachgrove Site Upgrades (Transformer/cable replacement, job 12-1236);
- Malden F1-FS70487 Conversion to station (Conversion, job 12-1152);

Account 1840 – Underground Conduit

Typical projects that flow through Account 1840 include:

- General engineering & operational support;
- Customer expansion requests;
- Cable Replacement projects;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $955,081 in Account 1840 from 2011 Actual to 2012 Actual. This variance is largely a result of greater than expected new connections both residential and commercial.

Significant projects in 2012 include:

- HPAC Subdivision Phase 6A (Subdivision, job 12-1277);
- David/Cada Cable & Transformer Replacement (Cable replacement, job 12-1134);
- Forest Trail Subdivision Phase 1 (Subdivision, job 12-1000);
- Tecumseh Road Medical Centre (New service C&I, job 12-1021);

Account 1845 – Underground Conduit & Devices

Typical projects that flow through Account 1845 include:

- General engineering & operational support;

- Customer expansion requests;
- Livefront Transformer replacements;
- Conversion projects;
- PMH Replacement projects;
- Emergencies;

EPLC realized an increase of $653,161 in Account 1845 from 2011 Actual to 2012 Actual. This variance is the result of ongoing PMH replacement work and cable replacement work in Tecumseh.

Significant projects in 2012 include:

- Switching cubicle replacement on Centennial (PMH Replacement Program, job 12-1144);
- Direct Buried Cable Replacement in Tecumseh (Direct Buried Cable Replacement program, job 1194)

Account 1850 – Line Transformers

Typical projects that flow through Account 1850 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Transformer Replacement program;
- PMH Replacement projects;
- Emergencies/reactive replacements;

EPLC realized an increase of $876,982 in Account 1850 from 2011 Actual to 2012 Actual. This variance is related to considerable C&I related work completed throughout the year as well as a significant industrial reactive transformer replacement.

Significant projects in 2012 include:

- Morton Industrial Transformer Replacement (U/G Reactive Replacements, job 12-1286);
- Sacred Heart School Expansion (New Service Upgrade C&I, job 12-1213);
- Leamington Robson Road Livefront upgrade (Transformer Replacement Program, job 12-1099);
- 3rd Concession New Service (New Service Upgrade C&I, job 12-1220);

Account 1855 – Services

Typical projects that flow through Account 1855 include:

- General engineering & operational support;
- Customer expansion requests;
- New service requests;
- Transformer Replacement program;
- Emergencies/reactive replacements;

EPLC realized an increase of $683,961 in Account 1855 from 2011 Actual to 2012 Actual. This variance is mainly the result of new residential secondary connections, ongoing Woodbridge Conversion as well as the installation of a retail point of supply at the Vollmer Complex in LaSalle in order to accommodate temporary switching conditions with Hydro One.

Significant projects in 2012 include:

- New Secondary Services/Connections (Residential Connection/Extension, job 12-0012);
- Laurier Transformer Conversion (Residential connection/extension; job 12-1285);
- Simcoe Underground Service (Residential connection/extension, job 12-1308);
- Essex Golf Club Transformer Replacement (Transformer Replacement Project; job 12-1202);

Account 1860 – Meters

Typical projects that flow through Account 1860 include:

- Retail metering replacements;
- Commercial and industrial investments;
- Smart Metering Initiative;

EPLC realized an increase of $960,149 in Account 1860 from 2011 Actual to 2012 Actual. This variance is primarily the result of the addition of smart metering initiative capital, new C&I services and Interval metering upgrades from A1R to A3R.

General Plant

Account 1908 – Building & Fixtures

The 2012 increase in 1908 of $761,185 is related to renovations completed at EPLC's 2730 Highway #3 location. EPLC consolidated billing and customer service from its prior location at the Essex Civic Center (360 Fairview Avenue, Essex, Ontario) to the Highway #3 location as EPLC's lease was expiring and future costs were proposed to increase substantially. EPLC's entire operation is now consolidated in one building instead of being split across multiple sites.

Account 1925 – Computer Software

EPLC realized an increase of $240,146 in Account 1925 from 2011 Actual to 2012 Actual. EPLC spent approximately $172k on finalizing its GP upgrade as well as $39k on management scorecards to track year over year performance. The remaining additions include standard software license renewals required for business continuity.

Account 1930 – Transportation Equipment

EPLC realized an increase of $110,392 in Account 1930 from 2011 Actual to 2012 Actual. Additions in 2012 include:

- New Truck #108 and associated hardware - $225k;
- Sale of 3x Small Trucks – ($62k);
- Sale of 1x Large Truck – ($140k);
- CPR Defibrillators - $6k;
- Fleet refurbishment - $2k;
- 2x New Trucks - $79k

Account 1940 – Tools, Shop & Garage Equipment

EPLC realized an increase of $86,797 in Account 1940 from 2011 Actual to 2012 Actual. Additions in 2012 include:

- Meter Testing Equipment - $21k
- VON ARC Reflection System - $30k
- Miscellaneous shop/garage equipment - $35k

EPLC experience a minor increase in equipment as it relates to the implementation of the smart metering initiative.

Contributions & Grants

Account 1995 – Contributions & Grants

While this variance is above EPLC's materiality threshold, EPLC traditionally receives approximately $1.4M per year in Capital Contributions & Grants, on average. This contribution can vary dramatically depending on the type of development that is ongoing at the time. The 2012 Actual balance results in a decrease of $530k from the average balance which is below average. This decrease is as a result of greater than expected contributions collected for new subdivision and service connections in the prior year.

2012 Actual Vs. 2013 Actual

Figure 8 – 2012 Actual vs. 2013 Actual – By Account

USoA	Description	2012 Actual	2013 Actual	Variance
	Intangible Plant			
1611	Computer Software	$ -	$ -	$ -
1612	Land Rights	$ -	$ -	$ -
	Subtotal	**$ -**	**$ -**	**$ -**
	Distribution Plant			
1805	Land	$ 47,899	$ 47,899	$ -
1806	Land Rights	$ 115,165	$ 175,427	$ 60,262
1820	Distribution Station Equipment < 50 kV	$ 114,073	$ 115,505	$ 1,432
1830	Poles, Towers & Fixtures	$ 6,463,571	$ 6,852,565	$ 388,994
1835	Overhead Conductors & Devices	$ 6,414,747	$ 6,909,277	$ 494,530
1840	Underground Conduit	$ 10,656,520	$ 11,489,326	$ 832,806
1845	Underground Conduit & Devices	$ 11,570,868	$ 12,495,775	$ 924,907
1850	Line Transformers	$ 15,077,416	$ 16,432,674	$ 1,355,258
1855	Services	$ 8,376,599	$ 9,221,942	$ 845,343
1860	Meters	$ 5,160,299	$ 5,319,772	$ 159,472
1860	Meters - Smart Meter Sub-Account	$ -	$ -	$ -
	Subtotal	**$ 63,997,158**	**$ 69,060,163**	**$ 5,063,004**
	General Plant			
1905	Land	$ 190,119	$ 190,119	$ -
1908	Building & Fixtures	$ 2,394,956	$ 2,422,357	$ 27,401
1915	Office Furniture & Equipment	$ 180,243	$ 188,609	$ 8,365
1920	Computer Equipment - Hardware	$ 306,043	$ 324,149	$ 18,106
1925	Computer Software	$ 1,186,475	$ 1,252,529	$ 66,055
1930	Transportation Equipment	$ 1,282,473	$ 1,553,552	$ 271,079
1935	Stores Equipment	$ 37,075	$ 37,075	$ -
1940	Tools, Shop & Garage Equipment	$ 329,469	$ 383,628	$ 54,159
1945	Measurement & Testing Equipment	$ 63,987	$ 63,987	$ -
1955	Communication Equipment	$ 276,532	$ 281,480	$ 4,947
	Subtotal	**$ 6,247,373**	**$ 6,697,485**	**$ 450,112**
	Contributions & Grants			
1995	Contributions & Grants	$(12,872,862)	$(15,064,761)	$(2,191,898)
	Subtotal	**$(12,872,862)**	**$(15,064,761)**	**$(2,191,898)**
	Grand Total	**$ 57,371,669**	**$ 60,692,887**	**$ 3,321,218**

Intangible Plant

No material variance to explain.

Distribution Plant

Account 1830 – Poles, Towers & Fixtures

Typical projects that flow through Account 1830 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $388,994 in Account 1830 from 2012 Actual to 2013 Actual. This variance is mainly attributed to increased spending for the Detroit River International Crossing ("DRIC") project and Herb Gray Parkway.

Significant projects in 2013 include:

- LaSalle DRIC Project (Municipal request, job 13-1032);
- Monopoly Subdivision transformer & cable replacement (Conversion; job 12-1084)
- Cherrylawn livefront replacement (transformer replacement; job 12-1120);

Account 1835 – Overhead Conductors & Devices

Typical projects that flow through Account 1835 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $494,530 in Account 1835 from 2012 Actual to 2013 Actual. This variance is largely made up of new connection requests that EPLC is required to facilitate as well as ongoing system conversion.

Significant projects in 2013 include:

- Northway Subdivision Phase 2 (Subdivision, job 12-1335);
- Legacy Grove Subdivision (Subdivision, job 13-1021);
- Malden F3-Maple Conversion (Conversion, job 12-1368);

Account 1840 – Underground Conduit

Typical projects that flow through Account 1840 include:

- General engineering & operational support;
- Customer expansion requests;
- Cable Replacement projects;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $832,806 in Account 1840 from 2012 Actual to 2013 Actual. This variance is a result of greater than expected new connections both residential and a livefront transformer conversion project.

Significant projects in 2013 include:

- Lithgow livefront transformer conversion (Replacement – Lithgow Livefront Transformers, job 12-1244);
- HPAC Subdivision Phase 7A (Subdivision, job 13-1070);
- HPAC Subdivision Phase 6B (Subdivision, job 13-1424);
- Woodbridge Phase 3 (Subdivision, job 13-1226);

Account 1845 – Underground Conduit & Devices

Typical projects that flow through Account 1845 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;

- Conversion projects;
- PMH Replacement projects;
- Emergencies;

EPLC realized an increase of $924,907 in Account 1845 from 2012 Actual to 2013 Actual. This variance is the result of ongoing PMH replacement work, and the beginning of work required for the DRIC/ Herb Gray Parkway projects.

Significant projects in 2013 include:

- Various PMH Replacements (PMH Replacement Program, job 13-1001);
- DRIC Homestead Supply (Municipal Request, job 13-1033);

Account 1850 – Line Transformers

Typical projects that flow through Account 1850 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Transformer Replacement program;
- PMH Replacement projects;
- Emergencies/reactive replacements;

EPLC realized an increase of $1,355,258 in Account 1850 from 2012 Actual to 2013 Actual. This variance is mainly related to considerable Municipal Request related work in relocation of service as well as new services.

Significant projects in 2013 include:

- Richmond Terrace Service (New Service Upgrade C&I, job 13-1094);
- Service Relocation – Lacasse Park (Municipal Request, job 13-1485);
- Amherstburg Livefront upgrades (Transformer Replacement Program, job 13-1485);
- LaSalle Townhall Relocation (Municipal Request, job 13-1056);

Account 1855 – Services

Typical projects that flow through Account 1855 include:

- General engineering & operational support;
- Customer expansion requests;
- New service requests;
- Transformer Replacement program;
- Emergencies/reactive replacements;

EPLC realized an increase of $845,343 in Account 1855 from 2012 Actual to 2013 Actual. This variance is mainly the result of new commercial and industrial expansions, with the largest projects residing in Leamington and Tecumseh as well as new residential secondary connections.

Significant projects in 2013 include:

- MNSI Insulator Replacements (New Service Upgrades C&I, job 13-1006);
- Sandwich Street C&I Expansion (New Service Upgrades C&I, job 13-1084);
- New Secondary Services/Connections (Residential Connection/Extension, job 13-0012);

Account 1860 – Meters

Typical projects that flow through Account 1860 include:

- Retail metering replacements;
- Commercial and industrial investments;
- Smart Metering Initiative;

EPLC realized an increase of $159,472 in Account 1860 from 2012 Actual to 2013 Actual. This variance is primarily the result of the change out of REX1 meters along with new C&I services.

General Plant

Account 1925 – Computer Software

EPLC realized an increase of $66,055 in Account 1925 from 2012 Actual to 2013 Actual. Additions in 2013 include:

- GP to CIS Integration
- CIS Mcare Upgrade
- Smart Meter Map Program
- Work Request Upgrade

- Unbilled Revenue Program

Account 1930 – Transportation Equipment

EPLC realized an increase of $271,079 in Account 1930 from 2012 Actual to 2013 Actual. Additions in 2013 include:

- 2x New Trucks and associated hardware - $347k;
- Sale of Fleet assets – ($111k);
- Trailer - $4k;
- Fleet refurbishment - $30k;

Contributions & Grants

Account 1995 – Contributions & Grants

While this variance is above EPLC's materiality threshold, EPLC traditionally receives approximately $1.4M per year in Capital Contributions & Grants, on average. This contribution can vary dramatically depending on the type of development that is ongoing at the time. The 2013 Actual balance results in an increase of $792k from the average balance which is above average. This increase is a result of greater than expected contributions collected for new subdivision and service connections.

2013 Actual Vs. 2014 Actual

Figure 9 – 2013 Actual vs. 2014 Actual – By Account

USoA	Description	2013 Actual	2014 Actual	Variance
	Intangible Plant			
1611	Computer Software	$ -	$ -	$ -
1612	Land Rights	$ -	$ -	$ -
	Subtotal	**$ -**	**$ -**	**$ -**
	Distribution Plant			
1805	Land	$ 47,899	$ 47,899	$ -
1806	Land Rights	$ 175,427	$ 190,498	$ 15,071
1820	Distribution Station Equipment < 50 kV	$ 115,505	$ 115,505	$ -
1830	Poles, Towers & Fixtures	$ 6,852,565	$ 7,343,189	$ 490,624
1835	Overhead Conductors & Devices	$ 6,909,277	$ 7,340,765	$ 431,488
1840	Underground Conduit	$ 11,489,326	$ 12,740,042	$ 1,250,716
1845	Underground Conduit & Devices	$ 12,495,775	$ 13,335,773	$ 839,997
1850	Line Transformers	$ 16,432,674	$ 17,747,645	$ 1,314,971
1855	Services	$ 9,221,942	$ 10,266,869	$ 1,044,927
1860	Meters	$ 5,319,772	$ 5,652,387	$ 332,615
1860	Meters - Smart Meter Sub-Account	$ -	$ -	$ -
	Subtotal	**$ 69,060,163**	**$ 74,780,571**	**$ 5,720,408**
	General Plant			
1905	Land	$ 190,119	$ 190,119	$ -
1908	Building & Fixtures	$ 2,422,357	$ 2,422,357	$ -
1915	Office Furniture & Equipment	$ 188,609	$ 190,108	$ 1,499
1920	Computer Equipment - Hardware	$ 324,149	$ 367,497	$ 43,348
1925	Computer Software	$ 1,252,529	$ 1,327,398	$ 74,868
1930	Transportation Equipment	$ 1,553,552	$ 1,842,598	$ 289,046
1935	Stores Equipment	$ 37,075	$ 37,075	$ -
1940	Tools, Shop & Garage Equipment	$ 383,628	$ 461,960	$ 78,333
1945	Measurement & Testing Equipment	$ 63,987	$ 63,987	$ -
1955	Communication Equipment	$ 281,480	$ 281,480	$ -
	Subtotal	**$ 6,697,485**	**$ 7,184,579**	**$ 487,094**
	Contributions & Grants			
1995	Contributions & Grants	$(15,064,761)	$(16,186,932)	$(1,122,171)
	Subtotal	**$(15,064,761)**	**$(16,186,932)**	**$(1,122,171)**
	Grand Total	**$ 60,692,887**	**$ 65,778,218**	**$ 5,085,331**

Intangible Plant

No material variance to explain.

Distribution Plant

Account 1830 – Poles, Towers & Fixtures

Typical projects that flow through Account 1830 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $490,624 in Account 1830 from 2013 Actual to 2014 Actual. This variance is mainly attributed to ongoing and increased spending for the DRIC/ Herb Gray Parkway projects.

Significant projects in 2014 include:

- LaSalle DRIC Project (Municipal request, job 13-1038);
- Monopoly Subdivision Conversion Phase 2 (Conversion; job 14-270)
- Cherrylawn Conversion Phase 2 (Cable replacement; job 14-1267);
- Sunnyside F1/F2 Conversion (Single Voltage Utility, job 13-1471/13-1512);

Account 1835 – Overhead Conductors & Devices

Typical projects that flow through Account 1835 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $431,488 in Account 1835 from 2013 Actual to 2014 Actual. This variance is largely made up of new connection requests that EPLC is required to facilitate as well as refurbishment of PMH50200.

Significant projects in 2014 include:

- PMH50200 Replacement (PMH Replacement Program, job 14-1265);
- Ulster Street Subdivision (Subdivision, job 13-1513);

Account 1840 – Underground Conduit

Typical projects that flow through Account 1840 include:

- General engineering & operational support;
- Customer expansion requests;
- Cable Replacement projects;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $1,250,716 in Account 1840 from 2013 Actual to 2014 Actual. This variance is a result of new connections both residential and mid-sized commercial development.

Significant projects in 2014 include:

- Wyoming Commercial Development (New service upgrades – C&I, job 13-1506);
- Boismier Subdivision Phase 2 (Subdivision, job 14-1406);
- Naccarato Phase 2 (Subdivision, job 14-1255);

Account 1845 – Underground Conduit & Devices

Typical projects that flow through Account 1845 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Conversion projects;
- PMH Replacement projects;
- Emergencies;

EPLC realized an increase of $839,997 in Account 1845 from 2013 Actual to 2014 Actual. This variance is the result of ongoing work required for the DRIC/ Herb Gray Parkway projects, residential connections requests as well as a large municipal pumping station project.

Significant projects in 2014 include:

- Lakewood Pumping Station (Municipal request, job 14-1409);
- Seven Lakes Phase 3A (Subdivisions, job 14-1325);
- Malden Tower Service (Residential Connection/Extension, job 13-1451);
- DRIC Homestead Supply (Municipal Request, job 13-1522);

Account 1850 – Line Transformers

Typical projects that flow through Account 1850 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Transformer Replacement program;
- PMH Replacement projects;
- Emergencies/reactive replacements;

EPLC realized an increase of $1,314,971 in Account 1850 from 2013 Actual to 2014 Actual. This variance is mainly related to ongoing work to replace livefront transformers in Amherstburg as well as servicing a new industrial load.

Significant projects in 2014 include:

- Amherstburg Livefront upgrades (Transformer Replacement Program, job 14-1268);
- Setterington Industrial Service (New Service Upgrade C&I, job 14-1424);
- Blown transformer Donalda Crescent (Transformer Replacement Program, job 14-1430);

Account 1855 – Services

Typical projects that flow through Account 1855 include:

- General engineering & operational support;
- Customer expansion requests;
- New service requests;

- Transformer Replacement program;
- Emergencies/reactive replacements;

EPLC realized an increase of $1,044,927 in Account 1855 from 2013 Actual to 2014 Actual. This variance is mainly the result of new commercial and industrial expansions, with the largest projects residing in Tecumseh as well as new residential secondary connections.

Significant projects in 2014 include:

- New Riverside Drive Service (New Service Upgrades C&I, job 14-1318);
- Sandwich Street FIT Connection (FIT & Generation Connections, job 13-1461);
- New Secondary Services/Connections (Residential Connection/Extension, job 14-0012);

Account 1860 – Meters

Typical projects that flow through Account 1860 include:

- Retail metering replacements;
- Commercial and industrial investments;

EPLC realized an increase of $332,615 in Account 1860 from 2013 Actual to 2014 Actual. This variance is primarily the result of the ongoing change out of REX1 meters from 2013 along with new C&I services.

General Plant

Account 1925 – Computer Software

EPLC realized an increase of $74,868 in Account 1925 from 2013 Actual to 2014 Actual. Additions in 2014 include:

- Northstar (Billing System) Upgrade;
- Work Estimation Update;
- MIS System Software

Account 1930 – Transportation Equipment

EPLC realized an increase of $289,046 in Account 1930 from 2013 Actual to 2014 Actual. Additions in 2014 include:

- Sale of Fleet assets – ($136k);
- Fleet refurbishment - $425k;

2014 saw a sharp increase in refurbishment required to maintain the safety and integrity of EPLC's existing fleet including approximately $202k for significant maintenance and body work on a bucket truck, $85k for new cab & chassis for truck #107 and $68k for refurbishing an F550.

Account 1940 – Tools, Shop & Garage Equipment

EPLC realized an increase of $78,333 in Account 1940 from 2013 Actual to 2014 Actual. Additions in 2014 include:

- Forklift - $55k
- Miscellaneous shop/garage equipment - $24k

EPLC experience a minor increase in equipment as a result of a forklift purchase required to safely load trucks and move distribution related equipment.

Contributions & Grants

Account 1995 – Contributions & Grants

While this variance is above EPLC's materiality threshold, EPLC traditionally receives approximately $1.4M per year in Capital Contributions & Grants, on average. This contribution can vary dramatically depending on the type of development that is ongoing at the time. The 2014 Actual balance results in a decrease of $278k from the average balance which is below average. This decrease is a result of greater than expected contributions collected for new subdivision and service connections in the prior year.

2014 Actual Vs. 2015 Actual

Figure 10 – 2014 Actual vs. 2015 Actual – By Account

USoA	Description	2014 Actual	2015 Actual	Variance
	Intangible Plant			
1611	Computer Software	$ -	$ -	$ -
1612	Land Rights	$ -	$ -	$ -
	Subtotal	**$ -**	**$ -**	**$ -**
	Distribution Plant			
1805	Land	$ 47,899	$ 47,899	$ -
1806	Land Rights	$ 190,498	$ 205,159	$ 14,661
1820	Distribution Station Equipment < 50 kV	$ 115,505	$ -	$ (115,505)
1830	Poles, Towers & Fixtures	$ 7,343,189	$ 8,277,989	$ 934,800
1835	Overhead Conductors & Devices	$ 7,340,765	$ 8,330,924	$ 990,160
1840	Underground Conduit	$ 12,740,042	$ 13,019,342	$ 279,301
1845	Underground Conduit & Devices	$ 13,335,773	$ 13,920,280	$ 584,507
1850	Line Transformers	$ 17,747,645	$ 18,562,128	$ 814,483
1855	Services	$ 10,266,869	$ 11,329,169	$ 1,062,301
1860	Meters	$ 5,652,387	$ 4,484,564	$(1,167,823)
1860	Meters - Smart Meter Sub-Account	$ -	$ 3,835,084	$ 3,835,084
	Subtotal	**$ 74,780,571**	**$ 82,012,540**	**$ 7,231,969**
	General Plant			
1905	Land	$ 190,119	$ 190,119	$ -
1908	Building & Fixtures	$ 2,422,357	$ 2,471,271	$ 48,914
1915	Office Furniture & Equipment	$ 190,108	$ 196,088	$ 5,980
1920	Computer Equipment - Hardware	$ 367,497	$ 371,372	$ 3,875
1925	Computer Software	$ 1,327,398	$ 1,344,441	$ 17,043
1930	Transportation Equipment	$ 1,842,598	$ 2,244,755	$ 402,157
1935	Stores Equipment	$ 37,075	$ 37,092	$ 17
1940	Tools, Shop & Garage Equipment	$ 461,960	$ 518,499	$ 56,539
1945	Measurement & Testing Equipment	$ 63,987	$ 63,987	$ -
1955	Communication Equipment	$ 281,480	$ 294,423	$ 12,943
	Subtotal	**$ 7,184,579**	**$ 7,732,047**	**$ 547,468**
	Contributions & Grants			
1995	Contributions & Grants	$(16,186,932)	$(17,635,115)	$(1,448,183)
	Subtotal	**$(16,186,932)**	**$(17,635,115)**	**$(1,448,183)**
	Grand Total	**$ 65,778,218**	**$ 72,109,471**	**$ 6,331,254**

Intangible Plant

No material variance to explain.

Distribution Plant

Account 1820 – Distribution Station Equipment <50 kV

As part of EPLC's Single Voltage Utility initiative, EPLC successfully retired all distribution substations feeding its customers in 2015. This retirement is the sole cause of the variance in 2015.

Account 1830 – Poles, Towers & Fixtures

Typical projects that flow through Account 1830 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $934,800 in Account 1830 from 2014 Actual to 2015 Actual. This variance is mainly attributed to ongoing and increased spending for the DRIC/ Herb Gray Parkway projects as well as the beginning of the Pole Replacement program in Amherstburg.

Significant projects in 2015 include:

- Howard/Huron Line Conversion related to DRIC (Conversion, job 15-1493)
- LaSalle DRIC Project (Municipal request, job 13-1036);
- Amherstburg Pole Replacement (Pole Replacement program, job 15-1606)
- Sunnyside F2 Conversion (Single Votlage Utility, job 13-1498)
- Golfwood Subdivision (Subdivisions, job 12-1225)

Account 1835 – Overhead Conductors & Devices

Typical projects that flow through Account 1835 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $990,160 in Account 1835 from 2014 Actual to 2015 Actual. This variance is largely made up of new connection requests that EPLC is required to facilitate, significant investment in cable replacement and the removal of porcelain insulators in Tecumseh and Leamington.

Significant projects in 2015 include:

- Porcelain insulator replacement – Tecumseh/Leamington (Insulator Replacement Program, job 15-1600, 13-1337);
- Cherrylawn Phase 2 Cable Replacement (Primary Cable Replacement, job 14-1267);
- New commercial connection Seacliff Drive (New service C&I, job 15-1629);

Account 1840 – Underground Conduit

Typical projects that flow through Account 1840 include:

- General engineering & operational support;
- Customer expansion requests;
- Cable Replacement projects;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $279,301 in Account 1840 from 2014 Actual to 2015 Actual. This variance is a result of new connections residential subdivision connections.

Significant projects in 2015 include:

- Lakewood Subdivision (Subdivision, job 15-1540);

- Seven Lakes Phase 2A (Subdivision, job 15-1638);
- HPAC Subdivision Phase 10A & 7B (Subdivision, job 15-1678);

Account 1845 – Underground Conduit & Devices

Typical projects that flow through Account 1845 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Conversion projects;
- PMH Replacement projects;
- Emergencies;

EPLC realized an increase of $584,507 in Account 1845 from 2014 Actual to 2015 Actual. This variance is mainly the result of EPLC's ongoing PMH replacement program, Transformer Replacement program as well as residential connection requests.

Significant projects in 2015 include:

- PMH32110 Replacement (PMH Replacement Program, job 14-1266);
- Elsworth Subdivision Phase 1 (Subdivisions, job 14-1327);
- Amherstburg Livefront Replacement (Transformer Replacement program, job 15-1668);
- Amherstburg MV50120 Replacement (PMH Replacement Program, job 15-1669);

Account 1850 – Line Transformers

Typical projects that flow through Account 1850 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Transformer Replacement program;
- PMH Replacement projects;
- Emergencies/reactive replacements;

EPLC realized an increase of $814,483 in Account 1850 from 2014 Actual to 2015 Actual. This variance is related to servicing new customer connections as well as EPLC's transformer Replacement program.

Significant projects in 2015 include:

- Seven Lakes Subdivision Phases 3B and 3D (Subdivision, job 15-1505);
- Amberly Crescent Conversion (Transformer Replacement Program, job 15-1698);
- Normandy Apartment Complex (Residential Connection/Extension, job 14-1436);
- Gore Street Service Upgrade (New Service Upgrades C&I, job 15-1546);

Account 1855 – Services

Typical projects that flow through Account 1855 include:

- General engineering & operational support;
- Customer expansion requests;
- New service requests;
- Transformer Replacement program;
- Emergencies/reactive replacements;

EPLC realized an increase of $1,062,301 in Account 1855 from 2014 Actual to 2015 Actual. This variance is mainly the result of new residential secondary connections, transformer replacements and service upgrades.

Significant projects in 2015 include:

- Front Road Transformer Conversion (Transformer Replacement program, job 15-1518);
- Reaume Road New Service (Residential Connection/Extension, job 15-1566);
- New Secondary Services/Connections (Residential Connection/Extension, job 15-0012);

Account 1860 – Meters

Typical projects that flow through Account 1860 include:

- Retail metering replacements;
- Commercial and industrial investments;
- Transactions related to recovery of the Smart Metering Initiative;

EPLC realized a decrease of $1,167,823 in Account 1860 from 2014 Actual to 2015 Actual as well as an increase in 1860 Smart Metering Sub-Account of $3,835,084 over the same time period. This variance is the result of EPLC allocating the actual costs associated with the Smart Metering Initiative to the correct Board approved account in preparation of disposition in 2016.

An offsetting decrease to account 1860 occurred as a result of remaining stranded meter costs and routine metering installations and replacements, where required over the course of regular business.

General Plant

Account 1930 – Transportation Equipment

EPLC realized an increase of $402,157 in Account 1930 from 2014 Actual to 2015 Actual. Additions in 2015 include:

- Purchase of Truck #113, RBD Freightliner - $271k;
- Purchase of Truck #106, Freightliner – $99k;
- Fleet Housing Refurbishment - $21k;
- Truck refurbishment - $10k;

Contributions & Grants

Account 1995 – Contributions & Grants

While this variance is above EPLC's materiality threshold, EPLC traditionally receives approximately $1.4M per year in Capital Contributions & Grants, on average. This contribution can vary dramatically depending on the type of development that is ongoing at the time. The 2015 Actual balance results are in line with the historical average.

2015 Actual Vs. 2016 Actual

Figure 11 – 2015 Actual vs. 2016 Actual – By Account

USoA	Description	2015 Actual	2016 Actual	Variance
	Intangible Plant			
1611	Computer Software	$ -	$ 1,349,073	$ 1,349,073
1612	Land Rights	$ -	$ 207,803	$ 207,803
	Subtotal	**$ -**	**$ 1,556,875**	**$ 1,556,875**
	Distribution Plant			
1805	Land	$ 47,899	$ 35,899	$ (12,000)
1806	Land Rights	$ 205,159	$ -	$ (205,159)
1820	Distribution Station Equipment < 50 kV	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 8,277,989	$ 8,897,418	$ 619,428
1835	Overhead Conductors & Devices	$ 8,330,924	$ 9,205,503	$ 874,579
1840	Underground Conduit	$ 13,019,342	$ 13,230,112	$ 210,770
1845	Underground Conduit & Devices	$ 13,920,280	$ 14,457,773	$ 537,493
1850	Line Transformers	$ 18,562,128	$ 19,300,481	$ 738,353
1855	Services	$ 11,329,169	$ 12,154,283	$ 825,114
1860	Meters	$ 4,484,564	$ 9,412,656	$ 4,928,093
1860	Meters - Smart Meter Sub-Account	$ 3,835,084	$ -	$(3,835,084)
	Subtotal	**$ 82,012,540**	**$ 86,694,126**	**$ 4,681,587**
	General Plant			
1905	Land	$ 190,119	$ 190,119	$ -
1908	Building & Fixtures	$ 2,471,271	$ 2,513,740	$ 42,469
1915	Office Furniture & Equipment	$ 196,088	$ 216,760	$ 20,672
1920	Computer Equipment - Hardware	$ 371,372	$ 488,700	$ 117,329
1925	Computer Software	$ 1,344,441	$ 585	$(1,343,856)
1930	Transportation Equipment	$ 2,244,755	$ 2,381,417	$ 136,662
1935	Stores Equipment	$ 37,092	$ 47,367	$ 10,275
1940	Tools, Shop & Garage Equipment	$ 518,499	$ 564,329	$ 45,830
1945	Measurement & Testing Equipment	$ 63,987	$ 70,248	$ 6,260
1955	Communication Equipment	$ 294,423	$ 294,423	$ -
	Subtotal	**$ 7,732,047**	**$ 6,767,688**	**$ (964,359)**
	Contributions & Grants			
1995	Contributions & Grants	$(17,635,115)	$(18,566,136)	$ (931,021)
	Subtotal	**$(17,635,115)**	**$(18,566,136)**	**$ (931,021)**
	Grand Total	**$ 72,109,471**	**$ 76,452,553**	**$ 4,343,082**

Intangible Plant

Account 1611 – Computer Software

EPLC realized an increase of $1,349,073 in Account 1611 from 2015 Actual to 2016 Actual. This large increase is a result of a re-allocation of Computer Software from Account 1925 to better align with direction in the APH.

Account 1612 – Land Rights

EPLC realized an increase of $205,803 in Account 1612 from 2015 Actual to 2016 Actual. This increase is a result of a re-allocation of Land Rights from Account 1806 to better align with direction in the APH.

Distribution Plant

Account 1806 – Land Rights

EPLC realized a decrease of $205,159 in Account 1806 from 2015 Actual to 2016 Actual. This decrease is a result of a re-allocation of Land Rights to Account 1612 to better align with direction in the APH.

Account 1830 – Poles, Towers & Fixtures

Typical projects that flow through Account 1830 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $619,428 in Account 1830 from 2015 Actual to 2016 Actual. This variance is attributed to EPLC's pole replacement program as well as the beginning of EPLC's Self-Healing Grid initiative for enhanced system reliability.

Significant projects in 2016 include:

- LaSalle Pole Replacement (Pole Replacement program, job 16-1619);
- Tecumseh Reclosure Installation (Self-Healing Grid, job 16-1598);
- Seven Lakes Phase 2B Subdivision (Subdivision, job 16-1691);

Account 1835 – Overhead Conductors & Devices

Typical projects that flow through Account 1835 include:

- Pole replacement;
- General engineering & operational support;
- Customer capital expansion requests;
- Transformer replacement;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $874,579 in Account 1835 from 2015 Actual to 2016 Actual. This variance is largely made up of new connection requests that EPLC is required to facilitate, a significant commercial service upgrade and the ongoing removal of porcelain insulators in Leamington.

Significant projects in 2016 include:

- Ongoing Porcelain insulator replacement – Leamington (Insulator Replacement Program, job 15-1600);
- Sunnyside F1 Front from Victory to Station (Single Voltage Utility, job 14-1269);
- New commercial upgrade - Ivan (New service upgrade C&I, job 13-1413);

Account 1840 – Underground Conduit

Typical projects that flow through Account 1840 include:

- General engineering & operational support;
- Customer expansion requests;
- Cable Replacement projects;
- Conversion projects;
- Emergencies;

EPLC realized an increase of $210,770 in Account 1840 from 2015 Actual to 2016 Actual. This variance is a result of new connections residential subdivision connections.

Significant projects in 2016 include:

- Monopoly Subdivision Phase 3 (Subdivision, job 15-1492);
- Santos Phase 2 (Subdivision, job 15-1488);
- Daytona Phase 1 (Subdivision, job 16-1731);
- Forest Trails Phase 2B (Subdivision, job 16-1682);

Account 1845 – Underground Conduit & Devices

Typical projects that flow through Account 1845 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Conversion projects;
- PMH Replacement projects;
- Emergencies;

EPLC realized an increase of $537,493 in Account 1845 from 2015 Actual to 2016 Actual. This variance is mainly the result of EPLC's ongoing PMH replacement program with the addition of some 8kV conversion work and a commercial expansion on Seacliff Drive.

Significant projects in 2016 include:

- Simcoe to Fryer 8kV Conversion (Single Voltage Utility Conversion, job 15-1693);
- Amherstburg PMH Replacements (PMH Replacement Program, job 16-1700);
- Seacliff Drive Expansion (New service upgrades C&I, job 16-1715);

Account 1850 – Line Transformers

Typical projects that flow through Account 1850 include:

- General engineering & operational support;
- Customer expansion requests;
- Livefront Transformer replacements;
- Transformer Replacement program;
- PMH Replacement projects;
- Emergencies/reactive replacements;

EPLC realized an increase of $738,353 in Account 1850 from 2015 Actual to 2016 Actual. This variance is related to servicing new customer connections as well as EPLC's transformer Replacement program.

Significant projects in 2016 include:

- Seacliff Drive Expansion (New service upgrades C&I, job 16-1704);
- Hamilton Drive Transformer Replacement (Transformer Replacement Program, job 16-1781);
- Manning Road Condo (Residential Connection/Extension, job 15-1637);

Account 1855 – Services

Typical projects that flow through Account 1855 include:

- General engineering & operational support;
- Customer expansion requests;
- New service requests;
- Transformer Replacement program;
- Emergencies/reactive replacements;

EPLC realized an increase of $825,114 in Account 1855 from 2015 Actual to 2016 Actual. This variance is mainly the result of new residential secondary connections and service upgrades.

Significant projects in 2016 include:

- Erie Street South Service Upgrade (New Service Upgrades C&I, job 16-1592);
- Setterington service relocation (Residential Connection/Extension, job 16-1638);
- New Secondary Services/Connections (Residential Connection/Extension, job 16-0012);

Account 1860 – Meters

Typical projects that flow through Account 1860 include:

- Retail metering replacements;
- Commercial and industrial investments;
- Transactions related to recovery of the Smart Metering Initiative;

EPLC realized an increase of $4,928,093 in Account 1860 from 2015 Actual to 2016 Actual as well as a corresponding decrease in 1860 Smart Metering Sub-Account of $3,835,084 over the

same time period. This variance is the result of EPLC receiving approval to recover the costs of the Smart Metering Initiative as part of its 2015 IRM (EB-2014-0072). As a result, EPLC moved the approved balance in Smart Meter Sub-Account to the main Meter account 1860. The incremental 2016 increase in account 1860 of $1,093,009 is a result of remaining stranded meter costs and routine metering installations and replacements, where required over the course of regular business.

General Plant

Account 1920 – Computer Equipment - Hardware

EPLC realized an increase of $117,329 in Account 1920 from 2015 Actual to 2016 Actual. Additions in 2016 include:

- Miscellaneous computer hardware (laptops, desktops, etc.) - $25k;
- IT Infrastructure & Security Upgrades - $103k
- Paper Folder Machine - $11k

Account 1925 – Computer Software

EPLC realized a decrease of $1,343,856 in Account 1925 from 2015 Actual to 2016 Actual. This large decrease is a result of a re-allocation of Computer Software to Account 1611 to better align with direction in the APH.

Account 1930 – Transportation Equipment

EPLC realized an increase of $136,662 in Account 1930 from 2015 Actual to 2016 Actual. Additions in 2016 include:

- Purchase of 3x small pickup Trucks - $135k;

Contributions & Grants

Account 1995 – Contributions & Grants

While this variance is above EPLC's materiality threshold, EPLC traditionally receives approximately $1.4M per year in Capital Contributions & Grants, on average. This contribution can vary dramatically depending on the type of development that is ongoing at the time. The

2016 Actual balance results in a decrease of $469k from the average balance which is below average.

2016 Actual Vs. 2017 Bridge

Figure 12 – 2016 Actual vs. 2017 Bridge – By Account

USoA	Description	2016 Actual	2017 Bridge	Variance
	Intangible Plant			
1611	Computer Software	$ 1,349,073	$ 1,603,573	$ 254,500
1612	Land Rights	$ 207,803	$ 249,995	$ 42,192
	Subtotal	**$ 1,556,875**	**$ 1,853,568**	**$ 296,692**
	Distribution Plant			
1805	Land	$ 35,899	$ 35,899	$ -
1806	Land Rights	$ -	$ -	$ -
1820	Distribution Station Equipment < 50 kV	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 8,897,418	$ 9,829,756	$ 932,338
1835	Overhead Conductors & Devices	$ 9,205,503	$ 9,747,151	$ 541,648
1840	Underground Conduit	$ 13,230,112	$ 13,964,522	$ 734,410
1845	Underground Conduit & Devices	$ 14,457,773	$ 15,245,984	$ 788,211
1850	Line Transformers	$ 19,300,481	$ 20,326,051	$ 1,025,570
1855	Services	$ 12,154,283	$ 12,976,997	$ 822,714
1860	Meters	$ 9,412,656	$ 9,679,588	$ 266,932
1860	Meters - Smart Meter Sub-Account	$ -	$ -	$ -
	Subtotal	**$ 86,694,126**	**$ 91,805,949**	**$ 5,111,823**
	General Plant			
1905	Land	$ 190,119	$ 190,119	$ -
1908	Building & Fixtures	$ 2,513,740	$ 2,800,544	$ 286,804
1915	Office Furniture & Equipment	$ 216,760	$ 226,760	$ 10,000
1920	Computer Equipment - Hardware	$ 488,700	$ 844,851	$ 356,150
1925	Computer Software	$ 585	$ 585	$ -
1930	Transportation Equipment	$ 2,381,417	$ 2,868,417	$ 487,000
1935	Stores Equipment	$ 47,367	$ 97,367	$ 50,000
1940	Tools, Shop & Garage Equipment	$ 564,329	$ 624,329	$ 60,000
1945	Measurement & Testing Equipment	$ 70,248	$ 70,247	$ (0)
1955	Communication Equipment	$ 294,423	$ 294,423	$ -
	Subtotal	**$ 6,767,688**	**$ 8,017,642**	**$ 1,249,954**
	Contributions & Grants			
1995	Contributions & Grants	$(18,566,136)	$(19,790,893)	$(1,224,757)
	Subtotal	**$(18,566,136)**	**$(19,790,893)**	**$(1,224,757)**
	Grand Total	**$ 76,452,553**	**$ 81,886,267**	**$ 5,433,713**

Intangible Plant

Account 1611 – Computer Software

EPLC is planning an increase of $254,500 in Account 1925 from 2016 Actual to 2017 Bridge Year. Additions in 2017 include:

- Harris Reporting Tool - $10k;
- Silver Blaze – Capricorn (CIS/Customer Service upgrade) – $40k;
- GP Upgrade - $90k;
- CIS Upgrade - $50k;
- Website Update - $65k;

The GP and CIS upgrades are required in order to allow ongoing product support into the future and to ensure the integrity of the systems that have not been upgraded for several years.

Distribution Plant

EPLC plans to invest $5,154,015 in Distribution Plant assets in the 2017 Bridge Year. Between 2010 and 2016, EPLC invested, on average, approximately $5,378,730 per year. EPLC submits that its expected investments in Distribution Plant are in line with historical spending (slightly less) and therefore reasonable. Figure 13 below provides a summary of EPLC planned Distribution Plant investments.

Figure 13 – 2017 Bridge Year Distribution Plant

Description	2017 Bridge
Residential Connections	$ 761,636
C&I Connections	$ 349,960
Conversions	$ 1,847,151
Municipal Requests & Asset Purchases	$ 770,360
FIT & Generation Connections	$ 188,892
Smart Grid/Self Healing Grid	$ 264,843
Replacements	$ 826,699
Emergencies	$ 144,474
Distribution Plant Total	**$ 5,154,015**

The following is a breakdown of Distribution Plant by category. Since values for 2017 are forecast only, they are not presented by account.

Residential Connections

Residential connections relate to the planned/forecast work required to facilitate connection of new residential customers to the distribution system as well as expand existing services, where required. In 2017, EPLC plans to invest $761,636 in residential connections where $375,000 relates to new connections and $386,636 relates to residential expansions. These values are based on historical spending and trending.

C&I Connections

C&I connections relate to the planned/forecasted work required to facilitate connection of new C&I customers to the distribution system as well as expand existing services, where required. In 2017, EPLC plans to invest $349,960 in C&I connections. These values are based on historical spending and trending.

Conversions

Conversion projects generally relate to upgrading existing 4kV/8kV distribution assets to 27.6kV. In 2017, EPLC plans to invest $1,847,151 in conversion projects. The following is a brief summary of planned conversion projects for 2017 which relate to the finalization of EPLC's Single Voltage Utility Initiative and the continuation of EPLC's Direct Buried Cable Replacement program:

- 8kV conversion from Gore to Dalhousie in Amherstburg. Removal of SD50002. Estimated cost of $425,000. This is a Single Voltage Utility Initiative;

- 4kV conversion of Main Street North in Amherstburg. Estimated cost $160,000. This is a Single Voltage Utility Initiative;

- Front road conversion in LaSalle. Estimated cost of $80,000. This is a Single Voltage Utility Initiative;

- Conversion of near end of life Direct Buried Cable, mainly located in residential backyards, allowed through easements, to front yard right of way. Estimated cost of $1,229,416. This is a Direct Buried Cable Replacement initiative;

Municipal Requests & Asset Purchases

Municipal Requests & Asset Purchases relate to planned/forecasted asset relocation work as well as asset purchases from HONI, where required. Types of asset relocations include road widening projects, right of way improvements, etc. EPLC typically sees one or two major municipal request per year.

EPLC also anticipates that HONI asset purchase will be required to facilitate long term load transfer removal as well to accommodate significant HONI work currently ongoing in the Leamington and Amherstburg service territories.

In 2017, EPLC plans to invest $770,360 in Municipal Requests & Asset Purchases where $600,000 relates to Municipal Requests and $170,360 relates to HONI asset purchase. These values are based on historical spending and trending.

FIT & Generation Connections

FIT & Generation connections relate to the planned/forecasted work required to facilitate connection of new FIT and other generation customers (ie. microFIT, net metering, merchant generation, etc.) to the distribution system. In 2017, EPLC plans to invest $188,892 in FIT & Generation connections. These values are based on historical spending and trending as well as known upcoming projects.

Smart Grid / Self-Healing Grid

Smart Grid / Self-Healing Grid refers to EPLC's planned investments to build a Self-Healing grid to reduce interruptions related to distribution/transmission plant owned by Hydro One. In 2017, EPLC plans to continue investing $264,843 in this initiative which largely relates to the installation and commissioning of reclosures at strategic points throughout its distribution system. More information can be found in EPLC's GEA Plan and DSP, included as Attachments in Exhibit 1 of this Application and as Attachment 2-C respectively.

Replacements

Replacement project generally relate to upgrading and/or replacing existing equipment that is either at end of life, not functioning as intended, damaged or deteriorated. In 2017, EPLC plans to invest $826,699 in replacement projects. The following is a brief summary of planned replacement projects for 2017:

- *Pole Replacement Program:* EPLC plans to replace approximately 119 poles in 2017 as part of its Pole Replacement Program. These poles were identified for replacement through EPLC's preventative maintenance program where core sampling was completed via pole drilling. EPLC's estimated cost in 2017 is $460,478;

- *Load Break Replacements:* EPLC has been slowly replacing approximately two load break switches per year to improve reliability, enhance distribution system operability and replace ageing assets. EPLC's estimated cost in 2017 is $58,752;

- PMH Replacement Program: Similarly to the Load Break Replacement program above, EPLC has been slowly replacing approximately two PMHs per year to improve reliability, enhance distribution system operability and replace ageing assets. EPLC's estimated cost in 2017 is $144,432;

- *Metering Upgrade & Replacement Program:* This program includes upgrading interval metering installations as a result of seal expiry, upgrades from A1R to A3R meters and GPRS upgrades for enhanced reliability and improved functionality, replacing smart meters, where required and replacing gatekeepers and modems for ongoing smart meter communication. EPLC's estimated cost in 2017 is $163,037;

Emergencies

Emergencies relate to the planned/forecasted work related to overhead and underground reactive replacements. In 2017, EPLC plans to invest $144,474 in Emergencies where $80,784 relates to forecasted overhead reactive replacements and $63,690 relates to forecasted underground reactive replacements. These values are based on historical spending and trending.

General Plant

Account 1908 – Building & Fixtures

EPLC is planning an increase of $286,804 in Account 1908 from 2016 Actual to the 2017 Bridge Year. Planned additions in 2017 include:

- Replace backup generator at operations center - $75k;
- Planned Rooftop HVAC maintenance - $36k;
- Operations Mapping Room Enhancements - $25k;
- Fleet garage drainage repair - $75k;
- New fencing at Leamington Pole Yard - $30k;
- A/C unit refurbishment in IT room - $19k;
- Miscellaneous Ops Center repairs/maintenance - $27k;

Account 1920 – Computer Equipment - Hardware

EPLC realized an increase of $356,150 in Account 1920 from 2016 Actual to 2017 Bridge Year. This variance is largely made up of the following items:

- Desktops/Laptops/Tablets/Toughbooks – $26k;
- Network/Security Appliances - $37k;
- Cybersecurity & GP Related Upgrade - $283k

In 2017, EPLC is investing in its Information Technology ("IT") infrastructure in order to be compliant with the Board's proposed Cybersecurity Framework (EB-2016-0032). For additional information about the capital requirements of the Cybersecurity Framework, please refer to EPLC's DSP which is included as Attachment 2-C of this Exhibit. The additional customer benefits of Cybersecurity Framework compliance include:

- Managed detection and response services;
- Network Interceptor Capabilities;
- Continuous Vulnerability Scanning;
- Threat Intelligence;
- Security Portal & Reporting;
- 24/7 Security Operations Centre;

Account 1930 – Transportation Equipment

EPLC is planning an increase of $487,000 in Account 1930 from 2016 Actual to the 2017 Bridge Year. Planned additions in 2017 include:

- Back RBD Truck - $250k;
- Purchase of UG Truck – $95k;
- Replacement of Truck #65 - 50k;
- Reel/Tensioner Trailer replacement - $80k;
- Yard ATV - $12k

Contributions & Grants

Account 1995 – Contributions & Grants

While this variance is above EPLC's materiality threshold, EPLC traditionally receives approximately $1.4M per year in Capital Contributions & Grants, on average. EPLC has budgeted conservative values of $1.22M for the Bridge and Test Years which are typical for years without large one time projects.

2017 Bridge Vs. 2018 Test

Figure 14 – 2017 Bridge vs. 2018 Test – By Account

USoA	Description	2017 Bridge	2018 Test	Variance
	Intangible Plant			
1611	Computer Software	$ 1,603,573	$ 1,718,573	$ 115,000
1612	Land Rights	$ 249,995	$ 298,936	$ 48,941
	Subtotal	**$ 1,853,568**	**$ 2,017,508**	**$ 163,941**
	Distribution Plant			
1805	Land	$ 35,899	$ 35,899	$ -
1806	Land Rights	$ -	$ -	$ -
1820	Distribution Station Equipment < 50 kV	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 9,829,756	$ 10,262,670	$ 432,914
1835	Overhead Conductors & Devices	$ 9,747,151	$ 10,586,627	$ 839,476
1840	Underground Conduit	$ 13,964,522	$ 14,829,081	$ 864,559
1845	Underground Conduit & Devices	$ 15,245,984	$ 16,099,450	$ 853,466
1850	Line Transformers	$ 20,326,051	$ 21,366,845	$ 1,040,794
1855	Services	$ 12,976,997	$ 13,777,367	$ 800,370
1860	Meters	$ 9,679,588	$ 9,945,259	$ 265,671
1860	Meters - Smart Meter Sub-Account	$ -	$ -	$ -
	Subtotal	**$ 91,805,949**	**$ 96,903,199**	**$ 5,097,250**
	General Plant			
1905	Land	$ 190,119	$ 190,119	$ -
1908	Building & Fixtures	$ 2,800,544	$ 3,170,540	$ 369,996
1915	Office Furniture & Equipment	$ 226,760	$ 236,760	$ 10,000
1920	Computer Equipment - Hardware	$ 844,851	$ 1,006,660	$ 161,809
1925	Computer Software	$ 585	$ 585	$ -
1930	Transportation Equipment	$ 2,868,417	$ 3,138,417	$ 270,000
1935	Stores Equipment	$ 97,367	$ 147,367	$ 50,000
1940	Tools, Shop & Garage Equipment	$ 624,329	$ 684,329	$ 60,000
1945	Measurement & Testing Equipment	$ 70,247	$ 70,247	$ -
1955	Communication Equipment	$ 294,423	$ 294,423	$ -
	Subtotal	**$ 8,017,642**	**$ 8,939,447**	**$ 921,805**
	Contributions & Grants			
1995	Contributions & Grants	$(19,790,893)	$(21,015,650)	$(1,224,757)
	Subtotal	**$(19,790,893)**	**$(21,015,650)**	**$(1,224,757)**
	Grand Total	**$ 81,886,267**	**$ 86,844,505**	**$ 4,958,239**

Intangible Plant

Account 1611 – Computer Software

EPLC is planning an increase of $115,000 in Account 1925 from 2017 Bridge Year to the 2018 Test Year. Planned additions in 2018 include:

- Utility Dashboard - $40k;
- ESRI ArcView/Arc Editor (GIS) Upgrade - $25k;
- New Work Estimator $30k;

Distribution Plant

EPLC plans to invest $5,146,191 in Distribution Plant assets in the 2018 Test Year. Between 2010 and 2016, EPLC invested, on average, approximately $5,378,730 per year. EPLC submits that its expected investments in Distribution Plant are in line with historical spending (slightly less) and therefore reasonable. Figure 15 below provides a summary of EPLC planned Distribution Plant investments.

Figure 15 – 2018 Test Year Distribution Plant

Description	2018 Test
Residential Connections	$ 776,869
C&I Connections	$ 356,959
Conversions	$ 2,224,410
Municipal Requests & Asset Purchases	$ 701,474
FIT & Generation Connections	$ 181,370
Smart Grid/Self Healing Grid	$ 270,140
Replacements	$ 487,606
Emergencies	$ 147,363
Distribution Plant Total	**$ 5,146,191**

The following is a breakdown of Distribution Plant by category. Since values for 2018 are forecasted only, they are not presented by account.

Residential Connections

Residential connections relate to the planned/forecasted work required to facilitate connection of new residential customers to the distribution system as well as expand existing services, where required. In 2018, EPLC plans to invest $776,869 in residential connections where $382,500 relates to new connections and $394,369 relates to residential expansions. These values are based on historical spending and trending.

C&I Connections

C&I connections relate to the planned/forecasted work required to facilitate connection of new C&I customers to the distribution system as well as expand existing services, where required. In 2018, EPLC plans to invest $356,959 in C&I connections. These values are based on historical spending and trending.

Conversions

Conversion projects generally relate to upgrading existing 4kV/8kV distribution assets to 27.6kV. In 2018, EPLC plans to invest $2,224,410 in conversion projects which related to the e continuation of EPLC's Direct Buried Cable Replacement program. The Direct Buried Cable Replacement program converts near end of life Direct Buried Cable, mainly located in residential backyards, allowed through easements, to front yard right of way.

Municipal Requests & Asset Purchases

Municipal Requests & Asset Purchases relate to planned/forecasted asset relocation work as well as asset purchases from HONI, where required. Types of asset relocations include road widening projects, right of way improvements, etc. EPLC typically sees one or two major municipal request per year.

EPLC also anticipates that HONI asset purchase will be required to facilitate long term load transfer removal as well to accommodate significant HONI work currently ongoing in the Leamington area.

In 2018, EPLC plans to invest $701,474 in Municipal Requests & Asset Purchases where $612,000 relates to Municipal Requests and $89,474 relates to HONI asset purchase. These values are based on historical spending and trending.

FIT & Generation Connections

FIT & Generation connections relate to the planned/forecasted work required to facilitate connection of new FIT and other generation customers (ie. microFIT, net metering, merchant generation, etc.) to the distribution system. In 2018, EPLC plans to invest $181,370 in FIT & Generation connections. These values are based on historical spending and trending as well as known upcoming projects.

Smart Grid / Self-Healing Grid

Smart Grid / Self-Healing Grid refers to EPLC's planned investments to build a Self-Healing grid to reduce interruptions related to distribution/transmission plant owned by Hydro One. In 2018, EPLC plans to continue investing $270,140 in this initiative which largely relates to the installation and commissioning of reclosures at strategic points throughout its distribution system. More information can be found in EPLC's GEA Plan and DSP, included as Attachments in Exhibit 1 of this Application and as Attachment 2-C respectively.

Replacements

Replacement project generally relate to upgrading and/or replacing existing equipment that is either at end of life, not functioning as intended, damaged or deteriorated. In 2018, EPLC plans to invest $487,606 in replacement projects. The following is a brief summary of planned replacement projects for 2018:

- *Pole Replacement Program:* EPLC plans to replace approximately 29 poles in 2018 as part of its Pole Replacement Program. These poles were identified for replacement through EPLC's preventative maintenance program where core sampling was completed via pole drilling. EPLC's estimated cost in 2018 is $114,062;

- *Load Break Replacements:* EPLC has been slowly replacing approximately two load break switches per year to improve reliability, enhance distribution system operability and replace ageing assets. EPLC's estimated cost in 2018 is $59,927;

- PMH Replacement Program: Similarly to the Load Break Replacement program above, EPLC has been slowly replacing approximately two PMHs per year to improve reliability, enhance distribution system operability and replace ageing assets. EPLC's estimated cost in 2018 is $147,321;

- *Metering Upgrade & Replacement Program:* This program includes upgrading interval metering installations as a result of seal expiry, upgrades from A1R to A3R meters and GPRS upgrades for enhanced reliability and improved functionality, replacing smart meters, where required and replacing gatekeepers and modems for ongoing smart meter communication. EPLC's estimated cost in 2018 is $166,297;

Emergencies

Emergencies relate to the planned/forecasted work related to overhead and underground reactive replacements. In 2018, EPLC plans to invest $147,363 in Emergencies where $82,400 relates to forecasted overhead reactive replacements and $64,964 relates to forecasted underground reactive replacements. These values are based on historical spending and trending.

General Plant

Account 1908 – Building & Fixtures

EPLC is planning an increase of $369,996 in Account 1908 from the 2017 Bridge Year to the 2018 Test Year. Planned additions in 2018 include:

- Storage Pole Barn for fleet - $300k;
- Miscellaneous Ops Center repairs/maintenance - $70k;

Additional information about EPLC's planned spending for account 1908 for the 2018 Test Year can be found in EPLC's DSP as Attachment 2-C.

Account 1920 – Computer Equipment - Hardware

EPLC realized an increase of $161,809 in Account 1920 from 2017 Bridge Year to 2018 Test Year. This variance is made up of the following items:

- Desktops/Laptops/Tablets/Toughbooks – $21k;
- Network/Security Appliances - $10k;
- Cybersecurity & GP Related Upgrade - $130k

In 2018, EPLC is planning on finalizing its initial investment in its IT infrastructure in order to be compliant with the Board's proposed Cybersecurity Framework (EB-2016-0032). For additional

information about the capital requirements of the Cybersecurity Framework, please refer to EPLC's DSP which is included as Attachment 2-C of this Exhibit. The additional customer benefits of Cybersecurity Framework compliance include:

- Managed detection and response services;
- Network Interceptor Capabilities;
- Continuous Vulnerability Scanning;
- Threat Intelligence;
- Security Portal & Reporting;
- 24/7 Security Operations Centre;

Account 1930 – Transportation Equipment

EPLC is planning an increase of $270,000 in Account 1930 from the 2017 Bridge Year to the 2018 Test Year. Planned additions in 2018 include:

- Replacement of Truck #66 – $50k;
- Replacement of Truck #68 – $95k
- Replacement of Truck #69 - $95k
- Replacement of Chipper - $30k

Additional information about EPLC's fleet management and 2018 Test Year spending can be found in EPLC's DSP as Attachment 2-C.

Contributions & Grants

Account 1995 – Contributions & Grants

While this variance is above EPLC's materiality threshold, EPLC traditionally receives approximately $1.4M per year in Capital Contributions & Grants, on average. EPLC has budgeted conservative values of $1.22M for the Bridge and Test Years which are typical for years without large one time projects.

2.3 Incremental Capital Module Adjustments

EPLC confirms that it has not received any Incremental Capital Module ("ICM") adjustments as part of any previous IRM application.

EPLC is in consultation with HONI as it relates to the construction of Leamington TS. Once costs and allocations are known and better defined, EPLC plans on submitting an ICM as part of that year's IRM application.

2.4 Allowance for Working Capital

2.4.1 Overview

On June 3rd, 2015, the Board issued an update to Electricity Distributors with the following direction related to the calculation of Working Capital Allowance:

"Effective immediately, the OEB is adopting a new default value of 7.5% of the sum of the cost of power and operating, maintenance and administration costs. As in the past, distributors who not wish to use the default value can request approval for a distributor-specific working capital allowance supported by the appropriate evidence from a lead-lag study or equivalent analysis."

In accordance with the Board's direction, EPLC is using the default value of 7.5% of the sum of the cost of power and operating, maintenance and administration costs. EPLC proposes a Working Capital Allowance of $5,705,908 outlined further below as Figure 16.

Figure 16 – EPLC Working Capital Summary

Description	2010 BAP	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Accounting Standard	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Operations	$ 1,111,126	$ 740,910	$ 886,624	$ 1,029,174	$ 989,797	$ 1,328,451	$ 1,174,581	$ 1,050,289	$ 923,551	$ 1,180,903
Maintenance	$ 1,517,732	$ 1,444,596	$ 1,425,359	$ 1,740,450	$ 1,274,077	$ 1,245,495	$ 1,594,293	$ 1,439,707	$ 1,188,941	$ 1,204,436
Billing & Collecting	$ 1,459,419	$ 1,285,533	$ 1,107,563	$ 1,157,794	$ 1,322,080	$ 1,158,128	$ 1,221,816	$ 1,348,249	$ 1,499,880	$ 1,550,150
Community Relations	$ 43,646	$ 36,522	$ 35,088	$ 25,312	$ 16,142	$ 10,016	$ 19,873	$ 6,482	$ 23,442	$ 23,396
Admin & General	$ 2,068,443	$ 1,970,775	$ 2,092,295	$ 2,240,566	$ 2,400,175	$ 2,948,703	$ 2,740,229	$ 3,123,469	$ 3,563,129	$ 3,751,390
Property Taxes	$ 85,824	$ 68,136	$ 43,471	$ 43,122	$ 45,301	$ 44,568	$ 41,843	$ 41,042	$ 42,621	$ 42,538
Total Controllable Costs	**$ 6,286,190**	**$ 5,546,471**	**$ 5,590,400**	**$ 6,236,418**	**$ 6,047,573**	**$ 6,748,787**	**$ 6,806,061**	**$ 7,022,665**	**$ 7,254,991**	**$ 7,752,813**
Cost of Power	$ 47,783,568	$ 49,232,444	$ 51,143,998	$ 52,354,545	$ 51,542,202	$ 57,503,389	$ 62,236,119	$ 71,601,477	$ 67,716,983	$ 68,325,958
Total Working Capital	**$54,069,758**	**$54,778,916**	**$56,734,399**	**$58,590,963**	**$57,589,775**	**$64,252,177**	**$69,042,180**	**$78,624,142**	**$74,971,974**	**$76,078,771**
Allowance Factor	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	7.50%
Working Capital Allowance	**$ 8,110,464**	**$ 8,216,837**	**$ 8,510,160**	**$ 8,788,644**	**$ 8,638,466**	**$ 9,637,826**	**$10,356,327**	**$11,793,621**	**$11,245,796**	**$ 5,705,908**

2.4.2 Controllable Costs

In order to calculate EPLC's proposed WCA, EPLC has utilized its expected Operations, Maintenance, Billing & Collecting, Community Relations, Admin & General, property taxes and annual LEAP contributions. For additional information about EPLC's OM&A expenses, please refer to Exhibit 4 of this Application.

EPLC has included forecasted LEAP contributions by multiplying its projected 2018 Test Year Service Revenue Requirement of $13,162,895 by 0.12%. Further details about the calculation of LEAP contributions can also be found in Exhibit 4 of this Application.

2.4.3 Cost of Power

Overview

EPLC has calculated its Cost of Power ("COP") for the 2018 Test Year based on its load forecast outlined in Exhibit 3 of this Application. EPLC's load forecast has been adjusted to account for savings related to Conservation & Demand Management initiatives. Figure 17 below outlines EPLC's 2010 BAP amounts, historical balances from 2010 through 2016 and projections for the 2017 Bridge and 2018 Test Years.

Figure 17 – Cost of Power Summary

Account	Description	2010 BAP	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
4705	Power Purchased	$ 37,397,381	$ 39,264,299	$ 40,910,118	$ 41,969,005	$ 34,467,556	$ 36,636,537	$ 36,289,026	$ 40,684,266	$ 14,422,756	$ 14,148,136
4707	Global Adjustment	$ -	$ -	$ -	$ -	$ 8,069,903	$ 12,453,890	$ 17,969,068	$ 22,465,594	$ 47,475,132	$ 46,571,172
4708	WMS & RRRP	$ 4,029,222	$ 3,869,446	$ 3,686,258	$ 3,771,378	$ 2,288,747	$ 2,261,797	$ 2,120,790	$ 2,969,459	$ 2,136,299	$ 2,095,622
4714	RTSR - Network	$ 3,061,960	$ 2,943,206	$ 3,367,535	$ 3,606,709	$ 3,821,304	$ 3,498,236	$ 3,473,406	$ 3,085,440	$ 2,480,774	$ 2,170,307
4716	RTSR - Connection	$ 2,764,186	$ 2,615,703	$ 2,675,457	$ 2,500,551	$ 2,401,567	$ 2,159,619	$ 1,887,852	$ 1,848,460	$ 1,651,540	$ 1,537,179
4750	Low Voltage	$ 530,819	$ 539,791	$ 504,630	$ 506,902	$ 493,126	$ 493,310	$ 495,977	$ 548,257	$ 507,088	$ 1,524,252
4751	Smart Metering Entity					$ 46,735	$ 40,253	$ (9,827)	$ (39,364)	$ 277,527	$ 279,290
Total		$ 47,783,568	$ 49,232,444	$ 51,143,998	$ 52,354,545	$ 51,588,937	$ 57,543,642	$ 62,226,291	$ 71,562,114	$ 68,951,117	$ 68,325,958

Power Purchased

EPLC used the "Regulated Price Plan Report – May 1 2017 to April 30 2018" (dated April 20th, 2017), published by the Board, to calculate the commodity price used for this Application. Figure 18 below outlines the information that EPLC used, more specifically from Table ES-1 on page 4 of the Board's report.

Figure 18 – Commodity Price

RPP Supply Cost Summary for the period from May 1, 2017 through April 30, 2018		
Forecast Wholesale Electricity Price		$ 22.81
Load-Weighted Price for RPP Consumers ($/MWh)		$ 24.83
Impact of the Global Adjustment ($/MWh)	+	$ 87.67
Adjustment to Address Bias Towards Unfavourable Variance ($/MWh)	+	$ 1.00
Adjustment to Clear Existing Variance ($/MWh)	+	$ 1.40
Average Supply Cost for RPP Consumers ($/MWh)	**=**	**$ 114.90**

EPLC used its 2016 actual consumption for both RPP and non-RPP to calculate the weighted average rate ($0.1130/kWh) summarized below in Figure 19.

Figure 19 – Commodity Price

Rate Class	RPP kWh	Non-RPP kWh	Total kWh
Residential	243,846,775	11,543,647	255,390,422
General Service < 50 kW	48,730,479	18,078,514	66,808,993
General Service > 50 to 4999 kW	21,566,532	198,051,917	219,618,449
Unmetered Scattered Load	1,086,503	467,865	1,554,368
Sentinel Lighting	306,413	29,345	335,758
Street Lighting	-	4,268,688	4,268,688
Embedded Distributor	-	-	-
Total	**315,536,702**	**232,439,976**	**547,976,678**
Allocation %	57.58%	42.42%	100.00%
Commodity Rate ($/kWh)	$ 0.1149	$ 0.1105	
Weighted Average Rate ($/kWh)	**$ 0.0662**	**$ 0.0469**	**$ 0.1130**

EPLC understands that these values can be updated to reflect more current projections prior to the approval of this Application.

Regulatory Charges

For both the 2017 Bridge Year and 2018 Test Year and as per the Decision and Order resulting from EB-2016-0362 (December 15th, 2016), EPLC used $0.0036 for Wholesale Market Service Charge ("WMS").

For both the 2017 Bridge Year and 2018 Test Year and as per the Decision and Order resulting from EB-2017-0234 (June 22nd, 2017), EPLC used $0.0003 for Rural or Remote Rate Protection ("RRRP").

Smart Metering Entity

EPLC's Smart Metering Entity ("SME") costs are calculated based on the Board approved rate of $0.79 per customer per month for all Residential and General Service < 50 kW customers as per EB-2012-0100/EB-2012-0211 (March 28th, 2013). This charge is in effect until October 31st, 2018 or as further directed by the Board.

Low Voltage

In order to calculate the 2017 Bridge Year Low Voltage charges, EPLC utilized its 2017 IRM Board approved rates (EB-2016-0069) and the results of the 2017 load forecast. The resulting charges are summarized below in Figure 20.

Figure 20 – 2017 LV Charges

Rate Class	2017 BAP LV Charges	
	kWh	kW
Residential	$ 0.0010	
General Service < 50 kW	$ 0.0010	
General Service > 50 to 4999 kW		$ 0.3506
Unmetered Scattered Load	$ 0.0010	
Sentinel Lighting		$ 0.2816
Street Lighting		$ 0.2798
Embedded Distributor		$ 0.3506

In order to calculate the proposed 2018 Test Year Low Voltage charges, EPLC utilized the processes outlined in Exhibit 8, Section 8.3. The resulting charges are summarized below in Figure 21.

Figure 21 – 2018 Proposed Low Voltage Charges

Rate Class	2018 Proposed Low Voltage	
	kWh	kW
Residential	$ 0.0031	
General Service < 50 kW	$ 0.0030	
General Service > 50 to 4999 kW		$ 1.2718
Unmetered Scattered Load	$ 0.0030	
Sentinel Lighting		$ 0.8743
Street Lighting		$ 0.8686
Embedded Distributor		$ -

RTSR Charges

In order to calculate the 2017 Bridge Year RTSR charges, EPLC utilized its 2017 IRM Board approved rates (EB-2016-0069) and the results of the 2017 load forecast. For the 2018 Test Year, EPLC utilized the RTSR rates calculated in Exhibit 8, section 8.4. The resulting calculations are summarized below as Figure 22.

Figure 22 – 2018 Proposed RTSR Charges

Rate Class	Unit	Proposed Network	Proposed Line & Connection
Residential	kWh	$ 0.0046	$ 0.0030
General Service Less Than 50 kW	kWh	$ 0.0039	$ 0.0029
General Service 50 to 4,999 kW	kW	$ 1.6326	$ 1.1567
General Service 50 to 4,999 kW – Interval Metered	kW	$ 2.0111	$ 1.2826
Unmetered Scattered Load	kWh	$ 0.0039	$ 0.0029
Sentinel Lighting	kW	$ 1.2569	$ 0.8817
Street Lighting	kW	$ 1.2393	$ 0.8760
Embedded Distributor	N/A	N/A	N/A

Cost of Power Calculations

Figure 23 below summarizes EPLC's calculation of its proposed 2017 Bridge Year and 2018 Test Year Cost of Power used for its WCA.

Figure 23 – Proposed Cost of Power - 2017/2018

Rate Class	2017 Bridge					2018 Test				
	Load Forecast	Loss Factor	Billing Determinant	Rate	Amount	Load Forecast	Loss Factor	Billing Determinant	Rate	Amount
Commodity										
Residential	247,700,344	1.0355	256,493,706	$ 0.1130	$ 28,983,789	245,374,118	1.0355	254,084,899	$ 0.1130	$ 28,711,594
General Service Less Than 50 kW	65,087,892	1.0355	67,398,512	$ 0.1130	$ 7,616,032	62,707,450	1.0355	64,933,564	$ 0.1130	$ 7,337,493
General Service 50 to 4,999 kW	179,829,958	1.0355	186,213,922	$ 0.1130	$ 21,042,173	176,280,306	1.0355	182,538,257	$ 0.1130	$ 20,626,823
Unmetered Scattered Load	1,554,368	1.0355	1,609,548	$ 0.1130	$ 181,879	1,554,368	1.0355	1,609,548	$ 0.1130	$ 181,879
Sentinel Lighting	335,758	1.0355	347,677	$ 0.1130	$ 39,288	335,758	1.0355	347,677	$ 0.1130	$ 39,288
Street Lighting	2,799,882	1.0355	2,899,278	$ 0.1130	$ 327,618	2,799,882	1.0355	2,899,278	$ 0.1130	$ 327,618
Embedded Distributor	31,681,583	1.0355	32,806,279	$ 0.1130	$ 3,707,110	29,865,554	1.0355	30,925,781	$ 0.1130	$ 3,494,613
Total					**$ 61,897,888**					**$ 60,719,308**
Regulatory Charges										
Residential	247,700,344	1.0355	256,493,706	$ 0.0039	$ 1,000,325	245,374,118	1.0355	254,084,899	$ 0.0039	$ 990,931
General Service Less Than 50 kW	65,087,892	1.0355	67,398,512	$ 0.0039	$ 262,854	62,707,450	1.0355	64,933,564	$ 0.0039	$ 253,241
General Service 50 to 4,999 kW	179,829,958	1.0355	186,213,922	$ 0.0039	$ 726,234	176,280,306	1.0355	182,538,257	$ 0.0039	$ 711,899
Unmetered Scattered Load	1,554,368	1.0355	1,609,548	$ 0.0039	$ 6,277	1,554,368	1.0355	1,609,548	$ 0.0039	$ 6,277
Sentinel Lighting	335,758	1.0355	347,677	$ 0.0039	$ 1,356	335,758	1.0355	347,677	$ 0.0039	$ 1,356
Street Lighting	2,799,882	1.0355	2,899,278	$ 0.0039	$ 11,307	2,799,882	1.0355	2,899,278	$ 0.0039	$ 11,307
Embedded Distributor	31,681,583	1.0355	32,806,279	$ 0.0039	$ 127,944	29,865,554	1.0355	30,925,781	$ 0.0039	$ 120,611
Total					**$ 2,136,299**					**$ 2,095,622**
Smart Metering Entity										
Residential	27,310		27,310	$ 0.7900	$ 258,899	27,484		27,484	$ 0.7900	$ 260,548
General Service Less Than 50 kW	1,965		1,965	$ 0.7900	$ 18,628	1,977		1,977	$ 0.7900	$ 18,742
General Service 50 to 4,999 kW	-		-	$ -	$ -	-		-	$ -	$ -
Unmetered Scattered Load	-		-	$ -	$ -	-		-	$ -	$ -
Sentinel Lighting	-		-	$ -	$ -	-		-	$ -	$ -
Street Lighting	-		-	$ -	$ -	-		-	$ -	$ -
Embedded Distributor	-		-	$ -	$ -	-		-	$ -	$ -
Total					**$ 277,527**					**$ 279,290**
Low Voltage Charges										
Residential	247,700,344	1.0000	247,700,344	$ 0.0010	$ 247,700	245,374,118	1.0000	245,374,118	$ 0.0031	$ 755,844
General Service Less Than 50 kW	65,087,892	1.0000	65,087,892	$ 0.0010	$ 65,088	62,707,450	1.0000	62,707,450	$ 0.0030	$ 186,724
General Service 50 to 4,999 kW	455,239	1.0000	455,239	$ 0.3506	$ 159,607	446,253	1.0000	446,253	$ 1.2718	$ 567,551
Unmetered Scattered Load	1,554,368	1.0000	1,554,368	$ 0.0010	$ 1,554	1,554,368	1.0000	1,554,368	$ 0.0030	$ 4,628
Sentinel Lighting	2,080	1.0000	2,080	$ 0.2816	$ 586	2,080	1.0000	2,080	$ 0.8743	$ 1,819
Street Lighting	8,848	1.0000	8,848	$ 0.2798	$ 2,476	8,848	1.0000	8,848	$ 0.8686	$ 7,686
Embedded Distributor	85,786	1.0000	85,786	$ 0.3506	$ 30,077	80,869	1.0000	80,869	$ -	$ -
Total					**$ 507,088**					**$ 1,524,252**
RTSR - Network										
Residential	247,700,344	1.0355	256,493,706	$ 0.0048	$ 1,231,170	245,374,118	1.0355	254,084,899	$ 0.0046	$ 1,168,791
General Service Less Than 50 kW	65,087,892	1.0355	67,398,512	$ 0.0041	$ 276,334	62,707,450	1.0355	64,933,564	$ 0.0039	$ 253,241
General Service 50 to 4,999 kW	455,239	1.0000	455,239	$ 2.0924	$ 952,543	446,253	1.0000	446,253	$ 1.9912	$ 888,580
Unmetered Scattered Load	1,554,368	1.0355	1,609,548	$ 0.0041	$ 6,599	1,554,368	1.0355	1,609,548	$ 0.0039	$ 6,277
Sentinel Lighting	2,080	1.0000	2,080	$ 1.3077	$ 2,720	2,080	1.0000	2,080	$ 1.2444	$ 2,588
Street Lighting	8,848	1.0000	8,848	$ 1.2894	$ 11,409	8,848	1.0000	8,848	$ 1.2270	$ 10,856
Embedded Distributor	85,786	1.0000	85,786	$ -	$ -	80,869	1.0000	80,869	$ -	$ -
Total					**$ 2,480,775**					**$ 2,330,333**
RTSR - Connection										
Residential	247,700,344	1.0355	256,493,706	$ 0.0032	$ 820,780	245,374,118	1.0355	254,084,899	$ 0.0030	$ 762,255
General Service Less Than 50 kW	65,087,892	1.0355	67,398,512	$ 0.0030	$ 202,196	62,707,450	1.0355	64,933,564	$ 0.0029	$ 188,307
General Service 50 to 4,999 kW	455,239	1.0000	455,239	$ 1.3480	$ 613,663	446,253	1.0000	446,253	$ 1.2826	$ 572,365
Unmetered Scattered Load	1,554,368	1.0355	1,609,548	$ 0.0030	$ 4,829	1,554,368	1.0355	1,609,548	$ 0.0029	$ 4,668
Sentinel Lighting	2,080	1.0000	2,080	$ 0.9267	$ 1,928	2,080	1.0000	2,080	$ 0.8817	$ 1,834
Street Lighting	8,848	1.0000	8,848	$ 0.9207	$ 8,147	8,848	1.0000	8,848	$ 0.8760	$ 7,751
Embedded Distributor	85,786	1.0000	85,786	$ -	$ -	80,869	1.0000	80,869	$ -	$ -
Total					**$ 1,651,541**					**$ 1,537,179**
Grand Total					**$ 68,951,118**					**$ 68,485,984**

2.4.4 Variance Analysis on Working Capital Allowance

EPLC has calculated year over year variances for its WCA. Figure 24 below details EPLC's calculation. This section will discuss variances in excess of EPLC's calculated materiality threshold which is discussed in Exhibit 1 of this Application.

Figure 24 – Working Capital Variance Analysis

Description	2010 BAP	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Accounting Standard	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Total Controllable Expenses	$ 6,286,190	$ 5,546,471	$ 5,590,400	$ 6,236,418	$ 6,047,573	$ 6,735,361	$ 6,792,635	$ 7,009,238	$ 7,241,564	$ 7,752,813
Total Cost of Power	$ 47,783,568	$ 49,232,444	$ 51,143,998	$ 52,354,545	$ 51,542,202	$ 57,503,389	$ 62,236,119	$ 71,601,477	$ 67,716,983	$ 68,325,958
Total Working Capital	**$ 54,069,758**	**$ 54,778,916**	**$ 56,734,399**	**$ 58,590,963**	**$ 57,589,775**	**$ 64,238,750**	**$ 69,028,753**	**$ 78,610,715**	**$ 74,958,547**	**$ 76,078,771**
Allowance Factor	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	7.50%
Working Capital Allowance	**$ 8,110,464**	**$ 8,216,837**	**$ 8,510,160**	**$ 8,788,644**	**$ 8,638,466**	**$ 9,635,812**	**$ 10,354,313**	**$ 11,791,607**	**$ 11,243,782**	**$ 5,705,908**
Variances		**2010 BAP vs. 2010 Actual**	**2010 Actual vs. 2011 Actual**	**2011 Actual vs. 2012 Actual**	**2012 Actual vs. 2013 Actual**	**2013 Actual vs. 2014 Actual**	**2014 Actual vs. 2015 Actual**	**2015 Actual vs. 2016 Actual**	**2016 Actual vs. 2017 Bridge**	**2017 Bridge vs. 2018 Test**
Total Controllable Expenses		$ (739,719)	$ 43,929	$ 646,018	$ (188,845)	$ 687,788	$ 57,274	$ 216,603	$ 232,326	$ 511,249
Total Cost of Power		$ 1,448,876	$ 1,911,554	$ 1,210,546	$ (812,342)	$ 5,961,187	$ 4,732,729	$ 9,365,359	$ (3,884,494)	$ 608,975
Total Working Capital		**$ 709,158**	**$ 1,955,483**	**$ 1,856,564**	**$ (1,001,188)**	**$ 6,648,975**	**$ 4,790,003**	**$ 9,581,962**	**$ (3,652,168)**	**$ 1,120,224**
Allowance Factor		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-7.50%
Working Capital Allowance		**$ 106,374**	**$ 293,322**	**$ 278,485**	**$ (150,178)**	**$ 997,346**	**$ 718,501**	**$ 1,437,294**	**$ (547,825)**	**$ (5,537,874)**

2010 BAP Vs. 2010 Actual

EPLC has calculated a net increase in WCA of $106,374 between the 2010 BAP and 2010 Actual results. This increase is a result of a significant increase to the Cost of Power, driven almost entirely by increases to the commodity cost of electricity (increase of $0.0060/kWh increase). The Cost of Power increase is offset by reductions to Controllable Expenses, driven mainly by efficiencies realized in the Operations department. EPLC's purchased kWh also decreased by 23,336,596 kWh.

2010 Actual Vs. 2011 Actual

EPLC has calculated a net increase in WCA of $293,322 between the 2010 Actual and 2011 Actual results. This increase is a result of a significant increase to the Cost of Power, driven almost entirely by increases to the commodity cost of electricity (increase of $0.0061/kWh). Increases to Controllable Expenses are not material. EPLC's purchased kWh also decreased by 16,048,761 kWh.

2011 Actual Vs. 2012 Actual

EPLC has calculated a net increase in WCA of $278,485 between the 2011 Actual and 2012 Actual results. This increase is a result of an increase to the Cost of Power, driven primarily by increases to the commodity cost of electricity (increase of $0.0054/kWh). EPLC's Controllable Costs increased by approximately $646k as a result of an increase in maintenance expense related to EPLC's voltage conversion initiative. EPLC's purchased kWh also decreased by 17,775,640 kWh.

2012 Actual Vs. 2013 Actual

EPLC has calculated a net decrease in WCA of $150,178 between the 2012 Actual and 2013 Actual results. This decrease is a result of a decrease to EPLC's average Cost of Power, driven primarily by a decrease in the commodity cost of electricity (decrease of $0.0013/kWh). EPLC's Controllable Costs also decreased largely as a result of a reduction/normalization of maintenance work related to EPLC's voltage conversion initiative. EPLC's purchased kWh also decreased marginally by 1,467,829 kWh.

2013 Actual Vs. 2014 Actual

EPLC has calculated a net increase in WCA of $999,360 between the 2013 Actual and 2014 Actual results. This increase is a result of an increase to the Cost of Power, driven primarily by increases to the commodity cost of electricity (increase of $0.0119/kWh). EPLC's Controllable Costs increased by approximately $701k as a result of an increase to Employee Pensions and Benefit allocations and the new bargaining unit contract terms coming into effect. EPLC's purchased kWh also decreased by 2,907,398 kWh.

2014 Actual Vs. 2015 Actual

EPLC has calculated a net increase in WCA of $718,501 between the 2014 Actual and 2015 Actual results. This increase is a result of an increase to the Cost of Power, driven primarily by increases to the commodity cost of electricity (increase of $0.0078/kWh Increases to Controllable Expenses are not material. EPLC's purchased kWh also increased by 5,596,628 kWh.

2015 Actual Vs. 2016 Actual

EPLC has calculated a net increase in WCA of $1,437,294 between the 2015 Actual and 2016 Actual results. This increase is a result of an increase to the Cost of Power, driven primarily by increases to the commodity cost of electricity (increase of $0.0130/kWh). Increases to Controllable Expenses are as a result of increases to Admin & General which are largely related to restructuring of EPLC management staff. Further information can be found in Exhibit 4 of this Application. EPLC's purchased kWh also increased by 19,233,823 kWh.

2016 Actual Vs. 2017 Bridge Year

EPLC has calculated a net decrease in WCA of $547,825 between the 2016 Actual results and 2017 Bridge Year forecast. This decrease is in small part a result of a decrease to the commodity portion of the cost of electricity (decrease of $0.0027/kWh). The WCA decrease is primarily driven by an expected decrease to EPLC's purchased kWh by 18,986,893. Increases to Controllable Expenses are mainly the result of incremental third party work required in IT to accommodate the Board's Cyber Security Framework. Further information can be found in Exhibit 4 of this Application.

2017 Actual Vs. 2018 Test Year

EPLC has calculated a net decrease in WCA of $5,537,874 between the 2017 Bridge Year and 2018 Test Year forecasts. This decrease is primarily driven by a decrease in the Working Capital Allowance factor from 15% to 7.5% as prescribed by the Board. Increases to Controllable Expenses are mainly the result of incremental third party work required in IT to accommodate the Board's Cyber Security Framework. Further information can be found in Exhibit 4 of this Application.

2.5 Treatment of Stranded Meter Assets

2.5.1 Overview

As part of the 2015 IRM (EB-2014-0072), EPLC applied for final disposition of Smart Metering Costs. Also in its 2015 IRM, EPLC stated that stranded meters would be brought forward at its next Cost of Service Application.

In this Application, EPLC is seeking disposition of $1,095,650 which represents the Net Book Value of stranded metering assets as at April 30th, 2018.

EPLC has prepared this section in accordance with the Board's *Guideline G-2011-0001, Smart Meter Funding and Cost Recovery – Final Disposition (December 15th, 2011)*.

As per Appendix A-1 of Board Guideline G-2011-0001, EPLC left stranded meters in Account 1860 and in Rate Base. The amount used in the calculation of stranded meters is based on balances accumulated in Account 1860 including labour, labour overhead, materials and expenses and vehicle related expenses, all allocated at standard EPLC rates. EPLC has been diligent in the deployment of smart meters as indicated by its installed cost below the provincial average.

Accumulated amortization of stranded metering assets was derived by estimating the year of installation, factoring the actual year of removal and using a 25 year useful life up to April 30th, 2018.

No carrying charges have been recorded for stranded metering assets, in accordance with the Accounting Procedures Handbook.

2.5.2 Stranded Meter Treatment

In accordance with Board Appendix 2-S, EPLC's proposed treatment of stranded meters is summarized below as Figure 25. The actual Board Appendix 2-S is also included as Attachment 2-B of this Exhibit.

Figure 25 –Treatment of Stranded Meters

Year	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
	(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2008	$ 65,437	$ 34,414		$ 31,023		$ 31,023
2009	$1,224,257	$ 359,336		$ 864,921		$ 864,921
2010	$2,328,222	$ 695,859		$ 1,632,363		$ 1,632,363
2011	$2,617,818	$ 858,988		$ 1,758,830		$ 1,758,830
2012	$2,617,818	$ 963,700		$ 1,654,118		$ 1,654,118
2013	$2,617,818	$ 1,068,413		$ 1,549,405		$ 1,549,405
2014	$2,617,818	$ 1,173,126		$ 1,444,692		$ 1,444,692
2015	$2,617,818	$ 1,277,838		$ 1,339,980		$ 1,339,980
2016	$2,617,818	$ 1,382,551		$ 1,235,267		$ 1,235,267
2017	$2,617,818	$ 1,487,264		$ 1,130,554		$ 1,130,554
2018	$2,617,818	$ 1,522,168		$ 1,095,650		$ 1,095,650

EPLC has included a proposed Rate Rider for the recovery of the $1,095,650 outlined in Figure 23 above. Further details are included in Exhibit 9 of this Application.

2.6 Capital Expenditures

2.6.1 Overview

In this section, EPLC has organized its capital expenditures in accordance with the work program categories in the Board's *"Filing Requirements for Electricity Distribution and Transmission Applications, Consolidated Distribution System Plan Filing Requirements"* (March 28th, 2013). Those categories are:

- System Access;
- System Renewal;
- System Service;
- General Plant;

Consistent with its DSP (Attachment 2-C), EPLC has, to the best of its ability, organized its planned spending by category as well as included an analysis of historical spending from 2010 through to the 2018 Test Year below.

EPLC actively participates in a variety of asset management and planning related initiatives within its communities and as a regional distributor. EPLC participates in Group 1 (Windsor/Essex) of the IESO's regional planning groups and also regularly meets with other entities such HONI, Union Gas, Bell, Cogeco Cable, IESO, various Provincial Ministries as well as the four municipal communities that it services. Also included in EPLC's DSP is coordinated infrastructure planning with third parties such as HONI.

EPLC is not planning any renewable energy generation capacity upgrades for the 2018 Test Year.

It should be noted that values in this section represent capital additions and does not consider Work In Progress, unless explicitly referenced.

2.6.2 Analysis of Capital Expenditures

Figure 26 below provides an overview of EPLC's historical capital expenditures by prescribed category for the years 2010 through 2017.

Figure 26 – Historical Capital Expenditure Summary

Category	2010		2011		2012		2013		2014		2015		2016		2017	
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Budget
	$ '000		$ '000		$ '000		$ '000		$ '000		$ '000		$ '000		$ '000	
System Access	Note 1	$ 1,928	Note 1	$ 1,502	Note 1	$ 1,717	Note 1	$ 1,766	Note 1	$ 2,532	Note 1	$ 2,341	Note 1	$ 1,759	Note 1	$ 1,712
System Renewal	Note 1	$ 1,675	Note 1	$ 1,833	Note 1	$ 2,698	Note 1	$ 3,113	Note 1	$ 3,012	Note 1	$ 2,695	Note 1	$ 2,125	Note 1	$ 2,655
System Service	Note 1	$ 693	Note 1	$ 940	Note 1	$ 885	Note 1	$ 185	Note 1	$ 177	Note 1	$ 2,196	Note 1	$ 1,005	Note 1	$ 787
General Plant	Note 1	$ 960	Note 1	$ 251	Note 1	$ 1,272	Note 1	$ 450	Note 1	$ 487	Note 1	$ 547	Note 1	$ 384	Note 1	$ 1,504
Total Expenditure	**$ -**	**$ 5,255**	**$-**	**$ 4,526**	**$-**	**$ 6,572**	**$-**	**$ 5,513**	**$-**	**$ 6,208**	**$-**	**$ 7,779**	**$-**	**$ 5,274**	**$ -**	**$ 6,658**
System OM&A	Note 1	$ 5,480	Note 1	$ 5,547	Note 1	$ 6,193	Note 1	$ 6,027	Note 1	$ 6,704	Note 1	$ 6,764	Note 1	$ 6,982	Note 1	$ 7,267

Figure 27 below provides an overview of ECPL's forecasted capital expenditures by prescribed category for the years 2018 through 2022.

Figure 27 – Forecasted Capital Expenditure Summary

Forecast Periods				
2018	2019	2020	2021	2022
$ '000				
$ 1,746	$ 1,781	$ 1,816	$ 1,853	$ 1,835
$ 2,693	$ 1,362	$ 2,304	$ 2,248	$ 2,195
$ 707	$ 2,186	$ 1,126	$ 1,243	$ 1,342
$ 1,037	$ 856	$ 976	$ 927	$ 968
$ 6,183	**$ 6,185**	**$ 6,222**	**$ 6,270**	**$ 6,339**
$ 7,710	$ 7,797	$ 7,834	$ 8,319	$ 8,444

Figures 26 and 27 above are consistent with Board Appendix 2-AB which is also included as Attachment 2-D of this Exhibit.

2.6.3 Variance Analysis by Spending Category

The following variance analysis is done in accordance with the materiality threshold calculated in Exhibit 1 of this Application. The materiality threshold calculated by EPLC is $65,000.

2010 Actual Vs. 2011 Actual

EPLC realized a net decrease in capital expenditures of $729,239 in 2011, relative to 2010. Figure 28 below summarizes these variances by category.

Figure 28 – 2010 Actual Vs. 2011 Actual Capital Expenditures

Category	2010 Actual	2011 Actual	Variance
System Access	$ 1,927.76	$ 1,502.38	$ (425.38)
System Renewal	$ 1,674.86	$ 1,832.55	$ 157.69
System Service	$ 692.63	$ 939.77	$ 247.14
General Plant	$ 959.55	$ 250.85	$ (708.69)
Total Expenditure	**$ 5,254.79**	**$ 4,525.55**	**$ (729.24)**

System Access

In 2011, EPLC realized a decrease in System Access of $425,380. This variance can be mainly attributed to a decrease in Municipal Request related work for the Herb Gray parkway compared to 2010, a reduction in Commercial/Industrial work related to the Leamington Pollution Control plant in Leamington and expansion of Laurier Parkway (both completed in 2010).

System Renewal

In 2011, EPLC realized an increase in System Renewal of $157,690. This variance can be mainly attributed to an increase to EPLC's Primary Cable Replacement program.

System Service

In 2011, EPLC realized an increase in System Service of $247,142. This variance can be mainly attributed significant resources being allocated to FIT & Generation connections as well as HONI asset purchases in the LaSalle area.

General Plant

In 2011, EPLC realized a decrease in General Plant of $708,691. This variance is related to limited refurbishment and investment required on EPLC buildings, computer software and hardware, fleet and tools & equipment.

2011 Actual Vs. 2012 Actual

EPLC realized a net increase in capital expenditures of $2,046,844 in 2012, relative to 2011. Figure 29 below summarizes these variances by category.

Figure 29 – 2011 Actual Vs. 2012 Actual Capital Expenditures

Category	2011 Actual	2012 Actual	Variance
System Access	$ 1,502.38	$ 1,717.27	$ 214.89
System Renewal	$ 1,832.55	$ 2,698.02	$ 865.47
System Service	$ 939.77	$ 885.44	$ (54.34)
General Plant	$ 250.85	$ 1,271.67	$ 1,020.82
Total Expenditure	**$ 4,525.55**	**$ 6,572.39**	**$ 2,046.84**

System Access

In 2012, EPLC realized an increase in System Access of $214,893. This variance can be mainly attributed to an increase in residential expansion and subdivision related work which is slightly offset in a reduction in Municipal related requests.

System Renewal

In 2012, EPLC realized an increase in System Renewal of $865,470. This variance can be mainly attributed to an increase to EPLC's Pole Replacement ($78,916), Direct Buried Cable Replacement ($667,752) and Voltage conversion ($506,294) programs with an offsetting decrease to its Primary Cable Replacement initiative ($498,387).

System Service

In 2012, EPLC realized a reduction in System Service of $54,340. This amount is deemed immaterial based on EPLC's calculated materiality threshold.

General Plant

In 2012, EPLC realized an increase in General Plant of $1,020,818. This variance is related to renovations completed at its 2730 Highway #3 location. EPLC consolidated billing and customer service from its prior location at the Essex Civic Center (360 Fairview Avenue, Essex, Ontario) to the Highway #3 location as EPLC's lease was expiring and future costs were proposed to increase substantially.

2012 Actual Vs. 2013 Actual

EPLC realized a net decrease in capital expenditures of $1,059,276 in 2013, relative to 2012. Figure 30 below summarizes these variances by category.

Figure 30 – 2012 Actual Vs. 2013 Actual Capital Expenditures

Category	2012 Actual	2013 Actual	Variance
System Access	$ 1,717.27	$ 1,765.51	$ 48.24
System Renewal	$ 2,698.02	$ 3,112.73	$ 414.71
System Service	$ 885.44	$ 184.77	$ (700.67)
General Plant	$ 1,271.67	$ 450.11	$ (821.56)
Total Expenditure	**$ 6,572.39**	**$ 5,513.12**	**$ (1,059.28)**

System Access

In 2013, EPLC realized an increase in System Access of $48,238. This amount is deemed immaterial based on EPLC's calculated materiality threshold.

System Renewal

In 2013, EPLC realized an increase in System Renewal of $414,714. This variance can be mainly attributed to an increase to EPLC's Pole Replacement program ($283,942) and addition of the Lithgow Livefront transformer replacement project ($389,704). The two aforementioned additions were slightly offset with a corresponding decrease to the Direct Buried Cable Replacement program ($196,702).

System Service

In 2013, EPLC realized a decrease in System Service of $700,666. This variance can be mainly attributed to a year over year reduction relating to the Smart Metering Initiative ($515,559) and a significant decrease relating to significant HONI asset purchases in 2012 ($218,901).

General Plant

In 2013, EPLC realized a decrease in General Plant of $821,561. This variance is largely related to the completion of renovations completed at its 2730 Highway #3 location described in 2012 above.

2013 Actual Vs. 2014 Actual

EPLC realized a net increase in capital expenditures of $694,385 in 2014, relative to 2013. Figure 31 below summarizes these variances by category.

Figure 31 – 2013 Actual Vs. 2014 Actual Capital Expenditures

Category	2013 Actual	2014 Actual	Variance
System Access	$ 1,765.51	$ 2,531.93	$ 766.43
System Renewal	$ 3,112.73	$ 3,011.97	$ (100.76)
System Service	$ 184.77	$ 176.50	$ (8.27)
General Plant	$ 450.11	$ 487.09	$ 36.98
Total Expenditure	**$ 5,513.12**	**$ 6,207.50**	**$ 694.39**

System Access

In 2014, EPLC had an increase in System Access of $766,426. This variance can be mainly attributed to an increase in Municipal Requests related to the Herb Gray Parkway project.

System Renewal

In 2014, EPLC had a decrease in System Renewal of $100,755. This variance can be mainly attributed to a decrease to EPLC's Pole Replacement ($283,942), Direct Buried Cable Replacement ($524,394) programs, completion of the Lithgow Livefront replacement ($389,704). The three aforementioned reductions were slightly offset with a corresponding increase to the Primary Cable replacement program ($713,295) and the beginning of the Monopoly subdivision conversion ($675,210).

System Service

In 2014, EPLC had a decrease in System Service of $8,267. This amount is deemed immaterial based on EPLC's calculated materiality threshold.

General Plant

In 2014, EPLC had an increase in General Plant of $36,981. This amount is deemed immaterial based on EPLC's calculated materiality threshold.

2014 Actual Vs. 2015 Actual

EPLC had a net increase in capital expenditures of $1,571,935 in 2015, relative to 2014. Figure 32 below summarizes these variances by category

Figure 32 – 2014 Actual Vs. 2015 Actual Capital Expenditures

Category	2014 Actual	2015 Actual	Variance
System Access	$ 2,531.93	$ 2,340.96	$ (190.97)
System Renewal	$ 3,011.97	$ 2,695.18	$ (316.79)
System Service	$ 176.50	$ 2,195.82	$ 2,019.32
General Plant	$ 487.09	$ 547.47	$ 60.37
Total Expenditure	**$ 6,207.50**	**$ 7,779.44**	**$ 1,571.93**

System Access

In 2015, EPLC realized a decrease in System Access of $190,972. This variance can be mainly attributed to an increase in residential expansion and subdivision related work which is offset by a significant reduction in Municipal related requests which relates to substantial completion of work for the Herb Gray Parkway project.

System Renewal

In 2015, EPLC realized a decrease in System Renewal of $316,790. This variance can be mainly attributed to a decrease to EPLC's Direct Buried Cable Replacement ($201,400), Voltage Conversion ($305,008) and Primary Cable Replacement ($599,677) programs and a reduction for the Monopoly subdivision conversion project ($415,373). The four aforementioned reductions were slightly offset with a corresponding increase to the Pole Replacement program ($142,617) and the beginning of the Insulator Replacement project ($132,486) and Howard/6th Concession conversion project ($744,587).

System Service

In 2015, EPLC realized an increase in System Service of $2,019,323. This variance is a result of the Smart Metering Initiative ($2,051,075).

General Plant

In 2015, EPLC realized an increase in General Plant of $60,375. This amount is deemed immaterial based on EPLC's calculated materiality threshold.

2015 Actual Vs. 2016 Actual

EPLC realized a net decrease in capital expenditures of $2,505,333 in 2016, relative to 2015. Figure 33 below summarizes these variances by category.

Figure 33 – 2015 Actual Vs. 2016 Actual Capital Expenditures

Category	2015 Actual	2016 Actual	Variance
System Access	$ 2,340.96	$ 1,759.27	$ (581.69)
System Renewal	$ 2,695.18	$ 2,125.34	$ (569.84)
System Service	$ 2,195.82	$ 1,005.36	$ (1,190.46)
General Plant	$ 547.47	$ 384.13	$ (163.34)
Total Expenditure	**$ 7,779.44**	**$ 5,274.10**	**$ (2,505.33)**

System Access

In 2016, EPLC realized a decrease in System Access of $581,691. This variance can be mainly attributed to a decrease in residential expansion and subdivision related work as well as completion of work for the Herb Gray Parkway project.

System Renewal

In 2016, EPLC realized a decrease in System Renewal of $569,841. This variance can be mainly attributed to the completion of the Howard/6th Concession project ($744,587) and decrease to EPLC's Voltage Conversion project ($461,232) offset by corresponding increases to the Transformer Replacement ($246,642) and Pole Replacement ($178,075) programs.

System Service

In 2016, EPLC realized a decrease in System Service of $1,190,461. This variance is a result of substantial completion of the Smart Metering Initiative ($1,963,154) project described above in 2015 offset by the commencement of EPLC's Self-Healing Grid initiative ($633,057).

General Plant

In 2016, EPLC realized a decrease in General Plant of $163,340. This variance is largely related to a substantial decrease in transportation equipment required offset by an increase in computer hardware. EPLC's fleet management required limited capital in 2016.

2016 Actual Vs. 2017 Bridge Year

EPLC is planning a net increase in capital expenditures of $1,384,361 in 2017, relative to 2016. Figure 34 below summarizes these variances by category.

Figure 34 – 2016 Actual Vs. 2017 Bridge Year Capital Expenditures

Category	2016 Actual	2017 Bridge	Variance
System Access	$ 1,759.27	$ 1,711.60	$ (47.67)
System Renewal	$ 2,125.34	$ 2,655.29	$ 529.94
System Service	$ 1,005.36	$ 787.13	$ (218.23)
General Plant	$ 384.13	$ 1,504.45	$ 1,120.32
Total Expenditure	**$ 5,274.10**	**$ 6,658.47**	**$ 1,384.36**

System Access

In 2017, EPLC is planning a decrease in System Access of $47,673. This amount is deemed immaterial based on EPLC's calculated materiality threshold.

System Renewal

In 2017, EPLC is planning an increase in System Renewal of $529,944. This variance can be mainly attributed to the planned increases to EPLC's Voltage Conversion ($531,793) and Direct Buried Cable Replacement ($856,380) programs as well as the beginning of the Overhead Rebuild program ($329,454). These increases are slightly offset by the completion of the Monopoly subdivision project ($312,264), Insulator Replacement program ($145,399) and Transformer Replacement program ($424,720).

System Service

In 2017, EPLC is planning a decrease in System Service of $218,231. This variance is a result of a reduction to EPLC's Self-Healing Grid initiative ($368,214) offset by HONI Asset Purchases in the LaSalle and Leamington areas ($170,360) and planned Feed-In-Tariff ("FIT") projects ($108,807).

General Plant

In 2017, EPLC is planning an increase in General Plant of $1,120,321. This increase is a result of three primary drivers. Approximately $244,331 of the variance relates to upgrades and required maintenance at EPLC's Highway #3 location. Approximately $238,821 of the variance relates to increase in computer hardware required for cyber security and financial system (Great Plains) upgrade. Approximately $350,338 of the variances relates to an increase in transportation equipment which is driven mainly by new backyard RBD truck.

2017 Bridge Year Vs. 2018 Test Year

EPLC is planning a net decrease in capital expenditures of $475,465 in 2018, relative to 2017. Figure 35 below summarizes these variances by category.

Figure 35 – 2017 Bridge Year Vs. 2018 Test Year Capital Expenditures

Category	2017 Bridge	2018 Test	Variance
System Access	$ 1,711.60	$ 1,745.83	$ 34.23
System Renewal	$ 2,655.29	$ 2,693.08	$ 37.80
System Service	$ 787.13	$ 707.28	$ (79.85)
General Plant	$ 1,504.45	$ 1,036.81	$ (467.64)
Total Expenditure	**$ 6,658.47**	**$ 6,183.00**	**$ (475.46)**

System Access

In 2018, EPLC is planning an increase in System Access of $34,232. This amount is deemed immaterial based on EPLC's calculated materiality threshold.

System Renewal

In 2018, EPLC is planning a decrease in System Renewal of $37,795. This amount is deemed immaterial based on EPLC's calculated materiality threshold.

System Service

In 2018, EPLC is planning a decrease in System Service of $79,851. This variance is primarily the result of a reduction in HONI Asset Purchases in the LaSalle and Leamington areas described above in 2017 ($80,886).

General Plant

In 201, EPLC is planning a decrease in General Plant of $467,641. This decrease is a result of the reduction of one-time spending related to computer hardware, transportation and building upgrades outlined in 2017 above. Further details about capital expenditures for the 2018 Test Year can be found in EPLC's DSP included as Attachment 2-C.

2019 to 2021 Forecast & Trend

EPLC is planning relatively flat net increases in capital expenditures over the course of 2019 through to 2021. Figure 36 below summarizes these variances by category along with the associated year over year variances in dollars and by percentage.

Figure 36 – 2019 to 2021 Forecast & Trend

Category	2019 Forecast	2020 Forecast	2021 Forecast
System Access	$ 1,780.74	$ 1,816.36	$ 1,852.69
System Renewal	$ 1,362.25	$ 2,303.72	$ 2,247.82
System Service	$ 2,186.07	$ 1,125.55	$ 1,243.06
General Plant	$ 855.60	$ 976.21	$ 926.84
Total Expenditure	**$ 6,184.66**	**$ 6,221.84**	**$ 6,270.40**
Year Over Year ($)		$ 37.18	$ 48.56
Year Over Year (%)		0.60%	0.78%

System Access

EPLC plans very flat and consistent System Access related capital expenditures from 2019-2021. Year over year increases are within EPLC's materiality threshold.

System Renewal

Planned System Renewal related capital expenditures are relatively flat in 2020 and 2021 however are significantly lower in 2019 as a result of planned System Service expenditures (see below). EPLC deferred portions of its Direct Buried Cable Replacement program into future years to smooth out planned investments.

System Service

Planned System Service related capital expenditures are flat in 2020 and 2021 however are significantly higher in 2019 to accommodate the planned purchase of two new breaker positions from Malden Transformer Station (estimated cost of $1,500,000). EPLC deferred other planned asset purchases and its Direct Buried Cable Replacement program (see System Renewal above) to future years in order to accommodate this purchase and also smooth capital expenditures.

General Plant

EPLC's fleet management plan is the primary cause of any year over year General Plant variance over the course of the 2019 through 2021 time periods. Planned spending in Transportation Equipment is $275,000 in 2019, $395,000 in 2020 and $445,000 in 2021.

2.6.4 Capital Projects

Figure 37 below outlines EPLC's historical capital expenditures by project, for years 2010 through 2016 and forecasted spending for the 2017 Bridge Year and 2018 Test Year. EPLC has completed Figure 37 consistent with Board Appendix 2-AA and is also included as Attachment 2-E of this Exhibit.

EPLC has provided a breakdown of all significant projects that approach its material threshold. Additionally, EPLC has also included detailed capital project summaries as part of its DSP (see Attachment 2-C).

Figure 37 – Capital Expenditures – By Project & Year

Projects	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
System Access								
Subdivisions	$ 540,677	$ 728,506	$ 240,014	$ 150,424	$ 1,020,249	$ 446,196	$ 375,000	$ 382,500
Residential Connection/Extension	$ 188,901	$ 471,954	$ 429,496	$ 677,866	$ 872,062	$ 1,050,696	$ 386,636	$ 394,369
Municipal Requests	$ 721,963	$ 140,953	$ 1,048,671	$ 1,577,009	$ 311,344	$ 12,336	$ 600,000	$ 612,000
New Service Upgrades - C&I	$ 120,392	$ 226,150	$ 100,871	$ 21,124	$ 3,767	$ 99,080	$ 349,960	$ 356,959
Miscellaneous	$ (69,558)	$ 149,705	$ (53,546)	$ 105,509	$ 133,539	$ 150,961	$ -	$ -
Subtotal - System Access	**$ 1,502,375**	**$ 1,717,268**	**$ 1,765,507**	**$ 2,531,933**	**$ 2,340,960**	**$ 1,759,269**	**$ 1,711,596**	**$ 1,745,828**
System Renewal								
Pole Replacement Program	$ 115,417	$ 194,333	$ 478,275	$ 193,281	$ 335,898	$ 513,973	$ 460,478	$ 114,062
O/H Reactive Replacements	$ 110,554	$ 6,908	$ -	$ 6,145	$ -	$ 104,563	$ 80,784	$ 82,400
U/G Reactive Replacements	$ 8,785	$ 53,159	$ 10,765	$ -	$ 6,890	$ -	$ 63,690	$ 64,964
Install/Replace Load Breaks	$ 34,236	$ 3,612	$ -	$ -	$ -	$ 64,119	$ 58,752	$ 59,927
Direct Buried Cable Replacement Program	$ 346,712	$ 1,100,768	$ 851,290	$ 299,670	$ 88,733	$ 43,582	$ 1,229,416	$ 2,224,410
PMH Replacement Program	$ 162,024	$ 27,180	$ 122,012	$ 63,630	$ 55,209	$ 135,236	$ 144,432	$ 147,321
Single Voltage Utility - Conversion	$ 423,196	$ 929,490	$ 935,091	$ 852,182	$ 547,174	$ 85,942	$ 617,735	$ -
Replacement - Lithgow Livefront Transformers	$ -	$ -	$ 389,704	$ -	$ -	$ -	$ -	$ -
Conversion - Monopoly Subdivisions	$ -	$ -	$ -	$ 675,210	$ 259,837	$ 312,264	$ -	$ -
Insulator Replacement	$ -	$ -	$ -	$ -	$ 132,486	$ 145,399	$ -	$ -
Conversion - Howard/6th Concession	$ -	$ -	$ -	$ -	$ 744,587	$ -	$ -	$ -
Primary Cable Replacement	$ 522,882	$ 24,495	$ -	$ 713,295	$ 113,618	$ 93,316	$ -	$ -
Transformer Replacement Program	$ 57,308	$ 47,978	$ 108,721	$ 143,405	$ 178,078	$ 424,720	$ -	$ -
Miscellaneous	$ 51,431	$ 310,092	$ 216,870	$ 65,157	$ 232,675	$ 202,228	$ -	$ -
Subtotal - System Renewal	**$ 1,832,545**	**$ 2,698,015**	**$ 3,112,729**	**$ 3,011,974**	**$ 2,695,184**	**$ 2,125,343**	**$ 2,655,287**	**$ 2,693,082**
System Service								
FIT & Generation Connections	$ 463,599	$ 30,227	$ 91,689	$ 25,824	$ 67,577	$ 80,085	$ 188,892	$ 181,370
HONI Asset Purchases	$ 468,859	$ 232,123	$ 13,222	$ 89,077	$ 21,142	$ -	$ 170,360	$ 89,474
Metering Upgrade & Replacement Program	$ -	$ 56,878	$ 100,139	$ 7,712	$ 8,460	$ 156,282	$ 163,037	$ 166,297
Smart Metering Initiative	$ -	$ 515,559	$ -	$ -	$ 2,051,075	$ 87,921	$ -	$ -
Self Healing Grid Reclosers	$ -	$ -	$ -	$ 61,005	$ -	$ 633,057	$ 264,843	$ 270,140
Miscellaneous	$ 7,314	$ 50,649	$ (20,282)	$ (7,117)	$ 47,571	$ 48,019	$ -	$ -
Subtotal - System Service	**$ 939,772**	**$ 885,435**	**$ 184,769**	**$ 176,502**	**$ 2,195,825**	**$ 1,005,363**	**$ 787,132**	**$ 707,281**
General Plant								
Bldgs & Fixtures	$ 13,214	$ 844,622	$ 21,981	$ -	$ 48,914	$ 42,469	$ 286,800	$ 370,000
Office Furniture/Equip	$ -	$ 29,967	$ 6,711	$ 876	$ 5,980	$ 20,672	$ 10,000	$ 10,000
Computer Equipment HW	$ 27,112	$ -	$ 13,501	$ 25,333	$ 5,837	$ 117,329	$ 356,150	$ 161,809
Computer Software	$ 17,981	$ 34,572	$ 52,989	$ 166,960	$ 17,043	$ 4,632	$ 254,500	$ 115,000
Transportation Equip	$ 156,970	$ 198,529	$ 307,516	$ 248,438	$ 401,244	$ 136,662	$ 487,000	$ 270,000
Tools & Equipment	$ 35,577	$ 163,983	$ 47,415	$ 45,486	$ 68,451	$ 62,365	$ 110,000	$ 110,000
Miscellaneous	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - General Plant	**$ 250,855**	**$ 1,271,673**	**$ 450,112**	**$ 487,094**	**$ 547,468**	**$ 384,129**	**$ 1,504,450**	**$ 1,036,809**
Total	**$ 4,525,547**	**$ 6,572,392**	**$ 5,513,117**	**$ 6,207,502**	**$ 7,779,437**	**$ 5,274,104**	**$ 6,658,465**	**$ 6,183,000**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*								
Total	**$ 4,525,547**	**$ 6,572,392**	**$ 5,513,117**	**$ 6,207,502**	**$ 7,779,437**	**$ 5,274,104**	**$ 6,658,465**	**$ 6,183,000**

2.6.5 Capitalization Policy

EPLC has included its approved Capitalization and Amortization policies as Attachment 2-F of this Exhibit.

2.6.6 Capitalization of Overhead

EPLC performed an analysis to determine whether overhead costs were eligible for capitalization under IFRS. The results of EPLC's analysis are detailed below in Figure 38. Figure 38 is consistent with Board Appendix 2-D which is included as Attachment 2-G of this Exhibit.

Figure 38 – Overhead Expense

Description	2011	2012	2013	2014	2015	2016	2017	2018
OM&A Before Capitalization	**Historical Year**	**Historical Year**	**Historical Year**	**Historical Year**	**Historical Year**	**Historical Year**	**Bridge Year**	**Test Year**
Distribution	$ 2,311,983	$ 2,769,624	$ 2,288,897	$ 2,573,946	$ 2,768,874	$ 2,489,996	$ 2,112,492	$ 2,200,339
Billing & Collecting	$ 1,131,257	$ 1,174,568	$ 1,329,771	$ 1,158,128	$ 1,229,676	$ 1,348,249	$ 1,499,880	$ 1,550,150
Community Relations	$ 11,394	$ 8,539	$ 8,451	$ 10,016	$ 12,013	$ 6,482	$ 23,442	$ 23,396
Administrative & General	$ 2,092,295	$ 2,240,566	$ 2,400,175	$ 2,962,130	$ 2,753,655	$ 3,136,895	$ 3,579,949	$ 3,796,390
Labour Burden	$ 229,006	$ 293,809	$ 370,247	$ 375,867	$ 420,809	$ 426,466	$ 486,528	$ 496,528
Material Burden	$ 415,547	$ 451,614	$ 117,111	$ 94,162	$ 92,905	$ 79,266	$ 88,476	$ 90,246
Vehicle Burden	$ 153,393	$ 234,821	$ 251,570	$ 216,004	$ 263,029	$ 228,808	$ 240,000	$ 250,000
Total OM&A Before Capitalization (B)	**$ 6,344,875**	**$ 7,173,540**	**$ 6,766,223**	**$ 7,390,252**	**$ 7,540,961**	**$ 7,716,163**	**$ 8,030,767**	**$ 8,407,049**
Capitalized OM&A								
Labour Burden	$ 229,006	$ 293,809	$ 370,247	$ 375,867	$ 420,809	$ 426,466	$ 486,528	$ 496,528
Material Burden	$ 415,547	$ 451,614	$ 117,111	$ 94,162	$ 92,905	$ 79,266	$ 88,476	$ 90,246
Vehicle Burden	$ 153,393	$ 234,821	$ 251,570	$ 216,004	$ 263,029	$ 228,808	$ 240,000	$ 250,000
Total Capitalized OM&A (A)	**$ 797,946**	**$ 980,244**	**$ 738,928**	**$ 686,033**	**$ 776,743**	**$ 734,540**	**$ 815,004**	**$ 836,774**
% of Capitalized OM&A (=A/B)	**12.6%**	**13.7%**	**10.9%**	**9.3%**	**10.3%**	**9.5%**	**10.1%**	**10.0%**

2.6.7 Costs of Eligible Investments for the Connection of Qualifying Generation Facilities

EPLC has included the total costs of $70,601.63, which includes carrying costs, for Renewable Expansion Investments incurred in 2014 and 2015. EPLC enabled the connection of two solar photovoltaic projects in its service territory that required distribution expansion above and beyond normal conditions.

The Burden Reduction Act, 2017 Schedule 10, Section (5) amended section 79.1 (1) which required the OEB to provide rate protection for costs incurred to make an eligible investment in order to connect a qualifying generation facility.

As a result, EPLC has not included Board Appendices 2-FA and 2-FC since the Renewable Expansion Investment costs are below materiality in each respective year. Further details about how EPLC intends to recover these costs are further described in Exhibit 9 of this Application.

2.6.8 Policy Options for the Funding of Capital

The Board released the *"Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module"* in September, 2014. In this report, the Board

established the following mechanism to allow distributors like EPLC to better align capital spending and prioritization with enhanced rate predictability and smoothing:

> *"The review and approval of business cases for incremental capital requests that are subject to the criteria of materiality, need and prudence are advanced to coincide with the distributor's cost of service application. To distinguish this from Incremental Capital Module ("ICM"), this new mechanism will be named the Advanced Capital Module ("ACM").*
>
> *Advancing the reviews of eligible discrete capital projects, included as part of a distributor's Distribution System Plan ("DSP") and scheduled to go into service during the IR term, is expected to facilitate enhanced pacing and smoothing of rate impacts, as the distributor, the Board and other stakeholders will be examining the capital projects over the five-year horizon of the DSP."*

As per section 2.3 above, EPLC is in consultation with HONI as it relates to the construction of Leamington TS. Once costs and allocations are known and better defined, EPLC plans on submitting an ICM as part of that year's IRM application.

Should the project expand beyond an ICM and where an ACM would be required, EPLC will review and notify the Board accordingly.

2.6.9 Addition of ICM Assets to Rate Base

EPLC confirms that it has not received any Incremental Capital Module ("ICM") adjustments as part of any previous IRM application. As a result, no ICM related assets have been added to Rate Base.

2.6.10 Service Quality & Reliability Performance

The Board's Reporting and Record Keeping Requirements ("RRR") Guideline requires distributors such as EPLC to file Service Quality Indicators ("SQIs") annually. Figure 39 below outlines EPLC's last 5 historical years from 2012 through 2016.

EPLC has consistently performed at or above the Board's prescribed targets and no corrective action is currently required. EPLC plans to maintain and/or improve on the performance metrics noted. EPLC has also included Board Appendix 2-G as Attachment 2-I of this Exhibit.

Figure 39 – Service Quality Indicators

Indicator	5 Year Historical Average	2012	2013	2014	2015	2016
Including outages caused by loss of supply						
SAIDI	3.698	4.530	5.370	3.820	2.230	2.540
SAIFI	2.982	3.830	3.580	2.460	1.840	3.200
Excluding outages caused by loss of supply						
SAIDI	1.252	0.890	2.240	1.160	1.340	0.630
SAIFI	0.744	0.610	1.120	0.660	0.830	0.500
Excluding major event days						
SAIDI	1.252	0.890	2.240	1.160	1.340	0.630
SAIFI	0.744	0.610	1.120	0.660	0.830	0.500
Indicator	**OEB Minimum Standard**	**2012**	**2013**	**2014**	**2015**	**2016**
Low Voltage Connections	90%	93.2%	92.7%	93.0%	92.3%	90.5%
High Voltage Connections	90%	N/A	N/A	N/A	N/A	N/A
Telephone Accessibility	65%	68.5%	66.4%	78.0%	79.2%	73.6%
Appointments Met	90%	95.7%	94.3%	94.7%	94.8%	90.8%
Written Response to Enquires	80%	93.9%	91.2%	91.7%	84.7%	96.3%
Emergency Urban Response	80%	91.2%	92.9%	96.3%	100.0%	97.7%
Emergency Rural Response	80%	N/A	N/A	N/A	N/A	N/A
Telephone Call Abandon Rate	10%	7.0%	1.7%	1.2%	1.4%	0.8%
Appointment Scheduling	90%	96.8%	96.5%	95.5%	98.5%	98.8%
Rescheduling a Missed Appointment	100%	100.0%	100.0%	100.0%	100.0%	100.0%
Reconnection Performance Standard	85%	96.7%	93.3%	95.3%	93.7%	97.5%

Attachment 2-A

Fixed Asset Continuity Schedules

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard CGAAP
Year **2010**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 588,578	$ 449,119		$ 1,037,697	-$ 334,169	-$ 150,110		-$ 484,278	$ 553,419
CEC	1612	Land Rights (Formally known as Account 1906)	$ 62,519	$ 35,061		$ 97,579	-$ 3,399	-$ 1,601		-$ 5,000	$ 92,579
N/A	1805	Land	$ 47,899	$ -		$ 47,899				$ -	$ 47,899
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV				$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 102,722	$ -		$ 102,722	-$ 18,379	-$ 4,773		-$ 23,152	$ 79,570
47	1825	Storage Battery Equipment				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 5,278,538	$ 453,101		$ 5,731,639	-$ 528,986	-$ 114,467		-$ 643,453	$ 5,088,186
47	1835	Overhead Conductors & Devices	$ 5,161,417	$ 334,496		$ 5,495,913	-$ 2,263,290	-$ 312,857		-$ 2,576,148	$ 2,919,765
47	1840	Underground Conduit	$ 8,233,531	$ 289,706		$ 8,523,236	-$ 1,575,660	-$ 210,276		-$ 1,785,936	$ 6,737,300
47	1845	Underground Conductors & Devices	$ 9,568,801	$ 721,049		$ 10,289,850	-$ 3,172,818	-$ 450,575		-$ 3,623,393	$ 6,666,457
47	1850	Line Transformers	$ 12,047,175	$ 1,309,499		$ 13,356,674	-$ 3,280,457	-$ 528,295		-$ 3,808,752	$ 9,547,921
47	1855	Services (Overhead & Underground)	$ 6,285,635	$ 532,935		$ 6,818,570	-$ 1,686,526	-$ 277,135		-$ 1,963,661	$ 4,854,909
47	1860	Meters	$ 3,432,272	$ 525,392		$ 3,957,663	-$ 805,475	-$ 148,395		-$ 953,871	$ 3,003,793
47	1860	Meters (Smart Meters)				$ -				$ -	$ -
N/A	1905	Land	$ 191,700	$ -	-$ 1,581	$ 190,119				$ -	$ 190,119
47	1908	Buildings & Fixtures	$ 1,606,060	$ 1,080		$ 1,607,140	-$ 156,568	-$ 78,512		-$ 235,080	$ 1,372,060
13	1910	Leasehold Improvements				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 128,881	$ 30,534		$ 159,415	-$ 57,171	-$ 22,200		-$ 79,371	$ 80,044
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 61,474	$ 189,930		$ 251,403	-$ 35,039	-$ 33,616		-$ 68,655	$ 182,748
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 759,026	$ 330,900	-$ 107,097	$ 982,829	-$ 205,602	-$ 92,823	$ 107,097	-$ 191,328	$ 791,500
8	1935	Stores Equipment	$ 29,711			$ 29,711	-$ 8,435	-$ 4,448		-$ 12,883	$ 16,829
8	1940	Tools, Shop & Garage Equipment	$ 174,134	$ 40,834		$ 214,968	-$ 48,885	-$ 25,181		-$ 74,066	$ 140,902
8	1945	Measurement & Testing Equipment	$ 43,186	$ 11,152		$ 54,338	-$ 6,458	-$ 5,443		-$ 11,901	$ 42,438
8	1950	Power Operated Equipment				$ -				$ -	$ -
8	1955	Communications Equipment	$ 197,224			$ 197,224	-$ 89,671	-$ 36,741		-$ 126,412	$ 70,812
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment				$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises				$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	1980	System Supervisor Equipment				$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants	-$ 8,396,091	-$ 1,667,247		-$ 10,063,338	$ 157,227	$ 219,928		$ 377,155	-$ 9,686,183
47	2440	Deferred Revenue[5]									
						$ -				$ -	$ -
		Sub-Total	**$ 45,604,391**	**$ 3,587,540**	**-$ 108,678**	**$ 49,083,253**	**-$ 14,119,761**	**-$ 2,277,521**	**$ 107,097**	**-$ 16,290,184**	**$ 32,793,068**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 45,604,391**	**$ 3,587,540**	**-$ 108,678**	**$ 49,083,253**	**-$ 14,119,761**	**-$ 2,277,521**	**$ 107,097**	**-$ 16,290,184**	**$ 32,793,068**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,277,521**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 89,667
Stores Equipment	
Net Depreciation	-$ 2,187,853

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Accounting Standard CGAAP
Year **2011**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 1,037,697	-$ 91,368		$ 946,329	-$ 484,278	-$ 120,676		-$ 604,954	$ 341,375
CEC	1612	Land Rights (Formally known as Account 1906)	$ 97,579	$ 11,410		$ 108,990	-$ 5,000	-$ 2,066		-$ 7,066	$ 101,924
N/A	1805	Land	$ 47,899	$ -		$ 47,899	$ -			$ -	$ 47,899
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 102,722	$ 385		$ 103,107	-$ 23,152	-$ 4,117		-$ 27,269	$ 75,838
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 5,731,639	$ 274,976		$ 6,006,615	-$ 643,453	-$ 193,867		-$ 837,320	$ 5,169,295
47	1835	Overhead Conductors & Devices	$ 5,495,913	$ 488,326	-$ 300,000	$ 5,684,239	-$ 2,576,148	-$ 228,956	$ 114,000	-$ 2,691,103	$ 2,993,135
47	1840	Underground Conduit	$ 8,523,236	$ 1,178,203		$ 9,701,439	-$ 1,785,936	-$ 274,681		-$ 2,060,617	$ 7,640,822
47	1845	Underground Conductors & Devices	$ 10,289,850	$ 627,858		$ 10,917,707	-$ 3,623,393	-$ 423,812		-$ 4,047,205	$ 6,870,502
47	1850	Line Transformers	$ 13,356,674	$ 876,982		$ 14,233,655	-$ 3,808,752	-$ 559,269		-$ 4,368,021	$ 9,865,634
47	1855	Services (Overhead & Underground)	$ 6,818,570	$ 874,068		$ 7,692,638	-$ 1,963,661	-$ 289,810		-$ 2,253,471	$ 5,439,167
47	1860	Meters	$ 3,957,663	$ 195,760	$ 22,310	$ 4,175,733	-$ 953,871	-$ 155,401		-$ 1,109,271	$ 3,066,462
47	1860	Meters (Smart Meters)	$ -	$ 24,417		$ 24,417	$ -	-$ 488		-$ 488	$ 23,928
N/A	1905	Land	$ 190,119			$ 190,119	$ -			$ -	$ 190,119
47	1908	Buildings & Fixtures	$ 1,607,140	$ 26,631		$ 1,633,771	-$ 235,080	-$ 64,818		-$ 299,898	$ 1,333,873
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 159,415			$ 159,415	-$ 79,371	-$ 15,061		-$ 94,431	$ 64,983
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 251,403	$ 54,640		$ 306,043	-$ 68,655	-$ 51,907		-$ 120,562	$ 185,481
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 982,829	$ 316,345	-$ 127,092	$ 1,172,081	-$ 191,328	-$ 161,612	$ 127,092	-$ 225,848	$ 946,233
8	1935	Stores Equipment	$ 29,711	$ 4,656		$ 34,367	-$ 12,883	-$ 3,204		-$ 16,087	$ 18,281
8	1940	Tools, Shop & Garage Equipment	$ 214,968	$ 27,703		$ 242,672	-$ 74,066	-$ 22,882		-$ 96,948	$ 145,724
8	1945	Measurement & Testing Equipment	$ 54,338	$ 9,649		$ 63,987	-$ 11,901	-$ 5,916		-$ 17,817	$ 46,170
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 197,224	$ 29,691		$ 226,916	-$ 126,412	-$ 16,874		-$ 143,286	$ 83,630
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 10,063,338	-$ 1,939,672		-$ 12,003,010	$ 377,155	$ 288,452		$ 665,607	-$ 11,337,403
47	2440	Deferred Revenue[5]	$ -				$ -				
						$ -				$ -	$ -
		Sub-Total	**$ 49,083,253**	**$ 2,990,657**	**-$ 404,782**	**$ 51,669,128**	**-$ 16,290,184**	**-$ 2,306,964**	**$ 241,092**	**-$ 18,356,056**	**$ 33,313,072**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 49,083,253**	**$ 2,990,657**	**-$ 404,782**	**$ 51,669,128**	**-$ 16,290,184**	**-$ 2,306,964**	**$ 241,092**	**-$ 18,356,056**	**$ 33,313,072**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,306,964**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 184,823
Stores Equipment	
Net Depreciation	-$ 2,122,141

Accounting Standard CGAAP
Year **2012**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 946,329	$ 29,330	$ 210,816	$ 1,186,475	-$ 604,954	-$ 76,486	-$ 89,939	-$ 771,379	$ 415,096
CEC	1612	Land Rights (Formally known as Account 1906)	$ 108,990	$ 6,175		$ 115,165	-$ 7,066	-$ 2,407		-$ 9,473	$ 105,692
N/A	1805	Land	$ 47,899	$ -		$ 47,899	$ -			$ -	$ 47,899
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 103,107	$ 10,966		$ 114,073	-$ 27,269	-$ 4,344		-$ 31,612	$ 82,461
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 6,006,615	$ 456,957		$ 6,463,571	-$ 837,320	-$ 205,289		-$ 1,042,609	$ 5,420,962
47	1835	Overhead Conductors & Devices	$ 5,684,239	$ 730,509		$ 6,414,747	-$ 2,691,103	-$ 252,579		-$ 2,943,682	$ 3,471,065
47	1840	Underground Conduit	$ 9,701,439	$ 955,081		$ 10,656,520	-$ 2,060,617	-$ 313,087		-$ 2,373,704	$ 8,282,816
47	1845	Underground Conductors & Devices	$ 10,917,707	$ 653,161		$ 11,570,868	-$ 4,047,205	-$ 448,094		-$ 4,495,300	$ 7,075,569
47	1850	Line Transformers	$ 14,233,655	$ 843,761		$ 15,077,416	-$ 4,368,021	-$ 592,640		-$ 4,960,661	$ 10,116,755
47	1855	Services (Overhead & Underground)	$ 7,692,638	$ 683,961		$ 8,376,599	-$ 2,253,471	-$ 322,721		-$ 2,576,192	$ 5,800,407
47	1860	Meters	$ 4,175,733	$ 210,492	$ 186,180	$ 4,572,405	-$ 1,109,271	-$ 169,377		-$ 1,278,648	$ 3,293,757
47	1860	Meters (Smart Meters)	$ 24,417	$ 570,008	-$ 6,531	$ 587,894	-$ 488	-$ 33,219		-$ 33,707	$ 554,186
N/A	1905	Land	$ 190,119			$ 190,119	$ -			$ -	$ 190,119
47	1908	Buildings & Fixtures	$ 1,633,771	$ 761,185		$ 2,394,956	-$ 299,898	-$ 79,682		-$ 379,580	$ 2,015,376
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 159,415	$ 25,424	-$ 4,595	$ 180,243	-$ 94,431	-$ 16,141	$ 4,595	-$ 105,977	$ 74,266
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 306,043			$ 306,043	-$ 120,562	-$ 50,831		-$ 171,393	$ 134,650
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 1,172,081	$ 312,049	-$ 201,657	$ 1,282,473	-$ 225,848	-$ 185,945	$ 172,491	-$ 239,302	$ 1,043,171
8	1935	Stores Equipment	$ 34,367	$ 2,708		$ 37,075	-$ 16,087	-$ 3,572		-$ 19,659	$ 17,416
8	1940	Tools, Shop & Garage Equipment	$ 242,672	$ 86,797		$ 329,469	-$ 96,948	-$ 28,086		-$ 125,034	$ 204,435
8	1945	Measurement & Testing Equipment	$ 63,987			$ 63,987	-$ 17,817	-$ 6,399		-$ 24,216	$ 39,772
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 226,916	$ 49,617		$ 276,532	-$ 143,286	-$ 20,766		-$ 164,051	$ 112,481
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 12,003,010	-$ 869,853		-$ 12,872,863	$ 665,607	$ 344,643		$ 1,010,250	-$ 11,862,613
47	2440	Deferred Revenue[5]	$ -				$ -				
						$ -				$ -	$ -
		Sub-Total	**$ 51,669,128**	**$ 5,518,327**	**$ 184,213**	**$ 57,371,668**	**-$ 18,356,056**	**-$ 2,467,021**	**$ 87,147**	**-$ 20,735,930**	**$ 36,635,738**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 51,669,128**	**$ 5,518,327**	**$ 184,213**	**$ 57,371,668**	**-$ 18,356,056**	**-$ 2,467,021**	**$ 87,147**	**-$ 20,735,930**	**$ 36,635,738**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,467,021**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 179,623
Stores Equipment	
Net Depreciation	-$ 2,287,398

Accounting Standard CGAAP
Year **2013**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 1,186,475	$ 66,055		$ 1,252,529	-$ 771,379	-$ 84,022		-$ 855,400	$ 397,129
CEC	1612	Land Rights (Formally known as Account 1906)	$ 115,165	$ 60,262		$ 175,427	-$ 9,473	-$ 2,902		-$ 12,375	$ 163,052
N/A	1805	Land	$ 47,899			$ 47,899	$ -			$ -	$ 47,899
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 114,073	$ 1,572		$ 115,645	-$ 31,612	-$ 4,594		-$ 36,207	$ 79,438
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 6,463,571	$ 427,090		$ 6,890,662	-$ 1,042,609	-$ 219,433		-$ 1,262,042	$ 5,628,619
47	1835	Overhead Conductors & Devices	$ 6,414,747	$ 542,962		$ 6,957,709	-$ 2,943,682	-$ 276,494		-$ 3,220,176	$ 3,737,534
47	1840	Underground Conduit	$ 10,656,520	$ 914,367		$ 11,570,888	-$ 2,373,704	-$ 346,792		-$ 2,720,496	$ 8,850,392
47	1845	Underground Conductors & Devices	$ 11,570,868	$ 1,015,489		$ 12,586,357	-$ 4,495,300	-$ 480,111		-$ 4,975,411	$ 7,610,947
47	1850	Line Transformers	$ 15,077,416	$ 1,487,986		$ 16,565,402	-$ 4,960,661	-$ 635,746		-$ 5,596,407	$ 10,968,996
47	1855	Services (Overhead & Underground)	$ 8,376,599	$ 928,132		$ 9,304,732	-$ 2,576,192	-$ 352,153		-$ 2,928,344	$ 6,376,387
47	1860	Meters	$ 4,572,405	$ 171,490	-$ 14,935	$ 4,728,961	-$ 1,278,648	-$ 274,103		-$ 1,552,751	$ 3,176,210
47	1860	Meters (Smart Meters)	$ 587,894	$ 37,316		$ 625,210	-$ 33,707	-$ 31,148		-$ 64,856	$ 560,354
N/A	1905	Land	$ 190,119			$ 190,119	$ -			$ -	$ 190,119
47	1908	Buildings & Fixtures	$ 2,394,956	$ 27,401		$ 2,422,357	-$ 379,580	-$ 94,562		-$ 474,141	$ 1,948,216
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 180,243	$ 8,365		$ 188,609	-$ 105,977	-$ 17,562		-$ 123,539	$ 65,070
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 306,043	$ 18,106		$ 324,149	-$ 171,393	-$ 50,350		-$ 221,744	$ 102,406
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 1,282,473	$ 382,064	-$ 110,985	$ 1,553,552	-$ 239,302	-$ 273,213	$ 110,986	-$ 401,529	$ 1,152,023
8	1935	Stores Equipment	$ 37,075			$ 37,075	-$ 19,659	-$ 3,708		-$ 23,366	$ 13,709
8	1940	Tools, Shop & Garage Equipment	$ 329,469	$ 54,159		$ 383,628	-$ 125,034	-$ 33,574		-$ 158,608	$ 225,020
8	1945	Measurement & Testing Equipment	$ 63,987			$ 63,987	-$ 24,216	-$ 6,399		-$ 30,614	$ 33,373
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 276,532	$ 4,947		$ 281,480	-$ 164,051	-$ 21,372		-$ 185,423	$ 96,057
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 12,872,863	-$ 2,191,898		-$ 15,064,761	$ 1,010,250	$ 360,377		$ 1,370,627	-$ 13,694,134
47	2440	Deferred Revenue[5]	$ -				$ -				
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 57,371,668**	**$ 3,955,868**	**-$ 125,920**	**$ 61,201,616**	**-$ 20,735,930**	**-$ 2,847,858**	**$ 110,986**	**-$ 23,472,802**	**$ 37,728,814**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 57,371,668**	**$ 3,955,868**	**-$ 125,920**	**$ 61,201,616**	**-$ 20,735,930**	**-$ 2,847,858**	**$ 110,986**	**-$ 23,472,802**	**$ 37,728,814**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,847,858**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 263,924
Stores Equipment	
Net Depreciation	-$ 2,583,934

Accounting Standard CGAAP Shown below is RCGAAP. The model did not have that
Year **2013** accounting standard as an available option in the list

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 1,186,475	$ 66,055		$ 1,252,529	-$ 771,379	-$ 342,040		-$ 1,113,418	$ 139,111
CEC	1612	Land Rights (Formally known as Account 1906)	$ 115,165	$ 60,262		$ 175,427	-$ 9,473	-$ 2,930		-$ 12,403	$ 163,024
N/A	1805	Land	$ 47,899			$ 47,899	$ -			$ -	$ 47,899
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 114,073	$ 1,432		$ 115,505	-$ 31,612	-$ 4,002		-$ 35,614	$ 79,890
47	1825	Storage Battery Equipment	$ -			$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 6,463,571	$ 388,994		$ 6,852,565	-$ 1,042,609	-$ 148,490		-$ 1,191,099	$ 5,661,466
47	1835	Overhead Conductors & Devices	$ 6,414,747	$ 494,530		$ 6,909,277	-$ 2,943,682	-$ 95,859		-$ 3,039,541	$ 3,869,736
47	1840	Underground Conduit	$ 10,656,520	$ 832,806		$ 11,489,326	-$ 2,373,704	-$ 199,739		-$ 2,573,444	$ 8,915,882
47	1845	Underground Conductors & Devices	$ 11,570,868	$ 924,907		$ 12,495,775	-$ 4,495,300	-$ 229,618		-$ 4,724,918	$ 7,770,857
47	1850	Line Transformers	$ 15,077,416	$ 1,355,258		$ 16,432,674	-$ 4,960,661	-$ 326,072		-$ 5,286,733	$ 11,145,941
47	1855	Services (Overhead & Underground)	$ 8,376,599	$ 845,343		$ 9,221,942	-$ 2,576,192	-$ 144,526		-$ 2,720,718	$ 6,501,224
47	1860	Meters	$ 4,572,405	$ 150,060	-$ 14,935	$ 4,707,530	-$ 1,278,648	-$ 167,575		-$ 1,446,223	$ 3,261,307
47	1860	Meters (Smart Meters)	$ 587,894	$ 24,347		$ 612,241	-$ 33,707	-$ 31,148		-$ 64,855	$ 547,385
N/A	1905	Land	$ 190,119			$ 190,119	$ -			$ -	$ 190,119
47	1908	Buildings & Fixtures	$ 2,394,956	$ 27,401		$ 2,422,357	-$ 379,580	-$ 42,858		-$ 422,438	$ 1,999,919
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 180,243	$ 8,365		$ 188,609	-$ 105,977	-$ 16,755		-$ 122,732	$ 65,876
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 306,043	$ 18,106		$ 324,149	-$ 171,393	-$ 141,384		-$ 312,778	$ 11,372
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 1,282,473	$ 382,064	-$ 110,985	$ 1,553,552	-$ 239,302	-$ 157,920	$ 110,986	-$ 286,236	$ 1,267,316
8	1935	Stores Equipment	$ 37,075			$ 37,075	-$ 19,659	-$ 3,670		-$ 23,329	$ 13,746
8	1940	Tools, Shop & Garage Equipment	$ 329,469	$ 54,159		$ 383,628	-$ 125,034	-$ 58,184		-$ 183,218	$ 200,410
8	1945	Measurement & Testing Equipment	$ 63,987			$ 63,987	-$ 24,216	-$ 11,669		-$ 35,885	$ 28,102
8	1950	Power Operated Equipment	$ -			$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	$ 276,532	$ 4,947		$ 281,480	-$ 164,051	-$ 59,435		-$ 223,486	$ 57,994
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 12,872,863	-$ 2,191,898		-$ 15,064,761	$ 1,010,250	$ 278,492		$ 1,288,742	-$ 13,776,019
47	2440	Deferred Revenue[5]	$ -				$ -				
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 57,371,668**	**$ 3,447,138**	**-$ 125,920**	**$ 60,692,886**	**-$ 20,735,930**	**-$ 1,905,383**	**$ 110,986**	**-$ 22,530,327**	**$ 38,162,559**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 57,371,668**	**$ 3,447,138**	**-$ 125,920**	**$ 60,692,886**	**-$ 20,735,930**	**-$ 1,905,383**	**$ 110,986**	**-$ 22,530,327**	**$ 38,162,559**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,905,383**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 152,550
Stores Equipment	
Net Depreciation	-$ 1,752,832

Accounting Standard CGAAP Shown below is RCGAAP. The model did not have that
Year **2014** accounting standard as an available option in the list

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 1,252,529	$ 74,868		$ 1,327,398	-$ 1,113,418	-$ 75,831		-$ 1,189,249	$ 138,148
CEC	1612	Land Rights (Formally known as Account 1906)	$ 175,427	$ 15,071		$ 190,498	-$ 12,403	-$ 3,679		-$ 16,082	$ 174,416
N/A	1805	Land	$ 47,899			$ 47,899	$ -			$ -	$ 47,899
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 115,505			$ 115,505	-$ 35,614	-$ 3,599		-$ 39,214	$ 76,291
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 6,852,565	$ 490,624		$ 7,343,189	-$ 1,191,099	-$ 129,121		-$ 1,320,220	$ 6,022,969
47	1835	Overhead Conductors & Devices	$ 6,909,277	$ 431,488		$ 7,340,765	-$ 3,039,541	-$ 73,359		-$ 3,112,900	$ 4,227,864
47	1840	Underground Conduit	$ 11,489,326	$ 1,250,716		$ 12,740,042	-$ 2,573,444	-$ 122,833		-$ 2,696,277	$ 10,043,765
47	1845	Underground Conductors & Devices	$ 12,495,775	$ 839,997		$ 13,335,773	-$ 4,724,918	-$ 365,105		-$ 5,090,023	$ 8,245,750
47	1850	Line Transformers	$ 16,432,674	$ 1,287,293	$ 27,678	$ 17,747,645	-$ 5,286,733	-$ 353,494		-$ 5,640,227	$ 12,107,418
47	1855	Services (Overhead & Underground)	$ 9,221,942	$ 1,044,927	-$ 0	$ 10,266,869	-$ 2,720,718	-$ 166,800		-$ 2,887,518	$ 7,379,351
47	1860	Meters	$ 4,707,530	$ 68,368	$ 237,709	$ 5,013,607	-$ 1,446,223	-$ 178,821		-$ 1,625,044	$ 3,388,563
47	1860	Meters (Smart Meters)	$ 612,241	$ 26,539		$ 638,780	-$ 64,855	-$ 23,884		-$ 88,739	$ 550,040
N/A	1905	Land	$ 190,119			$ 190,119	$ -			$ -	$ 190,119
47	1908	Buildings & Fixtures	$ 2,422,357			$ 2,422,357	-$ 422,438	-$ 27,100		-$ 449,538	$ 1,972,819
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 188,609	$ 1,499		$ 190,108	-$ 122,732	-$ 17,979		-$ 140,712	$ 49,396
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 324,149	$ 43,348		$ 367,497	-$ 312,778	-$ 4,346		-$ 317,124	$ 50,373
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 1,553,552	$ 425,100	-$ 136,054	$ 1,842,598	-$ 286,236	-$ 146,305	$ 136,054	-$ 296,487	$ 1,546,111
8	1935	Stores Equipment	$ 37,075		$ -	$ 37,075	-$ 23,329	-$ 2,673		-$ 26,002	$ 11,073
8	1940	Tools, Shop & Garage Equipment	$ 383,628	$ 78,333	$ -	$ 461,960	-$ 183,218	-$ 63,233		-$ 246,451	$ 215,509
8	1945	Measurement & Testing Equipment	$ 63,987			$ 63,987	-$ 35,885	-$ 11,235		-$ 47,120	$ 16,868
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 281,480			$ 281,480	-$ 223,486	-$ 43,937		-$ 267,423	$ 14,056
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 15,064,761	-$ 1,122,171		-$ 16,186,932	$ 1,288,742	$ 247,371		$ 1,536,113	-$ 14,650,819
47	2440	Deferred Revenue[5]	$ -				$ -				
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 60,692,886**	**$ 4,955,998**	**$ 129,333**	**$ 65,778,217**	**-$ 22,530,327**	**-$ 1,565,965**	**$ 136,054**	**-$ 23,960,237**	**$ 41,817,980**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 60,692,886**	**$ 4,955,998**	**$ 129,333**	**$ 65,778,217**	**-$ 22,530,327**	**-$ 1,565,965**	**$ 136,054**	**-$ 23,960,237**	**$ 41,817,980**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,565,965**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 141,330
Stores Equipment	
Net Depreciation	-$ 1,424,634

Accounting Standard MIFRS
Year **2015**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 1,327,398	$ 17,043		$ 1,344,441	-$ 1,189,249	-$ 75,579		-$ 1,264,828	$ 79,612
CEC	1612	Land Rights (Formally known as Account 1906)	$ 190,498	$ 14,661		$ 205,159	-$ 16,082	-$ 3,983		-$ 20,065	$ 185,094
N/A	1805	Land	$ 47,899			$ 47,899	$ -			$ -	$ 47,899
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 115,505		-$ 115,505	$ -	-$ 39,214	$ -	$ 39,214	$ 0	$ 0
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 7,343,189	$ 934,800		$ 8,277,989	-$ 1,320,220	-$ 133,666		-$ 1,453,886	$ 6,824,103
47	1835	Overhead Conductors & Devices	$ 7,340,765	$ 990,160		$ 8,330,925	-$ 3,112,900	-$ 73,557		-$ 3,186,457	$ 5,144,467
47	1840	Underground Conduit	$ 12,740,042	$ 279,301		$ 13,019,343	-$ 2,696,277	-$ 226,513		-$ 2,922,790	$ 10,096,553
47	1845	Underground Conductors & Devices	$ 13,335,773	$ 584,507		$ 13,920,280	-$ 5,090,023	-$ 287,646	$ 14,190	-$ 5,363,479	$ 8,556,801
47	1850	Line Transformers	$ 17,747,645	$ 923,100	-$ 108,617	$ 18,562,128	-$ 5,640,227	-$ 287,574	$ 47	-$ 5,927,754	$ 12,634,374
47	1855	Services (Overhead & Underground)	$ 10,266,869	$ 1,062,301	-$ 0	$ 11,329,169	-$ 2,887,518	-$ 158,272		-$ 3,045,790	$ 8,283,379
47	1860	Meters	$ 5,013,607	$ 241,104	-$ 770,147	$ 4,484,564	-$ 1,625,044	-$ 139,296		-$ 1,764,340	$ 2,720,224
47	1860	Meters (Smart Meters)	$ 638,780	$ 3,196,304		$ 3,835,084	-$ 88,739	-$ 244,350	-$ 1,104,875	-$ 1,437,964	$ 2,397,119
N/A	1905	Land	$ 190,119			$ 190,119	$ -			$ -	$ 190,119
47	1908	Buildings & Fixtures	$ 2,422,357	$ 48,914		$ 2,471,271	-$ 449,538	-$ 41,157		-$ 490,695	$ 1,980,576
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 190,108	$ 5,980		$ 196,088	-$ 140,712	-$ 8,342		-$ 149,054	$ 47,034
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 367,497	$ 3,875		$ 371,372	-$ 317,124	-$ 35,385		-$ 352,509	$ 18,863
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 1,842,598	$ 402,157		$ 2,244,755	-$ 296,487	-$ 189,589		-$ 486,076	$ 1,758,679
8	1935	Stores Equipment	$ 37,075	$ 17		$ 37,092	-$ 26,002	-$ 2,198		-$ 28,200	$ 8,892
8	1940	Tools, Shop & Garage Equipment	$ 461,960	$ 56,539		$ 518,499	-$ 246,451	-$ 42,042		-$ 288,493	$ 230,006
8	1945	Measurement & Testing Equipment	$ 63,987			$ 63,987	-$ 47,120	-$ 6,269		-$ 53,389	$ 10,599
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 281,480	$ 12,943		$ 294,423	-$ 267,423	-$ 29,553		-$ 296,976	-$ 2,554
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]	-$ 16,186,932	-$ 1,448,183		-$ 17,635,115	$ 1,536,113	$ 552,530		$ 2,088,643	-$ 15,546,472
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 65,778,217**	**$ 7,325,523**	**-$ 994,269**	**$ 72,109,471**	**-$ 23,960,237**	**-$ 1,432,441**	**-$ 1,051,424**	**-$ 26,444,102**	**$ 45,665,369**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 65,778,217**	**$ 7,325,523**	**-$ 994,269**	**$ 72,109,471**	**-$ 23,960,237**	**-$ 1,432,441**	**-$ 1,051,424**	**-$ 26,444,102**	**$ 45,665,369**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,432,441**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 183,143
Stores Equipment	
Net Depreciation	-$ 1,249,298

Accounting Standard MIFRS
Year **2016**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 1,344,441	$ 5,217		$ 1,349,658	-$ 1,264,828	-$ 63,196	$ 207,551	-$ 1,120,473	$ 229,184
CEC	1612	Land Rights (Formally known as Account 1906)	$ 205,159	$ 2,644		$ 207,803	-$ 20,065	-$ 4,114		-$ 24,179	$ 183,624
N/A	1805	Land	$ 47,899		-$ 12,000	$ 35,899	$ -			$ -	$ 35,899
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ -			$ -	$ 0			$ 0	$ 0
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,277,989	$ 598,652	$ 20,776	$ 8,897,417	-$ 1,453,886	-$ 148,824	$ 82,818	-$ 1,519,892	$ 7,377,525
47	1835	Overhead Conductors & Devices	$ 8,330,925	$ 956,400	-$ 81,821	$ 9,205,504	-$ 3,186,457	-$ 89,922	-$ 8,048	-$ 3,284,427	$ 5,921,076
47	1840	Underground Conduit	$ 13,019,343	$ 213,140	-$ 2,370	$ 13,230,112	-$ 2,922,790	-$ 232,711	$ 53,219	-$ 3,102,282	$ 10,127,831
47	1845	Underground Conductors & Devices	$ 13,920,280	$ 577,705	-$ 40,212	$ 14,457,773	-$ 5,363,479	-$ 293,497	-$ 20,759	-$ 5,677,735	$ 8,780,038
47	1850	Line Transformers	$ 18,562,128	$ 774,929	-$ 36,576	$ 19,300,481	-$ 5,927,754	-$ 334,035	$ 21,050	-$ 6,240,739	$ 13,059,743
47	1855	Services (Overhead & Underground)	$ 11,329,169	$ 893,280	-$ 68,166	$ 12,154,283	-$ 3,045,790	-$ 178,610	-$ 20,809	-$ 3,245,209	$ 8,909,074
47	1860	Meters	$ 4,484,564	$ 411,948	$ 664,128	$ 5,560,640	-$ 1,764,340	-$ 96,476	-$ 85,895	-$ 1,946,711	$ 3,613,929
47	1860	Meters (Smart Meters)	$ 3,835,084	$ 66,961	-$ 50,029	$ 3,852,015	-$ 1,437,964	-$ 278,118		-$ 1,716,082	$ 2,135,933
N/A	1905	Land	$ 190,119			$ 190,119	$ -			$ -	$ 190,119
47	1908	Buildings & Fixtures	$ 2,471,271	$ 42,469		$ 2,513,740	-$ 490,695	-$ 42,169	$ 12,486	-$ 520,378	$ 1,993,362
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 196,088	$ 20,672		$ 216,760	-$ 149,054	-$ 9,697	-$ 4,553	-$ 163,304	$ 53,456
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 371,372	$ 117,329		$ 488,701	-$ 352,509	-$ 11,815	$ 49,702	-$ 314,622	$ 174,079
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 2,244,755	$ 136,662		$ 2,381,417	-$ 486,076	-$ 213,884	-$ 27,154	-$ 727,114	$ 1,654,303
8	1935	Stores Equipment	$ 37,092	$ 10,275		$ 47,367	-$ 28,200	-$ 2,701	$ 10,121	-$ 20,780	$ 26,587
8	1940	Tools, Shop & Garage Equipment	$ 518,499	$ 45,830		$ 564,329	-$ 288,493	-$ 46,828	$ 53,783	-$ 281,538	$ 282,791
8	1945	Measurement & Testing Equipment	$ 63,987	$ 6,260		$ 70,247	-$ 53,389	-$ 6,599	$ 11,341	-$ 48,647	$ 21,601
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 294,423			$ 294,423	-$ 296,976	-$ 29,874	$ 51,594	-$ 275,256	$ 19,166
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 17,635,115	-$ 931,021		-$ 18,566,136	$ 2,088,643	$ 589,771		$ 2,678,414	-$ 15,887,722
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 72,109,471**	**$ 3,949,352**	**$ 393,730**	**$ 76,452,553**	**-$ 26,444,102**	**-$ 1,493,299**	**$ 386,447**	**-$ 27,550,954**	**$ 48,901,599**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 72,109,471**	**$ 3,949,352**	**$ 393,730**	**$ 76,452,553**	**-$ 26,444,102**	**-$ 1,493,299**	**$ 386,447**	**-$ 27,550,954**	**$ 48,901,599**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,493,299**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 206,612
Stores Equipment	
Net Depreciation	-$ 1,286,687

Accounting Standard MIFRS
Year **2017**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 1,349,658	$ 254,500		$ 1,604,158	-$ 1,120,473	-$ 81,624		-$ 1,202,097	$ 402,060
CEC	1612	Land Rights (Formally known as Account 1906)	$ 207,803	$ 42,192		$ 249,995	-$ 24,179	-$ 4,604		-$ 28,783	$ 221,212
N/A	1805	Land	$ 35,899			$ 35,899	$ -			$ -	$ 35,899
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ -			$ -	$ 0			$ 0	$ 0
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,897,417	$ 932,338		$ 9,829,755	-$ 1,519,892	-$ 163,794		-$ 1,683,686	$ 8,146,069
47	1835	Overhead Conductors & Devices	$ 9,205,504	$ 541,648		$ 9,747,152	-$ 3,284,427	-$ 104,679		-$ 3,389,106	$ 6,358,045
47	1840	Underground Conduit	$ 13,230,112	$ 734,410		$ 13,964,522	-$ 3,102,282	-$ 243,945		-$ 3,346,227	$ 10,618,296
47	1845	Underground Conductors & Devices	$ 14,457,773	$ 788,211		$ 15,245,984	-$ 5,677,735	-$ 314,089		-$ 5,991,824	$ 9,254,160
47	1850	Line Transformers	$ 19,300,481	$ 1,025,570		$ 20,326,051	-$ 6,240,739	-$ 322,980		-$ 6,563,719	$ 13,762,333
47	1855	Services (Overhead & Underground)	$ 12,154,283	$ 822,714		$ 12,976,997	-$ 3,245,209	-$ 197,036		-$ 3,442,245	$ 9,534,752
47	1860	Meters	$ 5,560,640	$ 266,932		$ 5,827,572	-$ 1,946,711	-$ 106,260		-$ 2,052,971	$ 3,774,601
47	1860	Meters (Smart Meters)	$ 3,852,015			$ 3,852,015	-$ 1,716,082	-$ 278,118		-$ 1,994,200	$ 1,857,815
N/A	1905	Land	$ 190,119			$ 190,119	$ -			$ -	$ 190,119
47	1908	Buildings & Fixtures	$ 2,513,740	$ 286,800		$ 2,800,540	-$ 520,378	-$ 45,350		-$ 565,728	$ 2,234,812
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 216,760	$ 10,000		$ 226,760	-$ 163,304	-$ 11,209		-$ 174,513	$ 52,247
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 488,701	$ 356,150		$ 844,851	-$ 314,622	-$ 73,917		-$ 388,539	$ 456,312
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 2,381,417	$ 487,000		$ 2,868,417	-$ 727,114	-$ 211,990		-$ 939,104	$ 1,929,313
8	1935	Stores Equipment	$ 47,367	$ 50,000		$ 97,367	-$ 20,780	-$ 5,708		-$ 26,488	$ 70,879
8	1940	Tools, Shop & Garage Equipment	$ 564,329	$ 60,000		$ 624,329	-$ 281,538	-$ 52,011		-$ 333,549	$ 290,780
8	1945	Measurement & Testing Equipment	$ 70,247			$ 70,247	-$ 48,647	-$ 6,895		-$ 55,542	$ 14,706
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 294,423			$ 294,423	-$ 275,256	-$ 15,040		-$ 290,296	$ 4,126
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 18,566,136	-$ 1,224,757		-$ 19,790,893	$ 2,678,414	$ 367,800	-$ 490,336	$ 2,555,878	-$ 17,235,015
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 76,452,553**	**$ 5,433,708**	**$ -**	**$ 81,886,261**	**-$ 27,550,954**	**-$ 1,871,449**	**-$ 490,336**	**-$ 29,912,740**	**$ 51,973,522**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 76,452,553**	**$ 5,433,708**	**$ -**	**$ 81,886,261**	**-$ 27,550,954**	**-$ 1,871,449**	**-$ 490,336**	**-$ 29,912,740**	**$ 51,973,522**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,871,449**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 204,782
Stores Equipment	
Net Depreciation	-$ 1,666,667

File Number:	EB-2017-0039
Exhibit:	2
Tab:	2-A
Page:	10 to 10
Date:	August 28th, 2017

Accounting Standard MIFRS
Year **2018**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 1,604,158	$ 115,000		$ 1,719,158	-$ 1,202,097	-$ 103,175		-$ 1,305,272	$ 413,885
CEC	1612	Land Rights (Formally known as Account 1906)	$ 249,995	$ 48,941		$ 298,936	-$ 28,783	-$ 5,515		-$ 34,298	$ 264,638
N/A	1805	Land	$ 35,899			$ 35,899	$ -			$ -	$ 35,899
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ -			$ -	$ 0			$ 0	$ 0
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 9,829,755	$ 432,914		$ 10,262,669	-$ 1,683,686	-$ 177,447		-$ 1,861,133	$ 8,401,536
47	1835	Overhead Conductors & Devices	$ 9,747,152	$ 839,476		$ 10,586,628	-$ 3,389,106	-$ 118,491		-$ 3,507,597	$ 7,079,030
47	1840	Underground Conduit	$ 13,964,522	$ 864,559		$ 14,829,081	-$ 3,346,227	-$ 263,932		-$ 3,610,159	$ 11,218,923
47	1845	Underground Conductors & Devices	$ 15,245,984	$ 853,466		$ 16,099,450	-$ 5,991,824	-$ 341,450		-$ 6,333,274	$ 9,766,176
47	1850	Line Transformers	$ 20,326,051	$ 1,040,794		$ 21,366,845	-$ 6,563,719	-$ 348,809		-$ 6,912,528	$ 14,454,318
47	1855	Services (Overhead & Underground)	$ 12,976,997	$ 800,370		$ 13,777,367	-$ 3,442,245	-$ 213,267		-$ 3,655,512	$ 10,121,855
47	1860	Meters	$ 5,827,572	$ 265,671		$ 6,093,243	-$ 2,052,971	-$ 124,013		-$ 2,176,984	$ 3,916,259
47	1860	Meters (Smart Meters)	$ 3,852,015			$ 3,852,015	-$ 1,994,200	-$ 278,118		-$ 2,272,318	$ 1,579,697
N/A	1905	Land	$ 190,119			$ 190,119	$ -			$ -	$ 190,119
47	1908	Buildings & Fixtures	$ 2,800,540	$ 370,000		$ 3,170,540	-$ 565,728	-$ 51,918		-$ 617,646	$ 2,552,894
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 226,760	$ 10,000		$ 236,760	-$ 174,513	-$ 11,445		-$ 185,958	$ 50,802
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 844,851	$ 161,809		$ 1,006,660	-$ 388,539	-$ 121,790		-$ 510,329	$ 496,331
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 2,868,417	$ 270,000		$ 3,138,417	-$ 939,104	-$ 273,932		-$ 1,213,036	$ 1,925,381
8	1935	Stores Equipment	$ 97,367	$ 50,000		$ 147,367	-$ 26,488	-$ 10,101		-$ 36,589	$ 110,778
8	1940	Tools, Shop & Garage Equipment	$ 624,329	$ 60,000		$ 684,329	-$ 333,549	-$ 49,066		-$ 382,615	$ 301,714
8	1945	Measurement & Testing Equipment	$ 70,247			$ 70,247	-$ 55,542	-$ 5,458		-$ 61,000	$ 9,248
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 294,423			$ 294,423	-$ 290,296	-$ 13,332		-$ 303,628	-$ 9,206
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 19,790,893	-$ 1,224,757		-$ 21,015,650	$ 2,555,878	$ 398,418		$ 2,954,295	-$ 18,061,355
						$ -	$ -			$ -	$ -
		Sub-Total	**$ 81,886,261**	**$ 4,958,243**	**$ -**	**$ 86,844,504**	**-$ 29,912,740**	**-$ 2,112,841**	**$ -**	**-$ 32,025,581**	**$ 54,818,923**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 81,886,261**	**$ 4,958,243**	**$ -**	**$ 86,844,504**	**-$ 29,912,740**	**-$ 2,112,841**	**$ -**	**-$ 32,025,581**	**$ 54,818,923**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,112,841**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 264,837
Stores Equipment	
Net Depreciation	-$ 1,848,004

Attachment 2-B

Stranded Meter Treatment

Appendix 2-S
Stranded Meter Treatment

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2008		$ 65,437	$ 34,414	$ -	$ 31,023	$ -	$ 31,023
2009		$ 1,224,257	$ 359,336	$ -	$ 864,921	$ -	$ 864,921
2010		$ 2,328,222	$ 695,859	$ -	$ 1,632,363	$ -	$ 1,632,363
2011		$ 2,617,818	$ 858,988	$ -	$ 1,758,830	$ -	$ 1,758,830
2012		$ 2,617,818	$ 963,700	$ -	$ 1,654,118	$ -	$ 1,654,118
2013		$ 2,617,818	$ 1,068,413	$ -	$ 1,549,405	$ -	$ 1,549,405
2014		$ 2,617,818	$ 1,173,126	$ -	$ 1,444,692	$ -	$ 1,444,692
2015		$ 2,617,818	$ 1,277,838	$ -	$ 1,339,980	$ -	$ 1,339,980
2016		$ 2,617,818	$ 1,382,551	$ -	$ 1,235,267	$ -	$ 1,235,267
2017	(1)	$ 2,617,818	$ 1,487,264	$ -	$ 1,130,554	$ -	$ 1,130,554
2018		$ 2,617,818	$ 1,522,168	$ -	$ 1,095,650	$ -	$ 1,095,650

Notes:

(1) *For 2017, please indicate whether the amounts provided are on a forecast or actual basis.*

Some distributors have transferred the cost of stranded meters from Account 1860 - Meters to "Sub-account Stranded Meter Costs of Account 1555", while in some cases distributors have left these costs in Account 1860. Depending on which treatment the applicant has chosen. please provide the information under either of the two scenarios (A and B below), as applicable.

Scenario A: *If the stranded meter costs were transferred to "Sub-account Stranded Meter Costs" of Account 1555, the above table should be completed and the following information should be provided in Exhibit 9.*

1 A description of the accounting treatment followed by the applicant on stranded meter costs for financial accounting and reporting purposes.

2 The amount of the pooled residual net book value of the removed from service stranded meters, less any contributed capital (net of accumulated amortization), and less any net proceeds from sales, which were transferred to this sub-account as of December 31, 2010.

3 A statement as to whether or not, since transferring the removed stranded meter costs to the sub-account, the recording of depreciation expenses was continued in order to reduce the net book value through accumulated depreciation. If so, the total depreciation expense amount for the period from the time the costs for the stranded meters were transferred to the sub-account to December 31, 2010 should be provided.

If no depreciation expenses were recorded to reduce the net book value of stranded meter costs through accumulated depreciation, the total depreciation expense amount that would have been applicable from the time that the stranded meter costs were transferred to the sub-account of Account 1555 to December 31, 2010 should be provided. In addition, the following information should be provided:

a) Whether or not carrying charges were recorded for the stranded meter cost balances in the sub-account, and if so, the total carrying charges recorded to December 31, 2010.

b) The estimated amount of the pooled residual net book value of the removed from service meters, less any net proceeds from sales and contributed capital, at the time when the smart meters will have been fully deployed (e.g., as of December 31, 2010). If the smart meters have been fully deployed, the actual amount should be provided.

c) A description as to how the applicant intends to recover in rates the remaining costs for stranded meters, including the proposed accounting treatment, the proposed disposition period, and the associated bill impacts.

Scenario B: *If the stranded meter costs remained recorded in Account 1860, the above table should be completed and the following information should be provided in Exhibit 9:*

1 A description of the accounting treatment followed by the applicant on stranded meter costs for financial accounting and reporting purposes.

2 The amount of the pooled residual net book value of the removed from service stranded meters, less any contributed capital (net of accumulated amortization), and less any net proceeds from sales, as of December 31, 2010.

3 A statement as to whether or not the recording of depreciation expenses continued in order to reduce the net book value through accumulated depreciation. If so, provision of the total (cumulative) depreciation expense for the period from the time that the meters became stranded to December 31, 2010.

4 If no depreciation expenses were recorded to reduce the net book value of stranded meters through accumulated depreciation, the total (cumulative) depreciation expense amount that would have been applicable for the period from the time that the meters became stranded to December 31, 2010.

5 The estimated amount of the pooled residual net book value of the removed from service meters, less any net proceeds from sales and contributed capital, at the time when smart meters will have been fully deployed. If the smart meters have been fully deployed, please provide the actual amount.

6 A description as to how the applicant intends to recover in rates the costs for stranded meters, including the proposed accounting treatment, the proposed disposition period and the associated bill impacts.

Distributors should also provide the Net Book Value per class of meter as of December 31, 2010 as well as the number of meters that were removed / stranded. In preparing this information, distributors should review the Board's letter of January 16, 2007 *Stranded Meter Costs Related to the Installation of Smart Meters* which stated that records were to be kept of the type and number of each meter to support the stranded meter costs.

Attachment 2-C

EPLC Distribution System Plan

Essex Powerlines Corporation
Distribution System Plan

2018 Cost of Service Application

Historical Period: 2013 to 2017

Forecast Period: 2018 to 2022

11 August 2017

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Appendix A: Project Narratives

Appendix B: Windsor-Essex Region Integrated Regional Resource Plan

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1 Introduction

Essex Powerlines Corporation ("**EPL**") has prepared this Distribution System Plan ("**DSP**") in accordance with the Ontario Energy Board's ("**OEB**'s") *Chapter 5 Consolidated Distribution System Plan Filing Requirements* dated 28 March 2013 (the "**Filing Requirements**") as part of its 4th Generation IR Application based on a 2018 forward test year cost of service review ("**the Application**").

1.1 Objectives & Scope of Work

EPL's DSP has been prepared to support the four (4) key objectives from the OEB's *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* ("**RRFE**"):

1. Customer Focus: services are provided in a manner that responds to identified customer preferences;
2. Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;
3. Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
4. Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.

In alignment with these four outcomes, EPL's overarching objective of its five (5)-year plan is to provide a modern, smart grid fit for the 21st century at inflation-aligned costs. In order to achieve the goals EPL has set for itself, EPL continually strives to:

- Provide detailed outage communication to all customers.
- Continually look to drive costs down with the implementation of modern management techniques and other process improvements.
- Incorporate full system control room functions by distributing the responsibility throughout the Operations department as opposed to centralizing the function into a twenty-four (24) hour control room.
- Invest in software systems to streamline and automate daily work tasks including: the tracking and recording of asset condition data, the inputting of time entry information, job cost tracking, inventory management, job kitting, the design and accurate estimation of planned work, and the recording of all asset information in the Geospatial Information System ("**GIS**"), among others.
- Develop and integrate into daily use an advanced distribution system monitoring mapping system, called "SmartMAP", that continuously monitors all measurable system events (e.g. meter outages, distribution fault indicators, transformer loading, etc.) and automatically notifies the appropriate personnel of any system condition that requires further investigation and inspection.

EPL chose to respond and manage its unique challenges by implementing changes and new processes that are responsive to the Values it has adopted. These Values and those

adopted by the electrical industry in Ontario, such as the RRFE, are integral to how EPL prioritizes its capital investments and guide its future direction.

1.2 Outline of Report

This DSP has been organized using the same headings as the Filing Requirements, with the corresponding section number from the Filing Requirements included in brackets for each heading.

The report contains four sections including this introductory section as Section 1. Section 2 provides a high-level overview of the DSP, including coordinated planning with third parties and performance measurement for continuous improvement. Section 3 provides an overview of EPL's asset management process, including an overview of the assets managed and asset lifecycle optimization policies and practices. Section 4 provides a summary of EPL's capital expenditure plan, including an overview of the capital expenditure planning process, an assessment of the system capability for REG, and justification of material projects.

1.3 Background & Drivers

EPL's capital investments over the planning period have been aligned to the four (4) categories of system access, system renewal, system service, and general plant. Investments within these categories have been paced and prioritized to meet the objectives of the RRFE.

System access investments are modifications to EPL's distribution system (including asset relocations) that EPL is obligated to perform to provide customers with access to electricity services via the distribution system. Drivers for this investment category are customer service requests, other third-party infrastructure development requests, and mandated service obligations (e.g. as per the Distribution System Code).

System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of EPL's distribution system to provide customers with electricity services. Assets and asset systems may be at the end of their service life due to failure, failure risk, substandard performance, high performance risk, or functional obsolescence.

System service investments are modifications to EPL's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements. Drivers for this investment category include expected changes in load that will constrain the ability of the system to provide consistent service delivery and meeting system operational objectives in safety, reliability, power quality, and system efficiency.

General plant investments are modifications, replacements or additions to EPL's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities. Drivers for this investment category include system capital investment

support, system maintenance support, business operations efficiency, and non-system physical plant.

Table 1-1 summarizes the drivers for the capital projects/programs planned over the forecast period.

Table 1-1: Capital investment drivers over the forecast period

Investment Category	Driver	Projects/Programs
System access	Customer service requests	Residential connections/extensions
		New service upgrades – commercial and industrial
		Subdivisions
	Third-party infrastructure development requirements	Municipal requests
	Mandated service obligations	Metering upgrade and replacement program
System renewal	Asset failure	Overhead reactive replacements
		Underground reactive replacements
	Assets at the end of their service life due to failure risk	Pole replacement program
		PMH replacement program
		Load break switch replacement
		Infrastructure rebuild program
System service	System operability	Purchase/sell HONI Leamington assets
		Purchase/sell HONI LaSalle assets
	System reliability	Self-healing grid reclosers
	System capacity	Malden TS new feeders and reconfiguration
	Customer-driven generation connection requests	FIT and generation connections
		MicroFIT connections
General plant	Non-system physical plant	Buildings and fixtures
	Business operations efficiency	Computer software
	Non-system equipment at the end of its service life	Tools and equipment
		Transportation equipment
		Office furniture and equipment
		Computer hardware
		Stores equipment

1.4 Description of the Utility Company

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

At that time, the four (4) municipalities of Amherstburg, LaSalle, Leamington, and Tecumseh made a strategic decision to pool the resources of their utilities together to avoid various costs of deregulation and to maximize efficiencies of scale.

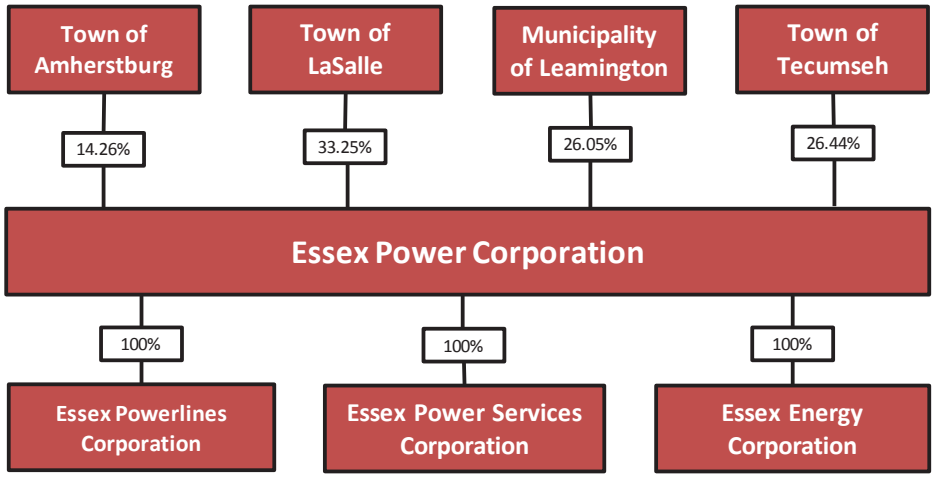
On June 1, 2000, the Towns of Amherstburg, LaSalle, and Tecumseh and the Municipality of Leamington amalgamated their small utilities to form what is currently known as the Essex Power Group of Companies. The assets, such as the wires were transferred to EPL. Essex Power Services Corporation received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

All administration from the four (4) utilities was consolidated. Operations such as billing, collecting, finance, payroll, and accounts payable were centralized in November 2000; administrative staff were located at the Essex County Civic Centre in Essex, Ontario. Outside staff were moved to the Oldcastle service station in the spring of 2003. All staff were consolidated into the Oldcastle service station in 2012.

Today, EPL strives to provide value to its now approximately 30,000 customers by minimizing outages and providing best-in-class customer service with minimal increases to electricity distribution rates. The Application will outline the various ways that EPL is achieving these goals.

Figure 1-1 illustrates Essex Power Corporation's corporate structure and its relationship with its four (4) respective shareholders.

Figure 1-1: Essex Power Corporation's corporate structure



Essex Power Corporation is owned by four (4) municipally-owned shareholders: the Town of Amherstburg (14.26%), the Town of LaSalle (33.25%), the Municipality of Leamington (26.05%), and the Town of Tecumseh (26.44%). While equity percentages differ for each shareholder, they each hold equal voting rights. Essex Power Corporation serves as the holding company for its subsidiary group of companies.

EPL is a wholly-owned subsidiary of Essex Power Corporation. EPL is a licensed local distribution company ("**LDC**"), with Distribution License ED-2002-0499, which distributes electricity to approximately 30,000 customers across its four (4) shareholder communities.

Essex Power Services Corporation is a wholly-owned, unregulated subsidiary of Essex Power Corporation and aims to provide best-in-class municipal and LDC services such as streetlight maintenance and subdivision work. Essex Power Services Corporation is also a Meter Service Provider – MSP1034 – registered with the Independent Electricity System Operator ("**IESO**").

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

1.4.1 Service Area including Map

EPL's service area consists of four non-contiguous regions in Essex County located in south-western Ontario: the Town of Amherstburg, the Town of LaSalle, the Municipality of Leamington, and the Town of Tecumseh. Figure 1-2 depicts the County of Essex with EPL's service areas highlighted. The individual towns are geographically dispersed over a large area, increasing travel time and increasing response time without thorough planning and the availability of advanced sensing and distribution automation equipment. EPL is bordered by Hydro One Networks Inc. ("**HONI**") south and east of Tecumseh and LaSalle, and the Leamington and Amherstburg service areas are completely encompassed by HONI. EPL is also bordered by EnWin Utilities west of Tecumseh and north of LaSalle. ELK Energy does not directly border EPL's service areas, but also distributes electricity in the County of Essex.

EPL does not own any substations and instead receives power from four (4) transformer stations ("**TS**") owned by HONI. Each service area is embedded in a densely-populated area of Ontario and the resultant distribution system is heavily tied to and dependent upon HONI-owned distribution assets. This dependence and influence results in a high percentage of outages originating on the HONI system and beyond the control of EPL to manage with traditional distribution assets such as manually-operated switches and without advanced distribution system sensing devices.

Figure 1-2: Map depicting EPL's four non-contiguous service areas

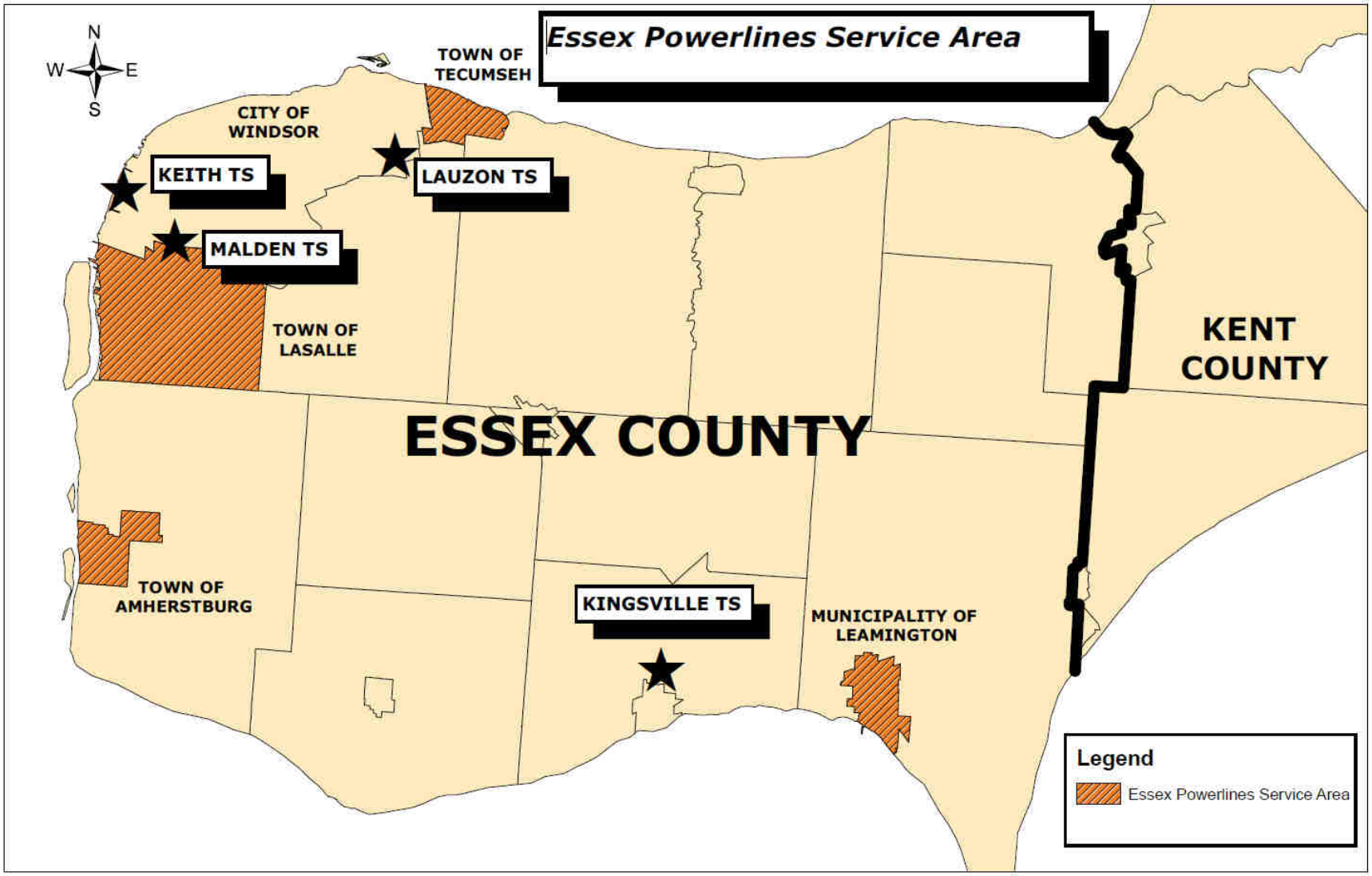


Figure 1-3: EPL's distribution system in LaSalle

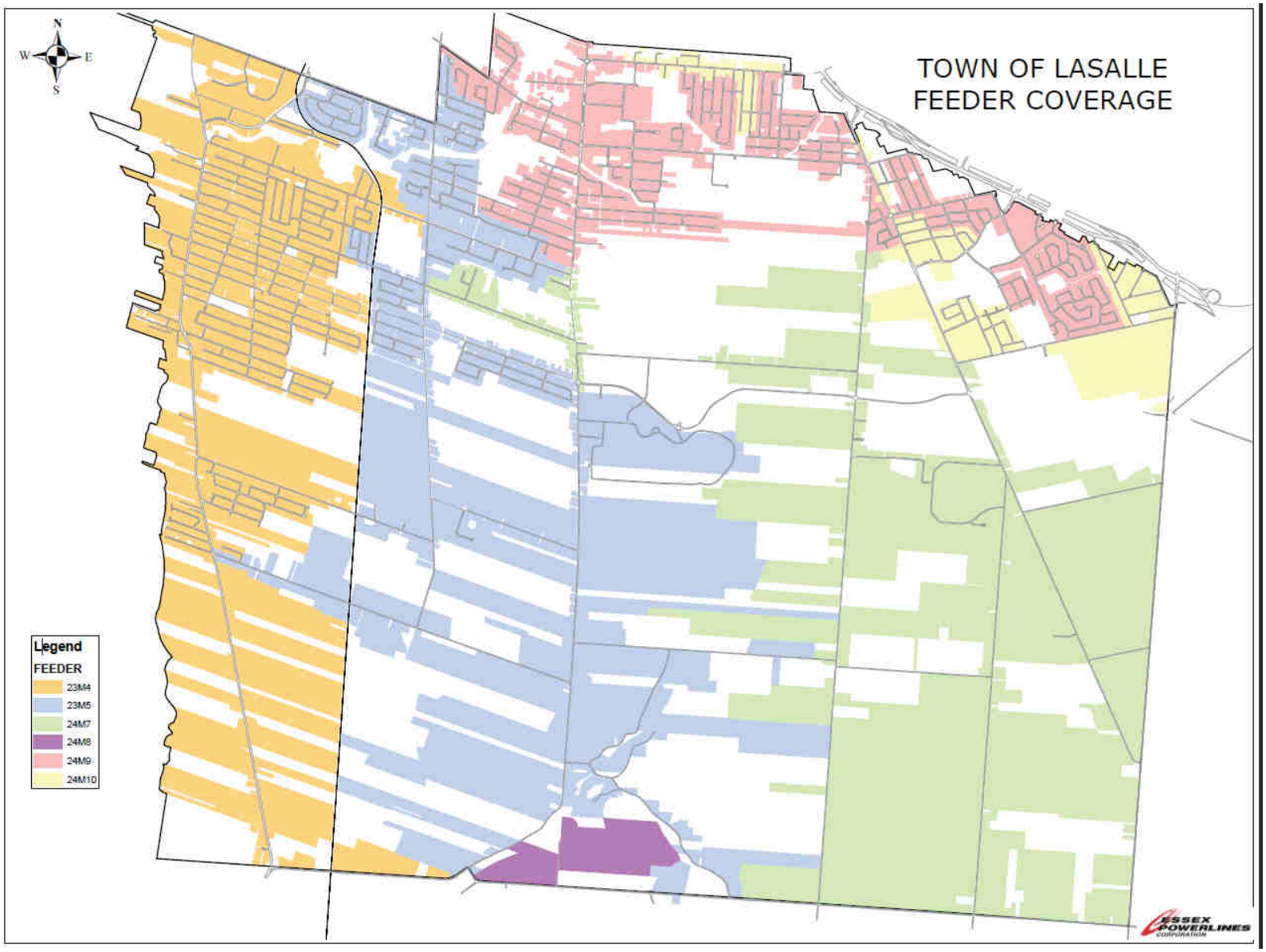


Figure 1-4: EPL's distribution system in Amherstburg

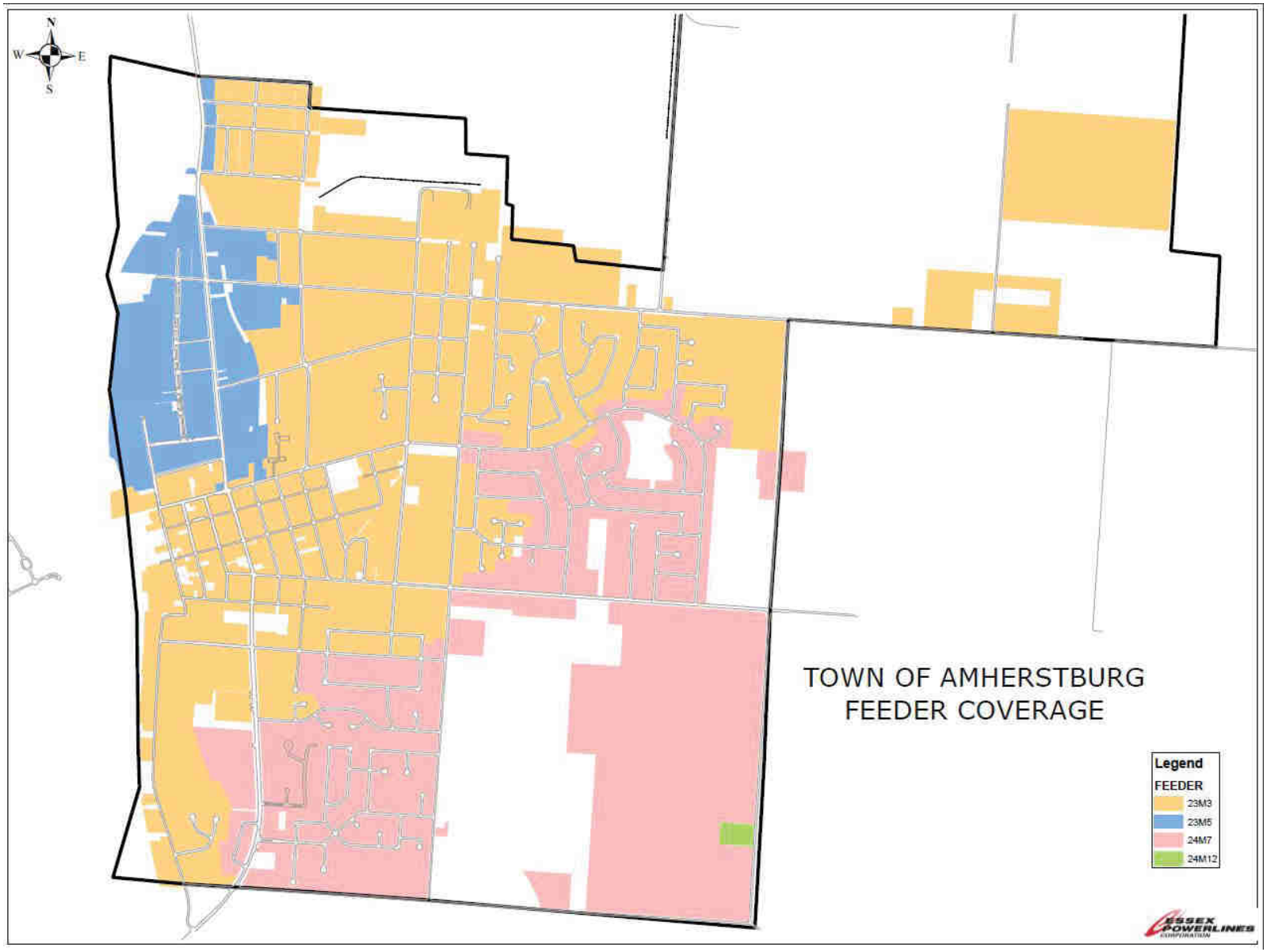


Figure 1-5: EPL's distribution system in Tecumseh

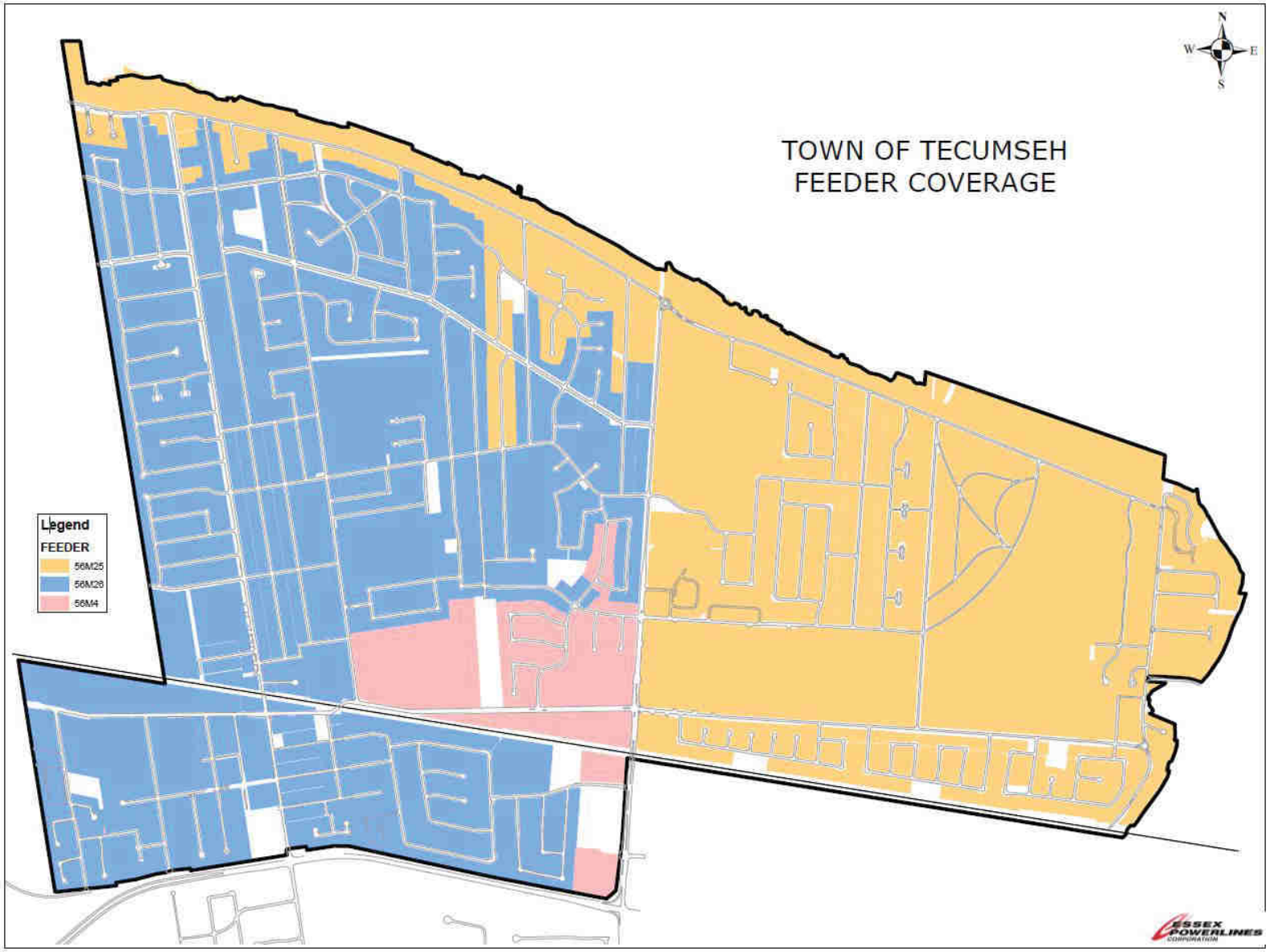
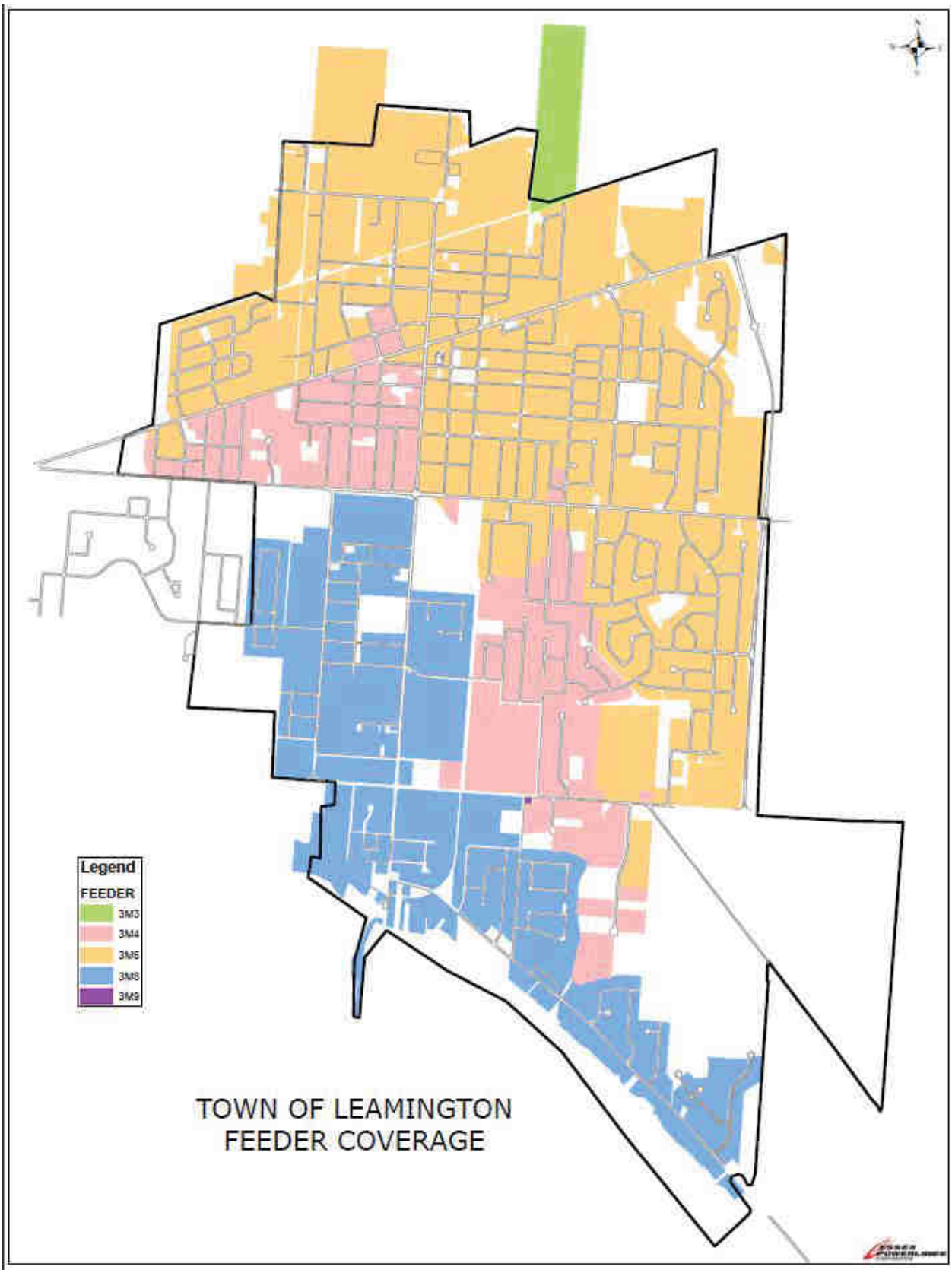


Figure 1-6: EPL's distribution system in Leamington



1.4.2 Mission & Vision Statement

EPL's mission and vision statements are presented below:

Mission Statement:

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

Vision Statement:

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

1.4.3 Corporate Values

EPL's capital investment strategy is driven by its corporate values. These corporate values, formulated for EPL's parent company, Essex Power Corporation, have been adopted without change by all affiliated companies in the Essex Power Corporation group of companies.

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

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

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

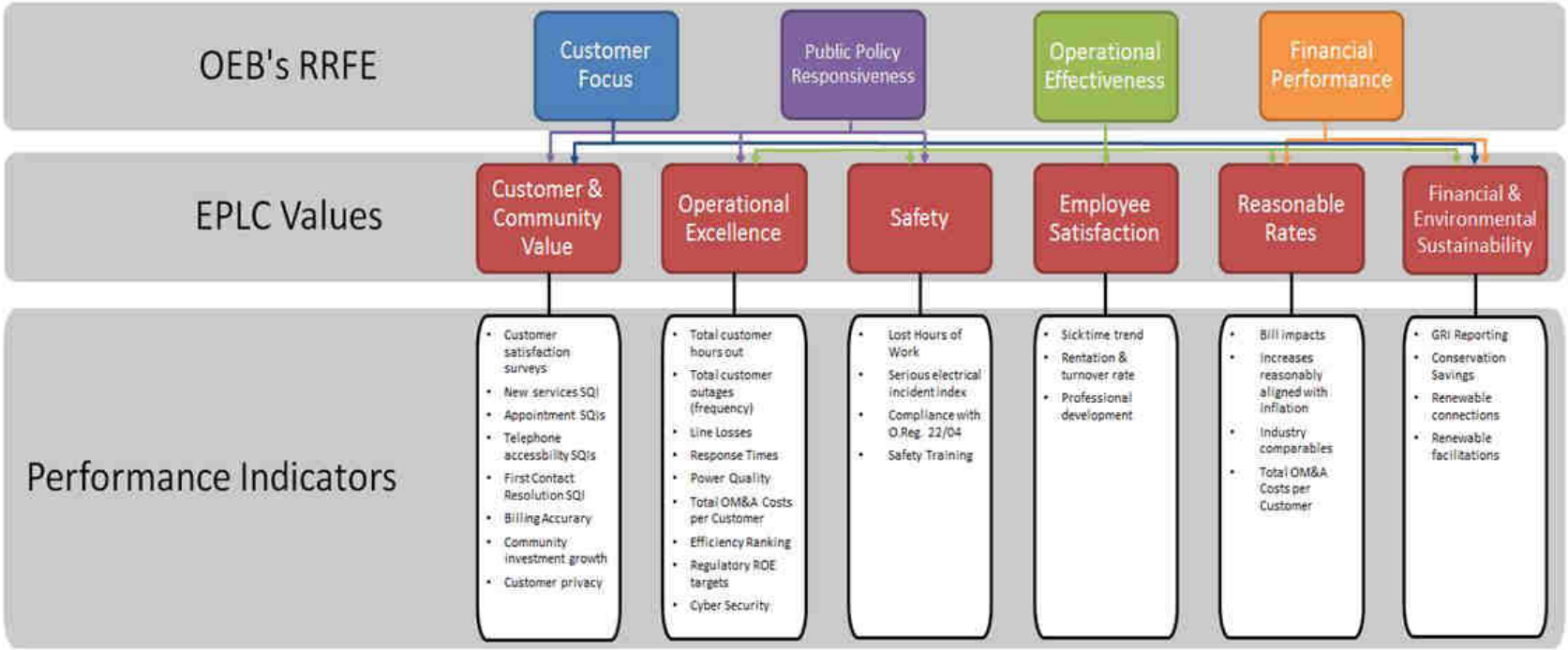
1.4.3.1 Tying EPL's Key Values with the RRFE

EPL has identified six (6) core corporate values:

1. Customer & Community Value;
2. Operational Excellence;
3. Safety;
4. Employee Satisfaction;
5. Reasonable Rates; and
6. Financial & Environmental Sustainability.

Figure 1-7 relates EPL's corporate values to the four (4) objectives of the RRFE.

Figure 1-7: EPL's corporate values



1.4.3.1.1 Customer & Community Value

Description of Value & Ties to RRFE:

EPL's core value of driving Customer & Community Value is defined as follows:

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

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

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

- Customer Satisfaction Surveys;
- Energy conservation and demand management ("**CDM**") program participation;
- Investing back in each of the four (4) shareholder communities through various charitable organizations; and
- Maintaining just and reasonable rates in line with inflation.

1.4.3.1.2 Operational Excellence

Description of Value & Ties to RRFE:

EPL's core value of delivering Operational Excellence is defined as follows:

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

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

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

- Development of EPL's DSP;
- Implementing best-in-class solutions and shared services;
- Facilitating the self-healing grid;
- Progressing towards a single distribution voltage;
- Successful and cost-effective implementation of public policy initiatives such as smart meters, Time of Use ("**TOU**") billing, renewable energy generation ("**REG**") connections and facilitation, CDM programs, etc.; and
- Maintaining just and reasonable rates in line with inflation.

1.4.3.1.3 Safety

Description of Value & Ties to RRFE:

EPL's core value of advocating the importance of Safety across its entire operation can be defined as follows:

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

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

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

- Joint Health & Safety Committee;
- First Aid, CPR, and defibrillator training;
- Specialized Safety Training; and
- School Electrical Safety Awareness.

1.4.3.1.4 Employee Satisfaction

Description of Value & Ties to RRFE:

EPL's core value of driving Employee Satisfaction is defined as follows:

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

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

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

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

1.4.3.1.5 Reasonable Rates

Description of Value & Ties to RRFE:

EPL's core value of maintaining Reasonable Rates is defined as follows:

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

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

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

- Maintaining just and reasonable rates, in line with inflation;
- Prudent Investments in Smart Grid; and
- Controllable Costs per Customer in line with leaders in Ontario.

1.4.3.1.6 Financial & Environmental Sustainability

Description of Value & Ties to RRFE:

EPL's core value of championing Financial & Environmental Sustainability is defined as follows:

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

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

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

- Yearly Global Reporting Initiative sustainability reporting;
- CDM program participation;
- Facilitating REG connections; and
- Maintaining just and reasonable rates in line with inflation.

1.4.3.2 Best-In-Class Solutions & Shared Services

EPL has worked closely with a variety of service providers to maximize the scope and quality of services rendered to customers. One such example of a Best-In-Class technology deployment was in 2012. EPL, in partnership with its sister company Essex Energy Corporation, was successfully awarded an Ontario Smart Grid Fund grant to demonstrate the capabilities and functionality of a new software product called SmartMAP.

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

The implementation of SmartMAP has enabled:

- Integration of existing smart meters with the Outage Management System to transmit "last gasp" data in real time, allowing the analysis component to pinpoint exact outage locations, predict causes, and suggest switching changes to restore power faster;
- Transformer loading profile (kWh vs. time of day, kVA vs. time of day) aiding in identification of under- or over-loaded assets;
- Reporting of line losses from wholesale meters, transformers, and residential meters;
- Identification and location of low voltage conditions which signal failing equipment or wrong transformer tap settings;
- Reconciliation of loads connected to each transformer to assist in identifying non-technical losses;
- Web application available to Operations personnel such that reporting and problem-solving is made quicker and easier;

- Ability to communicate critical network alarms and messages to a cellular phone through the use of email or SMS;
- Visual monitoring of real-time operational data from field devices (fault/line monitors, automated reclosers or switches, and any other field device capable of providing real time feedback) on a graphic display; and
- A common platform for data and analysis that can be used by different LDCs across any geography.

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

1.4.3.3 Essex Powerlines – An Efficient Single-Voltage Utility

For more than a decade now, EPL has prioritized the completion of necessary conversion work to simplify its distribution system, reduce inventory, shrink maintenance costs, and reduce its distribution losses for the benefit of EPL's customers. While EPL generally only controls approximately 20% of the total electricity (i.e. distribution charges), reducing losses has been a mandate for at EPL since distribution losses affect a broader portion of the electricity bill.

EPL has eliminated eight (8) substations (with the last one coming out of service in 2016) and converted significant lengths of line to become as close to a single-voltage utility as technically possible. EPL still has a small number of step down transformers in remote areas; however, EPL plans to convert them when most technically and financially feasible.

As a result of this work, EPL has been able to significantly reduce distribution losses throughout its distribution system resulting in significant savings for its customers.

Table 1-2: EPL Voltage Conversion Results

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

1.4.3.4 The Self-Healing Grid

In 2014, EPL completed its first iteration of its Green Energy Act Plan and, subsequently, a Smart Grid Development Plan. Along with SmartMAP, EPL outlined its plan to shift to a smarter grid that was capable of reducing the impact of Loss of Supply incidents on customers. By installing upgrades in three (3) key areas, EPL is evolving its grid into a "Self-Healing Grid":

1. Line monitors;
2. Reclosers; and
3. Wholesale meters.

Line Monitors:

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

Reclosers:

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

Wholesale Meters:

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

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

1.4.4 Customers Served

EPL services approximately 30,000 customers in its four non-contiguous service areas, but does not service all customers within the respective municipalities' borders except for the Town of LaSalle. In the other towns, the rural areas are serviced by HONI. EPL's customer base is primarily residential and small commercial customers and there are very few large industrial customers.

Most of EPL's customers fall into one of the following classes: Residential, General Service ("**GS**") less than 50 kW, GS greater than 50 kW (up to 2,999 kW), and GS 3,000 to 4,999 kW. EPL also serves streetlight customers (municipalities), sentinel lights, and unmetered loads. The year-end customer counts for the years 2013 to 2016 of the historical period are shown in Table 1-3. The total number of customers increased by an average rate of 5% per annum over this period.

Table 1-3: Year-end customer counts over the historical period

Customer Class	2013	2014	2015	2016
GS 3,000 to 4,999 kW	1	1	0	0
GS less than 50 kW	1,904	1,910	1,936	1,953
GS greater than 50 kW	214	216	217	223
Residential	26,466	26,590	26,815	27,137
Streetlights	2,621	2,713	2,701	2,720
Sentinel Lights	175	172	174	173
Unmetered	140	140	141	140
Total	**31,521**	**31,742**	**31,985**	**32,346**

1.4.5 Energy Conservation and Demand Management

EPL is an active participant in CDM programs administered by the IESO. Under the previous CDM framework spanning from 2011 to 2014, EPL was assigned a net annual peak demand savings target of 7.19 MW and a net cumulative energy savings target of 21.54 GWh.

As shown in Figure 1-8, Essex did not meet its target for net annual peak demand savings, finishing at 3.2 MW or forty-four percent (44.4%) of the target. The loss of a demand response contract with Heinz Corporation was the biggest detriment to EPL's performance. EPL's service territory is primarily residential with only small-scale industrial customers, making demand management programs difficult to implement.

Figure 1-8 also depicts the net cumulative energy savings performance, which exceeded EPL's target, totalling 23.3 GWh or 108.0% of the target. The two most effective programs for EPL were the Retrofit and HVAC Incentive programs. EPL's customers realized 9,806,366 kWh and 3,470,981 kWh in savings, respectively, through these programs.

Figure 1-8: CDM achievements under the previous framework

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

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

Achievement by Sector

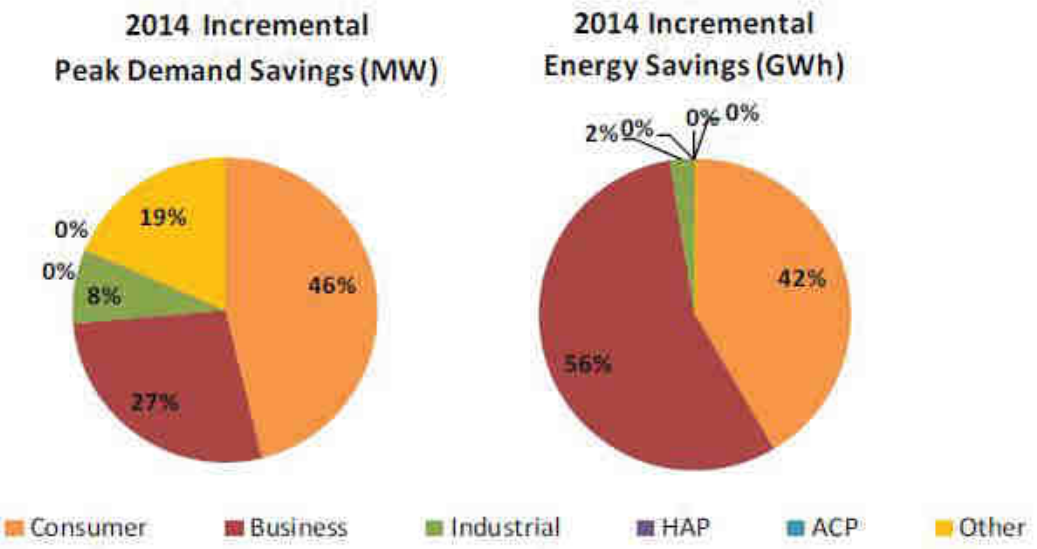


Figure 1-9: CDM performance under the previous framework relative to other LDCs

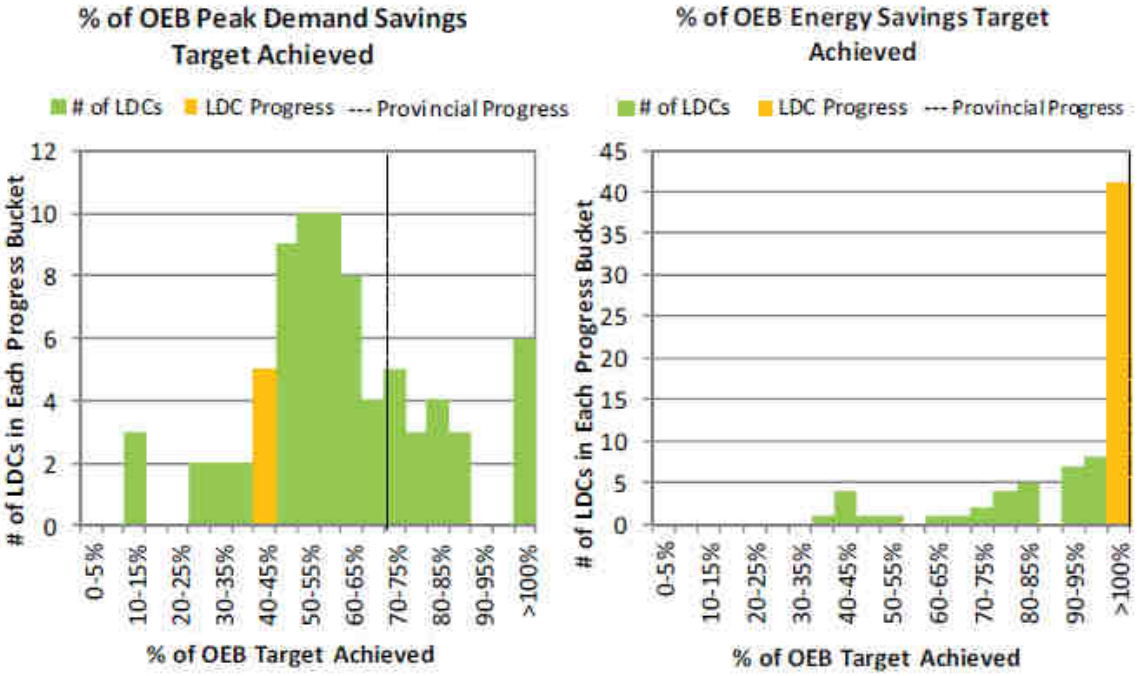


Figure 1-9 depicts EPL's performance under the previous CDM framework relative to other LDCs in the province of Ontario. EPL finished in the bottom quartile for net annual peak demand savings and at the top of the scale for net cumulative energy savings.

The IESO's latest Conservation First Framework spans from 2015 to 2020 and focuses solely on energy conservation. This approach is suited to EPL since its customer base mostly consists of residential customers. EPL was assigned a target of 31.43 GWh in net cumulative energy savings over the six (6)-year period. EPL's annual energy savings targets for the years 2015 through 2020 are presented in Table 1-4.

Table 1-4: EPL's CDM achievement plan under the Conservation First Framework

Year	2015	2016	2017	2018	2019	2020
Annual Energy Savings Target (MWh)	2,660	7,256	10,200	3,837	3,805	3,866

EPL plans to target residential and low-income customers through province-wide Coupon, Heating and Cooling, Home Assistance, and New Construction programs. Small business, customers will be targeted through province-wide Retrofit, Small Business Lighting, High Performance New Construction, and Audit Funding programs. EPL has also planned three unique programs: the Residential Solar PV program for residential customers, the Social Benchmarking program for residential and low-income customers, and the Smart Thermostat program for residential, low-income, and small business customers. Commercial, agricultural, institutional, and industrial customers will be targeted through a number of initiatives such as the Retrofit, High Performance New Construction, Audit Funding, Process and System Upgrades, and Energy Manager programs. These programs are all funded through the 2015-2020 CDM Framework.

In addition, there are several programs from the 2011-2014 CDM Framework that were extended into 2015 through the 2011-2014 Master CDM Agreement. These programs contributed to the 2015 energy savings achievements, but were not funded through the 2015-2020 CDM Framework. Key programs include Residential New Construction, the Bi-Annual Retailer Event, and Heating and Cooling Initiatives.

In 2015 EPL achieved twelve percent (12%) of its six (6)-year target, which is greater than the annual target shown in Table 1-4, while only spending two percent (2%) of its allocated budget. This first-year performance under the Conservation First Framework positions EPL suitably for achieving even greater energy savings in future program years, as significant conservation projects were identified in 2015 for implementation in 2016.

2 Distribution System Plan (5.2)

The section provides a high-level overview of the information filed in the DSP, coordinated infrastructure planning with third parties, and the measures used to monitor distribution system planning performance.

2.1 Distribution System Plan Overview (5.2.1)

As stated in the objective of this DSP, it is EPL's intention to provide a modern, smart grid fit for the 21st century at inflation-aligned costs. To achieve this, EPL is planning to spend less on reactive replacements since planned capital projects and programs are more cost effective. EPL is investing more of its system renewal budget towards underground cable replacements than overhead rebuilds, partly in response to the changing demographics of its system (less overhead kilometres of line) and partly in response to an increased impact of direct-buried cable failures. New reclosers, automated switches, and other smart grid devices are planned to be installed each year of the forecast period to improve the efficiency and functionality of the self-healing grid.

EPL is proposing to purchase and sell assets from and to HONI in LaSalle, Leamington and Amherstburg. This rationalization of asset ownership will accomplish several operational goals simultaneously:

- Create clearer demarcation of asset ownership between HONI and EPL. This will simplifier day-to-day operation of the distribution system.
- Increase the effectiveness of both parties to isolate parts of the system for maintenance and restore power to their respective customers more quickly.
- Significantly simplify the installation and development of a smart grid, a key focus of EPL's DSP throughout the forecast period.

In general, this will allow EPL to ensure that assets are managed more effectively.

In addition, as a result of the asset transfers and a planned HONI upgrade of Malden TS, a feeder reconfiguration planned over the forecast period will ensure sufficient capacity is available to serve EPL's customers. The overall impact of these changes is to focus and address loss of supply issues to improve system reliability.

Other key investments over the forecast period include: system access projects initiated by customers and municipalities, capital contributions to HONI related to Malden TS, and general plant investments required to replace key Automated Metering Infrastructure ("**AMI**") components such as gatekeepers and modems, at end of life.

2.1.1 Key Elements of the DSP (5.2.1a)

Table 2-1 presents the net capital expenditures by investment category, including the system operations and maintenance ("**O&M**") costs for both the historical and forecast period.

Table 2-1: Historical and forecast net capital expenditures and system O&M

Category	Historical ($ '000)					Forecast ($ '000)				
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
System Access	1,766	2,532	2,341	1,759	1,712	1,746	1,781	1,816	1,853	1,835
System Renewal	3,113	3,012	2,695	2,125	2,655	2,693	1,362	2,304	2,248	2,195
System Service	185	177	2,196	1,005	787	707	2,186	1,126	1,243	1,342
General Plant	450	487	547	384	1,504	1,037	856	976	927	968
Net Capital Expenses	5,513	6,208	7,779	5,274	6,658	6,183	6,185	6,222	6,270	6,339
System O&M	2,722	2,994	3,141	3,171	2,794	3,067	3,116	3,162	3,213	3,264

2.1.1.1 System Access

System access investments over the forecast period are driven by customer service requests, municipal infrastructure development requirements, and mandated service obligations such as metering. Customer service requests include residential expansions, individual secondary services, and commercial/industrial services, all of which are partially funded by the customer. Other services such as Feed-in-Tariff ("**FIT**") connections, MicroFIT connections, individual secondary commercial services, and additional commercial meters are 100% funded by the customer. EPL is obligated to relocate its assets, which occupy the public Right-of-Way ("**ROW**"), if requested by municipal entities. These types of jobs are subject to a partial cost-sharing agreement with the municipal entity involved. Mandated service obligations include metering costs over the forecast period, driven by failed and/or obsolete components.

2.1.1.2 System Renewal

System renewal investments over the forecast period are broadly driven by the capital requirements to replace assets at the end of their service life. This includes the planned replacements of poles, switches, and pad-mounted switchgear. Larger projects to rebuild sections the distribution system are planned over the forecast period. Unplanned, reactive replacement of failed underground and overhead assets are also included as part of this investment category.

Over the historical period, EPL's system renewal initiatives focused on voltage conversion – completed in 2017 – and other initiatives such as live-front switchgear replacements.

2.1.1.3 System Service

System service investments over the forecast period are driven by system expansions due to asset acquisitions, system expansions to enable REG investments, and investments into reclosers as part of a self-healing grid to improve system reliability and decrease outage

restoration costs. Capital investment in LaSalle from 2019 to 2021 will be made as part of the Malden TS upgrade and will reconfigure the feeders egressing from Malden TS. EPL has budgeted capital funds from 2018 through 2022 as the net expenditures from purchasing and selling assets to/from HONI: in Leamington during the years 2018 and 2019 and LaSalle for the years 2020 through 2022. Investments are required each year of the plan to enable new REG installations to be connected to EPL's system. Finally, new recloser and other smart grid device installations have been planned each year of the forecast period as part of the self-healing grid rollout. These devices will reduce: outage restoration times, the number of customers affected by outages, and EPL resources required to restore power.

2.1.1.4 General Plant

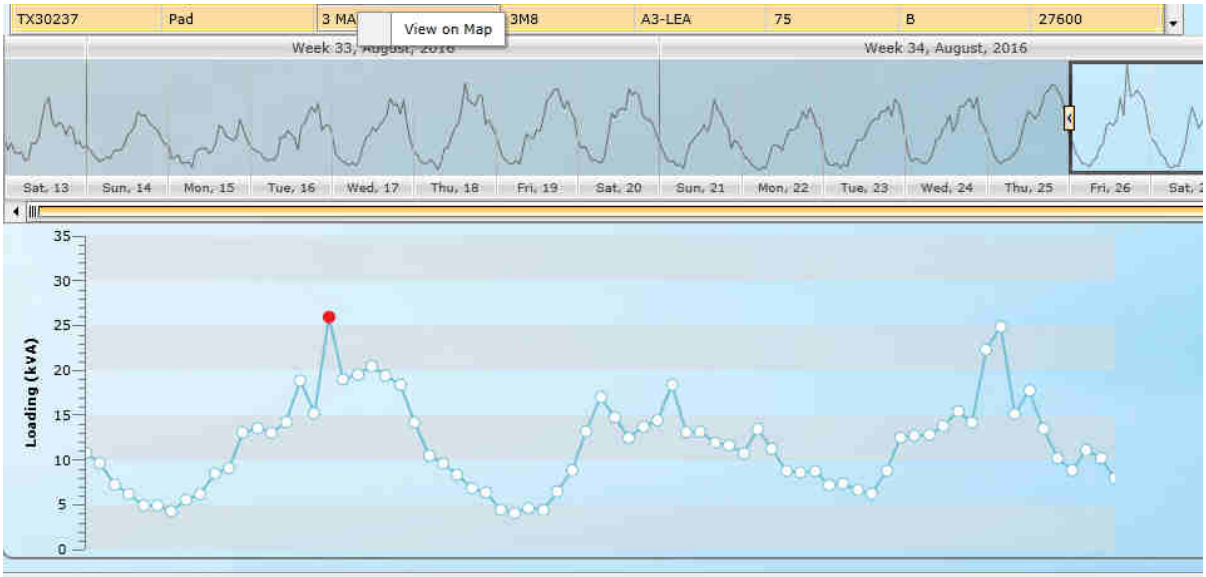
General plant investments over the forecast period are driven by business operations efficiency improvements and non-system physical plant and equipment at the end of its service life. Material programs in this category pertain to buildings and fixtures, transportation equipment, computer software, computer hardware, and tools and equipment.

2.1.2 Anticipated Sources of Cost Savings (5.2.1b)

EPL's investment plan has been optimized using the asset management tools and analyses described in Section 3.1.2. Inputs into EPL's risk-based decision-making model include cost savings and spending, which are optimized along with the other planning objectives (see Section 3.1.1) when developing the five-year investment plan. Therefore, EPL's holistic plan considers cost savings and spending for each proposed project. These impacts can most readily be quantified by annual system O&M spending. Over the historical period the average annual system O&M spending was $2.43M compared to an average of $2.11M over the forecast period. Meanwhile the annual inflation rate over this period is assumed to be 2% and, therefore, the cost savings impacts are greater in real terms.

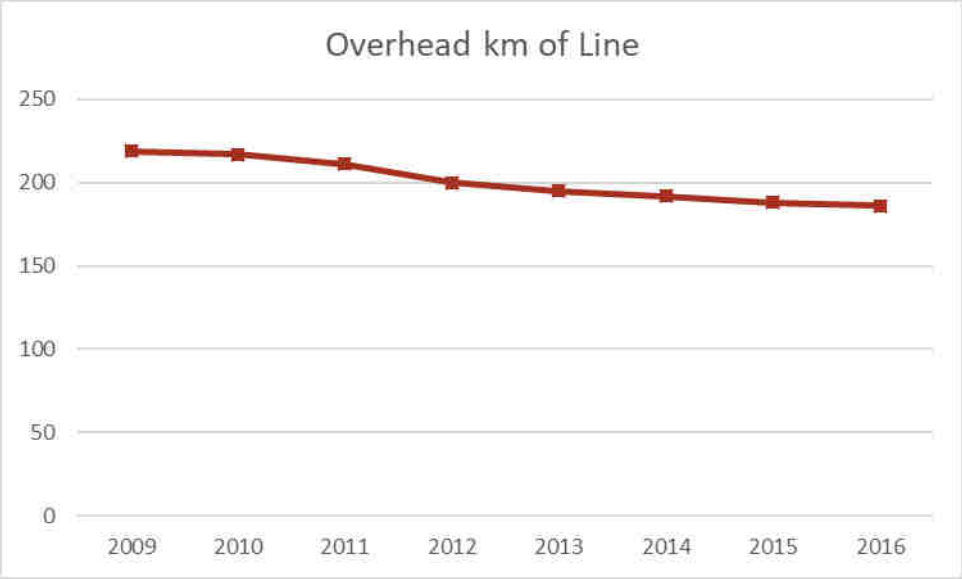
EPL considers lifecycle cost optimization as part of its planning process to fully utilize assets and improve their operating performance. Software models are used to determine the optimal size and number of transformers, as well as the optimal size and length of wires. Transformer peak and historical load data are used to determine how much load or how many customers can be added to the secondary system. In the example shown in Figure 2-1, EPL was able to verify the load history of a distribution transformer to allow additional customer connections without replacing the transformer. Alerts for overloading of a transformer can pre-emptively predict its overloading and can be used to calculate the loss of life due to overloading.

Figure 2-1: EPL is able to monitor transformer load



Recently, EPL completed a significant portion of its voltage conversion program, harmonizing its service area to 27.6/16 kV. In addition to eliminating the need to own and maintain a distribution substation, the voltage conversion investments have allowed EPL to reduce its stock, inventory, and kilometres of line under management while the number of customers has continued to increase. Figure 2-2 depicts a decrease in the overhead kilometres of line owned by EPL. Furthermore, EPL was able to reduce its inventory of transformers by analyzing failure rates to determine the number of each size required.

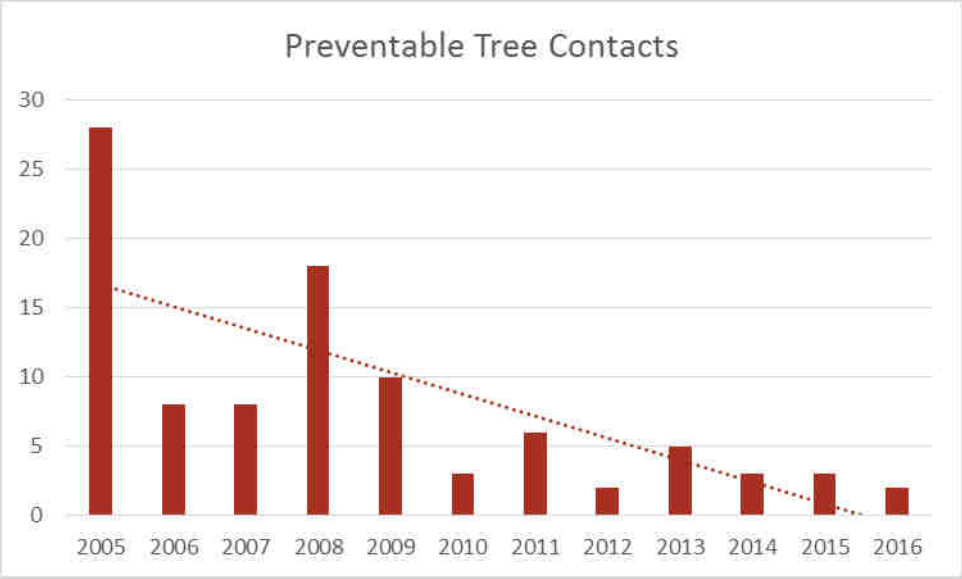
Figure 2-2: Kilometres of overhead line owned by EPL



EPL's robust tree-trimming program has reduced the number of preventable tree contacts (i.e. branch contacts) causing an outage. Along with improving the reliability experienced

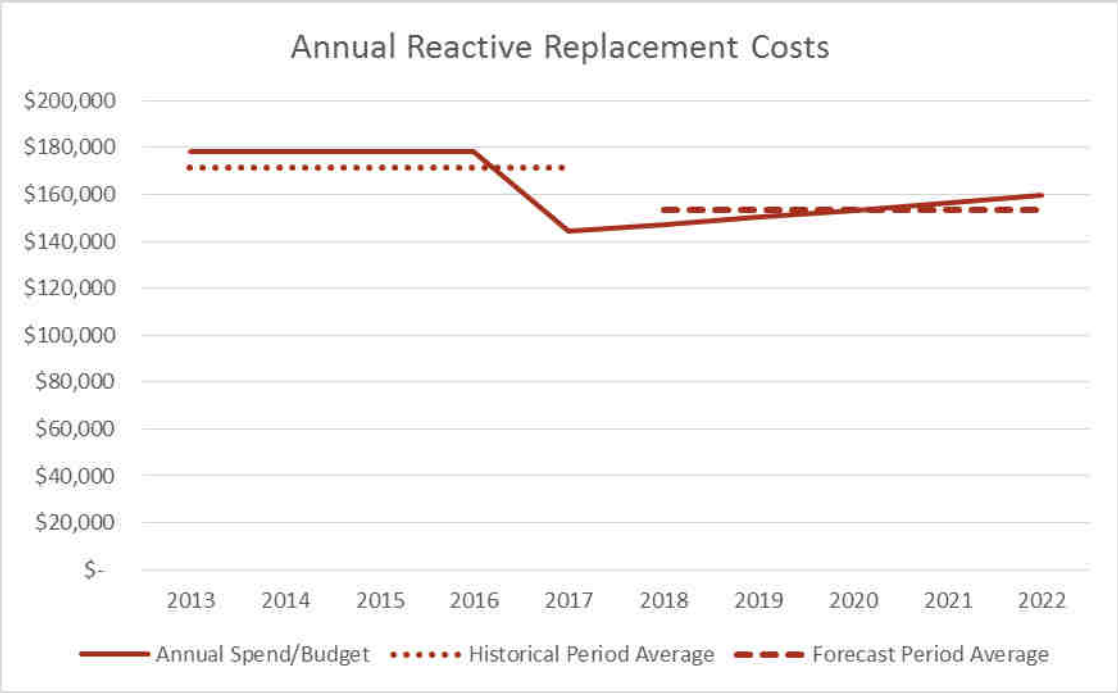
by EPL's customers, the reduction in tree contact outages decreases cost requirements to restore the line. Figure 2-3 depicts this trend.

Figure 2-3: Preventable tree contacts have been trending downwards



EPL has increased the amount of planned capital work over the forecast period and has consequently budgeted less capital spending on reactive replacements over the forecast period compared to the historical period average. This is a more cost-effective investment strategy since planned replacements generally cost less than reactive replacements, which may require emergency or overtime work.

Figure 2-4: Annual reactive replacement costs



EPL has also planned investments in the system service category that will help to achieve cost efficiencies over the forecast period. New distribution recloser installations as part of a self-healing grid are primarily installed to improve the reliability of EPL's system by reducing the duration and number of customers affected by an outage. The installation of new distribution reclosers and other smart grid devices, such as remote notification fault indicators, has the added benefit of localizing the source of an outage. This reduces the number of truck-rolls for locating the outage source, thereby reducing O&M costs associated with each outage restoration.

2.1.3 Period Covered by DSP (5.2.1c)

The proposed DSP has been prepared for the following period:

Table 2-2: Period covered by the DSP

Historical Period					Forecast Period				
				Bridge Year	Test Year				
2013	2014	2015	2016	2017	2018	2019	2020	2021	2022

2.1.4 Vintage of the Information (5.2.1d)

The information contained within this DSP should be considered current as of July 2017.

2.1.5 Important Changes to Asset Management Processes (5.2.1e)

This is EPL's first DSP filing; however, since its previous Cost of Service Application in 2010, EPL has invested in improved data quality and improved asset management analytic tools. Specifically, EPL has improved the data quality of its Geo-Spatial Information System ("**GIS**") and partnered with a technology firm, UtiliSmart Corporation, to overlay EPL's proven Distribution Engineering Simulation Software ("**DESS**") onto the GIS. The resultant SmartMAP software solution received funding through the Ontario Ministry of Energy's Smart Grid Fund. The initiative started in 2012 and continues to be developed and enhanced. EPL's asset management software was also enhanced with Asset Condition Assessment ("**ACA**") capabilities overlaid onto the GIS, called "HealthMAP". Additional information pertaining to EPL's asset management planning process can be found in Section 3.1.2.

The HealthMAP provides valuable inputs to the ACA report used to quantify the condition of EPL's assets. Deficiencies noted during inspections, the priority of the issues, and test results can be directly exported from the HealthMAP tool. EPL's ACA report is attached as Appendix J to the DSP.

2.1.6 DSP Contingencies (5.2.1f)

The majority of system access investments planned over the forecast period must be initiated by parties external to EPL. Customer service projects such as residential expansions, individual secondary services, and commercial/industrial services are requested

by the customer. Municipal requirements to relocate EPL's assets occupying the ROW are initiated at the request of the municipality involved. Therefore, the level of capital investment in these categories depends on the amount of work requested by customers and municipalities.

Reactive spending in the system renewal category is largely outside of EPL's control. Dependent on factors such as storms and unclaimed damage to EPL's plant, spending in this category can fluctuate between years.

Some system service investments pertaining to system expansion are contingent on construction activities by HONI. The need to invest in transmission capacity in these areas was identified through the Regional Planning Process (see Section 2.2.2). There are existing agreements related to the construction of Leamington TS to purchase assets from and sell assets to HONI. There is also an existing agreement to purchase assets from HONI in LaSalle that is contingent on the completion of the Malden TS upgrade project. A project to reconfigure EPL's feeders egressing from Malden TS is also contingent on the successful completion of the upgrade by HONI.

2.2 Coordinated Planning with Third Parties (5.2.2)

2.2.1 Summary of Consultations (5.2.2a)

2.2.1.1 Customer Surveys

EPL commissioned Innovative Research Group ("**INNOVATIVE**") to design and carry out a Customer Satisfaction Survey of EPL's residential and GS<50 customers on its behalf in 2014. Two years later, EPL commissioned Convergys to perform a Top Down Survey to measure and help improve customer satisfaction. The latest Ratepayer Telephone Survey was completed by INNOVATIVE in 2017.

Purpose of the Consultations

The purpose of the customer surveys is to measure customer satisfaction, determine customer needs and preferences, and identify opportunities to improve customer experience. The INNOVATIVE Customer Satisfaction Survey also educated participants about Ontario's distribution system, EPL's role in delivering power to households and businesses, the interpretation of their electricity bill, and the availability of e-billing. The Convergys survey focused on the key drivers to customer satisfaction to identify opportunities for improvement. The most recent INNOVATIVE Ratepayer Telephone Survey asked customers whether they accept EPL's current five-year plan (this DSP) and distinguished between customers' willingness to pay for reliability improvements versus maintaining system reliability and

Whether EPL Initiated the Consultation

EPL commissioned INNOVATIVE and Convergys to initiate the customer consultations on its behalf.

Other Participants in the Consultation

Customers participated in telephone surveys conducted by the research firms. The INNOVATIVE Customer Satisfaction Survey included 210 residential and 98 GS<50 customers. The Convergys survey interviewed 400 residential and 100 GS<50 customers. The INNOVATIVE Ratepayer Telephone Survey interviewed 524 residential customers, 51 GS<50 customers, and 9 GS>50 customers.

Nature and Prospective Timing of the Final Deliverables

Both INNOVATIVE reports are attached as Appendix D.

INNOVATIVE submitted the final report for its Customer Satisfaction Survey findings in November 2014. Overall, eighty-two percent (82%) of residential customers and seventy-eight percent (78%) of GS<50 customers indicated they were satisfied with EPL. Figure 2-5 depicts customer satisfaction measured in terms of:

- Power quality and reliability
- Reasonable price
- Billing accuracy
- First contact resolution
- Power outage communications
- Value for money

Figure 2-5: Percentage of satisfied customers for surveyed customer classes in 2014

The Ratepayer Telephone Survey was finalized in July 2017. Residential and GS customers agree that EPL should spend what is needed to maintain the current length of unexpected

outages. While residential customers tend to think EPL should spend what is needed to maintain the current level of unexpected outages, GS customers lean towards spending what is needed to reduce the number of unexpected power outages. The majority of residential and GS customers agree that EPL should:

- Invest what it takes to replace aging infrastructure to maintain system reliability, even if that requires an increase to their bill;
- Replace equipment proactively before it breaks down;
- Modernize the distribution system; and
- Ensure staff have access to proper tools and equipment as long as EPL spends its funds wisely.

At the end of the survey, eighty-two percent (82%) of residential customers gave social permission for a rate increase of approximately $0.30 per month based on EPL's proposed DSP, with forty-five percent (45%) opining that the rate increase is reasonable and they support it, while thirty-seven percent (37%) don't like the proposed rate increase but feel it is necessary. Meanwhile, only sixteen percent (16%) of surveyed residential customers oppose the rate increase and feel it is unreasonable. Out of the sixty (60) surveyed GS customers, twenty-five (25) find the proposed rate increase reasonable and support it, twenty-two (22 don't like the proposed rate increase but feel it is necessary, and twelve (12) oppose the rate increase and find it unreasonable.

Convergys submitted the final report of its findings in November 2016. The customer satisfaction measured by Convergys in 2016 is summarized in Figure 2-6. Overall satisfaction and the quality of power service (reliability) is consistent with 2014 measurements. Residential customers prioritize customer service as a key driver to overall satisfaction, while business customers prioritize reliability and power quality. Quality of customer service increased, while first contact resolution decreased. The 2014 INNOVATIVE survey indicated that first contact resolution tends to be low when customers call regarding power outages. Affordability of service is still a key issue for EPL's customers.

Figure 2-6: Customer satisfaction measured in 2016

The complete report is attached as Appendix E.

Effect on the DSP

The customer feedback received from the surveys indicates that the cost of electricity is important to EPL's customers, especially residential households. The majority of residential and General Service customers are satisfied with the reliability, power quality, and customer

service offered by EPL. To address the preferences of its customers, EPL has not planned any substantial rate increases for its customers. Instead EPL has developed a five-year DSP that identifies key investments to operate a modern smart grid fit for the 21st century, while keeping rate proposed rate increases in line with inflation. Specifically, a consumer bill impact metric has been identified in Section 2.3.1.2 to measure the success of the DSP.

EPL's customers support investing what it takes to replace aging infrastructure to maintain system reliability, even if that requires an increase to their bill. EPL has identified a number of programs in the system renewal program that meet these expectations including replacement of poles, replacement of load-break switches, replacement of live-front switchgear, and circuit rebuilds. These are all proactive replacement programs supported by EPL's customers.

EPL's customers see the importance of modernizing the grid. EPL has adopted a Smart Grid Development Plan – as introduced in Section 1.4.3.4 – to facilitate a self-healing grid. System service investments to install reclosers over the forecast period fit into this framework.

EPL's customers believe that it is important for EPL's staff to have the equipment and tools they need to manage the system efficiently, safely and reliably. Planned investments into computer hardware, computer software, transportation equipment, stores equipment, buildings and fixtures, and tools and equipment align with this customer preference.

Overall, customers surveyed in 2017 provided social permission for the DSP.

2.2.1.2 Municipal Consultations

Purpose of the Consultations

Consultations with municipalities, who are also EPL's shareholders, are critical components of EPL's project planning and daily operations. EPL is engaged in weekly Adjustment Committee meetings on property zoning variances. Weekly Development Support Committee meetings provide details regarding planned and ongoing construction activities for private businesses and residences. Quarterly utility meetings allow the municipalities and various utility participants to coordinate their planned and ongoing construction activities. In addition, meetings related to alley closing or land transfers take place as needed, Planning Act meetings take place as applicable, and meetings for specific projects take place as needed.

EPL also participates in meetings with the County of Essex and the Ontario Ministry of Transportation ("**MTO**") as required to obtain information pertaining to the capital work planned.

Whether EPL Initiated the Consultation

The meetings are initiated by EPL or the municipalities. County and MTO meetings are typically initiated by the County and MTO, respectively.

Other Participants in the Consultation

The meetings are attended by representatives of different municipal divisions (e.g. municipal projects, water) and other utilities (e.g. Bell, Cogeco, HONI, Union Gas, MNSi).

Nature and Prospective Timing of the Final Deliverables

The meeting minutes of items discusses are the main deliverables for most municipal consultations. Following the utility meetings, EPL receives an updated project list from the various municipal divisions and from the other utility participants. EPL provides its own list of capital projects and pertinent operations activities (e.g. tree trimming) to participants in the meetings.

Effect on the DSP

Municipal consultations are critical to allocating budget and resources for system access investments including residential expansions, individual secondary services, new commercial/industrial services, and third-party infrastructure development requests. Planned projects in the near-term are used to forecast the capital requirements of the five-year DSP.

2.2.1.3 Consultations with HONI

Purpose of the Consultations

EPL often communicates and meets with HONI with the overarching objective of providing reliable and cost-effective service to EPL's customers. In addition to the IESO's Regional Planning Process, HONI and EPL hold quarterly planning meetings to discuss operating issues, billing issues, customer complaints, work coordination, joint-use of poles, and generation connection. Other communications and meetings take place to discuss specific projects such as Leamington TS and the Malden TS upgrade, as well as projects to separate shared assets by LDC, asset, customer, etc.

Whether EPL Initiated the Consultation

Consultations may be initiated by either EPL or HONI.

Other Participants in the Consultation

The only participants are EPL and HONI.

Nature and Prospective Timing of the Final Deliverables

Meeting minutes from these consultations typically summarize the deliverables and timeline commitments agreed to by each party in the meeting. Deliverables include updated construction schedules, updated project cost estimates, an updated list of generation projects, agreements pertaining to asset transfers, and any requisite studies.

Effect on the DSP

A significant portion of the system service investments over the five-year planning period of the DSP are a result of coordinated planning activities with HONI. In 2018 and 2019, EPL will purchase and sell assets related to Leamington TS in transactions with HONI. From 2019 to 2021, EPL will reconfigure its feeders egressing from Malden TS in conjunction with two new feeders as a result of planning activities with HONI. Finally, the system service

budget from 2020 to 2022 includes the purchase and sale of assets in LaSalle in transactions with HONI. The planned asset transfers are anticipated to be required to facilitate long-term load transfer removal as well to accommodate significant HONI work currently ongoing in the respective areas.

2.2.1.4 Consultations with IESO

Purpose of the Consultations

Outside of the Regional Planning Process, EPL consults with the IESO to discuss the connection of new generation and energy storage projects to EPL's distribution system and the administration of CDM programs.

Whether EPL Initiated the Consultation

Consultations may be initiated by either EPL or the IESO.

Other Participants in the Consultation

The only participants are EPL and the IESO.

Nature and Prospective Timing of the Final Deliverables

The IESO provides updates to generator applications within EPL's service area. EPL worked closely with the IESO on a 1.25 MW energy storage facility planned in Leamington. This energy storage facility is scheduled to be connected in 2018. EPL previously submitted its CDM plan to the IESO and reports annual updates regarding budget spent and savings achieved.

Specifically for this DSP, EPL submitted its REG Investments Plan to the IESO and the IESO provided its Comment Letter in response. For more information, see Section 2.2.3.

Effect on the DSP

The cost of the assets required to connect the energy storage facility is included in EPL's 2018 budget. EPL has planned investments until 2018 to accommodate REG connections, which fall under the system service category and have been coordinated with the IESO. Consultations with the IESO are also used to forecast system access projects for FIT and MicroFIT connections (which are 100% contributed by the customer) and renewable expansions.

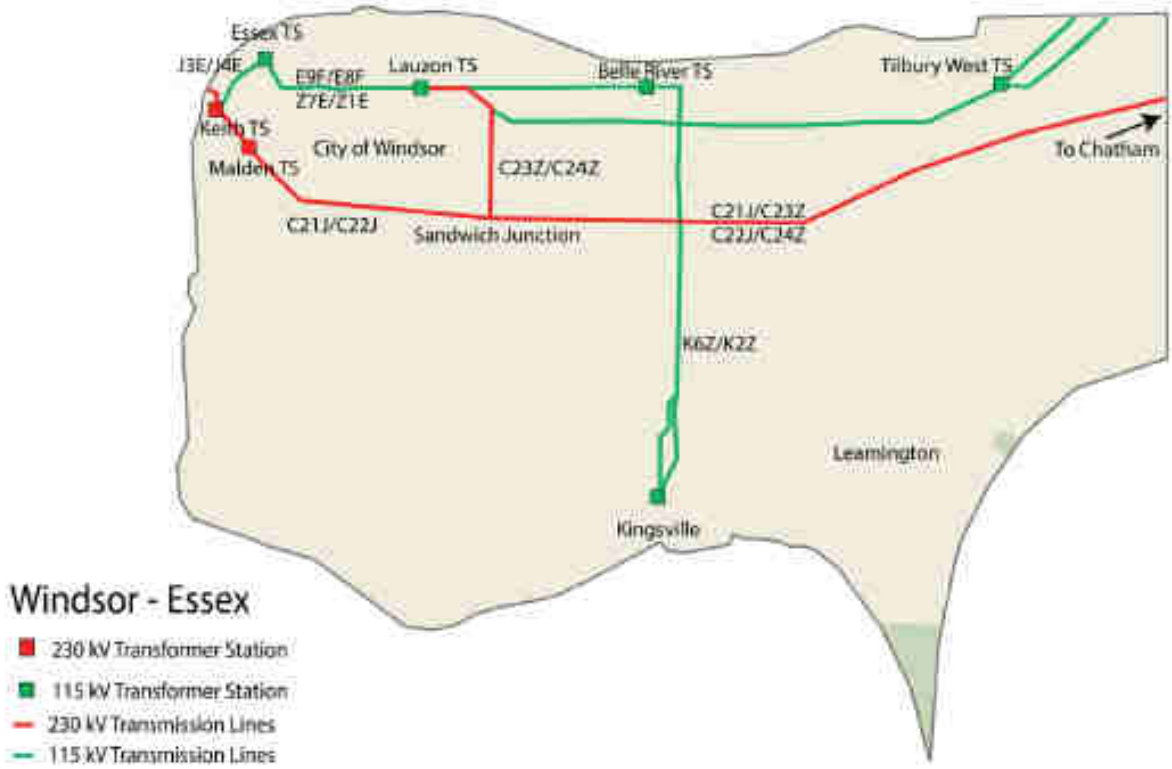
2.2.2 Regional Planning Process (5.2.2b)

EPL is part of the Windsor-Essex region in the most southerly part of Ontario that includes the City of Windsor, the Municipality of Leamington, the Towns of Amherstburg, Essex, Kingsville, Lakeshore, LaSalle, Tecumseh, and the Township of Pelee, as well as the western portion of the Municipality of Chatham-Kent.

EPL participated in the Regional Planning Process by providing the information required to complete the Regional Infrastructure Plan including impact assessments of regional supply plans and a review of potential distribution system options to meet regional needs. EPL attended the working group meetings for the Windsor-Essex region, which also involved the following entities:

- the IESO
- E.L.K. Energy Inc.
- Entegrus Inc.
- HONI

Figure 2-7: The transmission system in the Windsor-Essex region



The Regional Planning Process identified that the demand in the Kingsville-Leamington area had recently reached the supply capacity and that the supply in the broader region does not comply with the IESO's Ontario Resource and Transmission Assessment Criteria ("**ORTAC**") load restoration criteria. An Integrated Regional Resource Plan ("**IRRP**") was prepared on 28 April 2015, addressing the region's electricity needs from 2014 to 2033. The IRRP – attached as Appendix B – recommended an integrated solution with a mix of energy conservation, REG resources, and transmission reinforcements. A new 230-kV TS and transmission line will be constructed near Leamington providing an additional 150 MW of capacity. After the partial refurbishment of Kingsville TS, the combined supply in the Kingsville-Leamington area will be 210 MW, enough to meet the forecast demand accounting for energy conservation and REG resources.

2.2.3 IESO Comment Letter (5.2.2c)

On February 27, 2015 EPL submitted its REG Investments Plan to the IESO as part of its DSP. EPL's REG Investments Plan indicates that, as of the end of 2016, it has connected one hundred fifty (150) MicroFIT projects, twelve (12) FIT projects, and two (2) Renewable Energy Standard Offer Program ("**RESOP**") projects totalling 1.2536 MW, 2.838 MW, and 15 MW respectively. EPL has forecast connections for an additional 1.28 MW from four (4)

FIT projects in 2017, 0.9 MW from three (3) FIT projects in 2018, 0.384 MW from two (2) FIT projects in 2019, and 0.1 MW from ten (10) MicroFIT projects. The IESO commented that the information provided by EPL was "substantially consistent with that of the IESO". The Letter of Comment from the IESO is attached as Appendix C.

EPL's correspondence with the IESO also listed the investments planned to accommodate REG for the years 2017 through 2020. Table 2-3 summarizes the REG investments projected for the 2018 Test Year.

Table 2-3: REG investments projected in the 2018 Test Year

Type	Nameplate Capacity (kW)	Renewable Expansion Cost
Solar Rooftop	200	$25,000
Solar Rooftop	200	$0
Solar Rooftop	200	$25,000
Solar Rooftop	500	$30,000
Solar Rooftop	1250	$30,000
2018 (estimated)	**2350**	**$110,000**

The IESO also confirmed EPL's involvement in the Regional Planning Process and acknowledged that the REG investments identified in EPL's plan are consistent with the IESO's records.

2.3 Performance Measurement for Continuous Improvement (5.2.3)

Good distributor planning is an essential element of the OEB's performance-based rate-setting approach. Table 2-4 summarizes the metrics EPL will use to assess its DSP performance measured against customer-oriented performance, cost efficiency and effectiveness, and asset/system operations performance. The motivation for each measure and the desired outcome of each metric is listed.

Table 2-4: List of metrics and their desired outcomes

Performance Outcome	Measure	Motivation	Metric	Desired Outcome
Customer-oriented performance	System reliability	Regulatory/ consumer	SAIDI	0.91 or less
			SAIFI	1.77 or less
			CAIDI	1.77 or less
			Root cause of power interruptions	Identify root cause of outages
	Consumer bill impacts	Regulatory/ consumer	Percentage bill increase	2% or inflation annually
	Power quality	Regulatory/ consumer	Voltage at customer meter	0 unresolved power quality concerns
	Customer satisfaction	Regulatory/ consumer	Customer satisfaction survey results	80% or greater
	Service quality	Regulatory/ consumer	Telephone accessibility	Greater than 65%
			Telephone call abandon rate	Less than 10%
			Connection of new services	Greater than 90%
			Appointments scheduling	Greater than 90%
			Appointments met	Greater than 90%
			Missed appointments rescheduling	100%
			Written response to enquiries	Greater than 80%
			Emergency response	Greater than 80%
			Reconnection performance	Greater than 85%
			Billing accuracy	Greater than 98%
Cost efficiency and effectiveness	DSP implementation progress	Regulatory/ consumer	Percentage of projects completed in the budget year	Greater than 80%
			Project spending (planned vs. actual)	+/- 10%
			Annual capital spending (planned vs. actual)	+/- 10%
	Efficiency assessment	Regulatory/ consumer	Results of efficiency assessment	Group 2
	Total cost	Regulatory/ consumer	Total cost per customer	Monitor performance relative to peers
			Total cost per km of line	
Asset/system operations performance	Safety	Regulatory/ corporate	Serious electrical incident index	0
	System performance	Corporate	Distribution losses	4% or less
	Asset performance	Corporate	Primary Cable failures	3 per year or less
		Corporate	Switchgear failures	2 per year or less

2.3.1 Customer-oriented Performance

Customer-oriented performance is assessed using the following measures:

1. System reliability
2. Consumer bill impacts
3. Power quality
4. Customer satisfaction
5. Service quality

2.3.1.1 System Reliability

A reliable supply of electricity is important to consumers and businesses alike; therefore, system reliability indices are key metrics for measuring the success of a DSP.

2.3.1.1.1 Definition of Measures (5.2.3a)

In order to measure the reliability of electricity delivered to its customers, EPL tracks System Average Interruption Frequency Index ("**SAIFI**"), System Average Interruption Duration Index ("**SAIDI**"), and Customer Average Interruption Duration Index ("**CAIDI**"). SAIFI is the average frequency of sustained power interruptions and is calculated by dividing the total number of customer interruptions over a given year by the total number of customers served. SAIDI is the average outage duration and is calculated by dividing the total number of customer-hours of sustained interruptions over a given year by the number of customers served. CAIDI reflects the average time for electricity service to be restored following an outage and is calculated by dividing the total customer-hours of sustained interruptions over a given year by the total number of sustained interruptions for that year.

EPL's system reliability targets are to operate its system better than the previous five-year historical average measured in SAIFI, SAIDI, and CAIDI. Loss of supply outages are excluded in the calculation of the targets and performance since these outages are beyond EPL's control; however, EPL works closely with its supply transmitter (HONI) to reduce incidents of loss of supply. Based on the historical five-year average from 2012 to 2016, EPL's system reliability targets are 0.71 for SAIFI, 1.20 for SAIDI, and 1.77 for CAIDI (all excluding loss of supply).

2.3.1.1.2 Historical Performance (5.2.3b)

Since reliability performance targets are based on the previous five-year historical average, then naturally half of the years will be below target and half of the years will be above target. EPL's historical SAIFI performance, including and excluding loss of supply, is presented in Figure 2-8. SAIFI excluding loss of supply was better than the five-year average in 2014 and 2015 and worse than the average in 2013. EPL's historical SAIDI performance, including and excluding loss of supply, is presented in Figure 2-9. SAIDI excluding loss of supply was better than the five-year average in 2014 and 2015 and worse than the average in 2013. Finally, EPL's historical CAIDI performance, including and excluding loss of supply, is presented in Figure 2-10. CAIDI excluding loss of supply was better than the five-year average in 2015 and worse than the average in 2013 and 2014.

Figure 2-8: Historical SAIFI performance including and excluding loss of supply

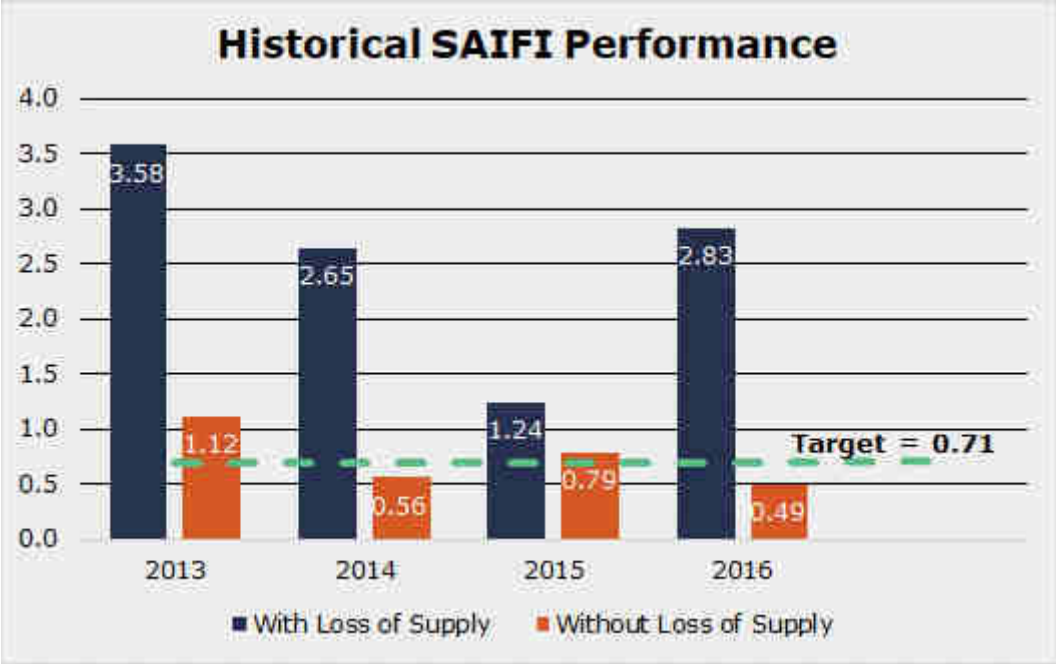


Figure 2-9: Historical SAIDI performance including and excluding loss of supply

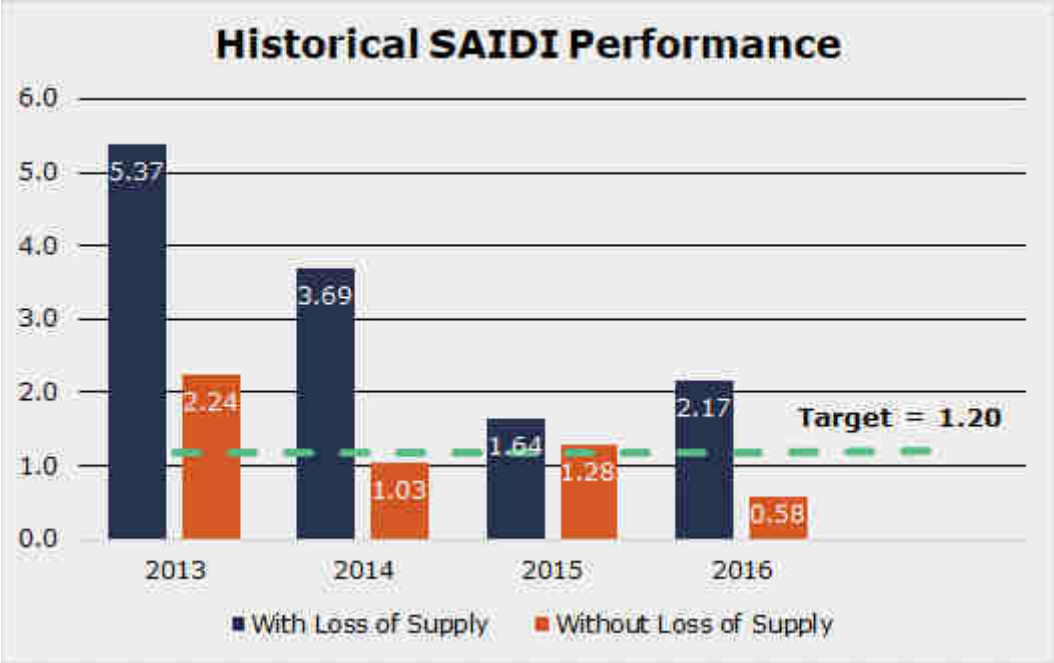
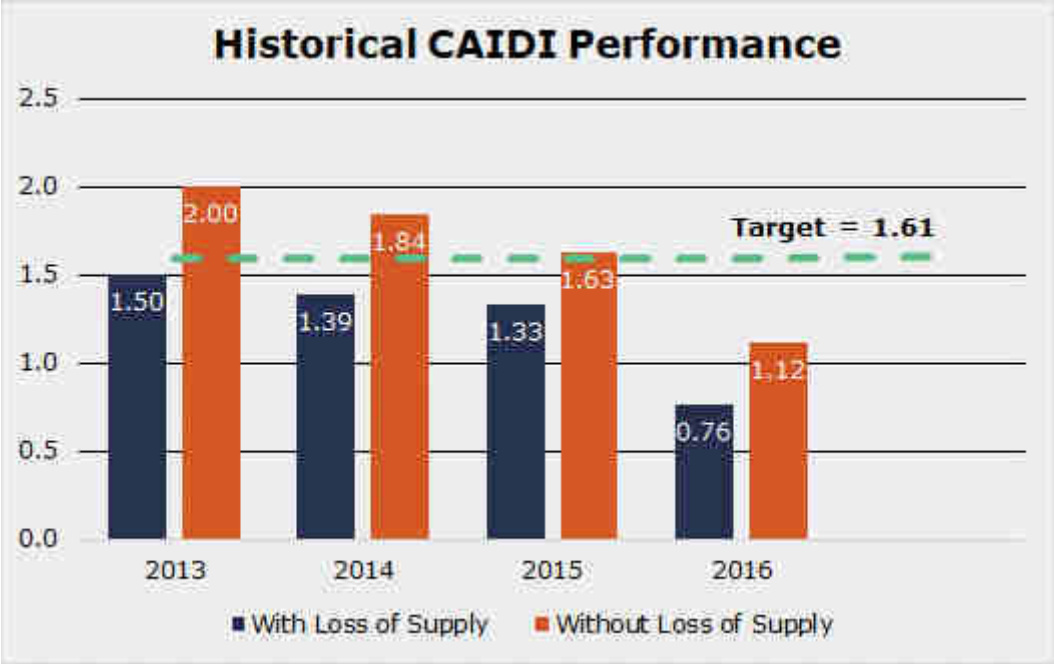


Figure 2-10: Historical CAIDI performance including and excluding loss of supply



For further analysis of the root cause of power interruption, Figure 2-11 presents the customer interruption hours by cause code and Figure 2-12 presents the number of customer interruptions by cause code for the years 2013 to 2016. As shown, loss of supply has by far the greatest reliability impact on EPL's customers. The next two biggest impacts are defective equipment outages and scheduled outages.

Figure 2-11: Customer interruption hours by cause code (2013 to 2016)

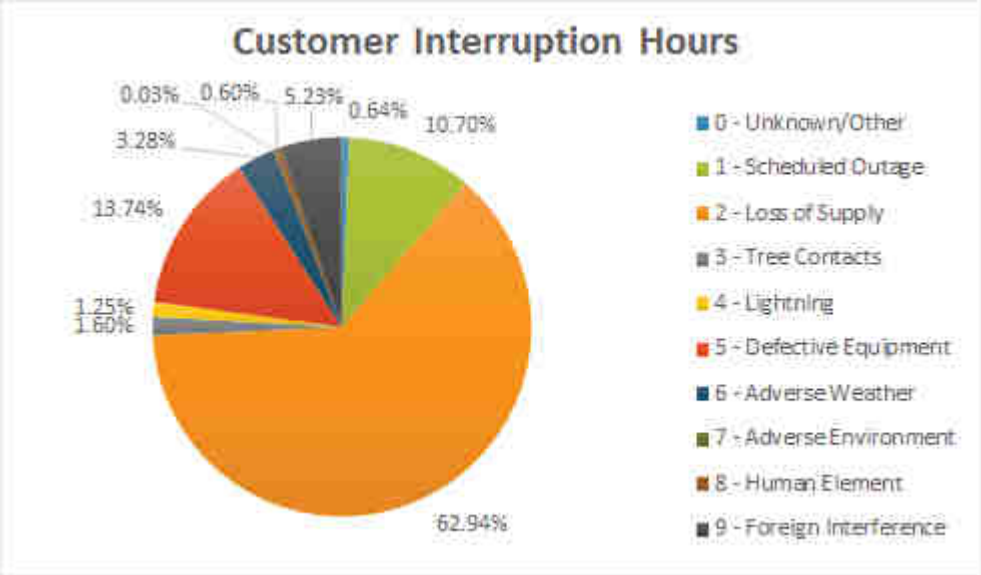
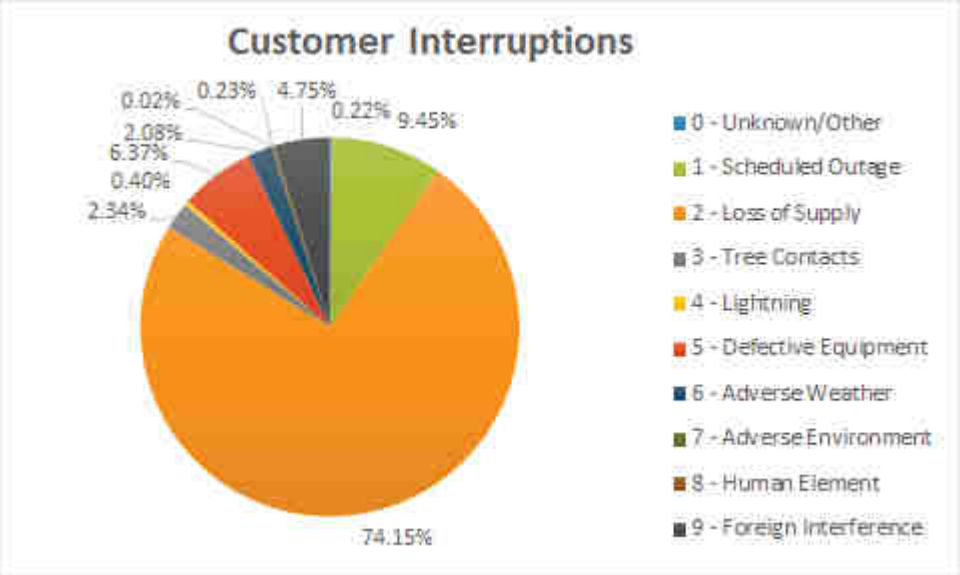


Figure 2-12: Customer interruptions by cause code (2013 to 2016)



2.3.1.1.3 Effect on the DSP (5.2.3c)

Loss of supply outages continue to be the foremost concern for power interruptions experienced by customers. As noted in Section 2.2.1.3, EPL meets regular with HONI in part to address concerns of EPL's customers including loss of supply outages. EPL has budgeted capital expenditures in the system service category to purchase assets owned by HONI that already supply EPL's customers. By effectively managing these assets, EPL is proactively addressing the loss of supply issues to provide better system reliability for its customers.

Planned outages are the next biggest contributor. The number of planned outages has increased as EPL has shifted its work from reactive replacements to planned capital programs. Although the number of planned outages has increased, the impact of outages caused by defective equipment has been trending downwards as shown in Figure 2-13. EPL mitigates the impact of planned outages by providing customers with advance notice so they can plan accordingly.

A more thorough analysis of the impact of defective equipment outages is provided in Figure 2-14 for overhead equipment and Figure 2-15 for underground equipment. The impacts of defective overhead equipment are trending downwards, while defective underground equipment impacts are trending upwards, indicating the need to invest relatively more in underground equipment compared to overhead. Over the forecast period, EPL plans to invest more in direct-buried cable replacements than overhead rebuilds under the system renewal investment category.

Figure 2-13: Severity - Impacts of outages caused by defective equipment

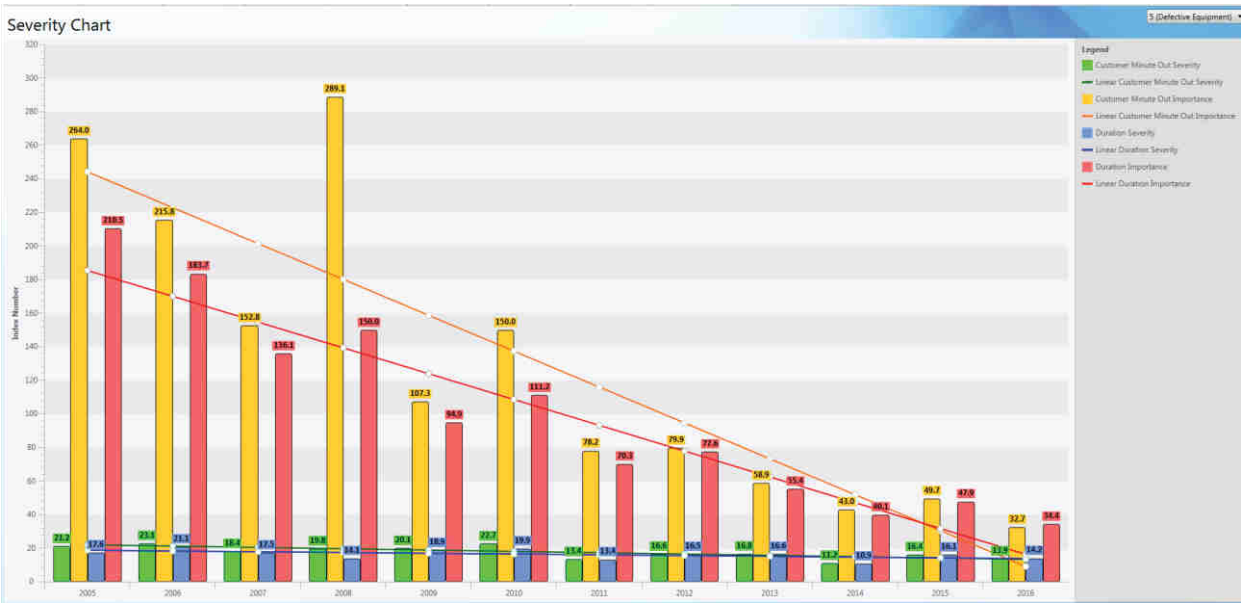


Figure 2-14: Severity - Impacts of outages caused by defective overhead equipment

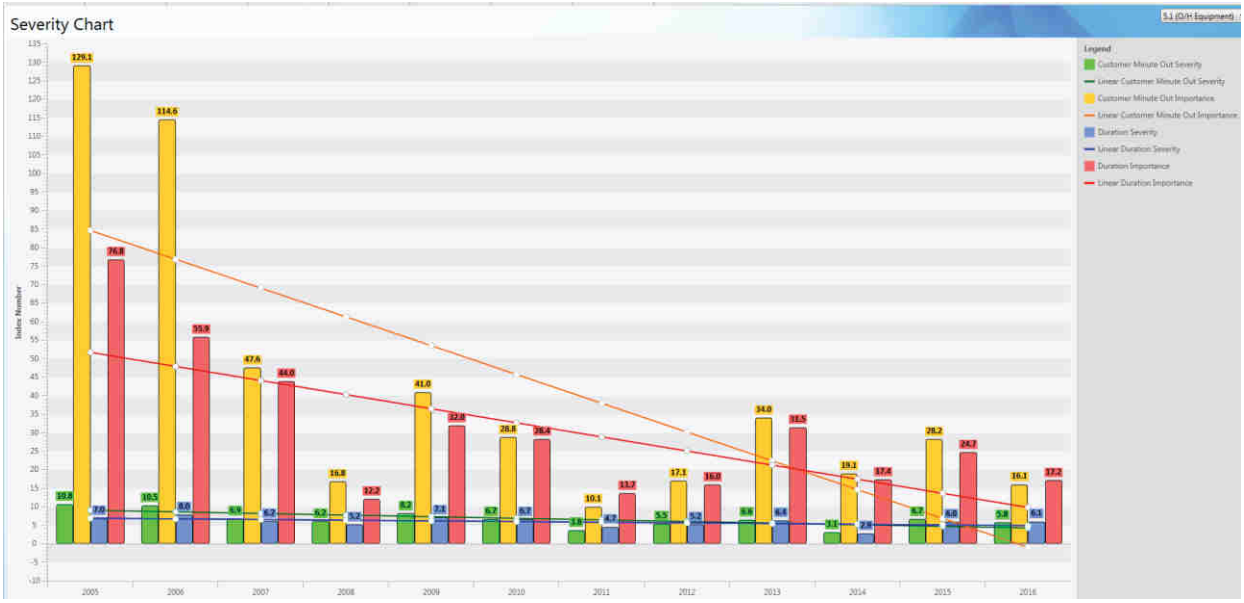
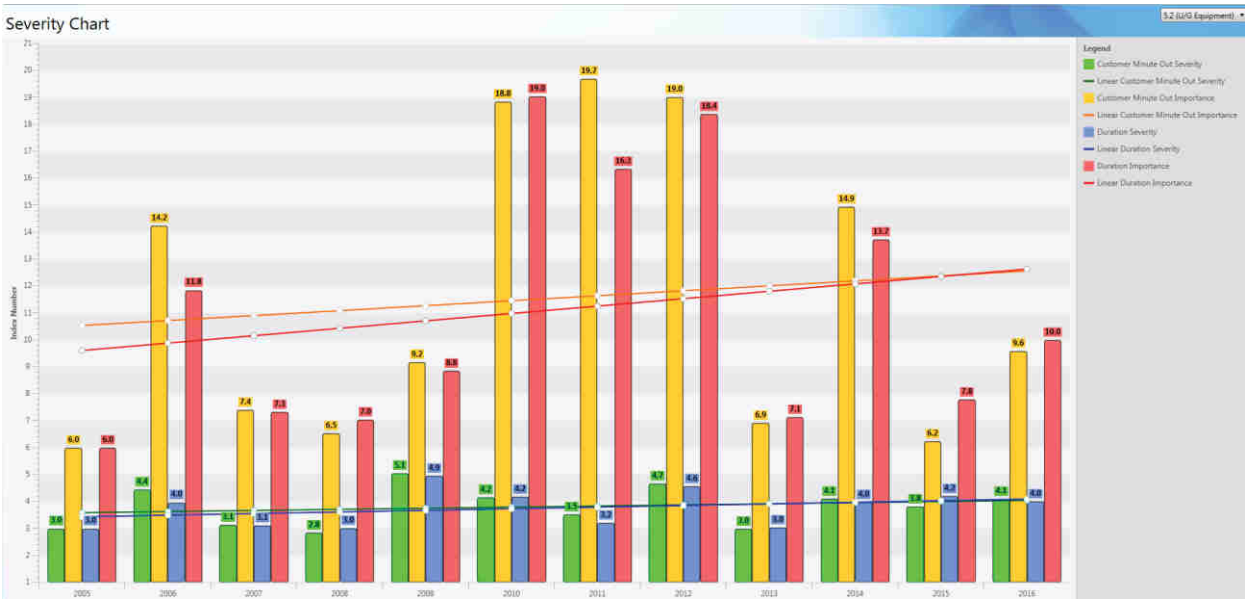


Figure 2-15: Severity - Impacts of outages caused by defective underground equipment



2.3.1.2 Consumer Bill Impacts

EPL's customers have stated that the cost of electricity is important to them and, furthermore, EPL's primary objective is to provide a modern distribution system at inflation-aligned rates. Therefore, the consumer bill impact metric is a key measure of the success of EPL's planning and DSP execution.

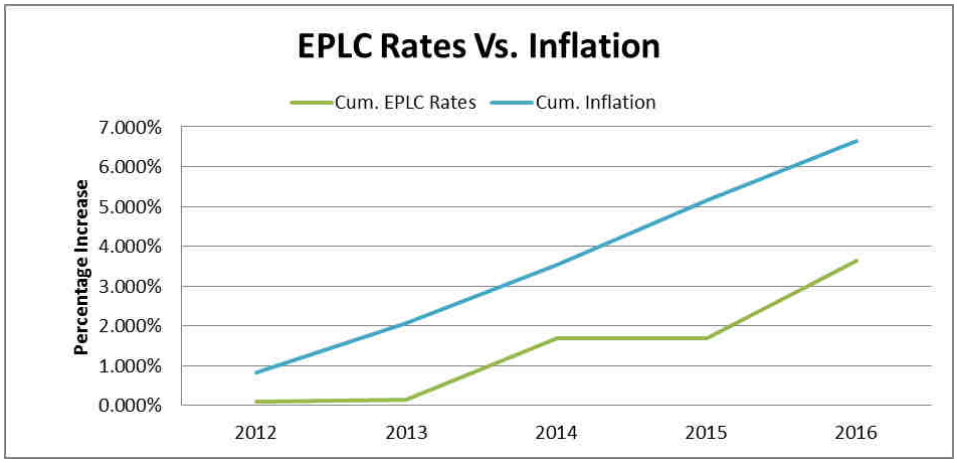
2.3.1.2.1 Definition of Measure (5.2.3a)

Consumer bill impacts are measured as the percentage annual increase of the distribution costs for a typical residential consumer. EPL's target for this metric is to align annual rate increases with inflation, which is close to two percent (2%) per year.

2.3.1.2.2 Historical Performance (5.2.3b)

Historically, EPL's annual distribution cost increases have been less than inflation.

Figure 2-16: Consumer rate increases compared to inflation



2.3.1.2.3 Effect on the DSP (5.2.3c)

EPL's total spending over the forecast period is limited by rigorously applying this metric. In EPL's project prioritization process, projected consumer bill impacts act as budget constraint. The projects and programs listed in this DSP have been selected based on this constraint.

2.3.1.3 Power Quality

EPL tracks power quality by monitoring the voltage at various customer meters.

2.3.1.3.1 Definition of Measure (5.2.3a)

A power quality concern exists when, under normal operating conditions, the voltage measured at the customer meter is outside of the CAN3-C235-83 voltage variation limits. To monitor power quality over the forecast period, EPL will begin to track the number of outstanding substantiated power quality concerns reported at year-end as a metric.

2.3.1.3.2 Historical Performance (5.2.3b)

EPL will begin tracking this metric in response to the Filing Requirements so there is no historical data to report on. Presently, EPL is monitoring voltage at various customer meters and there are no outstanding power quality concerns.

2.3.1.3.3 Effect on the DSP (5.2.3c)

Typically, a voltage excursion at the meter may indicate a problem with the meter itself. EPL has programs planned over the forecast period to upgrade interval meters and replace end-of-life smart meters. Otherwise there are no outstanding power quality concerns on EPL's system.

2.3.1.4 Customer Satisfaction

Customer satisfaction is measured by a third party which surveys EPL's customers.

2.3.1.4.1 Definition of Measure (5.2.3a)

The customer satisfaction measure is defined as the percentage of customers who are satisfied with the service they receive from EPL. EPL's target for this metric is to achieve a customer satisfaction score of 80% or greater

2.3.1.4.2 Historical Performance (5.2.3b)

EPL began formally tracking customer satisfaction using a metric in 2014. In each year, customer satisfaction has been above target.

Figure 2-17: Customer satisfaction measured in 2014, 2015, and 2016

2.3.1.4.3 Effect on the DSP (5.2.3c)

Each and every contact EPL has with its customers affects the level of satisfaction perceived by customers. Customer satisfaction impacts virtually every aspect of the DSP. Consultations and customer surveys are conducted to understand the needs and preferences of customers. EPL's customers are satisfied with the reliability and quality of power supplied by EPL, but are concerned with the cost of electricity. Therefore, EPL will continue to make investments into its distribution system as required without burdening its customers with large rate increases. In fact, EPL's planned budget aligns its annual rate increases with inflation while providing a modern and reliable distribution system.

2.3.1.5 Service Quality

Service quality metrics are defined in the *Distribution System Code* and provide a detailed overview of the quality of customer service provided by EPL.

2.3.1.5.1 Definition of Measure (5.2.3a)

The *Distribution System Code* sets the minimum service quality requirements that a distributor must meet in carrying out its obligations to distribute electricity under its license and the *Energy Competition Act, 1998*. As required by the OEB, EPL records and submits all performance measures, which are compared with the OEB's established levels to evaluate EPL's customer service quality. The performance measures are described below, as defined in the *Distribution System Code*.

Connection of New Services

The OEB sets out the following requirements for the connection of new services:

- A connection for a new service request for a low voltage ("**LV**") (less than 750 V) service must be completed within five business days from the day on which all

applicable service conditions are satisfied, or at such a later date as agreed by the customer and distributor.

- A connection for a new service request for a high voltage ("**HV**") (greater than 750 V) service must be completed within ten business days from the day on which all applicable service conditions are satisfied, or at such a later date as agreed to by the customer and distributor.

The target for this metric is ninety percent or greater (≥90%).

Telephone Accessibility

The OEB requires that qualified incoming calls to the distributor's customer care telephone number must be answered within the thirty (30)-second time period as established below:

- For qualified incoming calls that are transferred to the distributor's interactive voice response system, the thirty (30) seconds shall be counted from the time the customer selects to speak to a customer service representative.
- In all other cases, the thirty (30) seconds shall be counted from the first ring.

The target for this metric is sixty-five percent or greater (≥65%).

Telephone Call Abandon Rate

As required by the OEB, the number of qualified incoming calls to a distributor's customer care telephone number that are abandoned before they are answered shall be ten percent or less (≤10%) on a yearly basis. A qualified incoming call will only be considered abandoned if the call is abandoned after the thirty (30)-second time period has elapsed.

Appointments Scheduled

When a customer or a representative of a customer requests an appointment with a distributor, the distributor shall schedule the appointment to take place within five business days of the day on which all applicable service conditions are satisfied, or on such a later date as may be agreed upon by the customer and the distributor. This includes Underground Locate Requests. The target for this metric is ninety percent or greater (≥90%).

Appointments Met

When an appointment is either:

- requested by a customer or a representative of a customer; or
- required by a distributor with a customer or a representative of a customer,

the distributor must offer to schedule the appointment during the distributor's regular hours of operation within a window that is no greater than four hours. The distributor must then arrive for the appointment within the scheduled timeframe. This includes Underground Locate Requests. The target for this metric is ninety percent or greater (≥90%).

Appointments Rescheduled

When an appointment with a customer or a representative of a customer is going to be missed, a distributor must:

- attempt to contact the customer before the scheduled appointment to inform the customer that the appointment will be missed; and
- attempt to contact the customer within one business day to reschedule the appointment.

The target for this metric is one hundred percent (100%).

Written Responses to Enquiries

A written response to a qualified enquiry shall be sent by a distributor within ten business days. The target for this metric is eighty percent or greater (≥80%).

Emergency Response

Emergency calls (i.e. assistance by the distributor has been requested by fire, police, or ambulance services) must be responded to within two (2) hours in rural areas and within one (1) hour in urban areas. The target for this metric is eighty percent or greater (≥80%).

Reconnection Performance Standard

Where a distributor has disconnected the property of a customer for non-payment, the distributor shall reconnect the property within two (2) business days of the date on which the customer:

- makes payment in full of the amount overdue for payment as specified in the disconnection notice; or
- enters into an arrears payment agreement with the distributor.

The target for this metric is eighty-five percent or greater (≥85%).

Billing Accuracy

The billing accuracy metric was established by the OEB in 2014. The percentage of bills accurately issued is calculated by subtracting the number of inaccurate bills issued for the year from the total number of bills issued for the year and dividing that number by the total number of bills issued for the year (the total number of bills issued for the year includes original and reissued bills). Accurate bills that need to be cancelled in order to correct another bill shall not be included in the calculation of billing accuracy measure. A distributor should not include customer accounts that are unmetered accounts (e.g. street lighting and unmetered scattered loads) or power generation accounts when calculating the percentage of accurate bills.

A bill is considered inaccurate if:

- the bill contains incorrect customer information, meter readings, or rates; or
- the bill has been issued to the customer and subsequently cancelled due to a billing error; or
- there has been a billing adjustment in a subsequent bill as a result of a previous billing error.

The target for this metric is ninety-eight percent or greater (≥98%).

2.3.1.5.2 Historical Performance (5.2.3b)

EPL's service quality measure performance over the historical period is depicted in Table 2-5. There were not high voltage new service connections and no emergency calls for EPL's rural areas over this time period. Billing accuracy was added to the OEB's *Electricity Reporting & Record Keeping Requirements* for 2014 and was not tracked in prior years.

Table 2-5: Historical performance for service quality measures

Metric	Target	2013	2014	2015	2016
New Services - Low Voltage	≥90%	92.7%	93.0%	92.3%	90.5%
New Services - High Voltage	N/A	N/A	N/A	N/A	N/A
Telephone Accessibility	≥65%	66.4%	78.0%	79.2%	73.6%
Telephone Call Abandon Rate	≤10%	1.7%	1.2%	1.4%	0.8%
Appointments Scheduled	≥90%	96.5%	95.5%	98.52	98.8%
Appointments Met	≥90%	94.3%	94.7%	94.8%	90.8%
Appointments Rescheduled	100%	100.0%	100.0%	100.0%	100.0%
Written Responses to Enquiries	≥80%	91.2%	91.7%	84.7%	96.3%
Emergency Response - Urban	≥80%	92.9%	96.3%	100.0%	97.7%
Emergency Response - Rural	≥80%	N/A	N/A	N/A	N/A
Reconnection Performance Standard	≥85%	93.3%	95.3%	93.7%	97.5%
Billing Accuracy	≥98%	N/A	99.8%	98.1%	99.9%

2.3.1.5.3 Effect on the DSP (5.2.3c)

EPL has met all of its service quality targets and, therefore, has not planned any investments over the forecast period to specifically address these requirements.

2.3.2 Cost Efficiency and Effectiveness

Cost efficiency and effectiveness is measured in terms of:

1. DSP implementation progress
2. Pacific Economics Group ("**PEG**") Efficiency Assessment
3. Total cost

2.3.2.1 DSP Implementation Progress

DSP implementation progress measures the annual success of EPL's project execution and planning quality.

2.3.2.1.1 Definition of Measure (5.2.3a)

DSP implementation progress is measured as the percentage of projects completed in the budget year, the individual variance of project spending, and the total annual variance for capital spending compared to the budgeted amount. Table 2-6 summarizes the targets for each of these metrics. EPL understands that not all projects budgeted within a year will be completed that year, as other critical capital work may be required; therefore, this target

allows that twenty percent (20%) of projects may be deferred if necessary. The project and total capital budget variances targets are tighter, targeting spending within ten percent (10%) of the budget.

Table 2-6: DSP implementation metrics and targets

Metric	Target
Percentage of projects completed in the budget year	Greater than 80%
Project spending (planned vs. actual)	+/- 10%
Annual capital spending (planned vs. actual)	+/- 10%

2.3.2.1.2 Historical Performance (5.2.3b)

Since this is EPL's first DSP, there is no historical performance to report.

2.3.2.1.3 Effect on the DSP (5.2.3c)

From a work plan perspective, EPL is confident that it can capably execute its planned projects in their budget year. From a financial planning perspective, EPL has applied the utmost care in its budgeting process, considering both past replacement costs and expected future labour costs in its cost determination. The main risks in achieving these metrics are due to external factors. A significant portion of the system service budget over the forecast period will go towards the purchase and sale of assets to and from HONI. EPL has worked closely with HONI in drafting the agreements that will dictate the terms of these asset transfers to mitigate these risks and enable a successful DSP implementation.

2.3.2.2 Efficiency Assessment

The PEG Efficiency Assessment compares a distributor's expected costs to its actual costs based on models developed by PEG for the OEB.

2.3.2.2.1 Definition of Measure (5.2.3a)

The PEG Efficiency Assessment places distributors into five (5) groups as summarized in Table 2-7. EPL's target for this metric is to maintain its performance in Group 2.

Table 2-7: Definition of PEG Efficiency Assessment results

Group	Definition
Group 1	Actual costs are less than 25% of predicted costs
Group 2	Actual costs are between 10% and 25% less than predicted costs
Group 3	Actual costs are within 10% of predicted costs
Group 4	Actual costs are between 10% and 25% greater than predicted costs
Group 5	Actual costs are greater than 25% of predicted costs

2.3.2.2.2 Historical Performance (5.2.3b)

EPL was assessed to be in Group 2 during each year of the historical period for which an assessment was completed (2013 to 2015).

2.3.2.2.3 Effect on the DSP (5.2.3c)

EPL's holistic asset management process is built around improving cost effectiveness as described in Section 2.1.2. Inputs into EPL's risk-based decision-making model include cost savings and spending, which are optimized along with the other planning objectives to ensure the cost effectiveness of each project listed in this DSP. EPL has budgeted less reactive replacements over the forecast period than historical investment levels and this shift to more planned replacements will enable work to be completed more cost effectively. Other investments such as new recloser installations will improve operational efficiency by reducing the number of truck-rolls required to restore power during an outage.

2.3.2.3 Total Cost

The total cost measure on the OEB scorecards considers the sum of EPL's operating and capital costs.

2.3.2.3.1 Definition of Measure (5.2.3a)

The total cost measure is normalized per customer and per km of line. EPL monitors its performance with respect to these metrics relative to its peers, especially E.L.K. Energy Inc., Entegrus Powerlines Inc., and EnWin Utilities Ltd.

2.3.2.3.2 Historical Performance (5.2.3b)

Figure 2-18 depicts the total cost per customer over the historical period. In addition to usual wage and benefit costs for EPL's employees, EPL made in investments into new information, financial and operating systems technology, and renewal growth of the distribution system. There were also significant investments made during the years 2013 through 2015 related to a provincial construction project: the Herb Gray Parkway, an expressway route leading to the US. EPL's customer base grew by an average of 0.7% per year over the historical period.

Figure 2-18: Total cost per customer over the historical period

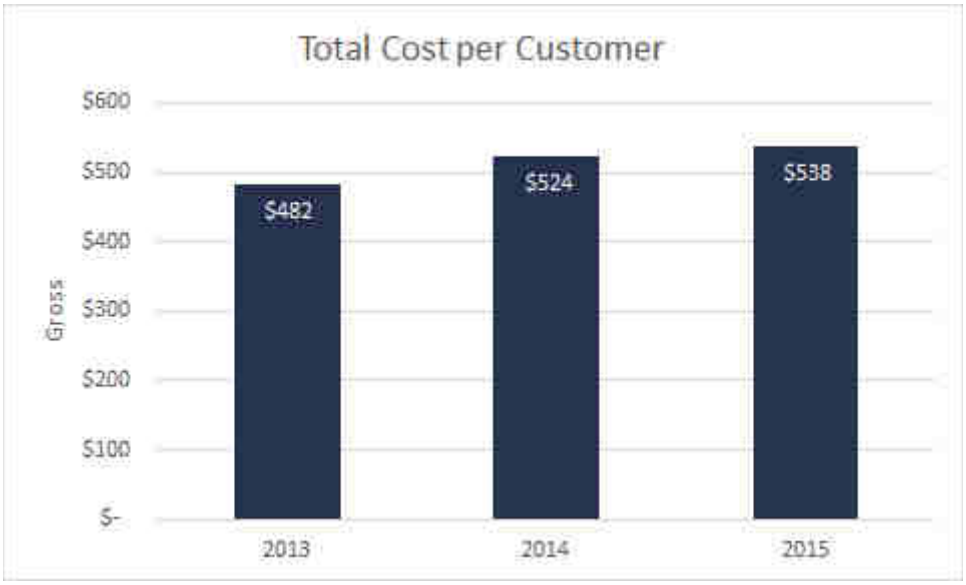
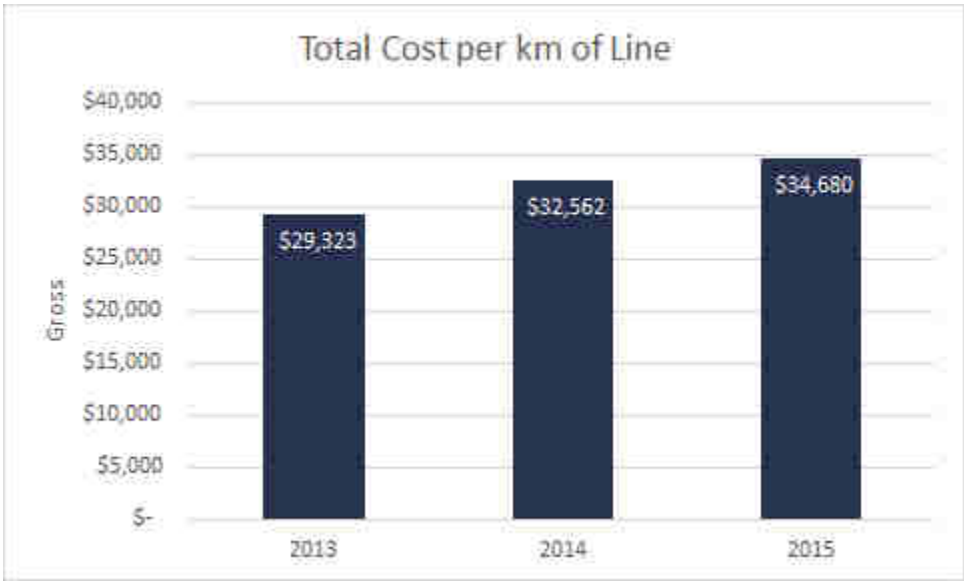


Figure 2-19 depicts the total cost per kilometre of line over the historical period. The total cost increased over the historical period for the same reasons listed above. In addition, EPL has decreased the length of line it manages due to voltage conversions.

Figure 2-19: Total cost per km of line over the historical period



EPL monitors its total cost performance relative to its peers, especially E.L.K. Energy Inc., Entegrus Powerlines Inc., and EnWin Utilities Ltd. Figure 2-20 compares EPL's total cost per customer to its peers based on a three (3)-year average from 2013 to 2015, while Figure 2-21 compares total cost per kilometre of line. In both comparisons, EPL is performing well compared to its peers. The results show that EPL is investing the right amount in its system and assets, while balancing external priorities, such as provincial construction projects.

Figure 2-20: Total cost per customer compared to peers

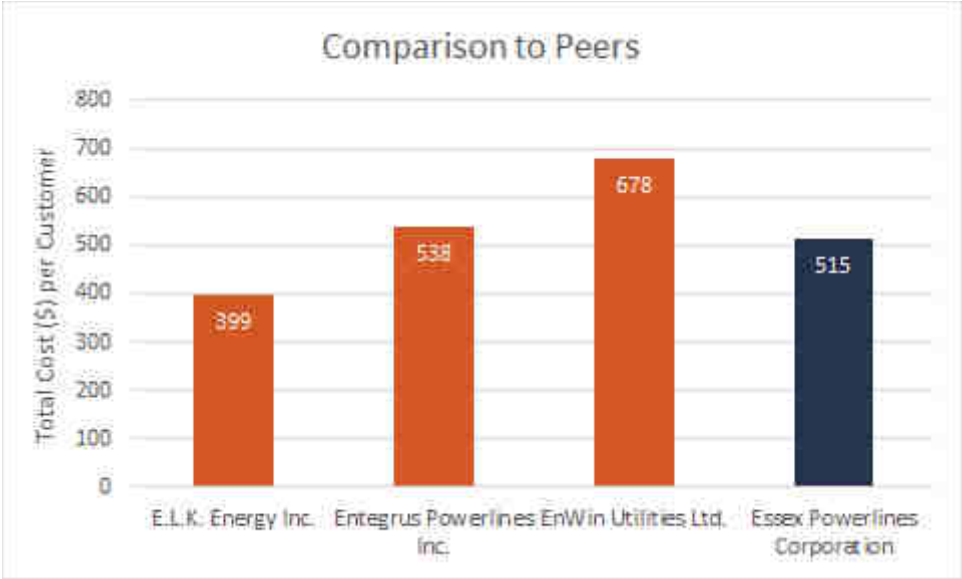
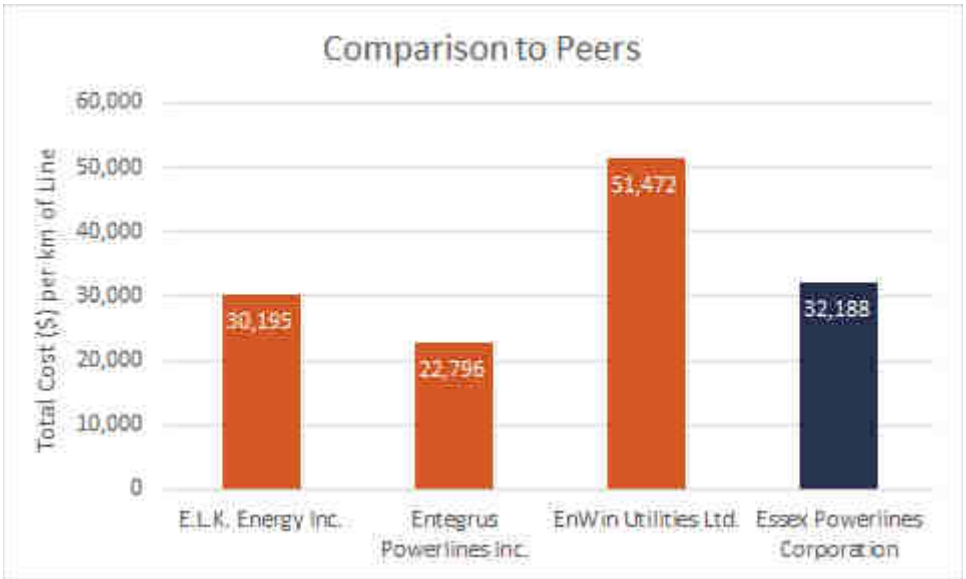


Figure 2-21: Total cost per km of line compared to peers



2.3.2.3.3 Effect on the DSP (5.2.3c)

Similar to the effects described in Section 2.3.2.2.3, EPL has developed a robust capital expenditure plan that will allow EPL to develop a modern distribution grid without the need for extraneous increases in cost. Furthermore, EPL plans to limit total cost increases to 2% per year in order to align consumer rate increases with inflation.

EPL's customer base is expected to continue to grow at a slow pace over the forecast period. Previous voltage conversions have reduced the kilometres of line owned by EPL. Although this has increased the total cost per kilometre of line, in the near- and long-term total cost increases are reduced since the elimination of substations and the reduction in line length under management equate to less O&M costs. As noted in Section 2.1.2, EPL's average system O&M spending over the forecast period is projected to $2.11M compared to $2.43M over the historical period. Investments in the system service category involving the sale and purchase of assets to and from HONI will also alter the length of line under management by EPL.

2.3.3 Asset/System Operations Performance

2.3.3.1 Safety

As noted in Section 3.1.1, EPL's top asset management objective is to ensure the safety of the public and its employees. Therefore, the success of EPL's DSP can be measured in terms of its safety performance.

2.3.3.1.1 Definition of Measure (5.2.3a)

Safety is measured using the OEB scorecard metric for Serious Electrical Incident Index. EPL's target for this metric is zero (0) serious electrical incidents.

2.3.3.1.2 Historical Performance (5.2.3b)

EPL has had zero (0) serious electrical incidents over the historical period.

2.3.3.1.3 Effect on the DSP (5.2.3c)

Safety is a key component in EPL's asset management practices. In a risk-based approach to asset management, safety must be balanced with other objectives such as environmental, regulatory, and service quality. Based on EPL's strategic business objectives, public and employee safety are weighted as the most significant asset management objective used to identify asset candidates for replacements, justify investments, and prioritize projects within the budget constraints. Therefore, projects identified in this DSP consider safety as part of a balanced, risk-based asset management approach. For example, EPL's pole replacement program has a safety component since poles are tested to identify those with the greatest risk of failure. Likewise, other system renewal investments consider safety impacts using the same methodology. System service investments pertaining to asset transfers do not have a significant safety component, but EPL will ensure compliance with Ontario Regulation 22/04 of the assets as a requirement. Investments into self-healing grid reclosers have many safety features including hot-line tagging and automated hold-offs. At a minimum, other investments in the system access and general plant categories will not add additional safety risks.

2.3.3.2 System Performance – Distribution Losses

System reliability was already discussed under customer-oriented performance (Section 2.3.1.1). EPL also measures system performance in terms of annual distribution losses.

2.3.3.2.1 Definition of Measure (5.2.3a)

Distribution losses are defined as the annual percentage line loss. Since EPL does not own any substations losses primarily occur along the distribution feeders, but distribution transformers and secondary lines also contribute to losses. Distribution losses depend on numerous factors including load, ambient temperature, conductor size, and imperfections in the assets. EPL would like its distribution losses to be as low as possible and considers four percent or less (≤4%) as a target for the historical period.

2.3.3.2.2 Historical Performance (5.2.3b)

Figure 2-22 depicts EPL's annual percentage line loss over the historical period, which shows significant variations due to external factors. Distribution losses are expected to be less than the four percent (4%) target over the forecast period since the voltage conversion program has been completed.

Figure 2-22: Annual percentage line loss over the historical period

2.3.3.2.3 Effect on the DSP (5.2.3c)

EPL recently completed its voltage conversion program, which has contributed to keeping distribution losses close to four percent (4%). As part of its asset management process, EPL calculates the optimal wire size for its system in order to reduce costs while considering line losses. Therefore, the replacement of underground direct-buried cables and overhead rebuilds are both expected to reduce distribution losses using the optimal wire size. The replacement of distribution transformers with new models that meet the latest energy efficiency standards will also reduce distribution losses.

2.3.3.3 Asset Performance

EPL tracks its asset-specific performance for the purpose of measuring the effectiveness of its planning and DSP implementation.

2.3.3.3.1 Definition of Measure (5.2.3a)

Asset performance is measured by the annual number of cable failures and annual number of switchgear failures. These assets were selected because they are major assets which cause defect equipment outages and which are also replaced proactively compared to run-to-failure assets. EPL's goal is for the failure rates for these assets over the forecast period to be better than the historical trends. EPL has defective equipment information going back to 2005 and observed an average of 4.3 cable failures and 2.6 switchgear failures per year until to 2016. Therefore, EPL is targeting to reduce this to three or less (≤3) cable failures and two or less (≤2) switchgear failures per year over the forecast period.

2.3.3.3.2 Historical Performance (5.2.3b)

The annual number of cable failures over the historical period is depicted in Figure 2-23 and the annual number of switchgear failures over the forecast period is depicted in Figure 2-24. Since the forecast period targets were chosen to show improvements over the historical

average, then naturally the number of failures was above target in some years: in 2013, there were four (4) cable failures and in 2016 there were three (3) switchgear failures.

Figure 2-23: Annual number of cable failures over the historical period

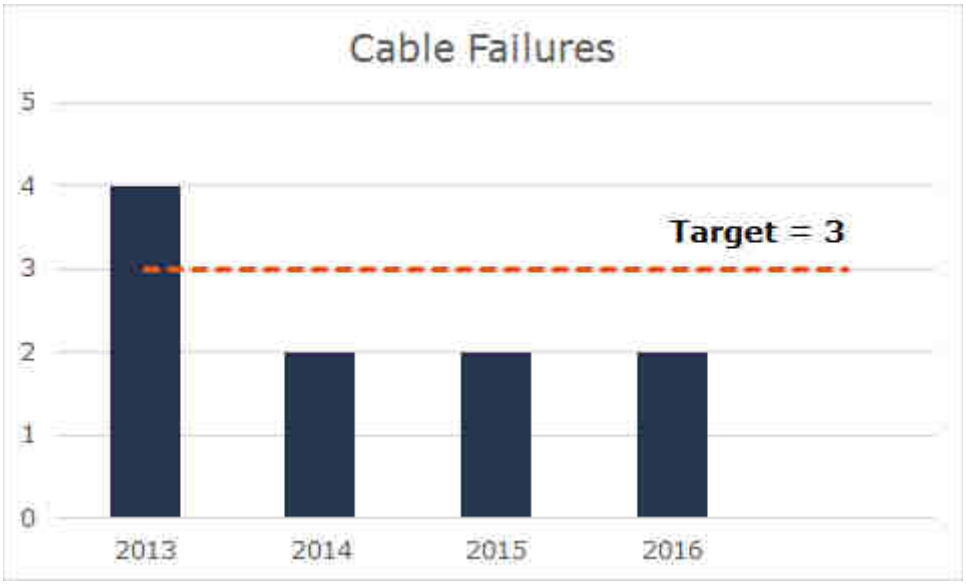
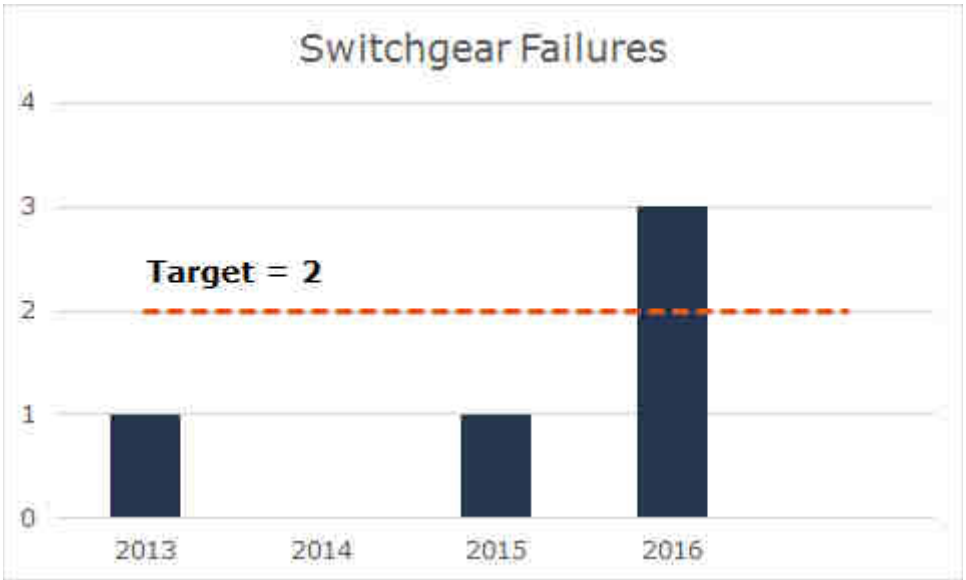


Figure 2-24: Annual number of switchgear failures over the historical period



2.3.3.3.3 Effect on the DSP (5.2.3c)

As previously mentioned, EPL has budgeted less reactive replacements over the forecast period and is moving towards a more proactive asset management approach. System renewal programs to replace direct-buried cable and pad-mounted switchgear will address these asset performance metrics.

3 Asset Management Process (5.3)

The purpose of EPL's asset management process is to develop projects for the future planning horizon using leading-edge Asset Investment Strategy ("**AIS**") tools. The Institute of Asset Management defines AIS as "the set of disciplines, methods, procedures, and tools to optimize the whole life business impact of costs, performance and risk exposures (associated with the availability, efficiency, quality, longevity and regulatory / safety / environmental compliance) of the company's physical assets".

The traditional approach to utility planning involved development of budgets using a "silo" approach where capital and O&M expenditures were planned for specific needs and then rolled up into an annual budget with no common linkage across the planning process. This approach is sub-optimal because little or no consideration is given to the trade-off opportunities, the value overlap, or the risk mitigation capability between capital investments and O&M programs. By determining its desired asset performance and risk tolerance, EPL is able to develop an optimal resource investment plan, as detailed in this section.

3.1 Asset Management Process Overview (5.3.1)

3.1.1 Asset Management Objectives (5.3.1a)

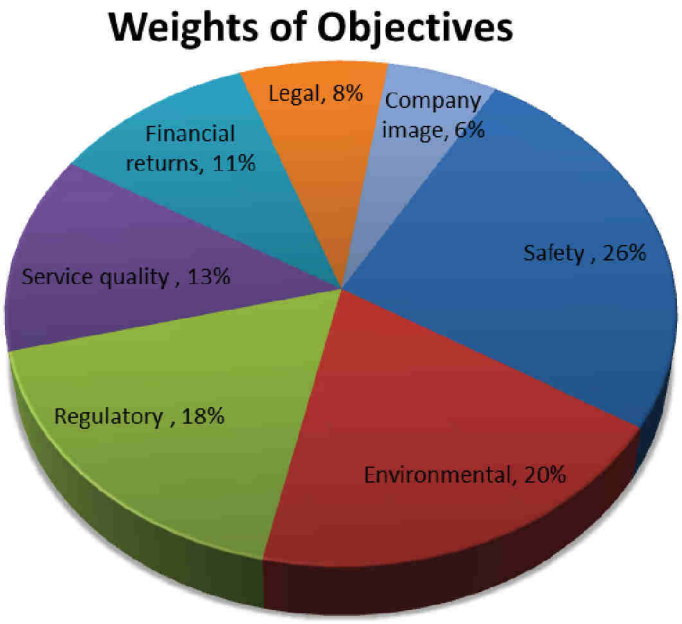
A robust AIS relies on a clear understanding and the precise definitions of the organization's strategic business objectives. EPL has established seven strategic business objectives that are applied to its asset management process. EPL assesses the risk that an asset poses to its performance in these seven objectives using quantified data whenever possible. In cases where EPL does not currently possess the capability to assess an asset's impact on a strategic business objective using quantitative data, then qualitative scores, which consider both the probability and consequence for each objective, are used. Table 3-1 lists the seven strategic business objectives and describes how EPL's risk exposure is accounted for through its asset management process for each objective.

Table 3-1: EPL's asset management objectives and related corporate goals

No.	Strategic Business Objective	Relation to Asset Management Processes
1	Public/Employee Safety	Qualitative scores (probability and consequence) for employee and public safety
2	Environmental	Qualitative scores (probability and consequence) for environmental implications
3	Regulatory	Qualitative scores (probability and consequence) for regulatory compliance
4	Service quality	Quantitative scores for SAIDI and SAIFI
5	Financial returns	Calculated Net Present Value ("**NPV**")
6	Legal	Qualitative scores (probability & consequence) for legal exposure
7	Company Image	Quantitative data for customer complaints

For the purpose of prioritizing investments, these seven business objectives are assigned relative weights, which are described in Figure 3-1.

Figure 3-1: Numerical weights assigned to EPL's asset management objectives



Since qualitative scoring is applied to the safety, environmental, and regulatory business objectives, all of which have high numerical weights, there is a risk of a high sensitivity in the asset management process results. To mitigate this risk, EPL applies a consistent methodology in its risk assessments, as described in Section 3.3.2 covering EPL's asset lifecycle risk management policies and practices. EPL is working towards developing a performance management framework that can quantify the risk exposure in these categories to ensure a more objective assessment in the future.

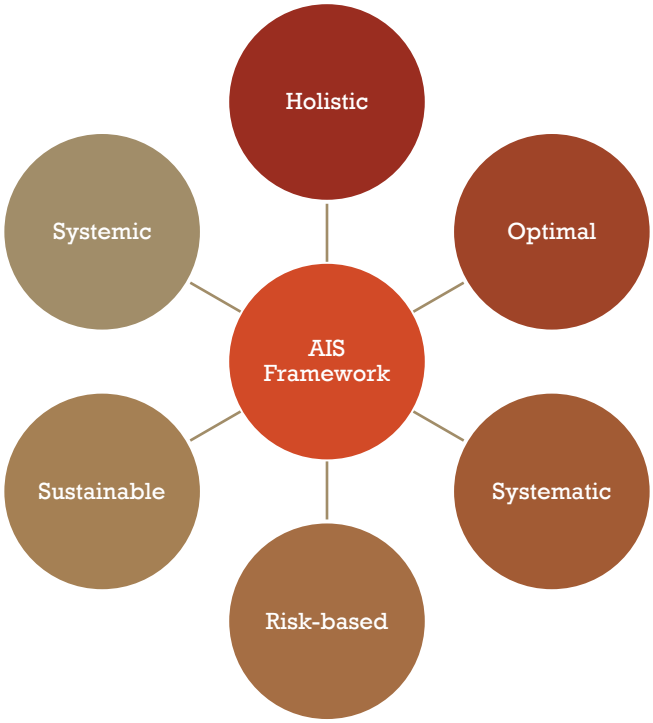
3.1.2 Components of the Asset Management Process (5.3.1b)

EPL's AIS is a risk-disciplined value-creation approach to strategic investment decisions that improves operational efficiency and system performance. In the past, utility companies built robust, redundant systems with underutilized capacity because regulatory environments encouraged such behaviour. By understanding the risk versus value trade-off associated with investing in asset replacement and system reticulation needs, the inherent value built into these systems can be reduced, released, or re-deployed for other capital resource requirements.

The capability to develop an effective value-added risk-disciplined approach to investment decisions, consistent data reporting, good data repositories, and good analysis tools are necessary. EPL uses an Asset Optimization Tool, which was developed by Texas Utilities and is currently owned by UMS Group Inc. The tool is used for making justified, risk-based decisions into asset investments on EPL's system. The AIS is based on the best-in-class asset management framework described by the PAS-55 and ISO 55000 series asset

management standards. The key characteristics of the AIS framework applied by the Asset Optimization Tool are shown in Figure 3-2.

Figure 3-2: Key characteristics of EPL's AIS framework



This AIS methodology employs a portfolio approach to investment decisions that embraces the performance linkage between capital and O&M expenditures. This approach helps facilitate development of an optimal Asset Investment Plan ("**AIP**") that includes a mixture of projects and programs that deliver the most value for the resource allocation. Spending is optimized based on the achievement of the seven strategic business objectives described in Section 3.1.1.

Quantification of the operational risk exposure mitigated by a project or program in the AIP is very important. Without this capability, management cannot make risk-informed financial decisions associated with a given resource allocation plan. Furthermore, better strategic and tactical decisions regarding asset replacement and maintenance investment decisions can only be made if the data is credible. Thus, the systems necessary for data reporting, storing, and analysis are crucial. EPL partnered with UtiliSmart Corporation to create SmartMAP: an integrated distribution monitoring and control system.

SmartMAP was developed based on EPL's proven DESS and overlaid on a GIS with full connectivity and asset information. SmartMAP integrates voltage and load profiles, line temperature monitoring, ambient temperature, and line loss measurement. With this information, EPL can accurately assess asset capacity utilization and identify constraints on the system. This streamlines EPL's ability to meet customer/developer requests and to identify potential capacity upgrade projects. SmartMAP also includes fault current

measurement and outage detection, which are used to identify damage to distribution assets and improve outage restoration time.

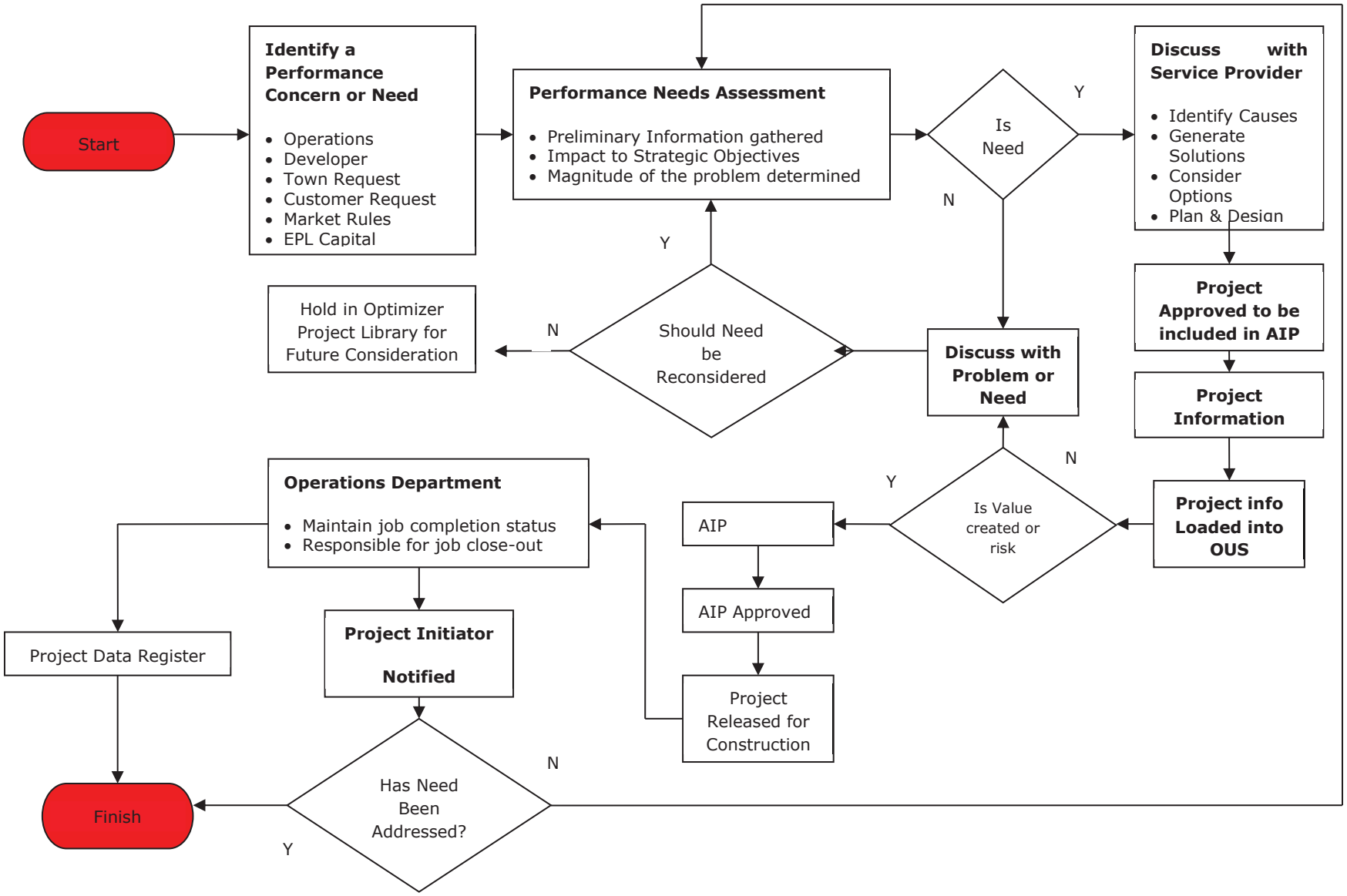
Figure 3-3: SmartMAP integrates the asset register, DESS, and GIS

The software suite also includes HealthMAP, which integrates the asset health index with the GIS and provides alerts for out-of-range distribution system data. The health index is used in the asset condition assessment to determine the probability of an asset failure. The probability combined with the consequence of an asset failure constitutes a complete risk analysis. This includes quantification of SAIDI and SAIFI to determine the reliability risk as part of the consequence of failure analysis. The value creation is defined in terms of performance delivery and the risk mitigation capability is defined in terms of the Operational Beta described in Section 3.3.2. EPL's customers directly benefit from the reduction in lifecycle costs of asset ownership, a reduction in the number of assets on the system, and inventory reduction.

Usage of these software tools allows EPL to manage its AIP as a live model and make modifications to the plan as necessary. Resource planning is also incorporated in the tools to ensure adequate resource availability to carry out the plan. EPL directs cyclical planned inspections and preventative maintenance activities to correct identified problems. Therefore, Reliability Centred Maintenance statistics are kept within acceptable severity/importance indices.

EPL also relies on analysis of outage statistics for each service area and historical period data on customer interruptions caused by equipment failure, as described in Section 2.3.1.1, to aid in its decision-making process. The complete AIS process is summarized in Figure 3-4. The integration of this consistent framework ensures that right-sized investments are made at the right time.

Figure 3-4: EPL's decision-making process based on the AIS



3.2 Overview of Assets Managed (5.3.2)

3.2.1 Description of the Service Area (5.3.2a)

EPL's service area is thirty-seven percent (37%) rural and sixty-three percent (63%) urban, consisting of four (4) non-contiguous service areas encompassing the Towns of Tecumseh, LaSalle, and Amherstburg and the Municipality of Leamington.

Situated in some of the most southern parts of Ontario, EPL's service areas are subject to periodic heavy snowfalls, ice accumulation, and strong winds typical of the region. In 2015, the region experienced 3013 heating degree days and 355 cooling degree days with a maximum recorded wind gust of 91 km/h.

Lengths of cables and conductors are measured in measured in kilometres of circuit, where a 1-km run of three-phase cable is measured as 1 km rather than 3 km. EPL owns 189.7 km of overhead lines and 262.6 km of underground cables.

The areas served by EPL have experienced slow economic growth over the past several years that have resulted in some load loss, while the recent completion of the Herb Gray Parkway in the Towns of LaSalle and Tecumseh has improved the economic conditions. The expansion of the greenhouse industry in the Municipality of Leamington has added additional load as well as spin-off customers within EPL's service territory.

3.2.2 Summary of System Configuration (5.3.2b)

EPL does not own any transformer stations and instead receives power directly from HONI feeders demarcated with primary metering units. EPL operates its distribution system at a single voltage: three phase lines are 27.6/16 kV and single-phase lines are 16 kV. Table 3-2 summarizes the system configuration.

Table 3-2: Summary of system configuration

Conductor Type	Three Phase (km)	Single Phase (km)	Total (km)*
Overhead	109.4	80.2	189.7
Underground	35.3	227.3	262.6

**totals may not add up due to rounding*

3.2.3 Summary of Asset Condition Assessment (5.3.2c)

The complete ACA report is attached as Appendix J. EPL's ACA is based on data compiled in June 2017 and covers the following classes of fixed assets owned:

- Wood poles;
- Concrete poles;
- Steel poles;
- Pad-mounted distribution transformers;
- Pole-mounted distribution transformers;
- Pad-mounted switchgear;
- Dip poles (primary risers); and

- Primary underground cables.

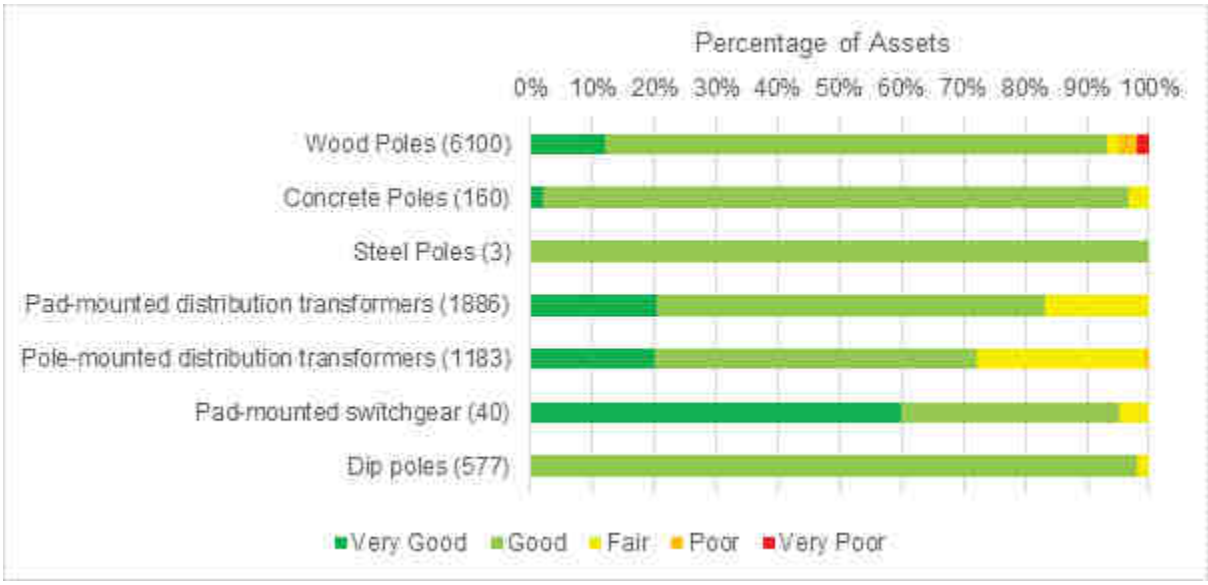
Table 3-3 summarizes the assessment criteria and Typical Useful Life ("**TUL**") for each asset class. Age demographics are not tracked for dip poles. The condition was determined for all asset classes except primary underground cables, for which only age demographics are known. Statistics for primary underground cable failures were used to support an age-based replacement plan.

Table 3-3: Asset count, assessment criteria, and TUL for each asset class

Asset Class	Count	Assessment Criteria	TUL (years)
Wood poles	6100	Test results (Resistograph), visual inspection results, service age	50
Concrete poles	160	Visual inspection results, service age	50
Steel poles	3	Visual inspection results, service age	60
Pad-mounted distribution transformers	1886	Visual inspection results, service age	40
Pole-mounted distribution transformers	1183	Visual inspection results, service age	40
Pad-mounted switchgear	40	Visual inspection results, service age	30
Dip poles (primary risers)	577	Visual inspection results	N/A
Direct-buried primary underground cables	45.8 km	Service age, reliability statistics	30
Primary underground cables in conduit	216.8 km	Service age, reliability statistics	40

The assets are assessed to be in one of five (5) conditions: Very Good, Good, Fair, Poor, or Very Poor. The results of the ACA are summarized in Figure 3-5, whereas underground cables are assessed separately (see Section 3.2.3.8). Overhead conductors generally do not drive investment decisions so are not assessed as part of the ACA.

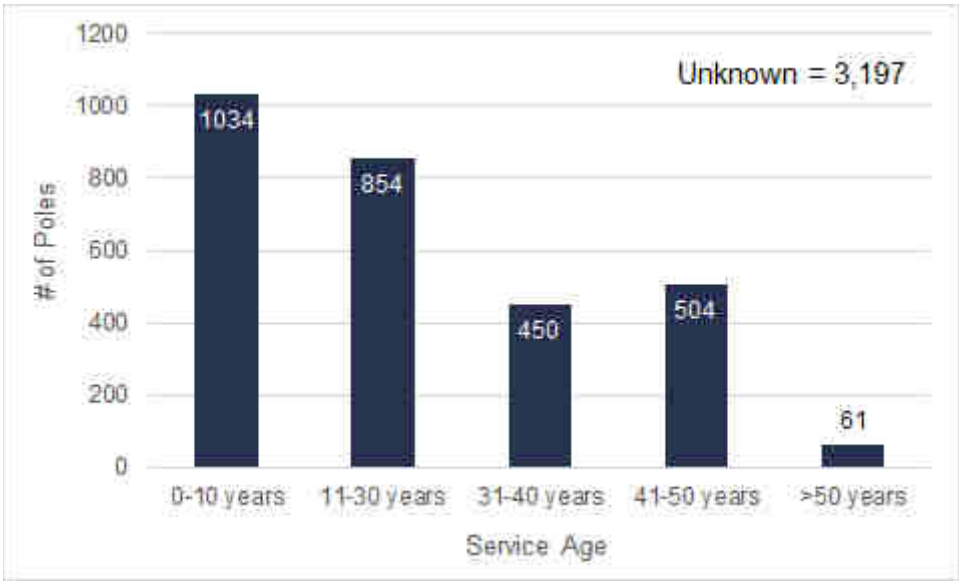
Figure 3-5: Summary of ACA



3.2.3.1 Wood Poles

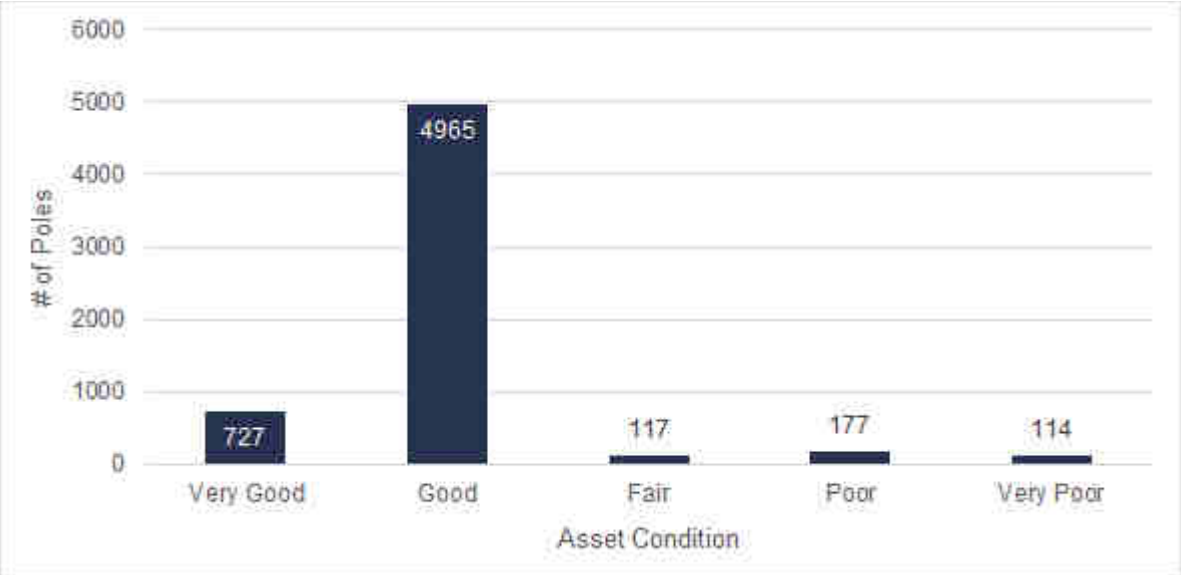
EPL owns 6100 wood poles across its four (4) service territories. The service age is known for 2903 – or 48% – of EPL's wood poles. Figure 3-6 presents the age distribution of the known set. The distribution is skewed towards newer poles since modern data collection processes are more accurate.

Figure 3-6: Age demographics of wood poles



The overall distribution consolidated between the four (4) service areas is presented in Figure 3-6. The results suggest a pole replacement rate of 1.5-2% per year, depending on the final results of the risk analysis, which is reflective of a fifty-year TUL.

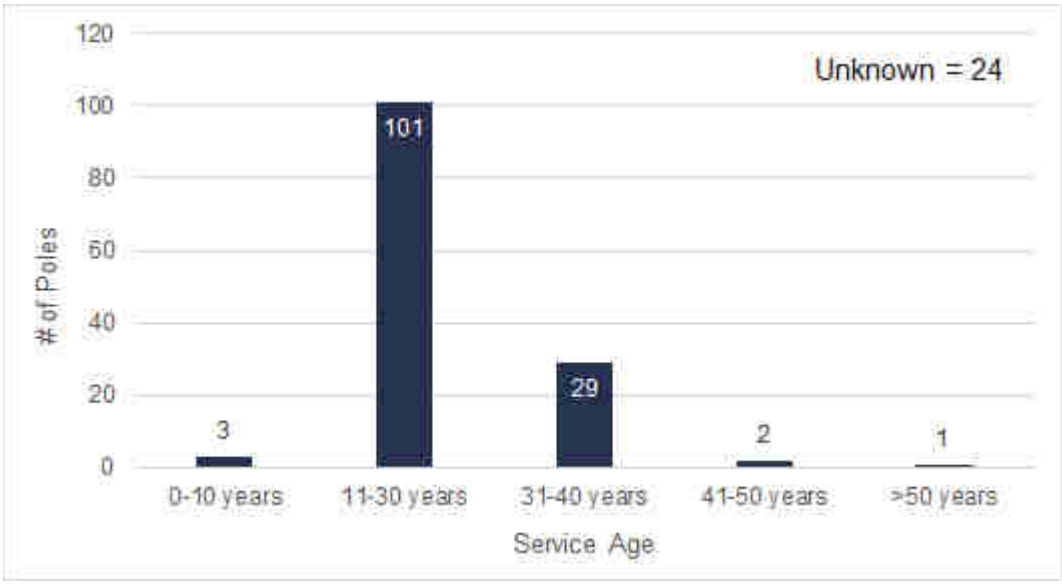
Figure 3-7: Condition assessment results for wood poles



3.2.3.2 Concrete Poles

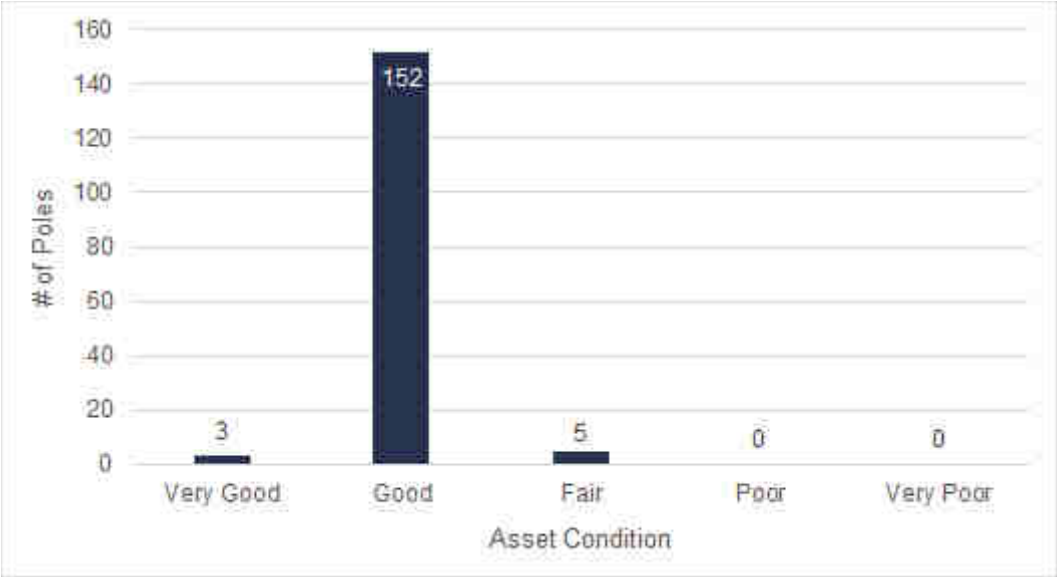
EPL owns 160 concrete poles across its four (4) service territories. The service age is known for 136 – or 85% – of the concrete poles. Figure 3-8 presents the age distribution of the known set of concrete poles. There have been very few concrete pole installations in the past ten (10) years.

Figure 3-8: Age demographics of concrete poles



The overall distribution of concrete pole condition consolidated between the four (4) service areas is depicted in Figure 3-9. The results suggest that there are no immediate replacement needs for concrete poles.

Figure 3-9: Condition assessment results for concrete poles



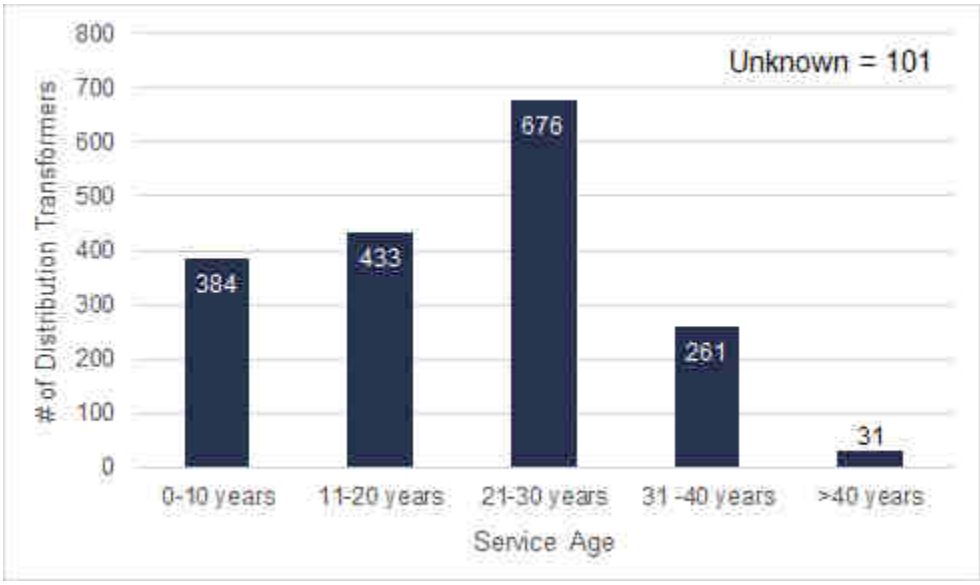
3.2.3.3 Steel Poles

EPL owns three (3) steel poles: two (2) in LaSalle and one (1) in Leamington. The service age is known for just one (1) of the poles, which is thirty-seven (37) years old and situated in LaSalle. The three (3) steel poles were all assessed to be in Good condition. The results suggest that there are also no immediate replacement needs for steel poles.

3.2.3.4 Pad-mounted Distribution Transformers

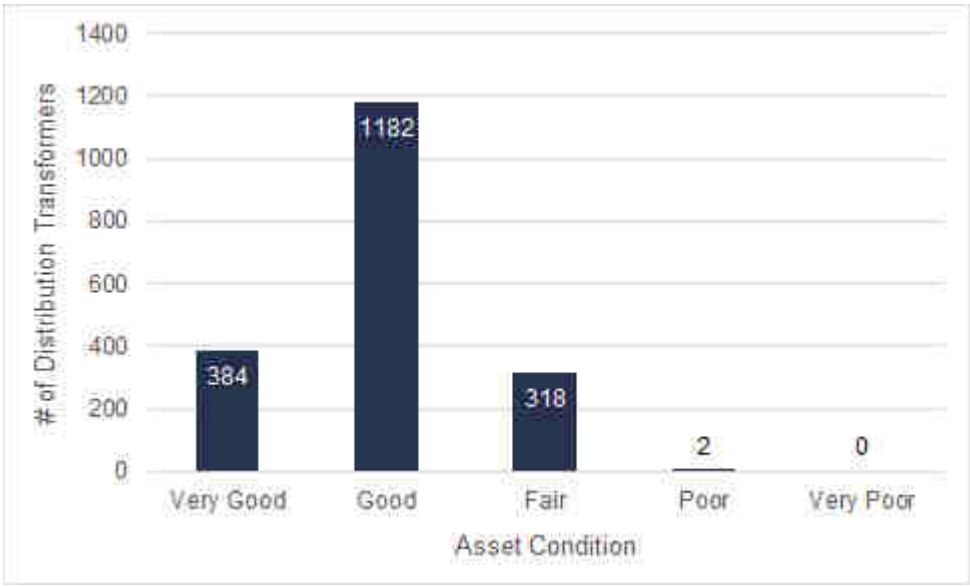
EPL owns 1886 pad-mounted distribution transformers across its four (4) service territories. The service age is known for 1785 – or 95% – of the pad-mounted transformers. Figure 3-10 presents the age distribution of the known set of pad-mounted transformers.

Figure 3-10: Age demographics of pad-mounted transformers



The overall distribution of pad-mounted transformer condition consolidated between the four (4) service areas is depicted in Figure 3-11. The majority of the pad-mounted distribution transformers are in Good condition, while just two (2) are in Poor condition.

Figure 3-11: Condition assessment results for pad-mounted transformers



3.2.3.5 Pole-mounted Distribution Transformers

EPL owns 1183 pole-mounted distribution transformers across its four (4) service territories. The service age is known for 991 – or 84% – of the pole-mounted transformers. Figure 3-12 presents the age distribution of the known set of pole-mounted transformers.

Figure 3-12: Age demographics of pole-mounted transformers

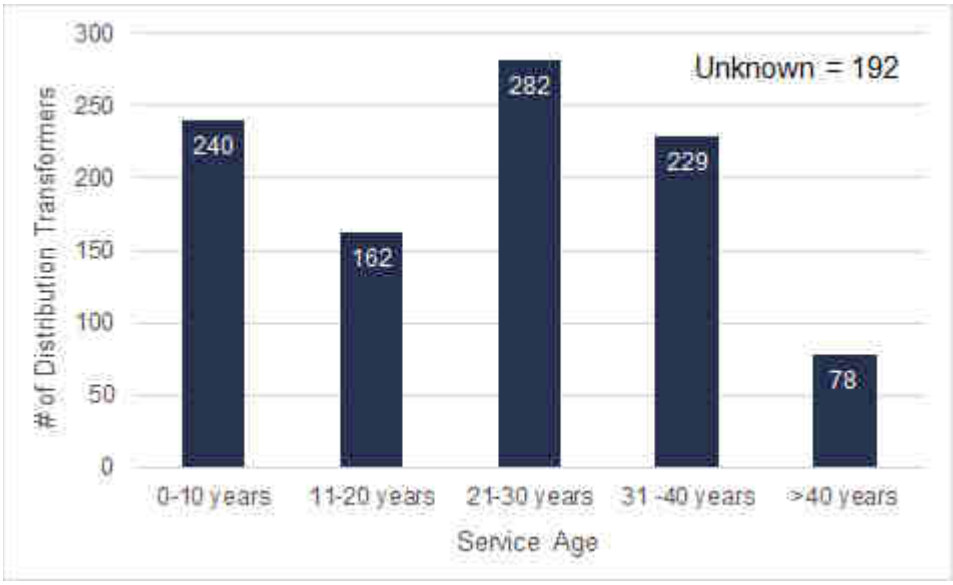


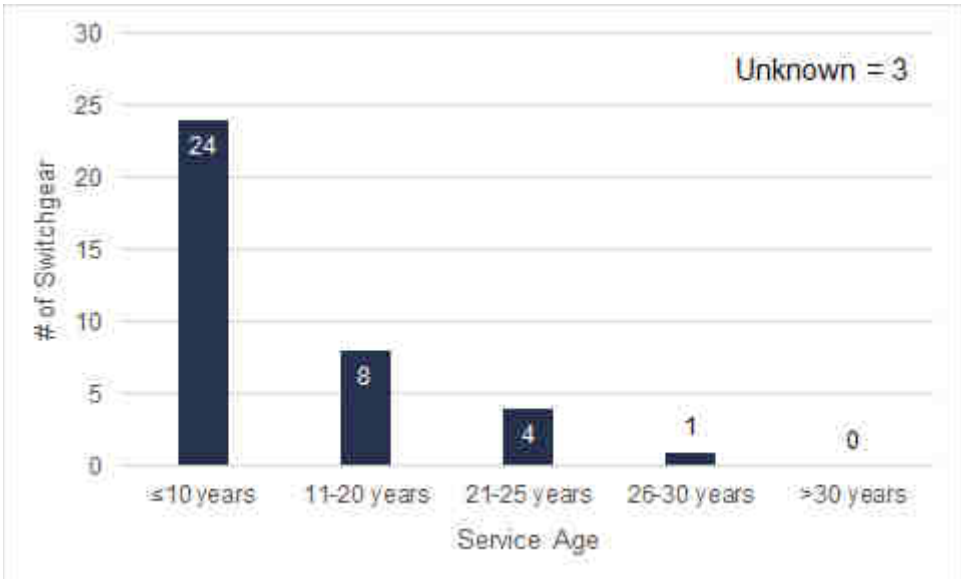
Figure 3-13 depicts the overall distribution of pole-mounted transformer condition consolidated between the four (4) service areas. Five (5) pole-mounted distribution transformers are in Poor condition and one (1) is in Very Poor condition. The majority of the pole-mounted distribution transformers are in Good condition.

Figure 3-13: Condition assessment results for pole-mounted transformers

3.2.3.6 Pad-mounted Distribution Switchgear

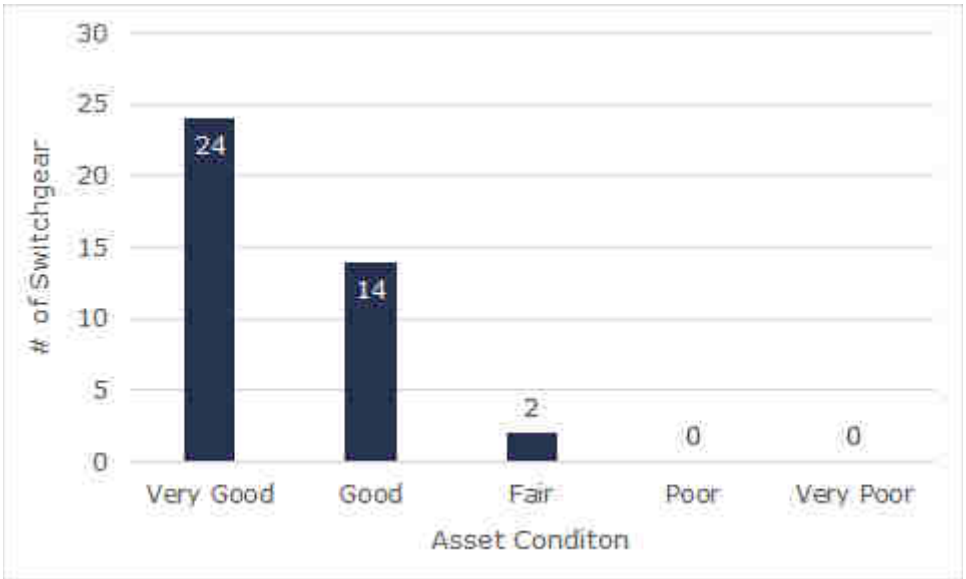
EPL owns forty (40) pad-mounted switchgear and the service age is known for thirty-seven (37) of them. Figure 3-14 presents the age distribution of the known set of pad-mounted switchgear.

Figure 3-14: Age demographics of pad-mounted switchgear



The condition assessment results for pad-mounted switchgear are presented in Figure 3-15. Two (2) of the switchgear are in Fair condition, while the rest are in Good or Very Good condition.

Figure 3-15: Condition assessment results for pad-mounted switchgear



3.2.3.7 Dip Poles (Primary Riser)

EPL has dip poles at 577 locations. Figure 3-16 presents the results of the condition assessment. Twelve poles are in Fair condition, while the rest are in Good condition.

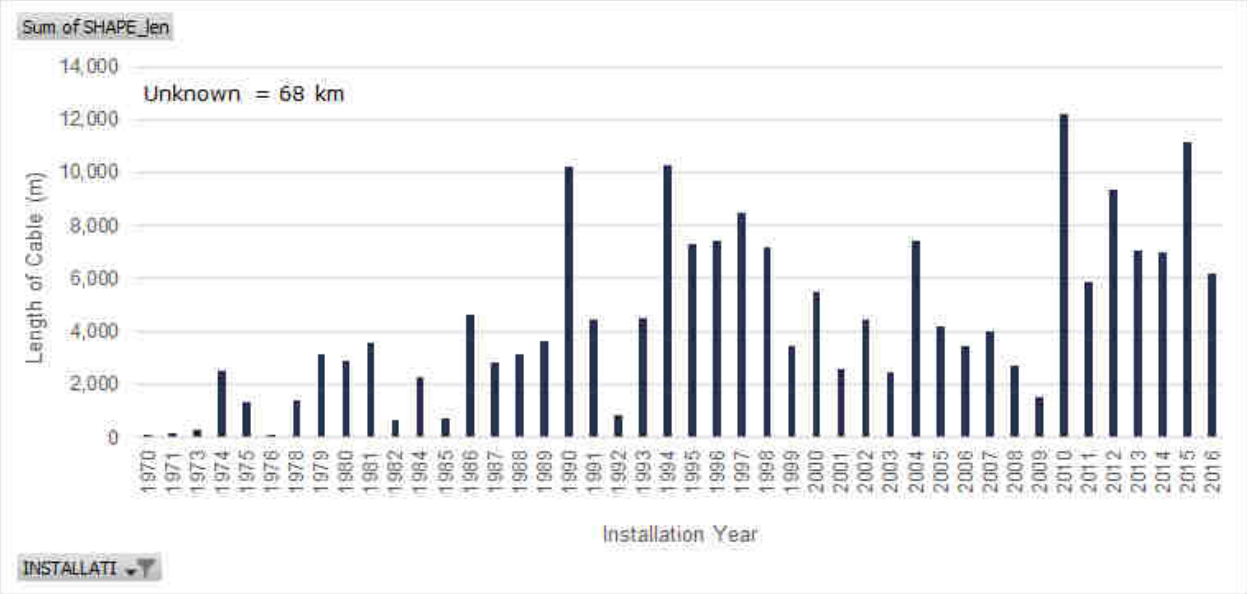
Figure 3-16: Condition Assessment Results for Dip Poles

3.2.3.8 Primary Underground Cables

The installation year is known for 194.9 km of the cables – or 74%. Figure 3-17 presents the cable length by installation year. EPL uses a TUL of thirty (30) years for direct-buried cables and forty (40) years for cables in conduits. Since 1986, all primary cables were

installed in conduits; therefore, the significant amount of cable installed in 1990 and from 1994 to 1997 will reach their TUL beginning in 2030.

Figure 3-17: Installation Year of Primary Underground Cable



Out of the 67.7 km for which the installation date is unknown, 25.8 km was installed in conduit and is most likely less than thirty (30) years old. The remaining 41.9 km direct-buried cable was presumably installed prior to 1986 and has exceeded TUL. Based on this analysis, 48.9 km – or 19% – of EPL's underground cable have exceeded TUL. Table 3-4 summarizes the service age of EPL's primary underground cable relative to TUL.

Table 3-4: Primary underground cable service age relative to TUL

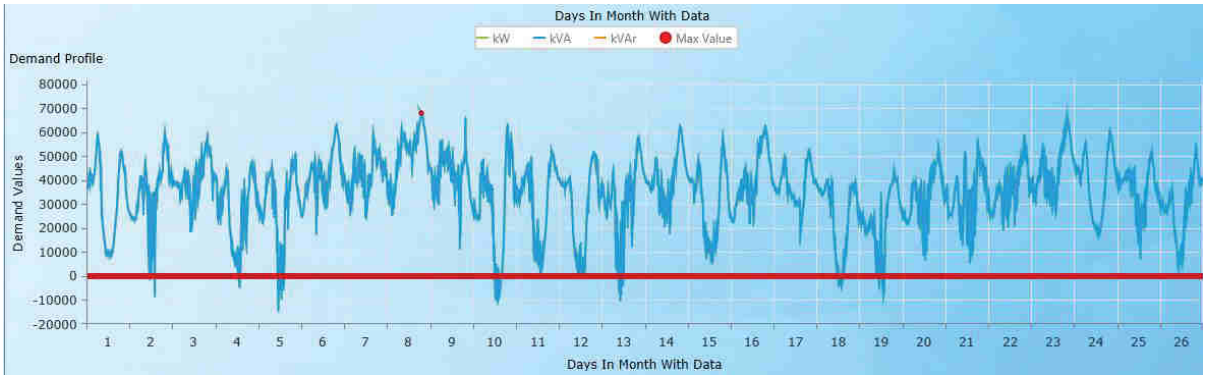
Service Age	Cable Length (km)
Past TUL	48.9
Will reach TUL by 2026	16.9
Will reach TUL by 2036	54.7
Will reach TUL by 2046	49.2
Will reach TUL by 2056	67.1
Unknown but will reach TUL after 2026	25.8
Total	**262.6**

3.2.4 System Utilization (5.3.2d)

System modeling is an important aspect of good distributor planning in order to meet customer needs. For example, fault levels must be calculated and provided to customers who request this information as per the *Distribution System Code*. The system model that EPL uses is called DESS, which is updated twice per year with current assets and customer information. SmartMAP is used on a yearly basis in conjunction with HONI to complete load

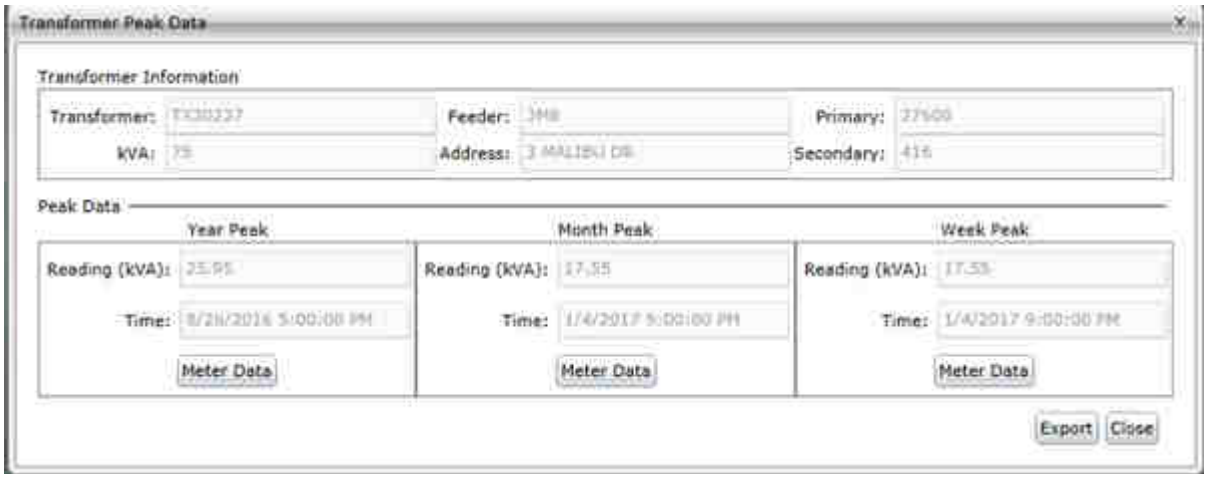
and phase balancing. This process ensures distribution feeders are balanced correctly per *Distribution System Code Section 6.4* requirements and verifies whether line loading, voltages, and equipment sizing are within acceptable the limits. DESS is integrated with SmartMAP to utilize actual distribution system data for its load flow simulations. Currently and over the past two years, EPL's total load has been in reverse flow at times because of the large amount of REG connected within and downstream of EPL's system. The load profile shown in *Figure 3-18* demonstrates that on days with large solar production along *with wind farm generation, the generation exceeds EPL's demand.*

Figure 3-18: EPL's net demand is negative at times due to the high penetration of REG



Transformer loading is an import part of the decision-making process when considering utilization of assets for system access and system renewal investments. HealthMAP and SmartMAP have full connectivity of all customers to transformers. The actual loading profiles are used by EPL's engineering department to determine if new customers can be added to existing transformers. Figure 3-19 depicts the dashboard of information available. Alert messages are set up to alert EPL staff of an overloaded transformer situation. Transformers are designed to operate above rated capacity for a limited period of time, but sustained overloading accelerates transformer degradation.

Figure 3-19: EPL considers the load of individual transformers



3.3 Asset Lifecycle Optimization Policies and Practices (5.3.3)

3.3.1 Asset Lifecycle Optimization Policies and Practices (5.3.3a)

Providing a reliable source of electricity to customers within a limited budget are the key pressures faced by LDCs in Ontario. The frequency and timing of distribution system equipment maintenance is an important factor in this balance. EPL relies on a combination of Reliability-Centred Maintenance ("**RCM**"), predictive maintenance, and cyclical inspections to manage its distribution assets.

RCM focuses on preventing failures with the most serious consequences, while predictive maintenance uses diagnostic methods to schedule maintenance in a timely manner. Integrating the two streams of information along with the asset risk assessment used for capital planning produces an optimal strategy for spending that considers both capital and system O&M costs. As assets are replaced through system renewal investments, the risk exposure on the system is reduced, thus reducing the need for RCM and preventative maintenance. At the same time, other assets on the system continue to age, thus increasing their failure probability and increasing the need for RCM and preventative maintenance. These two competing factors define the complex interactions between system renewal investments and system O&M costs, which EPL has yet to quantitatively define.

3.3.1.1 Reliability-Centred Maintenance

RCM considers the risk of customer outages, asset failure probabilities, methods to reduce the risk failure (probability or consequence), costs, the asset's role in the system, and other measures when selecting a specific maintenance program for an asset. RCM offers the following benefits:

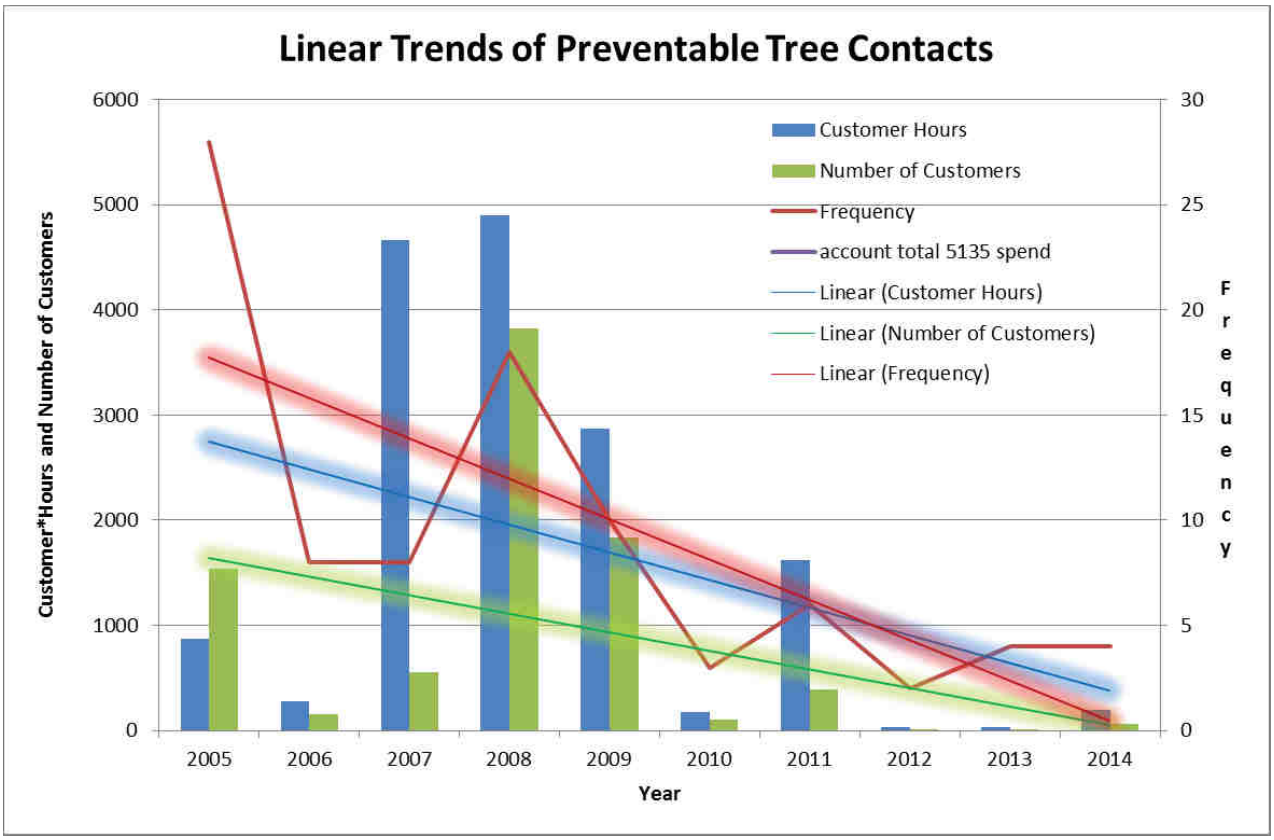
- The consequences of a single event on the distribution system are determined.
- The severity and importance of each component are assessed.
- Failures with the greatest consequences are prevented.
- Unnecessary maintenance is avoided.

The cost associated with each failure is used to predict future costs using failure trends. EPL has used RCM for the past ten years to assess and monitor the health of the distribution system assets. RCM is divided into 45 categories for reporting purposes and each outage is entered under the correct category.

Vegetation management is a key consideration of RCM. Using RCM trends EPL can monitor are preventable and unpreventable tree contacts resulting in an outage. A tree contact is defined as preventable when tree branches within the limits of the line cause a power outage – these could have been removed before the outage occurred. A tree contact is defined as unpreventable when the whole tree or long branches not within the limits of a line come in contact with the line. EPL also reviews road designs and customer plans submitted in order to ensure that new vegetation is planted be away from existing and future lines. During municipal and customer planning, EPL works with these groups to ensure vegetation clearance standards are conformed to.

EPL increased its spending on vegetation management since 2010, when Ontario Regulation 22/04 was modified to require vegetation management surrounding secondary lines as well as primary. Prior to 2011 secondary lines were not maintained just when power outages occurred on an unplanned basis. Preventable tree contact impacts to customers have trended sharply downward since this change was implemented, as shown in Figure 3-20. Therefore, in addition to meeting regulatory requirements EPL's vegetation management programs provide value in unplanned tree trimming cost reductions and improved reliability.

Figure 3-20: Preventable tree contact trends



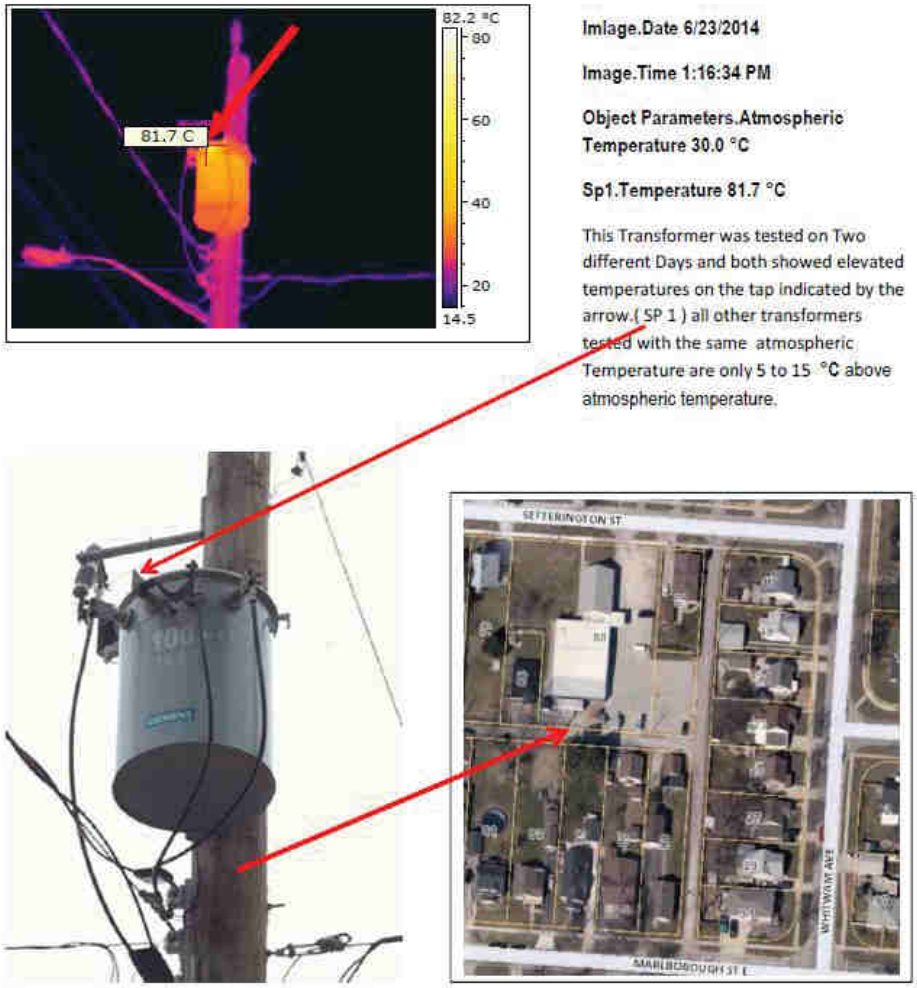
3.3.1.2 Predictive Maintenance

Predictive maintenance uses innovative technology, software, programs, and practices to identify components that are close to failure or are operating outside of normal ranges. EPL's predictive maintenance activities include infrared inspections and line monitors.

Infrared and ultrasonic inspections are both non-destructive test methods used to assess the performance of overhead components and major underground components of EPL's distribution system. These inspections identify distribution equipment which are close to failure or which are exhibiting signs of deterioration but still operating normally. Equipment which are close to failure are replaced on a high priority basis. Equipment which are starting to show signs of deterioration are monitored and programs are planned to repair or replace the equipment in the future.

Figure 3-21 depicts an example of an overhead transformer with an overheating connection. The mitigation strategy for this transformer would be to increase the inspection frequency of the transformer to check for signs of damage or wear and clean the connections.

Figure 3-21: Infrared inspection identifying hotspots on an overhead transformer



3.3.1.3 Preventative Maintenance

Regular preventative maintenance is performed on distribution assets to assess their condition and ensure proper operation. The preventative maintenance procedure follows standard industry practices and manufacturer recommendations. The assets are tracked in EPL's database and the results of the preventative maintenance are used to assess the condition of the equipment. Conditions are evaluated by linemen into three (3) severity categories: low, medium, and high. The database is reviewed for trends and problems requiring immediate actions.

3.3.1.4 Inspections

EPL's inspection programs are based on the minimum inspection requirements listed in Appendix C of the *Distribution System Code*. Line patrols are performed on a three (3)-year

cycle. Overhead transformers are inspected for signs of rust or oil leaks and transformer bushings are checked for cracks or contamination. Ground lead attachments and ground wire on arrestors are checked to ensure proper ground connection. In addition, transformers are checked for bird/animal nests and tree trimming requirements.

Wood poles are inspected for insect infestation or woodpecker damage; crossarms, pole tops, and pole shells are assessed for deterioration; leaning poles are noted; and a sound test determines the hollowness. Insulators on the poles are checked for chips, cracks, and contamination. Poles positioned in hazardous locations are also noted.

Load break switches are inspected for corrosion or mechanical deterioration and are maintained regularly. Overhead lines are checked for signs of corrosion, broken strands, abrasions, annealing, and elongation. Line connections to the switches are inspected. Line patrol inspection results are not formally documented. Instead, line staff note any deficiencies during line patrols or trouble calls for immediate or scheduled replacement depending on the severity of the damage or deterioration.

EPL's underground inspection program covers pad-mounted equipment and underground cable terminations. Underground transformers require very little maintenance and are inspected for paint condition, signs of corrosion, and oil leaks. Transformer bushings are checked for cracks or contamination. Switchgear are inspected for paint, corrosion, and mechanical deterioration and are maintained regularly. Underground cable terminations, which are exposed in pad-mounted equipment and riser poles, are inspected for signs of moisture ingress.

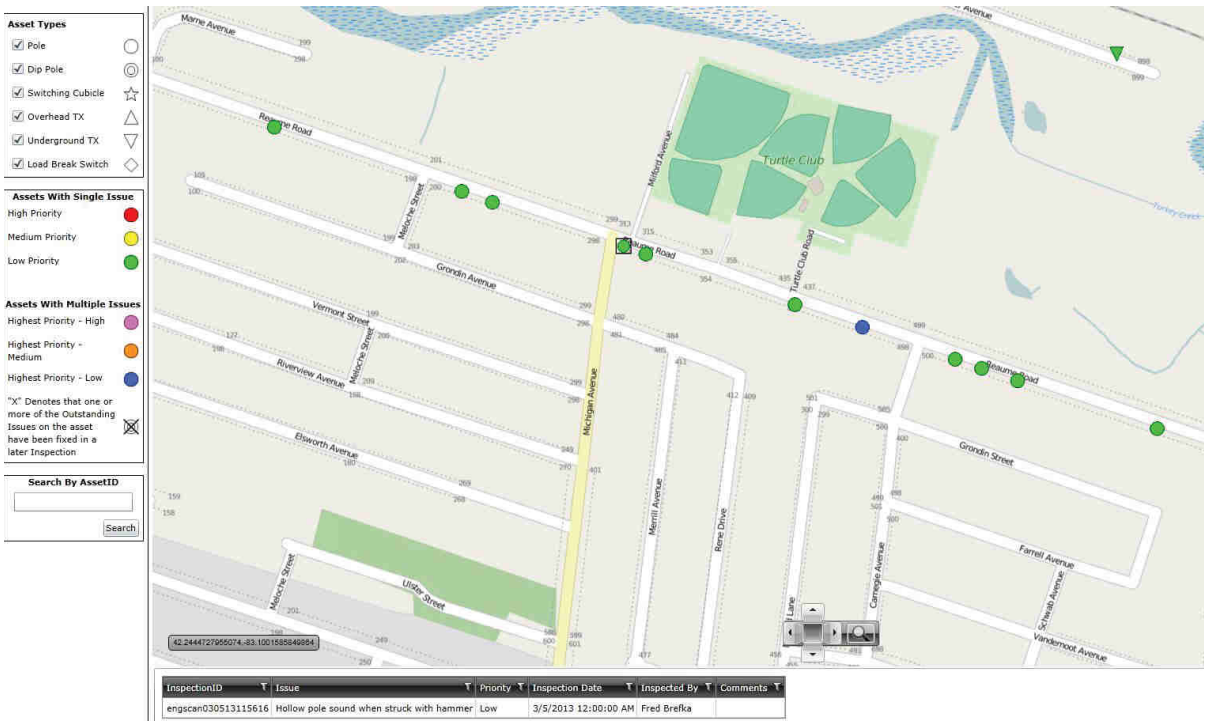
Table 3-5: EPL's inspection and maintenance programs

Asset	Inspection Programs	Maintenance Programs	Other
Overhead transformers	Inspected every three (3) years	None	Infrared scans
Underground transformers	Inspected every three (3) years	Some maintenance as required (vegetation control, paint condition, connection cleaning and tightening)	Infrared scans
Poles	Inspected every three (3) years	None	Pole testing
Load break switches	Inspected every three (3) years	Regular maintenance (adjustments as required)	Infrared scans
Switchgear	Inspected every three (3) years	Regular maintenance (cleaning and adjusting)	Infrared scans
Underground cables	Terminations inspected every three (3) years (at pad-mounted equipment and riser poles)	None	None
Overhead conductors	Inspected every three (3) years	None	None

EPL's assets are recorded in a database to manage inspection requirements based on standard industry practices and manufacturer recommendations. This database is reviewed for trends and problems requiring immediate action, and planned actions. Immediate actions may be taken if there is a concern for security, public access, or an outage.

Inspections are entered on a tablet and can be viewable through secure web portals. A map of inspection results is used by engineering staff to analyze and monitor asset condition. EPL staff can use this information to measure deterioration as assets age. Inspections also find items like theft of copper from poles as a covered ground wire runs down the outside of some poles to ground equipment. These items are repaired following the inspection.

Figure 3-22: Map of inspection results



3.3.2 Asset Lifecycle Risk Management Policies and Practices (5.3.3b)

EPL's distribution system maintenance and inspection programs are aimed in part to protect the public from physical, electrical and environmental hazards by maintaining a schedule of regular asset inspections and maintenance activities. *Ontario Regulation 22/04 – Electrical Distribution Safety* is a key regulation which requires all LDCs including EPL to maintain distribution standards, material standards, and construction verification programs to safeguard the public from hazards associated with the distribution system. EPL follows all regulatory requirements and guidelines to ensure the distribution system has a low risk impact on the environment.

A significant component of EPL's risk management policies and practices are the RCM and predictive maintenance activities described in Section 3.3.1. In addition, EPL's risk-based asset management process considers risk at each stage in the asset's lifecycle when making decision on the optimal timing of asset repair or replacement. Risk is evaluated by considering both the probability of an event occurring and its consequence. All seven strategic business objectives listed in Section 3.1.1 are considered in this analysis.

On the overhead distribution side, a pole failure can be a significant safety risk as the result could injure the public and/or cause a lengthy interruption. Poles which are closer to the

supply have a greater reliability impact in case of a failure, since they serve a greater number of downstream customers. Overhead transformers have a low risk of failure; their outage impact is limited to a small number of customers for a short duration. The risk of failure of load break switches and overhead conductors are low; although these assets may have a high failure impact, their failure probability is low.

On the underground system, switchgear failures also pose a significant failure risk, as a customer outage would likely occur and the safety of the public and staff would be impacted. As with overhead transformers, underground transformers have a low risk of failure; their outage impact is limited to a small number of customers for a short duration. The impact of an underground cable failure is low and public safety is not likely to be impacted as cables are buried and not exposed.

Conclusions of risk analyses use a scoring system to select and prioritize capital expenditures. Each potential project is scored in the risk matrix shown in Figure 3-23 by considering all seven strategic business objectives and using the following formulation.

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

- R_e is the expected rate of return.
- R_f is the risk-free rate of return
- R_m is the average market rate of return

By definition:

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

Figure 3-23: Risk matrix to select and prioritize capital expenditures

Risk Map

Probability						
5	Common/ Almost Certain	1.0	1.4	2.1	2.8	4.0
4	Most likely	0.9	1.3	1.8	2.5	3.5
3	Moderate	0.7	1.0	1.4	1.9	2.7
2	Likely	0.6	0.8	1.2	1.7	2.4
1	Rare	0.5	0.7	1.0	1.4	2.0
		Insignificant	Minor	Moderate	Major	Catastrophic
		1	2	3	4	5

Consequence

As part of the asset risk assessment, the asset's age and estimated remaining life are recorded and any concerns are identified. The risk assessment has three components:

- Public safety risk assessment
- Worker safety risk assessment
- Major equipment failure risk assessment

Crew members and the operations manager directly perform risk assessments of assets in the field. Any additional risks identified are populated in risk assessment forms. The inputs come from the operating personnel, shareholders, customer calls, emergency personnel (police, fire), health and safety meetings, other LDCs, and joint-use partners.

Based on the inspection during risk assessment process, every possible area of concern is noted and prioritized. Various criteria are evaluated such as concerns with unauthorized entry by public, proximity, clearance for workers, multiple sources of voltage, condition of the assets, presence of PCBs, etc. An overall asset risk ranking is produced as shown in Table 3-6. The rankings portray the severity of the risk with each asset by providing the timeframe within which capital work should be done to improve the condition.

Table 3-6: Overall asset risk rating

Priority	Low	Medium	High
Intervention timing	Four (4) to seven (7) years	Two (2) to three (3) years	One (1) year

4 Capital Expenditure Plan (5.4)

This section focuses on the capital investments planned by EPL over the forecast period. EPL's materiality threshold for this Application is $65,000.

4.1 Summary (5.4.1)

A summary of EPL's capital expenditure plan is outlined below and demonstrates key information explaining the significant aspects of the plan in order to meet EPL strategic corporate and asset management objectives. The capital expenditure plan was developed by leveraging key outputs of the asset management process. Projects have been divided into four (4) categories as outlined in the Filing Requirements.

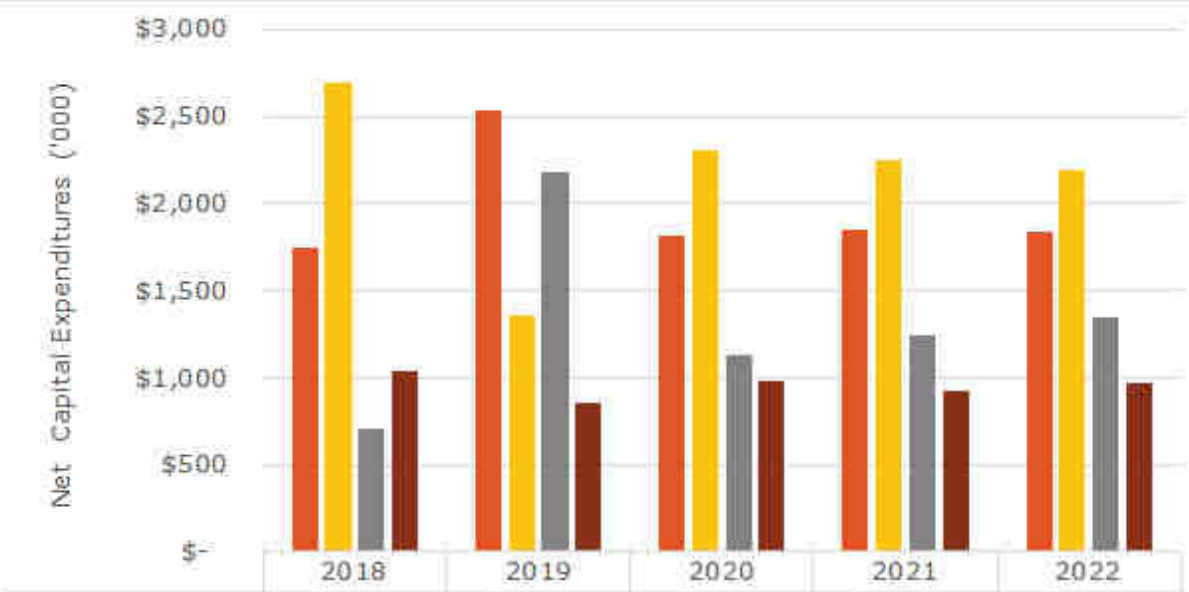
4.1.1 Ability to Connect New Load (5.4.1a)

With the exception of planned expansion-related spending in LaSalle, the remaining three (3) communities can accommodate planned load growth for the foreseeable future. Customer growth in LaSalle has necessitated the purchase of a new feeder and breaker position from HONI to continue to serve customers.

4.1.2 Capital Expenditures over the Forecast Period (5.4.1b)

Figure 4-1 presents the total annual capital expenditures by investment category over the forecast period.

Figure 4-1: Total annual capital expenditures over the forecast period



	2018	2019	2020	2021	2022
System Access	$1,746	$2,532	$1,816	$1,853	$1,835
System Renewal	$2,693	$1,362	$2,304	$2,248	$2,195
System Service	$707	$2,186	$1,126	$1,243	$1,342
General Plant	$1,037	$856	$976	$927	$968

4.1.3 Description of Investments (5.4.1c)

4.1.3.1 System Access

System access investments account for, on average, 31% of EPL's net capital expenditures over the forecast period. Investments in this category are driven by external requests and mandated obligations to accurately meter customers. For all programs, the forecast costs are driven by historical trends and increased by inflation.

Subdivisions

Investments are made to facilitate the connection of new residential subdivisions and the associated customers to EPL's distribution system. EPL coordinates its planning and construction activities directly with developers.

Residential Connections/Expansions

Residential requests for connection or expansion are costs associated with activities relating to plant relocation or plant upgrades to accommodate customer-related changes. EPL coordinates its planning and construction activities directly with customers and developers.

Municipal Requests

Municipal requests are costs associated with activities relating to plant relocation or plant upgrades to accommodate municipally-requested changes. Examples of municipal requests include, but are not limited to, road widenings, right of way improvements, and utility relocation projects. EPL coordinates its planning and construction activities directly with the municipalities and their contractors.

New Commercial/Industrial Service Upgrades

New service upgrades for commercial and industrial customers are budgeted annually. The investment costs are associated with activities relating to plant relocation or plant upgrades to accommodate customer-related changes. EPL coordinates its planning and construction activities directly with customers and their contractors.

Meter Upgrade and Replacement Program

The purpose of this program is to replace meters due to failure, technology limitations requiring upgrades, or seal expiry. The program also includes gatekeeper and modem replacements to enhance connection and reliability of data. In addition to considering historical spending trends and inflation, budgeting is reviewed annually based on communication and data needs of new technologies.

4.1.3.2 System Renewal

System renewal investments account for, on average, 34% of EPL's net capital expenditures over the forecast period. Investments in this category are driven by assets at the end of their service life due to failure or failure risk.

Pole Replacement Program

The purpose of this program is to replace poles that have either failed or are at the end of their service life due to failure risk. Through its thorough preventative maintenance program, EPL reviews the condition of its poles continuously to limit failure and maximize

safety via non-destructive testing methods such as drilling. Poles which have been tested to have a remaining strength of below sixty percent (60%) are prioritized for replacement. Budgeting is reviewed annually based on preventative maintenance program findings and availability of resources.

Reactive Replacement Programs

The purpose of these programs (overhead reactive replacements and underground reactive replacements) is to replace overhead and underground equipment that has failed as a result of damage incurred in the field. Budgeting is reviewed annually and is based on historical spending trends adjusted for expected inflation.

Install/Replace Load-Break Switches

The purpose of this program is to replace load-break switches that have either failed or are at the end of their service life due to failure risk. As part of the self-healing grid initiative, load-break switches are upgraded during their planned replacement for reliability and automation purposes.

Infrastructure Rebuild Program

The purpose of this program is to replace overhead and underground services and circuits that are located in alleys, right of ways, etc. in customer backyards. Budgeting is reviewed annually based on urgency of work required and potential safety hazards. EPL intends to increase accessibility of all of its plant while limiting inconveniences to its customers.

Switchgear Replacement Program

The purpose of this program is to replace live-front switchgear units that have failed or are at the end of their service life due to failure risk. Through its thorough preventative maintenance program, EPL reviews the condition of live-front switchgear units continuously to limit failure and maximize safety via infrared and physical inspection. Budgeting is reviewed annually based on preventative maintenance program findings and availability of resources.

4.1.3.3 System Service

System service investments account for, on average, 21% of EPL's net capital expenditures over the forecast period. Investments into this category are driven by customer requests for generation connection, system capacity constraints, and other system operational objectives: reliability and operability.

Purchase/Sell HONI Assets

The HONI Asset Purchase projects in Leamington (2018 and 2019) and LaSalle (2020 to 2022) are initiatives to transfer assets between EPL and HONI so that each distributor controls assets within its geographical distribution service territory boundary. Loss of supply outages have been a problem for EPL's customers; therefore, the asset transfers have been planned to improve operability and reliability. The budgeted expenditures are based on the estimated purchase and sale prices.

Malden TS – New Feeders and Reconfiguration

Capital expenditures pertaining to the upgrades at Malden TS, two (2) new feeders, and feeder reconfigurations in LaSalle are driven by system capacity constraints. Customer growth in LaSalle has necessitated the purchase of a new feeder and breaker position from HONI to continue to serve customers.

FIT and Generation Connections

This program accommodates the connection of REG to EPL's distribution system, including FIT connections (greater than 10 kW up to 500 kW) and generation connections (greater than 500 kW). Investments are driven by customer requests for FIT and generation connections. The expenditure forecast is made based on applications being processed and the projected nameplate capacity of applications to be received.

MicroFIT Connections

This program accommodates the connection of REG to EPL's distribution system under the MicroFIT program (10 kW or less). Investments are driven by customer requests and the expenditures are forecast based on the applications being processed and the projected number of applications to be received. This program falls below the materiality threshold.

Self-healing Grid Reclosers

The installation of new reclosers has been planned as part of EPL's broader Smart Grid Development Plan (see Section 1.4.3.4). EPL has identified that loss of supply outages are major concerns for the reliability of electricity experienced by its customers. The main benefit of installing reclosers as part of a self-healing grid is to reduce the impact of loss of supply incidents to customers. The new reclosers will allow remote operation, real-time outage detection, and the ability to isolate the distribution system from the upstream distributor/transmitter.

4.1.3.4 General Plant

General plant investments account for, on average, fifteen percent (15%) of EPL's net capital expenditures over the forecast period. General plant investments are modifications, replacements, or additions to assets that are not part of the distribution system; including land and buildings, tools and equipment, rolling stock (fleet), and computer hardware and software used to support day to day business and operations activities.

Tools and Equipment

Costs for tools correspond to all purchases of large or major tools with a value of $500 or more. The budget for this cost item is forecast based on scheduled replacement equipment for one of several reasons:

- If the equipment fails a required test for electrical integrity or continuity.
- If the equipment is at end-of-life.
- If the equipment is damaged beyond repair.

Office Furniture

Office furniture costs include desks, tables, chairs, and partitions. This forecast is based on a simple projection based on historical purchases. The budget is generally below the materiality threshold.

Transportation Equipment

EPL has identified fleet purchasing requirements using the criteria identified in its fleet management policy (see Appendix I: Fleet Purchasing Policy). The fleet assessment identifies large and small vehicles that will reach end-of-life in the forecast period and the associated replacement cost. EPL's capital expenditures related to fleet are designed to maintain the current compliment and functional capability.

The budget is forecast based on the fleet management policy, which uses a combination of mileage, maintenance costs, and age as determining factors. In all cases, a physical inspection is performed by the Facility Operations and Risk Mitigation Supervisor before a final determination is made. The Facility Operations and Risk Mitigation Supervisor's assessment includes a determination of whether or not the vehicle is safe to operate, is well maintained, and, in their estimation, can be reliably and economically maintained for an additional year. Vehicles are reviewed annually until retired from use.

Computer Hardware

Computer costs are for all purchases of all planned and unplanned computer related equipment, which includes: laptops, printers, and network equipment. Budgeting for this cost item is based on assessing forward looking requirements such as system upgrades, evaluating existing hardware obsolescence and assessing for regulatory changes (i.e. Cyber Security framework in 2017). Typically, EPL phases in its planned system upgrades gradually and consistently to keep expenditures relatively smooth.

Computer Software

Software costs are for all purchases of new software and upgrades to existing software. Throughout the forecast period, EPL plans to upgrade its website, work management systems, service order processes, and GIS, as well as implement utility dashboards for greater management visibility throughout its core business. Typically, EPL phases in its planned software upgrades gradually and consistently to keep expenditures relatively smooth.

Buildings and Fixtures

Building costs include all work, equipment, and services over $500 that are related to EPL-owned properties and buildings. The budget is forecast based on planned work and purchases required for the repair or replacement of old equipment.

EPL conducted a building assessment (see Appendix H: Building Condition Review) via a qualified third party, which factored into the determination of this forecast. This building assessment was completed by an external consulting firm specializing in building assessments of this nature and incudes reviews and analysis by civil and mechanical engineers.

Stores Equipment

Stores equipment costs can vary depending on the nature of the expenditure. EPL's budget for Stores Equipment is generally based on historical spending. Where specific items are known in advance of the budgeting process, EPL budgets accordingly but consistently tries to spend within a historical range of approximately $50,000.

4.1.4 List of Material Capital Expenditures (5.4.1d)

The material capital expenditure projects/programs are sorted by category and listed below.

4.1.4.1 System Access

Table 4-1 lists the material capital expenditures in the system access category planned over the forecast period.

Table 4-1: List of material capital expenditures – system access

Project/Program	Budget				
	2018	2019	2020	2021	2022
Subdivisions	$382,500	$390,150	$397,953	$405,912	$414,030
Residential Connections/Expansions	$394,369	$402,256	$410,301	$418,507	$426,877
Municipal Requests	$612,000	$624,240	$636,725	$649,459	$662,448
New Service Upgrades - C&I	$356,959	$364,098	$371,380	$378,808	$386,384
Metering Upgrade & Replacement Program	$166,297	$169,623	$173,016	$176,476	$180,006

4.1.4.2 System Renewal

Table 4-2 lists the material capital expenditures in the system renewal category planned over the forecast period.

Table 4-2: List of material capital expenditures – system renewal

Project/Program	Budget				
	2018	2019	2020	2021	2022
Pole Replacement Program	$114,062	$558,674	$488,663	$121,043	$592,870
Overhead Reactive Replacements	$82,400	$84,048	$85,729	$87,443	$89,192
Underground Reactive Replacements	$64,964	$66,263	$67,588	$68,940	$70,319
Install/Replace Load Breaks	$59,927	$61,126	$62,348	$63,595	$64,867
Infrastructure Rebuild Program	$2,229,416	$229,416	$1,229,416	$1,529,416	$1,329,416
Switchgear Replacement Program	$147,321	$150,267	$153,272	$156,338	$79,732

4.1.4.3 System Service

Table 4-3 lists the material capital expenditures in the system service category planned over the forecast period. MicroFIT connections are also categorized as system service investments but fall below the materiality threshold.

Table 4-3: List of material capital expenditures – system service

Project/Program	Budget				
	2018	2019	2020	2021	2022
Purchase/Sell HONI Leamington Assets	$89,474	$283,873	$-	$-	$-
Malden TS 2x New Feeder & Reconfiguration	$-	$1,500,000	$250,000	$350,000	$-
FIT & Generation Connections	$181,370	$112,200	$114,444	$116,733	$119,068
Purchase/Sell HONI LaSalle Assets	$-	$-	$465,311	$474,617	$584,109
Self-healing Grid Reclosers	$270,140	$275,543	$281,054	$286,675	$292,408

4.1.4.4 General Plant

Table 4-4 lists the material capital expenditures in the general plant category planned over the forecast period. Expenditures pertaining to office furniture and stores equipment are also planned over the forecast period, but fall below the materiality threshold.

Table 4-4: List of material capital expenditures – general plant

Project/Program	Budget				
	2018	2019	2020	2021	2022
Buildings & Fixtures	$370,000	$350,000	$350,000	$250,000	$250,000
Computer Software	$115,000	$80,000	$80,000	$80,000	$80,000
Fleet	$270,000	$275,000	$395,000	$445,000	$560,000
Tools & Equipment	$60,000	$60,000	$60,000	$60,000	$60,000
Computer Hardware	$161,809	$95,000	$80,000	$85,000	$80,000

4.1.5 Expenditures related to a Regional Planning Process (5.4.1e)

EPL has fulfilled its obligations with respect to the Regional Planning Process but no Regional Investment Plan has been completed for the Winsor-Essex region at this time. An IRRP has been completed for the Windsor-Essex region (see Appendix B: Windsor-Essex Region Integrated Regional Resource Plan). HONI is currently seeking Section 92 approval from the OEB.

Since there are currently neither details nor expectations with respect to line work that may be included in a Regional Investment Plan, the DSP does not include any related capital plans. There is, however, an upcoming capital contribution to HONI for the construction of the new Leamington TS, that will be required in 2018. The timing and the exact amount of EPL's expected capital contribution is not yet finalized.

EPL is committed to the Regional Planning Process and will continue to participate as the process evolves. Future DSP's will incorporate any capital expenditures that result out of such studies. The current DSP does not include any direct accommodation for such costs.

4.1.6 Customer Engagement Activities (5.4.1f)

EPL is committed to continuous customer engagement. The major initiatives to highlight include the INNOVATIVE Customer Satisfaction Surveys, the Convergys Top Down Survey, and the Customer Engagement Handbooks. The purpose of these surveys is to measure customer satisfaction, determine customer needs and preferences, and identify opportunities to improve customer experience.

4.1.6.1 INNOVATIVE Customer Surveys

Two (2) reports by INNOVATIVE are attached to this DSP as Appendix D. The Ratepayer Telephone Survey was completed in 2017 and the Customer Satisfaction Survey was completed in 2014.

4.1.6.1.1 INNOVATIVE Ratepayer Telephone Survey (2017)

The Ratepayer Telephone Survey interviewed 524 residential customers, 51 GS<50 customers, and 9 GS>50 customers. Both residential and GS customers agree that their top priorities are (in order):

1. Delivering reasonable electricity distribution prices;
2. Ensuring reliable electricity service; and
3. Preventing or reducing the length of power outages caused by extreme weather.

System Reliability Preferences

Residential customers prefer EPL spend what is needed to maintain the current number and duration of outages, while GS customers lean towards reducing the number of outages and maintaining the length of outages.

Figure 4-2: Residential customer system reliability preferences

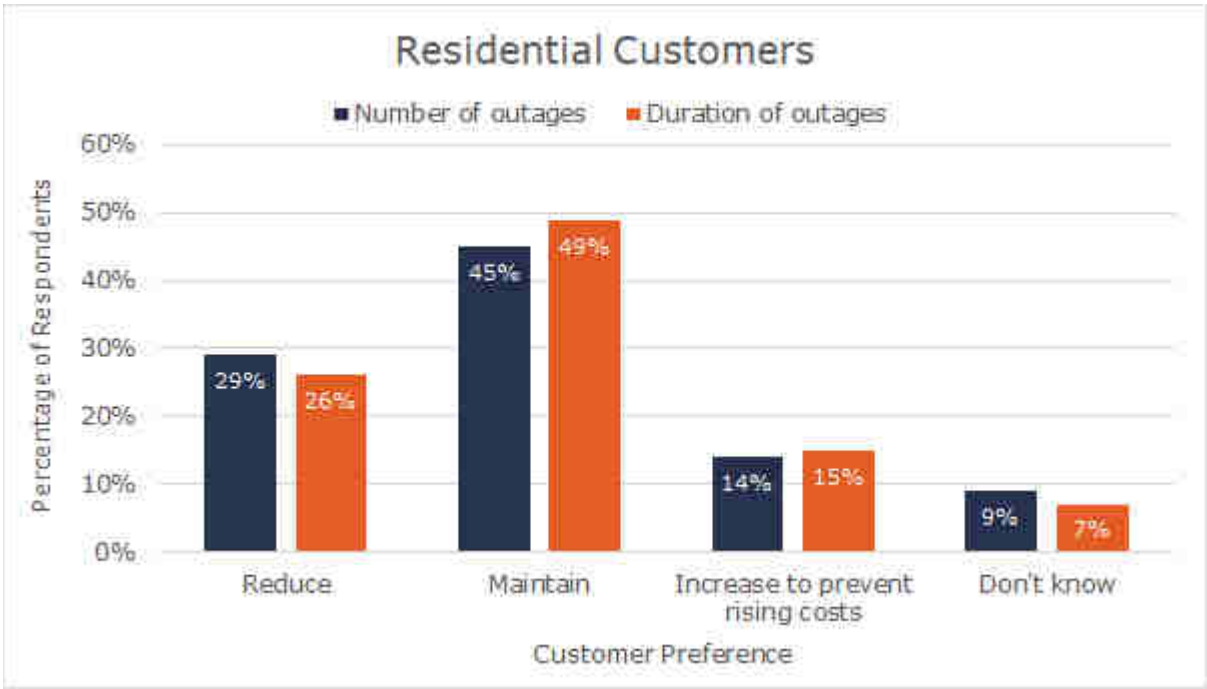
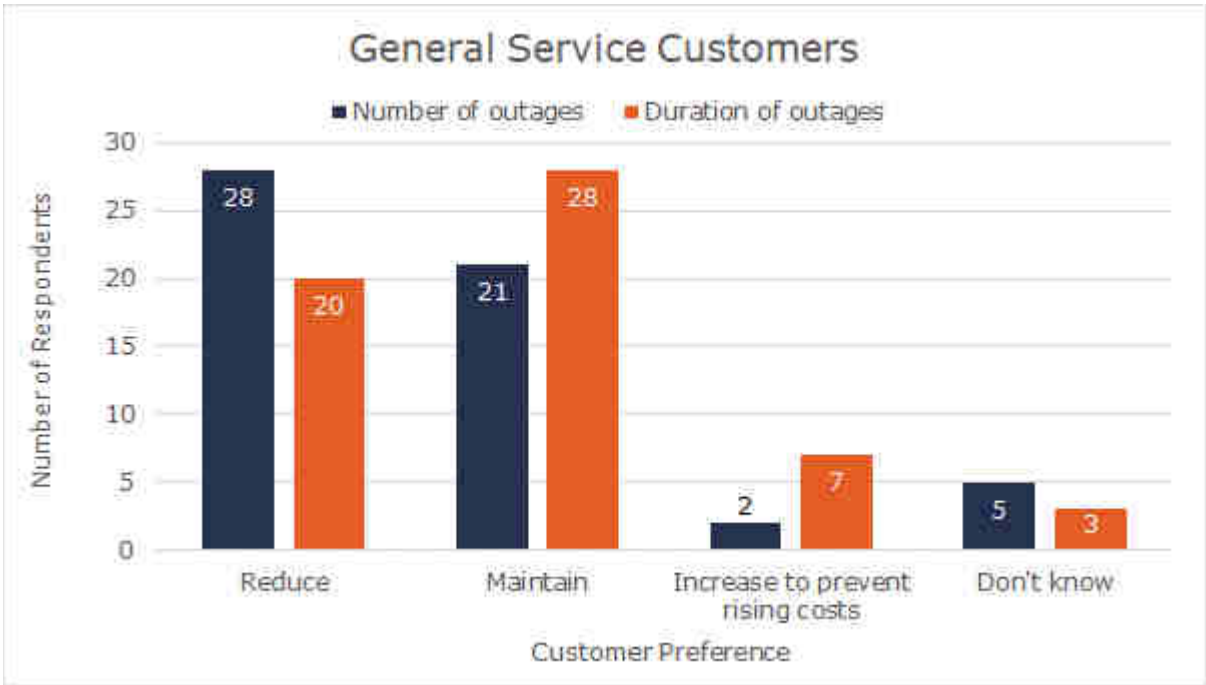


Figure 4-3: General Service customer system reliability preferences



Category-Specific Investment Preferences

Seventy-one percent (71%) of residential customers believe that EPL should invest what it takes to replace the system's aging infrastructure to maintain system reliability, while nineteen percent (19%) believe that EPL should lower its estimated investment in renewing the system's aging infrastructure to lessen possible bill increases. Similarly, eighty percent (80%) of GS customers are in favour of replacing aging infrastructure and fifteen percent (15%) believe system renewal spending should be reduced to lessen bill impacts.

Seventy-five percent (75%) of residential customers feel the best approach is to replace equipment before it breaks down, while nineteen percent (19%) feel a run-to-failure strategy is best. Similarly, 67% of GS customers support a proactive equipment replacement strategy, while 23% support a run-to-failure strategy.

Eighty-five percent (85%) of residential customers think grid modernization is "very" or "somewhat" important, while just twelve percent (12%) feel it is "not very important" or "not important at all". Similarly, 83% of GS customers think grid modernization is "very" or "somewhat" important, while 10% feel that it is "not very important".

Seventy-one percent (71%) of residential customers believe that, while EPL should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably. On the contrary, 25% of residential customers believe that EPL should find ways to make do with the buildings, equipment, and IT systems it already has. Similarly, seventy-two percent (72%) of GS customers believe that while EPL should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably. Twenty-three (23%) of GS

customers believe EPL should find ways to make do with the buildings, equipment, and IT systems it already has.

Customer Opinions

Survey participants were asked to describe their level of agreement with various statements related to the timing of investments, their trust in experts, reducing electricty consumption and costs, the obligation to maintain the existing electricity network for future genreations, grid modernization, and the impact of power outages on vulnerable people.

Table 4-5 summarizes the responses of residential customers, while Table 4-6 summarizes the responses of GS customers.

Table 4-5: Residential customer opinions on very topics

Statement	Percentage of Respondents					
	Strongly agree	Somewhat agree	Neither agree nor disagree	Somewhat disagree	Strongly disagree	Don't know
We should invest in our electricity system infrastructure now or we will end up paying more the longer we delay our system renewal.	39%	40%	1%	9%	5%	4%
The electricity sector is so complicated and confusing; we just have to trust that the experts will find the right balance in keeping cost down while making the right investments and spending decisions.	27%	38%	2%	11%	18%	2%
I think Essex Powerlines should do more to help customers find ways to reduce their electricity consumption and costs.	49%	31%	1%	9%	7%	2%
Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations.	43%	43%	2%	5%	4%	2%
We need to modernize the local electricity system so consumers can have greater control over their electricity usage.	37%	44%	2%	7%	5%	3%
A few power outages are fine for me personally, but I worry about the impact this has on more vulnerable people, such as the elderly.	52%	34%	1%	7%	4%	1%

Table 4-6: GS customer opinions on very topics

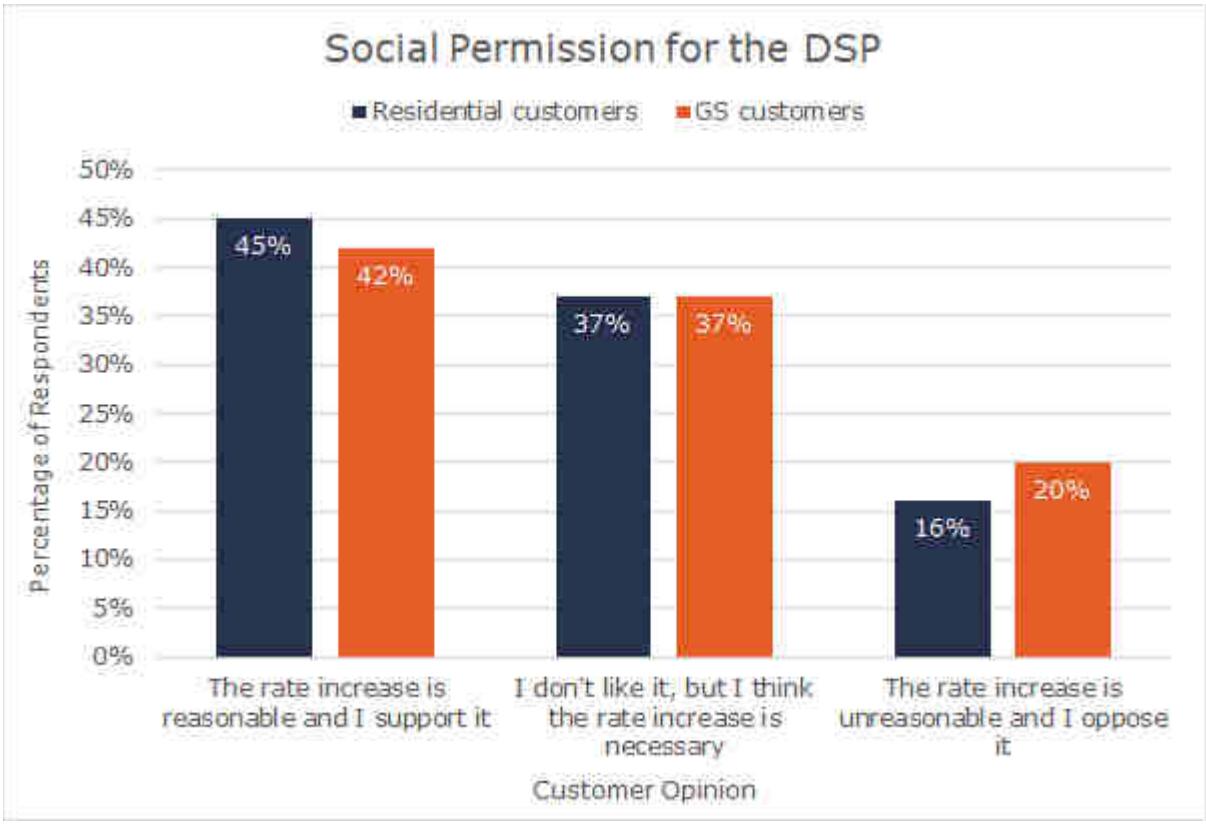
Statement	Number of Respondents					
	Strongly agree	Somewhat agree	Neither agree nor disagree	Somewhat disagree	Strongly disagree	Don't know
We should invest in our electricity system infrastructure now or we will end up paying more the longer we delay our system renewal.	25	22	0	5	2	5
The electricity sector is so complicated and confusing; we just have to trust that the experts will find the right balance in keeping cost down while making the right investments and spending decisions.	20	19	0	8	12	1
I think Essex Powerlines should do more to help customers find ways to reduce their electricity consumption and costs.	36	14	1	5	3	1
Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations.	32	20	0	6	1	0
We need to modernize the local electricity system so consumers can have greater control over their electricity usage.	20	32	0	4	3	0
A few power outages are fine for me personally, but I worry about the impact this has on more vulnerable people, such as the elderly.	17	20	2	8	12	1

In summation, both groups of customers believe that EPL should not defer infrastructure investment, experts in the industry should be trusted, EPL should help customers lower electricity consumption and costs, the electricity grid should be maintained for futrue future generations, there is a need to modernize the grid, and that the impact that power outages have on vulnerable people should be considered.

Assessment of the DSP

The majority of surveyd residential and GS customers provided social permission for the DSP, either by stating that the rate increase is reasonable and they support it, or that they don't like the rate increase but think it is necessary.

Figure 4-4: Customer assessment of the DSP



4.1.6.1.2 INNOVATIVE Customer Satisfaction Survey (2014)

The Customer Satisfaction Survey interviewed 210 residential and 98 GS<50 customers via telephone in 2014. Customers who participated were educated about Ontario's distribution system, EPL's role in delivering power to households and businesses, the interpretation of their electricity bill, and the availability of e-billing.

EPL's customers understand that some outages are unavoidable and the vast majority of EPL's customers are satisfied with reliability and power quality of electricity services provided by EPL. The cost of electricity is more of a concern to EPL's customers, particularly because over half of EPL's customers believe the cost of electricity has grown faster than other household (or business) expenses. About two-thirds of customers feel EPL offers good value for money.

Perceived issues with smart meters was the most commonly cited reason for lacking confidence in billing accuracy. Residential customers reporting an outage were less likely to find an immediate resolution, while GS<50 customers were less satisfied with making

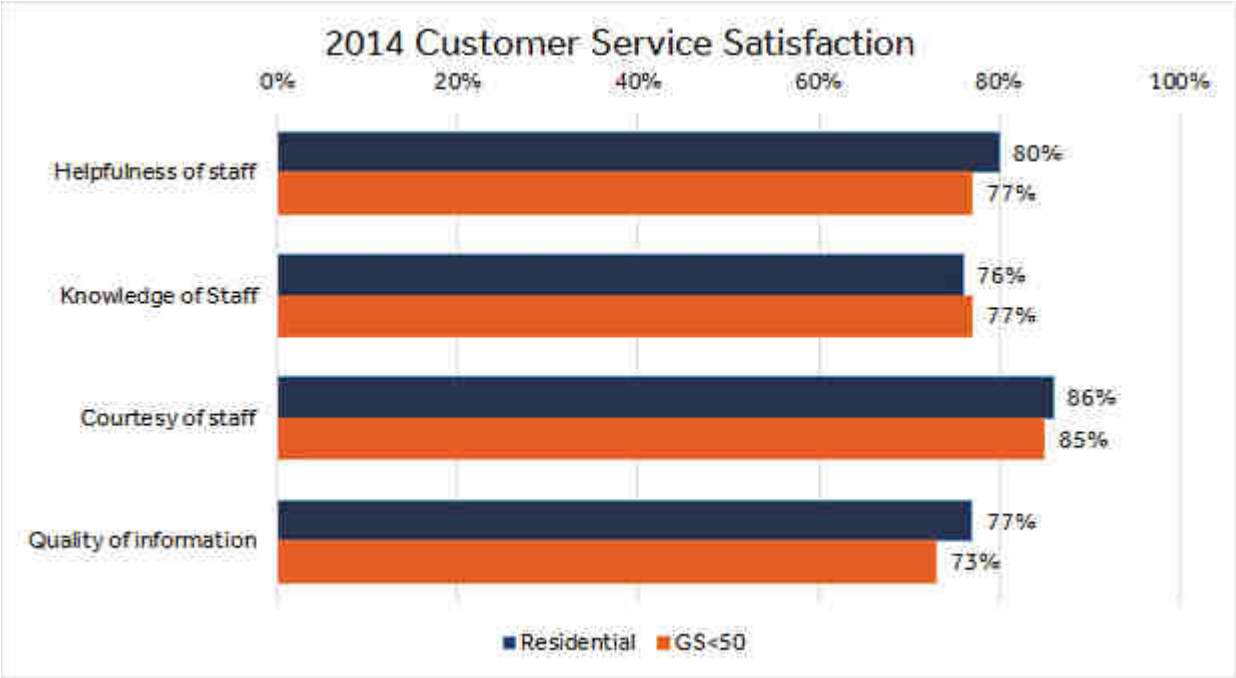
payment arrangements or other issues. Customers experiencing more outages were less satisfied with power outage communications.

The Customer Satisfaction Survey measured four (4) facets of customer service satisfaction for residential and GS<50 customers:

1. The helpfulness of staff;
2. The knowledge of staff;
3. The level of courtesy of staff; and
4. The quality of information provided by staff.

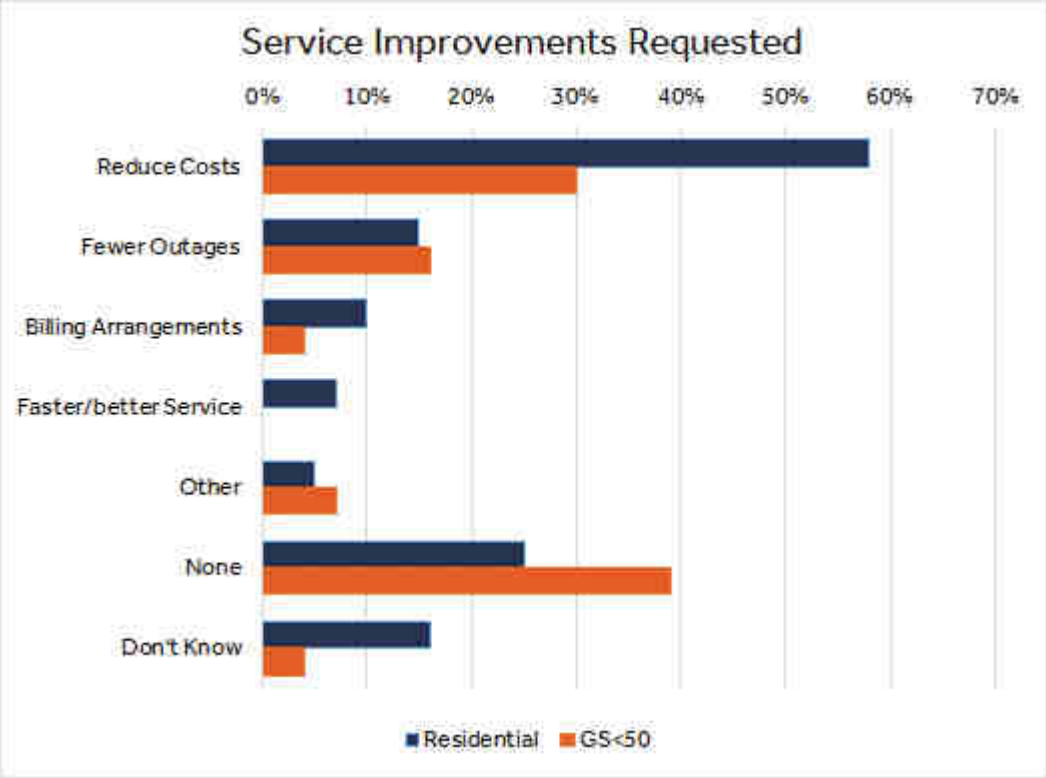
EPL scored between seventy-three percent (73%) and eighty-six percent (86%) in each of these categories.

Figure 4-5: 2014 customer service satisfaction survey results



As indicated in Figure 4-6, residential customers who indicated they would like reduced costs also asked for other improvements including fewer outages, improved billing arrangements, faster/better service, and other improvements. Customers haven't asked for online outage maps or a smart phone app; telephone communication is the preferred method to be informed of outages. The survey also indicated that the majority of EPL's customers are not users of social media.

Figure 4-6: Percentage of customers requesting service improvements (2014 survey)



4.1.6.2 Convergys Top Down Survey

The Convergys Top Down Survey culminates the results of four hundred (400) residential and one hundred (100) GS<50 customers interviewed in 2016. The survey measured customer satisfaction in terms of overall satisfaction, service/brand performance, communication, billing, and contact handling.

Figure 4-7 depicts customer satisfaction measured against key drivers. EPL scored highest when measured against the top drivers for business and residential customers. Ninety percent (90%) of customers are satisfied with power quality, eight-nine percent (89%) are satisfied with the customer service they receive, and eighty-eight percent (88%) are satisfied with the reliability of their electrical service. EPL scored eight percent (80%) when measured against value of service, seventy-seven percent (77%) for being a leader in the community, seventy-four percent (74%) for providing tools to manage energy consumption, and seventy-two percent (72%) for the promotion of energy conservation programs. The biggest opportunity to improve customer satisfaction is with respect to affordability of service, about which only forty-two percent (42%) of EPL's customers are satisfied. This was the lowest scoring attribute for both business and residential customers.

Figure 4-7: Drivers for customer satisfaction (2016 survey)

EPL's customers prefer to contact EPL via telephone, but the Convergys survey identified an opportunity to improve self-service options for billing and payment through EPL's website to reduce the number of related calls. Twenty-three percent (23%) of residential customers that had contacted EPL within the past six (6) months did not have their problems resolved, indicating an opportunity to follow through with services promised to avoid repeat contacts.

The Convergys report recommended investing in service reliability and customer service, which are the key drivers of customer satisfaction. The report also recommended better communication regarding billing to educate customers on rates and fees charged.

The complete report by Convergys is included as Appendix E.

4.1.6.3 Customer Engagement Handbooks

Customer Engagement Handbooks will be posted onto EPL's website. The purpose of this consultation is to collect customer feedback on EPL's DSP over the five-year period from 2018 to 2022. The Customer Engagement Handbooks are attached as Appendix F to the DSP.

4.1.6.4 Effects on the DSP

The customer feedback received from the surveys indicates that the cost of electricity is important to EPL's customers, especially residential households. The majority of residential and General Service customers are satisfied with the reliability, power quality, and customer service offered by EPL. To address the preferences of its customers, EPL has not planned any substantial rate increases for its customers. Instead EPL has developed a five (5)-year DSP that identifies key investments to operate a modern smart grid fit for the 21st century, while limiting annual rate increases to two percent (2%) or in line with inflation.

Investments into computer software and self-healing grid reclosers will improve operational efficiency and help to achieve this objective.

In general, EPL considers cost savings and investment optimization in all of its planned projects and programs. EPL uses a risk-based decision-making model to optimize spending relative to the targeted rate of expenditures. System O&M spending has been reduced compared to historical values through initiatives such as eliminating substations and voltage conversion. For a complete description of cost-saving measures implemented by EPL, see Section 2.1.2.

Reliability continues to be a top driver for customer satisfaction and EPL's customers have experienced a significant number of loss of supply outages. In 2016, the ten (10) largest outages experienced by customers were all loss of supply events. New recloser installations will help isolate EPL's customers from loss of supply events. Asset transfers with HONI planned in Leamington and LaSalle will ensure each LDC is responsible for the assets in its service area to improve operability and reliability for customers.

Figure 4-8: The ten largest outages in 2016 were all loss of supply events

10 Largest Customer Hour Outages Export

Search Clear

Code: ALL Interruption Date Begin: 2016-01-01 Interruption Date End: 2017-01-01

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Outage ID	Interruption Date	Restore Date	Restore Device ID	Code	Customer Hours
6010	9/22/2016 9:44:00 AM	9/22/2016 11:06:00 AM	WM3M3	2 (Loss of Supply)	9289.2
5958	8/30/2016 4:33:00 PM	8/30/2016 5:56:00 PM	WM33M8	2 (Loss of Supply)	8370.6
5956	8/28/2016 3:40:00 PM	8/28/2016 7:28:00 PM	WM33M8	2 (Loss of Supply)	5513.8
5969	2/19/2016 2:13:00 PM	2/19/2016 3:48:00 PM	SW-24M7	2 (Loss of Supply)	5508.4
5979	9/6/2016 1:00:00 PM	9/6/2016 1:47:00 PM	WM156M4	2 (Loss of Supply)	5301.6
5980	9/6/2016 1:00:00 PM	9/6/2016 1:44:00 PM	WM3M3	2 (Loss of Supply)	4976.4
5948	8/26/2016 4:17:00 PM	8/26/2016 4:58:00 PM	WM156M25	2 (Loss of Supply)	4430.7
5949	8/26/2016 4:15:00 PM	8/26/2016 4:44:00 PM	WM33M4	2 (Loss of Supply)	3175.5
5820	6/20/2016 11:29:00 PM	6/21/2016 1:31:00 AM	WM524M7	2 (Loss of Supply)	2411.5
5921	8/16/2016 11:43:00 AM	8/16/2016 1:36:00 PM	24M7LS-1	2 (Loss of Supply)	1610.3

EPL's customers believe it is important to invest in renewing the electricity system in order to maintain reliability and upkeep the infrastructure for future generations. EPL has identified a number of programs in the system renewal program that meet these expectations including replacement of poles, replacement of load-break switches, replacement of live-front switchgear, and circuit rebuilds. These are all proactive replacement programs supported by EPL's customers.

EPL's customers see the importance of modernizing the grid. EPL has adopted a Smart Grid Development Plan – as introduced in Section 1.4.3.4 – to facilitate a self-healing grid. System service investments to install reclosers over the forecast period fit into this framework.

EPL's customers believe that it is important for EPL's staff to have the equipment and tools they need to mange the system efficiently and reliably. Planned investments into computer hardware, computer software, transportation equipment, stores equipment, buildings and fixtures, and tools and equipment align with this customer preference.

Overall, customers surveyed in 2017 provided social permission for the DSP.

4.1.7 System Development over the Forecast Period (5.4.1g)

This section describes how EPL expects its system to develop over the forecast period with respect to load and customer growth, Smart Grid development, and the accommodation of REG projects.

4.1.7.1 Load and Customer Growth

Table 4-7 and Table 4-8 present the kWh and CDM-adjusted kWh forecasts, respectively. Table 4-9 and Table 4-10 present the kW and CDM-adjusted kW forecasts, respectively.

Table 4-7: Forecast of energy delivered (kWh)

Normal Forecast

kWh	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2016 Normalized	2017 Forecast	2018 Forecast
Residential	256,003,979	250,406,105	245,551,953	244,757,239	255,390,422	249,168,165	247,700,344	246,544,006
GS < 50	67,056,278	65,663,990	65,242,011	65,329,579	66,808,993	64,675,919	65,087,892	65,487,649
GS > 50	160,883,812	164,887,609	166,100,613	171,874,066	187,031,606	175,310,400	179,829,958	183,374,335
Embedded Distributor	35,429,534	36,931,636	38,058,828	38,655,620	32,586,843	32,586,843	31,681,583	29,865,554
Street Light	6,205,705	6,271,491	6,286,758	6,227,063	4,268,688	4,268,688	2,799,882	2,799,882
Sentinel Light	383,994	342,834	350,518	341,136	335,758	335,758	335,758	335,758
USL	1,558,152	1,549,960	1,555,546	1,558,152	1,554,368	1,554,368	1,554,368	1,554,368
Total	527,521,454	526,053,625	523,146,226	528,742,855	547,976,676	527,900,141	528,989,785	529,961,552

Table 4-8: CDM-adjusted forecast for energy delivered (kWh)

kWh	2018 Weather Normal Forecast	CDM Adjustment	2018 CDM Adjusted Forecast
Residential	246,544,006	1,169,888	245,374,118
GS < 50	65,487,649	2,780,199	62,707,450
GS > 50	183,374,335	7,094,029	176,280,306
Embedded Distributor	29,865,554	0	29,865,554
Street Light	2,799,882	0	2,799,882
Sentinel Light	335,758	0	335,758
USL	1,554,368	0	1,554,368
Total	529,961,552	11,044,116	518,917,436

Table 4-9: Load forecast (kW)

Normal Forecast

kW	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2016 Normalized	2017 Forecast	2018 Forecast
GS > 50	416,357	399,217	394,614	459,153	476,121	443,798	455,239	464,212
Embedded Distributor	109,304	96,078	84,453	106,798	87,828	88,238	85,786	80,869
Street Light	18,742	19,025	15,872	18,023	13,490	13,490	8,848	8,848
Sentinel Light	2,100	2,100	2,068	2,088	2,080	2,080	2,080	2,080
Total	546,503	516,420	497,007	586,062	579,519	547,606	551,954	556,009

Table 4-10: CDM-adjusted load forecast (kW)

kW	2018 Weather Normal Forecast	CDM Adjustment	2018 CDM Adjusted Forecast
GS > 50	464,212	17,959	446,253

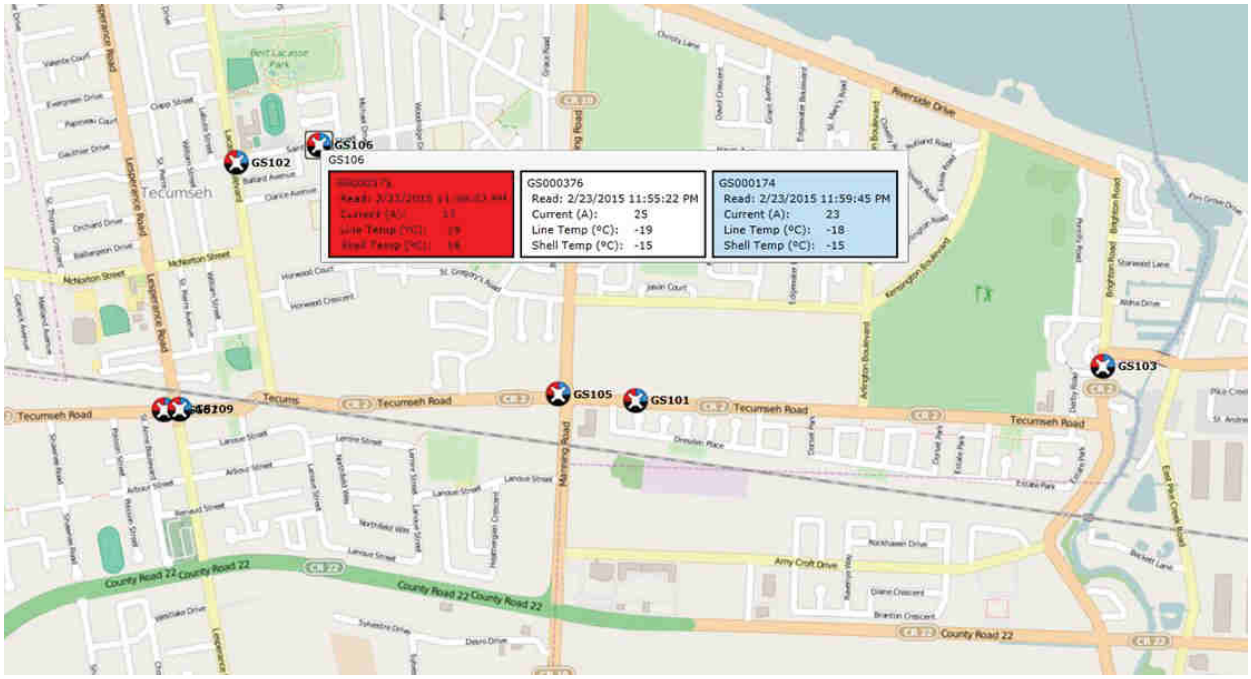
Embedded Distributor	80,869	0	80,869
Street Light	8,848	0	8,848
Sentinel Light	2,080	0	2,080
Total	556,009	17,959	538,051

4.1.7.2 Smart Grid Development

In 2014, EPL completed its first iteration of its Green Energy Act Plan and subsequently a Smart Grid Development Plan. In this plan, EPL outlined its plan to shift to a smarter grid that is capable of reducing the impact of loss of supply incidents to customers by investing in reclosers as part of a self-healing grid. Historically, EPL's service territory consisted solely of manual load break switches which required manual operation and provided no fault protection. Fault protection was provided by a station breaker or an upstream recloser outside of EPL service territory. With the implementation of smart reclosers, EPL is facilitating the capabilities of remote operation, real-time outage detection as well as the ability to isolate itself from an upstream distributor/transmitter. Further, incremental data about EPL's distribution system is gathered and fed into the SmartMAP toolset.

EPL has also been deploying line monitors to replace older Faulted Circuit Indicators. The line monitors can provide more information on real-time system status and historical events compared to the older technology. The deployment of these devices notifies operators that a fault has occurred in the distribution system, the date and time of the fault, and the specifics of that fault (fault current, location, phase, if it cleared or was momentary). A notification is also provided if a device is out of power and no power exists on the line. SmartMAP uses the fault data in its outage detection algorithm, which searches for customers that are out of power via the AMI and other power-monitoring devices. The approximate location of the fault is identified based on a calculation of the fault current in comparison to the measured value. This improves the outage response time. The line sensors themselves can be monitored through the SmartMAP tool.

Figure 4-9: Screenshot from SmartMAP depicting line sensor locations and statuses



The line monitors can measure and record air temperature and line temperature. Figure 4-10 depicts example measurements during winter, while Figure 4-11 depicts example measurements during summer, near-peak conditions. The profiles in both examples show that the line is not being heated due to loading. This type of information is used to identify the actual operating conditions for switching and load optimization.

Figure 4-10: Example air (top) and line (bottom) temperature measurements in winter

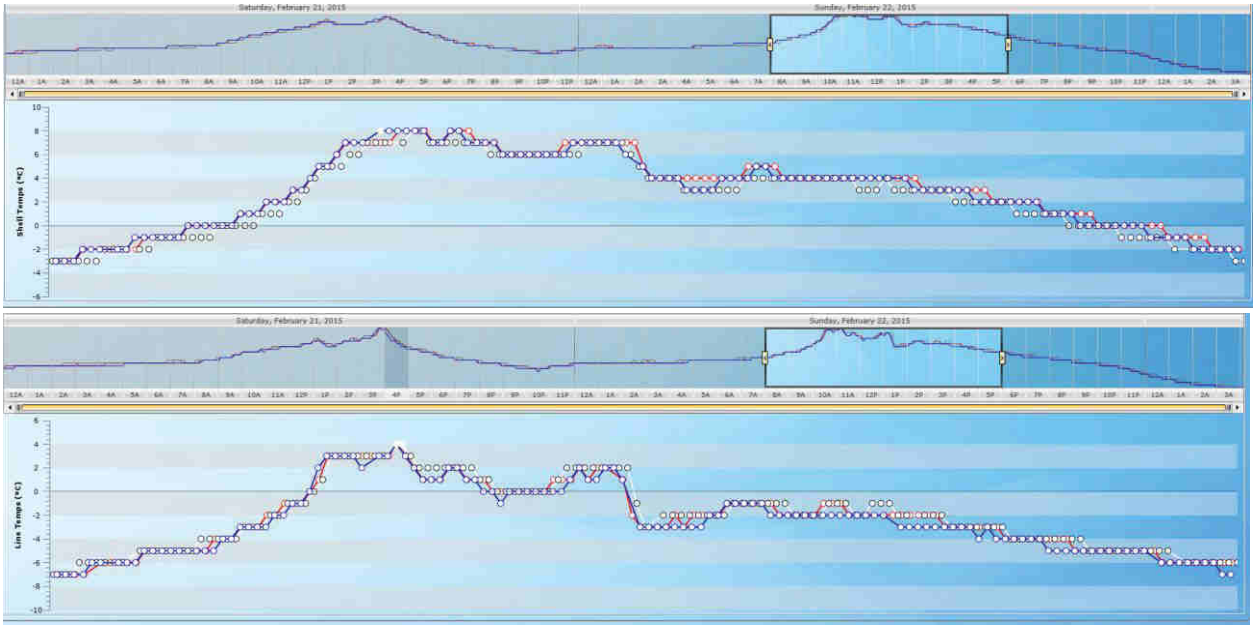
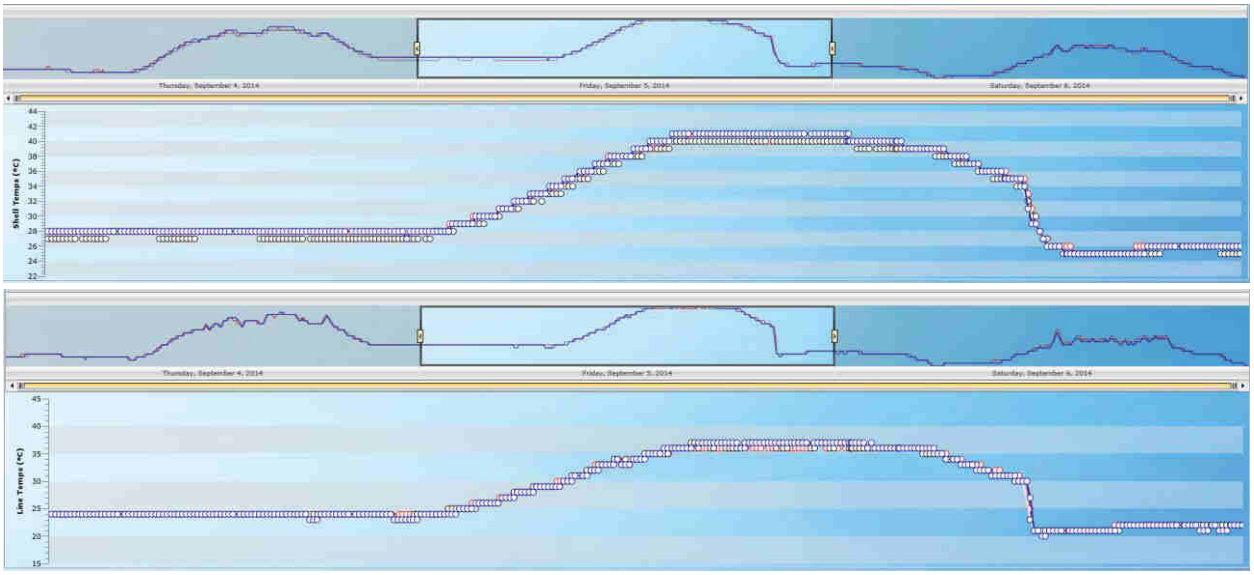
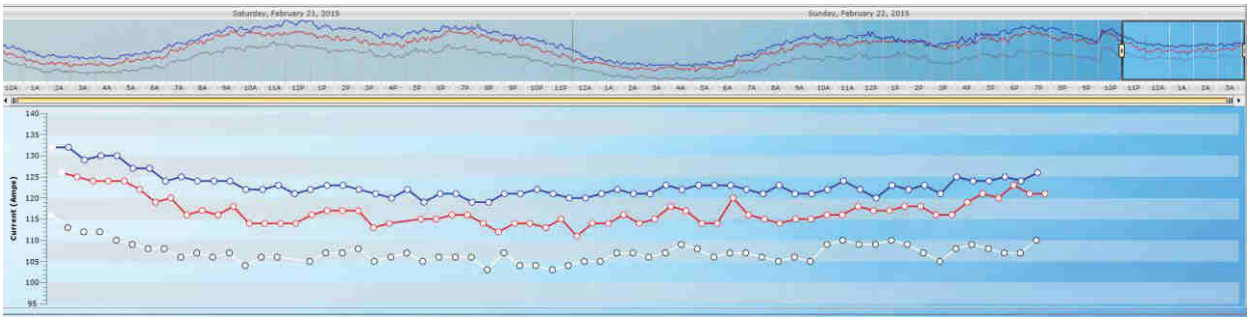


Figure 4-11: Example air (top) and line (bottom) temperature measurements in summer



Aggregation of line monitor data for each phase is used to determine the phase balance over time at the locations. Keeping the system in balance is an important part of the distribution system management. Figure 4-12 depicts an example where the current measurements differ for each phase

Figure 4-12: Example phase balance measurements



4.1.7.3 REG Accommodation

EPL has forecast the number and capacity of REG connections expected over the forecast period and has planned investments in the system service category, namely "FIT & Generation Connections" and "MicroFIT Connections", in order to continue to accommodate REG. In each case, additional transformation is planned and the need to expand the existing system is assessed. For more information, see Section 4.3.

4.1.8 Customer Preferences, Technology Opportunities, Innovation (5.4.1h)

Several projects/programs in the 2018 Test Year have been planned in response to customer preferences; to take advantage of technology-based opportunities to improve operational efficiency, asset management, and the integration of distributed generation and

complex loads; and to study or demonstrate innovative processes, services, business models, or technologies.

Table 4-11 lists the capital projects/programs planned for the Test Year along with an identifier indicating the planning driver, as determined by EPL: 1 = Customer preference, 2 = Technology, 3 = Innovation.

Table 4-11: Capital projects/programs by planning driver

	Project/Program	Alignment with EPL Core Values	(1) - Customer Preferences (2) – Technology (3) - Innovation	2018 Test Year Expenditure (Forecast)
System Access	Subdivisions	Customer & Community Value	1	$382,500
	Residential Connection/Expansion	Customer & Community Value	1	$394,369
	Municipal Requests	Customer & Community Value	1	$612,000
	New Service Upgrades - C&I	Customer & Community Value	1	$356,959
	Metering Upgrade & Replacement Program	Customer & Community Value, Operational Excellence	1,2	$166,297
System Service	Purchase/Sell HONI Leamington Assets	Customer & Community Value, Operational Excellence	1	$89,474
	FIT & Generation Connections	Customer & Community Value, Financial & Environmental Sustainability	1,2	$181,370
	MicroFIT Connections	Customer & Community Value, Financial & Environmental Sustainability	1,2	$14,166*
	Self-healing Grid Reclosers	Customer & Community Value, Operational Excellence	1,2,3	$270,140
System Renewal	Pole Replacement Program	Operational Excellence	1	$114,062
	Overhead Reactive Replacements	Operational Excellence	1	$82,400
	Underground Reactive Replacements	Operational Excellence	1	$64,964
	Install/Replace Load Breaks	Operational Excellence	1	$59,927
	Infrastructure Rebuild Program	Operational Excellence	1	$2,229,416
	Switchgear Replacement Program	Operational Excellence	1	$147,321
General Plant	Tools & Equipment	Operational Excellence, Safety	2	$60,000
	Office Furniture	Operational Excellence, Employee Satisfaction	2	$10,000*
	Transportation Equipment	Operational Excellence, Safety	2	$270,000
	Computer Hardware	Operational Excellence	2	$161,809
	Computer Software	Operational Excellence	1,2,3	$115,000
	Buildings & Fixtures	Operational Excellence	2	$370,000
	Stores Equipment	Operational Excellence	2	$50,000*

*Values below the materiality threshold of approximately $60,000

4.1.8.1 Customer Preferences

System access investments are all driven by customer preferences. Subdivisions, residential connections/expansions and new commercial and industrial service upgrades are initiated by customer requests to connect to EPL's distribution system. Capital expenditures related to municipal requests are in response to development in the communities EPL serves. Metering upgrades and replacements are driven by a mandated service obligation to accurately meter customers.

Investments related to FIT and generation connections (greater than 10 kW) and MicroFIT connections (10 kW or less) are driven by customer requests to connect REG to the distribution system.

System reliability is a key driver of customer satisfaction. EPL's customers have spent a significant amount of time without power due to loss of supply events. Investments into self-healing grid reclosers, computer software, and the purchase/sale of assets to/from HONI will address loss of supply issues. Investments in the system renewal category also address system reliability by replacing assets at the end of their service life due to failure or failure risk.

4.1.8.2 Technology-based Opportunities

Technology has always played an important role in the electricity industry. EPL has recently completed its voltage conversion program to improve operational efficiency and asset management, providing power at a single voltage without the need to own and operate distribution substations. Investments into smart meters will continue to be made as existing meters are replaced and upgraded; all new meters are equipped with two-way communication over the AMI.

MicroFIT, FIT, and generation connections take advantage of technology-based opportunities to integrate distributed generation. EPL already has a high penetration level of distributed generation and, at times, its net demand profile is negative.

EPL has been installing reclosers and line sensors in the field since 2011. These technologies are used to develop a self-healing grid able to locate and isolate faults to restore service to unfaulted sections of the line. The field hardware is supported by an integrated GIS, SCADA, and OMS combined with the analytical engineering toolset of the SmartMAP platform.

Other investments into tools and equipment, fleet, buildings and fixtures, office furniture, stores equipment, and computer hardware always take advantage of technology-based opportunities to improve operational efficiency.

EPL intends to continue to invest in field automation technologies in order to push technological tools to those employees who can take greatest advantage. Examples such as: mobile wireless laptops and tablets, smart phones, device aware enterprise services, smart grid device notifications, enhanced outage communication, distribution analysis result notifications to field staff, field work flow automation, etc. are all projects and technologies that EPL has implemented or intends to enhance throughout the forecast period.

Each of these technologies and enhanced services serve to increase worker productivity, situational awareness and customer communication. The desired result is to decrease operating costs while increasing EPL's ability to effectively manage its assets to the benefit of its customers.

4.1.8.3 Innovative Processes, Services, Business Models, or Technologies

EPL's overall goal of its innovative practices is to keep costs down while increasing the quality of service provided to EPL's customers. EPL's customers have indicated that the cost of electricity is an important driver to their satisfaction (see Appendix D and Appendix E). Investing in innovation will help EPL achieve its targets in system reliability, power quality, and consumer bill impacts.

The development of the SmartMAP and HealthMAP toolsets (under the computer software budget) and the implementation of reclosers as part of a self-healing grid demonstrate innovative processes and technologies. The SmartMAP toolset was developed by EPL in partnership with UtiliSmart Corporation. The toolset overlays EPL's proven DESS onto a GIS for improved data analytics and mapping capabilities. This was one of the projects in Ontario which received funding through the Ministry of Energy's Smart Grid Fund.

EPL is also able to demonstrate innovative processes, service, and business models by extending its control functionality to front line staff through field technologies such as laptops and the SmartMAP toolset. In this way, EPL does not operate a centralized control room. This reduces costs and increases the capability of front line staff to manage system issues.

4.2 Capital Expenditure Planning Process Overview (5.4.2)

4.2.1 Planning Objectives, Assumptions, and Criteria (5.4.2a)

EPL's capital expenditure planning objective is to find the optimal selection of projects with the maximum benefit-cost ratio. The capital expenditures are planned by taking into account of risk mitigation and value creation project benefits.

1. **Risk mitigation**: ensuring that all projects above the risk tolerance threshold are identified as part of the Business Plan and if the project(s) is/are deferred, due consideration is given to communicating the consequences associated with the deferral(s).
2. **Value creation**: optimal resource deployment to address well defined business objectives and track resulting performance value creation against desired performance value expectations.

In order to better understand underlying sensitivities and trade-offs between capital and operating expense, EPL has prepared project rankings and analysis for three (3) distinct scenarios:

1. **Scenario A: All Projects**. This is the unconstrained budget case where all projects are completed. This scenario is used as a base case assuming all resource needs are met.

2. **Scenario B: Minimum.** Only projects that mitigate risks beyond EPL's acceptable risk-level will be included in the business plan. This scenario includes all medium-to-high risk projects. This case is not recommended as a final plan because a risk hold posture is never cost effective. Mitigating risk or risk hold causes an organization to spend higher levels over time because risk mitigation is no longer planned and proactive as it becomes more an exercise in unplanned reactive encounters. These situations generate funding needs at higher premiums (by as much as twice the cost of proactive measures) because the materials generally have to be expedited and labor paid at overtime rates to ensure timely completion. This scenario is used as the least resource planning requirement and used as the low end of the range for optimal resource planning.
3. **Scenario C: Optimum.** This scenario comprises projects that optimize the value creation (benefits) and risk mitigation against cash-outlays.

Multiple scenarios were run to determine best case options for business planning. The final business plan was developed between Options "A" and "B". All high risk will be addressed and those projects creating real value for the investment will be included in the business plan.

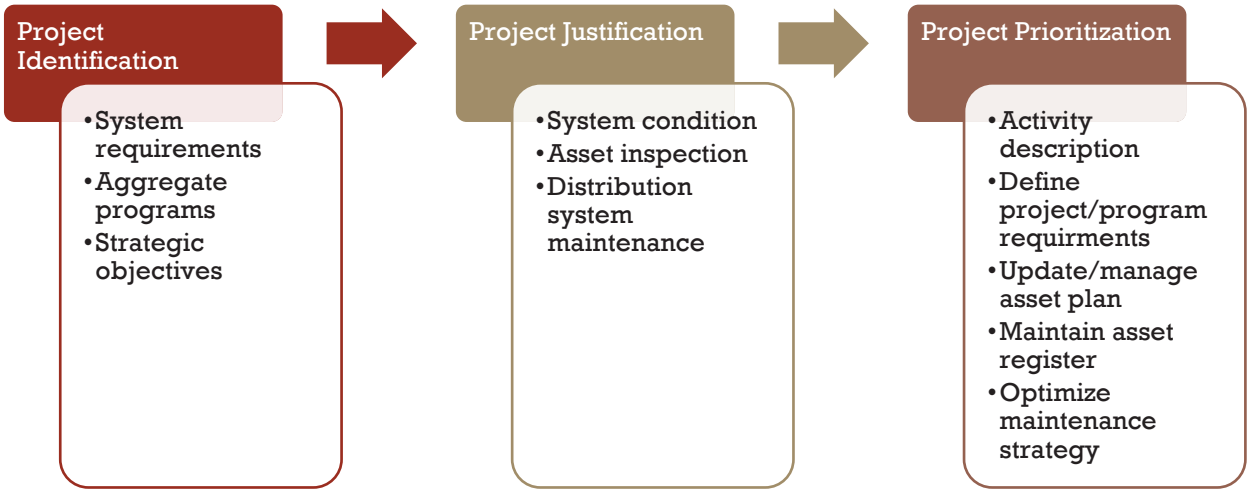
4.2.2 Non-Wires Alternatives to Relieving System Capacity (5.4.2b)

EPL does not have any policy nor procedure whereby non-distribution system alternatives to relieving system capacity or operational constraints are considered. For information pertaining to the Regional Planning Process, see Section 2.2.2.

4.2.3 Processes, Tools, and Methods (5.4.2c)

EPL uses a three (3)-step process to identify, select, prioritize, and pace the execution of its projects/programs in each investment category.

Figure 4-13: An overview of EPL's capital expenditure planning process



4.2.3.1 Project Identification

The EPL's AIS process begins by determining system requirements. The specific inputs include, but are not limited to, load additions, maintenance programs (outage restoration, Conditions of Service requirements, theft of assets, human intervention, etc.), conversions, system performance and new standards. Service orders, minor field maintenance (non-program work where no system reconfiguration is required), and any minor load additions are also included in these programs. However, these items are analyzed and monitored as aggregate programs (collection of like projects for the year). In addition, determining the system enhancement requirements as a function of asset deterioration, load growth, customer needs, and new product availability is performed.

Potential projects to be input in Project Information Plan are gathered and assessed. Input and analysis is done using tools, statistics, databases, customer/developer input, assessments, and non-destructive examination.

Maximizing the use of online systems allows recording and monitoring the distribution line operation through faults, operational counts, age, and load using IT-based solutions.

A component database stores, records, and monitors the condition of the distribution assets. This information is valuable in determining the value of individual equipment failures on the seven (7) strategic objectives used in the AIS. These integrated databases containing EPL's entire asset information allows recording of equipment failures and the specifics associated with each event. System inspection and condition data are used to plan proactive replacements as opposed to reactive replacements.

4.2.3.2 Project Justification

System condition using non-destructive techniques correlate the onset of failure allowing planned replacements as opposed to reactive replacements. Infrared and ultrasonic analysis of the system along with asset inspection can identify the onset of failure. For example, arrestors contain a pressure sensitive material that begins to break down with age. The onset of failure shows arrestors that have lost part of the pressure holding capacity. Similarly, failing connections, tracking insulators/equipment, and reduced oil levels can be identified using these non-destructive techniques and planned repairs or replacement can be scheduled before failure.

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

4.2.3.3 Project Prioritization

Once the potential investments have been identified, the projects are divided into phases that can be completed in any one (1) year. Each project or project phase (if applicable) requires the inputs to the project to be collected. The inputs into the Project Information Plan are costs (savings and spend), risks, and strategic value. All projects are run through the Optimizer Tool to determine the project mix that reduces the most amount of risk while providing the most strategic value.

The strategic value of a project is measured against the seven (7) asset management objectives described in Figure 3-1:

- Public and employee safety;
- Regulatory (OEB) direction;
- Service quality: SAIFI and SAIDI;
- Financial returns: NPV;
- Legal claims;
- Community image: customer complaints; and
- Environmental.

The risk of project deferral is assessed using the numeric scores for consequence and probability defined in Table 4-12 and Table 4-13. Risk is calculated as the product of the probability and consequence scores.

1 Table 4-12: Definitions of numeric scores describing the consequence of project deferral

Numeric Score	Definition of Financial Risk	Definition of Service Quality Risk	Company Image Risk	Legal Risk	Regulatory Risk	Safety Risk (Both staff and public risk)	Environmental Risk
Consequence = 5	>$50,000 in lost revenue or avoided cost	>1.0% overall reduction to SAIFI, SAIDI	>10 written or 50 verbal complaints, general public outcry	Litigation cost <$1,000	Non-reportable compliance issues	Minor WSIB injury	Minor disturbance, no documentation required
Consequence = 4	<$50,000 in lost revenue or avoided cost	<1.0% overall reduction to SAIFI, SAIDI	<10 written or 50 verbal complaints, concerns raised to regulator, coverage by local media	Litigation cost <$10,000	Regulator reportable issues - minor	WSIB reportable injury	Disturbance requiring internal environmental documentation and/or company environmental assistance
Consequence = 3	<$10,000 in lost revenue or avoided cost	<0.5% overall reduction to SAIFI, SAIDI	<8 written or 40 verbal complaints, concerns raised to local government, board of directors	Litigation cost <$50,000	Significant regulatory compliance issues. Notification required.	Medical injury, WSIB reportable, EUSA reportable, Ministry of Labour reportable	Disturbance involving private property and/or potential claims and company environmental assistance
Consequence = 2	<$5,000 in lost revenue or avoided cost	<0.1% overall reduction to SAIFI, SAIDI	<6 written or 30 verbal complaints, multiple concerns made to company	Litigation cost <$500,000	Serious regulatory compliance issues. Fines, direction or oversight required.	Lost time injury, WSIB reportable, EUSA investigation, Ministry of Labour investigation	Disturbance requiring Ministry of Environment documentation, company environmental assistance and regulatory assistance on site.
Consequence = 1	<$1,000 in lost revenue or avoided cost	<0.05% overall reduction to SAIFI, SAIDI	<4 written or 20 verbal complaints, individual concerns to company	Litigation cost >$500,000	Damaging regulatory compliance issues. Loss of license	Multiple lost time injuries, WSIB reportable, EUSA investigation, Ministry of Labour fine/directive	Disturbance requiring MOE assistance onsite and public evacuation and company environmental assistance.

2

1 Table 4-13: Definition of numeric scores describing the probability of each consequence

Numeric Score	Definition of Financial Risk	Definition of Service Quality Risk	Company Image Risk	Legal Risk	Regulatory Risk	Safety Risk (Both staff and public risk)	Environmental Risk
Probability = 5	More than 4 events per year	More than 4 events per year	More than 4 events per year	More than 4 events per year	More than 4 events per year	More than 4 events per year	More than 4 events per year
Probability = 4	Quarterly, 2-4 events per year	Quarterly, 2-4 events per year	Quarterly, 2-4 events per year	Quarterly, 2-4 events per year	Quarterly, 2-4 events per year	Quarterly, 2-4 events per year	Quarterly, 2-4 events per year
Probability = 3	One event per year	One event per year	One event per year	One event per year	One event per year	One event per year	One event per year
Probability = 2	1 event every 3 years	1 event every 3 years	1 event every 3 years	1 event every 3 years	1 event every 3 years	1 event every 3 years	1 event every 3 years
Probability = 1	1 event every 10 years	1 event every 10 years	1 event every 10 years	1 event every 10 years	1 event every 10 years	1 event every 10 years	1 event every 10 years

2

The AIS is used to gather the inputs needed for each Project Information Plan. The following items are used in each evaluate and optimize the investment portfolio.

Activity Description

- Identify potential risks.
- Estimate probability of occurrence.
- Define consequences.
- Calculate risk score.
- Compare to project risk threshold.
- Determine alignment of risk exposure with owner's requirements.
- Define risk mitigation strategy if required.
- Select solution.

Define Project/Program Requirements

- Approve selected option(s).
- Determine project/program impact.
- Conduct impact study or change standards, if required.
- Document objective and consequences.
- Identify unique requirements.
- Identify major material requirements.
- Identify appropriate standards.
- Identify resource requirements.
- Identify project milestones and program cycles.
- Assign priority score.

Update/Manage Asset Plan

- Incorporate project/program into asset plan.
- Determine impacts on plan.
- Determine need to reanalyze projects.
- Identify potential portfolio risks.
- Determine probability of occurrence.
- Calculate consequence.
- Calculate risk score of portfolio.

- Compare risk with threshold.
- Determine if impacts are acceptable
- Adjust plan if required.
- Analyze finances.
- Analyze completion status.
- Analyze performance results.
- Assess variance from plan.
- Identify potential solution to address variances if required.
- Issue/re-issue asset plan.

Maintain Asset Register

- Document individual asset information.
- Describe asset's role and mission in system.
- Define system configuration.
- Validate information.
- Determine validity of data.
- Input data into asset register.

Optimize Maintenance Strategy

- Review asset(s) condition/facts.
- Review asset(s) role/mission.
- Review asset performance history.
- Determine failure modes.
- Determine consequences of failure.
- Assess preventability of failure mode.
- Identify condition-based maintenance activities.
- Identify time-based maintenance activities.
- Identify redesign solutions.
- Determine run-to-failure options where appropriate.

The outputs are analyzed and listed for each year from 2018 to 2022. As new projects are identified or inputs change the optimized results are rerun to identify new project lists. Table 4-14 summarizes the output of the project prioritization tool for material projects planned in the 2018 Test Year. The sum of the risk and strategic objective scores are displayed in the rightmost column and used to rank the projects.

Table 4-14: 2018 Test Year project prioritization

Project Name	Project Classification	Project Type	Net Capital Expenditures	Risk/Strategic Objective Score
Residential Connection/Expansion	Serve New Customers - Residential	Residential Connections	$394,369	28.57
New Service Upgrades – C&I	Serve New Customers - C & I	Commercial Connections	$356,959	28.57
New Residential Subdivisions	Serve New Customers - Residential	Residential Connections	$382,500	28.43
Overhead Reactive Replacements	None	Reactive	$82,400	21.36
Underground Reactive Replacements	None	Reactive	$64,964	21.29
Municipal Requests	Increase System Capacity - Improvements	Expansions	$612,000	14.71
FIT & Generation Connections	Increase System Capacity - Improvements	Expansions	$181,370	14.00
Install/Replace Load Breaks	Increase System Capacity - Improvements	Preventative	$59,927	13.57
Switchgear Replacement Program	Increase System Capacity - Improvements	Preventative	$147,321	13.55
Metering Upgrade & Replacement Program	None	Metering	$166,297	13.43
Self-healing Grid Reclosers	Increase System Capacity - Improvements	Preventative	$270,140	11.03
Infrastructure Rebuild Program	Increase System Capacity - Improvements	Enhancements	$2,224,410	10.57
Computer Hardware	None	General Plant	$161,809	10.49
Computer Software	None	General Plant	$115,000	10.36
Purchase/Sell HONI Leamington Assets	None	Expansions	$89,474	9.86
Pole Replacement Program	None	Reactive	$114,062	9.43
Transportation Equipment	None	General Plant	$270,000	7.43
Tools & Equipment	None	General Plant	$60,000	7.13
Buildings & Fixtures	None	General Plant	$370,000	5.48

4.2.4 Customer Engagement (5.4.2d)

EPL employs a multi-faceted approach to customer engagement, as previously discussed in Section 2.2.1.1 and Section 4.1.6. Customer feedback is incorporated into every stage of the planning process, from project/program design, to budget allocation, to project execution. The methods used to engage customers for the purpose of identifying their needs, priorities, and preferences include:

- Engaged Innovative Research Group in 2017 to perform telephone surveys and solicit feedback (a copy of the report is attached as Appendix D).
- Engaged Convergys to perform a telephone-based customer survey in 2016 (see Appendix E).
- Hosted four (4) open house sessions – one (1) in each community – that were advertised through multiple channels where customers could attend and provide feedback.
- Posted customer class specific handbooks on its website which highlighted and summarized this document and provided a timeframe where customers could submit feedback online (copies of the various handbooks are attached as Appendix F).

4.2.5 REG Investment Prioritization (5.4.2e)

REG investments are prioritized alongside other capital projects using the processes, tools, and methods described in Section 4.2.3.

4.3 System Capability Assessment for REG (5.4.3)

4.3.1 Applications for Renewable Generators over 10 kW (5.4.3a)

Table 4-15 lists the applications from renewable generators over 10 kW for connection to EPL's service area.

Table 4-15: REG applications over 10 kW being processed

Feeder	Address	Type	Nameplate Capacity (kW)	Estimated Connection Year
23M3	400 Sandwich St. South, Amherstburg	Solar Rooftop	200	2018
3M4	55 Talbot St. West, Leamington	Solar Rooftop	500	2017
3M4	24 Oak Street East, Leamington	Solar Rooftop	190	2017
3M6	25 Ivan Street, Leamington	Solar Rooftop	500	2017
3M4	129 Erie Street South, Leamington	Solar Rooftop	90	2017
23M5	111 St. Arnaud, Amherstburg	Solar Rooftop	200	2018
24M9	5840 Malden Road, LaSalle	Solar Rooftop	250	2019
3M8	1 Henry Cres., Leamington	Solar Rooftop	134	2019
23M3	310 Thomas Road, Amherstburg	Solar Rooftop	500	2018
Total Nameplate Capacity (kW)			**2564**	

4.3.2 Forecast REG Connections (5.4.3b)

EPL has forecast the number and capacity of REG connections for the years 2017 through 2020 based on the applications being processed and those expected to be received.

Table 4-16: Forecast REG connections (2017 to 2020)

REG	Number	Nameplate Capacity (MW)
FIT applications being processed	9	2.564
MicroFIT applications being processed	10	0.1
Projected (2018)	5	1.25
Projected (2019)	5	1.25
Projected (2020)	5	1.25
Total	**34**	**6.414**

4.3.3 Capacity to Connect REG (5.4.3c)

EPL estimates that the following capacity is currently available across its distribution feeders for the following stations. Note that capacity is subject to change at any time. Values are calculated using HONI's Capacity Calculator:

- 15MW Malden;
- 13MW Keith;
- 10MW Lauzon; and
- 5MW Kingsville.

4.3.4 REG Connection Constraints (5.4.3d)

The following feeders are not currently accepting applications for connection based on guidance from HONI:

- Malden M7;
- Lauzon M25;
- Lauzon M26; and
- Keith M4.

4.3.5 Embedded Distributor Constraints (5.4.3e)

EPL does not have any current embedded distributor constraints.

4.4 Capital Expenditure Summary (5.4.4)

Table 4-17 presents the historical and forecast capital expenditures and system O&M. Since this is EPL's first DSP, the "previous plan" and variance are only reported for the total annual capital expenditures.

Table 4-17: Historical and forecast capital expenditures and system O&M

Category	Historical															Forecast				
	2013			2014			2015			2016			2017			2018	2019	2020	2021	2022
	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.*	Var.					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000	$ '000	$ '000	$ '000	$ '000
System Access	-	1,766	-	-	2,532	-	-	2,341	-	-	1,759	-	-	1,712	-	1,746	1,781	1,816	1,853	1,835
System Renewal	-	3,113	-	-	3,012	-	-	2,695	-	-	2,125	-	-	2,655	-	2,693	1,362	2,304	2,248	2,195
System Service	-	185	-	-	177	-	-	2,196	-	-	1,005	-	-	787	-	707	2,186	1,126	1,243	1,342
General Plant	-	450	-	-	487	-	-	547	-	-	384	-	-	1,504	-	1,037	856	976	927	968
Total	6,872	5,513	-20%	5,085	6,208	22%	5,571	7,779	40%	4,464	5,274	18%	6,658	6,658	0%	6,183	6,185	6,222	6,270	6,339
System O&M	-	2,289	-	-	2,574	-	-	2,769	-	-	2,490	-	-	2,112	-	2,200	2,275	2,413	2,247	2,342

**0 months of actual data included in 2017.*

4.4.1 Variances in Capital Expenditures

4.4.1.1 Intangible Plant

Account 1611 – Computer Software

EPL is planning an increase of $115,000 in Account 1925 from 2017 Bridge Year to the 2018 Test Year. Planned additions in 2018 include:

- Utility Dashboard - $40k;
- ESRI ArcView/Arc Editor (GIS) Upgrade - $25k; and
- New Work Estimator $30k.

4.4.1.2 Distribution Plant

EPL plans to invest $5,146,191 in Distribution Plant assets in the 2018 Test Year. Between 2010 and 2016, EPL invested, on average, approximately $5,378,730 per year. EPL submits that its expected investments in Distribution Plant are in line with historical spending (slightly less) and, therefore, reasonable. Table 4-18 provides a summary of EPL planned Distribution Plant investments.

Table 4-18: Summary of Distribution Plant investments

Description	2018 Test
Residential Connections	$ 776,868.72
C&I Connections	$ 356,959.20
Conversions	$ 2,224,409.82
Municipal Requests & Asset Purchases	$ 701,474.00
FIT & Generation Connections	$ 181,369.76
Smart Grid/Self Healing Grid	$ 270,139.86
Replacements	$ 487,606.35
Emergencies	$ 147,363.30
Distribution Plant Total	**$ 5,146,191.00**

The following is a breakdown of Distribution Plant by category. Since values for 2018 are forecasted only, they are not presented by account.

Residential Connections

Residential connections relate to the planned/forecast work required to facilitate connection of new residential customers to the distribution system as well as expand existing services, where required. In 2018, EPL plans to invest $776,869 in residential connections where $382,500 relates to new connections and $394,369 relates to residential expansions. These values are based on historical spending and trending.

C&I Connections

C&I connections relate to the planned/forecasted work required to facilitate connection of new C&I customers to the distribution system as well as expand existing services, where

required. In 2018, EPL plans to invest $356,959 in C&I connections. These values are based on historical spending and trending.

Conversions

Conversion projects generally relate to upgrading existing 4kV/8kV distribution assets to 27.6kV. In 2018, EPL plans to invest $2,224,410 in conversion projects which relates to the continuation of EPL's Infrastructure Replacement program and primarily focuses on replacement of end-of-life direct-buried cables, mainly located in residential backyards, allowed through easements, to front yard ROW.

Municipal Requests & Asset Purchases

Municipal Requests & Asset Purchases relate to planned/forecast asset relocation work as well as asset purchases from HONI, where required. Types of asset relocations include road widening projects, ROW improvements, etc. EPL typically sees one (1) or two (2) major municipal request per year.

EPL also anticipates that HONI asset purchase will be required to facilitate long-term load transfer removal as well to accommodate significant HONI work currently ongoing in the Leamington area.

In 2018, EPL plans to invest $701,474 in Municipal Requests & Asset Purchases where $612,000 relates to Municipal Requests and $89,474 relates to HONI asset purchase. These values are based on historical spending and trending.

FIT & Generation Connections

FIT & Generation connections relate to the planned/forecast work required to facilitate connection of new FIT and other generation customers (i.e. MicroFIT, net metering, merchant generation, etc.) to the distribution system. In 2018, EPL plans to invest $181,370 in FIT & Generation connections. These values are based on historical spending and trending as well as known upcoming projects.

Smart Grid / Self-Healing Grid

Smart Grid / Self-Healing Grid refers to EPL's planned investments to build a self-healing grid to reduce interruptions related to distribution/transmission plant owned by HONI. In 2018, EPL plans to continue investing $270,140 in this initiative which largely relates to the installation and commissioning of reclosers at strategic points throughout its distribution system. More information can be found in EPL's GEA Plan and DSP, included as Attachments 2-C and 2-D respectively.

Replacements

Replacement projects generally relate to upgrading and/or replacing existing equipment that is either at end of life, not functioning as intended, damaged, or deteriorated. In 2018, EPL plans to invest $487,606 in replacement projects. The following is a brief summary of planned replacement projects for 2018:

- *Pole Replacement Program:* EPL plans to replace approximately twenty-nine (29) poles in 2018 as part of its Pole Replacement Program. These poles were identified

for replacement through EPL's preventative maintenance program where core sampling was completed via pole drilling. EPL's estimated cost in 2018 is $114,062.

- *Load-Break Replacements:* EPL has been slowly replacing approximately two (2) load-break switches per year to improve reliability, enhance distribution system operability, and replace aging assets. EPL's estimated cost in 2018 is $59,927.
- *Switchgear Replacement Program*: Similar to the Load-Break Replacement program, EPL has been slowly replacing approximately two (2) live-front switchgear units per year to improve reliability, enhance distribution system operability, and replace aging assets. EPL's estimated cost in 2018 is $147,321.
- *Metering Upgrade & Replacement Program:* This program includes upgrading interval metering installations as a result of seal expiry, upgrades from A1R to A3R meters and GPRS upgrades for enhanced reliability and improved functionality, replacing smart meters where required, and replacing gatekeepers and modems for ongoing smart meter communication. EPL's estimated cost in 2018 is $166,297.

Emergencies

Emergencies relate to the planned/forecast work for overhead and underground reactive replacements. In 2018, EPL plans to invest $147,363 in Emergencies where $82,400 relates to forecast overhead reactive replacements and $64,964 relates to forecast underground reactive replacements. These values are based on historical spending and trending.

4.4.1.3 General Plant

Account 1908 – Building & Fixtures

EPL is planning an increase of $369,996 in Account 1908 from the 2017 Bridge Year to the 2018 Test Year. Planned additions in 2018 include:

- Storage Pole Barn for fleet - $300k; and
- Miscellaneous Ops Center repairs/maintenance - $70k.

Additional information about EPL's planned spending for account 1908 for the 2018 Test Year can be found in EPL's DSP as Attachment 2-C.

Account 1920 – Computer Equipment - Hardware

EPL realized an increase of $161,809 in Account 1920 from 2017 Bridge Year to 2018 Test Year. This variance is made up of the following items:

- Desktops/Laptops/Tablets/Toughbooks – $21k;
- Network/Security Appliances - $10k; and
- Cybersecurity & GP Related Upgrade - $130k.

Account 1930 – Transportation Equipment

EPL is planning an increase of $270,000 in Account 1930 from the 2017 Bridge Year to the 2018 Test Year. Planned additions in 2018 include:

- Replacement of Truck #66 – $50k;
- Replacement of Truck #68 – $95k;

- Replacement of Truck #69 - $95k; and
- Replacement of Chipper - $30k,

Additional information about EPL's fleet management and 2018 Test Year spending can be found in EPL's DSP as Attachment 2-C.

4.4.1.4 Contributions & Grants

Account 1995 – Contributions & Grants

While this variance is above EPL's materiality threshold, EPL traditionally receives approximately $1.4M per year in Capital Contributions & Grants, on average. EPL has budgeted conservative values of $1.22M for the Bridge and Test Years which are slightly below average but typical for years without large one-time projects.

4.4.2 Trends in Capital Expenditures

EPL generally projects its capital expenditures at least five (5) years into the future and prioritizes projects based on the methodology outlined in Section 4.2.3.3. Through this project prioritization process, EPL also considers historical spending and optimizing projects to smooth out spending, where possible. As a result, EPL is currently forecasting relatively flat capital spending into the future. This allows EPL to continuously re-invest in its asset base, but also modernize the grid as previously evidenced by the Single-Voltage Utility initiative and forthcoming with the Self-Healing Grid initiative planned to be implemented over the course of the next five (5) years.

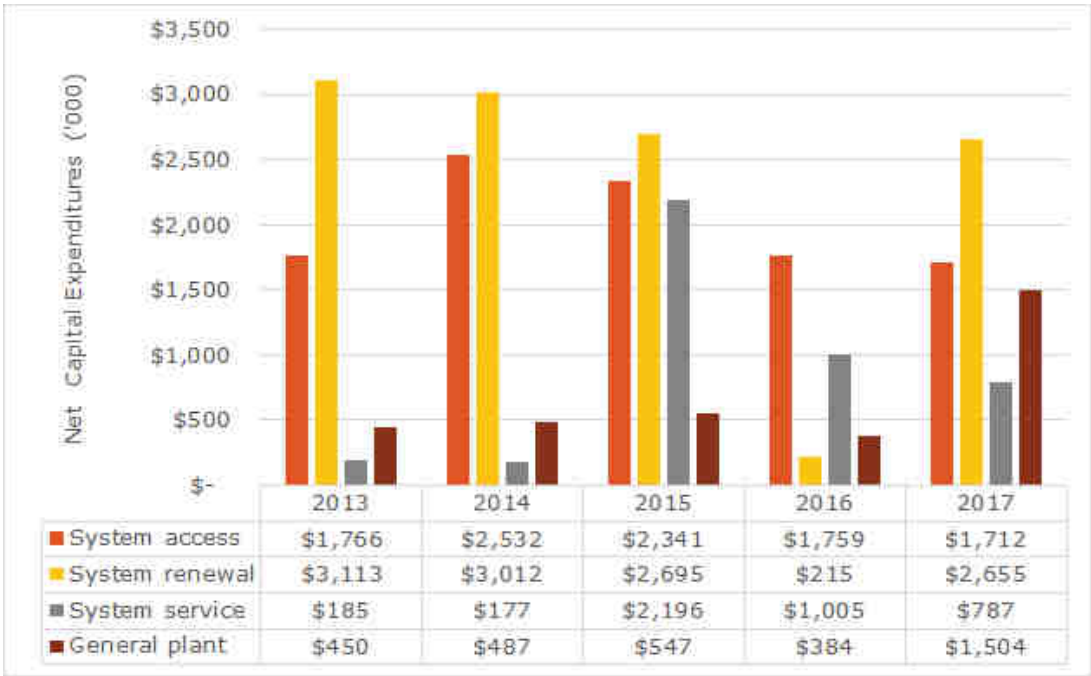
4.5 Justifying Capital Expenditures (5.4.5)

4.5.1 Overall Plan (5.4.5.1)

4.5.1.1 Comparative Expenditures by Category over the Historical Period

Figure 4-14 presents the net capital expenditures for each investment category – system access, system renewal, system service, and general plant – for the year 2013 through 2017

Figure 4-14: Comparative expenditures by category over the historical period



4.5.1.2 Forecast Impact of System Investment on System O&M Costs

Based on EPL's proposed investment plan and other cost-saving initiatives, system O&M costs have been forecast to increase below the rate of inflation to an average of $3.1M per year for the years 2017 through 2022 compared to an average of $3.0M per year 2013 through 2016. Figure 4-15 depicts the system O&M costs, actual and forecast, for the years 2013 through 2022.

Figure 4-15: Actual and forecast system O&M costs

4.5.1.3 Investment Drivers by Category

Table 4-19 lists the drivers of investment by category.

Table 4-19: Investment drivers by category

Investment Category	Driver	Projects/Programs
System access	Customer service requests	Residential connections/extensions
		New service upgrades – commercial and industrial
		Subdivisions
	Third-party infrastructure development requirements	Municipal requests
	Mandated service obligations	Metering upgrade and replacement program
System renewal	Asset failure	Overhead reactive replacements
		Underground reactive replacements
	Assets at the end of their service life due to failure risk	Pole replacement program
		PMH replacement program
		Load break switch replacement
		Infrastructure rebuild program
System service	System operability	Purchase/sell HONI Leamington assets
		Purchase/sell HONI LaSalle assets
	System reliability	Self-healing grid reclosers
	System capacity	Malden TS new feeders and reconfiguration
	Customer-driven generation connection requests	FIT and generation connections
		MicroFIT connections
General plant	Non-system physical plant	Buildings and fixtures
	Business operations efficiency	Computer software
	Non-system equipment at the end of its service life	Tools and equipment
		Transportation equipment
		Office furniture and equipment
		Computer hardware
		Stores equipment

4.5.1.3.1 System Access

Historically, customer service requests for residential connections/extensions, new commercial and industrial service upgrades, and subdivisions have fluctuated between years. EPL has forecast its required investments based on the expected number of customer service requests in each of these categories.

Third-party infrastructure development requirements are also prone to large fluctuation driven by external factors. The combined spending due to this driver was $2.6M in 2013

and 2014 due to a large provincial project, but was only $12k in 2016. The forecast budget is based on the expected requests to be received.

EPL is mandated to meter customers to ensure accurate billing. Meter replacements are made due to failure, technology limitations requiring upgrades, or seal expiry. There is a downward spending trend for metering investments as a result of the implementation of smart meters.

4.5.1.3.2 System Renewal

Reactive replacements of underground and overhead equipment are driven by asset failures. Reactive replacement requirements have been unusually low over the historical period and are expected to statistically correct towards the mean.

Several programs replace assets at the end of their service life due to failure risk. Over the historical period, EPL was focussing its efforts on its voltage conversion programs to complete the transition to a single-voltage system without substations. With the completion of its voltage conversion program in 2017, EPL will instead focus on its Overhead Line Rebuild Program, its Direct-buried Cable Replacement Program, and installing/replacing load break switches. Expenditure rates for pole and switchgear replacements align with historical spending.

4.5.1.3.3 System Service

EPL has gradually been improving the operability of its system and the ability to manage the distribution system equipment that serves its customers through asset purchases from HONI. EPL has planned additional asset transfers as part of a broader strategy for both LDCs to manage and control the assets serving their respective customers.

EPL installed its first recloser in 2011 and will continue to install reclosers over the forecast period. The primary driver is system reliability. Sixty-three percent (63%) of the customer-interruption hours and seventy-three percent (73%) of the customer interruption over the historical period were loss of supply events. Reclosers will be used as part of a self-healing grid for automatic source-transfer to quickly restore power using an alternate source in case of a loss of supply event.

Investments at Malden TS, along with new feeders and feeder reconfiguration address system capacity constraints in LaSalle. The investments will add approximately 10 MVA of new capacity for the LaSalle area, which will sufficiently meet its needs for a long period of time.

Projects to facilitate REG connections are driven by customer requests to connect to the system. Historically, this has included RESOP connections and more recently has included MicroFIT and FIT connections. The number and capacity of REG connection requests over the forecast period has been forecast based on the applications being processed and the applications expected to be received. The FIT program continues to be popular and the most recent FIT 5 offering resulted in many applications to the IESO. This investment category may also include connections of REG greater than 500 kW outside of the FIT program.

4.5.1.3.4 General Plant

EPL's IT strategy will continue to focus on business operational efficiency improvements in order to meet its goal of delivering a modern, smart grid at inflation-aligned prices. EPL has been developing a SmartMAP toolset used for operations and planning. The SmartMAP's control functionality is used by front-line staff to perform switching operations rather than relying on a centralized control room. The outage detection algorithms are able to automatically locate and isolate a fault before restoring power to customers on an unfaulted section of the line.

Investment into non-system physical plant (i.e. buildings and fixtures) was low for the years 2013 through 2016 and additional investments have been planned based on EPL's Building Condition Review (see Appendix H).

Other investments into non-system physical equipment at the end of their service life include tools, fleet, office furniture, computer hardware, and stores equipment. EPL invests in vehicles according to its Fleet Purchasing Policy (see Appendix I). Fleet investments can be lumpy when heavy vehicles require replacement compared to personnel vehicles. The forecast spending on tools and equipment aligns with the historical spending and is based on the expected rate of equipment reaching end-of-life. Office furniture expenditures are budgeted as $10k per year over the forecast period based on the expected rate of replacement. Computer hardware investments align with the lifecycles of the various equipment, such as servers, and EPL's overall IT strategy. Other investments such as stores equipment are adjusted for inflation.

4.5.1.4 REG Requirements

For information related to EPL's system capability assessment, see Section 4.3.

4.5.2 Material Investments (5.4.5.2)

The focus on this section is on projects/activities that meet the materiality threshold set out in Chapter 2 of the Filing Requirements. For EPL this threshold is $60,000.

This section provides information regarding material projects for the capital expenditure in 2018. Project narratives have been prepared for these projects and are assembled in Appendix A.

Appendix A: Project Narratives

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New Residential Subdivisions

A. General Information on the Project/Activity

The purpose of the New Residential Subdivisions program is to facilitate the connection of new Residential Subdivisions and associated customers to EPL's distribution system. New subdivision plans for the 2018 Test Year are not known at this time. Forecast costs are driven by historical trends and increased by inflation. The final cost is determined based on the economic evaluation, which is completed once project specifics are known.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Capital	$240.0	$150.4	$1,020.2	$446.2	$375.0	$382.5	$390.2	$398.0	$405.9	$414.0
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
150 residential (estimated)

Load
300 kVA (estimated)

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$95,625	$95,625	$95,625	$95,625
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

The biggest risk to completion of this program as planned relates to the cost and timing of the investment. Projects within this program are initiated by customers and the actual spending can vary between years. This is an OEB-mandated activity. EPL has highly-trained staff that work with project developers to the best of their ability to manage timelines and to best accommodate the customer. Meetings with customers take place frequently and at their request to best manage customer expectations.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Customer service requests.*

ii. Secondary Drivers: *Mandated service obligations.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, and Financial & Environmental Sustainability.*

iv. Information Used to Justify the Investment: *New residential subdivisions and connections are driven by customer/developer request and are to be connected within OEB-mandated timelines.*

b) Priority: *New Residential Subdivision investments are made based on customer/developer request. This program is non-discretionary. The process is managed by EPL staff through various systems to ensure proper visibility and timeliness. New Residential Subdivisions are a high priority for EPL since they are linked directly with the customers that EPL serves.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked third (3rd) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *These investments are mandated by the OEB.*

i. Cost Effectiveness: *Whenever possible, new subdivisions use standardized designs to maximize cost effectiveness for the affected customer and minimize rate impact for EPL's customers in general.*

ii. Net Customer Benefits: *Customers benefit from a connection to the electricity grid.*

iii. Impact on Reliability: *New subdivisions are constructed using best utility practices that consider reliability by design.*

iv. Cost-Benefit Analysis: *Not applicable.*

2. Safety

New construction meets the latest distribution standards for safety.

3. Cyber-Security, Privacy

The investment does not raise any cyber-security or privacy concerns.

4. Co-ordination, Interoperability

EPL coordinates directly with customers, contractors, developers, and other agencies such as ESA.

5. Economic Development

The connection of customers to the electricity grid supports economic development in the communities that EPL serves.

6. Environmental Benefits

New transformers installed in the subdivisions meet the latest standards for energy efficiency and line losses are considered in the design of the subdivision service.

C. Category-Specific Requirements

Timing/Priority

New Residential Subdivision investments are made based on customer/developer request. This process is managed by EPL staff through various systems to ensure proper visibility and timeliness. New Residential Subdivisions are a high priority for EPL since they are linked directly with the customers that EPL serves.

Customer Preferences

EPL consistently meets with developers and customers to ensure that their needs are met in accordance with EPL's Conditions of Service.

Cost Factors

Costs are generally driven by the specific requests of the customer/developer and can vary from project to project. EPL employs good utility practice and engineering practices to ensure that costs are controlled and minimized for the customer.

Planning Objectives

Other planning objectives such as reliability and operability are incorporated into the design of the subdivision service.

Project Design/Implementation Options

Project design and implementation options for this program are not known until the customer service request is received. In general, designs can vary from project to project and must be made in accordance with EPL's Conditions of Service. Final design and implementation decisions are made by EPL's engineering department.

Results of the Final Economic Evaluation

The results of the final economic evaluation will not be available until the subdivision plans have been finalized by developers. The number of new connections and 2018 Test Year spending has been estimated based on historical values.

REG Investment System Impacts

Not applicable.

Residential Connections/Expansions

A. General Information on the Project/Activity

Residential Connection/Expansion requests are costs associated with activities relating to plant relocation or plant upgrades to accommodate customer-related changes. EPL consistently deals with a variety of requests that are not known at the time of budgeting. Forecast costs are driven by historical trends and increased by inflation.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$429.5	$677.9	$872.1	$1,050.7	$386.6	$394.4	$402.3	$410.3	$418.5	$426.9
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not Applicable

Load
Not Applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$98,592	$98,592	$98,592	$98,592
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

The biggest risk to completion of this program as planned relates to the cost and timing of the investment. Projects within this program are initiated by customers and the actual spending can vary between years. This is an OEB-mandated activity. EPL has highly-trained staff that work with project developers to the best of their ability to manage timelines and to best accommodate the customer. Meetings with customers take place frequently and at their request to best manage customer expectations.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information. Note that actual costs can vary dramatically from year to year depending on the number of customer requests.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Customer service requests.*

ii. Secondary Drivers: *Mandated service obligations.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, and Financial & Environmental Sustainability.*

iv. Information Used to Justify the Investment: *New residential connections/expansions are driven by customer/developer request and are mandated by the OEB to be completed.*

b) Priority: *New Residential Connections/Expansions are made based on customer/developer request. This program is non-discretionary. The process is managed by EPL staff through various systems to ensure proper visibility and timeliness. Projects within this program are executed with a high priority, as they are linked directly with the customers that EPL serves and connections must be made within timelines specified in the Distribution System Code.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked first (1st) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *These investments are mandated by the OEB.*

i. Cost Effectiveness: *Whenever possible, residential connections/expansions use standardized designs to maximize cost effectiveness for the affected customer and minimize rate impact for EPL's customers in general.*

ii. Net Customer Benefits: *Customers benefit from a connection to the electricity grid.*

iii. Impact on Reliability: *Improvements to the secondary bus are considered as part of the projects in this program; however, reliability is not a significant driver.*

iv. Cost-Benefit Analysis: *Not applicable.*

2. Safety

New construction meets the latest distribution standards for safety.

3. Cyber-Security, Privacy

Not applicable.

4. Co-ordination, Interoperability

EPL coordinates directly with customers, contractors, developers and other agencies such as ESA.

5. Economic Development

The connection of customers to the electricity grid supports economic development in the communities that EPL serves.

6. Environmental Benefits

There are no applicable environmental benefits as a result of these investments.

C. Category-Specific Requirements

Timing/Priority

New Residential Connections/Expansion investments are made based on customer/developer request. This process is managed by EPL staff through various systems to ensure proper visibility and timeliness. New Residential Connections/Expansions are a high priority for EPL since they are linked directly with the customers that EPL serves.

Customer Preferences

EPL consistently meets with developers and customers to ensure that their needs are met in accordance with EPL's Conditions of Service.

Cost Factors

Costs are generally driven by the specific requests of the customer/developer and can vary from project to project. EPL employs good utility practice and engineering practices to ensure that costs are controlled and minimized for the customer.

Planning Objectives

Other objectives such as reliability of the secondary bus and transformer loading are always considered; however, investments under this program are driven primarily by customer requests.

Project Design/Implementation Options

Project design and implementation options for this program are not known until the customer service request is received. In general, designs can vary from project to project and must be made in accordance with EPL's Conditions of Service. Whenever possible, EPL uses standardized designs. Final design and implementation decisions are made by EPL's engineering department.

Results of the Final Economic Evaluation

Not applicable.

REG Investment System Impacts

Not applicable.

Municipal Requests

A. General Information on the Project/Activity

Municipal Requests are costs associated with activities relating to plant relocation or plant upgrades to accommodate municipally-requested changes. Examples of Municipal Requests include, but are not limited to, road widenings, right of way improvements, and utility relocation projects. EPL consistently deals with a variety of yearly requests that are not known at the time of budgeting. Forecast costs are driven by historical trends and increased by inflation.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$1,048	$1,577	$311.3	$12.3	$600.0	$612.0	$624.2	$636.7	$649.5	$662.4
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not Applicable

Load
Not Applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$153,000	$153,000	$153,000	$153,000
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

The biggest risk to the completion of the program is the initiation of the work by the municipalities. The historical spending above shows that the actual spending can vary greatly between years depending on the amount of work requested by municipalities. To mitigate this risk, EPL has highly-trained staff that work with project developers to manage timelines and to best accommodate municipal requests. Meetings with municipalities take place frequently and at their request to best manage expectations.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information. Note that actual costs can vary dramatically from year to year.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Third-party infrastructure development requirements.*

ii. Secondary Drivers: *Not applicable.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, and Financial & Environmental Sustainability.*

iv. Information Used to Justify the Investment: *Municipal Requests are driven by municipal/shareholder request and are to be mandated by the OEB to be completed.*

b) Priority: *Since EPL's assets occupy the public right of way, this work is mandatory; therefore, this program is non-discretionary. The municipal request process is managed by EPL staff through various systems to ensure proper visibility and timeliness. The scope of work can vary wildly therefore timing and resourcing are closely managed and monitored by EPL staff.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked sixth (6th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *These investments are mandated by the OEB however certain types of projects are fully or partially recoverable from the municipality.*

i. Cost Effectiveness: *Whenever possible, new construction uses standardized designs to maximize cost effectiveness.*

ii. Net Customer Benefits: *Customers benefit from the work performed by the municipalities, which supports development and quality of life improvements in various communities.*

iii. Impact on Reliability: *Reliability objectives are always considered; however, investments under this program are driven by municipal infrastructure development requirements.*

iv. Cost-Benefit Analysis: *Not applicable.*

2. Safety

New construction meets the latest distribution standards for safety.

3. Cyber-Security, Privacy

Not applicable.

4. Co-ordination, Interoperability

EPL coordinates directly with customers, Municipalities, contractors, developers, and other agencies such as ESA. Quarterly utility meetings allow the municipalities and various utility participants to coordinate their planned and ongoing construction activities.

5. Economic Development

Some of these projects include community improvement projects; therefore, some areas can become more accessible, reliable, and aesthetically pleasing.

6. Environmental Benefits

There are no applicable environmental benefits as a result of these investments.

C. Category-Specific Requirements

Timing/Priority

The timing and priority of projects within this program are based on specific municipal requests. This process is managed by EPL staff through various systems to ensure proper visibility and timeliness. Municipal Requests are a high priority for EPL since they are linked directly with the communities that EPL serves.

Customer Preferences

EPL consistently meets with developers, Municipalities and customers to ensure that their needs are met in accordance with EPL's Conditions of Service.

Cost Factors

Costs are generally driven by the specific requests of the municipality or developer and can vary from project to project. EPL employs good utility practice and engineering practices to ensure that costs are controlled and minimized.

Planning Objectives

Other objectives such as reliability and capacity are always considered; however, investments under this program are driven by municipal infrastructure development requirements.

Project Design/Implementation Options

Project design and implementation options for this program are not known until the municipal request is received. In general, designs can vary for projects under this program and must be made in accordance with EPL's Conditions of Service. Whenever possible, EPL uses standardized designs. Final design and implementation decisions are made by EPL's engineering department.

Results of the Final Economic Evaluation

Not applicable.

REG Investment System Impacts

Not applicable.

New Service Upgrades – C&I

A. General Information on the Project/Activity

*New Service Upgrades for commercial and industrial ("**C&I**") customers are budgeted annually. The investment costs are associated with activities relating to plant relocation or plant upgrades to accommodate customer-related changes. EPL consistently deals with a variety of requests that are not known at the time of budgeting. Forecast costs are driven by historical trends and increased by inflation. EPL received fewer requests for C&I service upgrades over the historical period compared to previous years. Historically, spending in this category has been aligned to the forecast costs.*

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$100.9	$21.1	$3.8	$99.1	$350.0	$357.0	$364.1	$371.4	$378.8	$386.4
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not Applicable

Load
Not Applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$89,240	$89,240	$89,240	$89,240
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

The biggest risk to completion of this program as planned relates to the cost and timing of the investment. Projects within this program are initiated by customers and the actual spending can vary between years. This is an OEB-mandated activity. EPL has highly-trained staff that work with project developers to the best of their ability to manage timelines and to best accommodate the customer. Meetings with customers take place frequently and at their request to best manage customer expectations.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information. Note that actual costs can vary dramatically from year to year and EPL saw a significant reduction from 2013 through 2016 as a result of less development in the region. More development is expected beginning in 2017 and EPL must ensure it has enough capital allocated to serve new connections.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Customer service requests.*

ii. Secondary Drivers: *Mandated service obligations.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, and Financial & Environmental Sustainability.*

iv. Information Used to Justify the Investment: *New Service Upgrades – C&I are driven by customer/developer request and are mandated by the OEB to be completed.*

b) Priority: *New Service Upgrades – C&I are made based on customer/developer request. This program is non-discretionary. The process is managed by EPL staff through various systems to ensure proper visibility and timeliness. Projects within this program are executed with a high priority, as they are linked directly with the customers that EPL serves and connections must be made within timelines specified in the Distribution System Code.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked second (2nd) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *These investments are mandated by the OEB.*

i. Cost Effectiveness: *Whenever possible, new service upgrades use standardized designs to maximize cost effectiveness for the affected customer and minimize rate impact for EPL's customers in general.*

ii. Net Customer Benefits: *Customers benefit from a connection to the electricity grid.*

iii. Impact on Reliability: *Improvements to the secondary bus are considered as part of the projects in this program; however, reliability is not a significant driver.*

iv. Cost-Benefit Analysis: *Not applicable.*

2. Safety

New construction meets the latest distribution standards for safety.

3. Cyber-Security, Privacy

Not applicable.

4. Co-ordination, Interoperability

EPL coordinates directly with customers, contractors, developers, and other agencies such as ESA.

5. Economic Development

The connection of C&I customers directly supports job creation in the communities that EPL serves.

6. Environmental Benefits

There are no applicable environmental benefits as a result of these investments.

C. Category-Specific Requirements

Timing/Priority

New Service Upgrades – C&I investments are made based on customer/developer request. This process is managed by EPL staff through various systems to ensure proper visibility and timeliness. New Service Upgrades – C&I are a high priority for EPL since they are linked directly with the customers that EPL serve.

Customer Preferences

EPL consistently meets with developers and customers to ensure that their needs are met in accordance with EPL's Conditions of Service.

Cost Factors

Costs are generally driven by the specific requests of the customer/developer and can vary from project to project. EPL employs good utility practice and engineering practices to ensure that costs are controlled and minimized for the customer.

Planning Objectives

Other objectives such as reliability of the secondary bus and transformer loading are always considered; however, investments under this program are driven primarily by customer requests.

Project Design/Implementation Options

Project design and implementation options for this program are not known until the customer service request is received. In general, designs can vary from project to project and must be made in accordance with EPL's Conditions of Service. Whenever possible, EPL uses standardized designs. Final design and implementation decisions are made by EPL's engineering department.

Results of the Final Economic Evaluation

Not applicable.

REG Investment System Impacts

Not applicable.

Metering Upgrade & Replacement Program

A. General Information on the Project/Activity

The purpose of this program is to replace meters due to communication failure, technology limitations requiring upgrades due to regulation changes, or seal expiry. The program also includes gatekeeper and modem replacements to enhance connection and reliability of data. Budgeting is reviewed annually based on communication and data needs of new technologies as well as historical spending trends adjusted for inflation. EPL received fewer requests for metering upgrades over the historical period compared to previous years. Historically, spending in this category has been aligned to the forecast costs. The 2018 Test Year expenditure forecast includes 351 interval meters, 672 smart meters, and 4 gatekeepers.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$100.1	$7.7	$8.5	$54.2	$163.0	$166.3	$169.6	$173.0	$176.5	$180.0
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not applicable

Load
Not applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$41,574	$41,574	$41,574	$41,574
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

Risks are minimal for these projects as they represent standard industry practices. There is risk in loss of data and equipment lead times; however, EPL is in regular communication with vendors to ensure customer value and is upgrading meters, where required, to avoid data related problems in the future.

Comparative Expenditure Information

Comparative expenditures over the historical period are shown in the table above.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Mandated service obligations.*

ii. Secondary Drivers: *Assets at the end of their service life due to failure or functional obsolescence.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, and Financial & Environmental Sustainability.*

iv. Information Used to Justify the Investment: *EPL uses Measurement Canada seal expiry and recent failures as the metrics to justify these projects.*

b) Priority: *Metering is a mandated service obligation; therefore, this program is non-discretionary. EPL prioritizes replacements based on recent failures and direction from the OEB and Measurement Canada.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked tenth (10th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *There are no alternatives to these metering upgrades and replacements as reliable and accurate metering information is mandated by the OEB and Measurement Canada.*

i. Cost Effectiveness: *All new meters include network connections to Advanced Metering Infrastructure ("**AMI**").*

ii. Net Customer Benefits: *Enhanced customer confidence.*

iii. Impact on Reliability: *These investments can improve the reliability of data provided to the provincial Meter Data Management Repository and billing system. New meters communicate a "last gasp" to EPL's self-healing grid in case of a loss of power. This information facilitates accurate assessment of the grid condition to restore the maximum number of customers as soon as possible.*

iv. Cost-Benefit Analysis: *Not applicable.*

2. Safety

New meters conform to the latest safety standards.

3. Cyber-Security, Privacy

The investment will be made in conjunction with major cyber-security upgrades underway in 2017. Smart meter data is collected and transferred over a secure network. In accordance with best practices for data security, access to the data is restricted to EPL staff who require access via secure log-in.

4. Co-ordination, Interoperability

Customer coordination is required in order to minimize customer impact and outage times. Appointments are made to attempt to best accommodate the customer.

5. Economic Development

*Metering is mandatory in order to supply a customer with electrical service, which supports economic development. Smart meters enable time-of-use ("**TOU**") rates and allow residential and business customers alike to manage their consumption.*

6. Environmental Benefits

Smart meters enable TOU billing, which incentivizes customers to shift consumption from peak hours (when gas-fired peaking plants are needed) to off-peak hours (more dependent on emission-free sources such as hydroelectric and nuclear).

C. Category-Specific Requirements

Timing/Priority

The Metering Upgrade & Replacement Program timing is dependent on the urgency of the replacement as well as availability of resources. Data/reliability centered replacements are dealt with as quickly as possible whereas scheduled replacements are accommodated when timing is optimal for EPL crews and customers.

Customer Preferences

The project is driven by mandated service obligations. Appointments are made to attempt to best accommodate the customer.

Cost Factors

The project is driven by mandated service obligations. EPL employs good utility practices and engineering practices to ensure that costs are controlled and minimized for the customer.

Planning Objectives

This program supports EPL's objective of a providing a modern, smart grid fit for the 21st century at inflation-aligned costs.

Project Design/Implementation Options

Standardized designs and installation procedures are used to maximize cost effectiveness of each job.

Results of the Final Economic Evaluation

Not applicable.

REG Investment System Impacts

Not applicable.

Pole Replacement Program

A. General Information on the Project/Activity

The purpose of this program is to replace poles that have either failed or are at the end of their service life due to failure risk. Through its thorough preventative maintenance program, EPL reviews the condition of its poles continuously to limit failure and maximize safety via non-destructive testing methods such as drilling. Budgeting is reviewed annually based on preventative maintenance program findings and availability of resources.

EPL plans to replace approximately twenty-nine (29) poles in 2018 as part of its Pole Replacement Program. These poles were identified for replacement through EPL's preventative maintenance program where core sampling was completed via pole drilling.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$478.3	$193.3	$335.9	$514.0	$460.5	$114.1	$558.7	$488.7	$121.0	$592.9
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not applicable

Load
Not applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$28,516	$28,516	$28,516	$28,516
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

Pole replacements are well understood and, therefore, risks are minimal for these projects as they represent standard industry practices. There is incremental risk in dealing with auguring holes during the winter months where sub-zero temperatures can persist. However, this can be mitigated by scheduling around predictable adverse weather conditions. Many replacements take place near customer premises or businesses; therefore, EPL will ensure that the necessary signage and safety precautions are utilized. Any/all inconvenienced customers will be notified.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information. Note that actual costs can vary dramatically from year to year based on the expected number of replacements planned/required. EPL's poles are inspected and tested on a three (3)-year cycle. Replacement of poles

also follows this cycle, which ensures that the poles prioritized for replacement were recently assessed to be at the end of their service life and pose an unacceptable risk without intervention.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Assets at the end of their service life as a result of failure risk.*

ii. Secondary Drivers: *The secondary drivers are poles at the end of their service life due to failure, safety, and reliability. Allowing old and deteriorating poles in the field can result in significant safety concerns to EPL staff and customers.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, Safety, and Financial & Environmental Sustainability.*

iv. Information Used to Justify the Investment: *EPL's preventative maintenance program and recent failures are the metrics that EPL uses to justify these projects.*

b) Priority: *All capital projects have been prioritized and optimized based on Financial, Service Quality, Community Image, Legal, Regulatory, Safety and Environmental metrics. EPL prioritizes replacements based on recent failures and its preventative maintenance program.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked sixteenth (16th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *Alternatives to pole replacements include a complete overhead rebuild, undergrounding the span, and the "do nothing". Poles included in this program are not part of an overhead rebuild since the adjacent poles are typically not at the end of their service life. Undergrounding a single span is not feasible. In the case of the "do nothing" option, old and deteriorating poles would remain in the field without intervention, which can result in significant safety concerns, lengthy customer outages, and increases to system O&M costs.*

i. Cost Effectiveness: *EPL uses inspection and age data to determine pole replacements cost effectively. For poles identified for replacement under this program, spot pole replacements – rather than planned overhead rebuilds – are the most cost-effective alternative.*

ii. Net Customer Benefits: *Customers will benefit from fewer outages.*

iii. Impact on Reliability: *This program will replace poles in poor condition before they fail and cause extended outages; hence, improving reliability.*

iv. Cost-Benefit Analysis: *The Pole Replacement Program replaces poles that are at end of service life due to failure or failure risk as identified during the pole inspection process. This will improve reliability by reducing unplanned outages and hence reducing outage costs. Also, this program avoids future system O&M costs since replacements can be scheduled during regular hours rather than relying on trouble calls, which take longer and can require overtime hours.*

Other alternatives, such as undergrounding the line section, are not feasible and are, therefore, not recommended. In the case of a failed pole, doing nothing is not an option as a pole is required to support the overhead conductors and provide proper clearances. In the case of a pole at risk of failure, doing nothing would not achieve the project benefits of eliminating risks to public and employee safety, maintaining system reliability, and avoiding future O&M (trouble call) costs.

This project will result in greater reliability for EPL customers, lower system O&M costs over time, lessen EPL's legal liability and exposure, and lead to enhanced safety for crews and the general population. The project as scoped is the optimal approach and the preferred trade-off between costs and benefits.

2. Safety

Proper asset management of old and deteriorating equipment in the field mitigates safety concerns for EPL staff and customers. All new construction meets the latest distribution standards for safety.

3. Cyber-Security, Privacy

This program does not raise any cyber-security or privacy concerns.

4. Co-ordination, Interoperability

Coordination with entities such as HONI is critical to ensure consistency with joint-use agreements, ensure safety, and co-ordinate planned outages.

5. Economic Development

One of the drivers for this program is reliability and a reliable electricity supply supports economic development.

6. Environmental Benefits

There are no significant environmental benefits as a result of these investments.

C. Category-Specific Requirements

Asset Performance-Related Targets

The replacement of aged and deteriorating overhead plant will maintain EPL's reliability performance, specifically with respect to the number of outages (SAIFI). For the years 2013 through 2016, defective equipment outages accounted for the most customer-hours of interruption excluding loss of supply events; therefore, the investment will contribute to reducing defective equipment outages. A reliable supply of electricity supports customer satisfaction.

*EPL relies on a combination of Reliability-Centred Maintenance ("**RCM**"), predictive maintenance, preventative maintenance, and cyclical inspections to manage its distribution assets. Plant that is scheduled for replacement is generally at the end of its service life due to failure or failure risk or otherwise requires replacement due to reliability and/or safety concerns.*

Condition of Assets

Poles are inspected on a three (3)-year cycle. EPL also has a pole testing program to assess the condition of its poles. EPL owns 6228 poles, of which 6062 are made of wood, 163 are made of concrete, and 3 are made of steel. The Pole Replacement Program focuses on wood poles.

1 presents the age profile for wood poles; the age demographics are unknown for the remaining 3291 wood poles. Figure 2 presents the results of the condition assessment.

Figure 1: System-wide age profile for wood poles

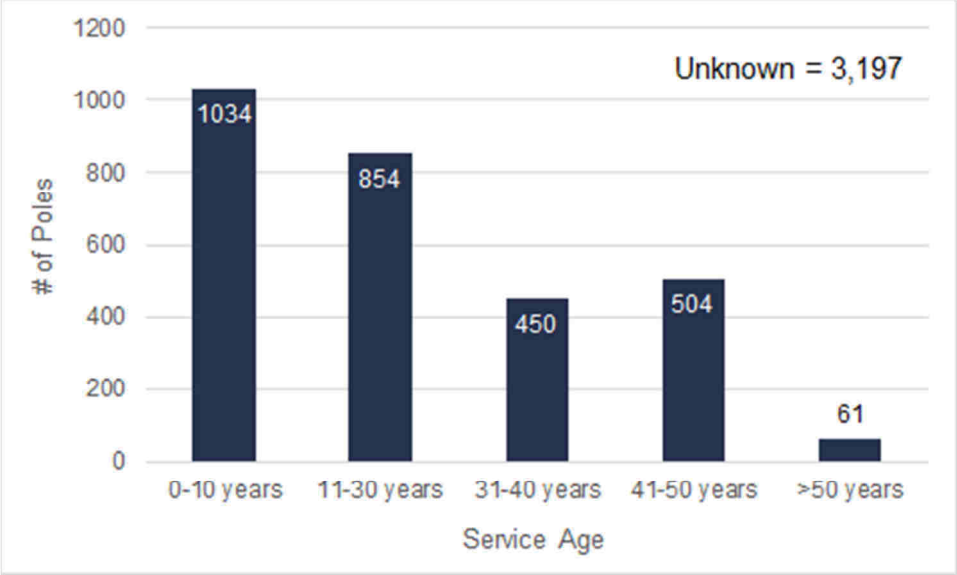
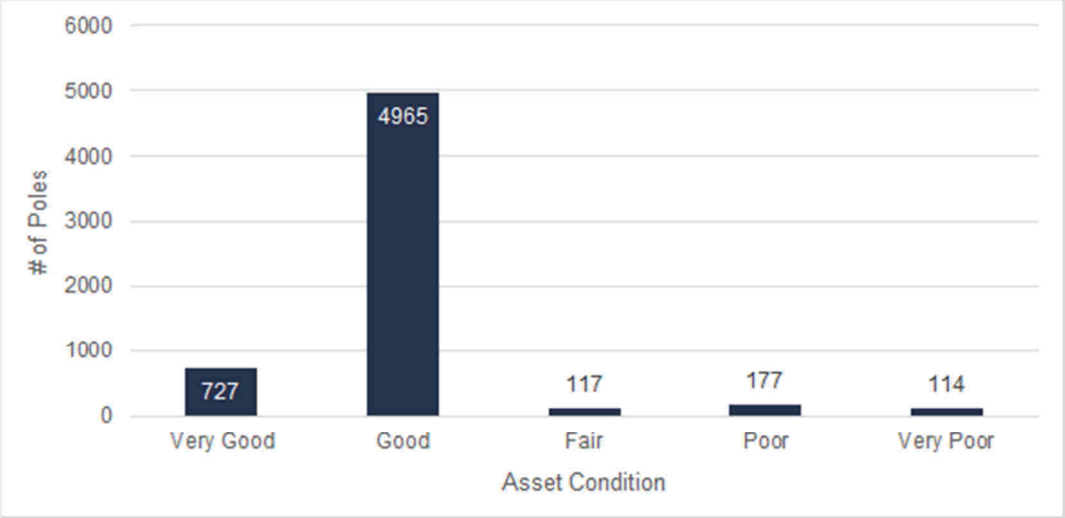


Figure 2: Condition assessment results for wood poles



Project Impacts

i. Number of Customers Affected: *Specific yearly values are not currently known; however, the number of customers can vary significantly from year to year.*

ii. Quantitative Customer Impacts: *Specific yearly values are not currently known; however, the length of outages can vary significantly from year to year.*

iii. Qualitative Customer Impacts: *Customers will receive value through reduced unplanned outages and enhanced reliability.*

iv. Value of Customer Impact: *Customers will receive value through reduced unplanned outages and enhanced reliability.*

Project Timing Factors

Pole replacement timing is dependent on the urgency of the replacement as well as availability of resources. Safety or reliability-centered replacements are dealt with as quickly as possible, whereas scheduled replacements are accommodated when timing is optimal for EPL crews.

Consequences for System O&M Cost

The Pole Replacement Program will help reduce O&M costs over time through reductions in reactive maintenance spending.

The failure of a pole increases system O&M costs. Unplanned pole change-outs usually take longer to replace, as the downed pole must first be located and the work may need to be done at night. A failed pole may also break the conductors, which are not usually replaced as part of the pole replacement program.

Reliability / Safety Factors

Proper asset management of old and deteriorating equipment in the field mitigates safety and reliability concerns.

Comparison of Project Timing Alternatives

There are limited alternatives to the Pole Replacement program and the consequences of delaying replacements can result in significant reliability and safety concerns.

Analysis of Project Enhancements

All new construction meets the latest distribution standards. Possible project enhancements are assessed when planning the pole replacement job. This can include selecting a higher pole class for corner poles or other key locations such as road or river crossings.

Overhead Reactive Replacements

A. General Information on the Project/Activity

The purpose of this program is to replace overhead equipment that has failed as a result of damage incurred in the field. Budgeting is reviewed annually and is based on historical spending trends adjusted for expected inflation. Reactive spending over the historical period was less than the long-term average, which is expected to statistically correct towards the mean.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$0	$6.1	$0	$0	$80.8	$82.4	$84.0	$85.7	$87.4	$89.2
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Varies

Load
Varies

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$20,600	$20,600	$20,600	$20,600
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

Since this is a reactive program, the actual spending can vary compared to the budget depending on the quantity of assets that fail during the year. Overhead lines are exposed to external factors such as wind, snow, ice, lightning, and unclaimed damage to EPL's plant from vehicles. The primary risk to the completion of this program is ensuring that sufficient capital is available to mitigate a variety of different restoration/repair scenarios. EPL's preventative maintenance program has allowed EPL to better control these costs over time.

Comparative Expenditure Information

Note that actual costs can vary dramatically from year to year based on the actual number of events incurred. Reactive spending over the historical period was less than the long-term average, which is expected to statistically correct towards the mean.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Assets at the end of their service life due to failure.*

ii. Secondary Drivers: *The secondary drivers are safety and reliability. Storm conditions can present safety-related risks to both EPL staff and customers. Failed assets need immediate repair or replacement for quick restoration. Other major cost drivers include third-party tree trimming, on-call premiums, etc.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, and Safety.*

iv. Information Used to Justify the Investment: *Customer restoration is an OEB-mandated activity. Public/employee safety is one of the top objectives of EPL's asset management. Failed assets, if not replaced/repaired immediately, pose safety hazards; therefore, this is investment is highly required.*

b) Priority: *This is a non-discretionary program. Customer restoration is an OEB-mandated activity and, therefore, this activity is required.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked fourth (4th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *The alternative to this program is a "do nothing" approach; however, doing nothing is not an option with failed assets as they need to be repaired/replaced for customer restoration. Design alternatives, where applicable, are evaluated for each case to ensure that restoration is completed quickly and cost effectively.*

i. Cost Effectiveness: *In each case, service is restored by the most cost effective means.*

ii. Net Customer Benefits: *Customers will benefit from quick restoration as a result of this activity.*

iii. Impact on Reliability: *Ensuring sufficient investment in case of a failure will lower or maintain SAIDI within the target by allowing quick customer restoration.*

iv. Cost-Benefit Analysis: *Overhead assets that generally fail as a result of storm or adverse conditions beyond the control of EPL need to be repaired /replaced to ensure customer restoration and deliver reliable service. Benefits of this activity are quick customer restoration and improved reliability and safety.*

2. Safety

Safety is a critical driver for this project since storm conditions can present safety-related risks to both EPL staff and customers. All new construction meets the latest distribution standards for safety.

3. Cyber-Security, Privacy

This program does not raise any cyber-security or privacy concerns.

4. Co-ordination, Interoperability

Coordination with entities such as HONI is critical to ensure timely and effective restoration.

5. Economic Development

Restoration of electrical service supports economic development in the areas that EPL serves.

6. Environmental Benefits

There are no significant environmental benefits as a result of these investments.

C. Category-Specific Requirements

Asset Performance-Related Targets

Replaced overhead assets have generally failed as a result of storm or adverse conditions beyond the control of EPL. Ensuring sufficient investment in case of a failure will lower or maintain SAIDI within the target by allowing quick customer restoration and will improve customer satisfaction.

*EPL relies on a combination of proactive replacements, Reliability-Centred Maintenance ("**RCM**"), predictive maintenance, preventative maintenance, and cyclical inspections to manage its distribution assets and reduce the amount of reactive work required.*

Condition of Assets

This program is not driven by asset condition; replaced overhead assets have generally failed as a result of storm or adverse conditions beyond the control of EPL.

Project Impacts

i. Number of Customers Affected: *Specific yearly values are not currently known; however, the number of customers can vary significantly from year to year.*

ii. Quantitative Customer Impacts: *Specific yearly values are not currently known; however, the length of outages can vary significantly from year to year.*

iii. Qualitative Customer Impacts: *Customers will receive value through quick customer restoration.*

iv. Value of Customer Impact: *Ensuring sufficient funding for this project ensures that EPL has the resources it requires to fund reactive overhead replacements in a timely and safe manner for its customers.*

Project Timing Factors

Restoration timing can vary dramatically depending on the nature of the asset failure(s), EPL's assessment of the damage, and coordination with other utilities including Hydro One.

Consequences for System O&M Cost

When there is a storm or otherwise adverse conditions, the initial response is treated as O&M, while new equipment installed in the field is capitalized.

Reliability / Safety Factors

Failed overhead equipment, if not responded to by EPL crews, pose safety and reliability concerns.

Comparison of Project Timing Alternatives

There are limited alternatives for this project and the consequences of delaying replacements can result in significant reliability and safety concerns.

Analysis of Project Enhancements

All new plant meets the latest distribution system standards.

Underground Reactive Replacements

A. General Information on the Project/Activity

The purpose of this program is to replace underground equipment that has failed as a result of damage incurred in the field. Budgeting is reviewed annually and is based on historical spending trends adjusted for expected inflation. Reactive spending over the historical period was less than the long-term average, which is expected to statistically correct towards the mean.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Capital	$10.7	$0	6.9	$0	$63.7	$65.0	$66.3	$67.6	$68.9	$70.3
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not applicable

Load
Not applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$16,241	$16,241	$16,241	$16,241
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

Since this is a reactive program, the actual spending can vary compared to the budget depending on the quantity of assets that fail during the year. Underground cables can exhibit insulation failure (e.g. treeing, pinhole) or fail due to a dig-in. The primary risk to the completion of this program is ensuring that sufficient capital is available to mitigate a variety of different restoration/repair scenarios. EPL's preventative maintenance program has allowed EPL to better control these costs over time.

Comparative Expenditure Information

Note that actual costs can vary dramatically from year to year based on the actual number of events incurred. Reactive spending over the historical period was less than the long-term average, which is expected to statistically correct towards the mean.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Assets at the end of their service life due to failure.*

ii. Secondary Drivers: *The secondary drivers are safety and reliability. Failed assets need immediate repair or replacement for quick restoration. Major cost drivers include third-party trenching, on-call premiums, etc.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, and Safety.*

iv. Information Used to Justify the Investment: *This program is required to replace failed assets and for fast restoration. Customer restoration is an OEB-mandated activity. Public/employee safety is one of the top objectives of EPL's asset management. Failed assets, if not replaced/repaired immediately, pose safety hazards; therefore, this is investment is highly required.*

b) Priority: *This is a non-discretionary program. Customer restoration is an OEB-mandated activity and, therefore, this activity is required.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked fifth (5th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *The alternative to this program is a "do nothing" approach. In case of failed assets doing nothing is not an option and hence not recommended. Other alternatives, where applicable, are evaluated based on each failure case to ensure that restoration is completed quickly and cost effectively.*

i. Cost Effectiveness: *In each case, service is restored by the most cost effective means.*

ii. Net Customer Benefits: *Customers will benefit from fast restoration.*

iii. Impact on Reliability: *Reserving sufficient budget for reactive replacement ensures fast restoration and hence maintaining reliability target.*

iv. Cost-Benefit Analysis: *Not applicable.*

2. Safety

Safety is a critical driver for this project since failed underground plant, if not corrected, can present potential safety-related risk to EPL staff and customers. All new construction meets the latest distribution standards for safety.

3. Cyber-Security, Privacy

This program does not raise any cyber-security or privacy concerns.

4. Co-ordination, Interoperability

Coordination with entities such as HONI is critical to ensure timely and effective restoration.

5. Economic Development

Restoration of electrical service supports economic development in the areas that EPL serves.

6. Environmental Benefits

There are no significant environmental benefits as a result of these investments.

C. Category-Specific Requirements

Asset Performance-Related Targets

*Ensuring sufficient investment in case of a failure will lower or maintain SAIDI within the target by allowing quick customer restoration and will improve customer satisfaction. EPL relies on a combination of proactive replacements, Reliability-Centred Maintenance ("**RCM**"), predictive maintenance, preventative maintenance, and cyclical inspections to manage its distribution assets and reduce the amount of reactive work required.*

Condition of Assets

This program is not driven by asset condition; replaced underground assets have generally failed as a result of storm or adverse conditions beyond the control of EPL.

Project Impacts

i. Number of Customers Affected: *Specific yearly values are not currently known; however, the number of customers can vary significantly from year to year.*

ii. Quantitative Customer Impacts: *Specific yearly values are not currently known; however, the length of outages can vary significantly from year to year.*

iii. Qualitative Customer Impacts: *The investment will maintain reliability performance associated with underground assets.*

iv. Value of Customer Impact: *Ensuring sufficient funding for this project ensures that EPL has the resources it requires to fund reactive underground replacements in a timely and safe manner for its customers.*

Project Timing Factors

Restoration timing can vary dramatically depending on the nature of the asset failure(s), EPL's assessment of the damage, and coordination with other utilities including HONI.

Consequences for System O&M Cost

When there is a storm or otherwise adverse conditions, the initial response is treated as O&M, while new equipment installed in the field is capitalized.

Reliability / Safety Factors

Allowing damaged assets in the field can result in significant safety concerns to EPL staff and customers.

Comparison of Project Timing Alternatives

Failed underground equipment, if not responded to by EPL crews, pose reliability and safety concerns.

1 Analysis of Project Enhancements

2 *All new plant meets the latest distribution system standards.*

Install/Replace Load Breaks

A. General Information on the Project/Activity

The purpose of this program is to replace load-break switches that have either failed or are at the end of their service life due to failure risk. As part of EPL's self-healing grid initiative, load-break switches identified for replacements are upgraded for reliability and automation purposes. EPL is planning to replace two (2) load-break switches per year.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Capital	$0	$0	$0	$0	$58.8	$59.9	$61.1	$62.3	$63.6	$64.9
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not applicable

Load
Not applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$14,982	$14,982	$14,982	$14,982
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

Risks are minimal for these projects as they represent standard industry practices. There is incremental risk in procurement; however, EPL is in regular communication with vendors to ensure customer value.

Comparative Expenditure Information

There were no expenditures under third program for the years 2013 through 2016. The planned investment beginning in 2017 coincides with the self-healing grid initiative.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Assets at the end of their service life as a result of failure risk.*

ii. Secondary Drivers: *The secondary drivers are asset failure, reliability, and safety. Switch failures can result in customer outages and reduce the operability of the system.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, Safety, and Financial & Environmental Sustainability.*

iv. Information Used to Justify the Investment: *EPL's preventative maintenance program and recent failures are the metrics that EPL uses to justify these projects.*

b) Priority: *All capital projects have been prioritized and optimized based on Financial, Service Quality, Community Image, Legal, Regulatory, Safety and Environmental metrics. EPL prioritizes replacements based on recent failures and its preventative maintenance program.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked eighth (8th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *Possible alternatives to the replacement of a load-break switch include the "do nothing" option. If a switch is identified as a failure risk or has failed, then it will reduce the operability of the system. Replacement is the optimal approach to enable grid operation during feeder work and when restoring power.*

i. Cost Effectiveness: *Planned replacements are more cost effective than reactive replacements, which may require emergency restoration or overtime hours.*

ii. Net Customer Benefits: *Customers will benefit from improved operability of the system, allowing EPL's crews to perform work on the system and power to be more restored more effectively during an outage.*

iii. Impact on Reliability: *Reliability impacts are mitigated through proactive switch replacement. The upkeep of load break switches allows EPL to flexibly transfer load under outage scenarios.*

iv. Cost-Benefit Analysis: *The proactive replacement of load break switches is the most cost-effective option and provides the greatest benefits for EPL's customers. This is the optimal approach.*

2. Safety

All new construction meets the latest distribution standards for safety.

3. Cyber-Security, Privacy

This program does not raise any cyber-security or privacy concerns. The communication capabilities of the new switches are secured on EPL's network.

4. Co-ordination, Interoperability

Coordination with entities such as HONI is critical to ensure consistency with joint-use agreements, ensure safety, and co-ordinate planned outages.

5. Economic Development

One of the drivers for this program is reliability and a reliable electricity supply supports economic development.

6. Environmental Benefits

There are no significant environmental benefits as a result of these investments.

C. Category-Specific Requirements

Asset Performance-Related Targets

The replacement of aged and deteriorating overhead plant will maintain EPL's reliability performance, specifically with respect to the number of outages (SAIFI). The proactive replacement of load-break switches also supports operability of the system, allowing EPL to quickly restore power under contingency scenarios and reducing the duration of outages (SAIDI). A reliable supply of electricity supports customer satisfaction.

*EPL relies on a combination of Reliability-Centred Maintenance ("**RCM**"), predictive maintenance, preventative maintenance, and cyclical inspections to manage its distribution assets. Plant that is scheduled for replacement is generally at the end of its service life due to failure or failure risk or otherwise requires replacement due to reliability and/or operability concerns.*

Condition of Assets

Load break switches are inspected on a three (3)-year cycle. Load break switches also undergo regular maintenance – with adjustments as required – and infrared inspection. Assets replaced under this program are assessed to be at the end of their service life based on the results of the maintenance and inspections.

Project Impacts

i. Number of Customers Affected: *Specific yearly values are not currently known; however, the number of customers can vary significantly from year to year.*

ii. Quantitative Customer Impacts: *Specific yearly values are not currently known; however, the length of outages can vary significantly from year to year.*

iii. Qualitative Customer Impacts: *Customers will receive value through reduced unplanned outages and enhanced reliability.*

iv. Value of Customer Impact: *Customers will receive value through reduced unplanned outages and enhanced reliability.*

Project Timing Factors

Load break switch replacement timing is dependent on the urgency of the replacement as well as availability of resources. Reliability-centered replacements are dealt with as quickly as possible, whereas scheduled replacements are accommodated when timing is optimal for EPL crews.

Consequences for System O&M Cost

This program will contribute to a reduction in reactive maintenance spending, which will reduce overall system O&M costs. The failure of a pole increases system O&M costs. Unplanned replacements usually take longer to perform and may require overtime hours.

Reliability / Safety Factors

Proper asset management of old and deteriorating equipment in the field mitigates safety and reliability concerns.

Comparison of Project Timing Alternatives

EPL has paced two (2) load-break switches per year to avoid replacing switches before they reach end-of-life. The timing also corresponds with EPL's self-healing grid initiative described in its Green Energy Act Plan and Smart Grid Development Plan.

Analysis of Project Enhancements

New load-break switches installed in the field are enhanced with communication capabilities to facilitate a self-healing grid.

Infrastructure Rebuild Program

A. General Information on the Project/Activity

The purpose of this program is to replace overhead and underground circuits that are located in alleys, right of ways, etc. in customer backyards. In particular, this program focuses on replacement of direct-buried cables. Budgeting is reviewed annually based on the urgency of work required and potential safety hazards. EPL intends to increase accessibility of all of its plant while limiting inconveniences to its customers.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$814.5	$290.1	$88.7	$43.6	$900.0	$2,229.4	$229.4	$1,229.4	$1,529.4	$1,329.4
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not applicable

Load
Not applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$557,354	$557,354	$557,354	$557,354
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

Program timing and cost can be impacted since work must be performed on customer premises. Customers are provided notice of the work well in advance to reduce the inconvenience and EPL will ensure that the necessary signage and safety precautions are utilized. The work will be done by dedicated crews who are familiar with this type of work.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information. Note that actual costs can vary dramatically from year to year based on the expected number of replacements planned/required.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Assets at the end of their service life due to failure risk.*

ii. Secondary Drivers: *The secondary drivers are safety and reliability. In response to customer requests, this project will increase accessibility of all of its plant while limiting inconveniences to its customers.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, and Safety.*

iv. Information Used to Justify the Investment: *EPL's preventative maintenance program, as well as customer requests, are used to justify these investments.*

b) Priority: *EPL prioritizes conversions based on recent failures, age of plant, customer requests, and other planned work in the area of the conversion. All capital projects have been prioritized and optimized based on Financial, Service Quality, Community Image, Legal, Regulatory, Safety, and Environmental metrics. Public/ employee safety is the highest priority objective for EPL.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked twelfth (12th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *For direct-buried cable replacements, there are four (4) alternatives: do nothing, replace with direct-buried cable, replace with cable runs in ducts, and replace with overhead service. Alternatives to overhead rebuilds include the "do nothing" option, like-for-like rear lot rebuild, spot pole replacements, undergrounding the circuits, or rebuilding the service in the front.*

i. Cost Effectiveness: *This program replaces rear lot infrastructure, which would otherwise require expensive emergency repairs since specialized equipment is oftentimes required in order to minimize customer inconvenience. The proactive replacement of assets and conversion of rear-lot to front service is the most cost-effective approach. Since the assets are in proximity to one another, the overhead rebuild option is more cost effective than reactive replacements or spot pole replacements.*

ii. Net Customer Benefits: *Customers benefit in terms of future reliability of their electricity supply and future convenience for inspection and repair work no longer required in customer backyards. This program lessens inconvenience for the customer in circumstances where EPL needs to access its equipment and results in faster restoration times.*

iii. Impact on Reliability: *This program mitigates the risk of an unplanned asset failure – particularly direct-buried cables – and also reduces outage restoration time since duct-embedded cables can be repaired much quicker than direct-buried cables. Overhead lines and poles in the field are aged and deteriorating which can result in unplanned outages. This will particularly impact outages due to adverse weather and tree contacts on customer premises. Moreover, with ease of access to equipment, fast restoration can be achieved.*

iv. Cost-Benefit Analysis: *In the case of the "do nothing" option, customer requests to increase accessibility will not be met and accessing plant in backyards can also prove to be difficult, unsafe, and cost-ineffective since specialized equipment is oftentimes required in order to minimize customer inconvenience. Replacing with direct-buried cables would require the right of way to be dug up again in case of a future cable failure, which is sub-optimal. Converting specific sections of the underground feeders would not be feasible and would reduce the satisfaction of the affected customers.*

Rebuilding in backyard does not solve the clearance issue which is one of the motives of this project. In most cases, a spot pole replacement is equivalent to a like-for-like replacement and does not solve the accessibility issue for assets on customer premises. Undergrounding an existing overhead circuit is much more expensive and, therefore, not recommended.

Replacing the direct-buried cable with duct-embedded cable runs is the optimal trade-off between benefits and costs, providing the most benefits to EPL's customers. Rebuilding overhead lines in the right of way at the front of a property eases access for EPL staff resulting in safer work and creates less inconvenience for the customer in circumstances where EPL needs to access its equipment and results in faster restoration times.

2. Safety

Proper asset management of old and deteriorating equipment in the field mitigates safety concerns for EPL staff and customers. Accessing plant in backyards can also prove to be difficult and unsafe. All new construction meets the latest distribution standards for safety. Furthermore, the risk of a dig-in in the customer's backyard is mitigated.

3. Cyber-Security, Privacy

This program does not raise any cyber-security or privacy concerns.

4. Co-ordination, Interoperability

Coordination with entities such as HONI is critical to ensure consistency with joint-use agreements, ensure safety, and co-ordinate planned outages.

5. Economic Development

This program proactively addresses system reliability, which is conducive to economic development.

6. Environmental Benefits

There are no applicable environmental benefits as a result of these investments.

C. Category-Specific Requirements

Asset Performance-Related Targets

To monitor asset performance, EPL tracks the number of cable failures each year. This investment will help EPL reduce the number of cable failures each year. The replacement of direct-buried cables will maintain EPL's reliability performance, specifically with respect to the number of outages (SAIFI) and the time required to restore power (SAIDI). The conversion from rear lot to front service will also reduce the time required to restore power (SAIDI). For the years 2013 through 2016, defective equipment

outages accounted for the most customer-hours of interruption excluding loss of supply events; therefore, the investment will contribute to reducing defective equipment outages. EPL is specifically targeting to limit the number of primary cable failures cable failures to three or less (≤3) per year. A reliable supply of electricity supports customer satisfaction.

*EPL relies on a combination of Reliability-Centred Maintenance ("**RCM**"), predictive maintenance, preventative maintenance, and cyclical inspections to manage its distribution assets. Plant that is scheduled for replacement is generally at the end of its service life due to failure risk or requires replacement due to reliability and/or safety concerns.*

Condition of the Assets

Underground cable terminations (at pad-mounted equipment and riser poles) are inspected every three (3) years. Figure 3 presents the cable length by installation year. EPL uses a TUL of thirty (30) years for direct-buried cables and forty (40) years for cables in conduits, which is consistent with common industry practices for primary TR XLPE cables. Since 1986, all primary cables were installed in conduits; therefore, the significant amount of cable installed in 1990 and from 1994 to 1997 will reach their TUL beginning in 2030.

Figure 3: Installation year of primary underground cables

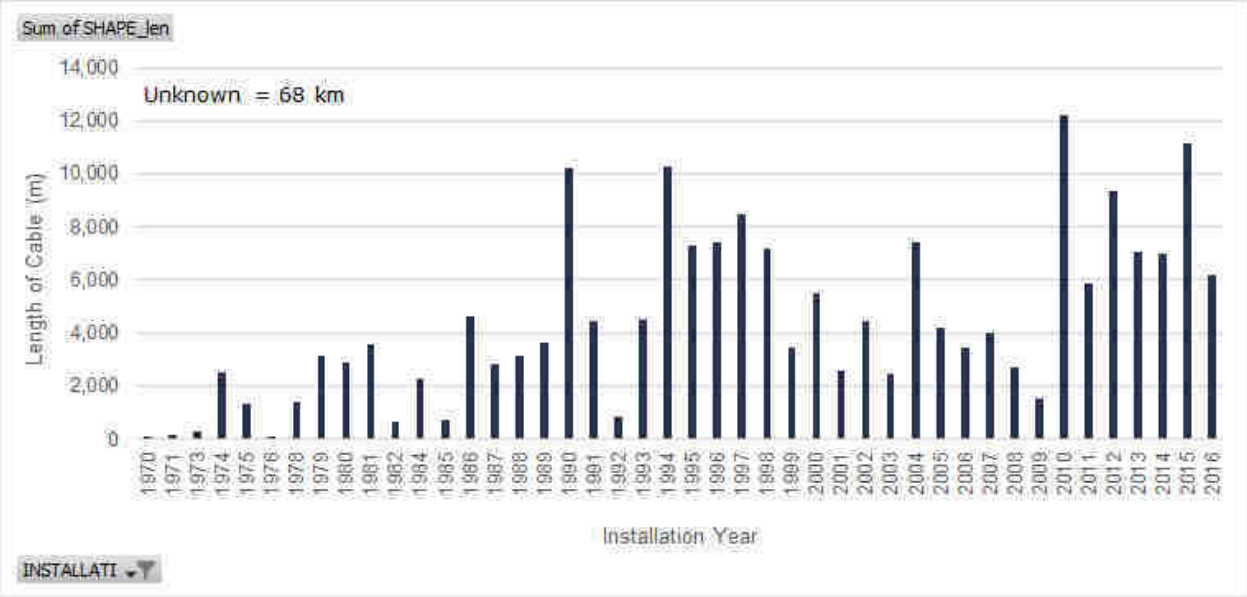
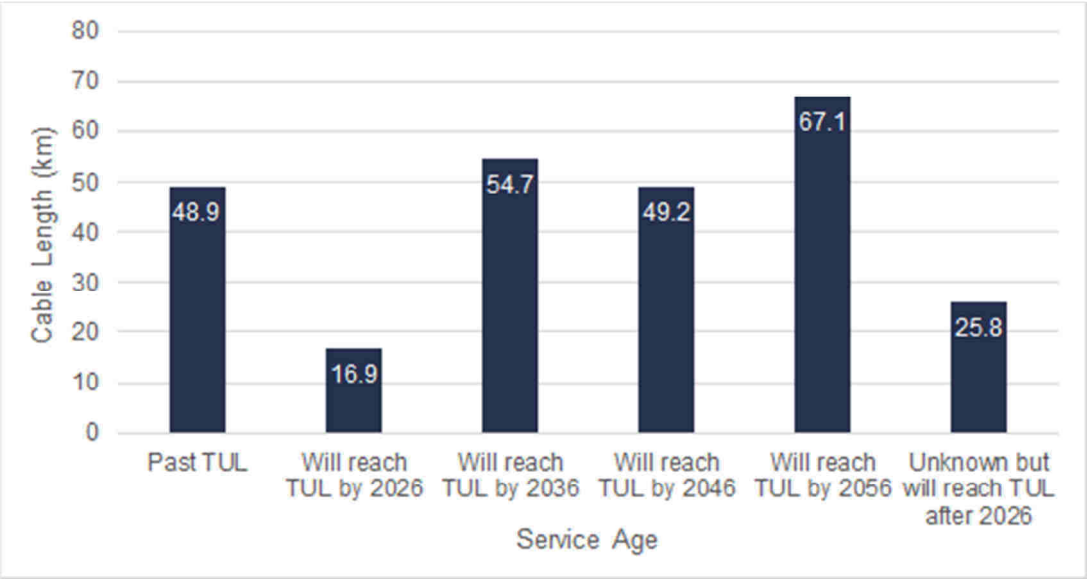


*Figure 4 depicts the age distribution of EPL's underground cables relative to TUL. A total of 48.9 km of cables are past their typical useful life ("**TUL**") and an additional 16.9 km will reach TUL by 2026. EPL will target the oldest direct-buried cables that have surpassed TUL.*

Figure 4: Age of cables relative to TUL



Overhead conductors and poles are inspected every three (3) years. Poles are also tested to assess their condition. 1 depicts the known age demographics for EPL's wood poles. The age demographics are unknown for the remaining 3197 wood poles. Figure 6 presents the results of the condition assessment for wood poles. EPL will target the worst condition poles.

Figure 5: System-wide age profile for wood poles

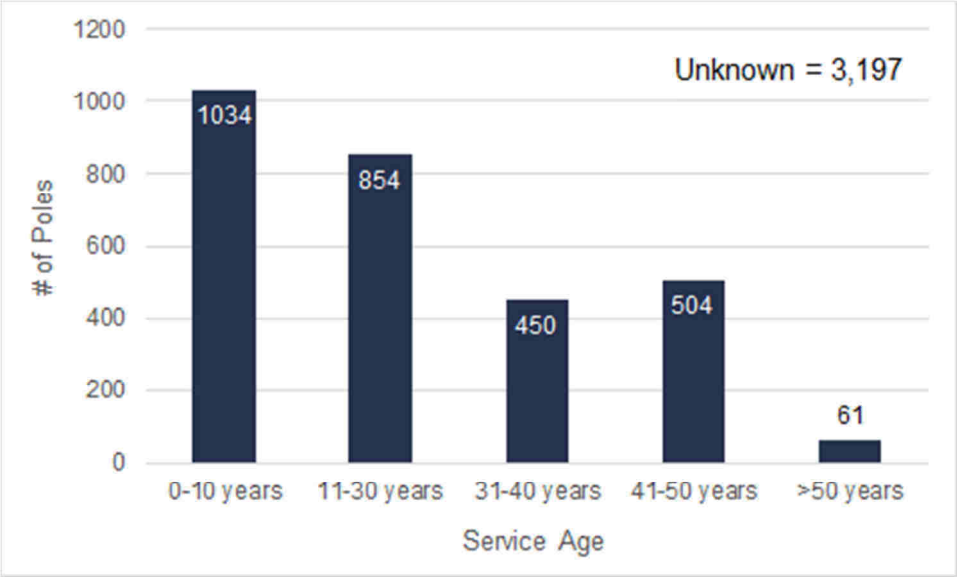
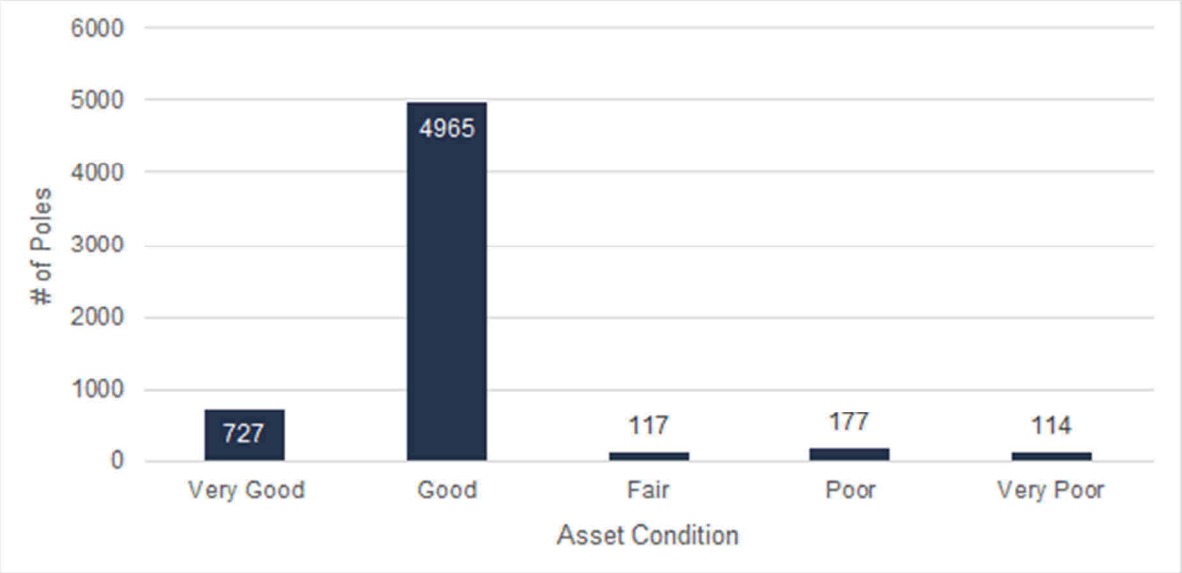


Figure 6: Condition assessment results for wood poles



Project Impacts

i. Number of Customers Affected: *Specific yearly values are not currently known; however, the number of customers is generally low.*

ii. Quantitative Customer Impacts: *Specific yearly values are not currently known; however, the length of outages can vary significantly from year to year.*

iii. Qualitative Customer Impacts: *Customers will receive value through faster response and restoration times.*

iv. Value of Customer Impact: *Customers will receive value through reduced unplanned outages, faster response times, less potential damage to customer property, and enhanced reliability.*

Project Timing Factors

The Infrastructure Rebuild Program timing is dependent on the urgency of the replacement as well as availability of resources. Safety or reliability-centered replacements are dealt with as quickly as possible, whereas scheduled replacements are accommodated when timing is optimal for EPL crews.

The timing of the investment is coordinated with other programs planned by EPL; therefore, the planned investment is less in 2019 compared to the other years due to the system service investments planned in that year. The timing of the investment is, therefore, also tied to external factors which may change the planned timing of system service investments and would also affect the timing of other investments planned by EPL.

Consequences for System O&M Cost

The Infrastructure Rebuild Program will help reduce customer outages and improve response times. There will be negligible impacts to system O&M costs.

Reliability / Safety Factors

Proper asset management of old and deteriorating equipment in the field mitigates safety concerns for EPL staff and customers. This program helps maintain system reliability.

Comparison of Project Timing Alternatives

There are limited alternatives to the Infrastructure Rebuild Program and the consequences of delaying replacements can result in significant reliability and safety concerns.

Analysis of Project Enhancements

A like-for-like replacement would restore rear lot service to customers, whereas the planned project installs duct-embedded or overhead front service. For a like-for-like replacement, customer requests to increase accessibility will not be met and accessing plant in backyards can also prove to be difficult, unsafe, and cost-ineffective since specialized equipment is oftentimes required in order to minimize customer inconvenience. This project will result in greater reliability for EPL's customers, lessen EPL's legal liability and exposure, and lead to enhanced safety for workers and the general population.

Switchgear Replacement Program

A. General Information on the Project/Activity

The purpose of this program is to replace live-front switchgear units that have failed or are at the end of their service life due failure risk. Through its thorough preventative maintenance program, EPL reviews the condition of all switchgear units continuously to limit failure and maximize safety via infrared and physical inspection. Budgeting is reviewed annually based on preventative maintenance program findings and availability of resources. EPL is planning to replace two (2) live-front switchgear per year.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Capital	$122.0	$63.6	$55.2	$135.2	$144.4	$147.3	$150.3	$153.3	$156.3	$79.7
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not applicable

Load
Not applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$36,830	$36,830	$36,830	$36,830
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

Risks are minimal for these projects as they represent standard industry practices. There is incremental risk in procurement however EPL is in regular communication with vendors to ensure customer value.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information. To date, EPL has been fairly consistent in spending and relating to planned investment.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Assets at the end of their service life due to failure risk.*

ii. Secondary Drivers: *The secondary drivers to this program include asset failure, safety, and reliability. Allowing old and deteriorating equipment in the field can result in significant safety and reliability concerns to EPL staff and customers.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, Safety, and Financial & Environmental Sustainability.*

iv. Information Used to Justify the Investment: *EPL's preventative maintenance program and recent failures are the metrics that EPL uses to justify these projects.*

b) Priority: *EPL prioritizes replacements based on recent failures and its preventative maintenance program. All capital projects have been prioritized and optimized based on Financial, Service Quality, Community Image, Legal, Regulatory, Safety and Environmental metrics.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked ninth (9th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *The alternative to replacing live-front switchgear units is to do nothing. In the case of a switchgear failure, this alternative is not feasible. Allowing old and deteriorating equipment in the field can result in significant safety concerns, lengthy customer outages, and resulting increases to O&M. Therefore, planned replacements are the preferred alternative.*

i. Cost Effectiveness: *EPL uses inspection and age data to cost-effectively plan live-front replacements. In general, it is more cost effective to proactively replace a switchgear unit rather than reactively, which may require emergency or overtime hours.*

ii. Net Customer Benefits: *Customers will benefit from reduced outages.*

iii. Impact on Reliability: *This program will replace live-front switchgear at the end of their service life before they fail and cause extended outages; hence, improving the reliability.*

iv. Cost-Benefit Analysis: *The Switchgear Replacement Program replaces assets that are at end of service life due to failure or failure risk as identified during the inspection process. This will improve reliability by reducing unplanned outages and will also reduce outage costs. Also, this program avoids future O&M costs as replacements can be scheduled during regular hours rather than relying on trouble calls, which take longer and can be overtime hours.*

In the case of the "do nothing" option, project benefits of eliminating risks to public and employee safety, maintaining system reliability, and avoiding future O&M (trouble calls) costs will not be achieved.

2. Safety

Proper asset management of old and deteriorating equipment in the field mitigates safety concerns to EPL staff and customers. All new construction meets the latest distribution standards for safety.

3. Cyber-Security, Privacy

Switchgear units can be controlled remotely and access to the units over SCADA is restricted to operators in EPL's office with log-in credentials.

4. Co-ordination, Interoperability

Co-ordination with entities such as HONI is critical to ensure consistency with joint-use agreements, manage switching, ensure safety, and when co-ordinate planned outages.

5. Economic Development

This program proactively addresses system reliability, which supports economic development.

6. Environmental Benefits

There are no significant environmental benefits as a result of these investments.

C. Category-Specific Requirements

Asset Performance-Related Targets

To monitor asset performance, EPL tracks the number of switchgear failures each year. This investment will help EPL reduce the number of switchgear failures each year and will maintain EPL's reliability performance, specifically with respect to the number of outages (SAIFI) and the time required to restore power (SAIDI) through availability of switching. For the years 2013 through 2016, defective equipment outages accounted for the most customer-hours of interruption excluding loss of supply events; therefore, the investment will contribute to reducing defective equipment outages. EPL specifically tracks the annual number of switchgear failures, with the goals of limiting them to two or less (≤2) per year. A reliable supply of electricity supports customer satisfaction.

*EPL relies on a combination of Reliability-Centred Maintenance ("**RCM**"), predictive maintenance, preventative maintenance, and cyclical inspections to manage its distribution assets. Plant that is scheduled for replacement is generally at the end of its service life due to failure risk or requires replacement due to reliability and/or safety concerns.*

Condition of Assets

EPL inspects its switchgear units on a three (3)-year cycle, including visual and infrared. Switchgear units are regularly maintained through adjustments and cleaning. Figure 7 depicts the age demographics of EPL's switchgear units and Figure 8 summarizes the results of the condition assessment.

Figure 7: System-wide age profile for PMH switchgear units

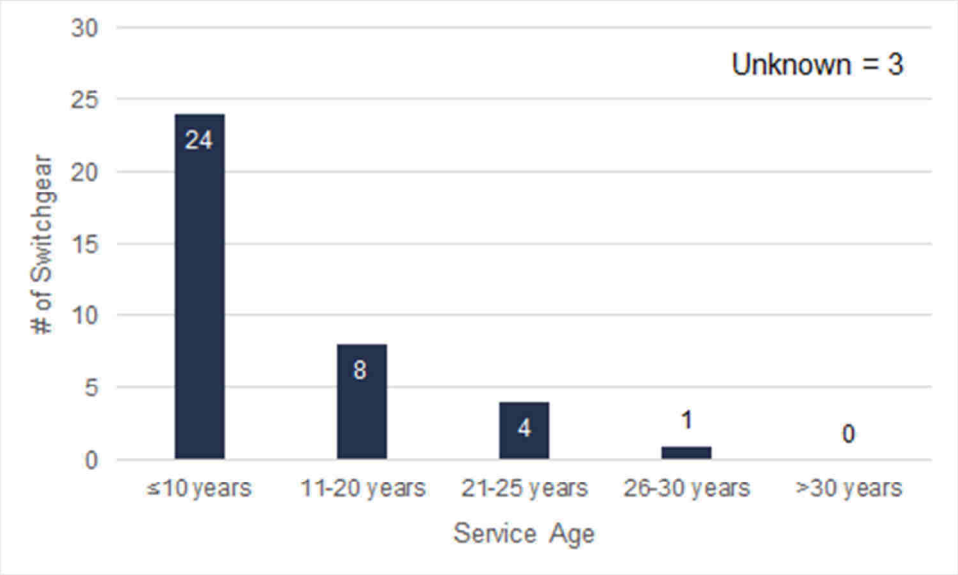
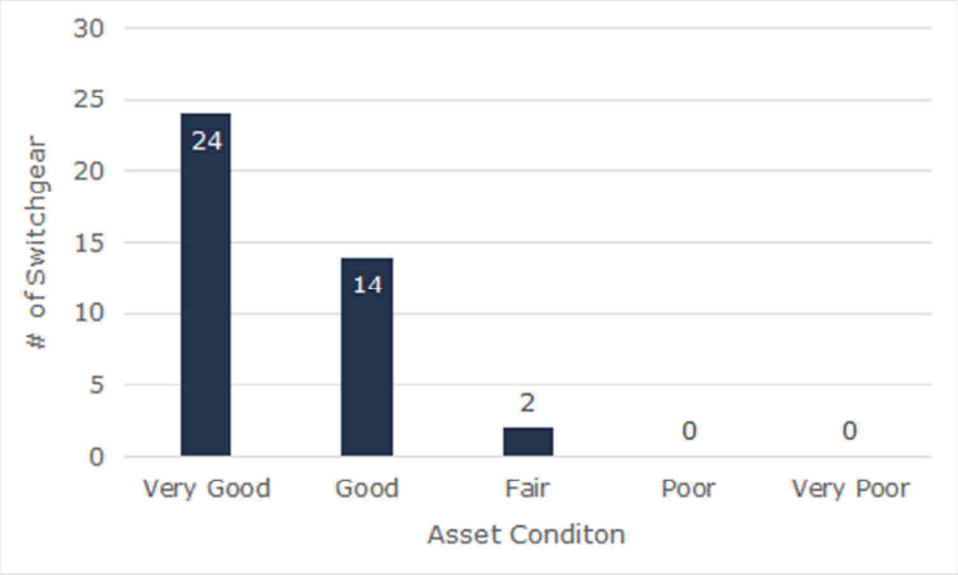


Figure 8: Condition assessment results for switchgear



Project Impacts

i. Number of Customers Affected: *Specific yearly values are not currently known; however, the number of customers can vary significantly from year to year.*

ii. Quantitative Customer Impacts: *Specific yearly values are not currently known; however, the length of outages can vary significantly from year to year.*

iii. Qualitative Customer Impacts: *Customers will receive value through reduced unplanned outages and enhanced reliability.*

iv. Value of Customer Impact: *Customers will receive value through reduced unplanned outages and enhanced reliability.*

Project Timing Factors

Switchgear replacement timing is dependent on the urgency of the replacement as well as availability of resources. Safety or reliability-centered replacements are dealt with as quickly as possible, whereas scheduled replacements are accommodated when timing is optimal for EPL crews.

Consequences for System O&M Cost

The PMH Replacement Program will help reduce system O&M costs over time through reductions in reactive maintenance spending.

Reliability / Safety Factors

Proper asset management of old and deteriorating equipment in the field mitigates safety and reliability concerns.

Comparison of Project Timing Alternatives

There are limited alternatives to the Switchgear Replacement Program and the consequences of delaying replacements can result in significant reliability and safety concerns.

Analysis of Project Enhancements

All new plant meets the latest distribution system standards. Remote access and control are both enabled on new switchgear units installed in the field.

HONI Asset Purchase - Leamington

A. General Information on the Project/Activity

The HONI Asset Purchase – Leamington project is an initiative to transfer assets between EPL and HONI so that each distributor controls assets within in geographical distribution service territory boundary. The estimated spend in 2018 is $278,307 and revenue from sale of assets to Hydro One is $188,833 for a net capital spend of $89,474. This constitutes:

1. *Purchase 5.9 km of poles, conductors, and insulators in locations where Hydro One does not have another feeder (i.e. 3M6 and 3M4) within EPL's service territory.*
2. *Sell 1.1 km of conductors and insulators (3M9 circuit).*
3. *Sell poles along the east side of an arterial road, on which EPL has no assets.*

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Capital	$0	$0	$0	$0	$0	$89.5	$283.9	$0	$0	$0
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
No incremental customer attachments

Load
No incremental load

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$22,369	$22,369	$22,369	$22,369
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

The primary risk with this project is the ongoing negotiation with HONI. There are transactions that go both ways and the fair market value of all assets considered will need to be agreed on by both parties.

Comparative Expenditure Information

This is a new project in 2018 and historical spending analysis is, therefore, not available.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *System operational objectives – operability.*

ii. Secondary Drivers: *System operational objectives – reliability.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, and Operational Excellence.*

iv. Information Used to Justify the Investment: *EPL used subject matter experts, good utility practice, and regulation as metrics to justify the investment.*

b) Priority: *EPL prioritizes asset transfers based on resource availability and in accordance with good utility practice and engineering. This is a mid/low priority project.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this project was ranked fifteenth (15th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *The alternative to this initiative would be to continue working closely with Hydro One to coordinate operation of the system for both preventative and reactive situations. Loss of Supply events has continued to become a larger portion of EPL's total customer outages.*

i. Cost Effectiveness: *Not applicable.*

ii. Net Customer Benefits: *EPLC customers will see an improvement to outage length and severity as Loss of Supply events are reduced through the implementation of this project. Ongoing implementation of this project will also see minor reduced OM&A costs over time as overtime and overall crew hours are reduced.*

iii. Impact on Reliability: *This project will lead to improved reliability as EPL strives to limit its exposure to Loss of Supply events. By gaining control of the assets serving its customers, EPL will have the ability to move loads between the feeders to quickly restore power to the customers.*

iv. Cost-Benefit Analysis: *Not applicable. Assets are selected based on location and proximity to EPL's service territory.*

2. Safety

EPL employees will see safety-related improvements as EPL staff will control the assets that serve its customers.

3. Cyber-Security, Privacy

This project does not raise any cyber-security or privacy concerns.

4. Co-ordination, Interoperability

EPL will continue discussing and negotiating the transaction with Hydro One. Following a successful transaction, EPL will have improved control of its own system. There are limited concerns with regards to interoperability.

5. Economic Development

One of the drivers of this project is reliability and a reliable supply of electricity is conducive to economic development.

6. Environmental Benefits

There are no significant environmental benefits achieved based on this project.

C. Category-Specific Requirements

Assessment of Benefits for Customers

EPL's customers will see an improvement to outage length and severity as Loss of Supply events are reduced through the implementation of this project.

Regional Electricity Infrastructure Requirements

This project did not result from a Regional Planning Process.

Incorporation of Advanced Technology

Since the investment entails a transfer of in-service assets, there will not be advanced technology incorporated.

Reliability, Safety, Efficiency and Coordination Benefits

EPL's employees will see safety-related improvements as EPL staff control the assets that serve its respective customers. This project will lead to improved reliability as EPL strives to limit its exposure to Loss of Supply events.

Timing/Priority Factors

Formal timelines are not yet established however it is believed that the transactions will take place over the course of 2018 and 2019.

Cost-Benefit Analysis

Not applicable.

FIT & Generation Connections

A. General Information on the Project/Activity

This project is to accommodate the connection of renewable energy generation to EPL's distribution system. This program includes FIT connections (10 kW up to 500 kW) and generation connections (greater than 500 kW), but does not include microFIT connections (less than 10 kW).

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Capital	$68.2	$13.6	$55.5	$63.1	$175.0	$167.2	$112.2	$114.4	$116.7	$119.0
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not applicable

Load
Not applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$41,801	$41,801	$41,801	$41,801
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

The primary risk with this project is whether or not the various generation projects planned by third parties proceed.

Comparative Expenditure Information

Historical spending is listed above. EPL is planning for two larger FIT connections in 2017/2018 which explain the increases in those respective years.

REG Investment Criteria

REG investments are planned and made in accordance with EPL's Green Energy Act Plan. The anticipated connections and expansion costs in 2018 are listed below.

Type	Nameplate Capacity (kW)	Renewable Expansion Cost
Solar Rooftop	200	$25,000
Solar Rooftop	200	$0
Solar Rooftop	200	$25,000
Solar Rooftop	500	$30,000
Solar Rooftop 5X250	1250	$30,000

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Customer-driven generation connection requests.*

ii. Secondary Drivers: *Not applicable.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, and Financial & Environmental Sustainability.*

iv. Information Used to Justify the Investment: *FIT & generation connections are driven by customer/developer request and are to be connected within OEB mandated timelines.*

b) Priority: *FIT & Generation connections are made based on customer/developer request. This process is managed by EPL staff through various systems to ensure proper visibility and timeliness. New FIT & Generation Connections are a high priority for EPL as they are linked directly with the customers that we serve.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked seventh (7th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *These investments are mandated by the OEB. Expansion options are evaluated to determine the least-cost solution while ensuring that a connection does not materially and/or negatively impact existing customers. Options which may exist to improve the system are also evaluated, where applicable.*

i. Cost Effectiveness: *EPL evaluates renewable expansion options to determine the least-cost option.*

ii. Net Customer Benefits: *Customers benefit from the ability to connect renewable energy generators to the grid to provide power.*

iii. Impact on Reliability: *Expansion options are evaluated to ensure that the connection does not materially and/or negatively impact existing customers.*

iv. Cost-Benefit Analysis: *EPL evaluates renewable expansion options to determine the least-cost option.*

2. Safety

These investments do not impact safety or raise safety-related awareness. EPL is, however, continuing to update its protocols and procedures as its distribution system evolves into a smarter grid.

3. Cyber-Security, Privacy

This program does not raise any cyber-security or privacy concerns.

4. Co-ordination, Interoperability

EPL coordinates directly with customers, contractors, developers, and other agencies such as ESA. EPL also coordinates with HONI on a regular basis to discuss connection constraint on specific feeders and possible solutions.

5. Economic Development

The connection of REG supports economic development in Ontario through the installation and commissioning work required at the facilities.

6. Environmental Benefits

REG is a provincially-mandated program intended to offset emissions from natural gas burning energy sources in Ontario.

C. Category-Specific Requirements

Assessment of Benefits for Customers

These investments are mandated by the OEB. Developers, who may also be customers, benefit from the connection facilitating the ability to sell power to the grid. EPL's customers benefit from distribution-connected REG facilities relieving capacity on its feeders. EPL's customers and, in general, Ontario residents benefit from energy generated from emission-free renewable sources.

Regional Electricity Infrastructure Requirements

This program is not a result of a Regional Planning Process. Information related to this planned investment was provided to the IESO.

Incorporation of Advanced Technology

Not applicable.

Reliability, Safety, Efficiency, and Coordination Benefits

These investments are mandated by the OEB and are intended to support a provincial objective to reduce greenhouse gases and ensure a sustainable energy future.

Timing/Priority Factors

The timing of projects within these programs depend on initiation by REG developers. EPL has forecast the number of anticipated connections in its GEA Plan based on the interconnection status of each applications being processed and projected applications to be received. Formal timelines for each connection are prescribed by the OEB.

Cost-Benefit Analysis

Expansion options are evaluated to determine the least-cost solution while ensuring that a connection does not materially and/or negatively impact existing customers. Options which may exist to improve the system are also evaluated, where applicable. Alternatives include not connecting the generator (which is non-compliant from a regulatory perspective), or other less cost-effective measures.

Self-Healing Grid - Reclosers

A. General Information on the Project/Activity

In 2014, EPL completed its first iteration of its Green Energy Act Plan and subsequently a Smart Grid Development Plan. In this plan, EPL outlined its plan to shift to a smarter grid that is capable of reducing the impact of Loss of Supply incidents to customers by investing in three primary categories. Reclosers represent one of these three categories. The reclosers will be installed as tie switches in multiple locations to facilitate automatic switching and service restoration in case of a Loss of Supply event.

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

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$0	$0	$0	$0	$264.8	$270.1	$275.5	$281.1	$286.7	$292.4
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
No incremental customer attachments

Load
No incremental load

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$67,535	$67,535	$67,535	$67,535
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

As EPL works towards implementing a variety of smart grid related initiatives, it is continuously updating its operating procedures and protocols to ensure staff safety. The automation of switches and reclosers throughout its distribution system introduces new and complex issues to be resolved by EPL and the industry in general.

Since this program is beginning in 2017, there are risks to its cost and execution, which are not well-known. To mitigate these risks, EPL works closely with third-party vendors and subject matter experts to ensure project within this program are completed on time and on budget.

Comparative Expenditure Information

This is a new project in 2017 and historical spending analysis is, therefore, not available.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *System operational objectives – reliability*

ii. Secondary Drivers: *Safety and cost effectiveness.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value and Operational Excellence.*

iv. Information Used to Justify the Investment: *EPL used subject matter experts, third-party vendors, good utility practice and regulation as metrics to justify the investment.*

b) Priority: *Reclosers are installed to isolate EPL from upstream Loss of Supply events and improve system reliability, which is a priority for EPL. These projects are medium/high in terms of priority and they fall behind only mandated regulated capital activities. Individual installations would occur as timing allows, prioritized based on resource availability and in accordance with the proper safety protocols.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked eleventh (11th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *The alternative to this initiative would be to continue working closely with Hydro One to coordinate outages to limit and minimize response times, outage frequency, outage severity and outage length. Loss of Supply events has continued to become a larger portion of EPL total customer outages.*

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

The reclosers are also able to provide system information to SmartMAP. A recloser action can trigger outage determination in SmartMAP to quickly identify an outage. Momentary outages caused by the reclosers can also be tracked in SmartMAP, contributing to the accuracy of CELDI and CEMI outage statistics. The data will also increase knowledge about power flow within the system, aiding in

operations and engineering decisions because voltage and current data will be stored and historical trends can be evaluated. In the event of an outage, SmartMAP has the ability to look at historical data supplied by all of its data sources and determine whether or not it is possible to do a short-term load transfer to restore power. This will greatly aid in moving towards a self-healing grid, because having switches which can be triggered remotely and knowledge about whether or not the switches can be operated safely is crucial to making the decision to operate the switch to restore power.

i. Cost Effectiveness: *Ongoing implementation of this project will reduce O&M costs as overtime and overall crew hours are reduced. Auto-reclosing after a temporary fault will restore power without sending a crew.*

ii. Net Customer Benefits: *EPL customers will see a significant improvement to outage length and severity as Loss of Supply events are reduced through the implementation of this project. The improved cost effectiveness will improve customer value by reducing O&M costs and allowing EPL to deliver a modern smart grid at inflation-aligned prices.*

iii. Impact on Reliability: *This project will have a significant impact on reliability as EPL strives to limit its exposure to Loss of Supply events. The project is expected to improve SAIDI and SAIFI performance.*

iv. Cost-Benefit Analysis: *No detailed analysis of benefits and costs was performed.*

2. Safety

As EPL works towards implementing a variety of smart grid related initiatives, it is continuously updating its operating procedures and protocols to ensure staff safety. The automation of switches and reclosers throughout its distribution system introduces new and complex issues to be resolved by EPL and the industry in general. The timing curves of the reclosers will reduce the exposure to fault energy in the event of a contact. Reclosers will be installed as per up to date installation standards, and on poles that meet current standards ensuring that the highest levels of worker and public safety are met. The reclosers include safety features such as hold-off tags that prevent remote/automatic operation when manual work is being performed. Where installations require the placement of new poles or hardware, the new assets will also be up to current safety standards.

3. Cyber-Security, Privacy

EPL will ensure that all equipment and software deployed using best industry related practice. The improvements will be made in conjunction with major cyber-security upgrades underway in 2017.

4. Co-ordination, Interoperability

Discussions with Hydro One are ongoing as smart grid initiatives are implemented that affect equipment from both distributors. The automation of these devices will require constant communication with Hydro One and it is expected that improved reliability will result. Several meetings have already taken place and, as additional switches are integrated and commissioned, several more will be required. There is substantial work on HONI's end to update their systems, processes, and protocols to accommodate the request.

5. Economic Development

The main driver of this project is reliability and a reliable supply of electricity is conducive to economic development.

6. Environmental Benefits

The recloser installations – as part of a self-healing grid – will reduce the number of truck-rolls required to respond to trouble calls; firstly, by automatically isolating the fault and restoring service and, secondly, by auto-reclosing to clear temporary faults. The net environmental benefit is less emissions.

C. Category-Specific Requirements

Assessment of Benefits for Customers

EPL's customers will see a significant improvement to outage length and severity as Loss of Supply events are reduced through the implementation of this project. Ongoing implementation of this project will reduce O&M costs time as overtime and overall crew hours are reduced.

Regional Electricity Infrastructure Requirements

This program was not a result of a Regional Planning Process.

Incorporation of Advanced Technology

Historically, EPL's service territory consisted solely of manual load break switches which required manual operation and provided no fault protection. Fault protection was provided by a station breaker or an upstream recloser outside of EPL service territory. With the implementation of smart reclosers, EPL is facilitating the capabilities of remote operation, real-time outage detection as well as the ability to isolate itself from an upstream distributor/transmitter.

Reliability, Safety, Efficiency and Coordination Benefits

This project will have a significant impact on reliability as EPL strives to limit its exposure to Loss of Supply events.

Timing/Priority Factors

Reclosers are planned to be installed throughout 2017-2022 in each of the four distinct service territories.

Detailed Analysis by Feeder

Single line diagrams depicting the proposed locations of the reclosers are attached to accompany the analysis provided below for each feeder.

Tecumseh

56M26: This feeder is located in the Tecumseh service area and has an interconnected distribution network with normally-open interconnection points. The 56M26 has had a consistently-high SAIDI. EPL owns all of the distribution lines on this feeder within the territory allowing the addition of distribution automation equipment to be placed where it is most effective without ownership restrictions. The approximate locations of three (3) recommended reclosers, five (5) normally-open smart switches, and five (5) line monitors have been marked on the single line of Tecumseh (attached).

56M4: This feeder is located in the Tecumseh service area and has an interconnected distribution network with normally-open interconnection points. The 56M4 feeder has low SAIDI and the recommended switching adding a recloser, a normally-open smart switch, and one (1) line monitor.

56M25: This feeder is located in the Tecumseh service area and has an interconnected distribution network with normally-open interconnection points. The 56M25 feeder has had an average SAIDI. EPL owns all of the distribution lines on this feeder within the territory allowing the addition of distribution automation equipment to be placed where it is most effective without ownership restrictions. The approximate locations of four (4) recommended reclosers, three (3) normally-open smart switches, and two (2) line monitors have been marked on the single line of Tecumseh (attached).

Leamington

3M6: This feeder is located in the Leamington service area with a radial distribution network and normally-open interconnection points. The 3M6 feeder has had the highest SAIDI with most customer outage hours and a drastic increase over the last two (2) years. HONI owns most of the main feeder running through the service area with EPL owning the lines branching off. This makes it more difficult to add automated switching/reclosers to sectionalize areas. If possible, it would be most beneficial if EPL could install equipment on HONI-owned lines in EPL's service territory, but this would first have to be arranged with HONI. With this challenge, there are not a lot of recommended additions on this feeder even though it has had a high SAIDI index. The approximate location of three (3) recommended reclosers, two (2) normally-open smart switches, and four (4) line monitors have been marked on the single line of Leamington (attached).

3M4: This feeder is located in the Leamington service area with a radial distribution network and normally-open interconnection points. The 3M4 feeder has a low SAIDI and the only switching added would be five (5) normally-open smart switches proposed in the other feeders, and two (2) line monitors.

3M8: This feeder is located in the Leamington service area with a radial distribution network and normally-open interconnection points. The 3M8 feeder has a SAIDI that is a little high but the highest year, 2010, was due in large part to a tornado. The approximate locations of two (2) recommended reclosers, three (3) normally open smart switches, and two (2) line monitors have been marked on the single line of Leamington (attached).

LaSalle and Amherstburg

23M3: This feeder is located in the Amherstburg service area with a radial distribution network and normally-open interconnection points. The 23M3 feeder has had a SAIDI higher than desired. EPL owns all of the distribution lines on this feeder within the territory making the addition of distribution automation equipment to be placed where it is most effective without restrictions. The recommended additions of two (2) reclosers, four (4) normally open smart switches, and four (4) line monitors are located on the single line of LaSalle and Amherstburg (attached).

23M4: This feeder is located in the LaSalle service area with a radial distribution network and normally-open interconnection points. The 23M4 feeder has a low SAIDI index, but EPL would like to allow for sectionalizing faulted sections by adding switching to the start of the service territory and after the area with the most outages. One (1) recloser, three (3) normally-open smart switches, and two (2) line monitors will be placed as shown in the single line for LaSalle and Amherstburg (attached).

23M5: This feeder is located in the LaSalle and Amherstburg service areas with a radial distribution network and normally-open interconnection points. The 23M5 feeder has a low SAIDI, so two (2) reclosers will be installed, three (3) normally-open smart switches, and three (3) line monitors will be added as indicated in the single line for LaSalle and Amherstburg (attached).

24M7: This feeder is located in the LaSalle and Amherstburg service areas with a radial distribution network and normally open interconnection points. The 24M7 feeder has had a decreasing SAIDI over the last few years and most of the outage time came from the Amherstburg service area. HONI owns most of the main feeder running through the Amherstburg with EPL owning the lines branching off. Two (2) reclosers, two (2) normally-open smart switches, and four (4) line monitors are located on the single line for LaSalle and Amherstburg (attached).

24M9: This feeder is located in the LaSalle service area with a radial distribution network and normally-open interconnection points. The 24M9 feeder has had an increasing SAIDI over the past few years. HONI owns a portion of the main feeder running through the service area with EPL owning the lines branching off. This makes it more difficult to add automated switching/reclosers to sectionalize areas. The addition of one (1) recloser, one (1) normally-open smart switch, and two (2) line monitors are located on the single line for LaSalle and Amherstburg (attached).

24M10: This feeder is located in the LaSalle service area with a radial distribution network and normally-open interconnection points. The 24M10 feeder has a low SAIDI and the only recommended switching is one (1) recloser.

Figure 9: Single line diagram of Tecumseh depicting proposed recloser locations

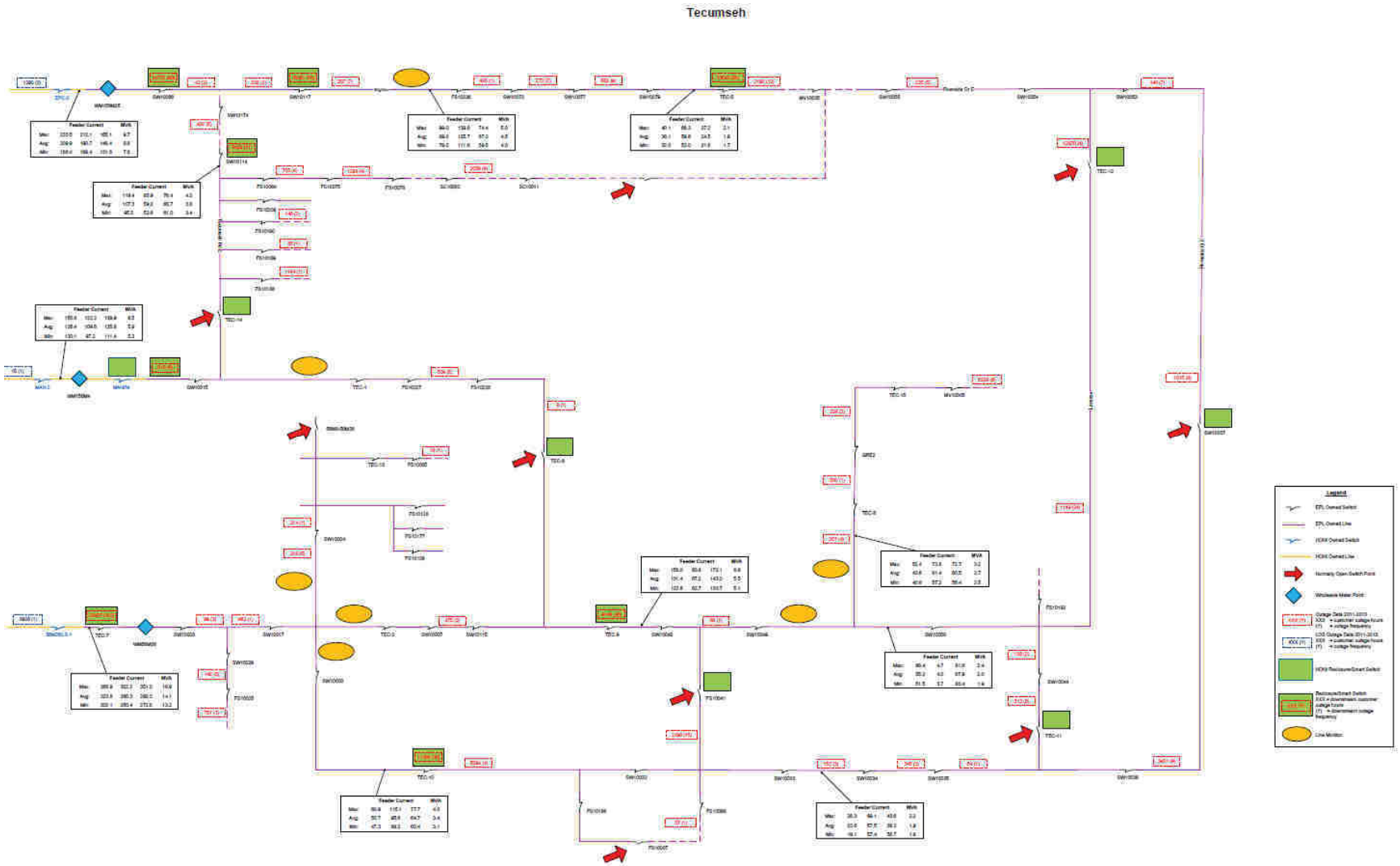


Figure 10: Single line diagram of Leamington depicting proposed recloser locations

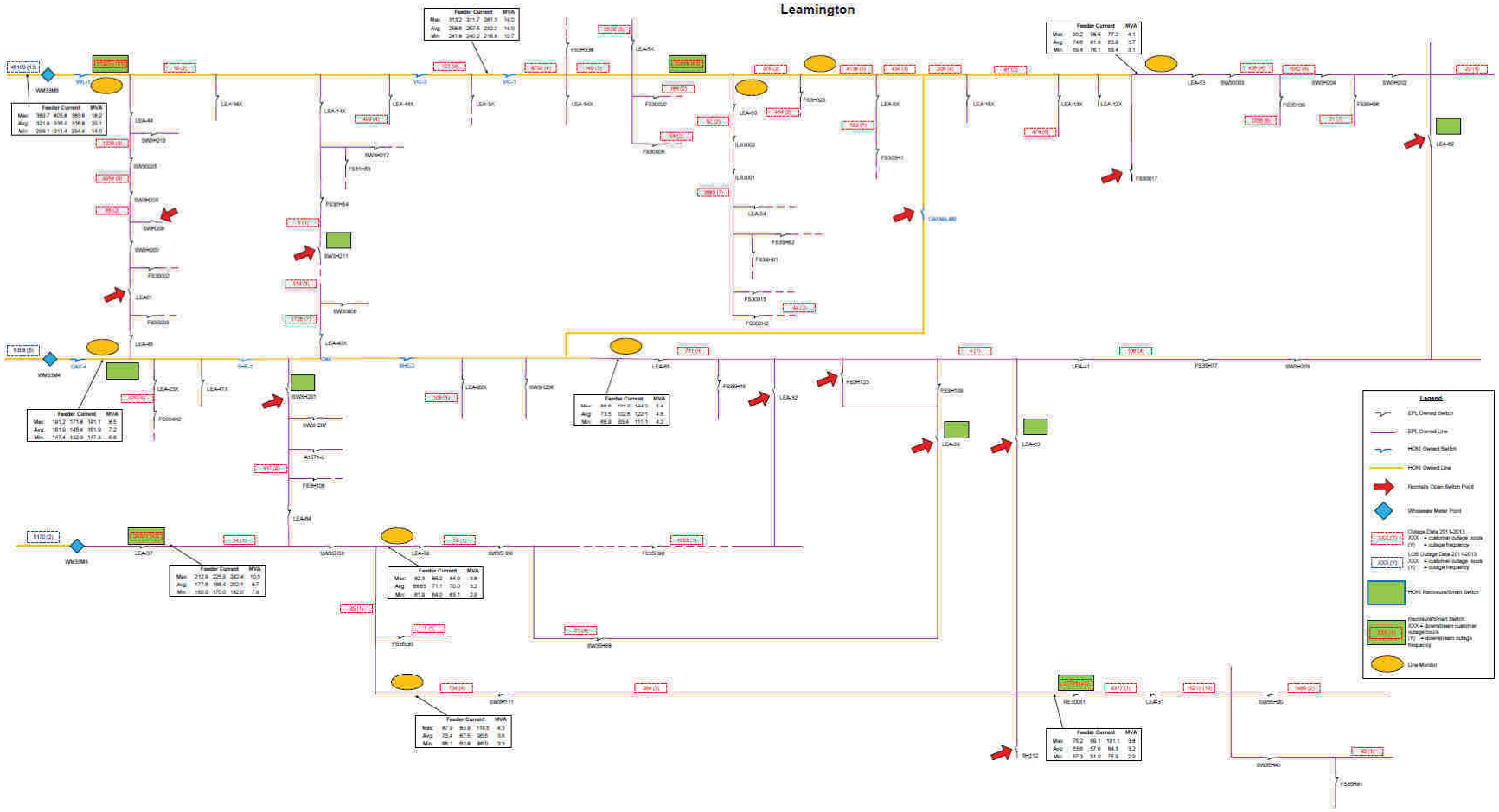
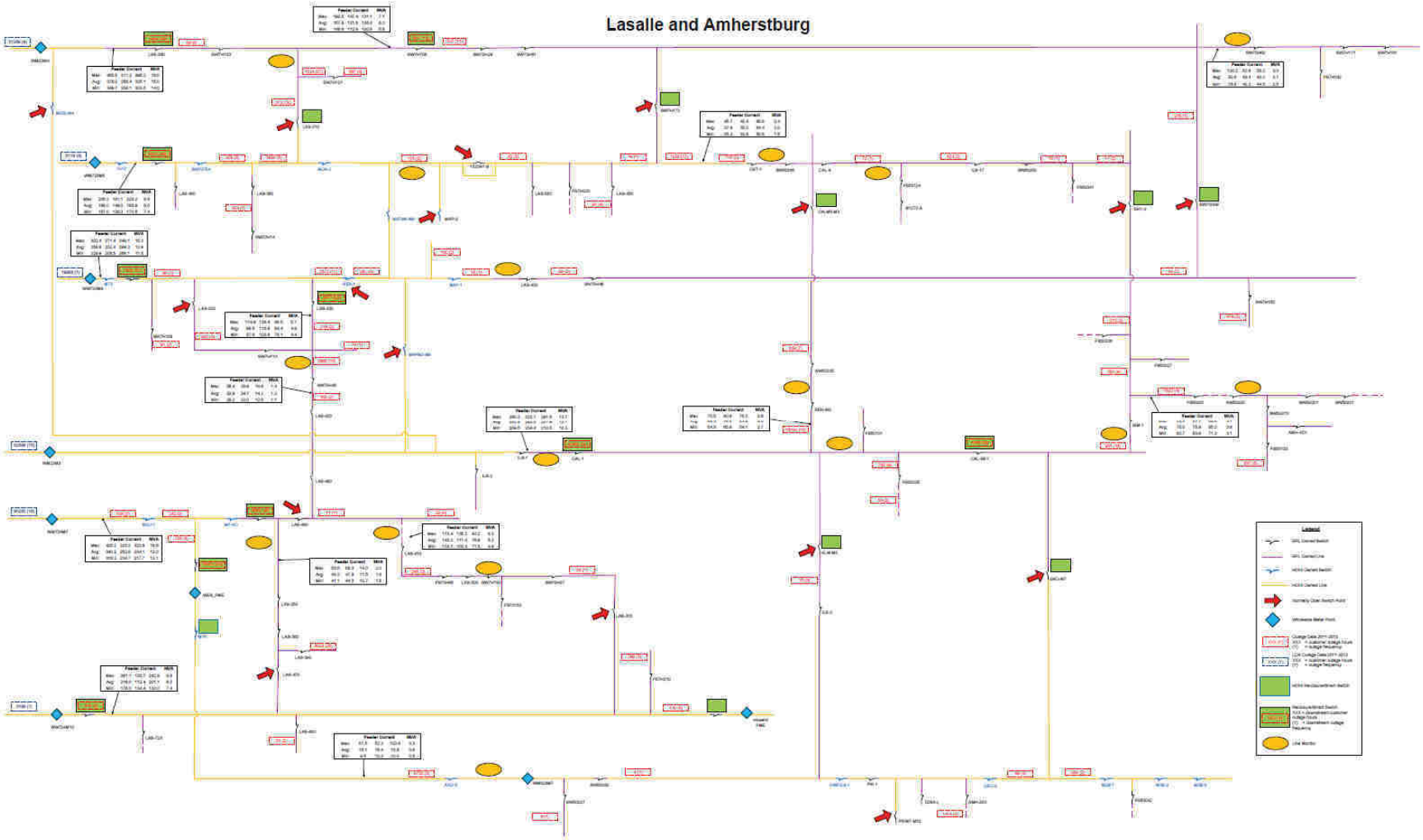


Figure 11: Single line diagram of LaSalle and Amherstburg depicting proposed recloser locations



Building & Fixtures

A. General Information on the Project/Activity

The Building Condition Review, completed in 2016 and attached as Appendix H of the DSP, outlined and recommended several major projects to be completed over the next several years. EPL has spread the investment over multiple years to reduce the rate impact.

The planned work in 2018 includes the construction of a new storage facility for fleet and some supplies. The existing facility is not designed for the number of vehicles currently accommodated and backing vehicles in and out is problematic and an identified safety issue. A smaller, non-heated garage is proposed to store some larger vehicles, while the existing garage will continue to be used for the remainder of the vehicles.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$22.0	$0.0	$48.9	$42.5	$286.8	$370.0	$350.0	$350.0	$250.0	$250.0
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not applicable

Load
Not applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$92,500	$92,500	$92,500	$92,500
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

There is limited risk/exposure for this project.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information. Historical spending relates to minor improvements to the existing improvements. Planned work in 2018 and 2019 includes re-paving the parking lot; phased over two (2) years. Planned work in 2021 includes replacement of end-of-life HVAC units.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Non-system physical plant.*

ii. Secondary Drivers: *Not applicable.*

iii. Related Objectives: *This project supports EPL's Core Values of Operational Excellence and Employee Satisfaction.*

iv. Information Used to Justify the Investment: *EPL used subject matter experts, third-party vendors, good utility practice, and regulation as metrics to justify the investment.*

b) Priority: *This project represents a lower priority project however EPL requires additional garage space in the near future or risks the integrity of its existing fleet and inventory. This project is lower priority than distribution system projects (system access, system renewal, and system service) planned in the 2018 Test Year.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked nineteenth (19th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *Failure to properly house and maintain EPL's fleet and miscellaneous equipment/inventory will result in increased maintenance costs and OM&A, as well as faster asset degradation. An alternative would include housing EPL fleet and inventory at a third-party offsite garage; however, this alternative introduces a variety of other risks and liabilities.*

i. Cost Effectiveness: *Not applicable.*

ii. Net Customer Benefits: *This project supplies space to house and maintain EPL's fleet of vehicles. Properly-stored vehicles are protected from the elements and last longer; therefore, customers benefit from the rate impact.*

iii. Impact on Reliability: *Better maintained fleet and equipment can result in longer asset lives as well as enhanced performance resulting in improved reliability.*

2. Safety

Backing vehicles in and out of existing garage is currently creating safety concerns as a result of site limitations. The proposed new garage will eliminate this safety concern.

3. Cyber-Security, Privacy

Not applicable.

4. Co-ordination, Interoperability

Not applicable.

5. Economic Development

Not applicable.

6. Environmental Benefits

Not applicable.

C. Category-specific Requirements

Results of Quantitative and Qualitative Analyses

The existing garage is too small to properly house fleet and perform required maintenance. There is very limited risk associated with not doing this project. See Appendix H of the DSP – Building Condition Review – for detailed analysis.

Business Case Justification

See Appendix H of the DSP – Building Condition Review – for detailed analysis.

Computer Software

A. General Information on the Project/Activity

*EPL strives to continuously improve its interactions with customers and overall customer service. Throughout 2018, EPL plans to upgrade its website, Work Management Systems, service order processes, upgrade its Geo-Spatial Information System ("**GIS**"), and implement utility dashboards for greater management visibility throughout its core business.*

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$53.0	$167.0	$17.0	$4.6	$254.5	$115.0	$80.0	$80.0	$80.0	$80.0
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not applicable

Load
Not applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$28,750	$28,750	$28,750	$28,750
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

EPL's primary computer software risk revolves around service interruption. EPL plans to mitigate potential service related outages by implementing contingency plans and parallel systems, where possible, as well as cost-effective solutions.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information. Note that actual costs can vary dramatically from year to year based on the expected number of system upgrades or new systems purchased. Historical spending was allocated to SmartMAP, GIS upgrades, and the Work Management System.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Business operations efficiency.*

ii. Secondary Drivers: *Not applicable.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence, and Financial & Environmental Sustainability.*

iv. Information Used to Justify the Investment: *EPL utilized subject matter experts, third-party vendors, good utility practice, and regulation as metrics to justify the investment.*

b) Priority: *Having up-to-date software and technologies promotes efficiency and reliability of information across EPL's various departments. Failure to make these investments over time will result in EPL failure to meet its various regulatory and customer satisfaction levels. This is a medium-priority project, as it is partly customer-driven.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked fourteenth (14th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *Failure to maintain, upgrade and embrace new technologies can ultimately lead to potential system failures, productivity decreases, poor customer service and lost data. EPL evaluates alternative products and vendors on a regular basis to ensure the best and most cost-effective solution is selected based on prescribed needs.*

i. Cost Effectiveness: *Enhanced work management, service order, and GIS will improve workflow and enhance decision-making by increasing available information and thereby helping EPL optimize available resources.*

ii. Net Customer Benefits: *Upgrades to the GIS will provide more accurate information being available to EPL staff, which can help with decision-making and can lead to reduced outage times as well as faster response times. Customer service will be improved.*

iii. Impact on Reliability: *The accuracy of field data recorded in SmartMAP and the GIS directly affects the ability of field crews to safely and quickly perform work on the distribution system. Upgrades to the Work Management Systems will improve tracking Service Quality Indicators, thus improving the quality of data reported. Improved data quality will allow EPL to design projects that address specific types of outages identified.*

2. Safety

Safety is not a major driver for this project.

3. Cyber-Security, Privacy

EPL will ensure that all equipment and software deployed using best industry related practice. This project will be completed in conjunction with ongoing cyber-security upgrades underway in 2017.

4. Co-ordination, Interoperability

There is no material impact to the program as it results to coordination/interoperability.

5. Economic Development

Not applicable.

6. Environmental Benefits

Not applicable.

C. Category-Specific Requirements

Results of Quantitative and Qualitative Analyses

EPL's goal is to maintain the most up to date or most cost-effective software necessary to meet its obligations to customers and relevant regulation and ensure maximized employee efficiency.

Business Case Justification

Alternative options to the planned project include "do nothing", which will cause many of systems to become unsupported by the vendor/supplier and, thus, posing intolerable risk to customer service, and purchasing difference software, which is cost prohibitive.

Transportation Equipment

A. General Information on the Project/Activity

EPL plans to replace three (3) on-call trucks and a wood chipper. Two (2) trucks (i.e. Ford F350 or equivalent) are budgeted at $95,000 each and a third truck at $50,000 (i.e. Ford F150 or equivalent). The wood chipper replacement is budgeted at $30,000. Existing trucks are nearing end-of-life and require substantial maintenance in accordance with EPL's Fleet Purchasing Policy. Details are provided in EPL's Fleet Purchasing Policy, attached as Appendix I of the DSP.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$307.5	$248.4	$401.2	$136.7	$487.0	$270.0	$275.0	$395.0	$445.0	$560.0
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not applicable

Load
Not applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$67,500	$67,500	$67,500	$67,500
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

There is limited risk/exposure for this project.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information. Note that actual costs can vary dramatically from year to year based on fleet investment requirements.

*Investments in 2013 included replacement of a radial boom derrick ("**RBD**") (unit 710 in the Fleet Purchasing Policy replaced with unit 110), the purchase of a landscape trailer, and the purchase of unit 73 (metering van for sub-foreperson).*

Investments in 2014 included replacement of a medium-duty dump truck (unit 711 with unit 112), replacement of a bucket unit with a material handler (unit 75 with unit 111), replacement of a forklift with a larger forklift, and replacement of a front-loader with a case tractor equipped with a bucket and scraper.

Expenditures were made in 2015 to replace an RBD (unit 358 with unit 113).

Investments in 2016 included replacement of unit 62 with unit 76 (Supervisor unit) and replacement of units 63 and 64 with units 74 and 75 (metering vans).

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Non-system equipment at the end of its service due to failure, failure risk, or substandard performance.*

ii. Secondary Drivers: *Not applicable.*

iii. Related Objectives: *This project supports EPL's Core Values of Operational Excellence, Safety, and Employee Satisfaction.*

iv. Information Used to Justify the Investment: *The investment is justified based on EPL's Fleet Management Policy, which considers the age and mileage for all gas-power vehicles (less than 4500 kg).*

b) Priority: *Delay of this project will result in increased OM&A costs and could moderately affect operational effectiveness. This project is a low-mid range priority relative to other material projets/programs planned in the 2018 Test Year.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked seventeenth (17th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *Project alternatives include continuous maintenance; however, this option will drive OM&A costs up over time as well as put EPL staff and customers at risk of mechanical breakdown due to aging equipment which could have impacts on reliability, employee safety, and overall customer satisfaction.*

i. Cost Effectiveness: *This investment will ensure that EPL staff are able to effectively perform their duties in the field and perform routine and reactive maintenance and system-related expansions.*

ii. Net Customer Benefits: *Customers will receive enhanced operational effectiveness as EPL staff will have access to better equipment.*

iii. Impact on Reliability: *The availability of vehicles to ensure the necessary reactive and proactive work is completed supports reliability on the system.*

2. Safety

Newer vehicles include enhanced safety features (i.e. backup camera) as well as less risk associated with older vehicles that have general wear and tear incurred over time and substantial usage.

3. Cyber-Security, Privacy

Not applicable.

4. Co-ordination, Interoperability

Not applicable.

5. Economic Development

The purchasing of vehicles supports economic development in other sectors of the economy.

6. Environmental Benefits

This program replaces older vehicles, which have substandard performance with respect to efficiency and emissions, with new vehicles, which meet the latest emissions and energy efficiency standards.

C. Category-Specific Requirements

Results of Quantitative and Qualitative Analyses

The three (3) trucks to be replaced are all 2006 pickups.

Business Case Justification

Investments in this program are made relative to EPL's Fleet Purchasing Policy, which is attached as Appendix I to the DSP.

Tools & Equipment

A. General Information on the Project/Activity

The purpose of this yearly project is to replace major tools and equipment that has reached end-of-life due to substandard performance and functional obsolescence. Equipment purchased includes, but is not limited to, equipment for troubleshooting, rubber goods, radio equipment, etc. Equipment is purchased on an as-needed basis depending on the type of work required.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$43.4	$45.5	$55.5	$45.8	$60.0	$60.0	$60.0	$60.0	$60.0	$60.0
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date
January 1st, 2018

In-Service Date
December 31st, 2018

Customer Attachments
Not applicable

Load
Not applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$15,000	$15,000	$15,000	$15,000
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

Tools and equipment purchases are prioritized based on an as-needed basis as determined by the Manager of Operations with input from the Line Supervisor and other EPL staff.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information. Historical spending for this project is fairly consistent over time and no major changes are planned in the near future.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Non-system equipment at the end of its service life due to substandard performance or functional obsolescence.*

ii. Secondary Drivers: *Not applicable.*

iii. Related Objectives: *This project supports EPL's Core Values of Operational Excellence and Safety.*

iv. Information Used to Justify the Investment: *EPC used subject matter experts, third-party vendors, good utility practice, and regulation as metrics to justify the investment.*

b) Priority: *Purchases for Tools and Equipment are completed on an as needed basis. Continual investment is required to ensure compliance and that EPL staff is adequately equipped to maintain its distribution system. Tools and equipment are required to perform routine maintenance on the distribution system.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked eighteenth (18th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *EPL management evaluates, on a case-by-case basis, three (3) primary alternative scenarios when it pertains to Tools and Equipment: Do Not Replace, Like for Like Replacement, or Upgrade. EPL management evaluates each of these scenarios for each Tools and Equipment investment based on information from subject matter experts, third-party vendors, good utility practice, and regulation.*

i. Cost Effectiveness: *Access to the appropriate Tools and Equipment allows EPL staff to maximize workmanship and task completion resulting in shorter task completion timelines.*

ii. Net Customer Benefits: *Access to the appropriate Tools and Equipment allows EPL staff to maximize workmanship and task completion in a timely manner.*

iii. Impact on Reliability: *Access to the appropriate Tools and Equipment allows EPL staff to maximize workmanship and task completion in a timely manner which can have minor impacts on reliability.*

2. Safety

Failure to provide safe, up-to-date, and reliable Tools and Equipment can have substantial safety-related impacts for EPL staff.

3. Cyber-Security, Privacy

Not applicable.

4. Co-ordination, Interoperability

Not applicable.

5. Economic Development

Not applicable.

6. Environmental Benefits

Not applicable.

C. Category-Specific Requirements

Results of Quantitative and Qualitative Analyses

EPL management evaluates, on a case-by-case basis, three (3) primary alternative scenarios when it pertains to Tools and Equipment: Do Not Replace, Like for Like Replacement, or Upgrade. EPL management evaluates each of these scenarios for each Tools and Equipment investment based on information from subject matter experts, third-party vendors, good utility practice, and regulation. Since investments under this program are determined during the year of implementation, these analyses cannot be presented ahead of time.

Business Case Justification

This program's cost is exactly equal to the materiality threshold and investments under this program are determined during the year of implementation on an as-needed basis; therefore, a thorough business case documentation was not completed.

Computer Hardware

A. General Information on the Project/Activity

EPL strives to continuously improve its interactions with customers and overall customer service. Throughout 2017 and 2018, EPL plans to upgrade its IT infrastructure to be more resilient to cyber security threats. Investments include implementation of new IT hardware, standards, processes, and independent review. EPL also expects ongoing capital requirements in order to maintain the appropriate hardware and keep up with cyber security updates.

This category also includes minor Computer Hardware purchases such as computers, monitors, and other computer equipment in line with historical spending.

Historical and Future Capital and Related O&M Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	$13.5	$25.3	$5.8	$117.3	$356.2	$161.8	$80.0	$80.0	$80.0	$80.0
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Start Date

January 1st, 2017

In-Service Date

December 31st, 2018

Customer Attachments

Not applicable

Load

Not applicable

2018 Test Year Expenditure Timing

	Q1	Q2	Q3	Q4
Capital	$40,452	$40,452	$40,452	$40,452
O&M	$0	$0	$0	$0

Risks and Risk Mitigation

EPL's primary computer hardware risk revolves around service interruption and cyber security. EPL plans to mitigate potential service-related outages and/or cyber-attacks and threats by implementing contingency plans, third-party expert review, and parallel systems, where possible. EPL is working to ensure that it implements compliant measures as cost-effectively as possible.

Comparative Expenditure Information

Historical costs are provided above that show comparative expenditure information. Note that historical costs have not been significant however we have begun work in relation to compliance with the Cyber Security Framework starting at the end of 2016 with the vast majority of work being completed in 2018.

REG Investment Criteria

Not applicable.

Leave to Construct Approval

Not applicable.

B. Evaluation Criteria and Information

1. Efficiency, Customer Value, Reliability

a) Project Drivers:

i. Main Driver: *Compliance with the Cyber Security Framework and reduce/eliminate risk associated with cyber threats and attacks.*

ii. Secondary Drivers: *Enhance workflow and customer service. Equipment at the end of its service life.*

iii. Related Objectives: *This project supports EPL's Core Values of Customer & Community Value, Operational Excellence and Financial & Environmental Sustainability.*

iv. Information Used to Justify the Investment: *EPL utilized subject matter experts, third-party vendors, good utility practice and regulation as metrics to justify the investment.*

b) Priority: *Having up to date software and technologies promotes efficiency and reliability of information across EPL's various departments. Failure to make these investments over time will result in EPLC failure to meet its various regulatory and customer satisfaction levels.*

Out of nineteen (19) material projects/programs planned in the 2018 Test Year, this program was ranked thirteenth (13th) based on its Risk/Strategic Objective Score, as shown in Table 4-14 of EPL's DSP.

c) Analysis of Design, Scheduling, and Ownership Alternatives: *Failure to maintain, upgrade and embrace new technologies can ultimately lead to potential system failures, productivity decreases, poor customer service and lost data. EPL evaluates alternative products and vendors on a regular basis to ensure the best and most cost-effective solution is selected based on prescribed needs.*

i. Cost Effectiveness: *Reducing the number of cyber threats and attacks against EPL will allow for avoided costs of resolving cyber security related gaps and customer information breaches.*

ii. Net Customer Benefits: *Implementing cybersecurity upgrades will allow EPL to be in a better position to defend against cyber threats and protect its customers' data and information.*

iii. Impact on Reliability: *This project does not have an effect on system reliability.*

2. Safety

Safety is not a major driver for this project.

3. Cyber-Security, Privacy

Cyber-Security and privacy are the primary drivers of expenditures in the Computer Hardware category. EPL will ensure that all equipment and software deployed using best industry related practice.

4. Co-ordination, Interoperability

EPL will need to coordinate across multiple departments and across different third-party vendors as it relates to the various system upgrades planned.

5. Economic Development

Not applicable.

6. Environmental Benefits

Not applicable

C. Category-Specific Requirements

Results of Quantitative and Qualitative Analyses

EPL's goal is to maintain the most up to date or most cost-effective computer hardware necessary to meet its obligations to customers and relevant regulation (cyber-security framework) and ensure maximized employee efficiency.

Business Case Justification

Failure to maintain, upgrade and embrace new technologies can ultimately lead to potential system failures, productivity decreases, poor customer service and lost data. EPL evaluates alternative products and vendors on a regular basis to ensure the best and most cost-effective solution is selected based on prescribed needs.

Appendix B: Windsor-Essex Region Integrated Regional Resource Plan

WINDSOR-ESSEX REGION INTEGRATED REGIONAL RESOURCE PLAN

April 28, 2015

ieso
Independent Electricity System Operator

Integrated Regional Resource Plan

Windsor-Essex Region

This Integrated Regional Resource Plan ("IRRP") was prepared by the IESO pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

This IRRP was prepared on behalf of the Windsor-Essex Region Working Group, which included the following members:

- Independent Electricity System Operator
- Essex Powerlines Corporation
- E.L.K Energy Inc.
- Entegrus Inc.
- Hydro One Networks Inc. (Distribution) and
- Hydro One Networks Inc. (Transmission)

The Windsor-Essex Region Working Group assessed the adequacy of electricity supply to customers in the Windsor-Essex Region over a 20-year period; developed a flexible, comprehensive, integrated plan that considers opportunities for coordination in anticipation of potential demand growth scenarios and varying supply conditions in the Windsor-Essex Region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key assumptions over time.

Windsor-Essex Region Working Group members agree with the IRRP's recommendations and support implementation of the plan through the recommended actions. Windsor-Essex Region Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

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List of Abbreviations

Abbreviation	Description
C&S	Codes and standards ("C&S")
CDM	Conservation Demand Management
CEP	Community Energy Plan
CHP	Combined Heat and Power
CHPSOP	Combined Heat and Power Standard Offer Program
DE	District Energy
DG	Distributed Generation
DR	Demand Response
EA	Environmental Assessment
EM&V	Evaluation, Measurement and Verification
EMS	Energy Management Systems
DESN	Dual Element Spot Network
FIT	Feed-in Tariff
GEA	Green Energy Act, 2009
GHG	Greenhouse Gas
IAP	Industrial Accelerator Program
IESO	Independent Electricity System Operator
IPSP	(2007) Integrated Power System Plan
IRRP	Integrated Regional Resource Planning
L/R	Load Rejection
LAC	Local Advisory Committee
LDC	Local Distribution Company
LTEP	(2013) Long-Term Energy Plan
LTR	Limited Time Rating
MEP	Municipal Energy Plan
MEP/CEP	Municipal or Community Energy Planning
MTS	Municipal Transformer Station
OEB or Board	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPS	(Ontario's) Provincial Policy Statement
PPWG	Planning Process Working Group
PV	Photovoltaic
Region	Windsor-Essex Region
RIP	Regional Infrastructure Plan
SCADA	Supervisory Control And Data Acquisition
SCGT	Simple-Cycle Gas Turbine
SECTR	Supply to Essex County Transmission Reinforcement
SPS	Special Protection System
TOU	Time-of-Use
TS	Transformer Station
Working Group	Technical Working Group for the Windsor-Essex Region

1. Introduction

This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs of the Windsor-Essex Region ("Region") over the next 20 years. This report was prepared by the Independent Electricity System Operator ("IESO") on behalf of a Technical Working Group[1] composed of the IESO, EnWin Utilities Ltd. ("EnWin"), Essex Powerlines Corporation, E.L.K. Energy Inc., Entegrus Inc., and Hydro One Distribution and Hydro One Transmission ("Working Group").[2]

The Region encompasses the City of Windsor, Town of Amherstburg, Town of Essex, Town of Kingsville, Town of Lakeshore, Town of LaSalle, Municipality of Leamington, Town of Tecumseh, the western portion of the Municipality of Chatham-Kent and the Township of Pelee Island. With roughly 400,000 people presently living in the Region, population has remained flat over recent years[3] despite the impacts of the 2008 and 2009 global recession and the decline of automotive manufacturing facilities in the City of Windsor. While the manufacturing sector continues to face recovery challenges in the Region, economic diversification is changing the Region's growth and electricity use. The 2011 Windsor-Essex Regional Economic Roadmap identifies nine industry groups that hold potential for the Region, including advanced manufacturing, tourism, and agri-business.[4] The Region presently has a peak electricity demand of about 800 MW, and this demand is expected to increase at an average of nearly 1% per year.

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is done through regional electricity planning, a process that was formalized by the Ontario Energy Board ("OEB" or "Board") in 2013. In accordance with the OEB regional planning process, transmitters, distributers and the IESO are required to carry out regional planning activities for the 21 electricity planning regions at least once every five years.

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[1] Information on the working group is available at: www.ieso.ca/Windsor-Essex

[2] See Appendix B for a description of some of the LDCs serving the Region.

[3] *Population counts, for Canada, provinces and territories, census divisions, population centre size groups and rural areas, 2011 Census*, Statistics Canada. At https://www12.statcan.gc.ca/census-recensement/2011/dp-pd/hlt-fst/pd-pl/Table-Tableau.cfm?LANG=Eng&T=703&SR=1&S=80&O=A&RPP=99&CMA=0&PR=35

[4] Windsor--Essex Regional Economic Roadmap, Windsor-Essex Economic Development Corporation, February 2011.

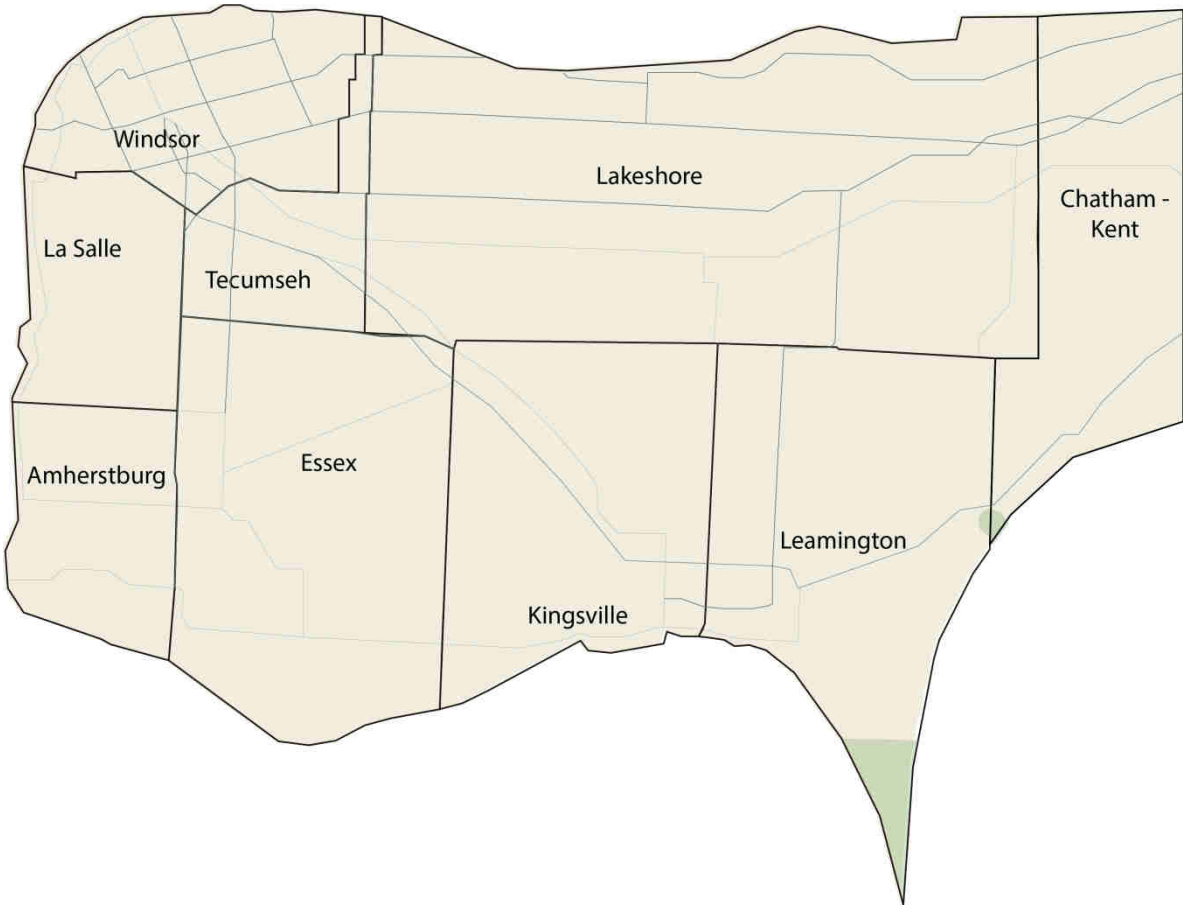
Figure 1-1: Ontario's 21 Regional Planning Zones

The area covered by the Windsor-Essex IRRP constitutes one of the 21 electricity planning regions established through the OEB's regional planning process which is shown in Figure 1-1. This IRRP fulfills the requirements for the region as mandated by the OEB.

This IRRP for Windsor-Essex identifies investments for immediate implementation to meet near- and medium-term needs in the Region, and considers whether there are any long-term needs that necessitate options to be developed. No needs were identified for the Township of Pelee Island. Since economic, demographic, and technological conditions will inevitably change, IRRPs will be reviewed on a 5-year cycle so that plans can be updated to reflect the changing electricity outlook. The Windsor-Essex IRRP will be revisited in 2020 or sooner, if

significant changes occur relative to the current forecast. The Region, shown in Figure 1-2 below, is defined electrically based on the connectivity of supply stations to Ontario's electricity grid. It is comprised of the City of Windsor, Town of Amherstburg, Town of Essex, Town of Kingsville, Town of Lakeshore, Town of LaSalle, Municipality of Leamington, Town of Tecumseh, and the western portion of the Municipality of Chatham-Kent. The Region has a peak electricity demand of about 800 MW and is served by five local distribution companies ("LDCs"): EnWin Utilities Ltd. ("EnWin"), Essex Powerlines Corporation, E.L.K. Energy Inc., Entegrus Inc., and Hydro One. EnWin and Hydro One are directly connected to the transmission system, while the three other LDCs have low voltage connections to Hydro One distribution feeders.

Figure 1-2: The Windsor-Essex Region



This report is organized as follows:

- A summary of the recommended plan for the Region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the Region and the study scope are discussed in Section 4;
- Demand forecast scenarios, conservation and distributed generation assumptions, are described in Section 5;
- The near- and medium-term plan is presented in Section 6;
- The long-term plan is presented in Section 7;
- A summary of community, aboriginal and stakeholder engagement to date in developing this IRRP and moving forward is provided in Section 8;
- A conclusion is provided in Section 9.

2. The Integrated Regional Resource Plan

The Windsor-Essex IRRP addresses the Region's electricity needs over the next 20 years, from 2014 to 2033, based on application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"). The IRRP identifies needs that are forecast to arise in the near term (0-5 years), medium term (5-10 years) and long term (10-20 years). These planning horizons are distinguished in the IRRP to reflect the different level of commitment required over these time horizons. The plans to address these timeframes are coordinated to ensure consistency. The IRRP was developed based on consideration of planning criteria, including reliability, cost and feasibility; and, in the near term, it seeks to maximize the use of the existing electricity system, where it is economic to do so.

For the near and medium term, the IRRP identifies specific investments that are already being implemented. This is necessary to ensure that they are in service in time to address the Region's more urgent needs, which have been forecast with relative certainty based on current demand trends, conservation targets and other local developments.

For the long term, the IRRP identifies a number of alternatives to meet needs. However, as these needs are forecast to arise further in the future, it is not necessary (nor would it be prudent given forecast uncertainty and the potential for technological change) to commit to specific projects at this time. Instead the IRRP for the long term focuses on developing and maintaining the viability of long-term electricity supply options, engaging with the community, and gathering information to lay the groundwork for future options. A particular emphasis of the long term is identifying the potential for integrating conservation, distributed generation ("DG"), or other localized solutions into the Region and gathering input on community preferences for long-term options.

The needs and recommended actions are summarized below.

2.1 Plan to Address the Near- and Medium-Term Needs

The first component of the near- and medium-term plan is the implementation of targeted conservation. While this planned CDM is expected to make a significant contribution to addressing growth in the

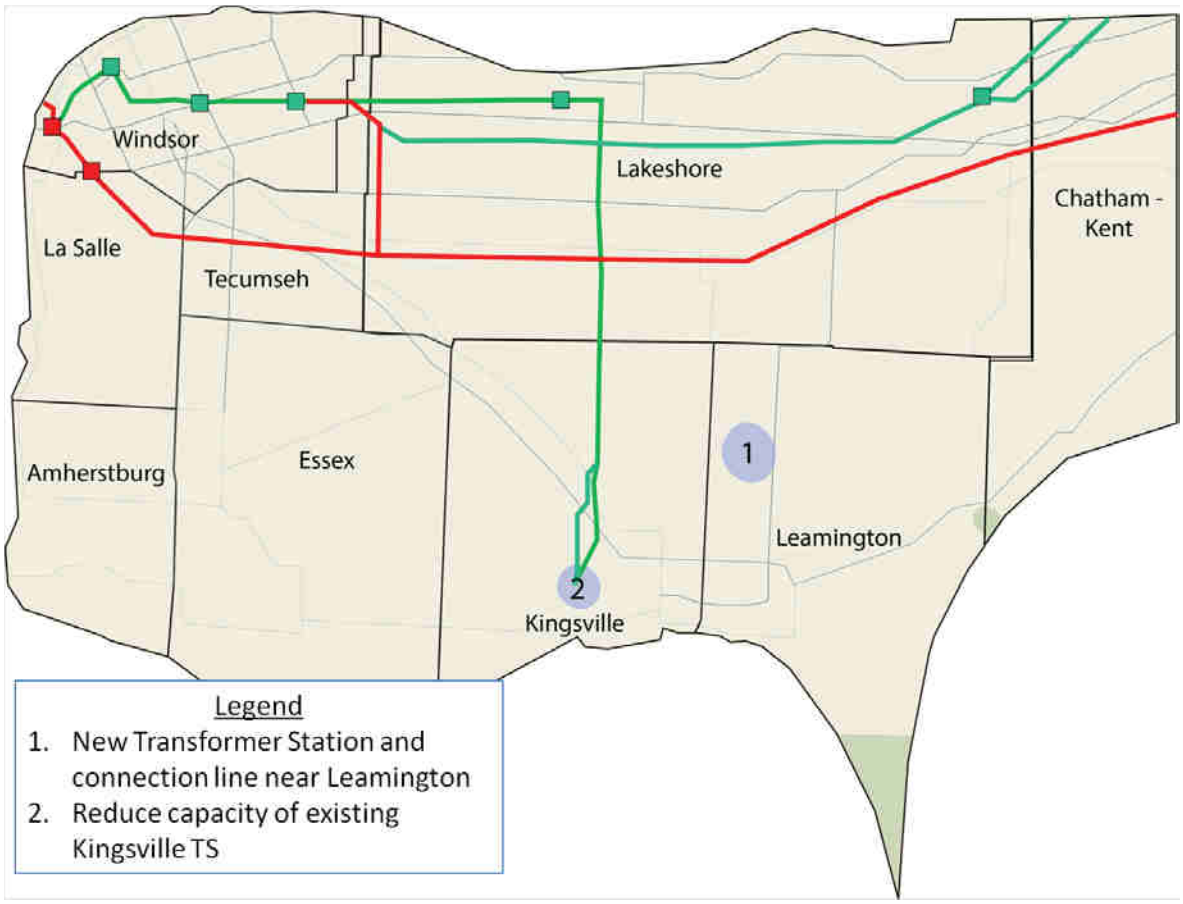
Near- and Medium-Term Needs

- Additional supply capacity in the Kingsville-Leamington area
- Additional restoration capability in the broader Region

Region, residual demand growth, as well as other reliability needs which are not growth related give rise to near-term supply capacity and restoration needs in the Region (see sidebar). Demand in the Kingsville-Leamington portion of the Region has exceeded the supply capacity in recent years and this is expected to continue over the 20-year forecast period. In addition, supply to a large portion of the Region does not comply with the prescribed ORTAC restoration criteria.

An integrated solution composed of conservation, DG resources, and transmission reinforcements in the Region is recommended to address these supply capacity and restoration needs. These components are described in further detail below and the location of transmission investments are indicated in Figure 2-1.

Figure 2-1: Transmission Projects Included in the Windsor-Essex Near-Term Plan



Recommended Actions:

1. Implement conservation and distributed generation

The implementation of provincial conservation targets established in the 2013 Long-Term Energy Plan ("LTEP") is a key component of the near- and medium-term plan for the Region. In developing the demand forecast, peak-demand impacts associated with the provincial targets established in the LTEP were assumed before identifying any residual need; this is consistent with the Conservation First policy. The achievement of these demand reductions will partially depend on the extent to which LDC conservation programs provide peak-demand reductions. Monitoring of conservation success, including measurement of peak demand savings, will be an important element of the near- and medium-term plan, and will also provide input for long-term planning by gauging the actual performance of specific conservation measures, and assessing the potential for future conservation initiatives in the Region.

Provincial programs that encourage the development of DG, such as the Feed-in Tariff ("FIT"), microFIT, and the Combined Heat and Power Standard Offer Program ("CHPSOP"), can also contribute to reducing peak demands on the transmission system in the Region, these will be influenced by local interest and opportunities for development. The LDCs and the IESO will continue supporting these initiatives and will monitor their impacts. Together, conservation and DG resources are expected to offset more than 90% of the growth in the area between 2014 and 2033.

2. Develop new transformer station in Leamington

The balance of the Region's supply capacity and restoration needs can be addressed by the new Supply to Essex County Transmission Reinforcement ("SECTR") project, plus planned sustainment work in the Region.[5] The transmitter that serves the Region, Hydro One, filed the regulatory application for approval of the SECTR project with the OEB in June, 2014. The project consists of the installation of a new 230 kV-supplied transformer station ("TS") near Leamington connected to the existing 230 kV circuits in the Region via a new 13 km double-circuit 230 kV connection line. The estimated completion date for the SECTR project is 2018 and

[5] Evidence on the SECTR project is available at the Ontario Energy Board's website at EB-2013-0421: http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=eb-2013-0421&sortd1=rs_dateregistered&rows=200
Evidence on the needs and alternatives is available in Exhibit B-1-5. Evidence on cost responsibility is available in Exhibit B-4-4.

the total cost is approximately $77 million. On completion, some of the load currently supplied by Kingsville TS will be transferred to the new Leamington TS.

3. Downsize the existing Kingsville transformer station

In conjunction with transferring the majority of the load from the existing Kingsville TS to the new Leamington TS, the Kingsville TS will be downsized through the retirement of aging assets. This will increase the cost-effectiveness of the overall solution.

Together with targeted conservation, these planned transmission facilities will meet the supply capacity and restoration needs of the Kingsville-Leamington area over the forecast period. The addition of a new supply point will also substantially meet the transmission restoration needs for the broader Region. This integrated solution benefits both local customers and broader transmission ratepayers.

2.2 Plan to Address the Long-Term Needs

No long-term needs have been identified in the Region. The Region's demand growth, conservation achievements and generation development will be monitored until the Region's needs are reassessed in the next regional planning cycle. If significant changes occur relative to the current forecast, the next planning cycle may be initiated in advance of the 5-year minimum review timeline.

3. Development of the IRRP

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is done through regional planning. Regional planning assesses the interrelated needs of a region - defined by common electricity supply infrastructure over the near, medium and long term, and develops a plan to ensure cost-effective, reliable, electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as needed basis in Ontario for many years. Most recently, the Ontario Power Authority ("OPA") carried out regional planning activities to address regional electricity supply needs. The OPA conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In 2012, the Ontario Energy Board convened the Planning Process Working Group ("PPWG") to develop a more structured, transparent, and systematic regional planning process. This group was composed of industry stakeholders including electricity agencies, utilities, and stakeholders. In May 2013, the PPWG released the Working Group Report to the Board, setting out the new regional planning process. Twenty-one electricity planning regions in the province were identified in the Working Group Report and a phased schedule for completion was outlined. The Board endorsed the Working Group Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, as well as through changes to the OPA's licence in October 2013. The OPA license changes required it to lead a number of aspects of regional planning, including the completion of comprehensive IRRPs. Following the merger of the IESO and the OPA on January 1, 2015, the regional planning responsibilities identified in the OPA's licence were transferred to the IESO.

The regional planning process begins with a Needs Screening process performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO then conducts a Scoping Assessment to determine whether a comprehensive IRRP is required, which considers conservation, generation, transmission, and distribution solutions, or whether a straightforward "wires" solution is the

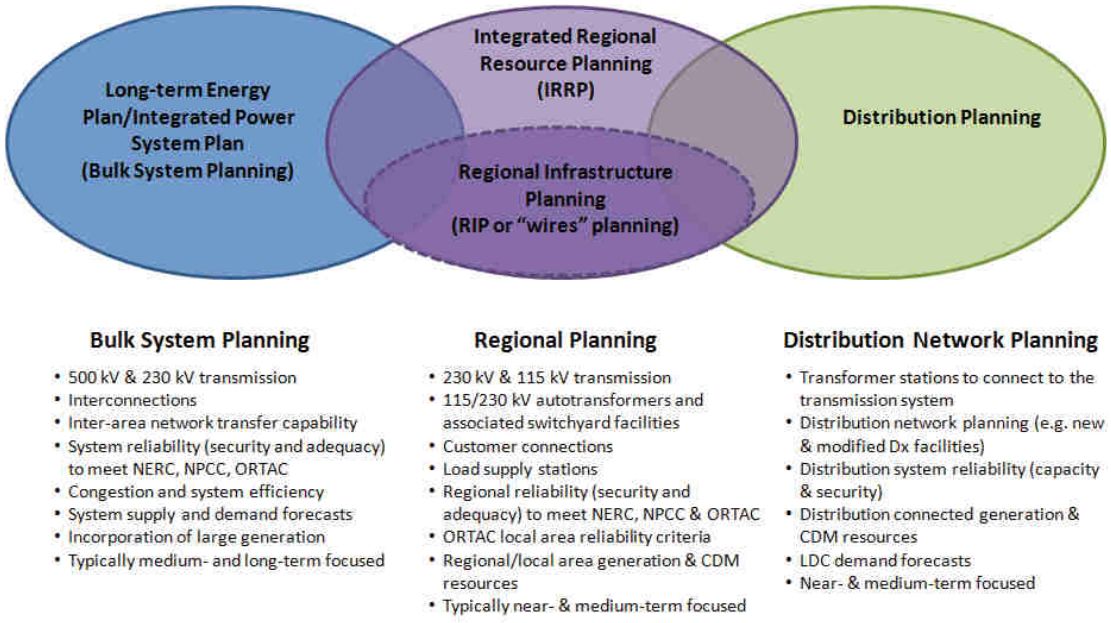
only option. If the latter applies, then a transmission and distribution focused Regional Infrastructure Plan ("RIP") is required. The Scoping Assessment process also identifies any sub-regions that require assessment. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter, outside of the regional planning process. At the conclusion of the Scoping Assessment, the IESO produces a report that includes the results of the Needs Screening process – identifying whether an IRRP, RIP or no regional coordination is required - and a preliminary terms of reference. If an IRRP is the identified outcome, then the IESO is required to complete the IRRP within 18 months. If a RIP is required, the transmitter takes the lead and has six months to complete it. Both RIPs and IRRPs are to be updated at least every five years.

The final IRRPs and RIPs are to be posted on the IESO and relevant transmitter websites, and can be used as supporting evidence in a rate hearing or leave to construct application for specific infrastructure investments. These documents may also be used by municipalities and communities for planning purposes and by other parties to better understand local electricity growth and infrastructure requirements.

Regional planning, as shown in Figure 3-1, is just one form of electricity planning that is undertaken in Ontario. There are three types of electricity planning in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

Figure 3-1: Levels of Electricity System Planning



Planning at the bulk system level typically considers the 230 kV and 500 kV network. Bulk system planning considers the major transmission facilities and assesses the resources needed to adequately supply the province. Bulk system planning is typically carried out by the IESO. Distribution planning, which is carried out by LDCs, looks at specific investments on the low voltage, distribution system.

Regional planning can overlap with bulk system planning. For example, overlap can occur at interface points where regional resource options may also address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. An example of this is when a distribution solution addresses the needs of the broader local area or region. Therefore, to ensure efficiency and cost-effectiveness, it is important for regional planning to be coordinated with both bulk and distribution system planning.

By recognizing the linkages with bulk and distribution system planning, and coordinating multiple needs identified within a given region over the long term, the regional planning process provides an integrated assessment of needs. Regional planning aligns near- and long-term solutions and allows specific investments recommended in the plan to be understood as part of a larger context. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication, and allows Ontario ratepayers' interests to be represented along with the interests of LDC ratepayers. Where IRRPs are undertaken, they

allow an evaluation of the multiple options available to meet needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

3.2 The IESO's Approach to Regional Planning

IRRPs assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends so that near-term actions are developed within the context of a longer-term view. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

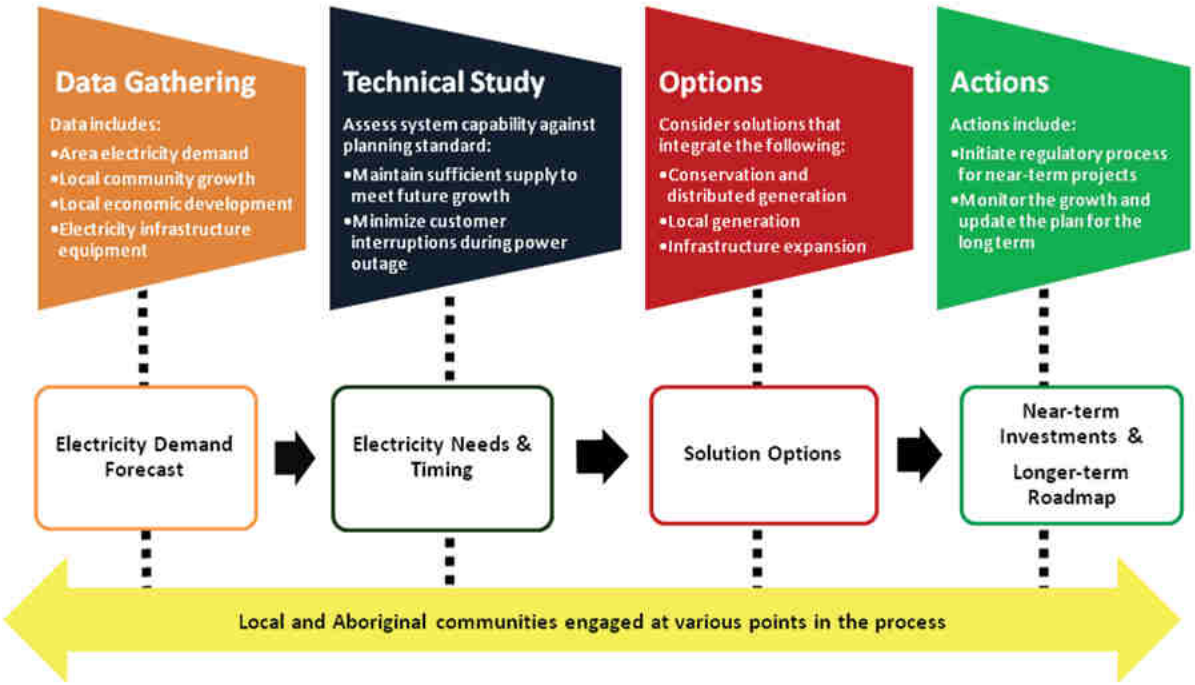
In developing an IRRP, a different approach is taken to developing the plan for the first 10 years of the plan—the near- and medium-term—than for the longer-term period of 10-20 years. The plan for the first 10 years is developed based on best available information on demand, conservation, and other local developments. Given the long lead time to develop electricity infrastructure, near-term electricity needs require prompt action to enable the specified solutions in a timely manner. By contrast, the long-term plan is characterized by greater forecast uncertainty and longer development lead time; as such solutions do not need to be committed to immediately. Given the potential for changing conditions and technological development, the IRRP for the long term is more directional, focusing on developing and maintaining the viability of options for the future, and continuing to monitor demand forecast scenarios.

In developing an IRRP, the IESO and regional working group (see Figure 3-2 below) carry out a number of steps. These steps include electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and, a recommended plan including actions for the near and long term. Throughout this process, engagement is carried out with First Nation and Métis communities, stakeholders and communities who may have an interest in the regional planning area. The steps of an IRRP are illustrated in Figure 3-2 below.

The IRRP report documents the inputs, findings and recommendations developed through the process described above, and provides recommended actions for the various entities responsible for plan implementation. Where "wires" solutions are included in the plan recommendations, the completion of the IRRP report is the trigger for the transmitter to initiate an RIP process to develop those options. Other actions may involve: development of

conservation, local generation, or other solutions; community engagement; or information gathering to support future iterations of the regional planning process in the region.

Figure 3-2: Steps in the IRRP Process



3.3 Windsor-Essex Working Group and IRRP Development

Regional planning was underway in the Windsor-Essex Region prior to the OEB's formalization of the regional planning process. The first phase of regional planning began with the regional plan developed by the former-OPA[6] as part of the 2007 Integrated Power System Plan ("IPSP"), which identified a need for conservation as well as transmission reinforcement in the Region. In 2010, Hydro One received environmental approval for the staged reinforcement identified in the IPSP. The planning work carried out for the IPSP has formed the basis for subsequent regional planning in the Region.

Beginning in 2008, the global economic downturn had a significant impact on electricity demand in the Region, especially the urban portion in and around Windsor. In 2010, a Regional working group consisting of members from the former OPA, the transmitter, the five LDCs, and

[6] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

the IESO, was formed. A study carried out by the former OPA and presented to the working group in 2011 recommended that development activities associated with the proposed Leamington TS temporarily be put on hold as a result of the reduced regional electricity demand.

In 2013 the former-OPA revisited the 2011 study based on an updated load forecast provided by the Region's LDCs. Based on the near-term needs identified, especially in the rural portion in and around Kingsville-Leamington, a transmission solution - the SECTR project - was recommended. In June 2014 Hydro One submitted a Leave to Construct application for this project with the OEB. This was the first of the two stages of transmission expansion described in Hydro One's environmental assessment. The second stage is not contemplated at this time.

As a continuation of this planning work for the Region the former-OPA in 2013 initiated an IRRP for the Region. The Working Group, first established in 2010 and consisting of staff from the former-OPA, the IESO, Hydro One, and the five LDCs serving the Region, was reconvened to support this work.

This Windsor-Essex IRRP is therefore a "transitional" IRRP in that it began prior to development of the OEB's regional planning process and much of the work was completed before the new process and its requirements were known.

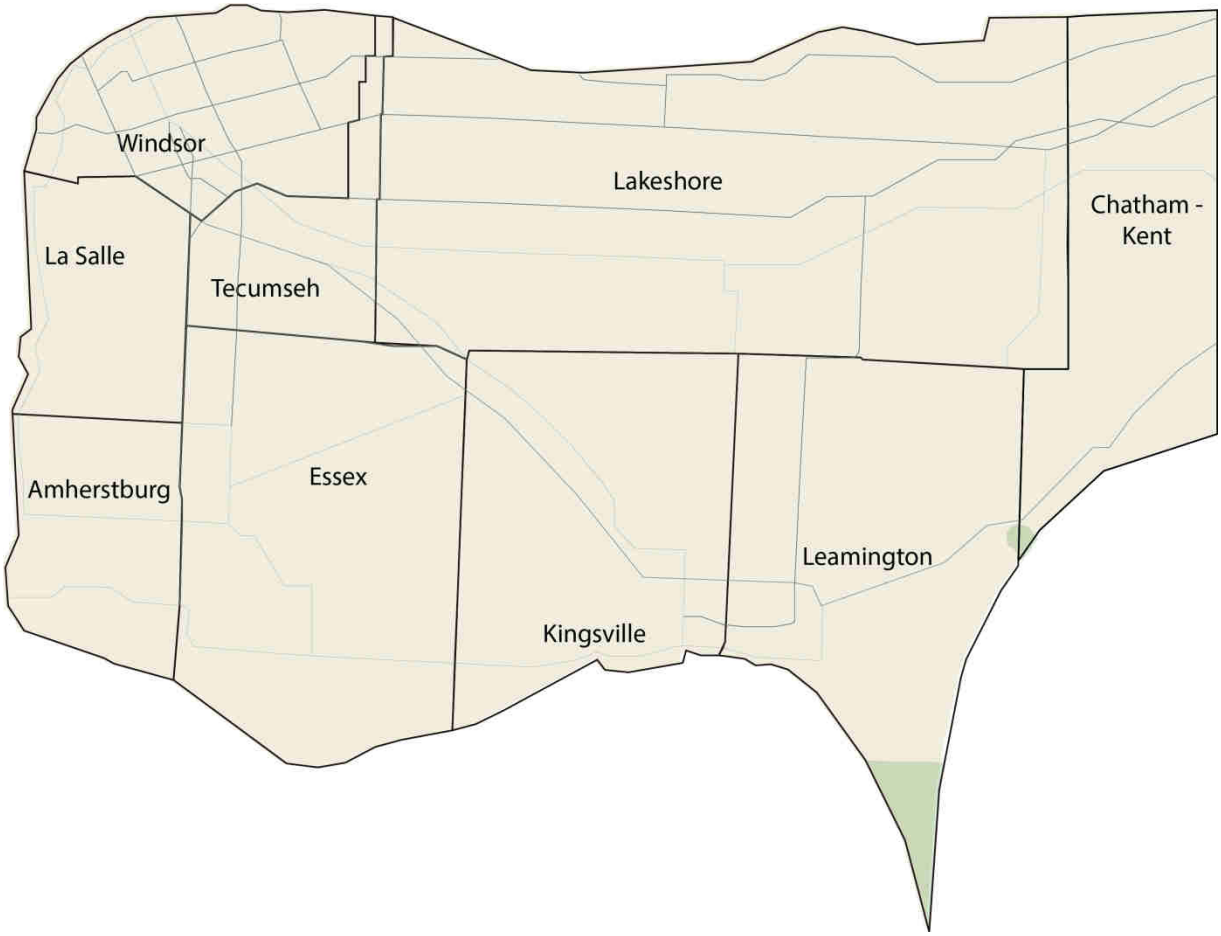
4. Background and Study Scope

This report presents an integrated regional electricity plan for the Windsor-Essex Region for the 20-year period from 2014 to 2033. To set the context for this IRRP, the scope of this IRRP and a description of the Region are described in Section 4.1. Section 4.2 details the transmission-connected generation that plays an important role in providing supply to this Region. Section 4.3 describes the transmission configuration in the Region, and defines the regional planning sub-systems which are used later in this report.

4.1 Study Scope

The Region is comprised of the City of Windsor, Town of Amherstburg, Town of Essex, Town of Kingsville, Town of Lakeshore, Town of LaSalle, Municipality of Leamington, Town of Tecumseh, and the western portion of the Municipality of Chatham-Kent and the Township of Pelee Island. This Region, shown in Figure 4-1 below is comprised of and is served by five LDCs: EnWin Utilities Ltd. ("EnWin"), Essex Powerlines Corporation, E.L.K. Energy Inc., Entegrus Inc., and Hydro One. EnWin and Hydro One are directly connected to the transmission system, while the three other LDCs have low voltage connections to Hydro One distribution feeders.

Figure 4-1: The Windsor-Essex Region



The urban portion of the Region in and around Windsor has a long history of advanced manufacturing, especially in the automotive sector. In light of this the transmitter and distributors over the decades have made investments in electricity infrastructure to enable a very high standard of reliability, which is of strategic importance to the regional and provincial economies. Entertainment tourism is particularly strong in the downtown core, the most significant individual component of which is a provincially owned resort casino.

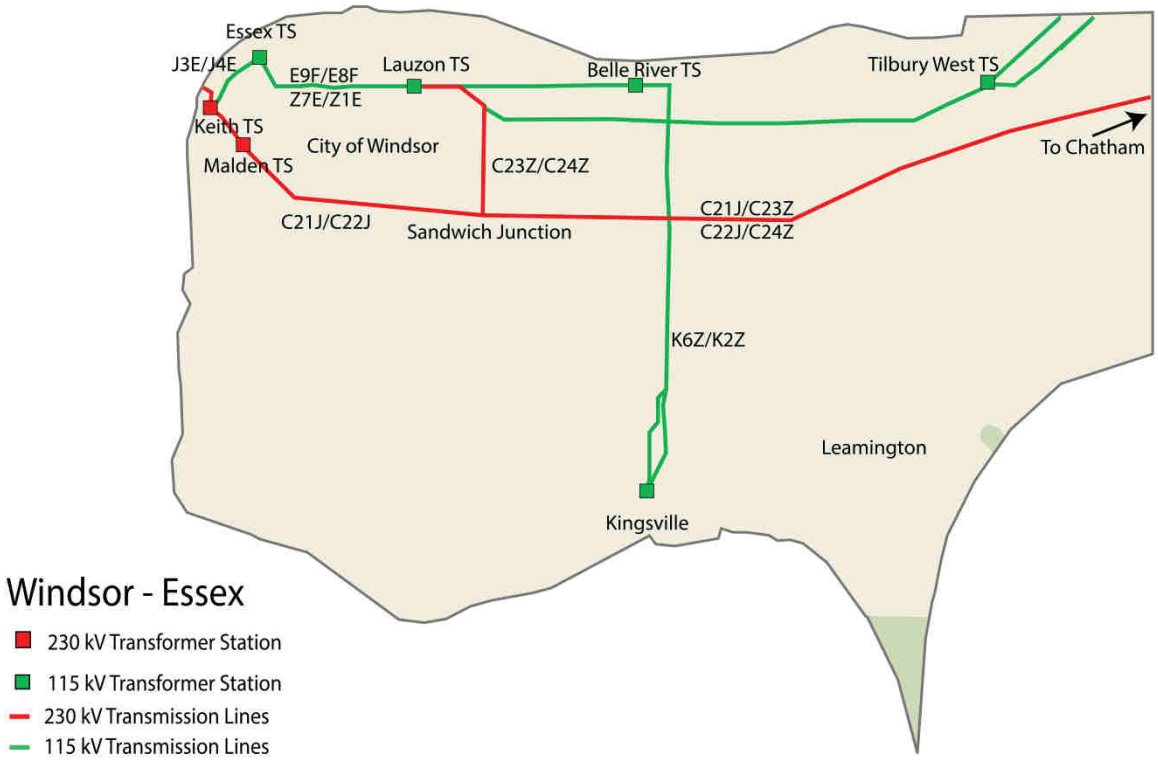
The rural portion of the Region in Essex County supports a combination of manufacturing and agri-business. Essex County contains the largest concentration of greenhouse vegetable production in North America.[7] This sector is expected to experience major growth in the future, with much of the activity taking place in the Kingsville-Leamington area, increasing electricity

[7] County of Essex website:
http://www.countyofessex.on.ca/wps/wcm/connect/COE/COE/ABOUT+ESSEX+COUNTY/

supply requirements in that part of the Region. The County is also home to several large food processing operations, and a growing winery sector.

The Region is supplied from a combination of local generation and from connection to the Ontario grid via a network of 230 kV and 115 kV transmission lines and stations shown in Figure 4-2 below. Electricity distribution and conservation initiatives are carried out by the five LDCs serving the Region.

Figure 4-2: Transmission System in the Windsor-Essex Region



4.2 Transmission Connected Generation

Transmission connected generation comes from a mix of large natural gas generators, load-offsetting behind-the-meter embedded generators, and renewable generation that is shown in Table 4-1 below.

The impact of DG on the demand forecast for the Region will be discussed in more detail later in this report.

Table 4-1: Transmission Connected Generation Facilities in the Region

Technology	Station Name	Contract Expiry Date	Connection Point	Contract Capacity (MW)	Summer Effective Capacity (MW)
Combined Cycle Generating Facility	Brighton Beach Power Station	December 31, 2024	Keith TS	541	526
Combined Heat and Power ("CHP")	West Windsor Power	May 31, 2016	J2N (Keith TS)	128	107
	TransAlta Windsor	December 1, 2016	Z1E	74	74
	East Windsor Cogeneration Centre	November 5, 2029	E8F/E9F	84	80
Renewables	Gosfield Wind Project	January 12, 2029	K2Z	51	8
	Point Aux Roches Wind Farm	December 5, 2031	K6Z	49	8

Electricity transmission connects the Region to the rest of the province through two 230 kV double circuits and two 115 kV single circuits. The principal connection points are Keith TS and Lauzon TS, both of which are transmission assets owned by Hydro One and are located in Windsor. Hydro One also owns Malden TS, Crawford TS, Essex TS, and Walker 1 TS in Windsor. Hydro One owns Belle River TS and Tilbury TS in the northern part of Essex county and Kingsville TS in the southern part of the county. Hydro One is currently seeking OEB approval to build Leamington TS (as part of the SECTR project), also located in the southern part of the county. EnWin owns five transformer stations. One of these serves a broad base of customers (Walker 2 TS); three others are dedicated to individual large users; and one is in the process of being repurposed to serve a broad base of customers as a result of the closure of the large user it previously served. There is also a customer-owned TS serving that customer's facility in Windsor.

The main transmission corridor in the Region connects with the rest of the province at Chatham SS in the Municipality of Chatham-Kent. Two 230 kV double-circuit lines, C21J/C23Z and C22J/C24Z, run east-west in this corridor, located south of Highway 401, from Chatham SS to Sandwich Junction in the Town of Lakeshore. The circuits are reconfigured at this location and double-circuit line C21J/C22J continues west to Keith TS in Windsor, while double-circuit line C23Z/C24Z runs northwest on another corridor to Lauzon TS in Windsor. Keith TS provides an interconnection with the Michigan system via 230 kV circuit J5D and an in-line phase shifter.

Keith TS and Lauzon TS, connect the Region's 115 kV network to the 230 kV transmission system via two auto-transformers in each station. As can be seen in Figure 4-2, above, the main 115 kV transmission corridor runs through the City of Windsor from Keith TS through Essex TS to Lauzon TS. Double-circuit line J3E/J4E located in this corridor connects Keith TS with Essex TS, and double-circuit line Z1E/Z7E connects Essex TS with Lauzon TS. Other 115 kV transmission corridors provide for circuits K2Z and K6Z. 115 kV circuits E8F and E9F are underground cables and provide supply to four EnWin-owned stations. Approximately 65% of the Region's load is supplied by the 115 kV system, with the remainder supplied by transformer stations connected directly to the 230 kV system. Given the large proportion of load which is supplied by the 115 kV system, the reliability of supply via the two connection points at Keith TS and Lauzon TS is especially important.

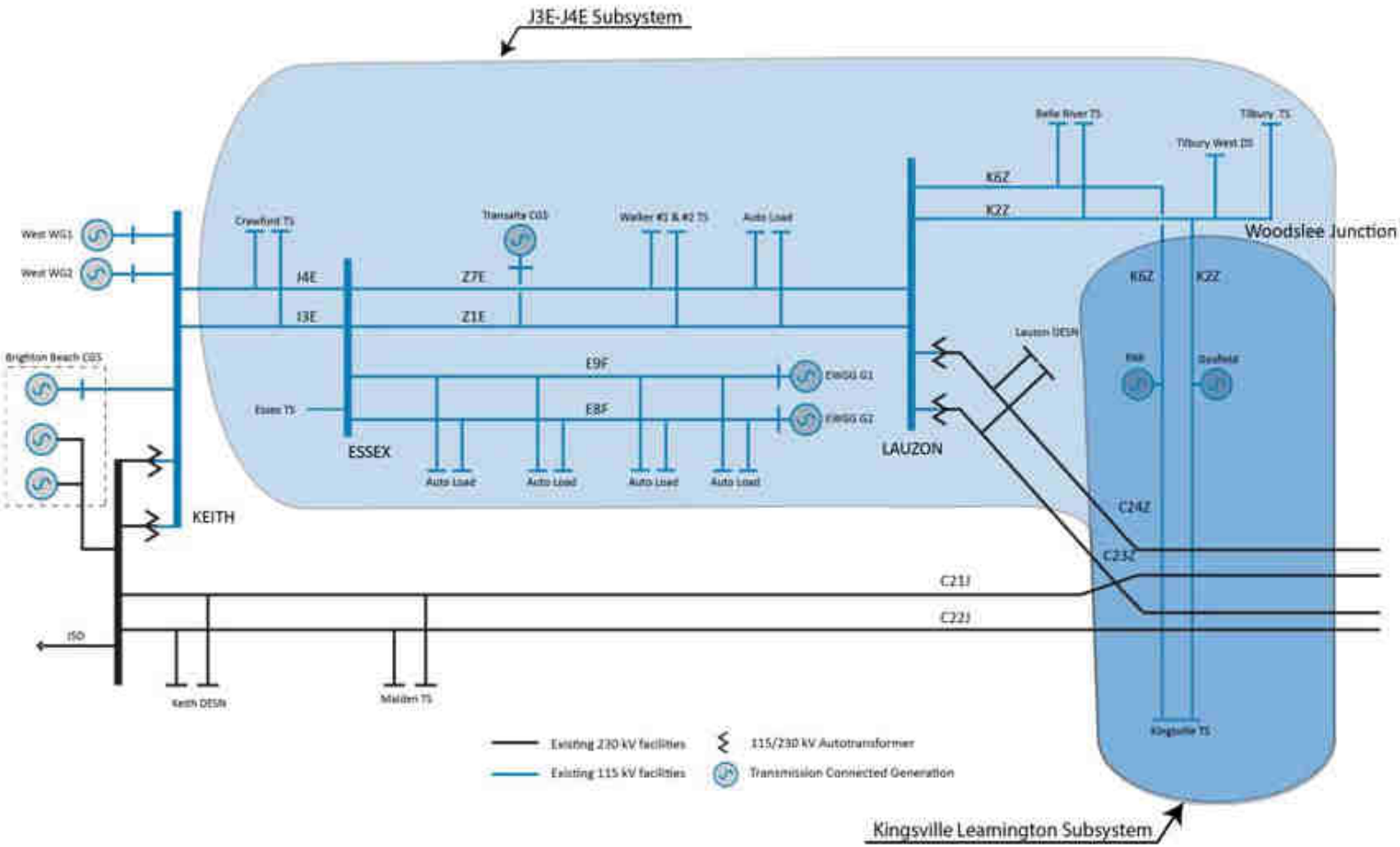
4.2.1 Regional Planning Sub-systems

For the purposes of this IRRP, the transmission system in the Region is divided into the two "nested" sub-systems described below and shown in Figure 4-3:

1. The Kingsville-Leamington sub-system: customers currently supplied from Kingsville TS; and
2. The J3E-J4E sub-system: customers supplied from the 230/115 kV auto-transformers at Keith TS and Lauzon TS via the 115k kV system, as well as customers supplied from the 230 kV Lauzon Dual Element Spot Network ("DESN").

It is important to note that the two sub-systems are overlapping, with the Kingsville-Leamington sub-system nested within the other. Therefore, where the demand for the J3E-J4E sub-system is referred to in this plan it is inclusive of demand in the Kingsville-Leamington sub-system. Similarly, increasing supply to the Kingsville-Leamington sub-system will impact the supply and demand balance in the J3E-J4E sub-system.

Figure 4-3: Windsor-Essex Region Sub-systems



5. Demand Forecast

This section describes the development of the regional demand forecast. Section 5.1 begins by describing electricity demand trends in the Region from 2004 to 2014. Section 5.2 describes the demand forecast used in this study and the methodology used to develop it.

5.1 Historical Demand

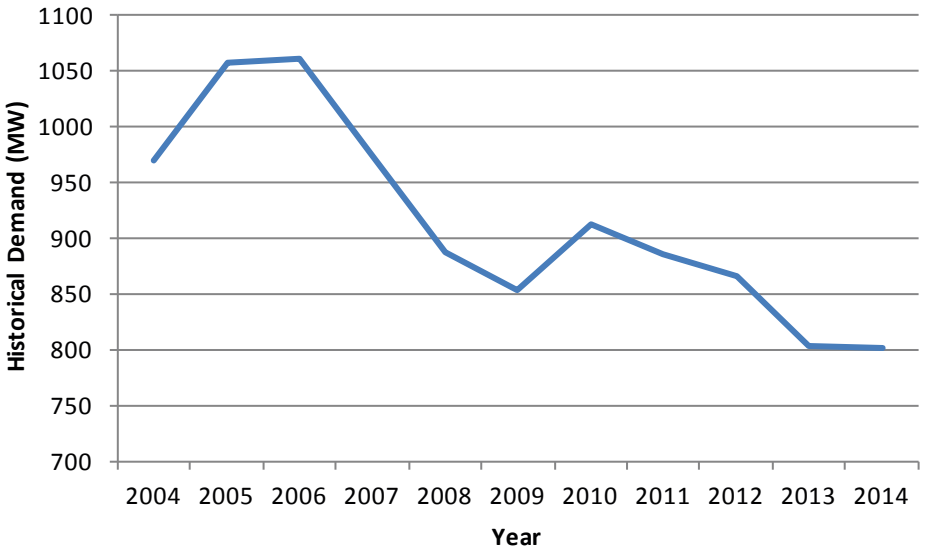
The peak demand in the Region has declined from a high of 1,060 MW in the summer of 2006 to approximately 800 MW in both 2013 and 2014. Figure 5-1 shows the historical summer peak demand observed in the Region from 2004 to 2014. A noticeable peak in 2006 is coincident with the all-time peak in Ontario power demand, while a dip in 2008 and 2009 shows the area's response to the global recession. There is a large concentration of automotive manufacturing facilities in the City of Windsor. The sector is a major economic driver and electricity user within the Region. The decline in Ontario's manufacturing sector and the 2008/09 economic downturn have both caused a decline in electricity use in the Region.

While the manufacturing sector continues to face challenges in recovering, economic diversification is changing the Region's growth and electricity use. The 5-year Windsor-Essex Regional Economic Roadmap, released in 2011, identifies nine industry groups that hold growth potential for the Region, including advanced manufacturing, tourism, and agri-business.[8]

It is important to note some other trends that are reflected in this data. First, this measured demand includes the impact of summer weather conditions, which were unusually cool across the province in 2014. Second, demand on the distribution system that was being met by DG resources operating at the time of the annual peak is not reflected in the measured demand that is supplied from the transmission system. Finally, the data also reflects the achievements of provincial conservation and peak-shifting initiatives, including the Industrial Conservation Initiative for large customers.

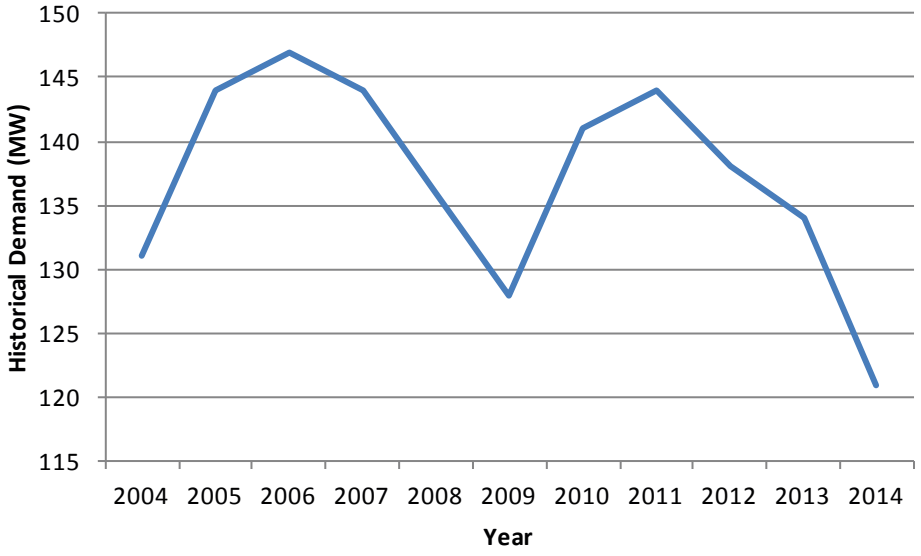
[8] Regional Economic Roadmap, Windsor-Essex Economic Development Corporation, February 2011

Figure 5-1: Historical Electricity Demand in the Region



Peak demand in the Kingsville-Leamington area has experienced fluctuations comparable to the Region since 2004, which is shown in Figure 5-2 below. In addition to the trends described above, this figure shows the impact of approximately 16 MW of effective capacity of DG connected at Kingsville TS by 2015, none of which was connected in 2004.

Figure 5-2: Kingsville-Leamington Historical Electricity Demand[9]



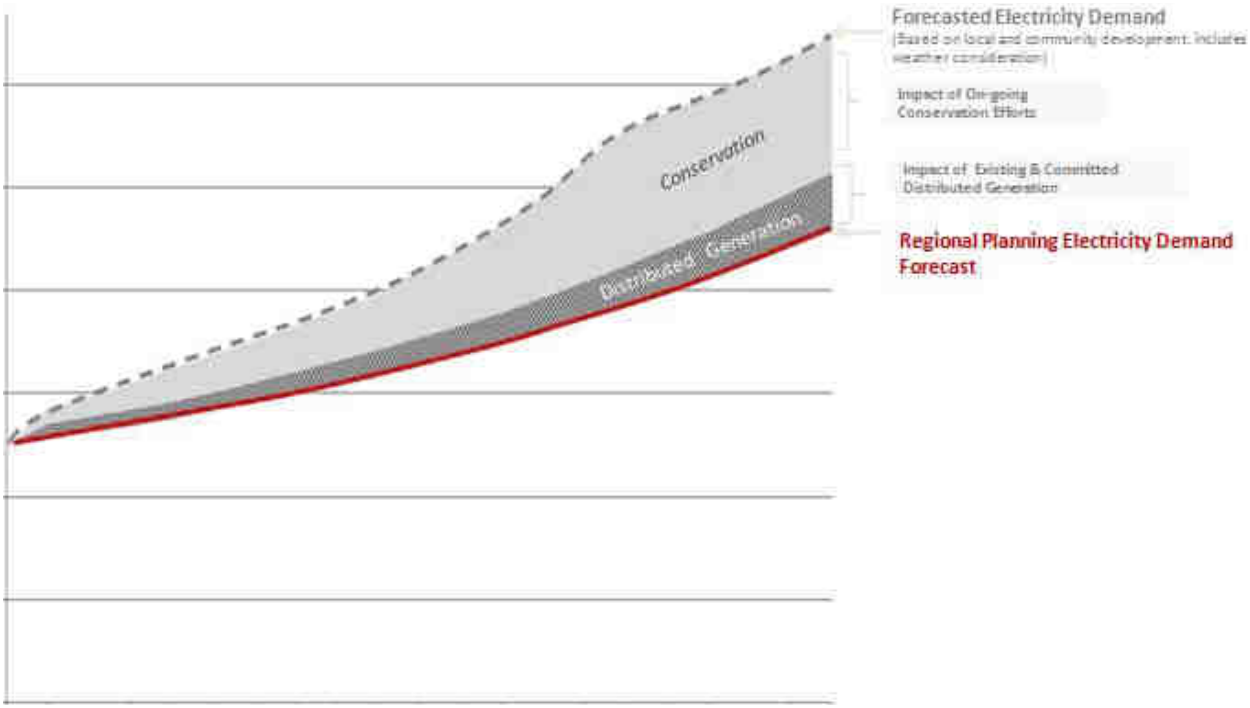
[9] Historical electricity demand reflects the weather experienced at the time of system peak.

5.2 Demand Forecast Methodology

Regional electricity needs are driven by the limits of the infrastructure supplying an area, which is sized to meet peak demand requirements. Therefore, regional planning typically focuses on growth in coincident peak demand, which is the electricity demand of individual stations that coincides in time with the annual peak demand of the region. This represents the electricity demand when the assets in the area are most stressed and resources are most constrained. Energy adequacy is usually not a concern in regional planning, as the Region can generally draw upon energy available from the provincial electricity grid and energy adequacy for the province is planned through a separate process.

A regional peak demand forecast was developed for the forecast period. The steps taken to develop the planning forecast are depicted in Figure 5-3. Gross demand forecasts assuming extreme weather conditions were provided by EnWin and Hydro One, which are directly connected to the transmission system. These forecasts were then modified to reflect the peak demand impacts of provincial conservation targets and DG contracted through provincial programs such as FIT and microFIT to produce a reference planning forecast. The reference planning forecast was then used to assess electricity supply needs in the Region.

Figure 5-3: Development of Demand Forecasts



Using a planning forecast that is net of provincial conservation targets ensures consistency with the province's Conservation First policy by reducing demand requirements before assessing any growth-related needs. However, it should be noted that this inherently assumes that the targets will be met, and that the targets, which are energy-based, will produce the expected local peak demand impacts. An important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by the local LDCs.

For the long-term outlook, from 2024 to 2033, a second demand forecast scenario, consistent with the growth assumptions embodied in the government's 2013 LTEP was added. This low-demand scenario represents a future with lower electricity demand growth, due to higher electricity prices, increased electricity conservation, and lower energy intensity of the economy.

5.3 Reference Forecast

5.3.1 Gross Demand Forecast

Summer peak gross demand forecasts for the 20-year planning horizon were provided by EnWin and Hydro One, the two LDCs which are directly connected to the transmission system, for each of the transformer stations and transmission connected customers in the area. These

forecasts reflect the expected demand at each station at the time of the Region's coincident peak under extreme weather conditions, based on factors such as population, household and economic growth, consistent with municipal planning assumptions. It is expected that each station will reach its individual peak demand at a different point in time. From the perspective of ensuring sufficient transmission supply to the Region, it is important to consider the coincident peak, the point in time when the total demand from the stations in the Region peaks. Aggregating the station forecasts identifies the peak electricity demand that must be served by the Region's transmission system.

Based on the LDC's gross demand forecasts, the Region's peak electricity demand is expected to grow by about 175 MW over the next 20 years, with an average annual growth rate of just under 1%, not including the impacts of conservation or DG. The Kingsville-Leamington area is expected to experience over 50 MW of demand growth, or average annual growth of about 1.6%. The reference gross demand forecasts provided by the LDCs are shown in Appendix A.

5.3.2 Conservation Assumed in the Forecast

Conservation plays a key role in maximizing the useful life of existing infrastructure and maintaining reliable supply. Conservation is achieved through a mix of program-related activities including behavioral changes by customers and mandated efficiencies from building codes and equipment standards ("C&S"). These approaches complement each other to maximize conservation results. The conservation savings forecast for the Region are applied to the gross peak demand forecast, along with contracted DG resources, to determine the net peak demand for the Region.

In December 2013 the Ministry of Energy released a revised LTEP, which outlined a provincial conservation target of 30 TWh of energy savings by 2032. In order to represent the effect of these targets within regional planning, the IESO developed an annual forecast for peak demand savings resulting from the provincial energy savings target, which was then expressed as a percentage of demand in each year. These percentages were applied to the LDCs' demand forecasts to develop an estimate of the peak demand impacts from the provincial targets in the Region. The resulting conservation assumed in the reference forecast is shown in Table 5-1. This contribution from conservation is expected to offset most of the growth in electricity demand in the Region to 2033. The above conservation forecast methodology was not applied in developing the low-demand forecast scenario used for the long-term because the scenario

already accounts for the anticipated impact of the 2032 conservation targets in its overall growth rate assumptions.

Table 5-1: Peak Demand Savings from 2013 LTEP Conservation Targets in the Windsor-Essex Region

Year	2015	2017	2019	2021	2023	2025	2027	2029	2031	2033
Savings (MW)	12	20	40	58	72	89	105	122	139	149

It is assumed that demand response ("DR") resources already existing in the base year will continue. Savings from potential future DR resources are not included in the forecast and are instead considered as possible solutions to identified needs.

The 2013 LTEP also committed to establishing a new 6-year Conservation First Framework beginning in January 2015 to enable the achievement of all cost-effective conservation. In the near term, Ontario's LDCs have an energy reduction target of 7 TWh to be achieved between 2015 and the end of 2020 through LDC conservation programs enabled by the new Framework. For the program targets, each LDC is required to prepare a conservation plan describing how the target will be achieved. The first conservation plans are due to be completed by LDCs by May, 2015. The LDC conservation plans will link closely with regional plans, providing more detail about how a portion of the conservation targets that have been incorporated into regional planning will be realized.

5.3.3 Distributed Generation Assumed in the Forecast

In addition to conservation resources, DG connected alongside load on the distribution system reduces the amount of demand needed to be supplied via the transmission system. The introduction of the Green Energy and Green Economy Act, and the associated development of Ontario's FIT program, has increased the development of DG in Ontario from renewable fuel sources including wind, solar and biomass. There are also thermal DG resources in the Region, such as combined heat and power generation ("CHP") associated with industrial customers.

With respect to renewable generation, the full installed capacity of these facilities cannot be relied upon to meet the Region's electricity needs due the intermittent nature of the generation. The installed capacity of these facilities is adjusted to reflect the expected, or effective, power output at time of coincident peak. In other words, the effective capacity is the portion of

installed renewable generation capacity that contributes to meeting peak demand. Distributed thermal generation is expected to fully contribute to meeting peak demand.

After netting-off the conservation savings, as described above, the forecast is further reduced by the effective capacity of existing and committed DG in the Region. It is estimated that DG in the Region will contribute approximately 65 MW of effective capacity to meeting area peak demand in 2014.

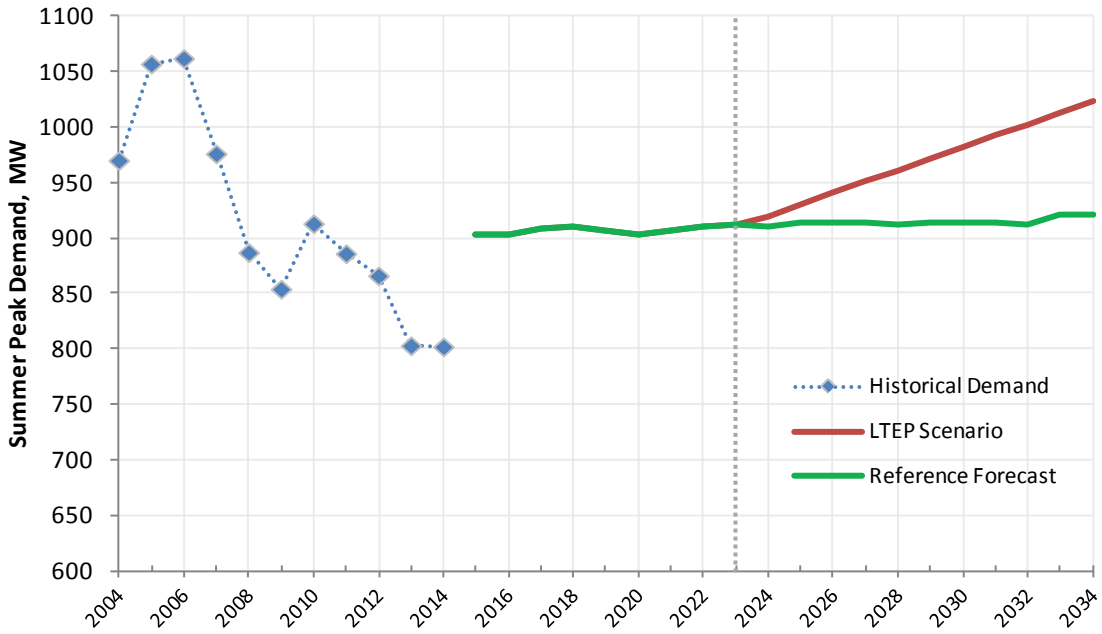
5.4 Windsor-Essex Low Growth Scenario

As noted in Section 5.2, beyond the first 10-years of the planning horizon (ie. beginning in 2024) the IESO developed a second forecast scenario based on the 2013 LTEP. Similar to the reference forecast, this scenario reflects the impact of the conservation targets described in the LTEP. This scenario projects growth over a region, rather than on a station-by-station basis. It was developed by applying the average annual growth rate assumed for southwestern Ontario in the low-demand forecast, about 1.0% per year, to the Region, starting from 2024.

5.5 Planning Forecasts

Figure 5-4 shows the reference forecast and the 2013 low-demand scenario, along with historic demand in the Region.

Figure 5-4: Reference Forecast, 2013 Low-Demand Scenario and Historic Demand in the Region



6. Near- and Medium-Term Plan

Regional planning requires comparing future electricity demand (based on planning forecast) with the capability of the existing system (based on provincial planning criteria). This section includes discussion of the near-term needs and the options to address those needs. No medium-term needs have been identified in the Region. As noted in the previous section, these near-term needs are based on the reference planning forecast provided by the Region's LDCs, reflecting known developments in the area as well as the impact of planned conservation initiatives and DG. These conservation and DG resources are already making a significant contribution toward managing the growth across the Region. For needs related to meeting ORTAC load restoration and load security criteria, which are described in 6.1 Planning Criteria, conservation is not considered a feasible alternative, as these needs are driven by the configuration of the transmission and distribution systems, and are not related to demand growth. Therefore, the Working Group did not consider additional conservation as an alternative to address load restoration times in the Region, and therefore, the near-term plan focuses on improvements to the transmission system.

6.1 Planning Criteria

ORTAC[10] is the provincial standard for assessing the reliability of the transmission system and was applied to assess supply capacity and reliability needs in the Region.

ORTAC includes criteria related to assessment of the bulk transmission system, as well as the assessment of local or regional reliability requirements. The latter criteria are of relevance to regional planning. They can be broadly categorized as addressing two distinct aspects of reliability: (1) providing supply capacity, and (2) limiting the impact of supply interruptions.

With respect to supply capability ORTAC specifies that the transmission system must be able to provide continuous supply to a local area, under specific transmission and generation outage scenarios. The performance of the system in meeting these conditions is used to determine the load meeting capability ("LMC") of an area for the purpose of regional planning. The LMC is the maximum load that can be supplied in the local area with no interruptions in supply or, under certain permissible conditions, with limited controlled interruptions as specified by the ORTAC.

[10] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

With respect to supply interruptions ORTAC requires that the transmission system be designed to minimize the impact to customers of major outages, such as a contingency on a double-circuit tower line resulting in the loss of both circuits, in two ways: by limiting the amount of customer load affected; and by restoring power to those affected within a reasonable timeframe. Specifically, ORTAC requires that no more than 600 MW of load be interrupted in the event of a major outage involving two elements. Further, load lost during a major outage must be restored within the following timeframes:

- All load lost in excess of 250 MW must be restored within 30 minutes;
- All load lost in excess of 150 MW must be restored within four hours; and
- All load lost must be restored within eight hours.

6.2 Near-Term Needs

Based on an application of ORTAC two near-term transmission system reliability needs, shown in Table 6-1 below, have been identified. These needs affect different groups of customers in the Region (i.e., different sub-systems), however they can be addressed through the same transmission reinforcement project consisting of a new TS located in Leamington.

Table 6-1: Summary of Windsor-Essex Region Reliability Needs

Sub-system	Need Type	Need Description	Need Date
Kingsville-Leamington Sub-system	Capacity to Meet Demand	Forecast loading on K6Z exceeds the thermal load meeting capability	Today
J3E-J4E Sub-system	Minimize the Impact of Interruption	J3E-J4E does not comply with ORTAC service interruption criteria — i.e., restoration of all load within 8 hours	Today

6.2.1 Kingsville-Leamington: Plan to Address the Need for Additional Supply Capacity and End-of-Life Replacement

Within the Region, the strongest growth in electricity demand is expected to occur in the Kingsville-Leamington area. This growth is predominantly attributable to growth in the greenhouse sector as indicated by customer connection requests received by the applicable LDC, the current outlook for expansion of existing greenhouse operations, and anticipated

growth from new operations. Such growth expectations are based on approved and proposed development plans provided by the municipalities of Leamington and Kingsville, and a survey completed by the Ontario Greenhouse Vegetable Growers on behalf of local greenhouse growers.

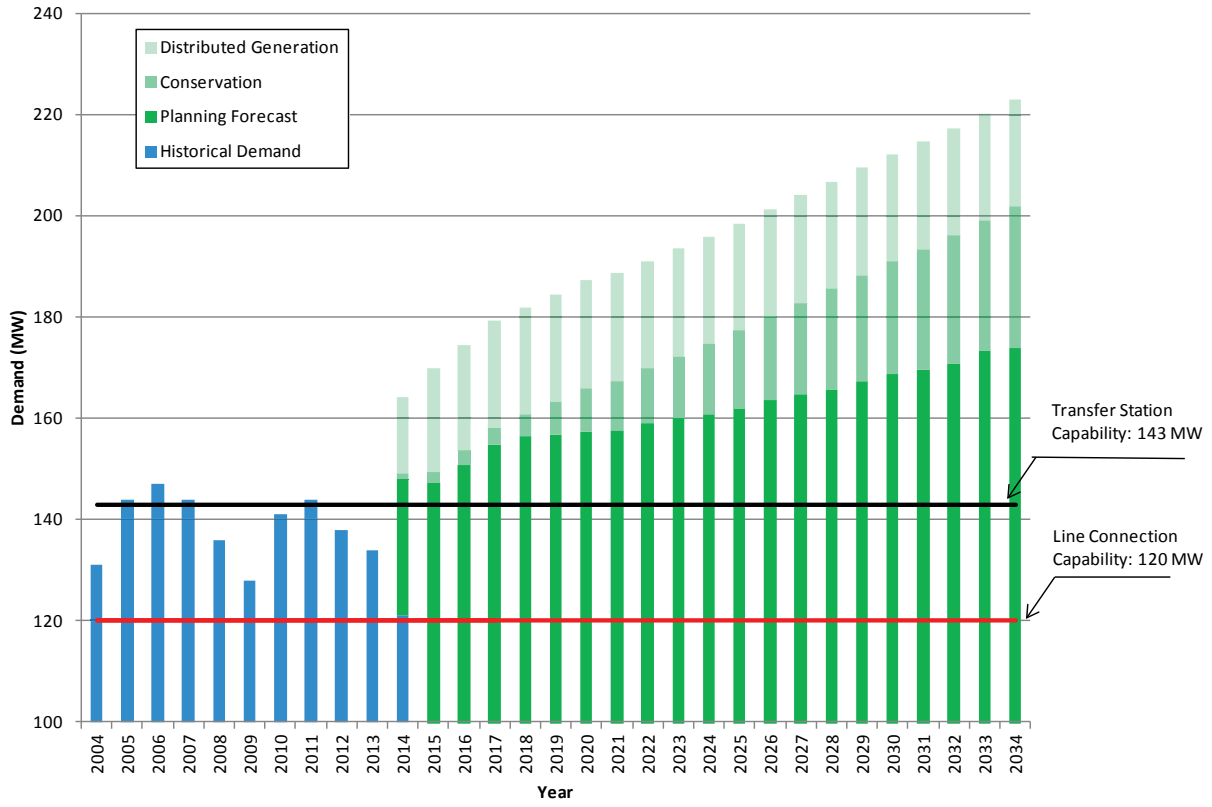
Similarly, the population of Kingsville is expected to increase by 0.5% per year over the next decade, which is higher than the slight population decline expected in the Region overall during the 2014 to 2033 planning horizon.[11]

The planning forecast for the Kingsville-Leamington area is shown in Figure 6-1 below, along with the LMC for the existing Kingsville TS. The approximate planned peak demand reduction between 2014 and 2033 for the Kingsville-Leamington sub-system is 25 MW from conservation, and 6 MW from DG. The peak demand reduction from conservation and DG is expected to offset about 57% of the forecast gross demand growth in the Region between 2014 and 2033. The LMC is based on the 120 MW thermal capability of the 115 kV connection line between Lauzon TS and Kingsville TS, which is the most limiting element of supply to the station. The Kingsville TS capability is higher, at 143 MW.

As shown in Figure 6-1, during the summer months the peak demand has exceeded the 120 MW limit, requiring the use of operating measures. The figure shows that based on the planning forecast, the Kingsville-Leamington area is expected to continue to exceed the capability of the existing Kingsville TS for the forecast period. Additional capacity is therefore required to meet current and future electricity demand in the Kingsville-Leamington sub-system. Until additional capacity is provided, operating measures such as an existing load rejection scheme (which is in violation of ORTAC) will be required. The existing system does not meet ORTAC criteria for supply capacity.

[11] Windsor-Essex Economic Development Corporation website. At www.choosewindsoressex.com.

Figure 6-1: Historical and Forecast Demand and Supply Capabilities in the Kingsville-Leamington Sub-system[12]



After considering "non-wires" and "wires" alternatives, the former-OPA, with the support of working group members, recommended a new station in Leamington to address the need.

In 2014 Hydro One filed a Leave to Construct application with the OEB for transmission expansion in the Leamington area, the SECTR project. The application is currently proceeding through the regulatory process and has a planned in-service date of 2018.

As part of the SECTR planning process, Hydro One identified a near-term need for transformer refurbishment due to end-of-life assets at Kingsville TS. There are currently four transformers at Kingsville TS. One of these units was recently replaced, but the other three units are reaching their end-of-life in the near future. In conjunction with the Leamington area transmission expansion, the option of partially refurbishing Kingsville TS by replacing one of the three transformers that are near end-of-life was recommended. This plan reduces the capacity at

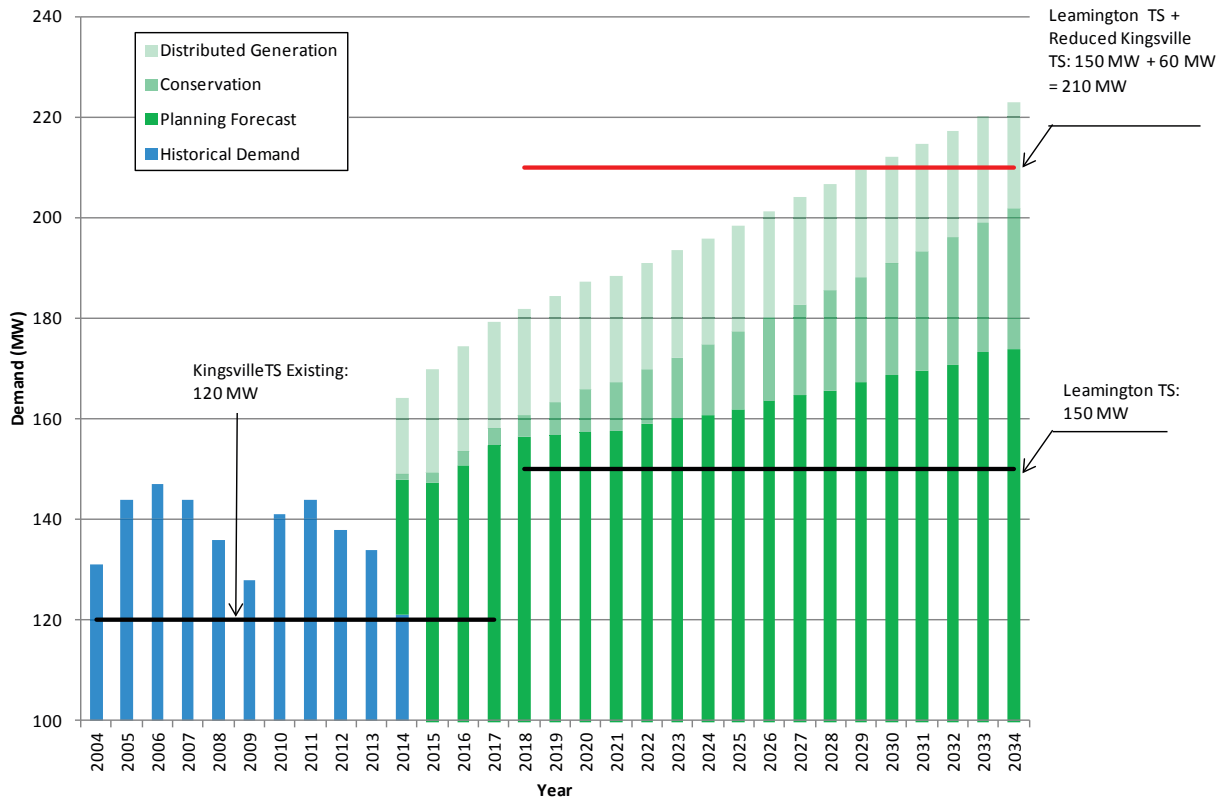
[12] Historic demand values reflect actual electricity demand and weather.

Kingsville TS by reducing the number of the station's transformers from four to two and reduces the LMC of the station from 120 MW to 60 MW, depending on the ability to transfer sufficient existing demand to the new Leamington TS. The result is a net increase in station capacity in the Kingsville-Leamington area, but with a different geographic distribution. This plan results in reduced flexibility for LDCs supplying customers in the Kingsville area. It will, however, be possible to return Kingsville TS to its current capacity in the future, should the forecast indicate the need for additional capacity.

The former-OPA prepared evidence to support Hydro One's regulatory application to the OEB for SECTR. This evidence details the needs in the Region; evaluates "non-wires" and "wires" alternatives; and recommends an integrated solution, comprised of planned conservation and DG resources, the new TS at Leamington, and partial refurbishment at Kingsville TS.

When the SECTR project is completed, and Kingsville TS refurbished with a reduced capacity, the combined supply capability in the Kingsville-Leamington area will be 210 MW. Figure 6-2 shows the supply capability in the Kingsville-Leamington area.

Figure 6-2: Kingsville-Leamington Sub-system Capability after Leamington TS is In-Service



6.2.2 Plan to Minimize the Impact of Supply Interruptions in the Windsor-Essex Region

A large portion of the transmission system in the Region, referred to as the "J3E-J4E sub-system", does not currently comply with ORTAC restoration criteria. In addition to addressing the supply capacity need in the Kingsville-Leamington area, the plan to build a new TS at Leamington will address the restoration need. This need is described in Figure 6-3.

Sub-system Configuration and the Limiting Outage

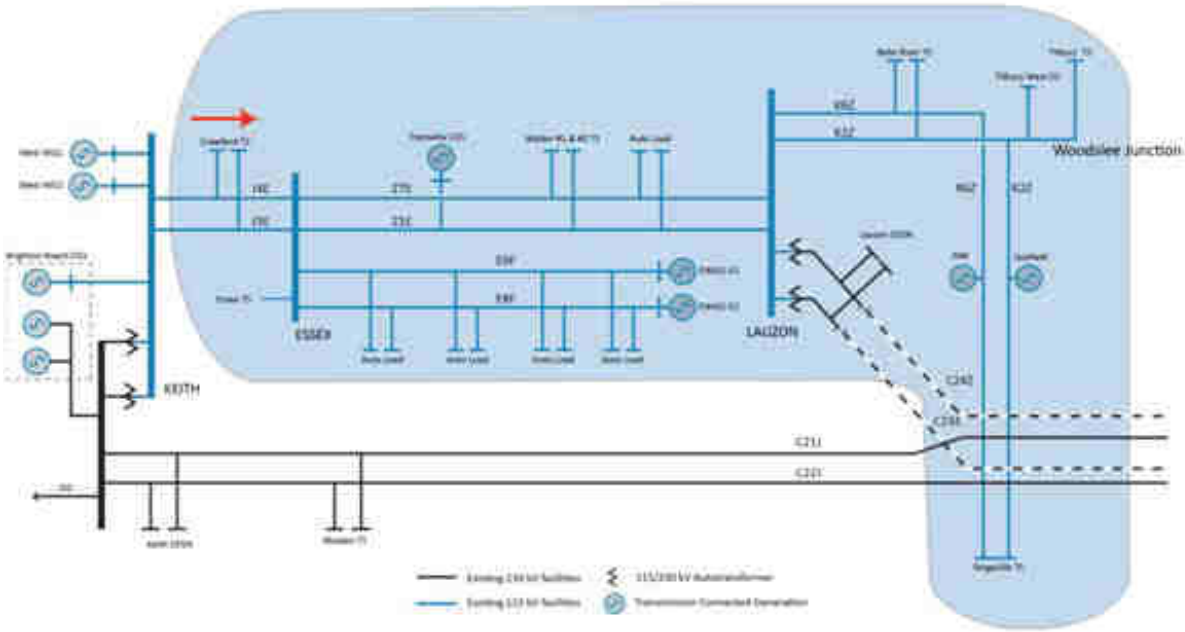
The J3E-J4E sub-system is supplied by two double-circuit 230 kV transmission lines between Chatham SS and Lauzon TS and Keith TS, respectively. The loss of one of these lines (C23Z/C24Z between Chatham and Lauzon) is the most limiting outage for this sub-system. In the event of the loss of the C23Z/C24Z transmission line, the Lauzon DESN station, which is directly connected to this line, is lost immediately. Subsequent to the outage, the 115 kV system supplying most of the City of Windsor, as well as Kingsville, Belle River and Tilbury, must be supplied entirely through the path consisting of the transformers at Keith TS and the 115 kV transmission line between Keith TS and Essex TS (J3E/J4E). The thermal capacity of the two

230/115 kV transformers at Keith TS limits the supply to the 115 kV system to approximately 300 MW. The C23Z/C24Z outage, and the J3E-J4E sub-system which is affected by this outage, are shown in Figure 6-3 below.

One of the Brighton Beach GS gas-fired generators is connected to the 115 kV bus at Keith TS between the Keith transformers and the J3E/J4E transmission line. The capability of the J3E/J4E line, which is higher than the capability of the Keith transformers, can be fully utilized by a combination of supply from the transmission system and generation at Brighton Beach GS. Due to this arrangement, the thermal capacity of the J3E/J4E transmission line limits the supply to the 115 kV system after the C23Z/C24Z double-circuit outage to approximately 440 MW. Because this would not be enough to meet the peak demand on the 115 kV system, the existing load rejection scheme would reject sufficient load immediately following the outage to respect the ratings of J3E/J4E.

The amount of load rejection required will depend on whether or not all local generation is in operation. For example, based on the planning forecast for 2017, following the loss of the C23Z/C24Z double-circuit transmission line, a total of 245 MW of load is interrupted, consisting of about 175 MW at Lauzon DESN and about 70 MW which is interrupted through load rejection, assuming local gas and renewable generation sources are running. This represents approximately 28% of the Windsor-Essex Region electricity demand, and is a substantial amount of demand to be interrupted following an outage. Following the contingency this load must be restored within the period of time prescribed by the ORTAC.

Figure 6-3: Windsor-Essex Region Transmission System Following an Outage to the C23Z/C24Z Transmission Line



Restoration Capability

The existing system lacks the capability to restore power to customers in the J3E-J4E sub-system in accordance with the ORTAC criteria which specifies that load greater than 250 MW must be restored within half an hour, load greater than 150 MW must be restored within 4 hours, and all load interrupted must be restored within 8 hours.

There are three sources of restoration capability which have been identified in the J3E-J4E sub-system: 1) gas-fired generation at Brighton Beach GS and in the J3E-J4E sub-system, 2) transferring load out of the J3E-J4E sub-system, and 3) transmission connected renewable generation within the J3E-J4E sub-system. These three contributors are discussed further below.

As noted previously, one of the gas-fired generating units at Brighton Beach GS is connected to the 115 kV bus at Keith TS. This generation capacity allows the capability of the J3E/J4E transmission line to be fully utilized after the C23Z/C24Z outage.

In addition, there is currently 154 MW of gas-fired generation within the J3E-J4E sub-system, consisting of East Windsor Cogeneration and TransAlta Windsor. The contract for one of these generators, TransAlta Windsor (74 MW), expires in December, 2016. Beyond this date, the

amount of gas-fired generation within the sub-system will be reduced to 80 MW. This 80 MW of effective generation will help supply demand in the J3E-J4E sub-system following a major transmission outage until the expiry of the East Windsor Cogeneration contract in November, 2029.

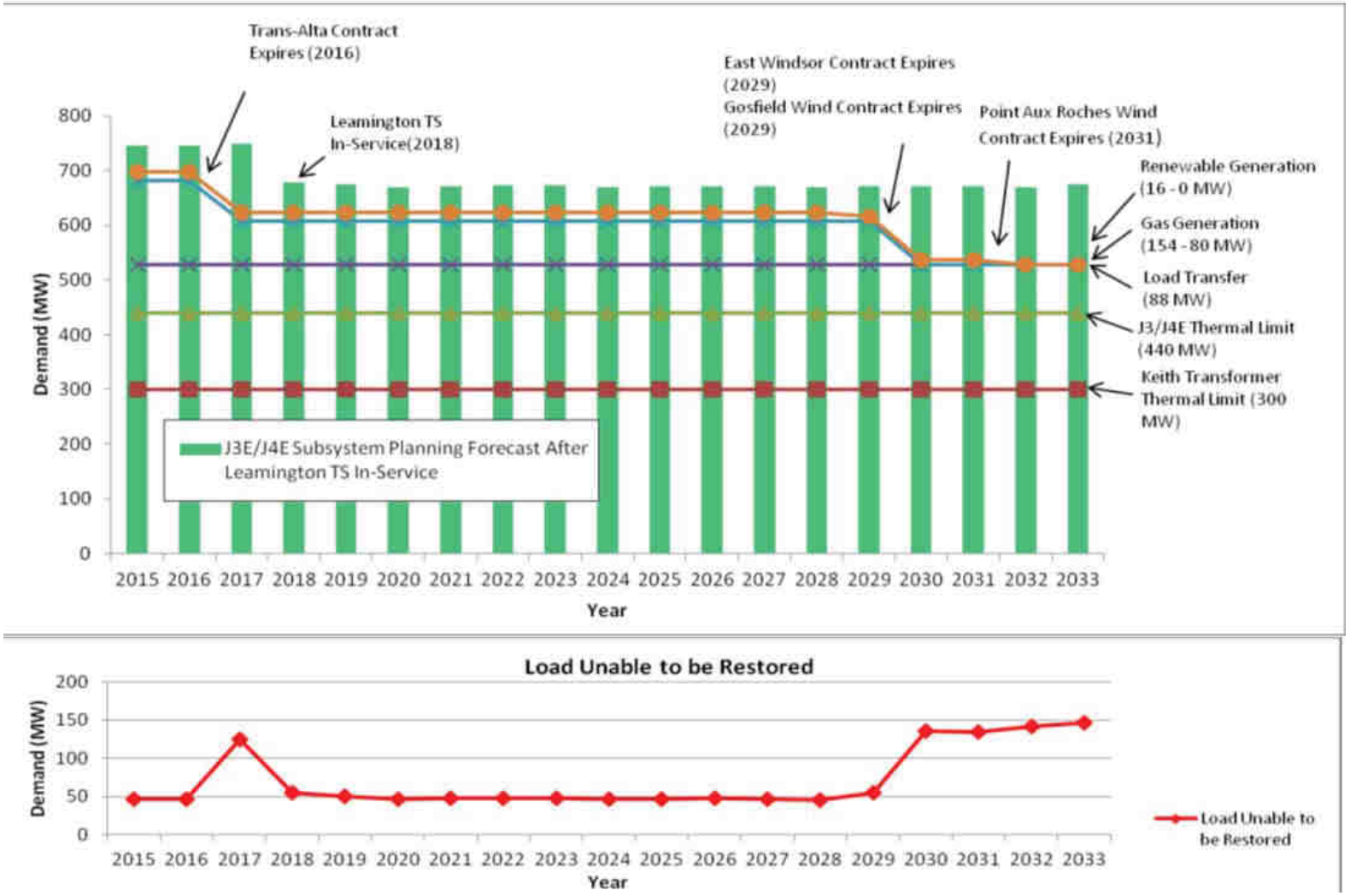
Hydro One has identified that there is a total of 88 MW of capability to transfer load supplied by the 115 kV system to stations supplied by the 230 kV system. This consists of 18 MW of transfer capability to Keith TS, 50 MW to Malden TS, and up to 20 MW of load at Tilbury West DS which can be supplied by the N5K circuit (outside the Region, near Chatham). These transfer capabilities are based on the station capability of Keith TS and Malden TS, and the capability of the N5K circuit.

In addition, as noted in Section 4.2 there is 100 MW of transmission connected renewable generation within the Kingsville-Leamington sub-system. It is reasonable to count on the effective capacity of 16 MW from these facilities for the purpose of providing restoration capability until the two contracts expire in 2029 and 2031 respectively.

The new Leamington TS which has a planned in-service date of 2017 would improve the restoration situation by moving some of the load out of the J3E-J4E sub-system to a new 230 kV supply point. Leamington TS will be supplied by C21J and C22J and will therefore not be affected by the C23Z/C24Z contingency.

Figure 6-4 summarizes the above analysis. After 2016 there is a need for approximately 125 MW of additional restoration capability in order to fully restore the J3E-J4E sub-system following the C23Z/C24Z double-circuit contingency. With the planned Leamington TS in-service in 2018 this requirement will decrease to about 50 MW.

Figure 6-4: J3E – J4E Sub-system Restoration



7. Long-Term Plan

No long-term supply capacity needs have been identified in the Region at this time. Therefore, instead of considering specific needs and planning options, long-term planning activities for the Region will include engaging with stakeholders and communities; monitoring demand, conservation, and DG trends in the area; coordinating with municipal or community energy planning activities; and generally laying the foundation for informed planning in the future. The OEB's regional planning process suggests a minimum 5-year cycle, however if significant changes are noted in the region over the coming years the process may be initiated earlier.

In recent years, a number of trends, including technology advances, policy changes supporting DG, greater emphasis on conservation as part of electricity system planning, and increased community interest and desire for involvement in electricity planning and infrastructure siting, are changing the landscape for regional electricity planning. Traditional, "wires" based approaches to electricity planning may not be the best fit for all communities. New approaches that acknowledge and take advantage of these trends, in addition to more traditional "wires-based", should also be considered.

To facilitate discussions about how a community might plan its future electricity supply, three conceptual approaches for meeting a region's long-term electricity needs provide a useful framework (see Figure 7-1). Based on regional planning experience across the province over the last 10 years, it is clear that different approaches are preferred in different regions, depending on local electricity needs and opportunities, and the desired level of involvement by the community in planning and developing its electricity infrastructure.

Figure 7-1: Approaches to Meeting Long-Term Needs

The three approaches are as follows:

- **Delivering provincial resources**, or "wires" planning, is the traditional regional electricity planning approach associated with the development of centralized electric power systems over many decades. This approach involves using transmission and distribution infrastructure to supply a region's electricity needs, taking power from the provincial electricity system. This model takes advantage of generation that is planned at the provincial level, with generation sources typically located remotely from the region. In this approach, utilities (transmitters and distributors) play a lead role in development.
- The **Centralized local resources** approach involves developing one or a few large, local generation resources to supply a community. While this approach shares the goal of providing supply locally with the community self-sufficiency approach below, the emphasis is on large central-plant facilities rather than smaller, distributed resources.
- The **Community self-sufficiency** approach entails an emphasis on meeting community needs largely with local, distributed resources, which can include: aggressive conservation beyond provincial targets; DR; DG and storage; smart grid technologies for managing distributed resources; integrated heat/power/process systems; and electric vehicles. While many of these applications are not currently in widespread use, for regions with long-term needs (i.e., 10-20 years in the future) there is an opportunity to develop and test out these options before commitment of specific projects is required.

The success of this approach depends on early action to explore potential and develop options, and on the local community taking a lead role. This could be through a municipal energy planning or community energy planning process, or an LDC or other local entity taking initiative to pursue and develop options.

Given that no long-term supply capacity needs have been identified in the Region, it is not necessary to consider the application of these options to Windsor-Essex at this time. These concepts, which are being referenced in other planning regions around the province, are provided as background information for community members and stakeholders who are interested in the long-term considerations for regional electricity supply in Windsor-Essex.

8. Community, Aboriginal and Stakeholder Engagement

Community engagement is an important aspect of the regional planning process. Providing opportunities for input in the regional planning process enables the views and preferences of the community to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken to date for the Windsor-Essex Region IRRP and those that will take place to discuss the Regional planning process and electricity supply needs in the area.

A phased community engagement approach has been developed for the Windsor-Essex IRRP based on the core principles of creating transparency, engaging early and often, and bringing communities to the table. These principles were articulated as a result of the IESO's outreach with Ontarians to determine how to improve the regional planning process, and they are now guiding the IRRP outreach with communities.

Figure 8-1: Summary of Windsor-Essex IRRP Community Engagement Process

Creating Transparency:

Creation of Windsor-Essex IRRP Information Resources

- Dedicated Windsor-Essex IRRP web page created on IESO (former OPA) website providing background information, the IRRP Terms of Reference and listing of the Working Group members
- Dedicated web page added to Hydro One website, and information posted on LDC websites
- Self-subscription service established for Windsor-Essex IRRP for subscribers to receive regional specific updates
- Status: complete

Engaging Early and Often:

Municipal, First Nation & Métis Outreach

- Presentation and discussion at three group meetings with municipal planners from across the planning region
- Information on the plan provided to First Nation communities who may have an interest in the planning area with an invitation to meet
- Information provided to the Métis Nation of Ontario
- Status: initial outreach complete; dialogue to continue

Bringing Communities to the Table:

Broader Community Outreach

- Presentation at Municipal Councils, First Nation communities and Métis Nation of Ontario as requested
- Webinar to discuss regional planning process and electricity needs in the area
- Broader community outreach to be undertaken on education about regional planning in the Windsor-Essex area; feedback from this phase on community values and preferences will inform the decisions to be made in the next planning cycle
- Status: beginning in May 2015; no time limit

Creating Transparency

To start the dialogue on the Windsor-Essex IRRP and build transparency in the planning process, a number of information resources were created for the plan. A dedicated web page was created on the IESO (former-OPA) website to provide a map of the regional planning area, information on why the plan was being developed, the terms of reference for the IRRP and a listing of the organizations involved was posted on the websites of the Working Group members. A dedicated email subscription service was also established for the Windsor-Essex IRRP where communities and stakeholders could subscribe to receive email updates about the IRRP.

Engaging Early and Often

The first step in the engagement of the Windsor-Essex IRRP was providing information to representatives from the municipalities and First Nation communities in the Region. For the municipal meetings, presentations were made to the Windsor-Essex Region municipal planners and Chief Administrative Officers at three group meetings held in Windsor and Chatham during October and November, 2014. Key topics discussed during the meetings included confirmation that the demand forecast reflects municipal planning expectations, system restoration needs, and the strong interest shown by the local greenhouse industry in CHPSOP offered by the former-OPA.

Bringing Communities to the Table

This engagement will begin with a webinar hosted by the Working Group to discuss the plan and approaches for near-term options. Presentations on the Windsor-Essex IRRP will also be made to Municipal Councils, First Nation communities and the Métis Nation of Ontario on request.

To strengthen the discussion, an informational meeting will be held with local representatives from Municipalities including Mayors and economic development groups, Aboriginal communities, local industry and community groups. Following this meeting, a public open house will be held to further expand the discussion and awareness at a community level.

Strengthening processes for early and sustained engagement with communities and the public were introduced following an engagement held in 2013 with 1,250 Ontarians on how to enhance regional electricity planning. This feedback resulted in the development of a series of

recommendations that were presented to, and subsequently adopted by the Minister of Energy. Further information can be found in the report entitled "Engaging Local Communities in Ontario's Electricity Planning Continuum"[13] available on the IESO website.

Information on outreach activities for the Windsor-Essex Region IRRP can be found on the IESO website and updates will be sent to all subscribers who have requested updates on the Windsor-Essex IRRP.

[13] http://www.powerauthority.on.ca/stakeholder-engagement/stakeholder-consultation/ontario-regional-energy-planning-review

9. Conclusion

This report documents the IRRP that has been carried out for the Windsor-Essex Region and it largely fulfils the OEB requirement to conduct regional planning for this Region. The IRRP identifies electricity needs in the Region over the 20-year period from 2014 to 2033, recommends a plan to address near-term needs, and identifies a monitoring and engagement plan for the next few years, to inform the next regional planning cycle.

Implementation of the near-term plan is already underway, with the LDCs developing conservation plans consistent with the Conservation First policy and with infrastructure projects being developed by Hydro One.

The planning process does not end with the publishing of this IRRP. The Windsor-Essex Working Group will continue to meet at least annually to monitor progress and developments in the Region.

Appendix C: IESO Comment Letter

IESO Letter of Comment

Essex Powerlines Corporation

Renewable Energy Generation Investments Plan

April 28, 2017

ieso
Independent Electricity System Operator

Introduction

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

As outlined in the Chapter 5 filing requirements, the Board expects that the [Independent Electricity System Operator][1] ("[IESO]") comment letter will include:

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

Essex Powerlines Corporation – Distribution System Plan

On April 10, 2017, the IESO received a REG Information consisting of FIT and microFIT connections, expansion investments, and in-progress applications ("Plan") from Essex Powerlines Corporation ("Essex"). The IESO has reviewed the Plan and provides the following comments.

IESO FIT/microFIT Applications Received

As of December 31, 2016, the Plan indicates that Essex has connected 150 microFIT projects, representing 1.2536 MW of capacity, along with 12 FIT projects and 2 RESOP projects representing 2.838 MW and 15 MW respectively. Essex has forecast connections of an additional 1.28 MW from 4 additional FIT projects in 2017, 0.9 MW from 3 FIT projects in 2018, 0.384 MW from 2 FIT projects in 2019, and an additional 0.1 MW from 10 additional microFIT projects.

According to the IESO's information as of March 31, 2017, the IESO has offered contracts to 152 microFIT projects totalling 1.2628 MW of capacity, 16 FIT projects totaling 4.114 MW, and 2 RESOP projects totalling 15 MW. The additional 4 FIT projects the IESO has record of are assumed to be the 4 additional projects in Essex' forecast for 2017 for which the IESO has issued contracts.

The REG connections information in Essex' Plan is therefore substantially consistent with that of the IESO.

[1] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

Independent Electricity System Operator
1600 – 120 Adelaide Street West, Toronto, ON M5H 1T1
t 416 967-7474 f 416 967-1947 toll free 1-800-797-9604 customer.relations@ieso.ca www.ieso.ca

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

Essex is one of the five local distribution companies in the Windsor-Essex Region identified through the OEB regional planning process. As member of the Technical Working Group for the Windsor-Essex Region, Essex has been involved in the development of the Windsor-Essex Region Integrated Regional Resource Plan ("IRRP"), which was published in April 2015.[2] On December 22, 2015, Hydro One Networks Inc. published a Regional Infrastructure Plan ("RIP") for this region in which Essex participated as a member of the Working Group.[3]

The regional planning process for this region is now complete and will be undertaken again when the next 5-year planning cycle commences, unless there is sufficient load growth, or an event that triggers the requirement to initiate the regional planning process earlier.

Essex' Plan identifies investments throughout the 2017-2020 period for "transformation and expansions" which will support REG connections. While these investments are not identified in the Hydro One RIP or the IRRP, the IESO's perspective is that they do not require further regional coordination as they are driven by individual connections.

The IESO appreciates the opportunity to comment on the REG Investments Plan provided by Essex, as part of its Distribution System Plan at this time.

[2] http://www.ieso.ca/get-involved/regional-planning/southwest-ontario/windsor-essex
[3] http://www.hydroone.com/RegionalPlanning/Windsor-Essex/Documents/RIP%20Report%20Windsor-Essex.pdf

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Appendix D: INNOVATIVE Customer Satisfaction Surveys

INNOVATIVE RESEARCH GROUP

Essex Powerlines Corp.

Ratepayer Telephone Survey

Report

JULY 2017

STRICTLY PRIVILEGED AND CONFIDENTIAL

Summary of Findings:
Residential Customers

- Residential customers are price-sensitive, but they may be willing to pay more if it means improved reliability. While they are confident that they are well protected when it comes to the quality and reliability of electricity in the province, they cannot say the same about price. Further, most report that they are having to do without some other priorities in order to pay their electricity bills.

- Familiarity with the local electricity distribution system is moderate (51% are at least somewhat familiar), but satisfaction with the service they are receiving from Essex Powerlines is high (85%). In response to an open-ended question designed to elicit unmet needs, customers ask for lower rates (32%), or a reduction in outages (19%). However, 31% had no suggestions, and an additional 6% reported that their service is good.

- Respondents were provided with a list of six potential customer priorities and asked to indicate which were most important to them. When it comes to establishing priorities, price outweighs reliability: 57% say delivering reasonable electricity distribution prices is the *most important* priority, compared to 21% who opt for ensuring reliable electrical service. Customers are least interested in storage and solar panels. In response to an open-ended question, 78% reported that there were no important priorities missing from the list that was presented to them.

- Only a third (34%) of customers are at least somewhat familiar with the amount of their electricity bill that is allocated to Essex Powerlines. Almost half (45%) said they were not familiar.

- Almost half (48%) of Essex Powerlines' residential customers have experienced between one and three outages in the past 12 months, but a plurality (40%) report their most recent outage lasted less than 15 minutes and most (55%) said it was a minor inconvenience.

- Asked if Essex Powerlines should aim to maintain or reduce the current number of unplanned outages, 45% would like them to spend what is needed to maintain the current number. Similarly, 49% would prefer the utility spends what is needed to maintain the current duration of unplanned outages.

- However, customers are not averse to spending on improving reliability: most (71%) would like Essex Powerlines to invest what it takes to replace aging infrastructure to maintain system reliability, even if there is an increase to their bill. Further, 75% would like the utility to replace equipment before failure, and 85% feel it is important to invest now in modernizing the local distribution system. And, finally, 71% feel prudence is important, but that utility staff need to have the proper tools and equipment.

- At the end of the survey, 82% of residential customers give social permission to a rate increase of approximately $0.30 per month based on Essex Powerlines' proposed five year plan. Almost half (45%) say the increase is reasonable and they support it, while a further 37% don't like it, but feel it is necessary. By comparison, only 16% find the proposed increase unreasonable and oppose it.

Summary of Findings:
General Service Customers

- Like residential customers, general service customers feel more protected when it comes to the reliability and quality of electricity than the price of electricity. They too report having to put off other spending priorities in order to pay their electricity bills, but they are less likely than residential customers to be willing to pay more for increased reliability.

- About half (n=29) of the general service customers interviewed are familiar with the local electricity distribution system, but most (n=46) are satisfied with the service Essex Powerlines is providing their organization. In response to an open-ended question designed to elicit any unmet needs, the two predominant themes were lower rates, and improved reliability. Many are fine with their current service as is and do not have suggestions for improvement.

- From a list of six customer priorities, the general service customers interviewed ranked delivering reasonably electricity distribution prices most important, followed by ensuring reliable electrical service. The two least important priorities were electrical storage and solar panel installation, and minimizing impact on the environment. Sixteen general service respondents suggested additional priorities, ranging from new infrastructure to reducing (utility) management pay.

- Fewer than half (n=21) of general service respondents are familiar with how much of their monthly bill is allocated to Essex Powerlines.

- While some (n=11) reported no outages in the past 12 months, 22 general service respondents reported experiencing between one and three outages. Some (n=10) said their last outage lasted less than 15 minutes, but 18 said theirs lasted between an hour and six hours. Further, more than half (n=34) said their most recent power outage was a major inconvenience.

- Unlike residential customers, most (n=28) general service respondents would prefer that Essex Powerlines spend what is needed to reduce the number of unexpected power outages. The same number (n=28) would like a more moderate approach when it comes to reducing the duration of unplanned outages, with the goal being to maintain the current length.

- General service respondents feel Essex Powerlines should invest what it takes to replace aging infrastructure to maintain reliability – even if that mean a slight increase in their monthly bill (n=48). And, most (n=40) do not want to wait until breakdown before replacing equipment. Fifty of the sixty general service customers interviewed feel it is important to invest now in modernizing the distribution system, and 43 say the utility should be wise with its spending, but that staff need the proper tools and equipment.

- At the end of the survey, 21 of the 34 general service respondents asked either find the proposed rate increase reasonable and they support it (n=10), or they don't like it but think it is necessary (n=11). Only 13 oppose the rate increase and find it unreasonable.

Survey Methodology

Field and Design

Essex Powerlines commissioned Innovative Research Group (INNOVATIVE) to conduct a customer engagement telephone survey among their residential, general service under 50 kWh and general service over 50 kWh rate classes in preparation for their upcoming rate application filing with the Ontario Energy Board. INNOVATIVE, on behalf of Essex Powerlines, invited customers from these three rate classes to participate in a 12 minute telephone survey.

- The **residential** survey fielded from June 19th to 27th, 2017
- The **general service** surveys fielded from June 22nd to 29th, 2017

The residential telephone survey used a stratified random sampling approach based on known characteristics, in this case, consumption and community. Overall, 524 residential customers, completed the survey. Slight statistical weights were applied to the final data to ensure the sample was representative of Essex Powerlines customers by community and annual consumption level. The margin of error for the final weighted residential sample of n=500 is ±4.4%, 19 times out of 20.

A total of 51 general service under 50 kWh customers and 9 general service over 50 kWh customers completed the survey. Numerous attempts were made to recruit customers in these rate classes to complete the survey, and these figures represent the final sample once the contact list had been exhausted. The data was combined for reporting purposes, and a qualitative assessment is provided in this report. Due to the qualitative nature of the analysis, no margin error is applied.

Sample lists were provided by Essex Powerlines. Screening questions were designed to ensure only customers who received an electricity bill from Essex Powerlines were included. In addition, residential customers needed to have primary or shared responsibility over their household's electricity bill and only the organizations' decision makers on electricity use were included in the business interviews. Business customers could also be household customers of Essex Powerlines, but were reminded to respond as their organization's decision-maker.

ESSEX POWERLINES CORPORATION

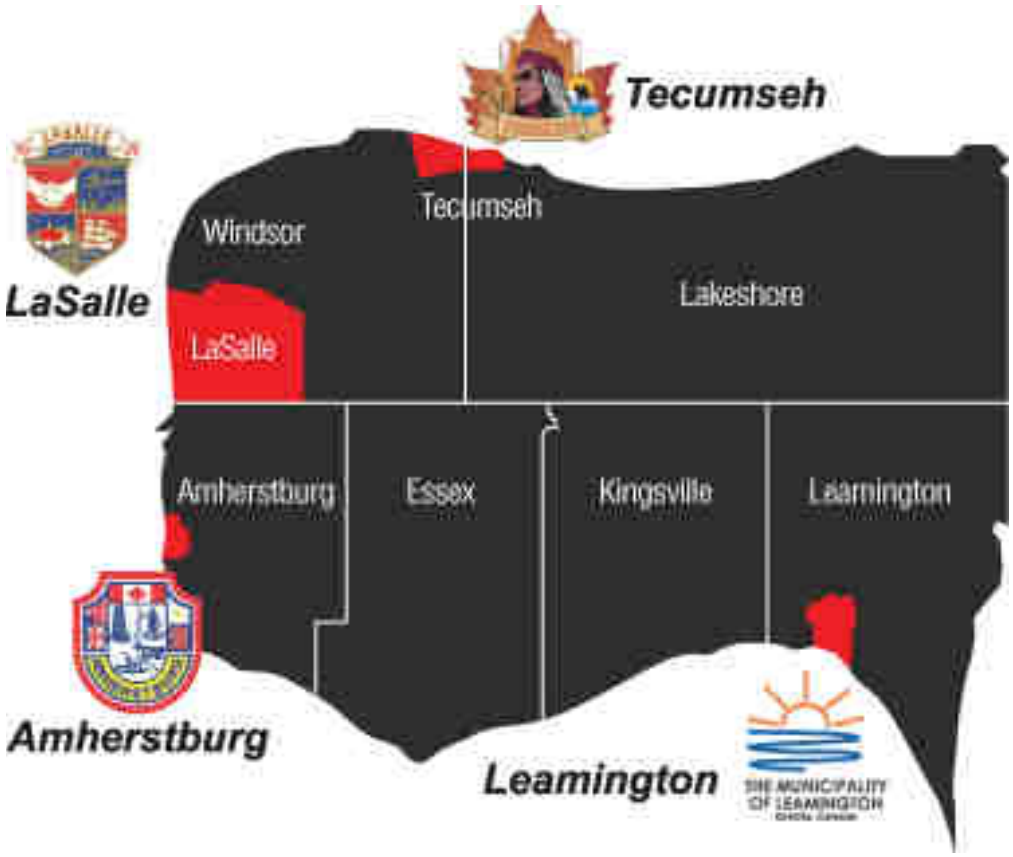
Residential Rate Class

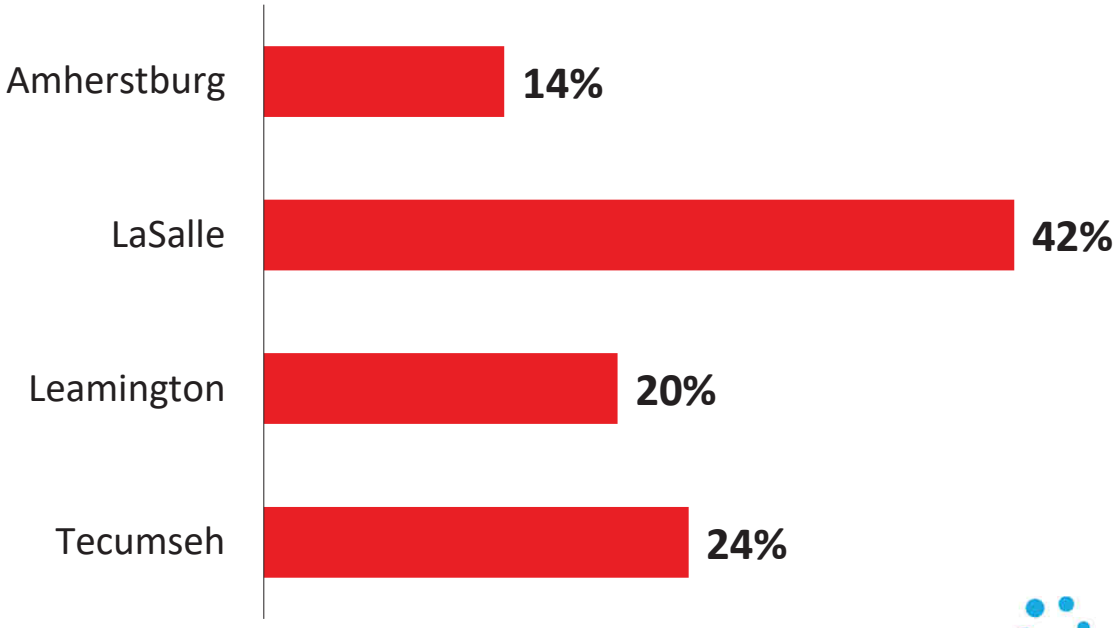
Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

INNOVATIVE RESEARCH GROUP

Residential

Regional Segmentation



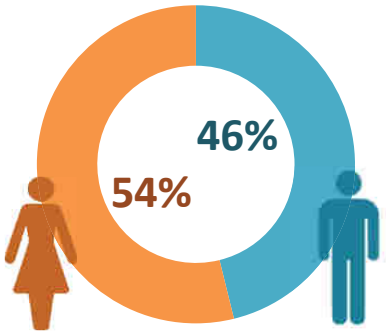


INNOVATIVE RESEARCH GROUP

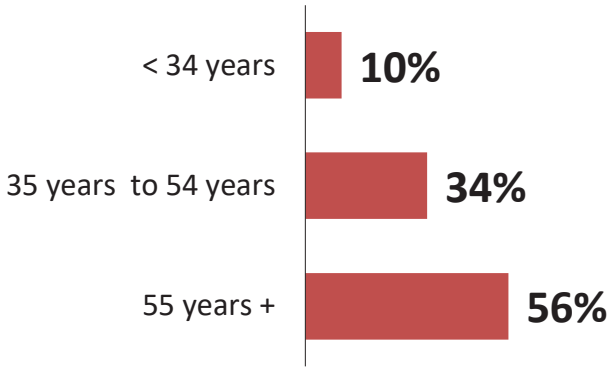
Residential

Segmentation & Demographics

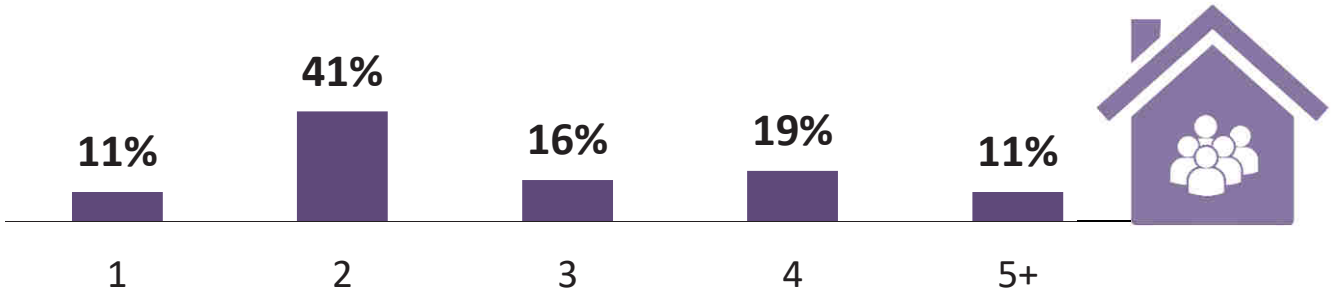
Gender



Age

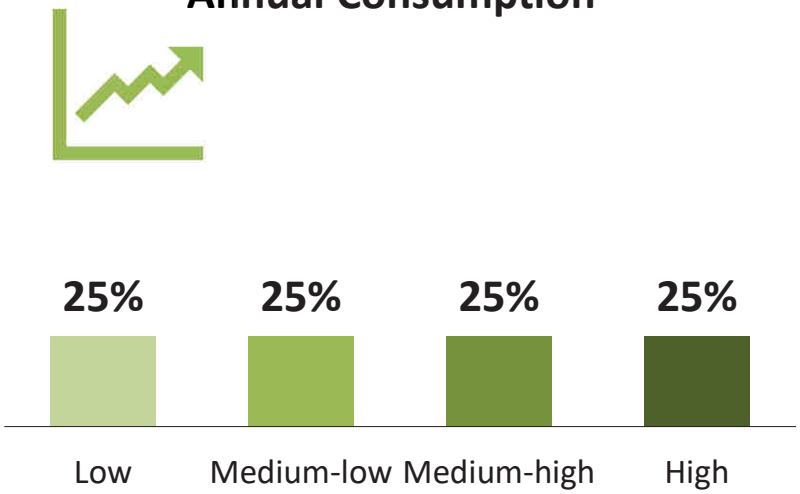


Household Size

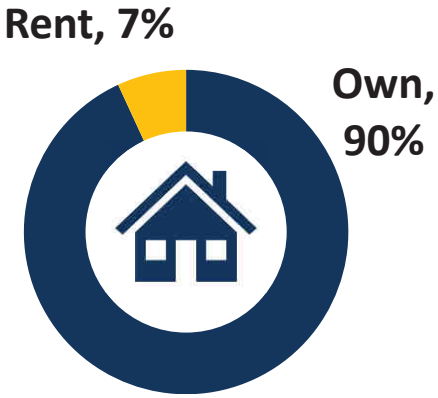


Note: 'Refused' (3%) not shown.

Annual Consumption



Home Ownership



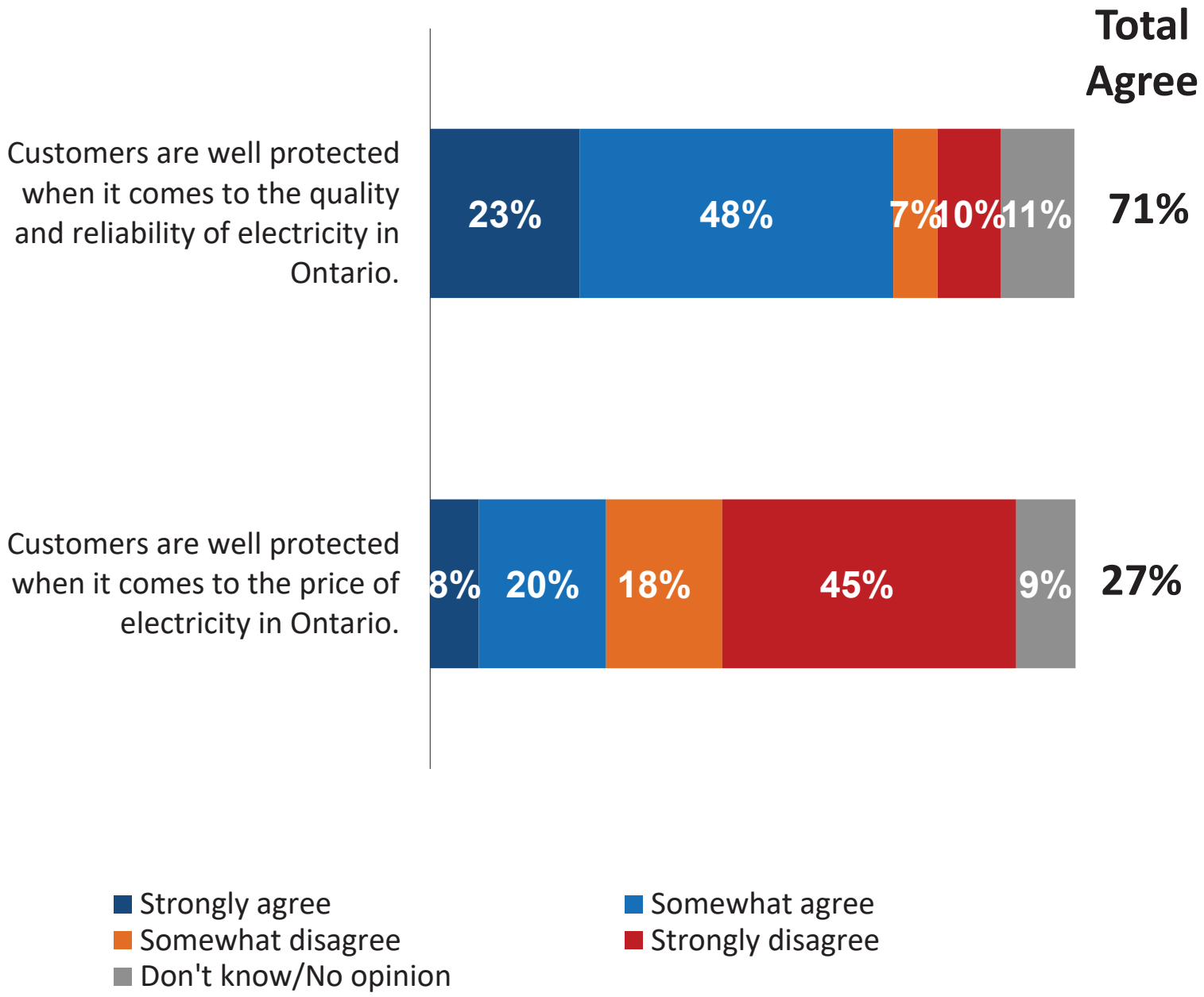
Note: 'Refused' (4%) not shown.

Attitudes Toward Electricity in Ontario:

Residential customers feel protected on quality and reliability, but not on price

Residential

Q Lastly, I'd like to ask you some general questions about the electricity system in Ontario. For each statement please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree. If you don't know enough to say or don't have an opinion just let me know.
[asked all respondents, n=500]



INNOVATIVE RESEARCH GROUP

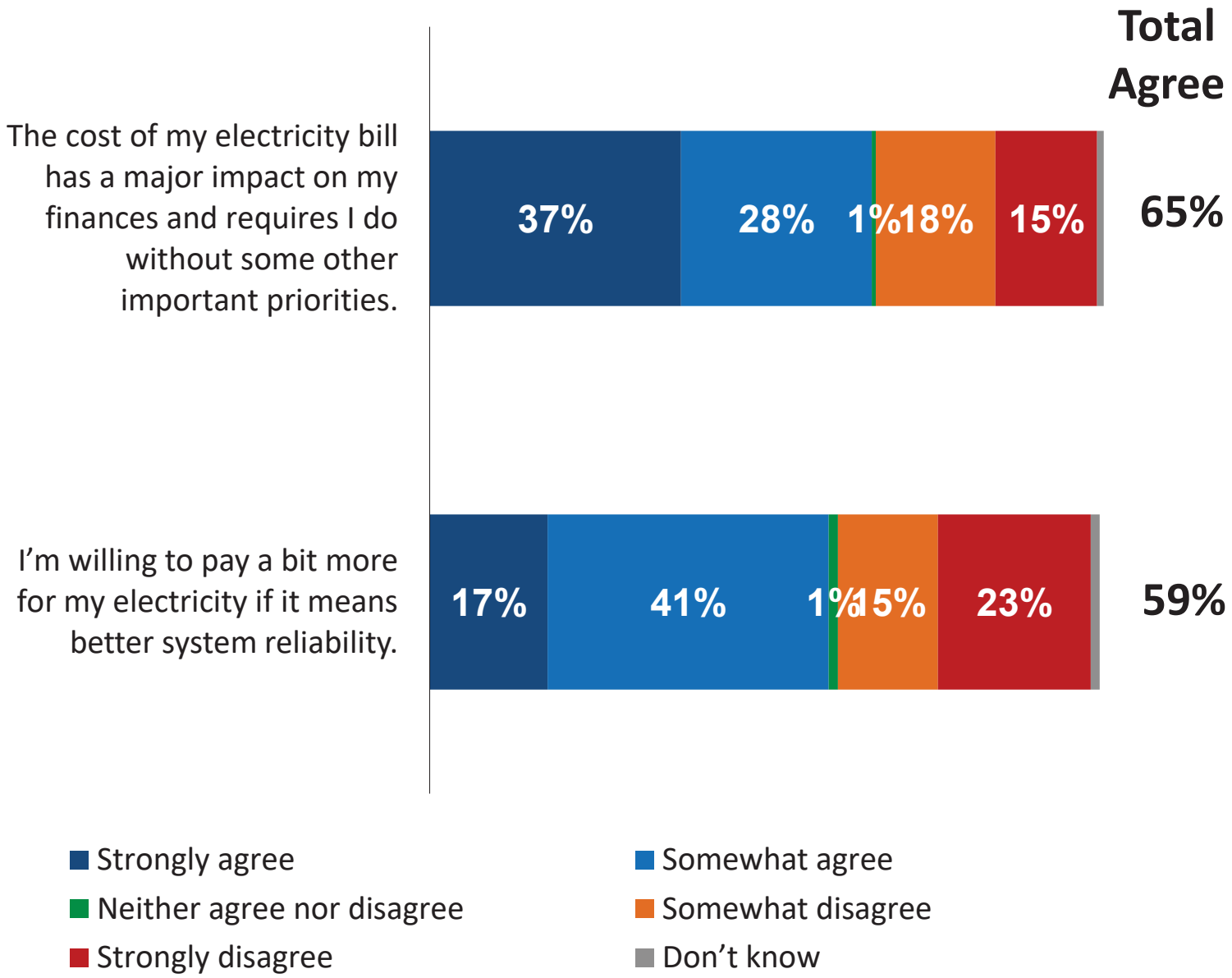
Note: 'Refused' (1%) not shown.

Paying for Electricity:

While most (65%) say their hydro bill has a major impact on their finances, more than half (59%) would pay more for improved reliability

Residential

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=500]



Note: 'Refused' (1%) not shown.

Familiarity:

Approximately half (51%) are familiar with the local electricity distribution system; highest among those with high annual consumption

Residential

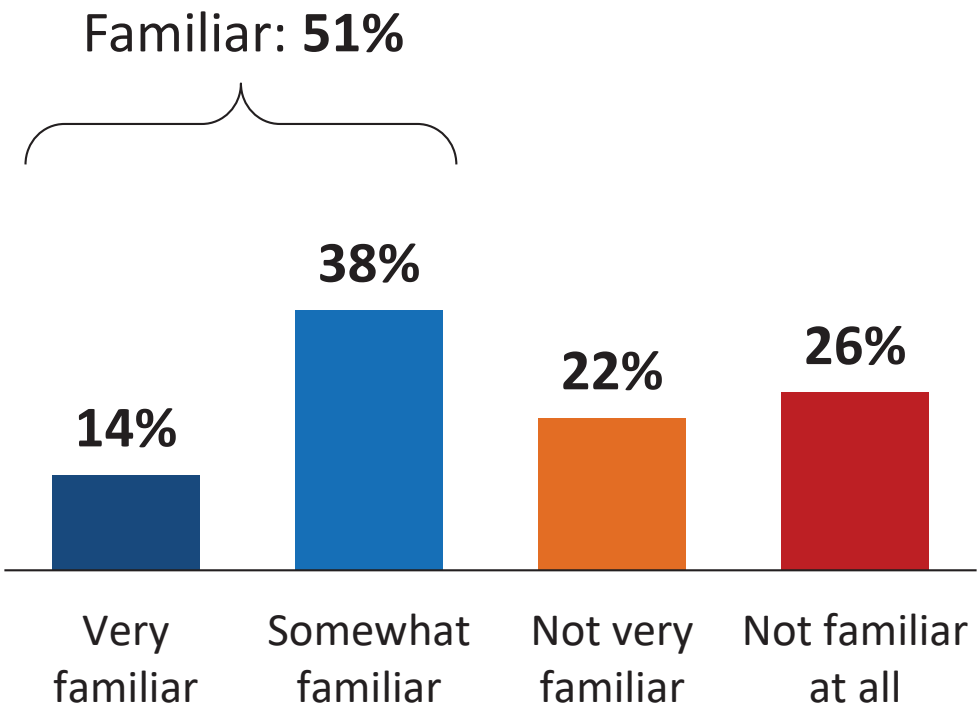
Q To start, I'd like to ask you a few questions about the electricity system… As you may know, Ontario's electricity system has three key components: **generation, transmission** and **distribution**.

- **Generating stations** convert various forms of energy into electric power;
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province; and
- **Distribution lines** carry electricity to the homes and businesses in our communities.

Today we're going to talk about your local distribution system which, in your community, is maintained and operated by Essex Powerlines.

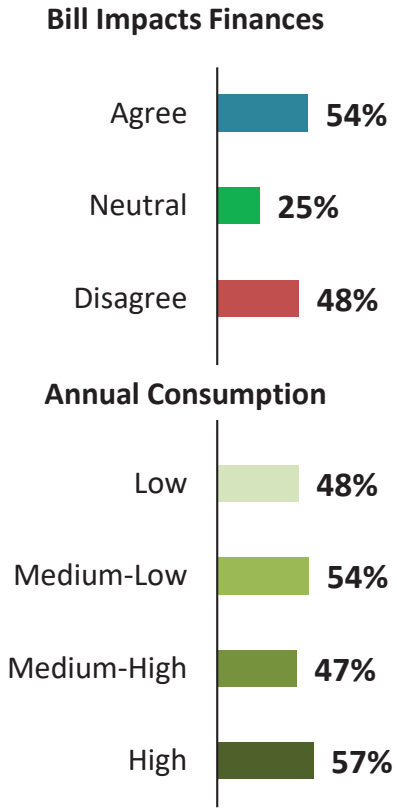
How familiar are you with the local electricity distribution system? Would you say …

[asked all respondents, n=500]



Segmentation ▸▸

*Those who say "**Familiar**":*



INNOVATIVE RESEARCH GROUP

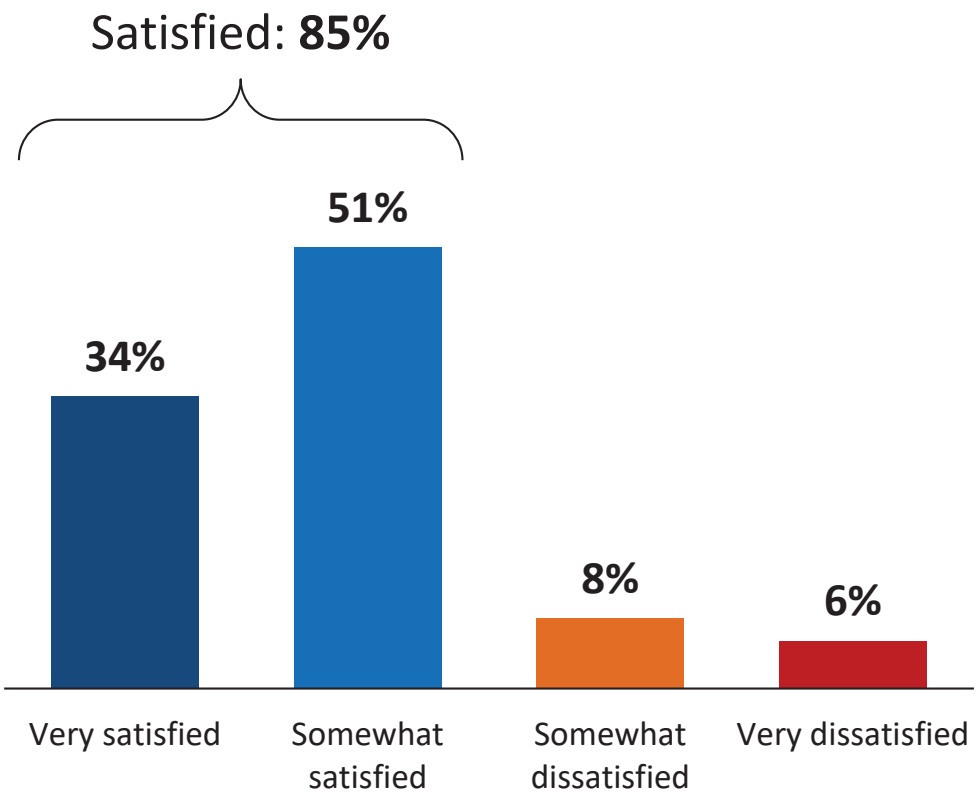
Note: 'Don't know' (1%) not shown.

Satisfaction with Services:

Majority (85%) are satisfied with Essex Powerline's performance; highest among those with lowest annual consumption

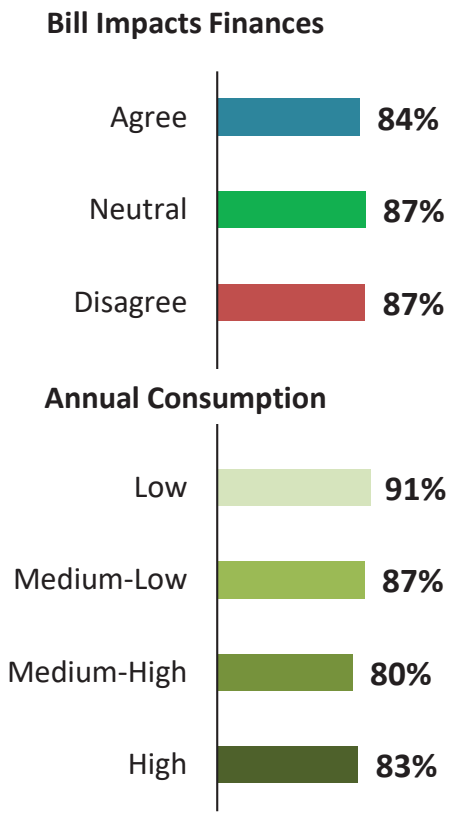
Residential

Q Generally speaking, how satisfied are you with the job **Essex Powerlines** is doing running your local distribution system? Would you say…
[asked all respondents, n=500]



Segmentation

*Those who say "**Satisfied**":*



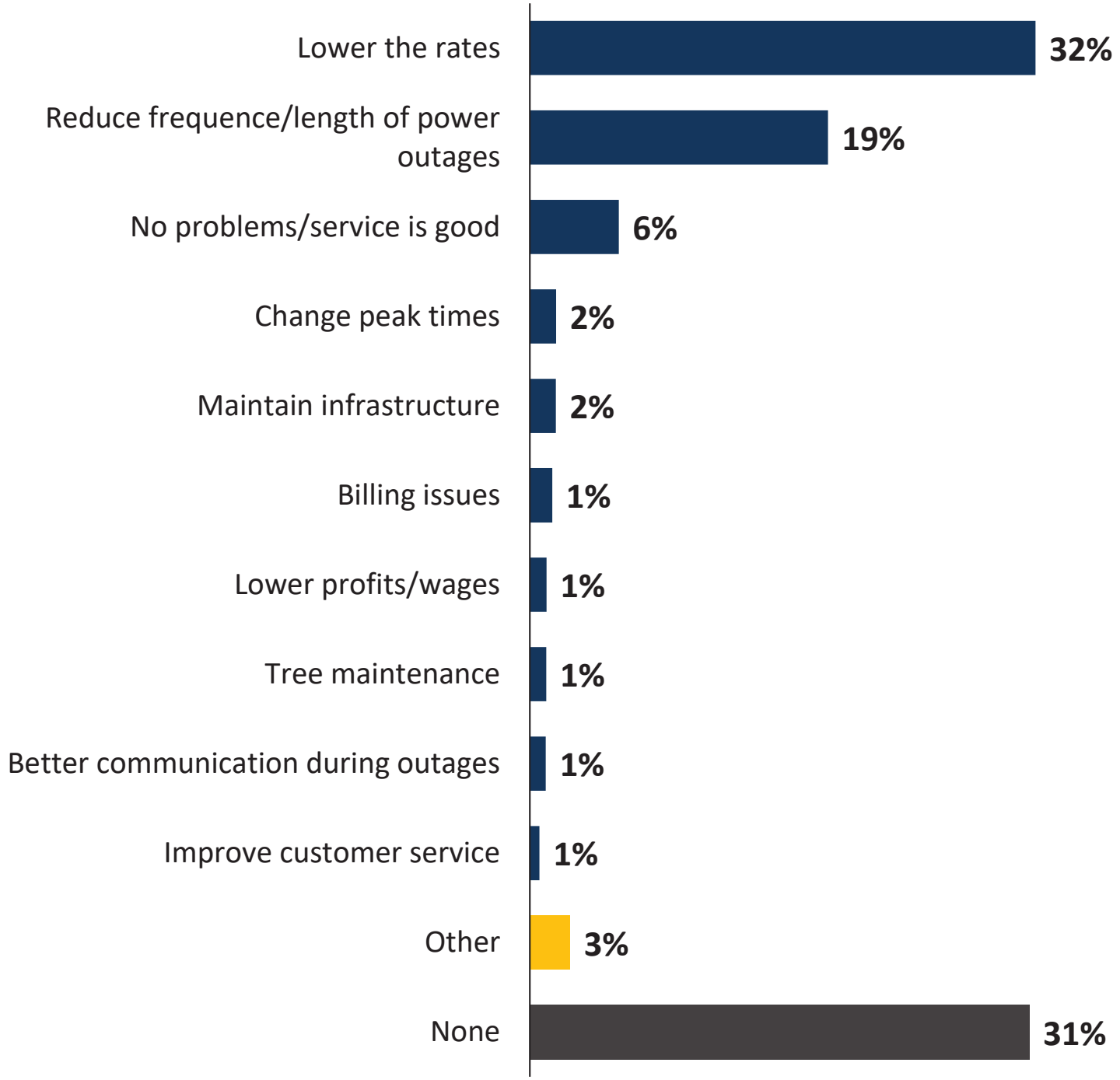
Note: 'Don't know' (1%) not shown.

Suggestions for Improvement:

Almost 1-in-3 (31%) do not have any suggestions for improvement; those who did identified lowering rates as the top suggestion

Residential

Q Is there anything in particular **Essex Powerlines** can do to improve its service to you?
[asked all respondents, n=500]



INNOVATIVE RESEARCH GROUP

Note: 'Don't know' (1%) not shown.

Customer Priorities:

Majority (57%) identified 'delivering reasonable electricity distribution prices' as their most important priority

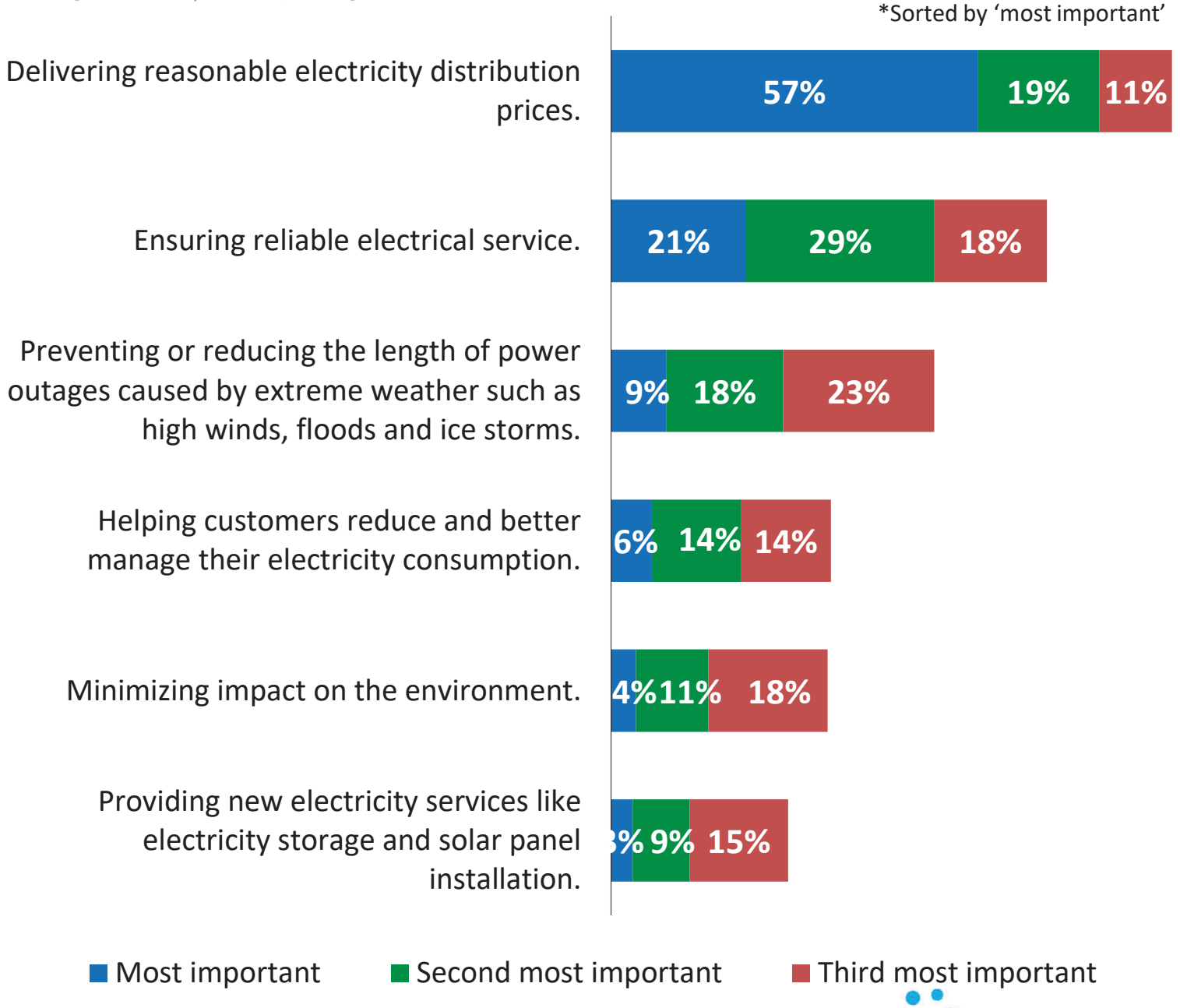
Residential

Q Essex Powerlines regularly holds discussions with its customers to better understand how it should set spending priorities with the money customers pay for service. In recent conversations with customers, a number of company goals were identified as key priorities for Essex Powerlines.

Among the following Essex Powerlines priorities, please tell me which one is most important to you. What is the next most important priority you think Essex Powerlines should focus on? And what do you consider the third most important priority?

[asked all respondents, n=500]

*Sorted by 'most important'



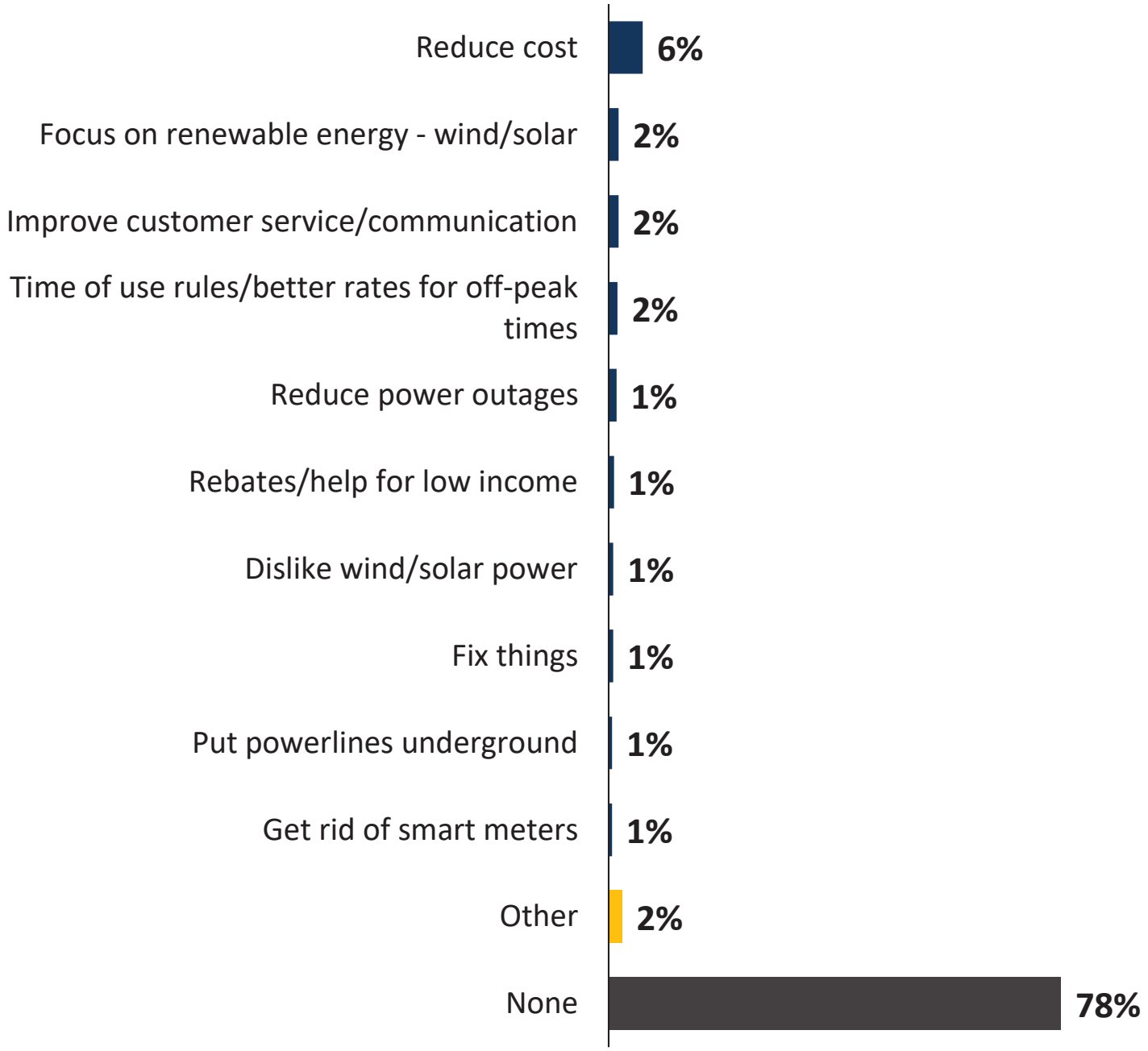
INNOVATIVE RESEARCH GROUP

Additional Priorities:

Majority (78%) have no suggestions for missed priorities; those who did mentioned reducing cost (6%)

Residential

Q Are there any other important priorities that Essex Powerlines should be focusing on that weren't included in the previous list I read to you?
[asked all respondents, n=500]



INNOVATIVE RESEARCH GROUP

Note: 'Don't know' (1%), 'Refused' (2%) not shown.

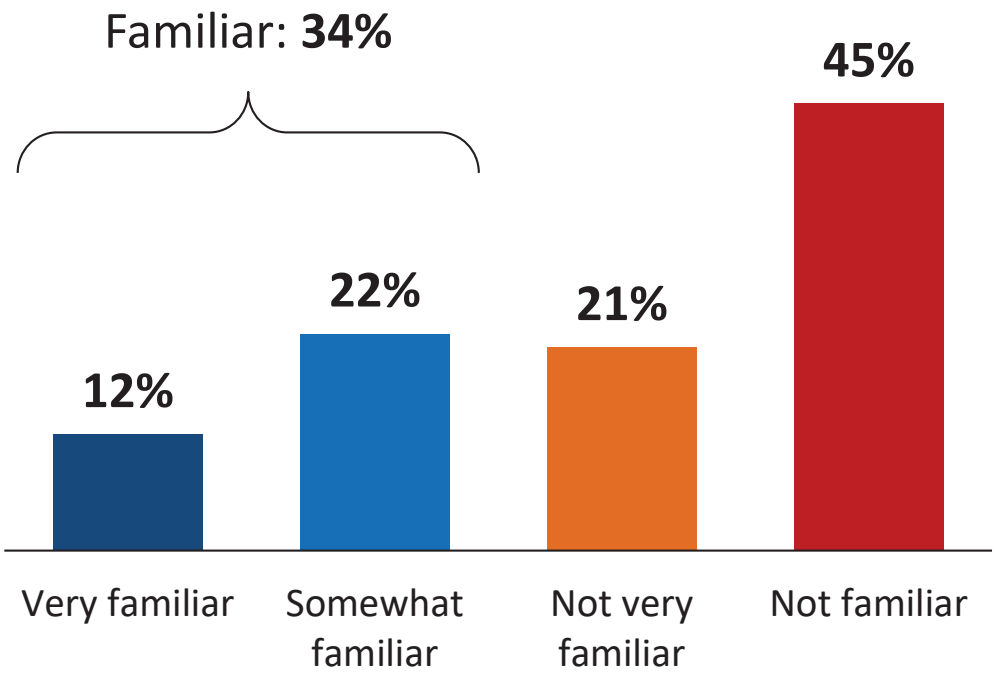
Bill Knowledge & Impact:

Approximately 1-in-3 (34%) are familiar with the amount remitted; familiarity appears highest among those with highest annual consumption

Residential

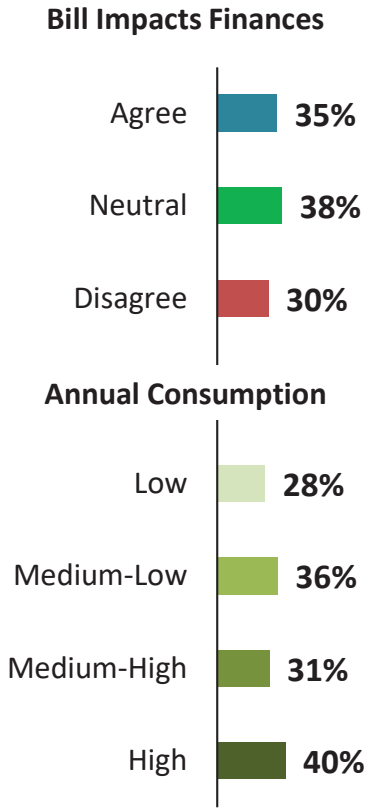
Q I'd now like to talk with you about your electricity bill… While some customers pay more and others pay less, the **average residential customer pays about $145 a month** for electricity and other municipal services, of which **approximately $26 or 20% goes to Essex Powerlines**. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the amount of your electricity bill that went to Essex Powerlines? Would you say…
[asked all respondents, n=500]



Segmentation

*Those who say "**Familiar**":*



Note: 'Don't know' (0%) not shown.

ESSEX POWERLINES CORPORATION

System Reliability

Residential

INNOVATIVE RESEARCH GROUP

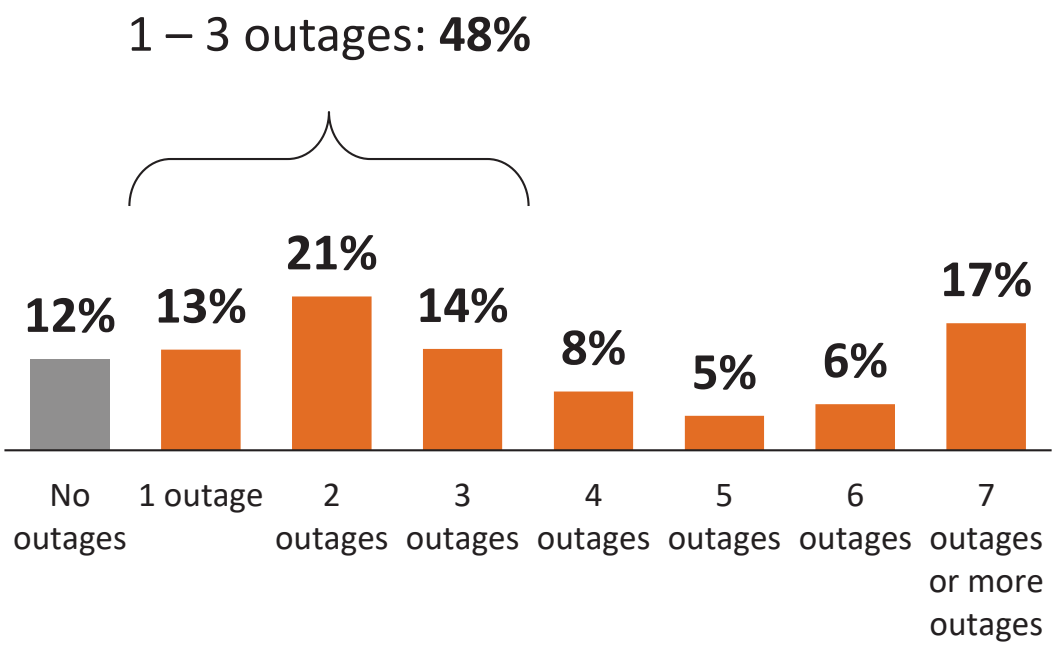
System Reliability:

A plurality (48%) have experienced 1-3 outages in the past 12 months; 17% report 7 outages or more; 12% report no outages

Residential

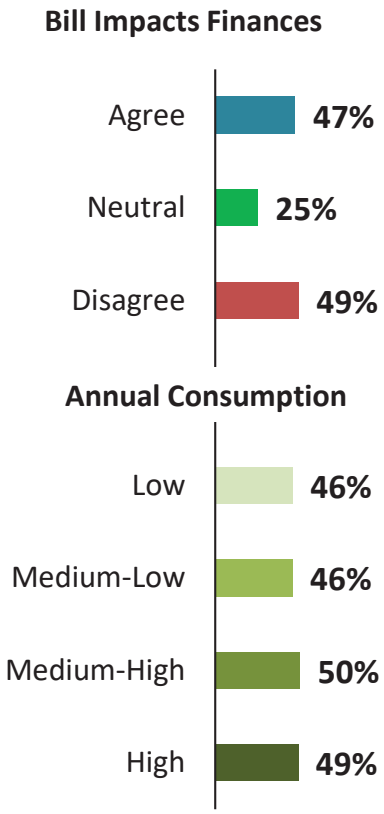
Q Despite best efforts, no electrical distribution system can deliver perfectly reliable electricity. As a general rule, the more reliable the system, the more expensive the system is to build and maintain. With that said, the average **Essex Powerlines** customer experiences one unexpected power outage per year.

Have you experienced any power outages in the past 12 months, and if so, approximately how many?
[asked all respondents, n=500]



Segmentation ▸▸

*Those who say "**1-3 Outages**":*



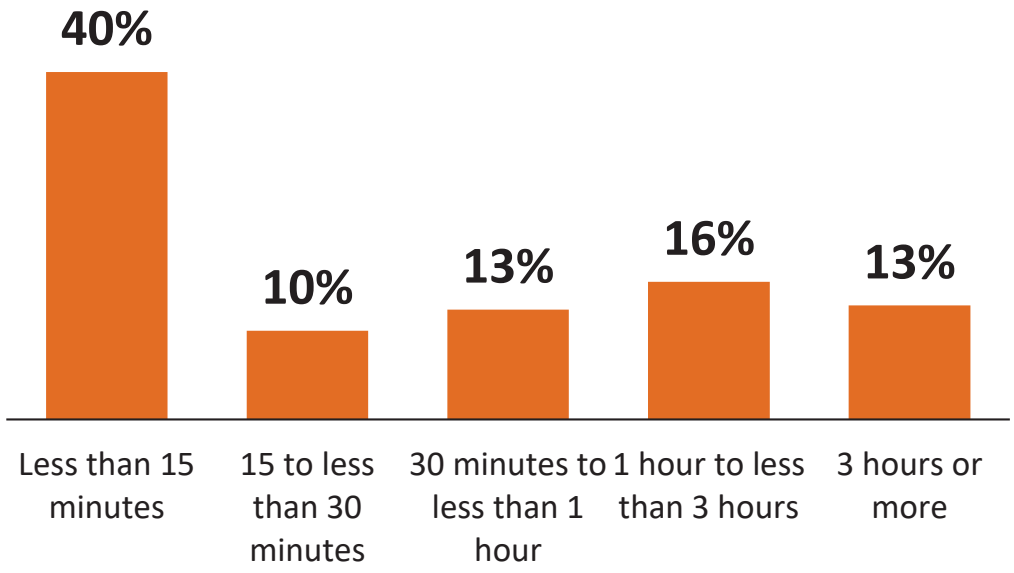
Note: 'Don't know' (4%) not shown.

System Reliability:

2-in-5 (40%) report that the most recent power outage they experienced lasted less than 15 minutes

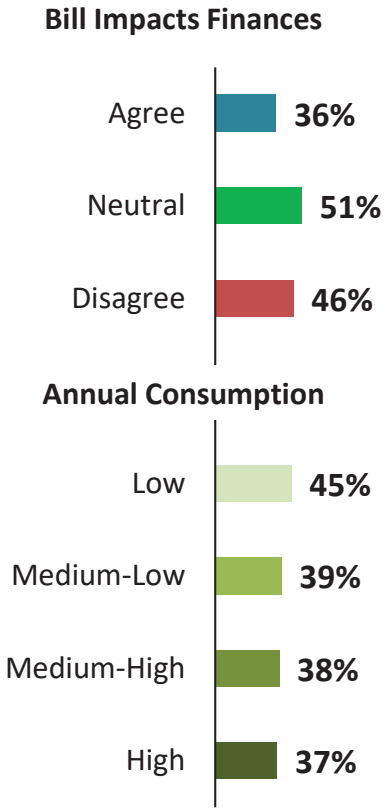
Residential

Q And approximately how many minutes did the most recent power outage last?
[asked of those who have experienced an outage, n=418]



Segmentation

*Those who say "**Less than 15 minutes**":*



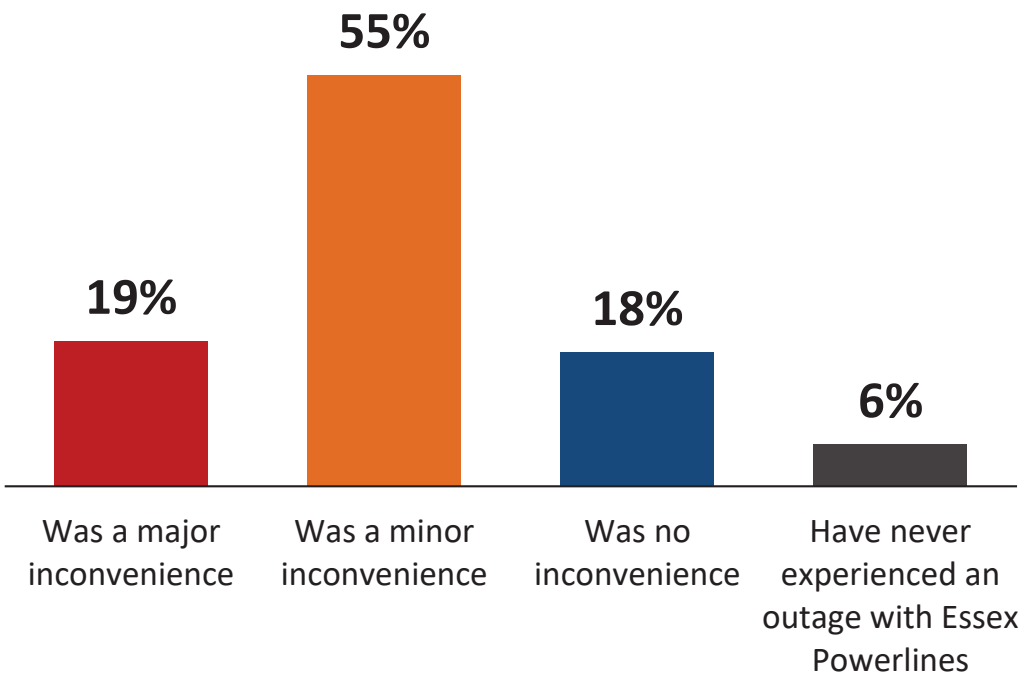
Note: 'Don't know' (9%) not shown.

System Reliability:

When reflecting on their most recent power outage experience, more than half (55%) said it was a minor inconvenience

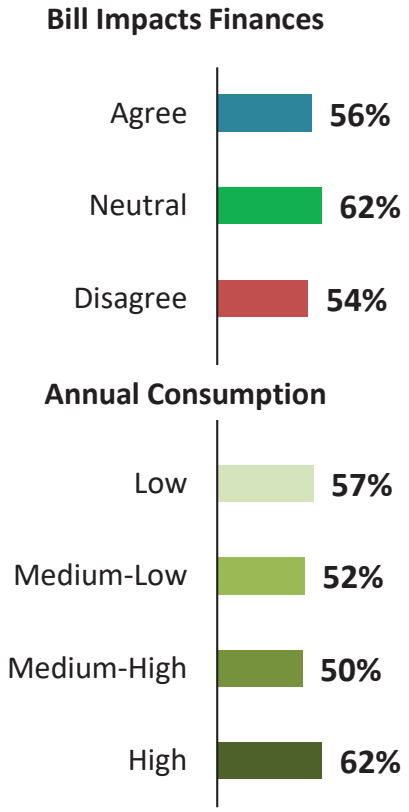
Residential

Q Thinking back to the most recent power outage you experienced as an Essex Powerlines customer, would you say the power outage…
[asked of those who have experienced an outage, n=500]



Segmentation

*Those who say "**Minor inconvenience**":*



Note: 'Don't know' (2%) not shown.

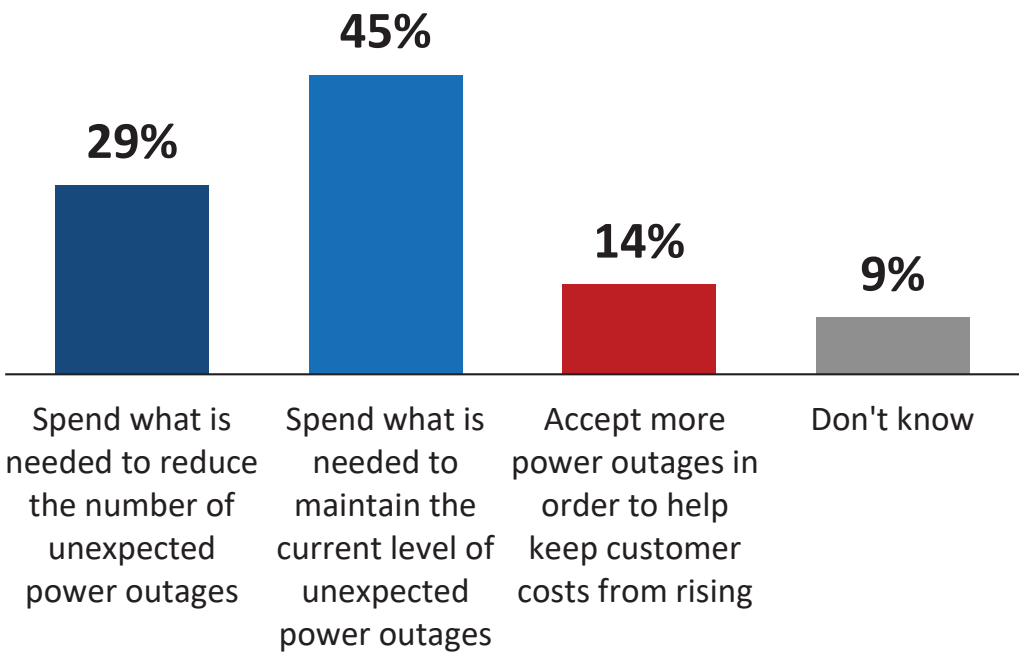
System Reliability:

A plurality (45%) say Essex Powerlines should spend what is needed to maintain the current level of unexpected power outages

Residential

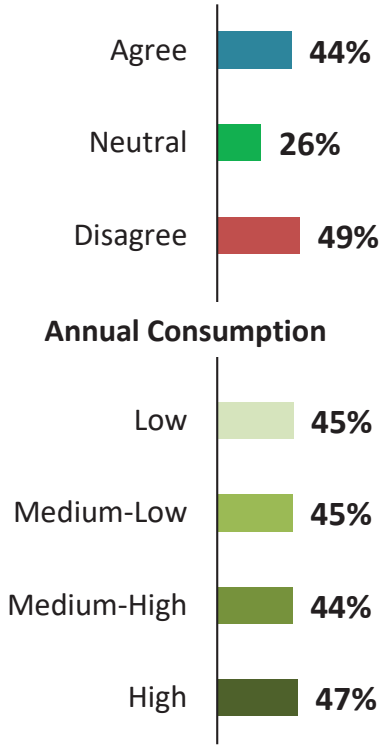
Q In your view, how do you think Essex Powerlines should address the **number** of customer power outages? Would you say…

[asked of those who have experienced an outage, n=500]



Segmentation

*Those who say "**Spend what is needed to maintain…**":*



INNOVATIVE RESEARCH GROUP

Note: 'Refused' (4%) not shown.

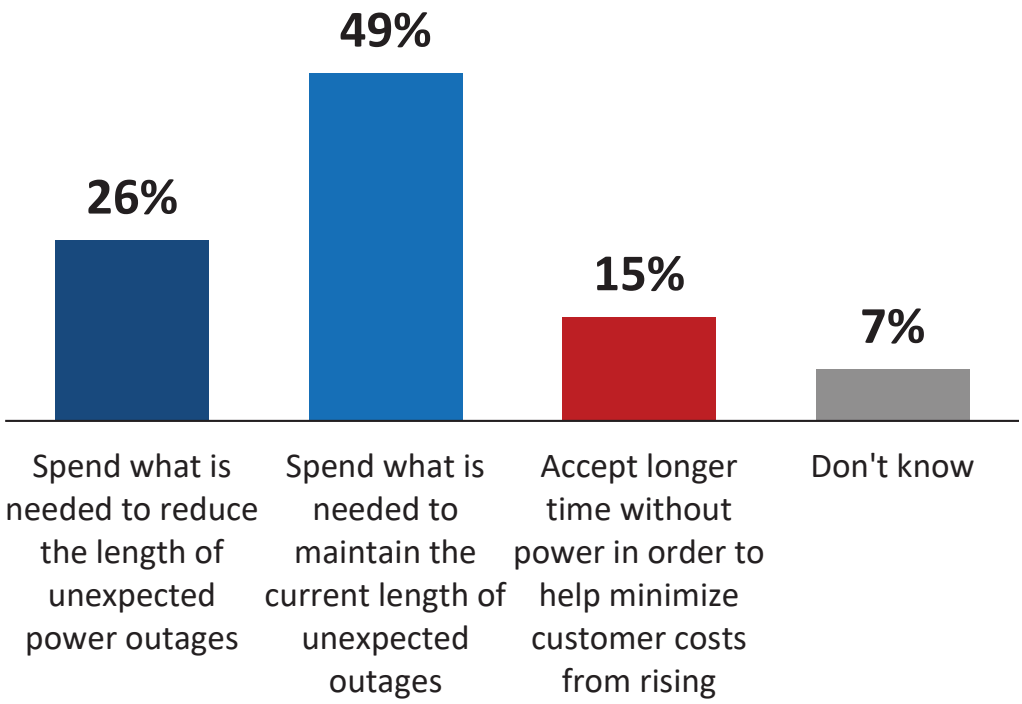
System Reliability:

Almost half (49%) say Essex Powerlines should spending what is needed to maintain the current length of unexpected outages

Residential

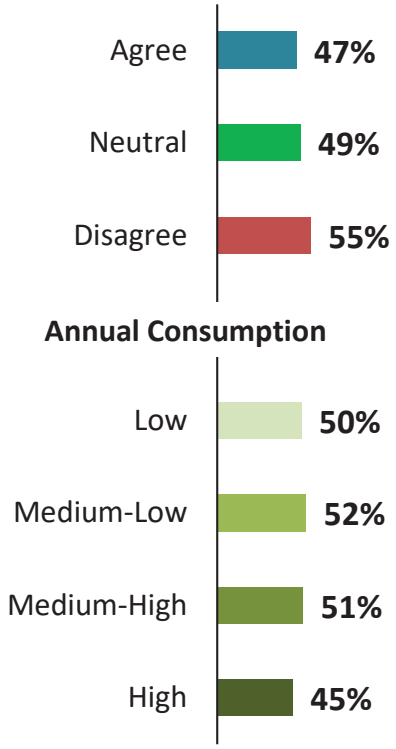
Q Overall, the average **Essex Powerlines** customer is without power for about **one hour per year**. In your view, how do you think Essex Powerlines should address the **length of time** customers are without power? Would you say…

[asked of those who have experienced an outage, n=500]



Segmentation

*Those who say "**Spend what is needed to maintain…**":*



Note: 'Refused' (3%) not shown.

ESSEX POWERLINES CORPORATION

System Challenges & Priorities

Residential

INNOVATIVE RESEARCH GROUP

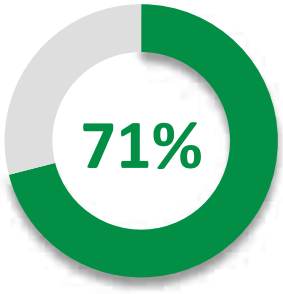
System Challenges & Priorities:

Majority (71%) hold the view that Essex Powerlines should invest what it takes to replace the system's aging infrastructure

Residential

Q While **Essex Powerlines** believes it has done its best to prolong the life of the assets that make up the distribution system, many of these assets are approaching the end of their useful life. As part of its investment plan, Essex Powerlines is proposing an infrastructure renewal program. The estimated cost of this system renewal program is **$31 million** between 2018 and 2022. Although this plan will allow Essex Powerlines to make, what independent studies suggest are, the necessary investments needed to maintain system reliability, **it *may* have an impact on customer bills**.

Which of the following statements best represents your point of view?
[asked all respondents, n=500]

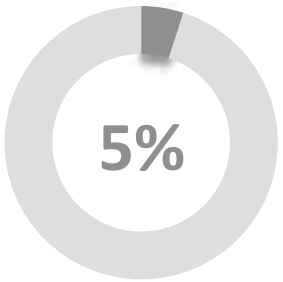


Invest What It Takes

Some customers have said…
Essex Powerlines should invest what it takes to replace the system's aging infrastructure to maintain system reliability, even if that increases my monthly electricity bill by less than a dollar over the next few years.

Lower Investment

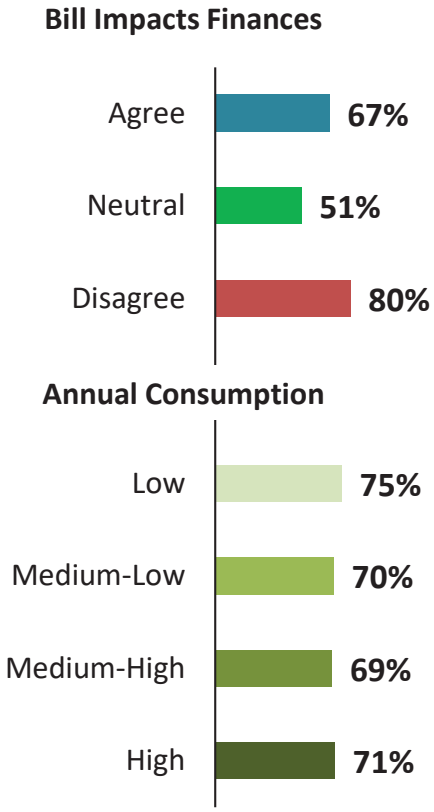
Others have said…
Essex Powerlines should lower its estimated investment in renewing the system's aging infrastructure to lessen possible bill increases, even if that means more or longer power outages.



Don't know

Segmentation ▸▸

*Those who say "**Invest what it takes**":*



INNOVATIVE RESEARCH GROUP

Note: 'Refused' (5%) not shown.

Run-to-Failure:

Majority (75%) feel the best approach is to replace the equipment before it breaks down

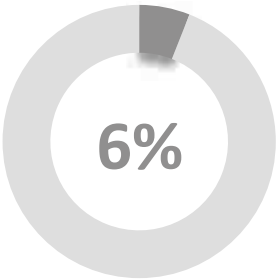
Residential

Q Thinking about the aging equipment in Essex Powerlines' distribution system, do you feel it's best to wait until non-critical infrastructure – that is, equipment that impacts a limited number of customers – breaks down to get full value from each piece of equipment, even if it means short power outages for some customers…

…Or do you feel the best approach is to replace the equipment before it breaks down to avoid unscheduled power outages, even if it means not getting the "full" value from each piece of equipment?
[asked all respondents, n=500]

Replace Equipment Before Breakdown

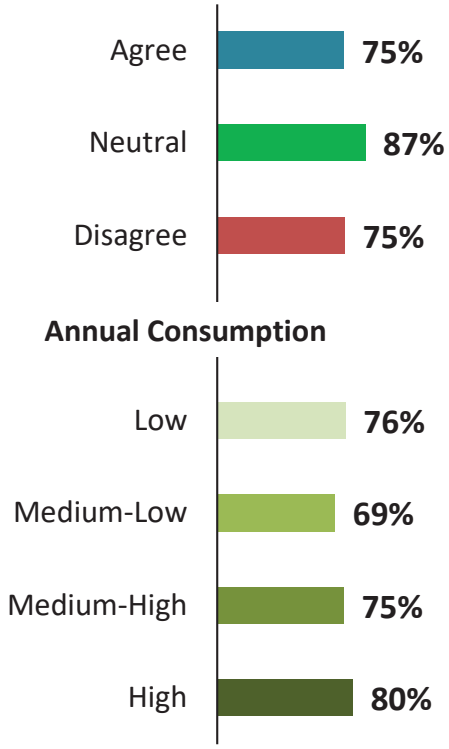
Wait Until Equipment Breakdown



Don't know

Segmentation ▸▸

*Those who say "**Replace before equipment breakdown**":*



INNOVATIVE RESEARCH GROUP

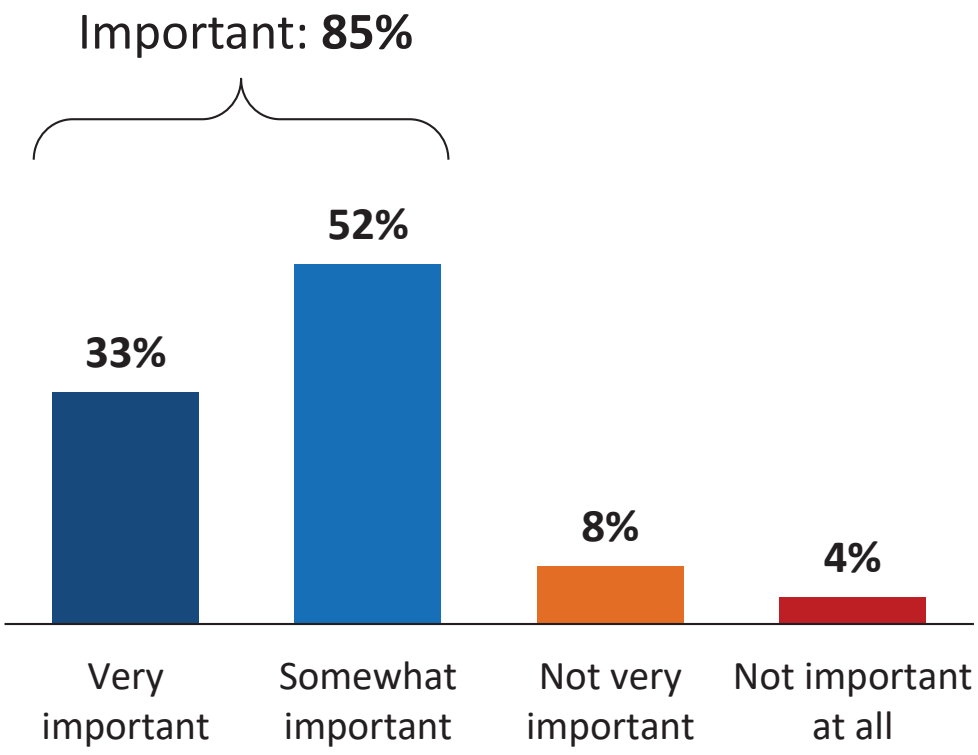
System Service:

Majority (85%) feel investing in modernizing the distribution system is important; feelings appear strongest among medium-high annual consumers

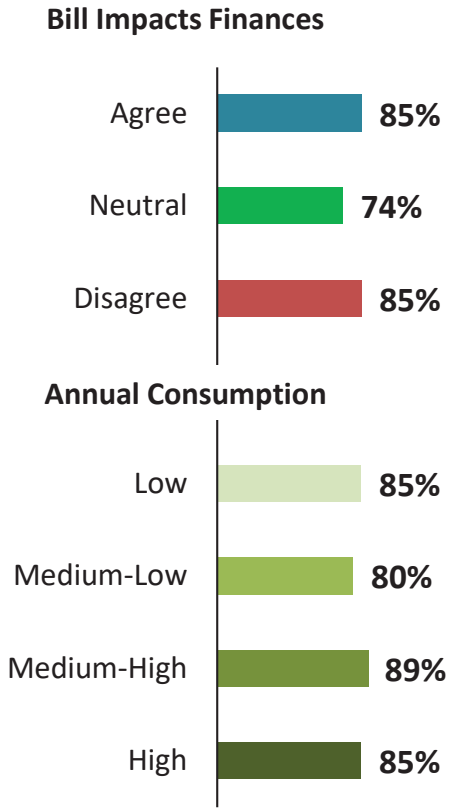
Residential

Q Modernizing the distribution system can allow Essex Powerlines to improve reliability. Investments, such as automated switches, may allow Essex Powerlines to minimize the number of people impacted by outages and to restore electricity to many customers in a matter of seconds.

Given there are many other areas of needed investments, such as connecting new customers, replacing aging equipment and expanding capacity for long-term growth, how important do you feel it is for Essex Powerlines to invest now in modernizing the distribution system?
[asked all respondents, n=500]



Segmentation ▸▸
*Those who say "**Important**"*



INNOVATIVE RESEARCH GROUP

Note: 'Don't know' (3%) not shown.

General Plant:

Majority (75%) say Essex Powerlines should be wise with spending but acknowledge the importance of proper tools and equipment

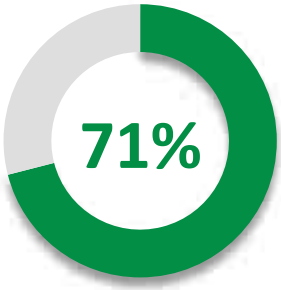
Residential

Q Essex Powerlines is not just the local electricity distribution system itself, but a company that operates the system. As a company, Essex Powerlines needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the electrical system and customer information.

Again, customers have made a number of statements about this sort of investment. Which of the following statements best represents your point of view?
[asked all respondents, n=500]

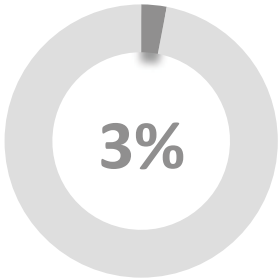
Find Ways To Make Due

Some customers have said…
Essex Powerlines should find ways to make do with the buildings, equipment and IT systems it already has.



Be Wise With Spending

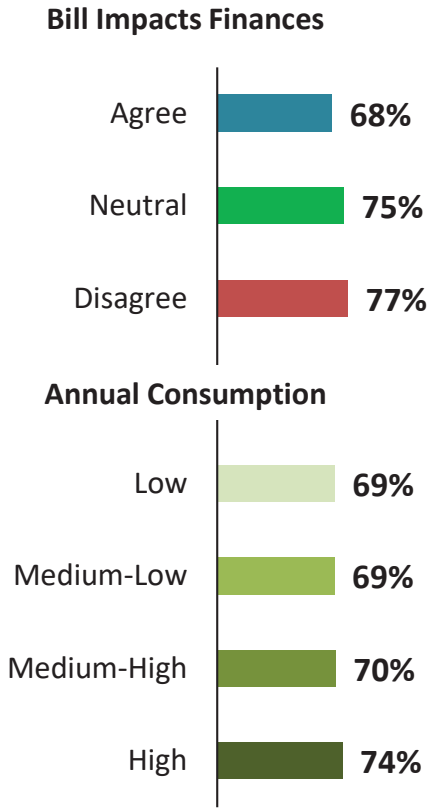
Others have said…
While Essex Powerlines should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably.



Don't know

Segmentation ▸▸

*Those who say "**Be wise with spending**"*



INNOVATIVE RESEARCH GROUP

Note: 'Refused' (2%) not shown.

ESSEX POWERLINES CORPORATION

Reaction to Customer Input

Residential

INNOVATIVE RESEARCH GROUP

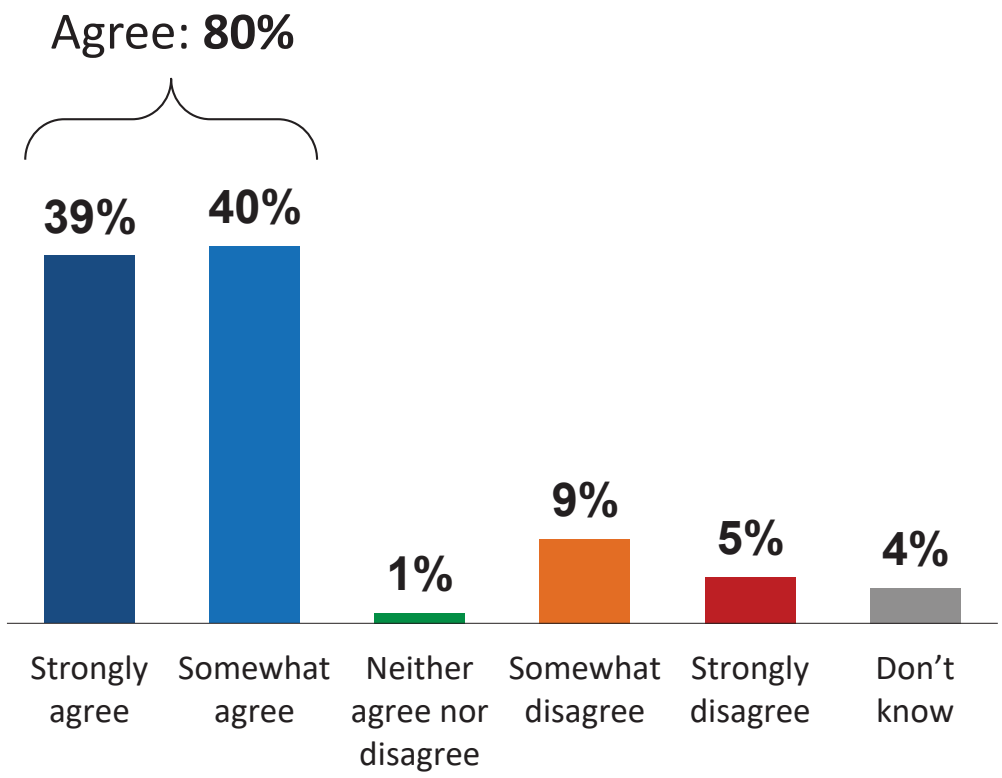
Pay Now or Later:

Majority (80%) agree that delaying infrastructure investments will result in having to pay more in the future

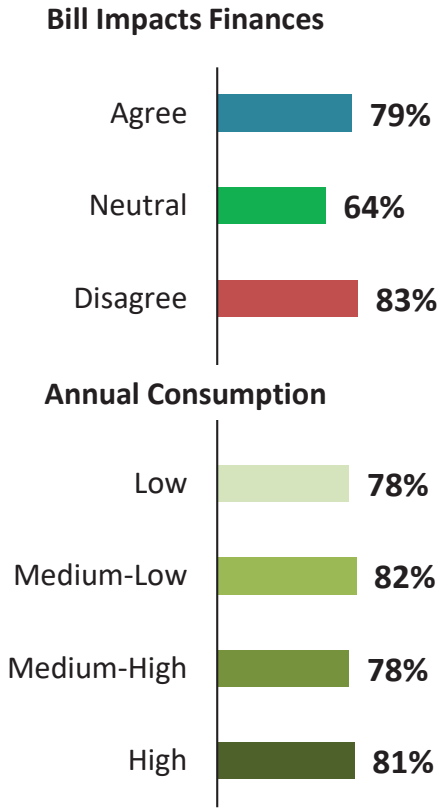
Residential

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=500]

We should invest in our electricity system infrastructure now or we will end up paying more the longer we delay our system renewal.



Segmentation ▸▸
*Those who say "**Agree**"*



Note: 'Refused' (1%) not shown.

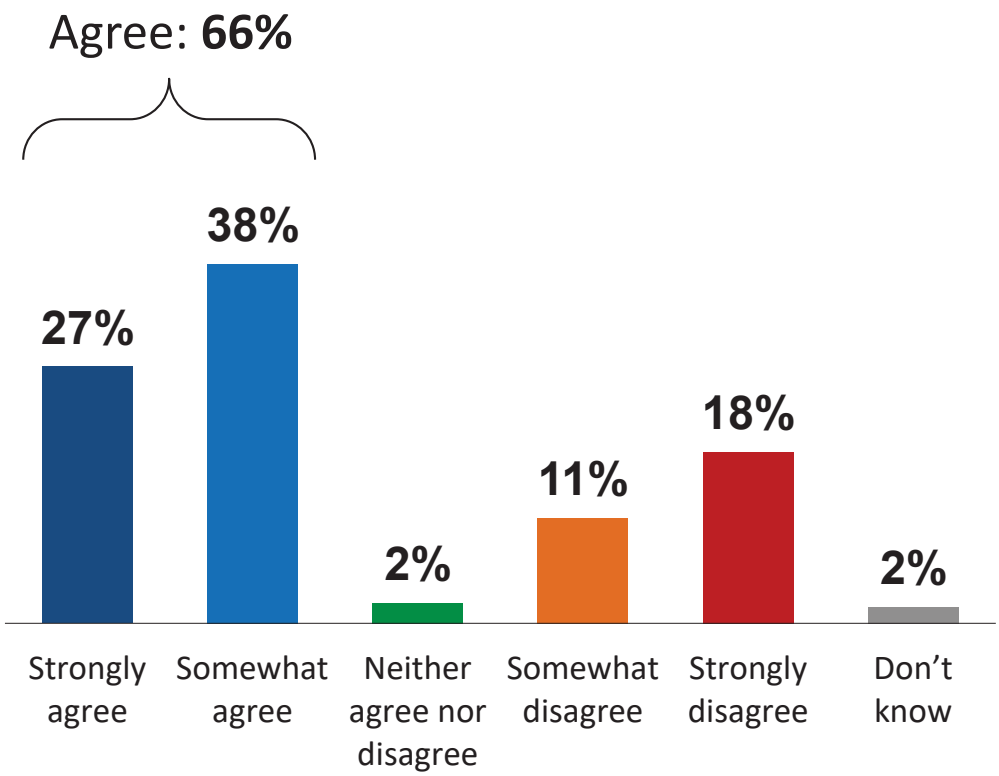
Deferring to the Experts:

Majority (66%) agree that there is a need to trust the experts to balance costs, investments, and spending decisions

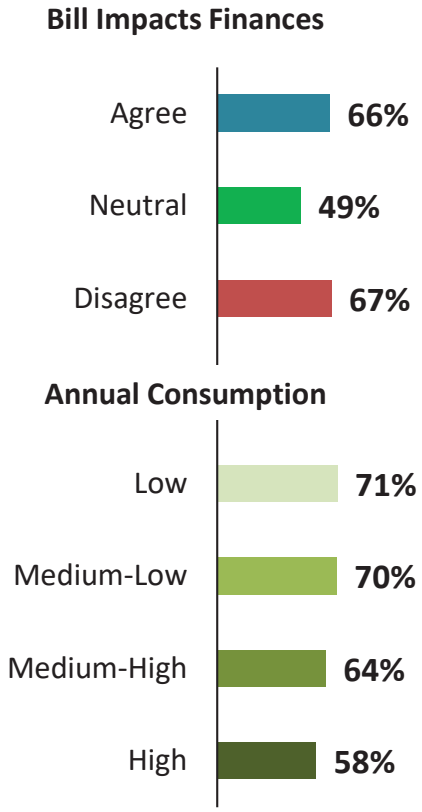
Residential

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=500]

The electricity sector is so complicated and confusing; we just have to trust that the experts will find the right balance in keeping cost down while making the right investments and spending decisions.



Segmentation ▸▸
*Those who say "**Agree**"*



INNOVATIVE RESEARCH GROUP

Note: 'Refused' (1%) not shown.

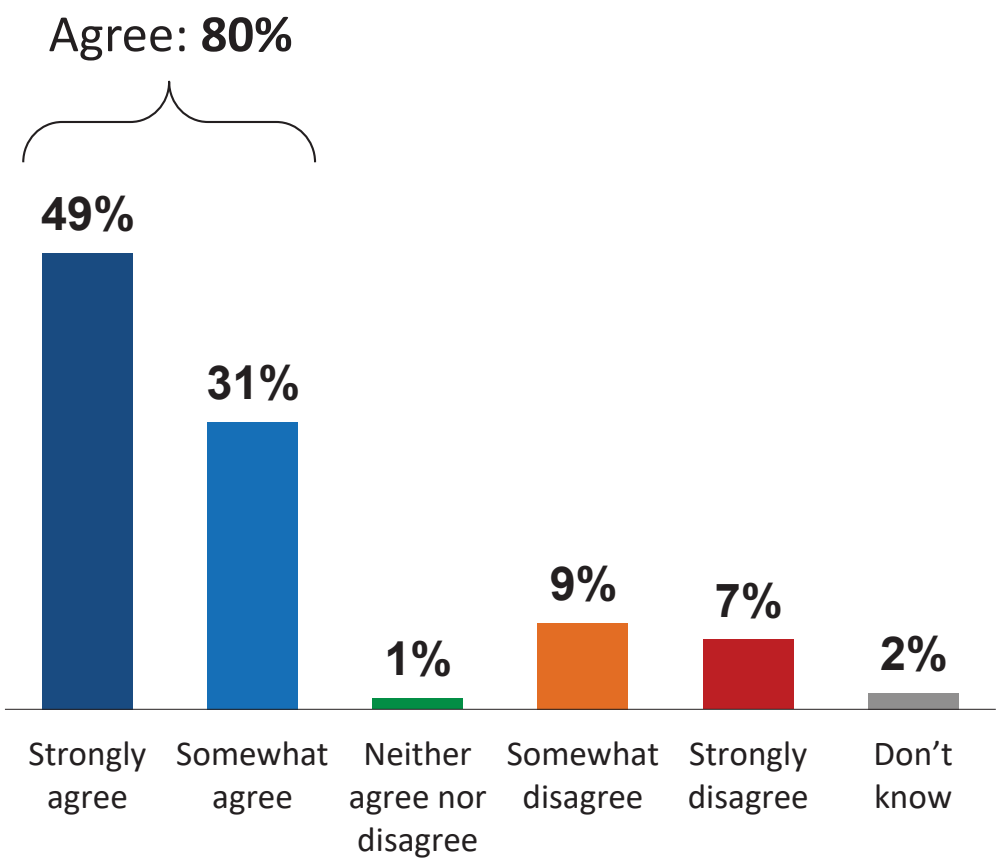
Conservation Demand Management:

Majority (80%) agree that Essex Powerlines should do more to help customers find ways to reduce electricity consumption and costs

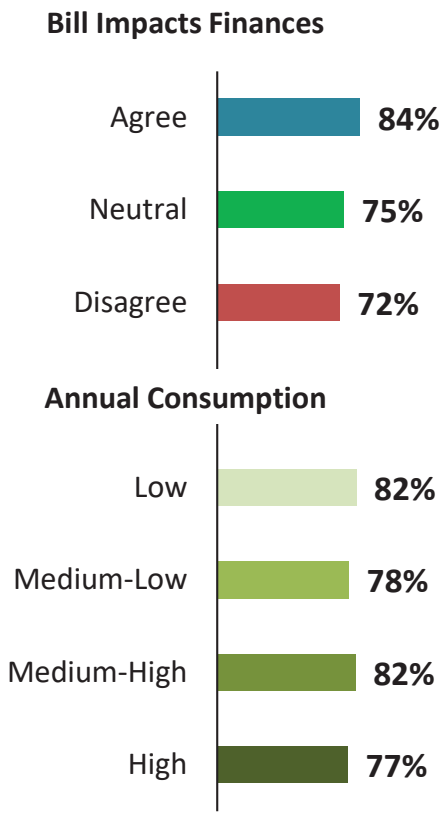
Residential

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=500]

I think Essex Powerlines should do more to help customers find ways to reduce their electricity consumption and costs.



Segmentation
*Those who say "**Agree**"*



INNOVATIVE RESEARCH GROUP

Note: 'Refused' (1%) not shown.

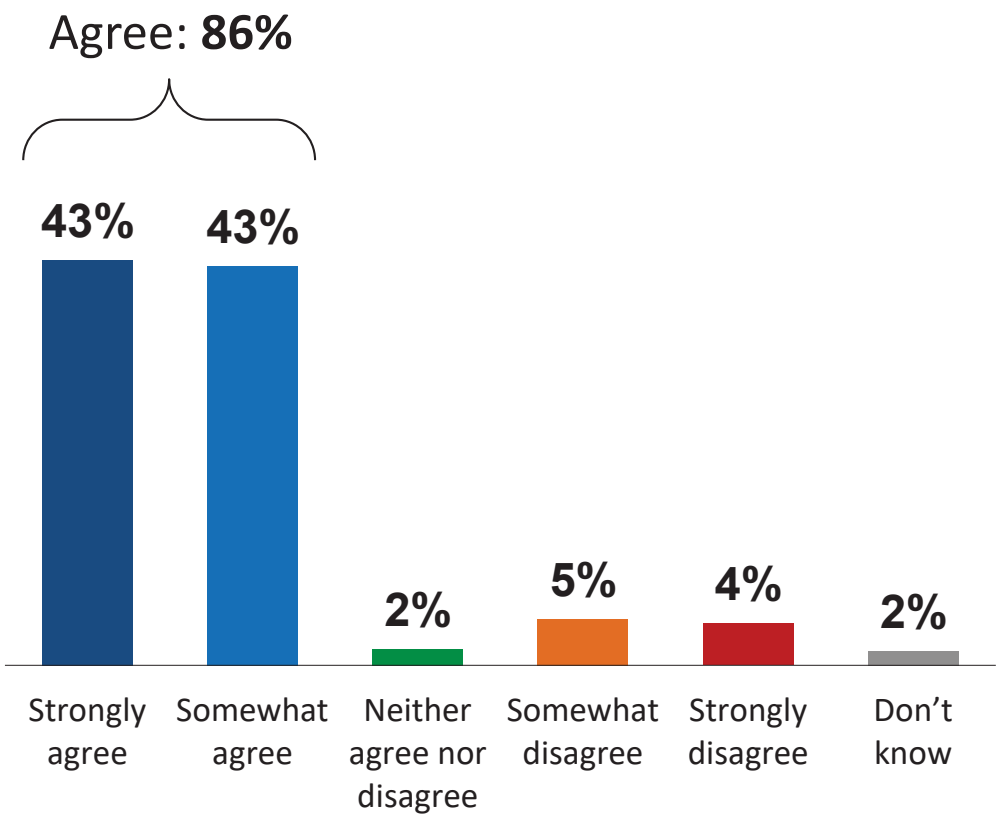
Legacy:

Majority (86%) agree that there is an obligation to maintain the reliability of our local electrical system for future generations

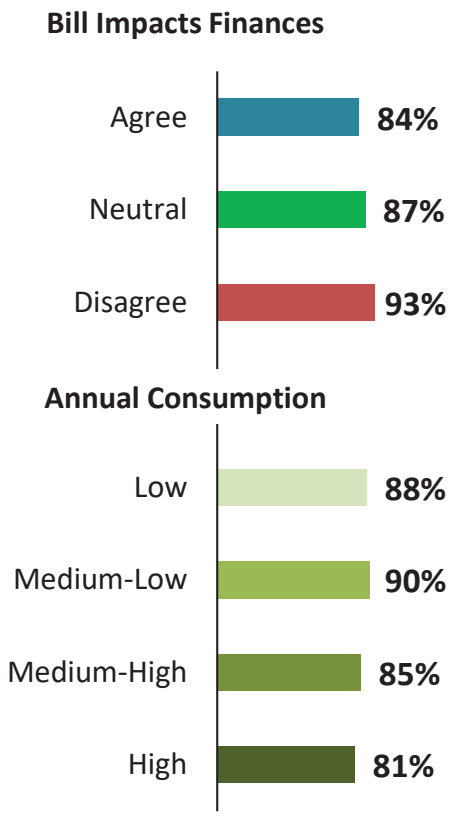
Residential

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=500]

Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations.



Segmentation ▸▸
*Those who say "**Agree**"*



Note: 'Refused' (1%) not shown.

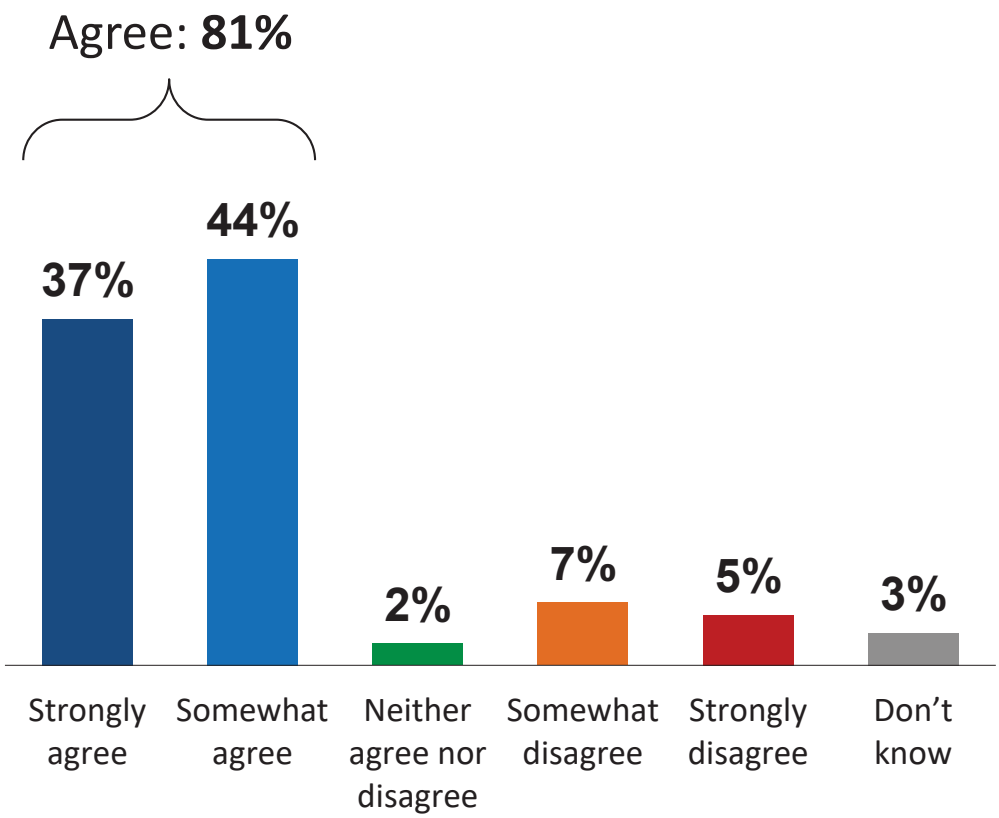
Modernizing the Grid:

Majority (81%) agree that there is a need to modernize the local electricity system so consumers can better control their usage

Residential

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=500]

We need to modernize the local electricity system so consumers can have greater control over their electricity usage.



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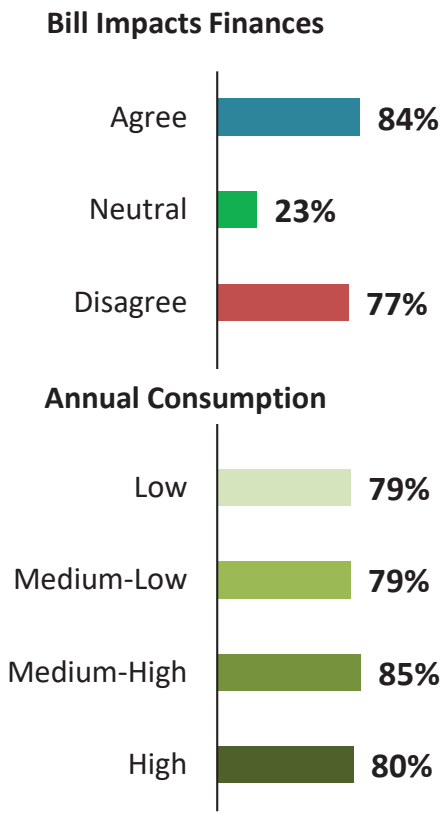
*Those who say "**Agree**"*



Note: 'Refused' (2%) not shown.

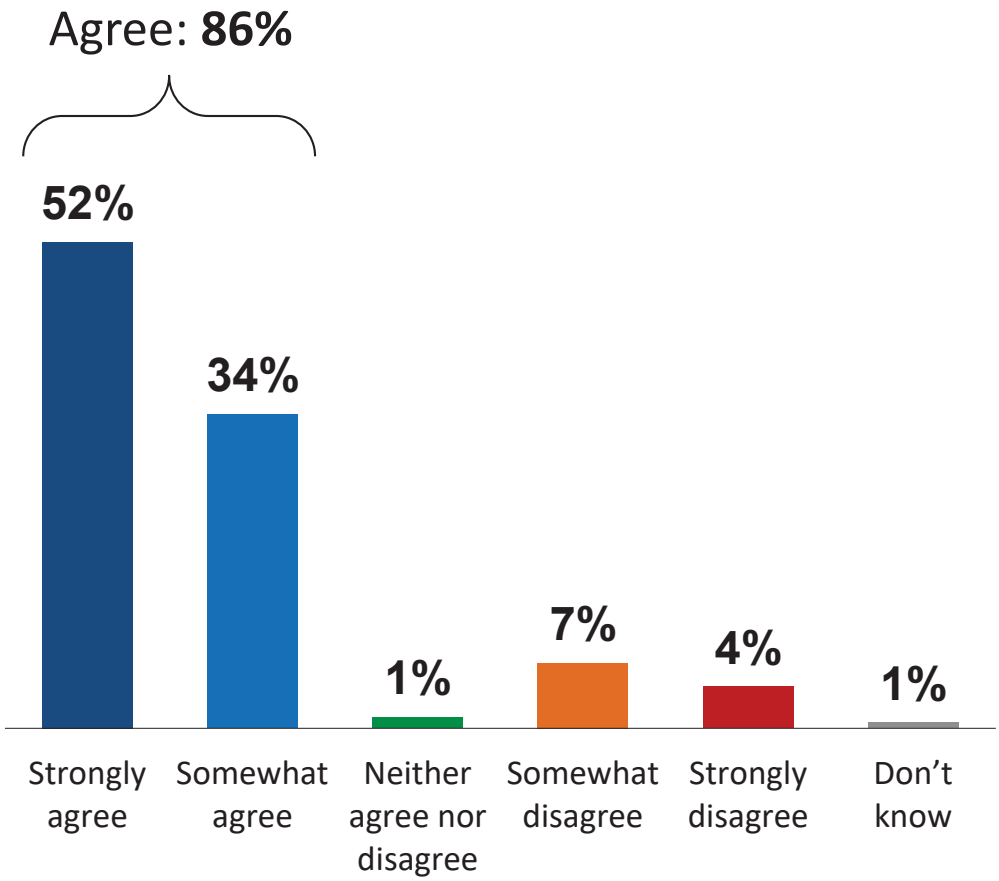
System Reliability:

Majority (86%) agree that they worry about the impact outages have on vulnerable people; more than half (52%) *strongly* agree

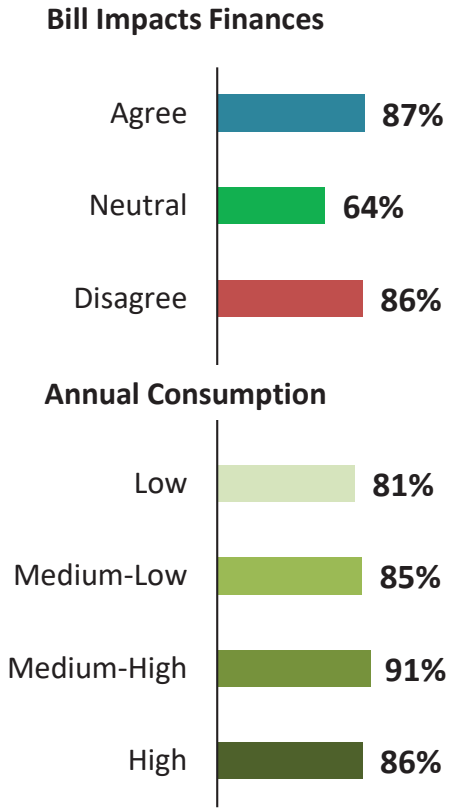
Residential

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=500]

A few power outages are fine for me personally, but I worry about the impact this has on more vulnerable people, such as the elderly.



Segmentation
*Those who say "**Agree**"*



Note: 'Refused' (1%) not shown.

Assessment of Plan:

82% give social permission for rate increase; those with limited bill impact most likely to find it reasonable

Residential

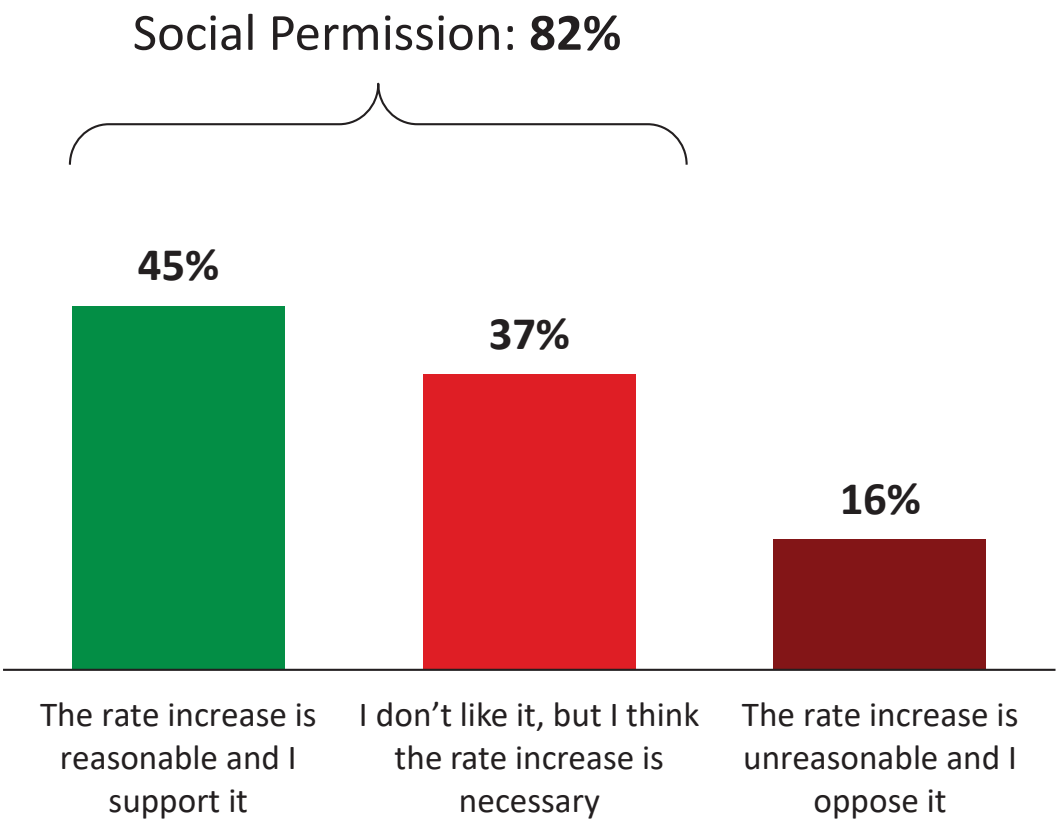
Q **Essex Powerlines** believes that proactive renewal and consistent maintenance is needed to maintain system performance, while keeping the impact on customer bills manageable over the long-term. Over its proposed 5 year plan, **Essex Powerlines** will…

- spend an estimated **$15 million** on on-going maintenance and the operation of the distribution system; and
- invest an estimated **$16 million** in new equipment and infrastructure priorities that will help ensure system reliability.

To fund this proposed plan, the **average residential customer in Essex Powerlines service area will see their rates increase by approximately $0.30 per month** on the distribution portion of their bill over the next five years. So, by 2022, the average residential household will be paying an **estimated $1.53 more per month** on the distribution portion of its electricity bill, which is roughly the rate of inflation.

Considering the cost of Essex Powerlines plan, would you say …

[asked all respondents, n=500]



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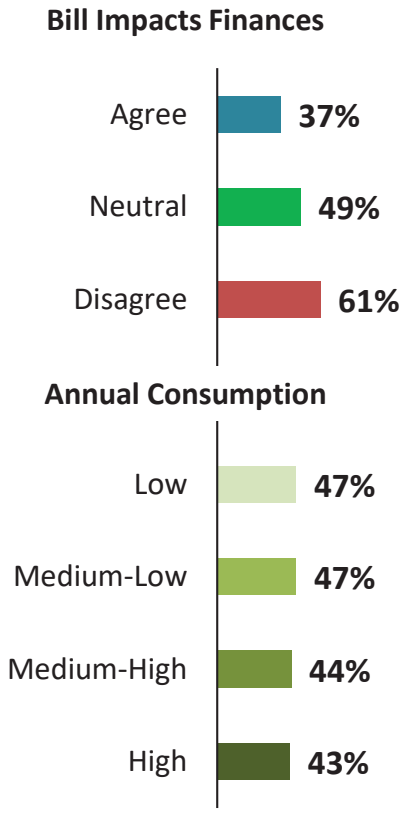
*Those who say "**The rate increase is reasonable and I support it**"*



INNOVATIVE RESEARCH GROUP

Note: 'Don't know' (1%), 'Refused' (2%) not shown.

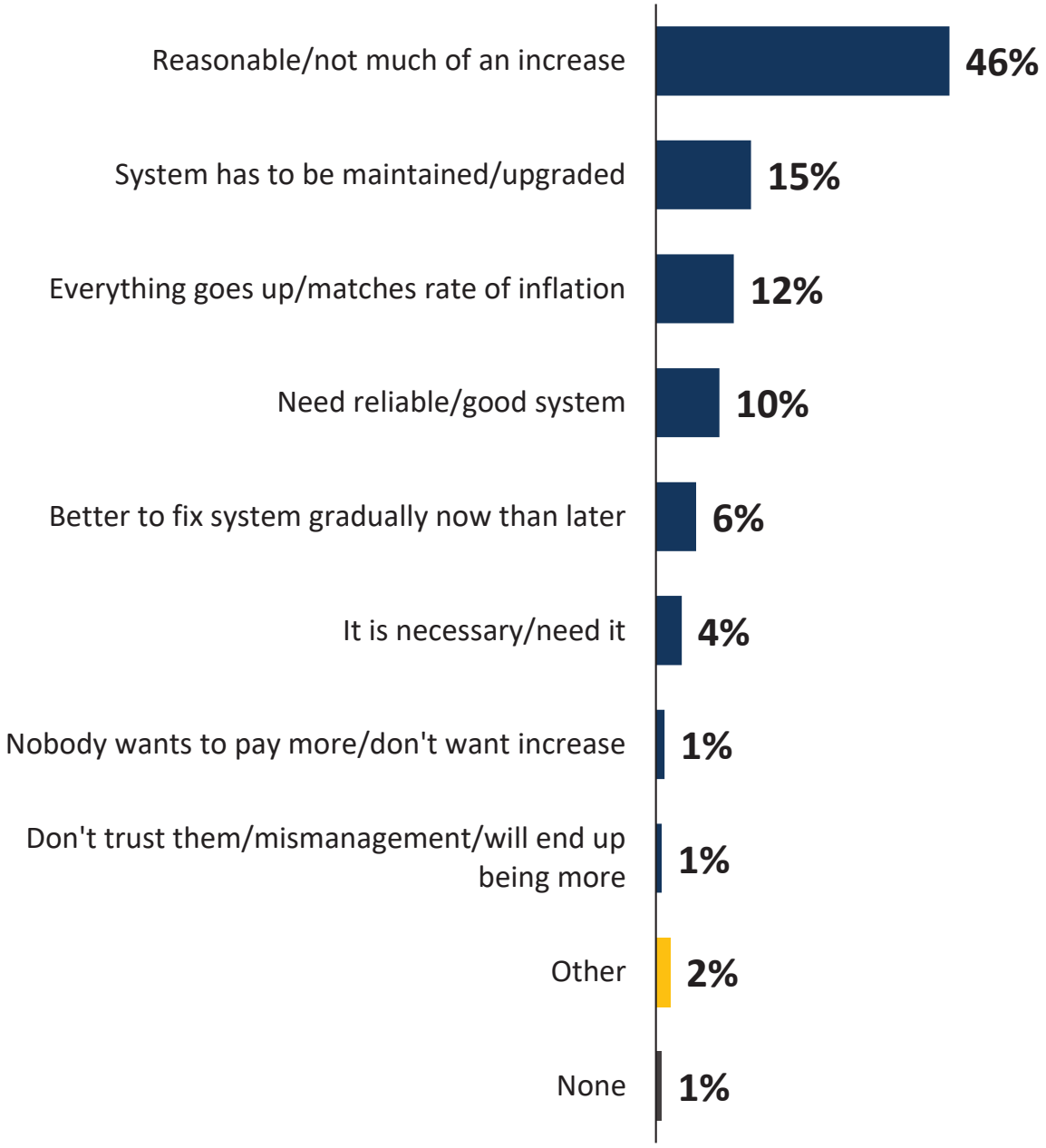
Rationale:

Almost half (46%) of those who support the rate increase do so because it is 'reasonable/not much of an increase'

Residential

Q And why do you say that?
[asked only of those who have an opinion on the assessment of plan, n=488]

Among those who say…
"The rate increase is reasonable and I support it." *(n=225)*



INNOVATIVE RESEARCH GROUP

Note: 'Don't know' (0%), 'Refused' (0%) not shown.

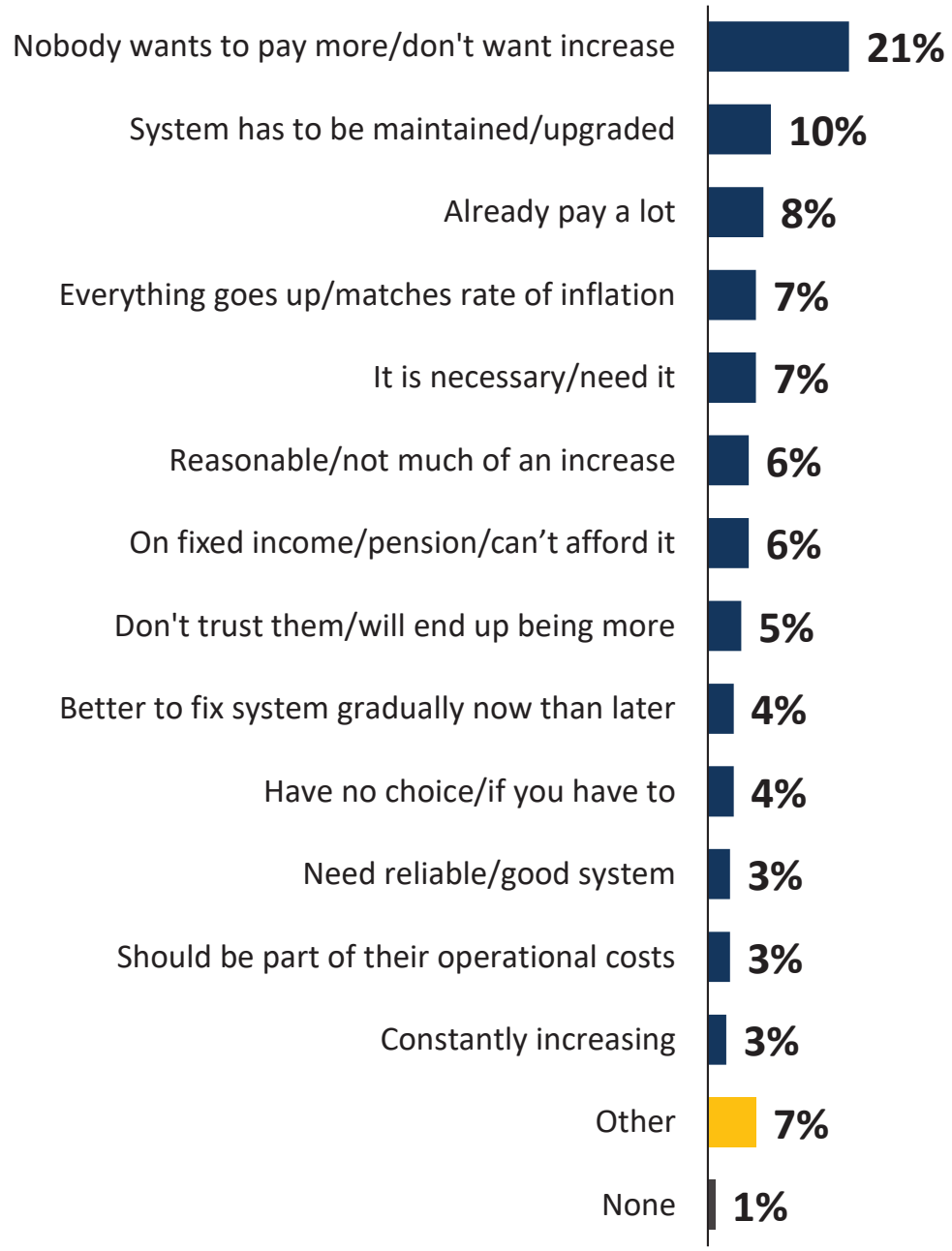
Rationale (2):

1-in-5 (21%) of those who don't like the rate increase but think it's necessary say 'nobody wants to pay more/don't want increase'

Residential

Q And why do you say that?
[asked only of those who have an opinion on the assessment of plan, n=488]

Among those who say…
"I don't like it, but I think the rate increase is necessary." *(n=183)*



INNOVATIVE RESEARCH GROUP

Note: 'Don't know' (1%), 'Refused' (2%) not shown.

Rationale (3):

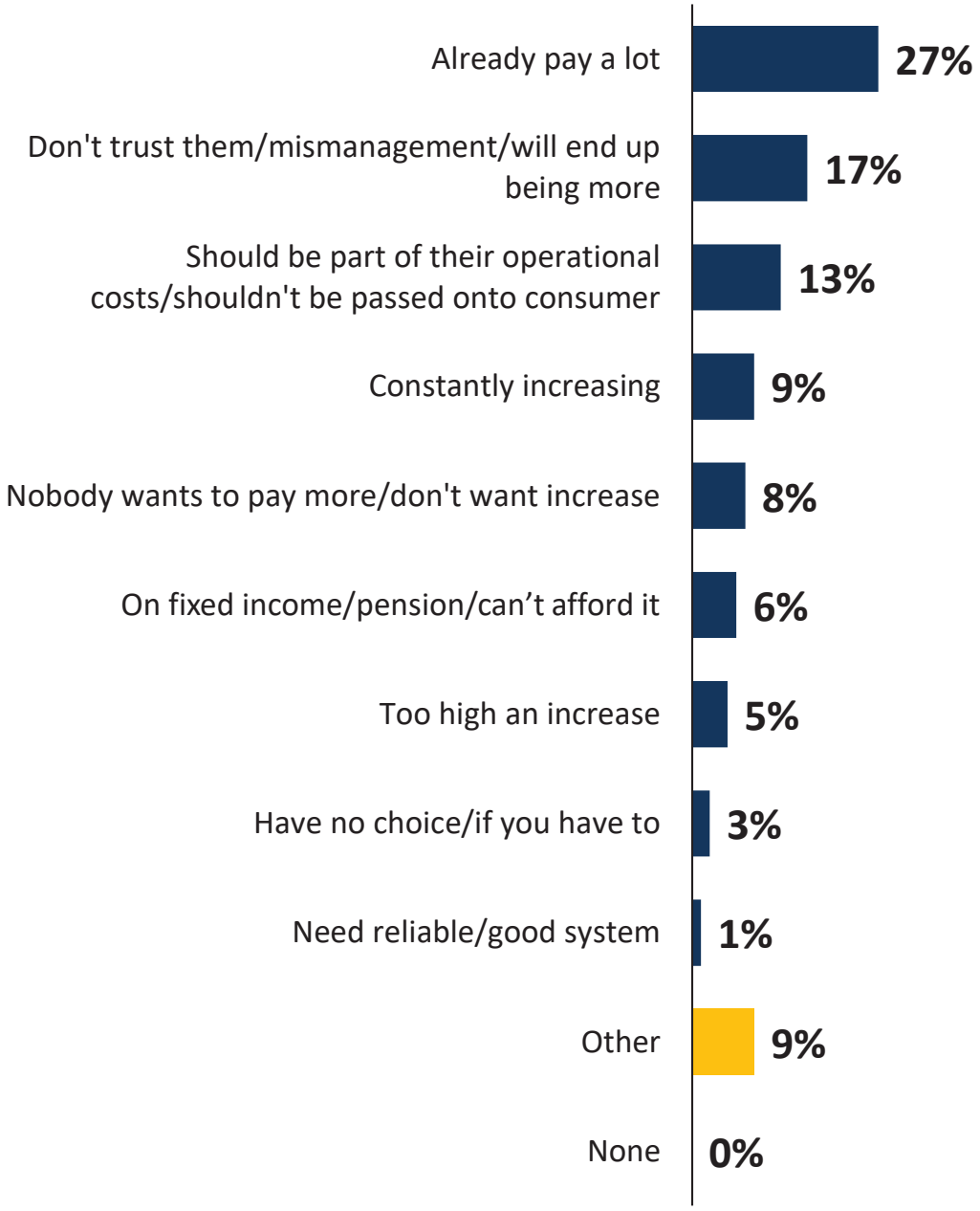
Top reasons for opposition are 'already pay a lot' and 'don't trust them/mismanagement/will end up being more'

Residential

Q And why do you say that?
[asked only of those who have an opinion on the assessment of plan, n=488]

Among those who say…

"The rate increase is unreasonable and I oppose it." *(n=81)*



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Note: 'Don't know' (0%), 'Refused' (0%) not shown.

ESSEX POWERLINES CORPORATION

General Service

Under & Over 50 kWh Rate Classes

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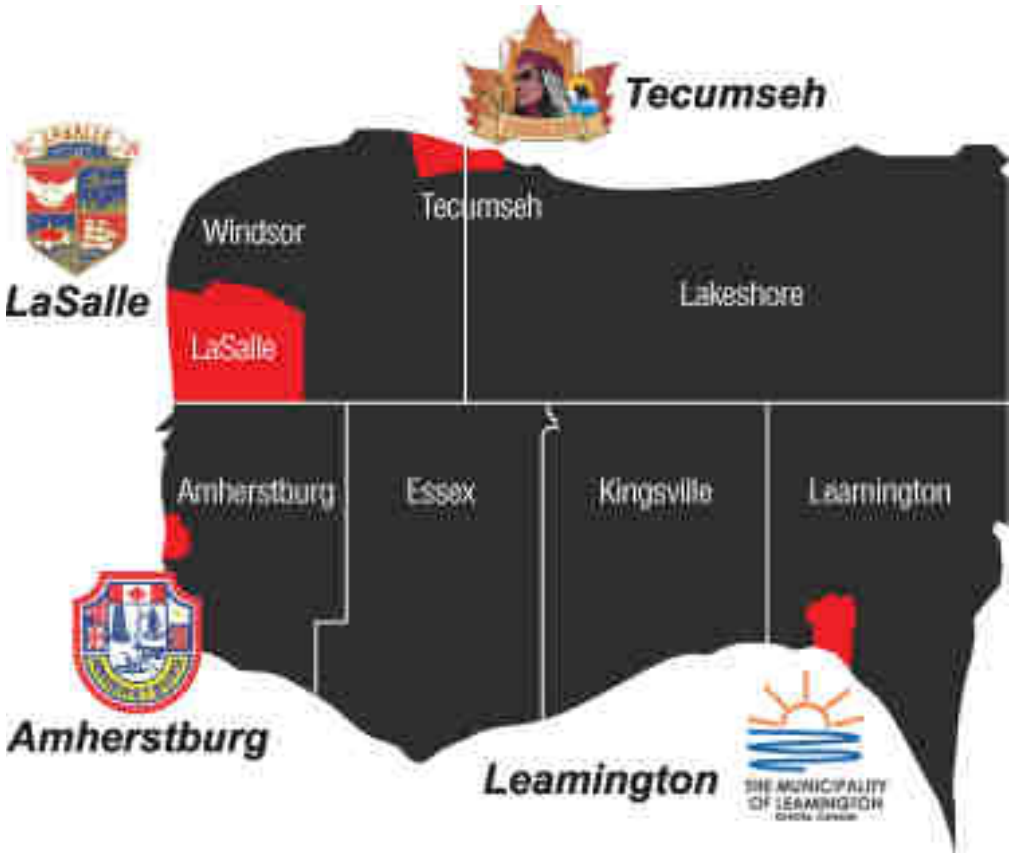
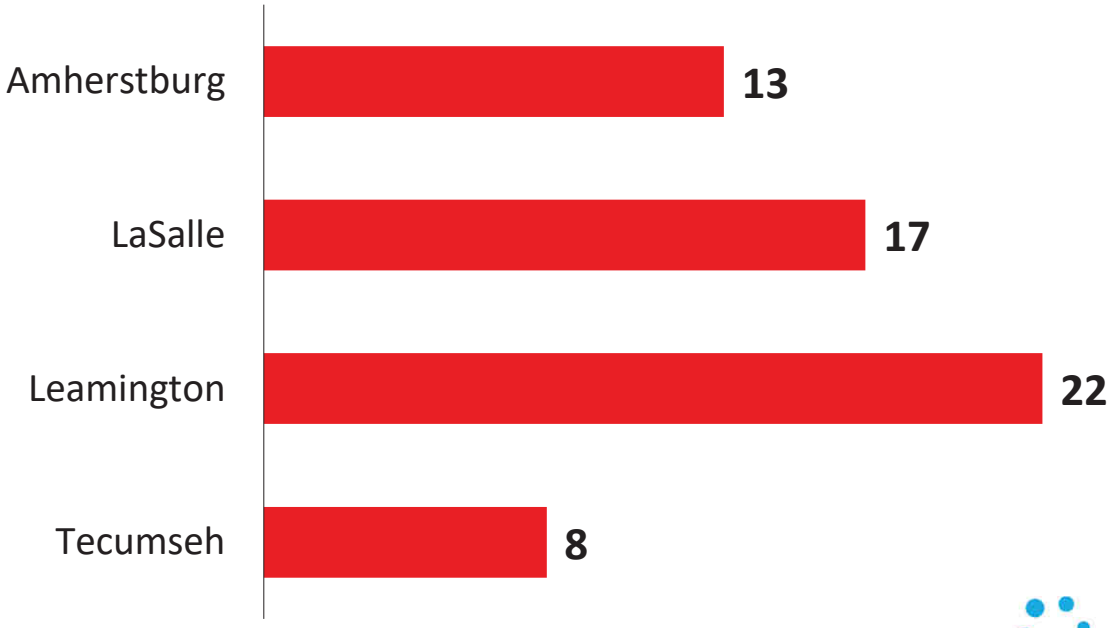
Regional Segmentation

General Service





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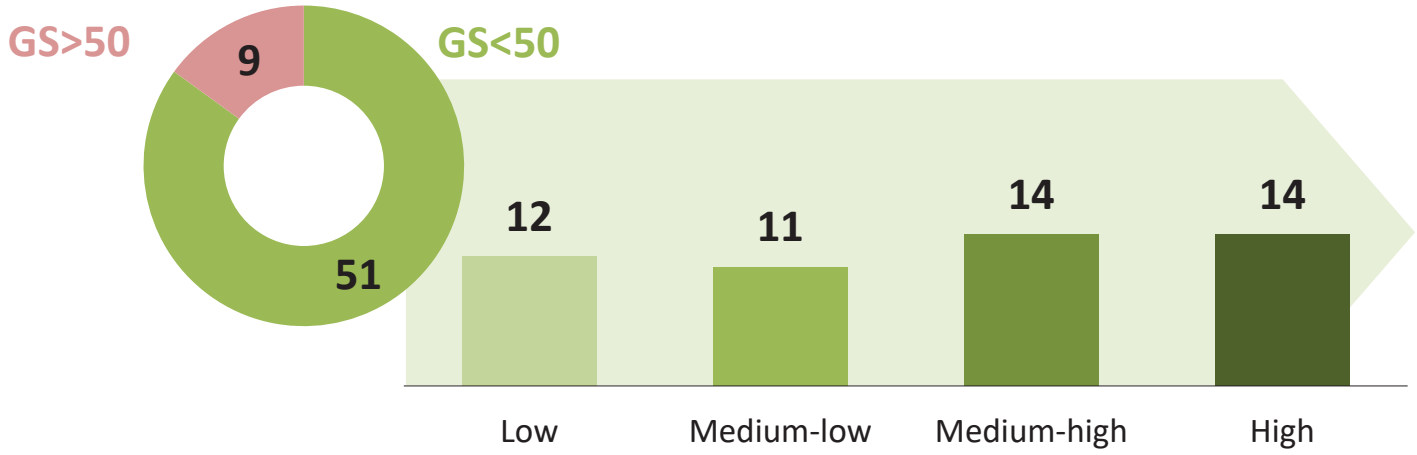
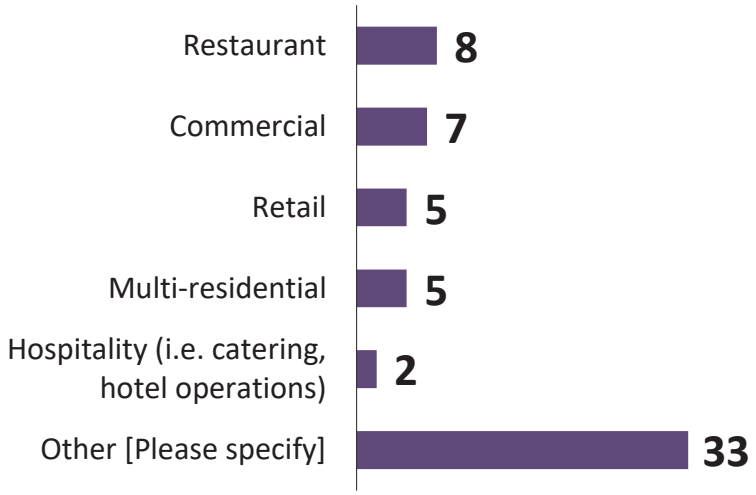
Firmographics

General Service

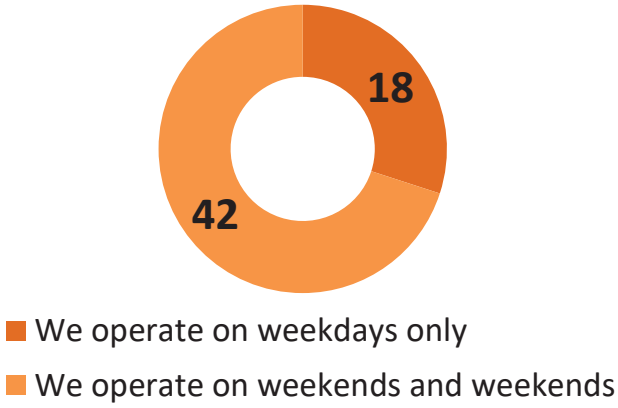
Annual Consumption



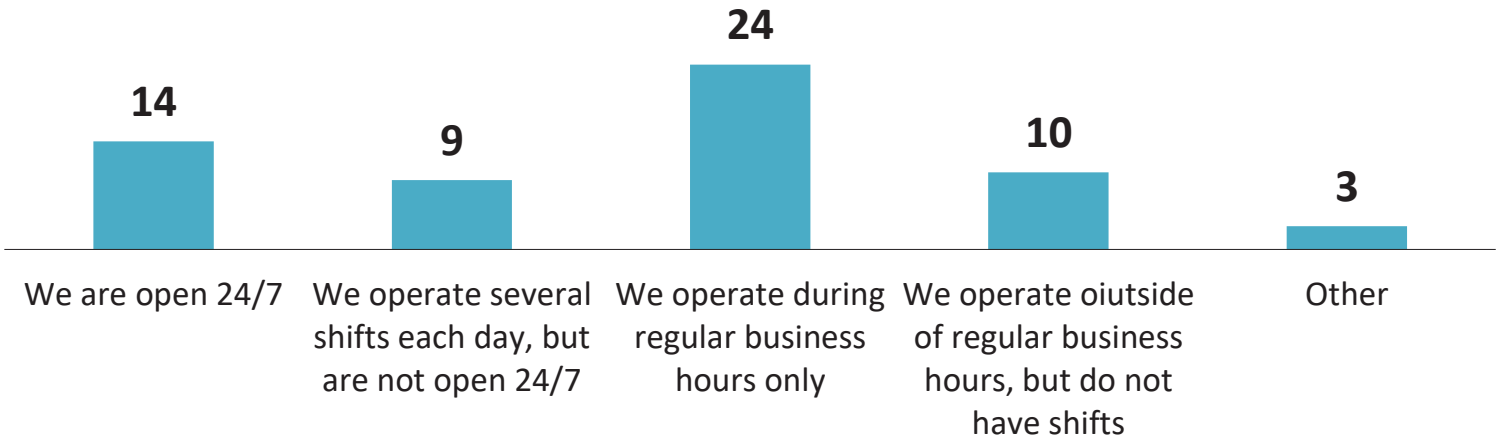
Sector



Schedule



Hours of Operation

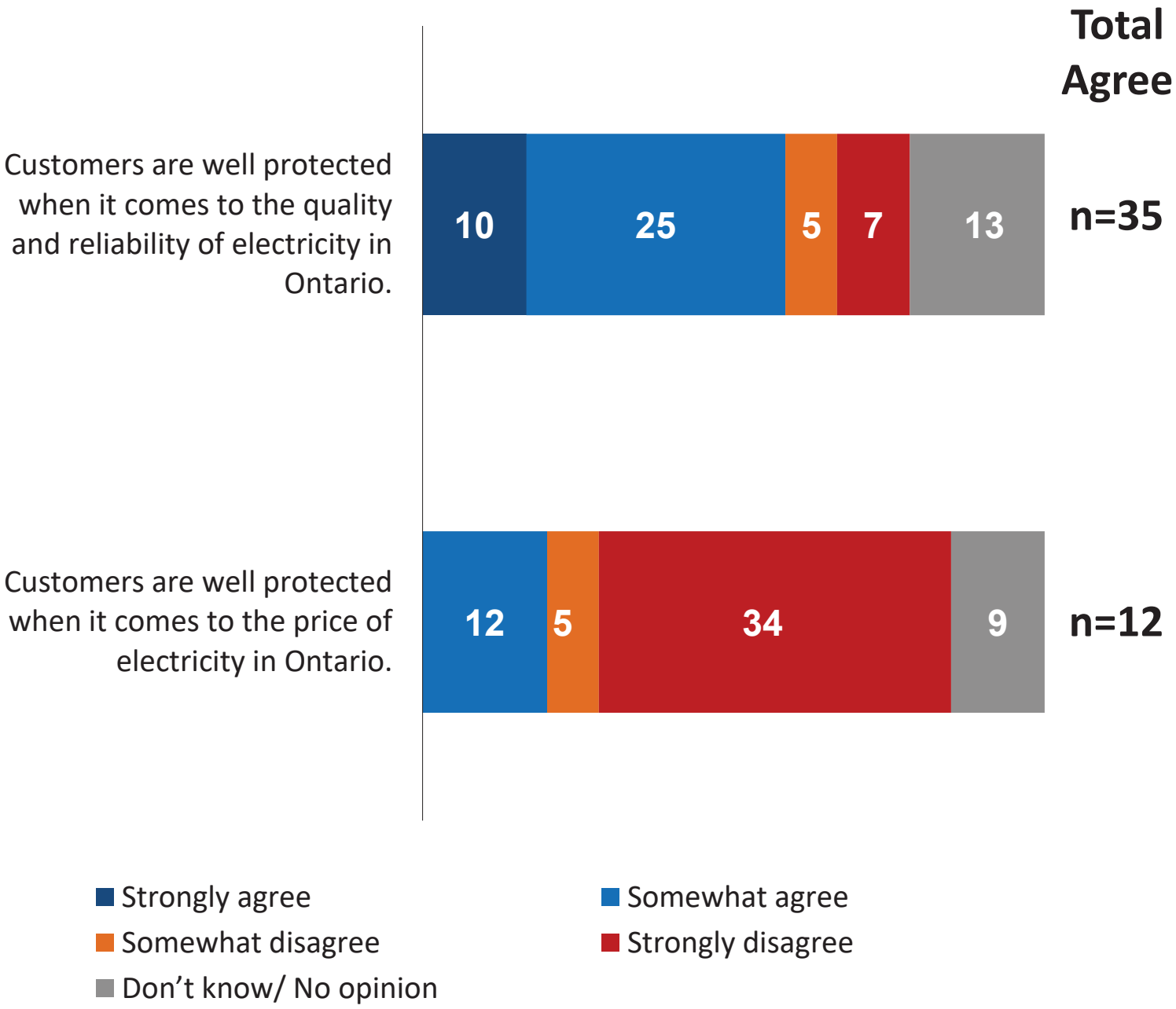


Attitudes Toward Electricity in Ontario:

More than half feel well protected on quality and reliability, but most do no feel protected on price

General Service

Q Lastly, I'd like to ask you some general questions about the electricity system in Ontario.
For each statement please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree. If you don't know enough to say or don't have an opinion just let me know.
[asked all respondents, n=60]



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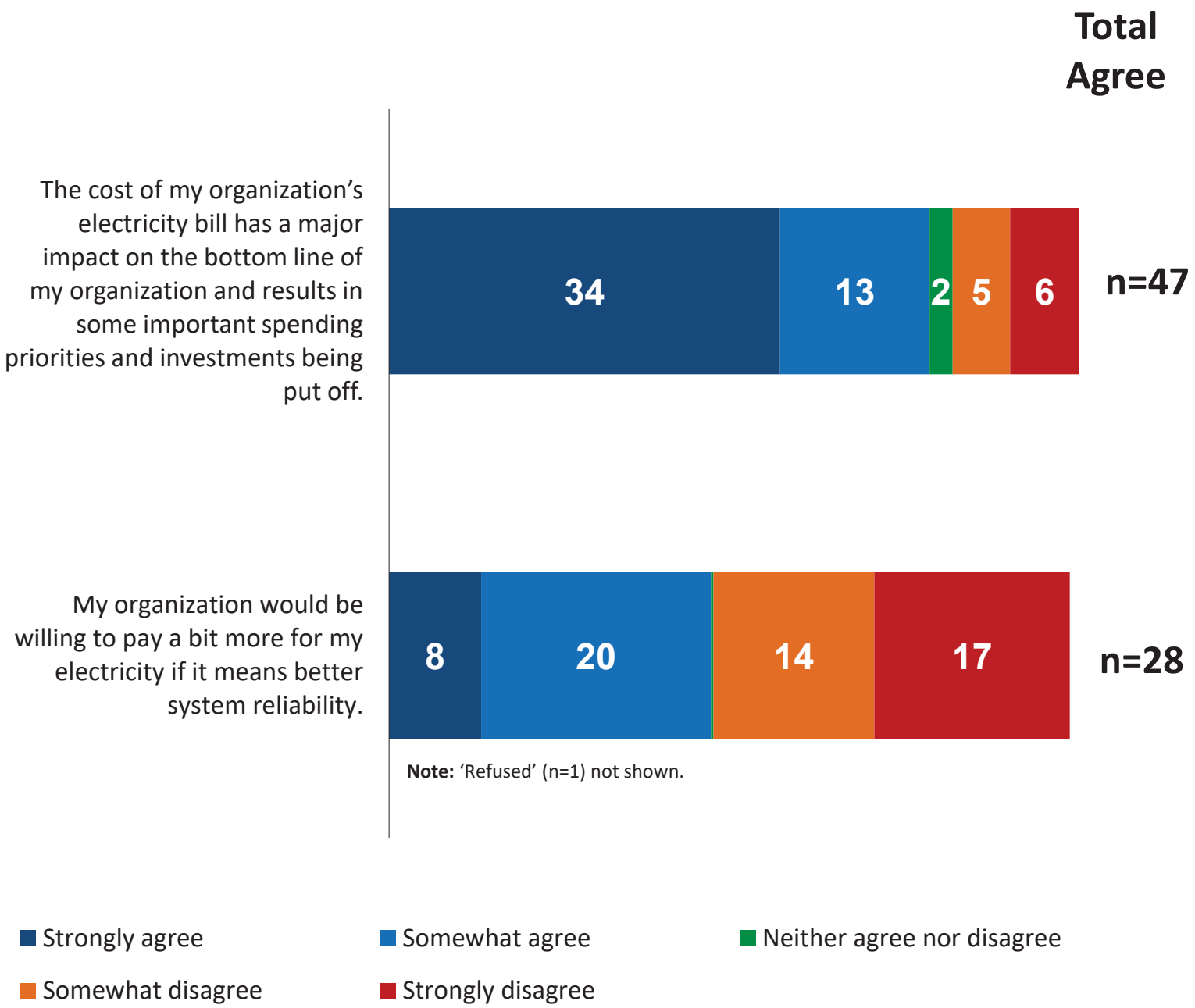
Paying for Electricity:

Most report the electricity bill has a major impact, and fewer than half would pay more if it meant improved reliability

General Service

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=60]



Note: 'Refused' (n=1) not shown.

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Familiarity:

Just under half of respondents (n=29) are familiar with the local electricity distribution system

General Service

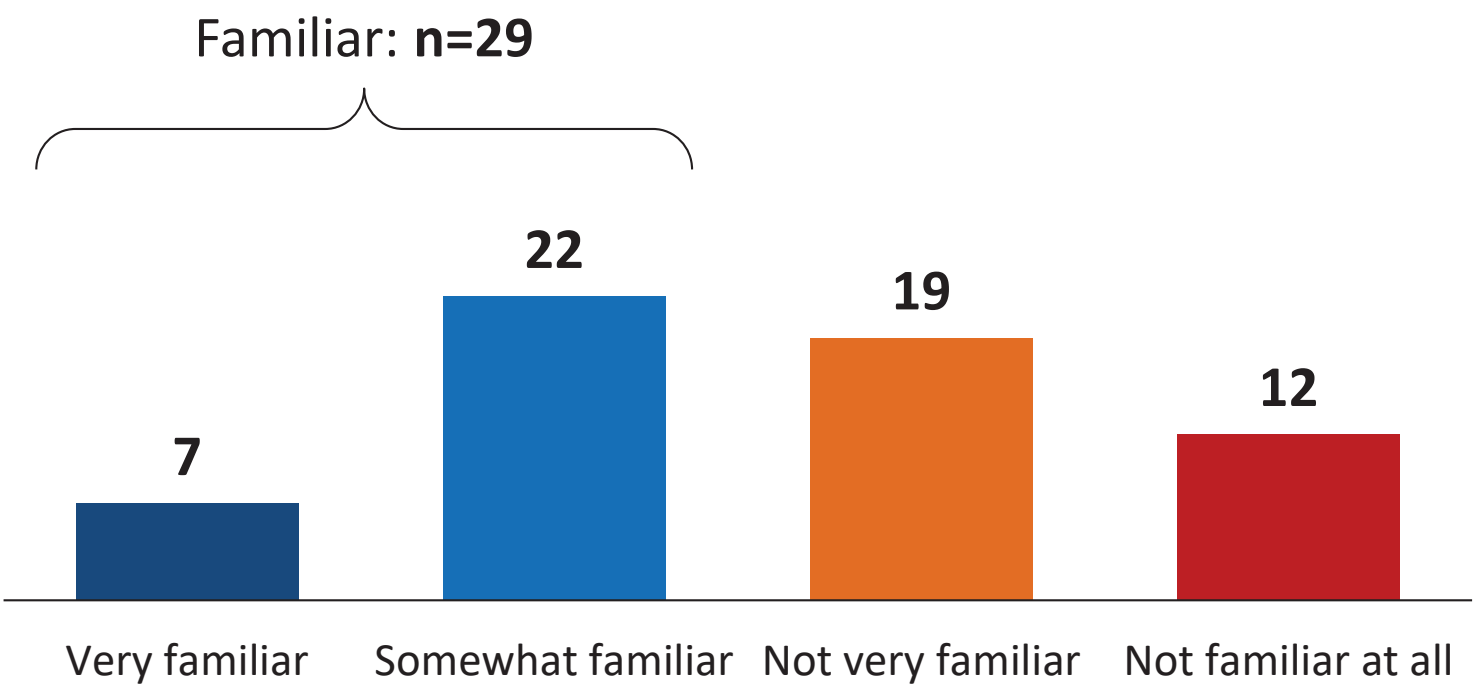
Q To start, I'd like to ask you a few questions about the electricity system… As you may know, Ontario's electricity system has three key components: generation, transmission and distribution.

- Generating stations convert various forms of energy into electric power;
- Transmission lines connect the power produced at generating stations to where it is needed across the province; and
- Distribution lines carry electricity to the homes and businesses in our communities.

Today we're going to talk about your local distribution system which, in your community, is maintained and operated by Essex Powerlines.

How familiar are you with the local electricity distribution system? Would you say…

[asked all respondents, n=60]

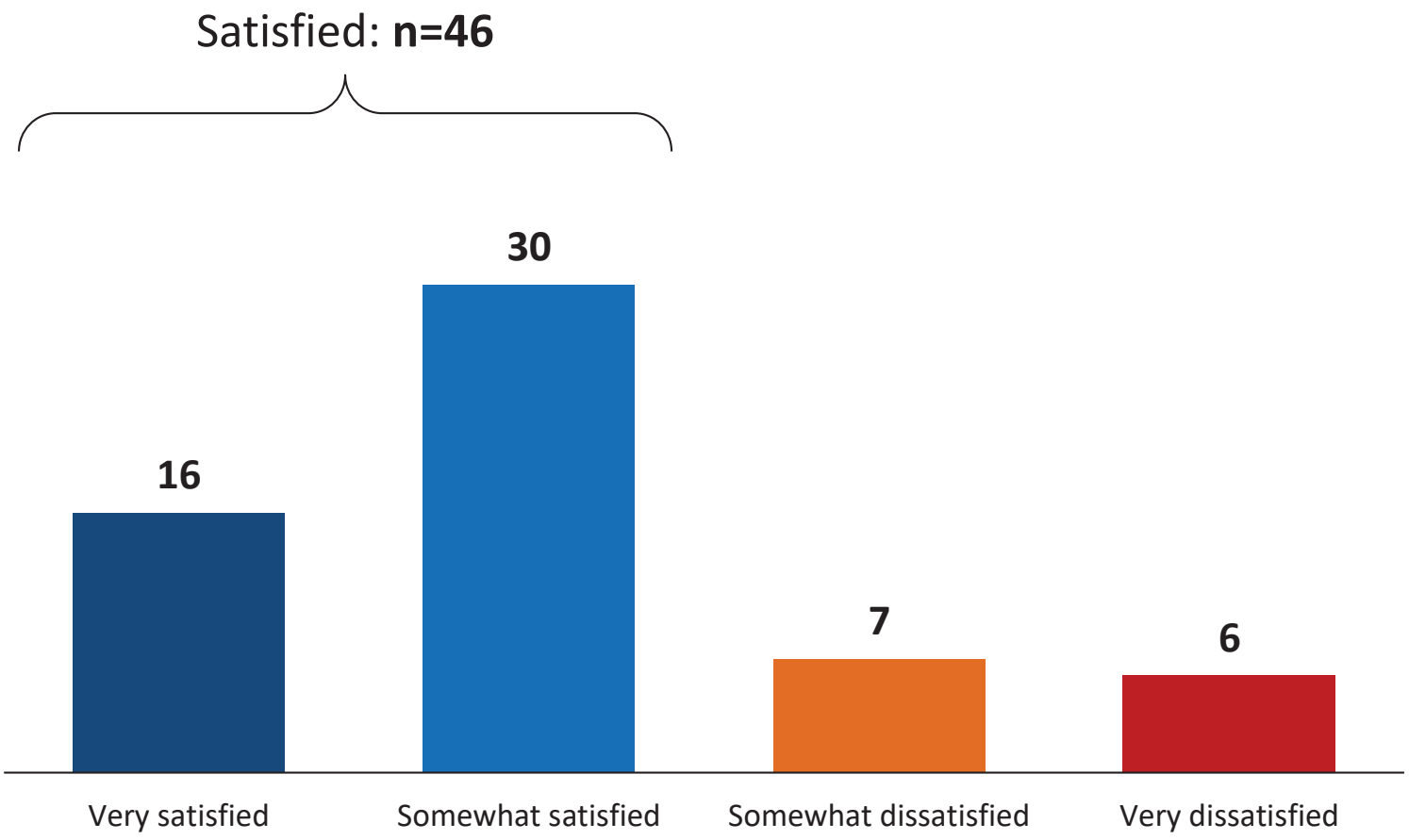


Satisfaction with Services:

Majority of respondents (n=46) are satisfied with Essex Powerline's performance

General Service

Q Generally speaking, how satisfied are you with the job Essex Powerlines is doing running your local distribution system? Would you say…
[asked all respondents, n=60]



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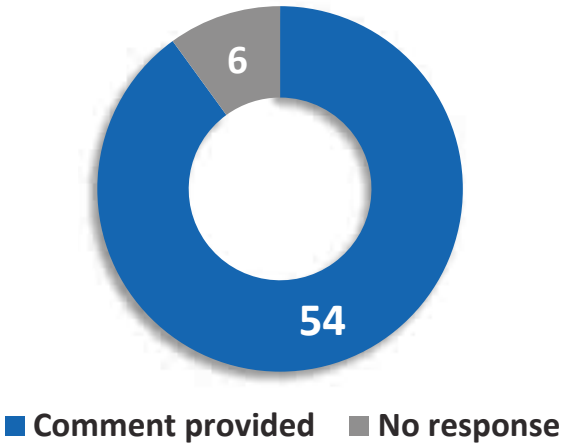
Note: 'Don't know' (n=1) not shown.

Suggestions for Improvement:

Those who had suggestions noted improvements regarding lower rates/prices/costs/bills

General Service

Q Is there anything in particular **Essex Powerlines** can do to improve its service to your organization?
[asked all respondents, n=60]



Lower rates/prices/costs

- cheaper hydro give us
- constantly power going out, too much money
- cut the bill down
- give us service we want, but too costly
- I feel I am paying too much money.
- I would like them to lower the prices.
- I would like them to lower their costs, make it cheaper.
- lower bills
- Lower the bill.
- lower the cost of electricity
- Lower the cost.
- Lower the prices
- lower the rates
- rates are way too high and sometimes power has gone out
- reduce the pricing
- reducing rates
- they should lower the rates. It is a small town
- I would like them to lower their electricity rates.
- Lower the prices.
- Prices
- I've got billing on my mind not services.

No/Nothing/Don't know

- I have no complaints.
- I have no opinions.
- No
- No
- No, they have been very good working with us regarding power outages with upgrading of cables.
- nothing
- nothing
- not sure
- not that I can think about it.
- not that I'm aware of
- nothing
- Nothing comes to mind
- nothing I can think of off of the top of my head
- don't think so
- everything is fine so far

Suggestions for Improvement (Cont'd):

Topics of reliability were mentioned a number of times; a few mentioned improvements to customer services and time-of-use

General Service

Q Is there anything in particular **Essex Powerlines** can do to improve its service to your organization?
[asked all respondents, n=60]

Other

- have to wait very long on the phone
- occasional billing delays
- should collect rent from tenants and not landlords
- When Essex Powerlines come on my property. They need to contact us first. They need to communicate with their business customers. Their communication skills are very poor.
- I would like them to take care of the power outages sooner and the hotline number provided should actually get some results. Commercial properties should be prioritized based on the emergency situation.
- Lost power in between transmission or in traffic. Eliminate times of use for businesses. Hitting me with higher rates because I have to operate during prime to keep customers.
- The peak times for the businesses we are paying peak rates. If you could change peak times for businesses.
- I think they could meet with us to save money or save on our systems. Like to have a meeting with conserving energy for the building.
- new infrastructure is key, not solar panels, wind. New poles, TR cables, are required
- provide maybe upgraded thermostats
- replace the 3 phase power that keeps shorting

Reliability

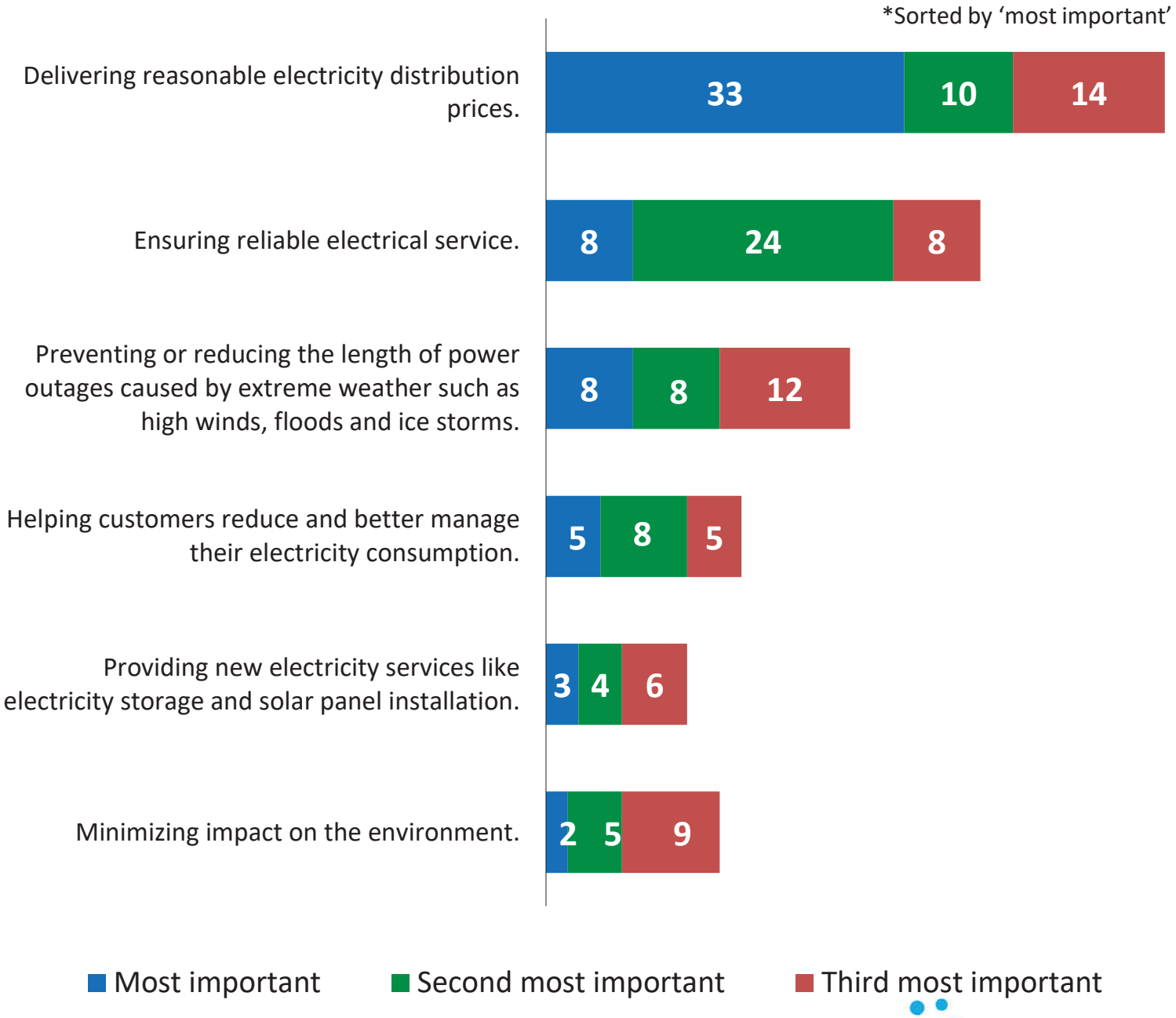
- goes out a little too often
- I have a lot of brownouts and lots of flickering in the electricity. Like to see improvements in that area.
- not adding so much power interruptions
- They should have better control of there level of control of there voltage supply. It draws too much and I burn out of equipment.
- We have a lot of brownouts. Like improvements of the system.
- we have trouble transitioning the builders name to the new home owners name. and paperwork to fill out for new customers is not conducive to home builder

Customer Priorities:

'Delivering reasonable electricity distribution prices' is identified as most important priority

General Service

Q Essex Powerlines regularly holds discussions with its customers to better understand how it should set spending priorities with the money customers pay for service. In recent conversions with customers, a number of company goals were identified as key priorities for Essex Powerlines.
Among the following Essex Powerlines priorities, please tell me which one is most important to your organization. What is the next most important priority you think Essex Powerlines should focus on? And what do you consider the third most important priority?
[asked all respondents, n=60]



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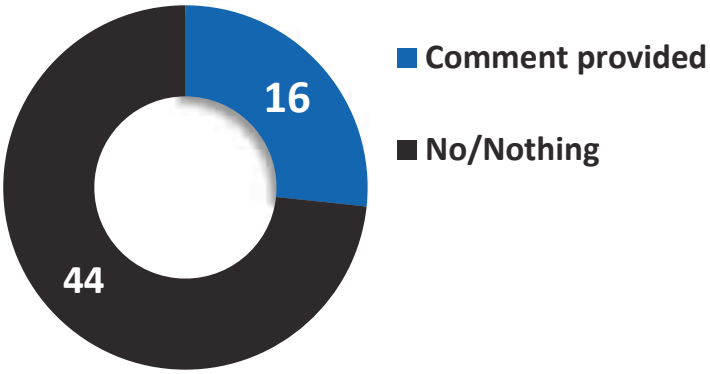
Additional Priorities:

Most respondents (n=44) had nothing to offer regarding additional priorities

General Service

Q Are there any other important priorities that Essex Powerlines should be focusing on that weren't included in the previous list I read to you?
[asked all respondents, n=60]



- these are my top priorities
- cost - a small business has to open there business and have to pay for the premium, and we have to provide services to our community. and theses facilities cannot work at midnight. And we have to work on peak time, so we should have a fixed cost, or some sort of discount so we are not penalized.
- Energy conservation
- put programs and grants in place for solar programs.
- incentives, making businesses aware of yearly incentives
- making equipment affordable
- the business does not have a choice of using off peak hours because the business is not open at that time. If they could make it different between residential and business.
- lower their rate during peak times
- they can extend the time of use. Extend the low peak a bit.
- They cut their pay raises with management at the top. They have reasonable prices.
- new infrastructure, staff efficiency (do not waste time eating lunch)
- I think they should have better sense of responsibility for their commercial customers. They should invest in stronger infrastructure to reduce power outages which is a normal occurrence in my area.
- to help businesses they should change the peak times
- lobby provincial government to deregulate the infrastructure and hire Canadians to do it
- stop outsourcing it to companies, used a different piece and fried the transformer
- customer service in general

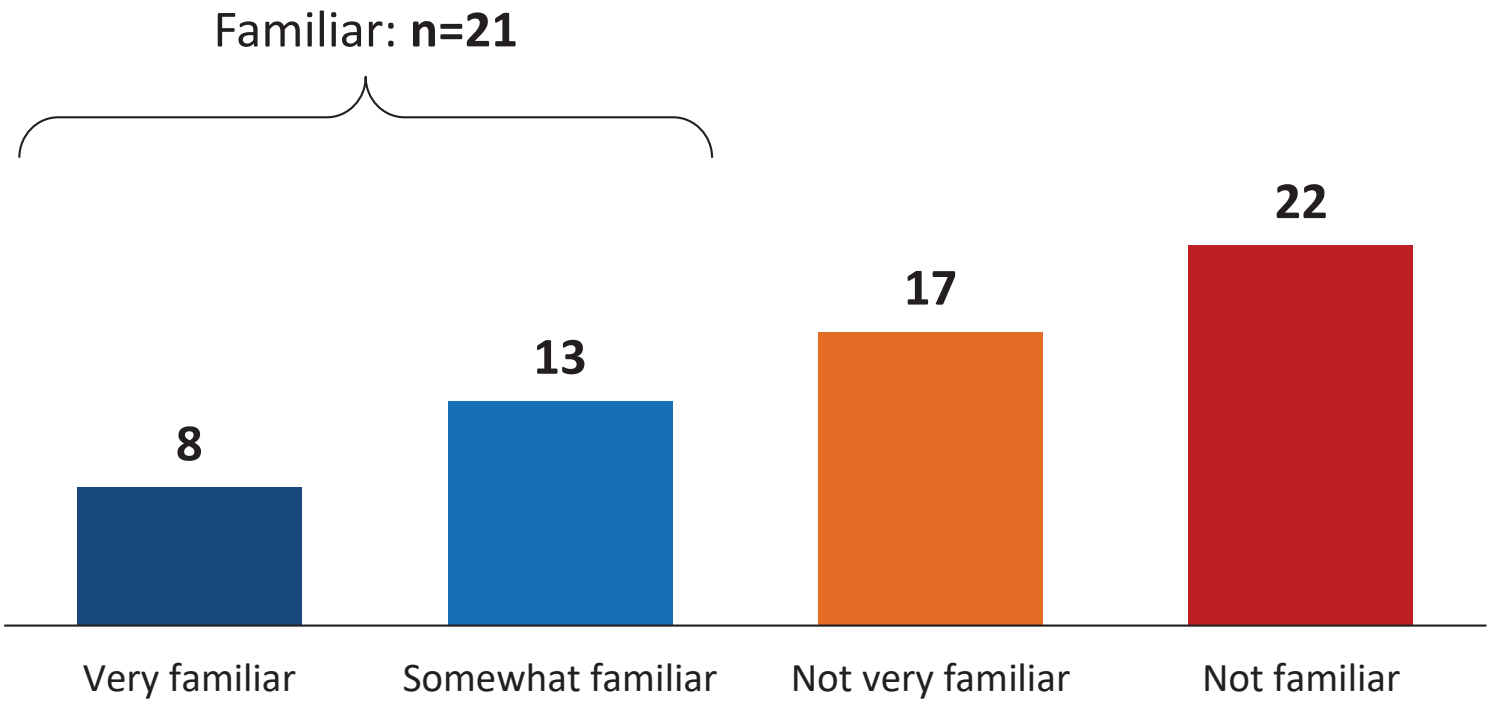
Bill Knowledge & Impact:

Fewer than half (n=21) were familiar with their bill breakdown

General Service

Q I'd now like to talk with you about your electricity bill… While some customers pay more and others pay less, the **average small business or general service customer pays about $387 a month** for electricity and other municipal services, of which **approximately $59 or 17% goes to Essex Powerlines**. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the amount of your electricity bill that went to Essex Powerlines? Would you say…
[asked all respondents, n=60]



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ESSEX POWERLINES CORPORATION

System Reliability

General Service

INNOVATIVE RESEARCH GROUP

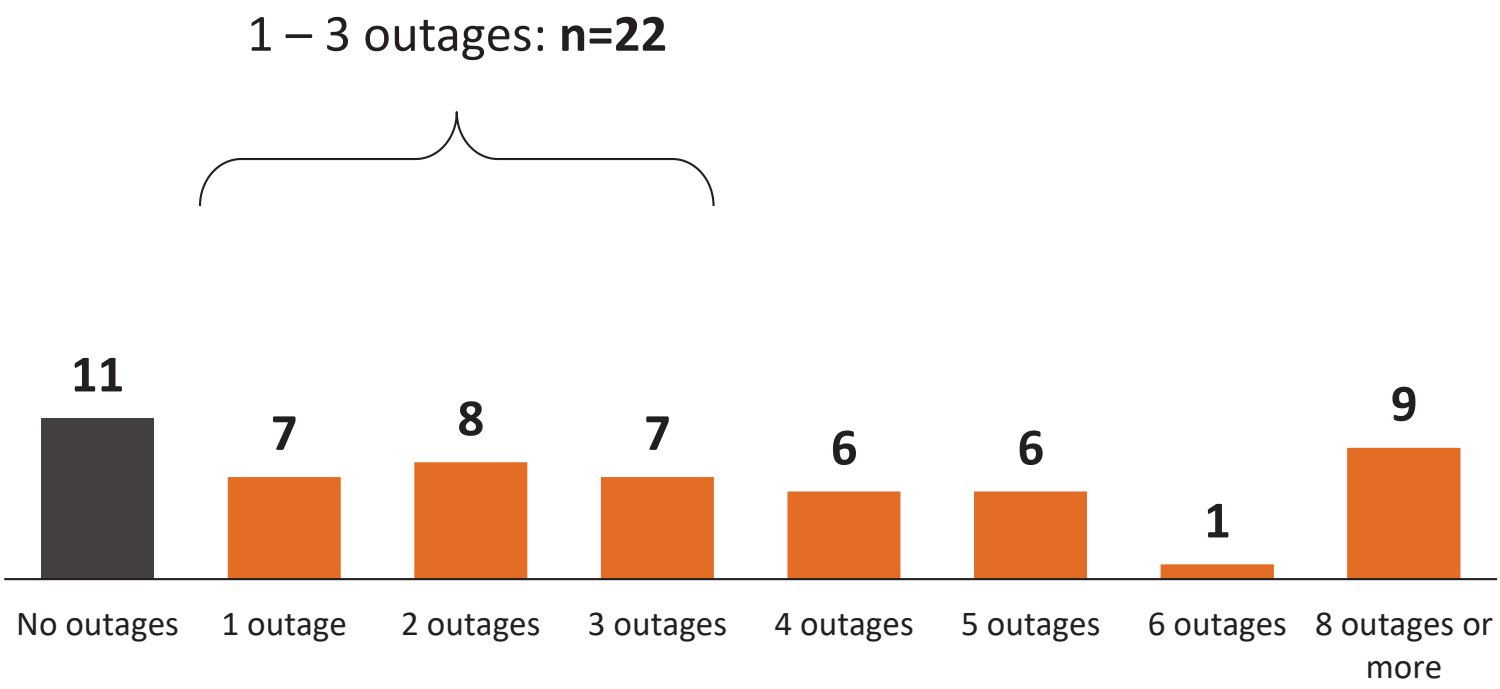
System Reliability:

About a third (n=22) experienced 1-3 outages; n=9 experienced 8 or more; n=11 experienced no outages

General Service

Q Despite best efforts, no electrical distribution system can deliver *perfectly reliable* electricity. As a general rule, the more reliable the system, the more expensive the system is to build and maintain. With that said, the average **Essex Powerlines** customer experiences **one** unexpected power outage per year.

Has your organization experienced any power outages in the past 12 months, and if so, approximately how many?
[asked all respondents, n=60]



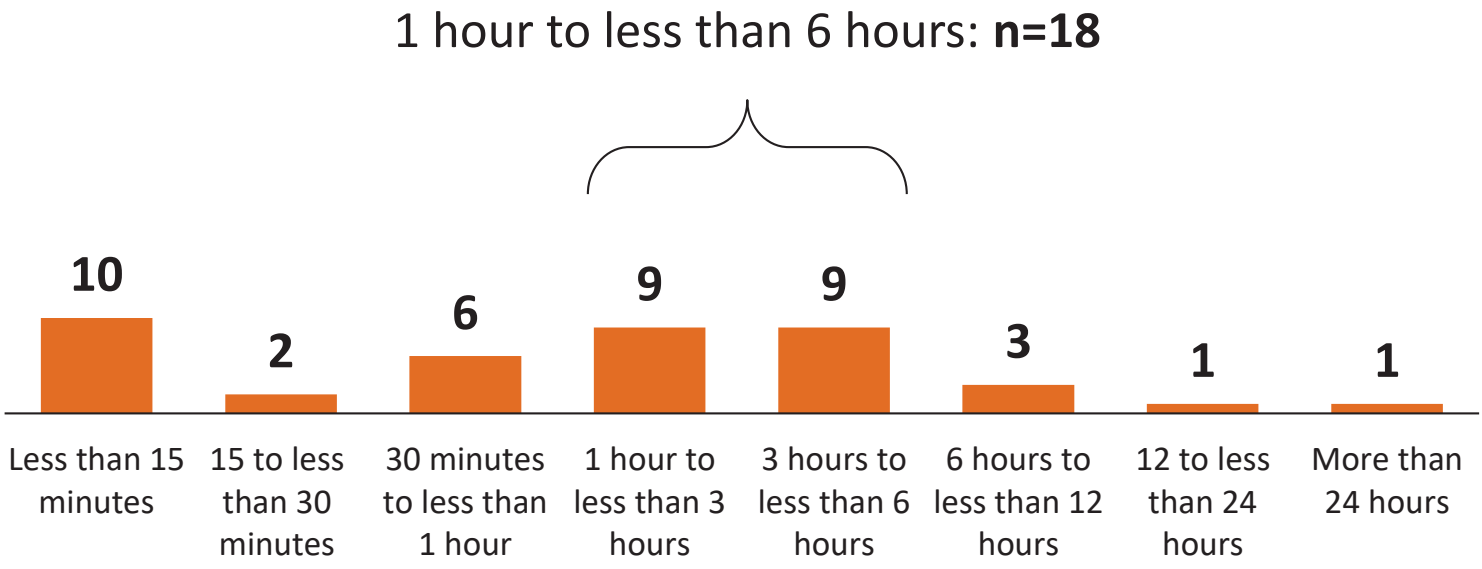
Note: 'Don't know' (n=4), 'Refused' (n=1) not shown.

System Reliability:

Some (n=10) experienced outages lasting less than 15 minutes, but n=18 experienced outages ranging from 1 to less than 6 hours

General Service

Q And approximately how many minutes did the most recent power outage last at your organization?
[asked of those who have experienced an outage, n=44]



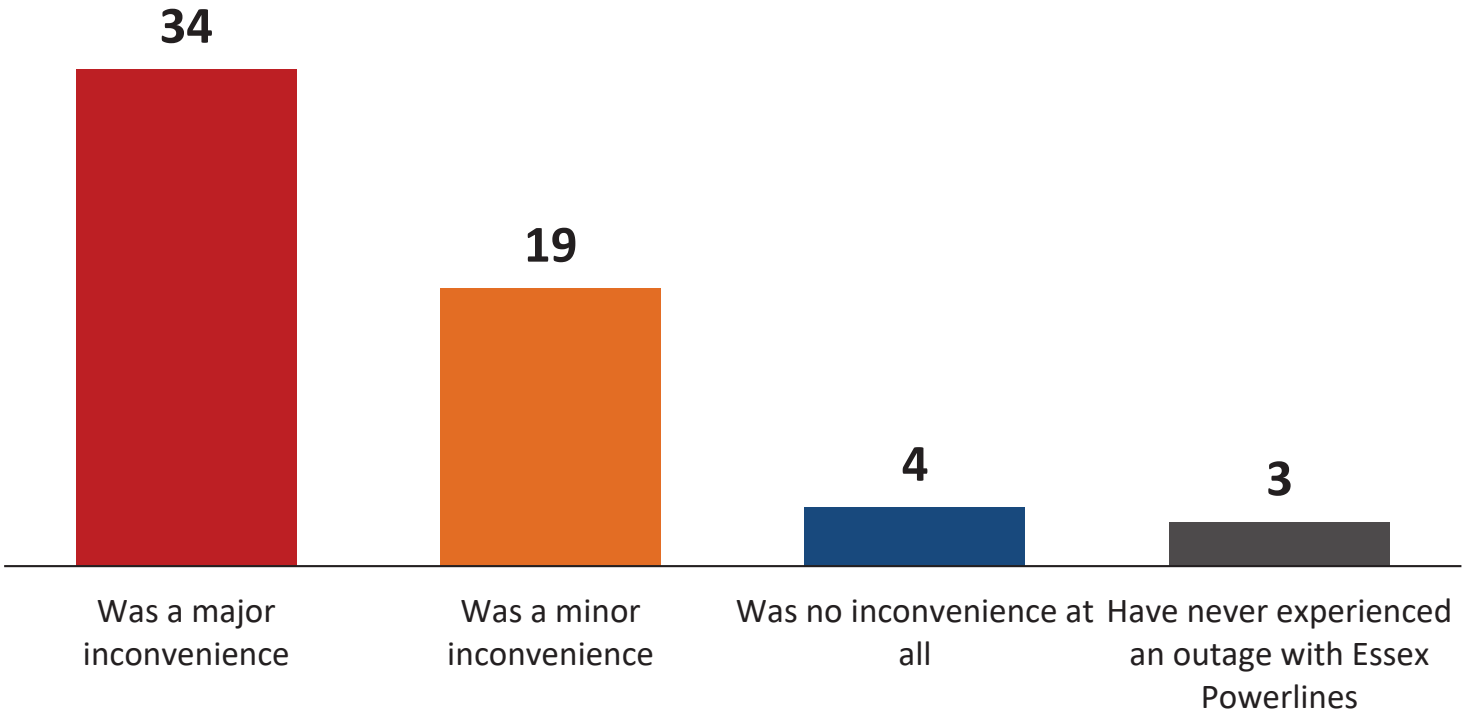
Note: 'Don't know' (n=3) not shown.

System Reliability:

More than half (n=34) of respondents report that the most recent outage was a major inconvenience

General Service

Q Thinking back to the **most recent** power outage you experienced as an Essex Powerlines small business customer, would you say the power outage…
[asked all respondents, n=60]



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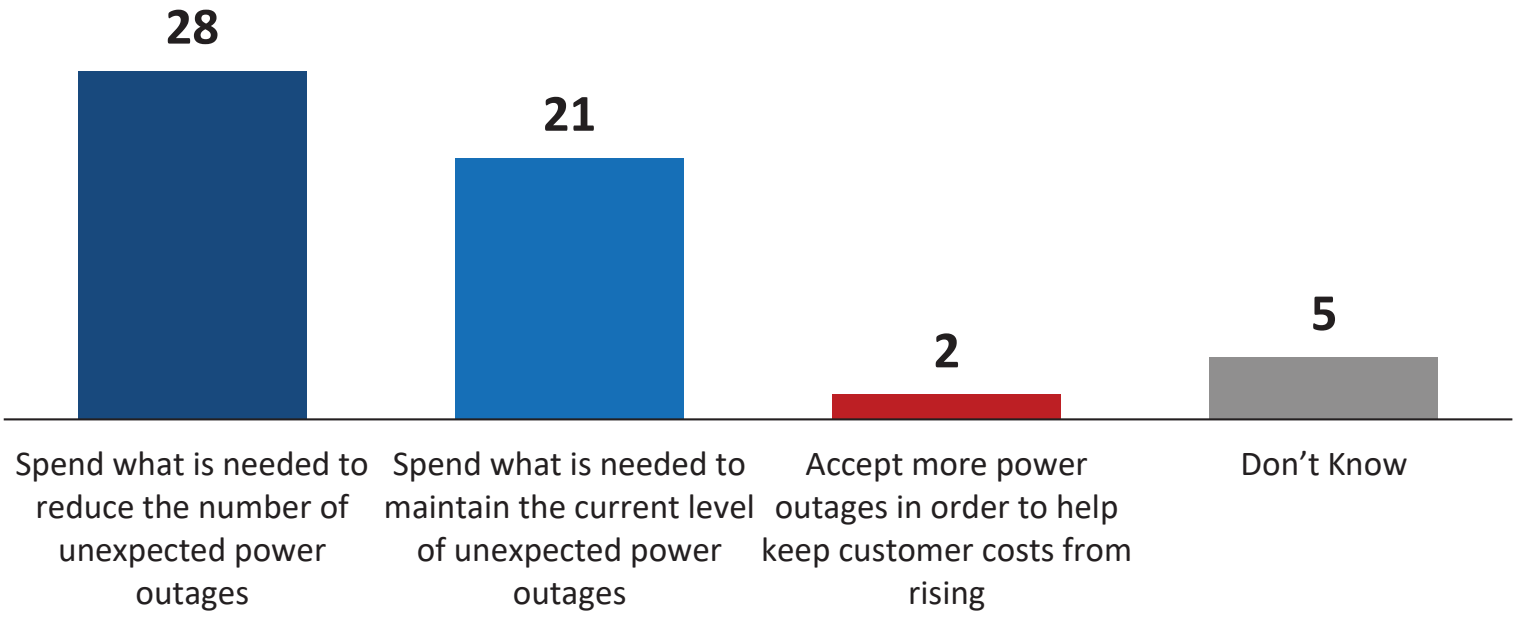
System Reliability:

Approximately half (n=28) think Essex Powerlines should spend what is needed to reduce the number of unexpected power outages

General Service

Q In your view, how do you think Essex Powerlines should address the **number** of customer power outages? Would you say…
[asked all respondents, n=60]



Note: 'Refused' (n=4) not shown.

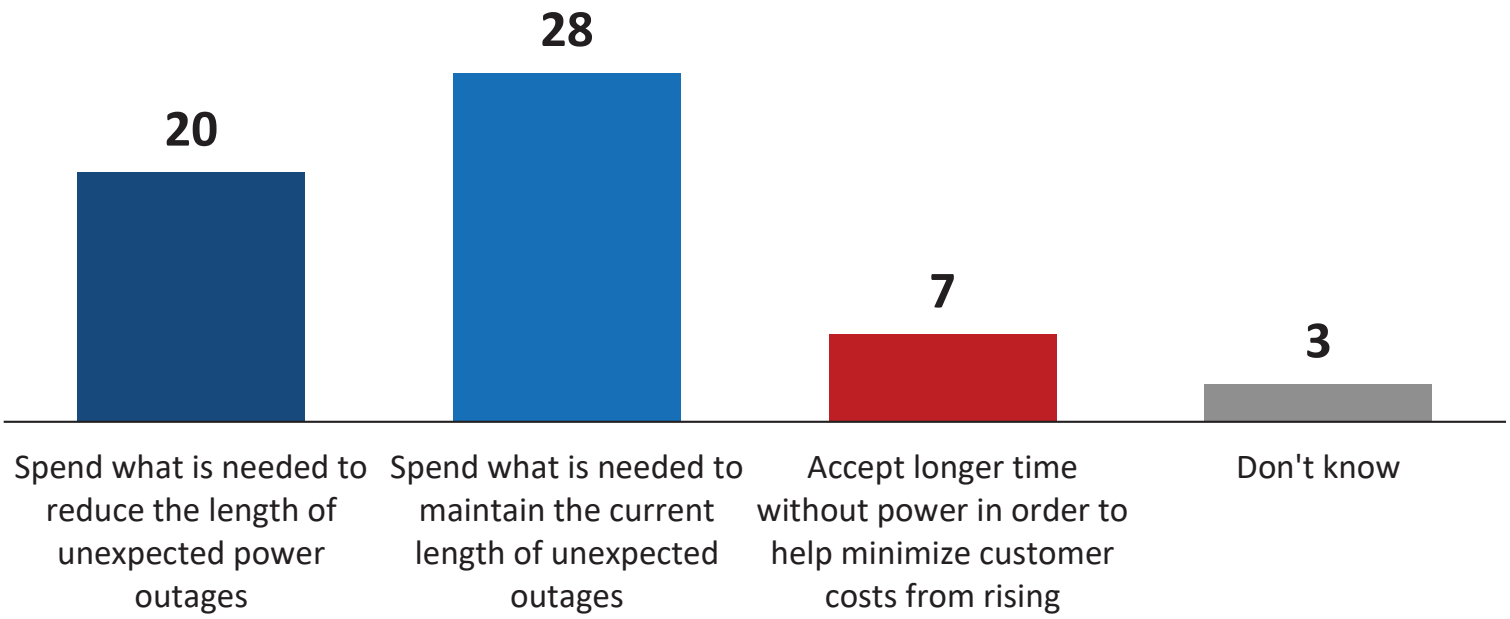
System Reliability:

Approximately half (n=28) say Essex Powerlines should spend what is needed to maintain the current length of unexpected outages

General Service

Q Overall, the average **Essex Powerlines** customer is without power for about **one hour per year**. In your view, how do you think Essex Powerlines should address the **length of time** customers are without power? Would you say…

[asked all respondents, n=60]



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Note: 'Refused' (n=2) not shown.

ESSEX POWERLINES CORPORATION

System Challenges & Priorities

General Service

INNOVATIVE RESEARCH GROUP

System Challenges & Priorities:

Most (n=48) think Essex Powerlines should invest what it takes to replace the system's aging infrastructure

General Service

Q While **Essex Powerlines** believes it has done its best to prolong the life of the assets that make up the distribution system, many of these assets are approaching the end of their useful life. As part of its investment plan, Essex Powerlines is proposing an infrastructure renewal program. The estimated cost of this system renewal program is **$31 million** between 2018 and 2022. Although this plan will allow Essex Powerlines to make, what independent studies suggest are, the necessary investments needed to maintain system reliability, **it *may* have an impact on customer bills**.

Which of the following statements best represents your point of view?
[asked all respondents, n=60]

Invest What It Takes

Some customers have said…

Essex Powerlines should invest what it takes to replace the system's aging infrastructure to maintain system reliability, even if that increases my organization's monthly electricity bill by less than a dollar over the next few years.

Lower Investment

Others have said…

Essex Powerlines should lower its estimated investment in renewing the system's aging infrastructure to lessen possible bill increases, even if that means more or longer power outages.

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Note: 'Don't know' (n=1), 'Refused' (n=2) not shown.

Run-to-Failure:

Most (n=40) feel the best approach is to replace the equipment before it breaks down

General Service

Q Thinking about the aging equipment in Essex Powerlines' distribution system, do you feel it's best to wait until non-critical infrastructure – that is, equipment that impacts a limited number of customers – breaks down to get full value from each piece of equipment, even if it means short power outages for some customers…

…Or do you feel the best approach is to replace the equipment before it breaks down to avoid unscheduled power outages, even if it means not getting the "full" value from each piece of equipment?
[asked all respondents, n=60]

Replace Equipment Before Breakdown

Wait Until Equipment Breakdown

Don't know

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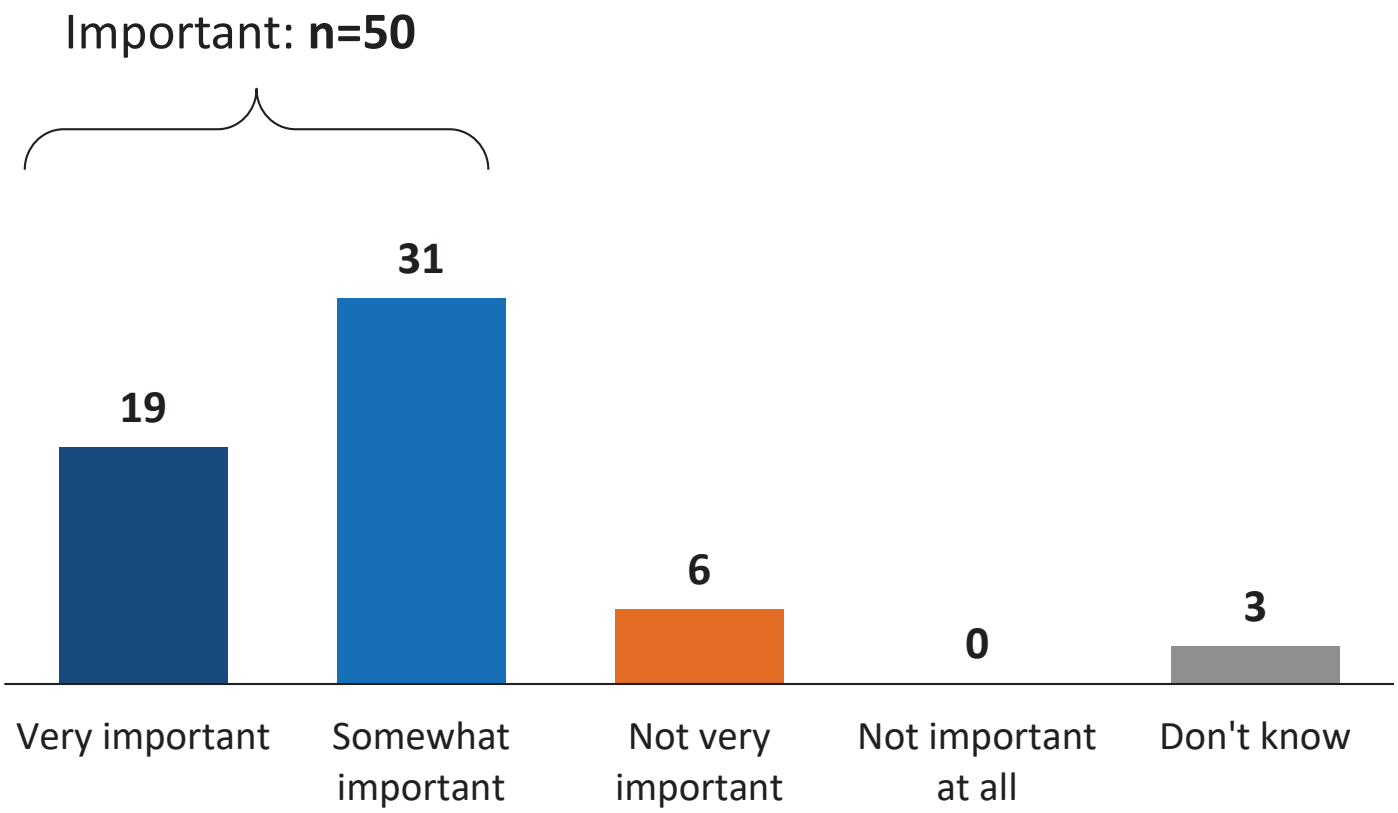
System Service:

Most (n=50) feel that investing in modernizing the distribution system now is important

General Service

Q Modernizing the distribution system can allow Essex Powerlines to improve reliability. Investments, such as automated switches, may allow Essex Powerlines to minimize the number of people impacted by outages and to restore electricity to many customers in a matter of seconds.

Given there are many other areas of needed investments, such as connecting new customers, replacing aging equipment and expanding capacity for long-term growth, how important do you feel it is for Essex Powerlines to invest now in modernizing the distribution system?
[asked all respondents, n=60]



INNOVATIVE RESEARCH GROUP

Note: 'Refused' (n=1) not shown.

General Plant:

Most (n=43) say Essex Powerlines should be wise with spending but acknowledge the importance of having the proper tools and equipment

General Service

Q Essex Powerlines is not just the local electricity distribution system itself, but a company that operates the system. As a company, Essex Powerlines needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the electrical system and customer information.

Again, customers have made a number of statements about this sort of investment. Which of the following statements best represents your point of view?
[asked all respondents, n=60]

Spend wisely, but it's important staff have what it needs

Others have said…

While Essex Powerlines should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system efficiently and reliably.

Make do with what it has

Some customers have said…

Essex Powerlines should find ways to make do with the buildings, equipment and IT systems it already has.

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Note: 'Don't know' (n=2), 'Refused' (n=1) not shown.

ESSEX POWERLINES CORPORATION

Reaction to Customer Input

General Service

INNOVATIVE RESEARCH GROUP

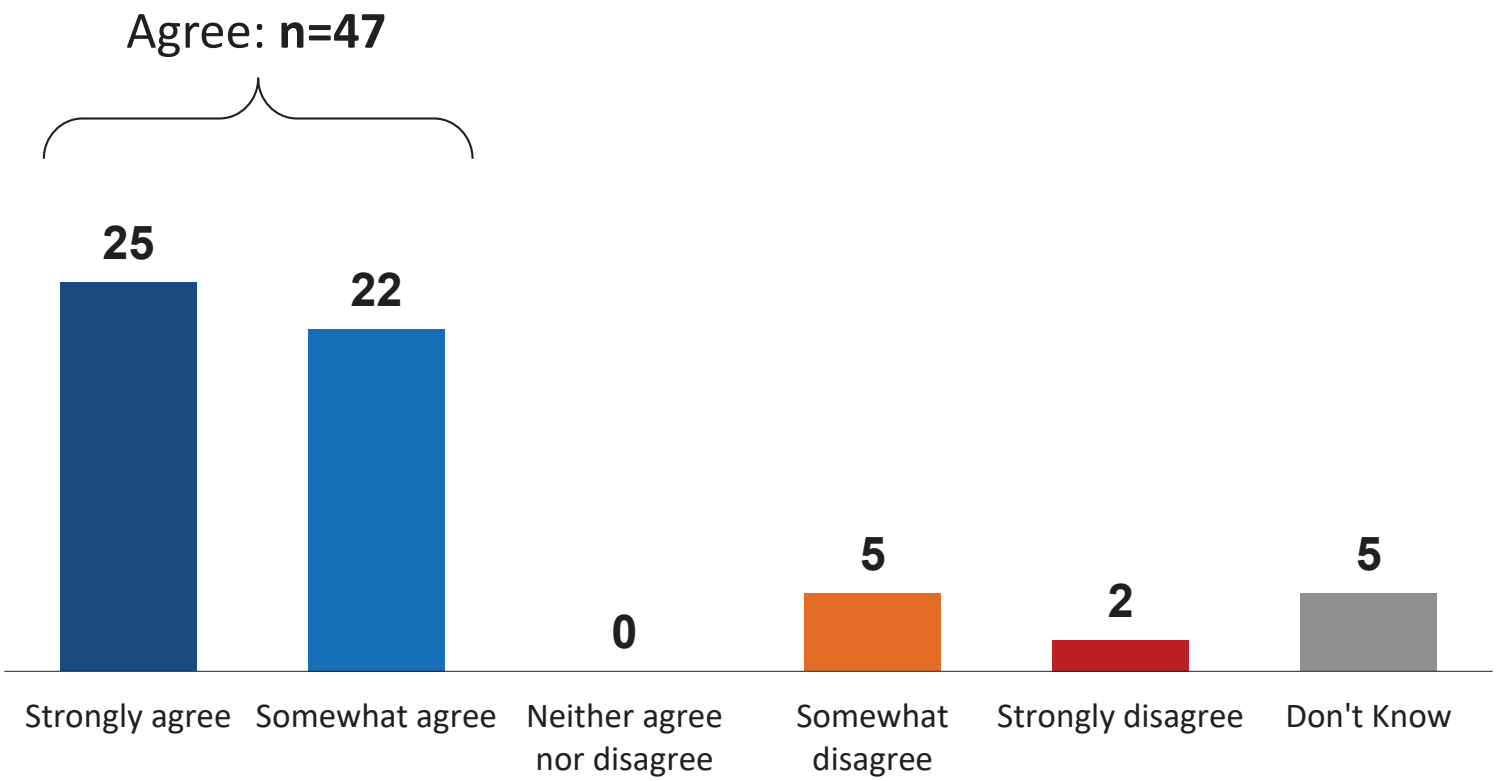
Pay Now or Later:

Most (n=47) agree to invest in infrastructure now to save down the line

General Service

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=60]

We should invest in our electricity system infrastructure now or we will end up paying more the longer we delay our system renewal.



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Note: 'Refused' (n=1) not shown.

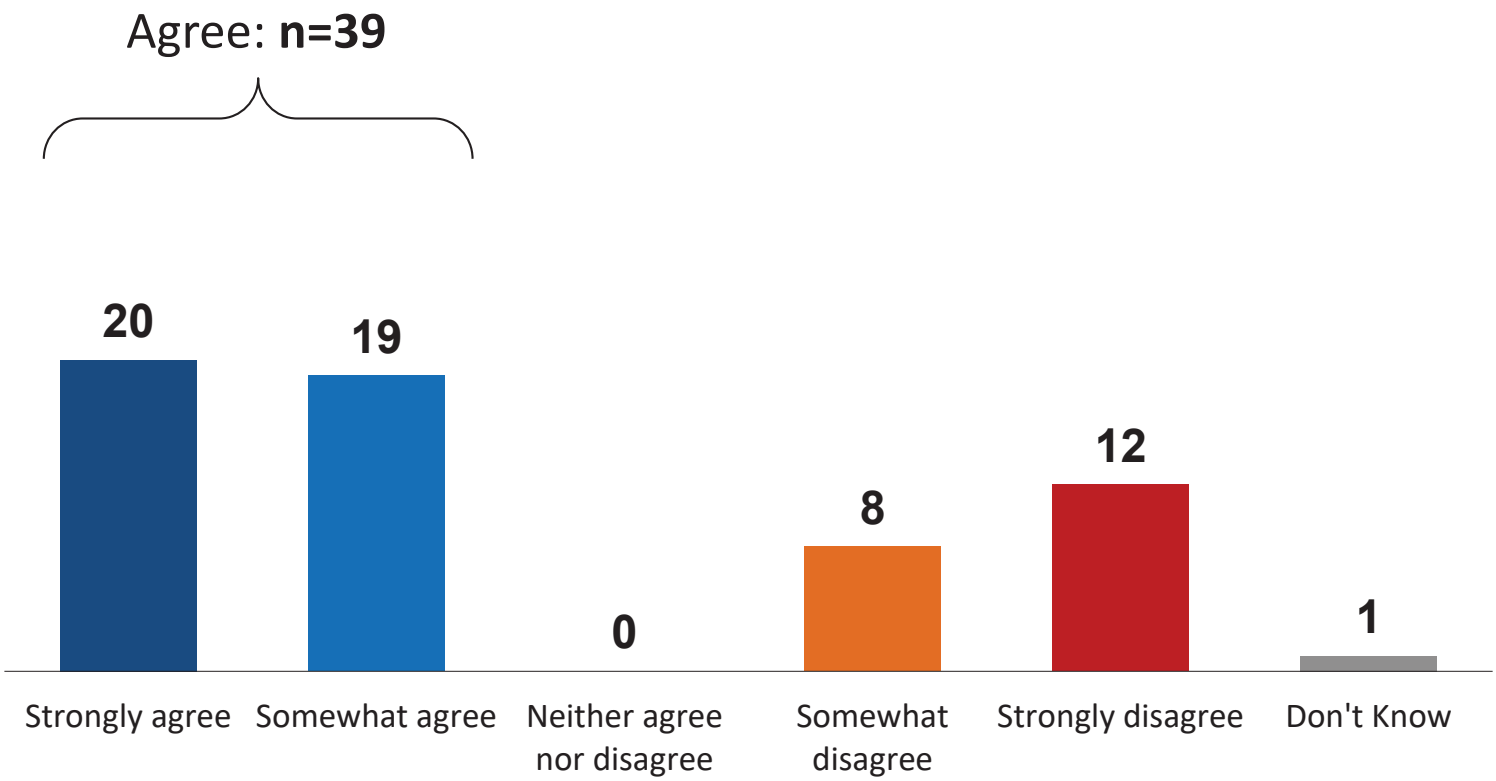
Deferring To The Experts:

Most (n=39) agree to trust that the experts will find the right balance between costs, investments, and spending decisions

General Service

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=60]

The electricity sector is so complicated and confusing; we just have to trust that the experts will find the right balance in keeping cost down while making the right investments and spending decisions.



INNOVATIVE RESEARCH GROUP

Note: 'Refused' (n=0) not shown.

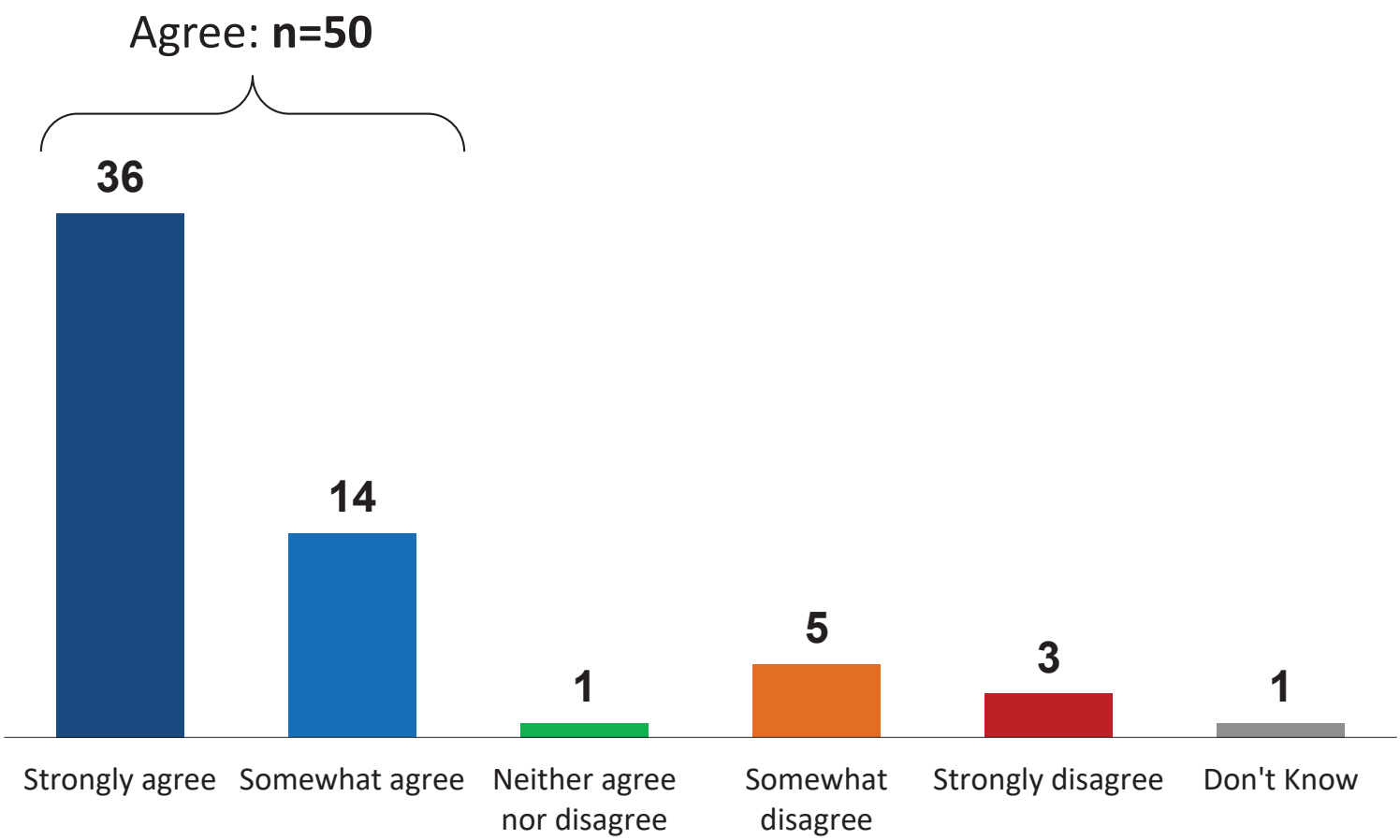
Conservation Demand Management:

Most (n=50) agree that Essex Powerlines should do more to help customers find ways to reduce consumption and costs

General Service

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=60]

I think Essex Powerlines should do more to help customers find ways to reduce their electricity consumption and costs.



Note: 'Refused' (n=0) not shown.

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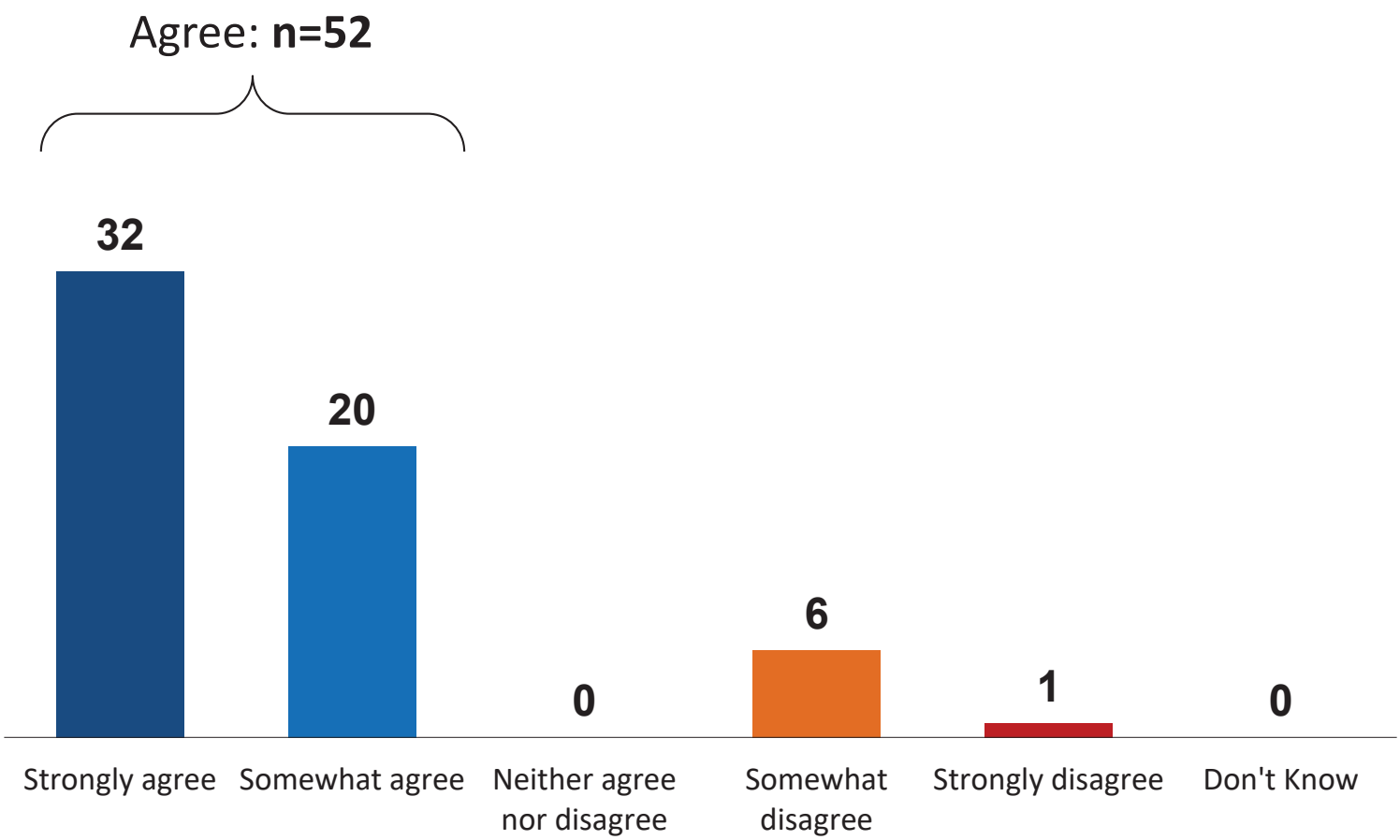
Legacy:

Most (n=52) agree that although nobody likes to pay more, there is an obligation to maintain reliability for future generations

General Service

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=60]

Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations.



Note: 'Refused' (n=1) not shown.

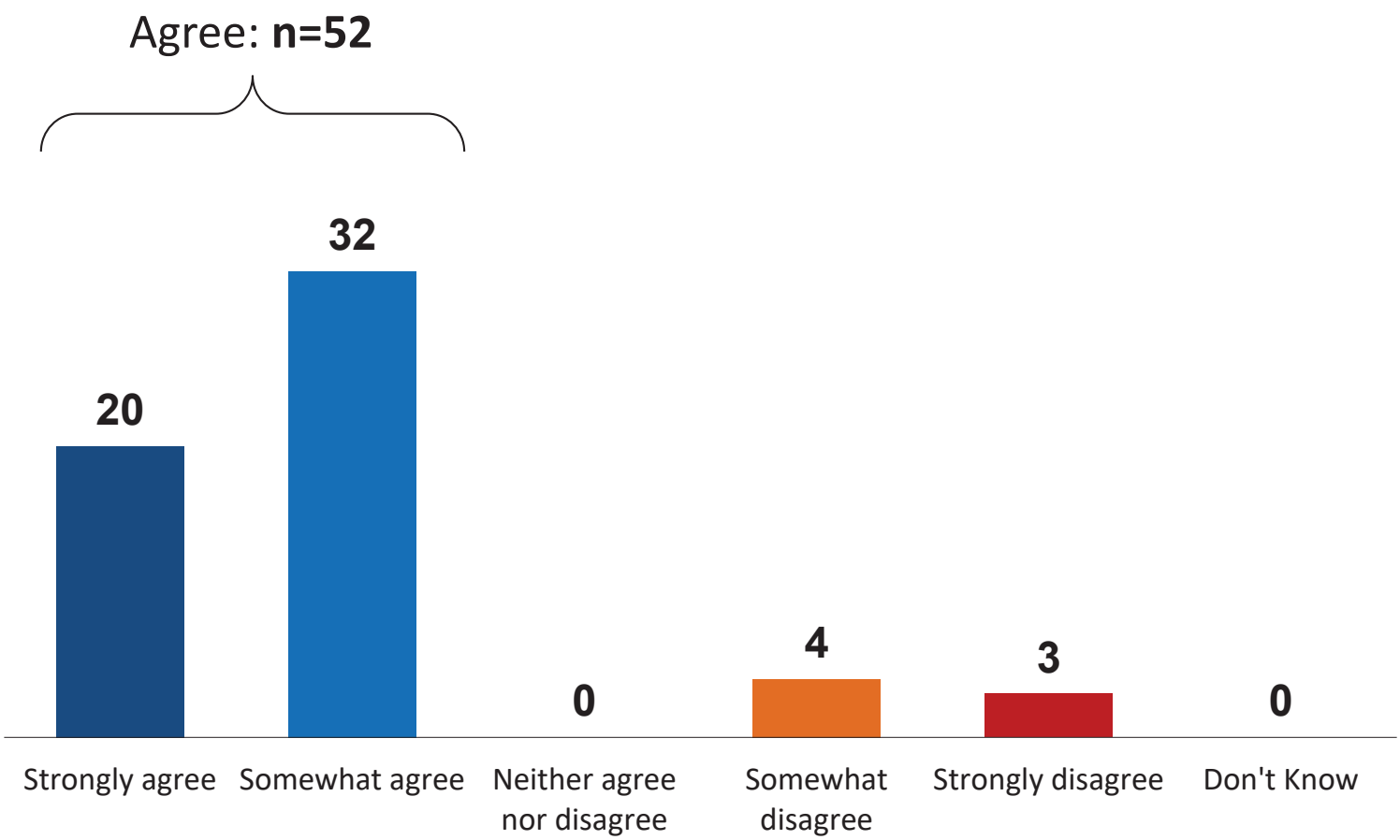
Modernizing The Grid:

Most (n=52) agree that modernizing the system will allow consumers to have greater control over usage

General Service

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=60]

We need to modernize the local electricity system so consumers can have greater control over their electricity usage.



Note: 'Refused' (n=1) not shown.

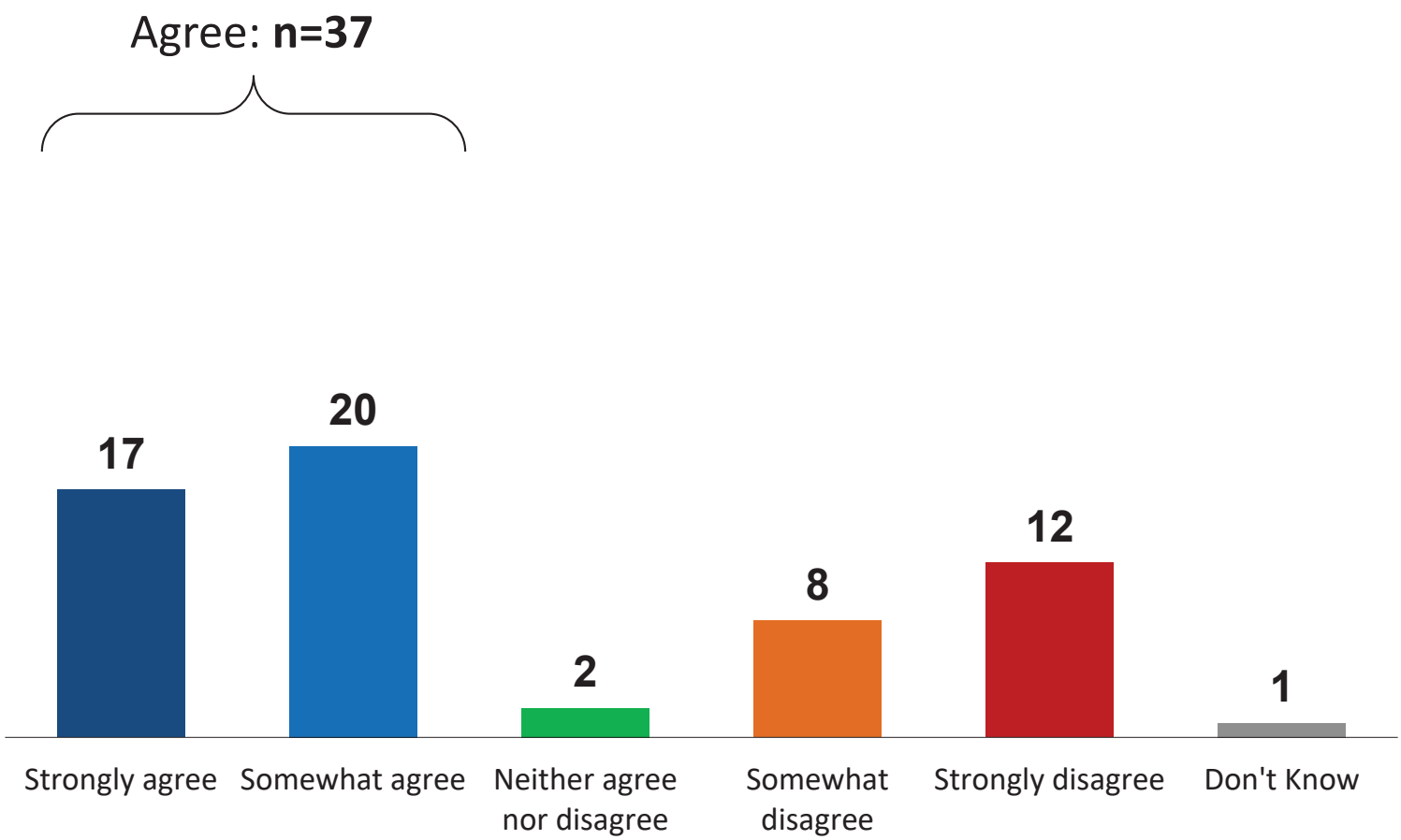
System Reliability:

Most (n=37) agree they worry about the impact outages have on vulnerable people

General Service

Q I am going to read you a number of statements. For each statement, please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree.
[asked all respondents, n=60]

A few power outages are fine for my organization, but I worry about the impact this has on more vulnerable people, such as the elderly.



Note: 'Refused' (n=0) not shown.

Assessment of Plan:

Some (n=10) think the rate increase is reasonable and support it; n=11 respondents do not like the increase but think it is necessary

General Service

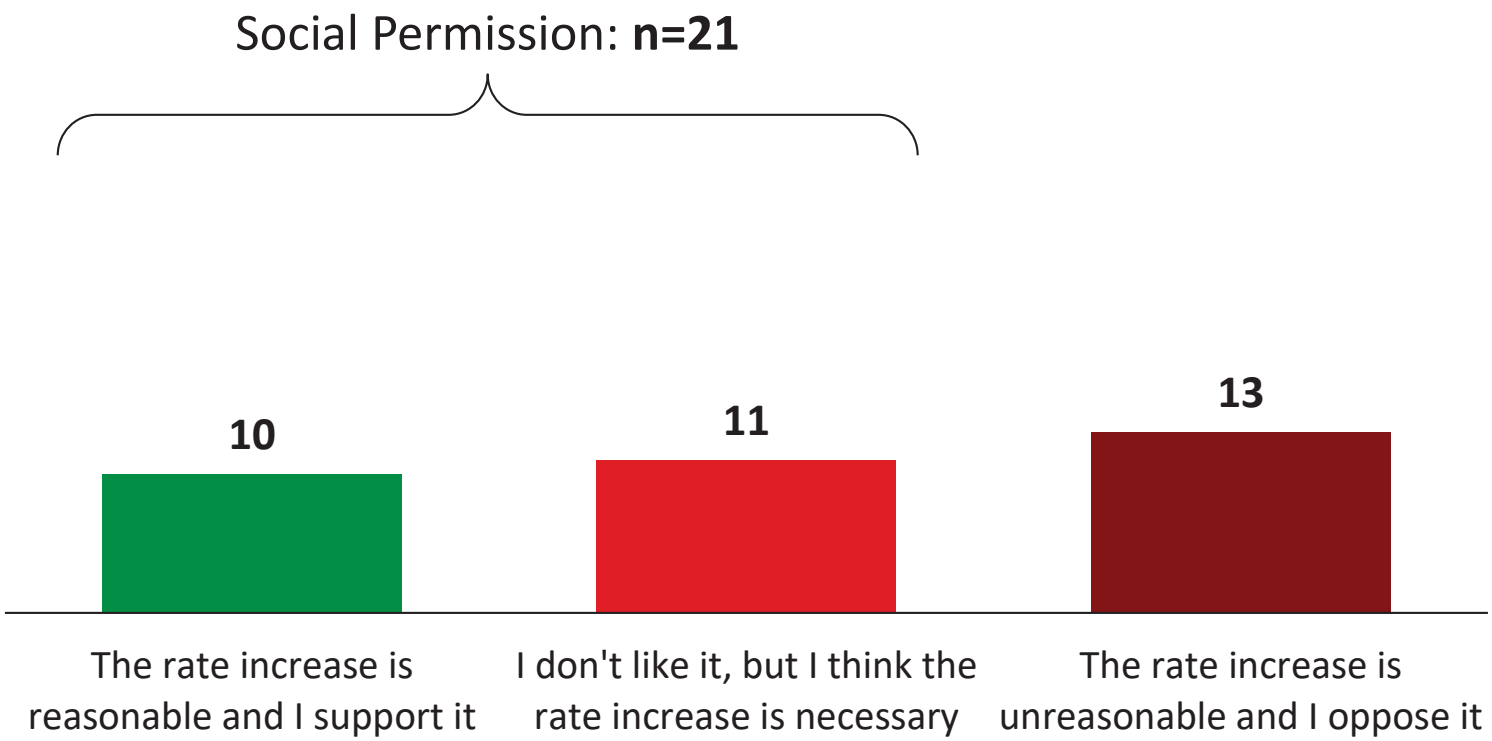
Q Essex Powerlines believes that proactive renewal and consistent maintenance is needed to maintain system performance, while keeping the impact on customer bills manageable over the long-term. Over its proposed 5 year plan, **Essex Powerlines** will…

- spend an estimated **$15 million** on on-going maintenance and the operation of the distribution system; and
- invest an estimated **$16 million** in new equipment and infrastructure priorities that will help ensure system reliability.

To fund this proposed plan, the average business customer in your rate class in Essex Powerlines service area will see their rates increase by approximately [$0.86 GS<50, $6.19 GS>50] per month on the distribution portion of their bill over the next five years. So, by 2022, the average business customer in your rate class will be paying an estimated [$4.92 GS <50, $42.67 GS >50] more per month on the distribution portion of its electricity bill, which is roughly the rate of inflation.

Considering the cost of Essex Powerlines plan, would you say…

[asked all respondents, n=34*]



** In the original interviews, respondents were provided inaccurate rate impact information. Callbacks were conducted to contact as many of the original respondents as possible to re-ask this question (and the follow-up open-ended question) with the corrected rate impact figures shown above.*

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Rationale:

Some who support appear to be motivated by the need to maintain; others think the proposed increase is a reasonable amount

General Service

Q And why do you say that?
[asked only of those who have an opinion on the assessment of plan, n=34]

Among those who say…
"The rate increase is reasonable and I support it." *(n=10)*

- to fix something you have to spend money
- Because I think its is probably necessary to keep everything working and we need it
- has to be done, we need it
- over the 5 years it's reasonable
- they are spending that much so someone has to pay for it, it makes sense
- Because it's reasonable and I support it.
- because for what they will be doing the cost to the customer will be small and it will benefit to the customer
- I agree with it
- the increase is not that big and if it will contribute to maintenance it wont be that noticeable.
- It's a minimal amount of money

Rationale (2):

Most of the verbatim comments re-affirm that although some respondents don't want to pay more they acknowledge that it is a necessity

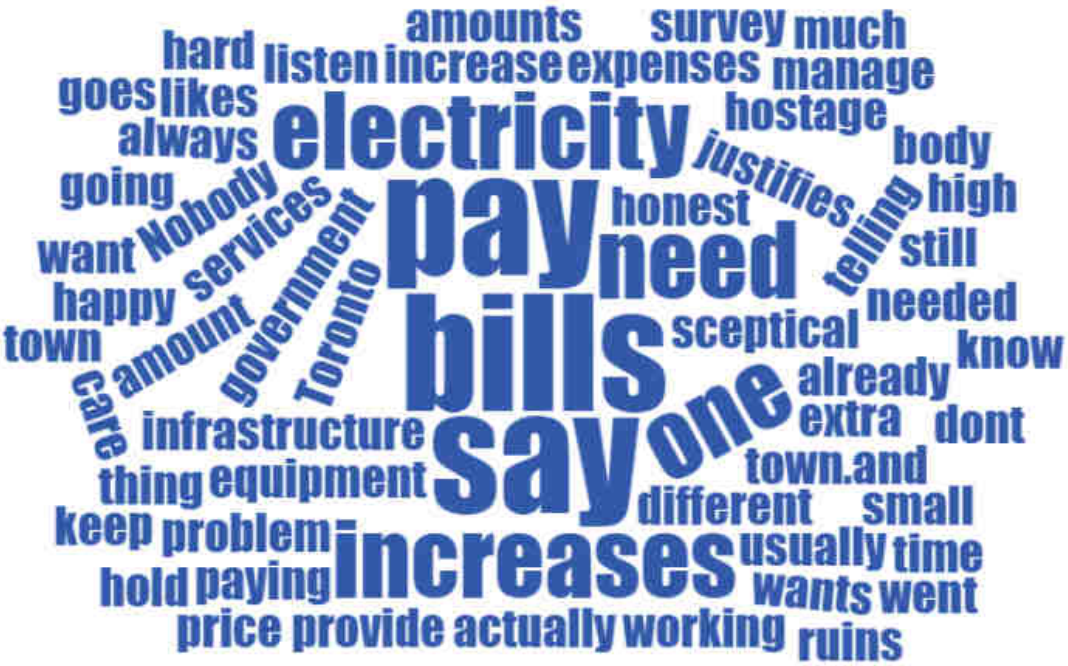
General Service

Q And why do you say that?
[asked only of those who have an opinion on the assessment of plan, n=34]

Among those who say…

"I don't like it, but I think the rate increase is necessary." ***(n=11)***

- who would be happy with a price increase?
- nobody wants increases but if it is needed
- it justifies the expenses
- it went up too high
- Because we are paying already too much.
- its hard for people to manage their bills, but I know they need to keep the infrastructure working
- Nobody likes to pay extra on their bills
- what they say it will be and what it actually will be are usually 2 different amounts. I'm sceptical that it will be that amount. the government has been telling us one thing and its not
- No one likes increases in any bills but if it is going to provide services that we need then it will have to be.
- because we always have a problem with our electricity. to be honest we pay more than any other town and our electricity goes out all the time and ruins our equipment. this is a small town and we pay more than Toronto
- they hold us hostage we have no say. Why do a survey when they do what they want. and they don't care what we say and still not listen to us



Rationale (3):

Some of those opposed to the rate increase feel the cost of electricity is already too much

General Service

Q And why do you say that?
[asked only of those who have an opinion on the assessment of plan, n=34]

Among those who say…
"The rate increase is unreasonable and I oppose it." (n=13)

- long time customer and we have been paying for a long time and from all the bills we paid Essex should have put some money on the side to do these repairs. its like buying a car, you don't ask your boss for a raise to buy a car. you save towards it.
- we already pay a lot as it is
- that's quite a significant increase
- I don't think we should have to pay for it.
- my cost keeps going every up and we are a little place. I went form 130 to 160 to 190. and I'm on a budget
- It's the question you are not giving me any choices, the infrastructure is fine the way it is. There is very few power outages, there are no issues. Who said there was an issue? They did. take a poll and see if people think the infrastructure is fine.
- on the bill the delivery charges is more than the usage. we try to cut down on usage but the delivery charges goes up. this should be included in the rates and not be charged
- we are paying too much as it is and we can barely pay our bills
- they should maintain the system themselves, they are not a non profit organization.
- because I can not afford the way it is now
- we are getting hit with everything gas, hydro, wages. I don't know how we are going to afford it.
- I think anything they do with hydro is unreasonable. there are people who can't pay their bills, we are selling it cheaper to others. Hydro has been mismanaged and they need to fix it.
- Because I don't believe them, I think it will be more. We are not a normal business, and how do they figure that we are?

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Building Understanding.

Personalized research to connect you and your audiences.

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Appendix E: Convergys Top Down Survey

CONVERGYS
ANALYTICS

ESSEX POWERLINES
Top Down Survey

Wave I Results

November 2016

SURVEY OVERVIEW & METHODOLOGY

Objective

- Gather Customer Satisfaction metrics to be used for OEB and scorecard reporting
- To measure Satisfaction in the following areas: Overall Satisfaction, Service/Brand Performance, Communication, Billing, and Contact Handling

Timing

- Surveying conducted October 3 – October 14, 2016

Methodology

- Telephone Survey conducted by a Convergys live agent

Sampling

- 500 total completed surveys – 400 Residential completes and 100 Business completes

Question Scales & Reporting

- Satisfaction asked on a 5 (Very Satisfied) to 1 (Not at all Satisfied) scale
- Top 3-Box (3, 4 and 5 ratings) reporting used for reporting of survey attributes

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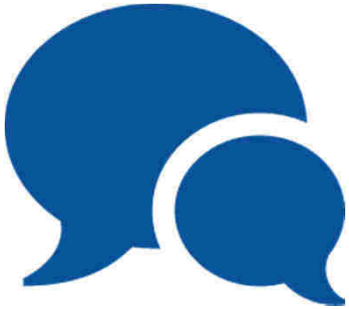
OUR OBJECTIVE AS A BUSINESS PARTNER IS TO HELP ESSEX POWERLINES INCREASE CUSTOMER SATISFACTION

Increase customer satisfaction

How we do this…

- Outline what factors have the largest impact on satisfaction
- Identify differences in Business and Residential customer segments
- Identify underperforming areas to target for improvement
- Mine customer comments to determine what common themes reflect opportunities for improvement



Improve customer interactions

How we do this…

- Working smarter to serve customers better by identifying and optimizing self-service opportunities
- Provide recommendations to improve the customer's experience when they do need to contact customer service

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AGENDA

Essex Powerlines Top Down Survey

1 OEB Metric & Satisfaction Overview

2 Key Satisfaction Drivers

3 Touchpoint Satisfaction

4 Recommendations

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EXECUTIVE SUMMARY

OEB Metric & Satisfaction Overview

- Overall Satisfaction is high (81%), but there are opportunities to improve service reliability, billing expectations, and customer service
- Business customers are more satisfied (by 8% pts) compared to Residential customers

Key Drivers

- Top Satisfaction drivers for Business customers are Reliability and Power Quality
- Customer Service is a top Satisfaction driver for Residential customers

Touchpoint Satisfaction

- Customers almost exclusively use the phone to contact Essex Powerlines where offering/enhancing self-service capabilities is a prime opportunity to reduce contacts
- Residential customers generally have a preference for mail while Business customers opt for several methods

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OEB METRIC & SATISFACTION OVERVIEW

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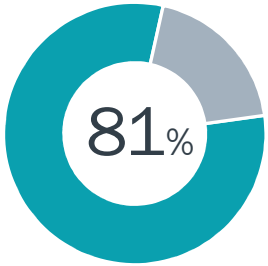
THE MAJORITY OF CUSTOMERS ARE HIGHLY SATISFIED WITH ESSEX POWERLINES

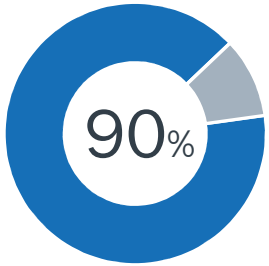
KEY METRIC AND OEB REQUIREMENTS

Top 3 Box

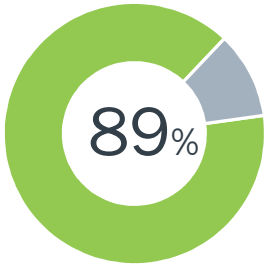
Overall Satisfaction



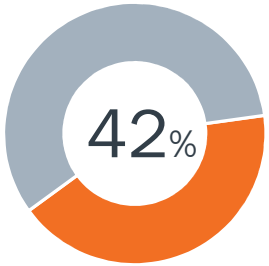
Quality of Power Service



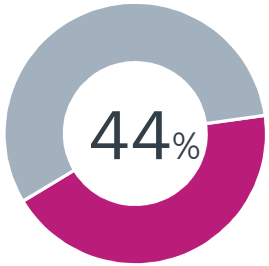
Quality of Customer Service



Affordability of Service



First Contact Resolution*



"Essex Powerlines is always very helpful and has a quick response. It is appropriate for the situation. If I have any questions about the service, Essex Powerlines answers those in a timely manner." ~ '5' Overall Satisfaction rating

"I gave Essex Powerlines a phone call and they were here within a half an hour and my problem was fixed within a few hours." ~ '5' Overall Satisfaction rating

*First Contact Resolution (FCR) = %Yes; Customers contacting Essex by phone and resolved on one contact

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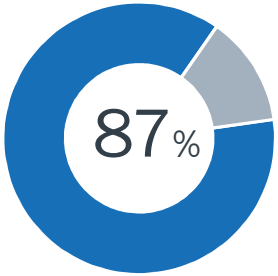
CONVERGYS ANALYTICS

OVERALL SATISFACTION IS HIGH, BUT OPPORTUNITIES FOR IMPROVEMENT EXIST, MORE SO FOR RESIDENTIAL CUSTOMERS

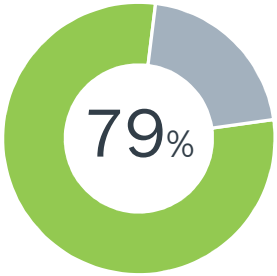
Customer Satisfaction

Top 3 Box

Business



Residential



2016 Reasons for Satisfaction

Positive Mentions

- No Issues/ Reliable
- Good Customer Service
- Good Service/ Satisfied

Negative Mentions

- Service Interruptions
- Price/Cost
- Poor Customer Service

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CONVERGYS ANALYTICS

KEY SATISFACTION DRIVERS

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WHAT IS A KEY DRIVER ANALYSIS?

Key Drivers represent what is most important to Customers and where to focus efforts to have the greatest impact on Overall Satisfaction.

1. What are the attributes' relationship to Overall Satisfaction?

   Action: Calculate each attributes' correlation to Overall Satisfaction

2. If several attributes have a moderate to strong relationship to Overall Satisfaction, how can attributes be prioritized?

   Action: Calculate the Relative Importance

3. Once a Relative Importance model is developed, how much does it explain Overall Satisfaction?

   Action: Calculate the proportion of variance that explains Overall Satisfaction

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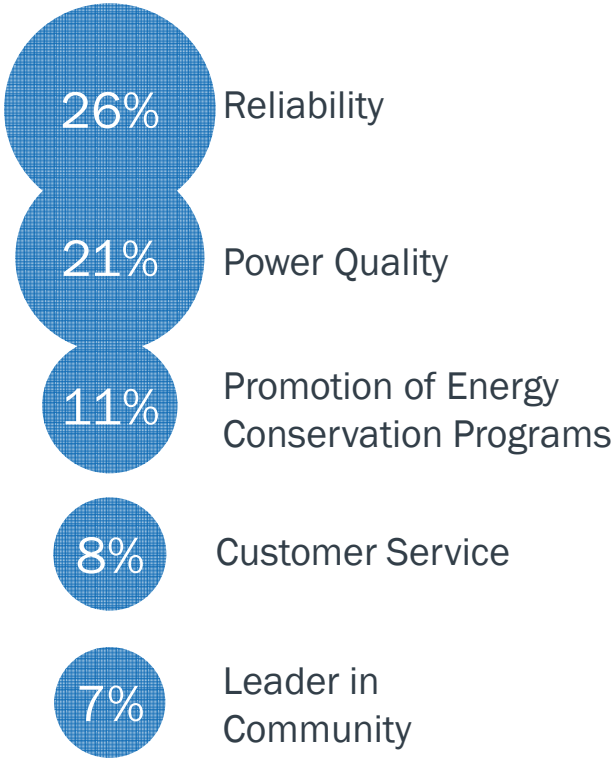
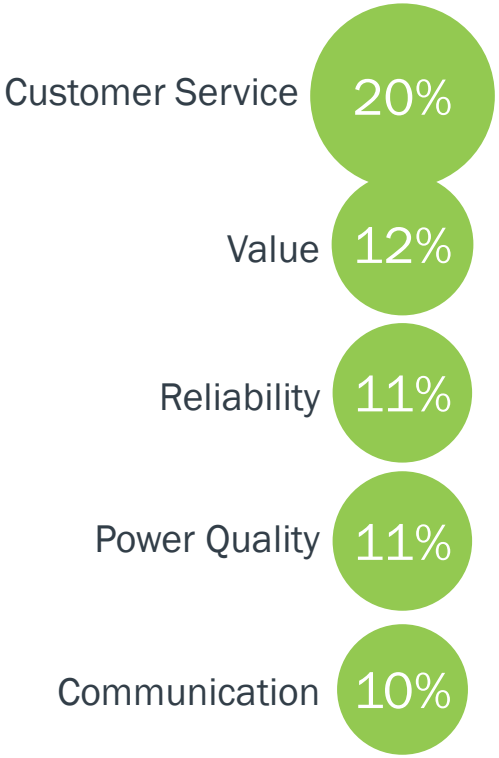
BUSINESS CUSTOMERS WANT AN INTERRUPTION-FREE SERVICE WHILE RESIDENTIAL CUSTOMERS PRIORITIZE CARE WITHIN CUSTOMER SERVICE

Key Drivers to Overall Satisfaction

% Variance explained: 61%





% Variance explained: 56%

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Percentages represent the relative impact of each attribute on Overall Satisfaction.

TOUCHPOINT SATISFACTION

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CONTACT METHODS AND REASONS ARE SIMILAR FOR BOTH BUSINESS & RESIDENTIAL, HOWEVER, BUSINESS CUSTOMERS CALL MORE OFTEN

Business

Reported Contacts in Past 6 Months: 44%

Resolved: 83%

Contact Methods

- Telephone 98%
- Email: 5%

Contact Reasons *n=43*

- Service Issue 44%
- Billing/Payments 40%
- Account Change 14%

Call Handling

Residential

Reported Contacts in Past 6 Months: 24%

Resolved: 77%

Contact Methods

- Telephone 97%
- Email: 1%

Contact Reasons *n=93*

- Billing/Payments 39%
- Service Issue 37%
- Account Change 13%

Total may sum to more than 100% due to multiple responses

Based on customer comments, Q8.

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CONTACT HANDLING FINDINGS & OPPORTUNITIES

	Finding	Opportunity	Customer Feedback
Residential	*23% of Customers' inquiries were not resolved*	Follow through with services promised to avoid repeat contacts	*"We've had one issue here and the service through the employee was delayed by hours. We called around 8 and didn't see anyone till around midnight."*
Business & Residential	*Almost half of all customer contacts were for billing and payments*	Increase awareness and enhance online self-service options to reduce the need for contacts	*"I needed to make a payment arrangement."* *"We never received our bill in the mail. I wanted to see if I could receive a copy."*

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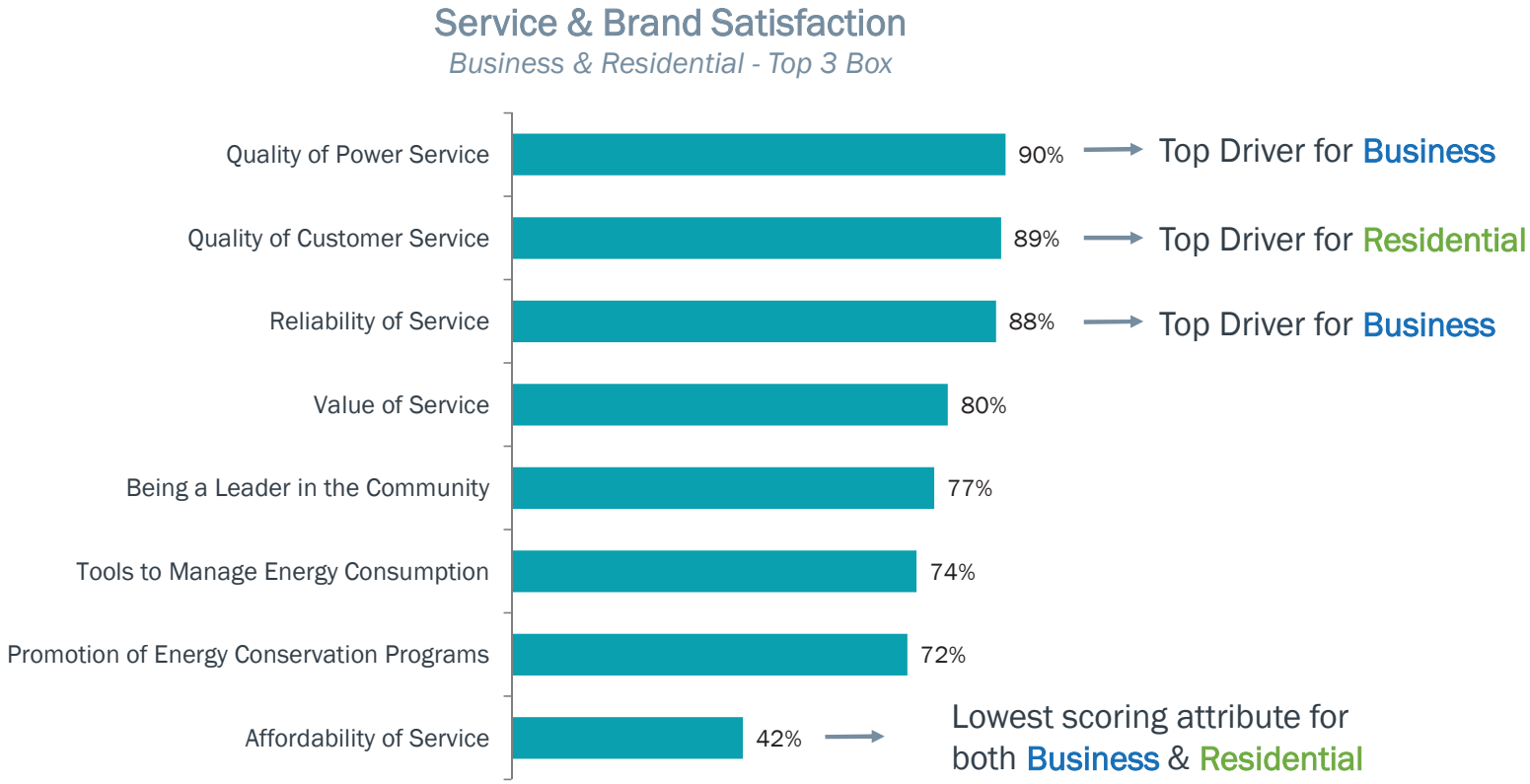
CUSTOMERS ARE HIGHLY SATISFIED WITH THE TOP DRIVING MEASURES



Business & Residential data breakout in Appendix - Differences ratings are not statistically significant.

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CONVERGYS ANALYTICS

SERVICE & BRAND FINDINGS & OPPORTUNITIES

	Finding	Opportunity	Customer Feedback
Business	*Drivers: Power Service & Reliability*	Reduce recurring issues with loss of service	*"Our power seems to go out a lot, interruptions where the power is off for 5 minutes and the computers go off with no explanation."* *"I was looking at the number of times the hydro service was going out. It happens more than it has in previous years."*
Residential	*Driver: Customer Service*	Continue to focus on providing high quality customer service	*"They are very easy to work with and to talk to. They try not to interfere in your life, which to me, all are very good things."* *"They are very helpful with anything I need help with."*
Business & Residential	*Affordability of Service*	Educate Customers on rates and on fees charged	*"The price is too high. Even after we cut down on our hydro consumption it is still pretty high."* *"It is very hard to justify the rates that we have to pay for the services."*

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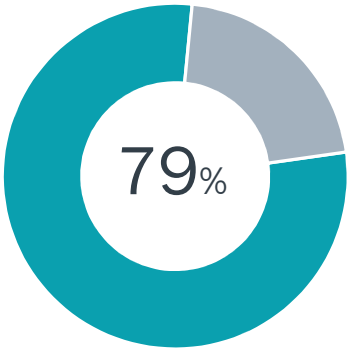
CONVERGYS ANALYTICS

RESIDENTIAL CUSTOMERS STRONGLY PREFER LETTERS; BUSINESS CUSTOMERS ARE LIKELY TO PREFER SEVERAL METHODS SIMILARLY

Business & Residential

Top 3 Box

Communication



Communication Preference

	Business	Residential
Letter in the Mail	41%	53%
Email	27%	24%
Telephone Call	30%	22%

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COMMUNICATION FINDINGS & OPPORTUNITIES

	Finding	Opportunity	Customer Feedback
Business	***Preference several methods – Mail, Email, and Telephone***	Important to leverage all touchpoints for communication	*"I wish they would go back to talking to people, instead of having everything be so automated. It's really annoying needing to talk to someone, and having to combat all these numbers. It's inconvenient for emergencies, but I understand how it's easy for the company."*

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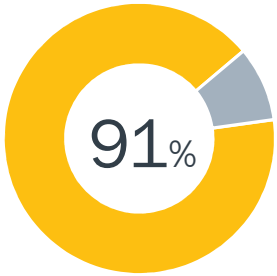
THE BILLING PROCESS APPEARS TO BE WELL RECEIVED BY ESSEX POWERLINES CUSTOMERS, BUT HAS ROOM FOR IMPROVEMENT

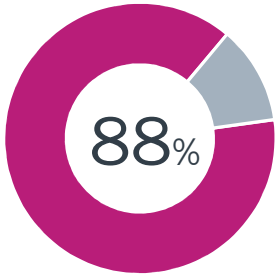
Business & Residential

Top 3 Box

Ease of Accessing Account Information



Billing Accuracy



"A few times, we have an overdue when our bill was already paid."

Continue to ensure billing is understandable and accurate

"Need to do something about the pricing. I have all this green energy but it's not helping anyone with their bill."

Leverage the use of current touchpoints to help Customers better understand how to manage their energy consumption

"I don't agree with people on fixed income having to pay a late fee for paying bill late. I have no control."

Endorse the benefits and feasibility of current payment options

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RECOMMENDATIONS

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TAKEAWAYS & RECOMMENDATIONS

1

PRIORITIZE KEY DRIVERS OF SATISFACTION

Investing in service reliability and customer service will help minimize the impact of the dissatisfaction triggers

2

PROMOTE SELF-SERVICE SOLUTIONS

Almost all customers are contacting Essex Powerlines via phone and about half are related to billing inquiries; if self-service options and other methods for communication are leveraged, the call center can see a reduction in call volume and costs associated with each call

3

BE PROACTIVE & REACTIVE WHEN COMMUNICATING BILLING

Customers are heavily critiquing their bills due to continuous rate increases; mailing/emailing a bill explanation, posting a bill tutorial to the website, and coaching key agent behaviors (i.e., empathy, clear explanations, etc.) within customer care are ways to effectively communicate billing accuracy and set billing expectations

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TOOLS TO MANAGE ENERGY CONSUMPTION

Help Customers learn and better understand how to manage their energy consumption by:

Enhance the website. Add visibility and accessibility to "Save Energy" on the home page, and augment the graphics.

Send information. Send monthly email marketing messages to consenting customers containing tips or postcards that can direct them to more information; also, Customer Service Reps can ask customers if they are interested in learning about managing energy consumption and send them information via email/mailing.

Leverage the social media space. Post information or "how-to" videos online, or create a blog for customers to subscribe to, to learn about managing energy consumption.

Interact with the community. Continue to issue press releases and work with local media (e.g., radio, news, etc.) to share information on managing energy consumption. Host events/seminars at Essex Powerlines so people can come in and learn more or have booths/tables at community events with information on available tools.

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APPENDIX

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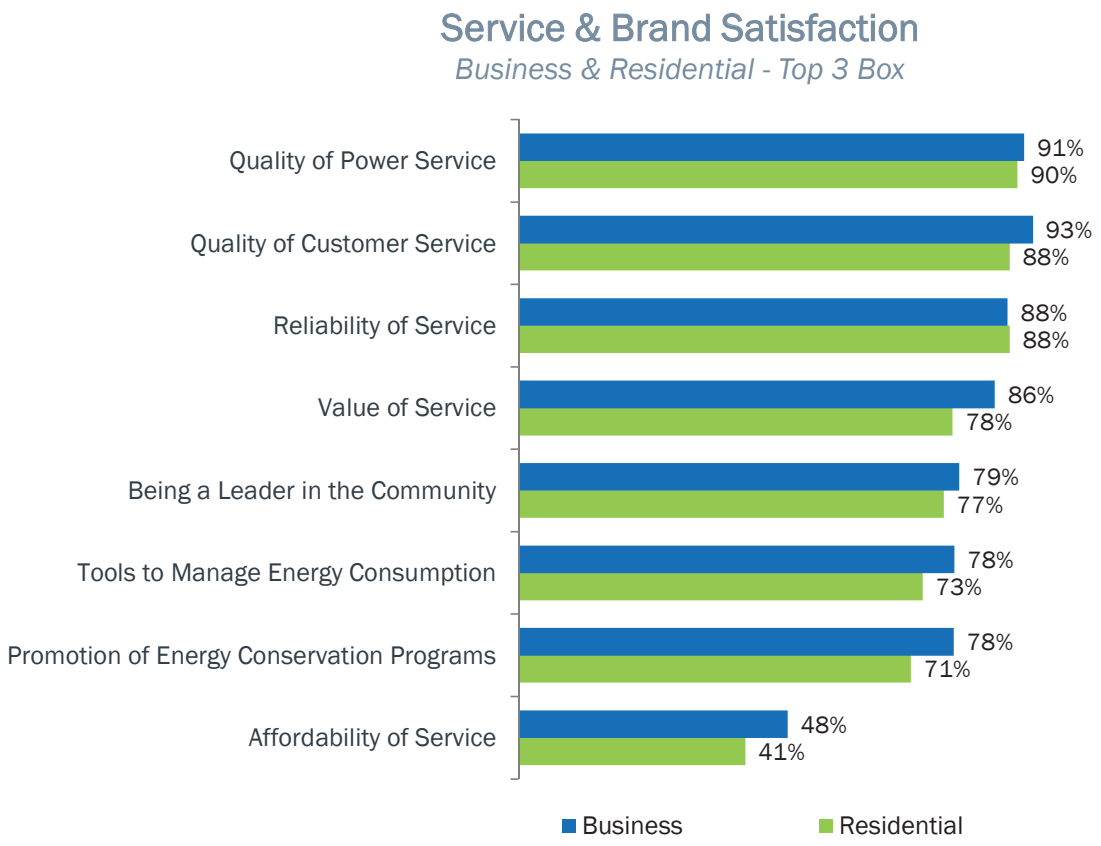
SERVICE AND BRAND SATISFACTION



Differences in Business & Residential ratings are not statistically significant.

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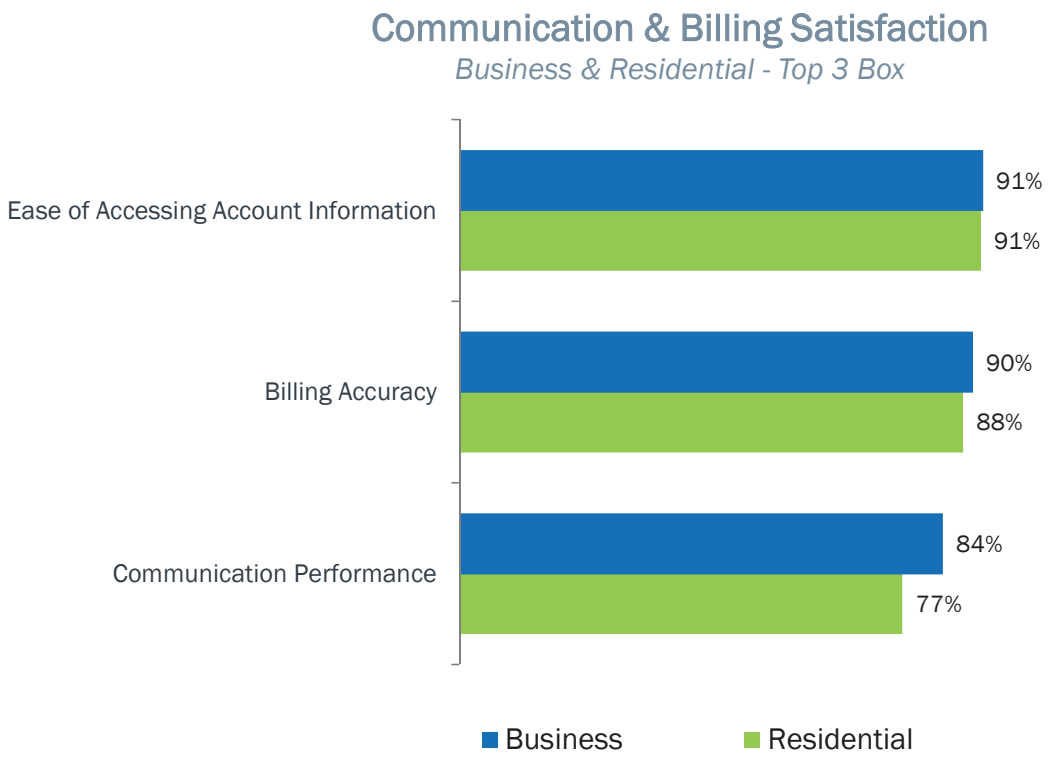
CONVERGYS ANALYTICS

COMMUNICATION AND BILLING SATISFACTION



Differences in Business & Residential ratings are not statistically significant.

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Appendix F: Customer Engagement Handbooks

2018 RATE APPLICATION REVIEW

Customer Consultation Workbook

ESSEX POWERLINES CORPORATION

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

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

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

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

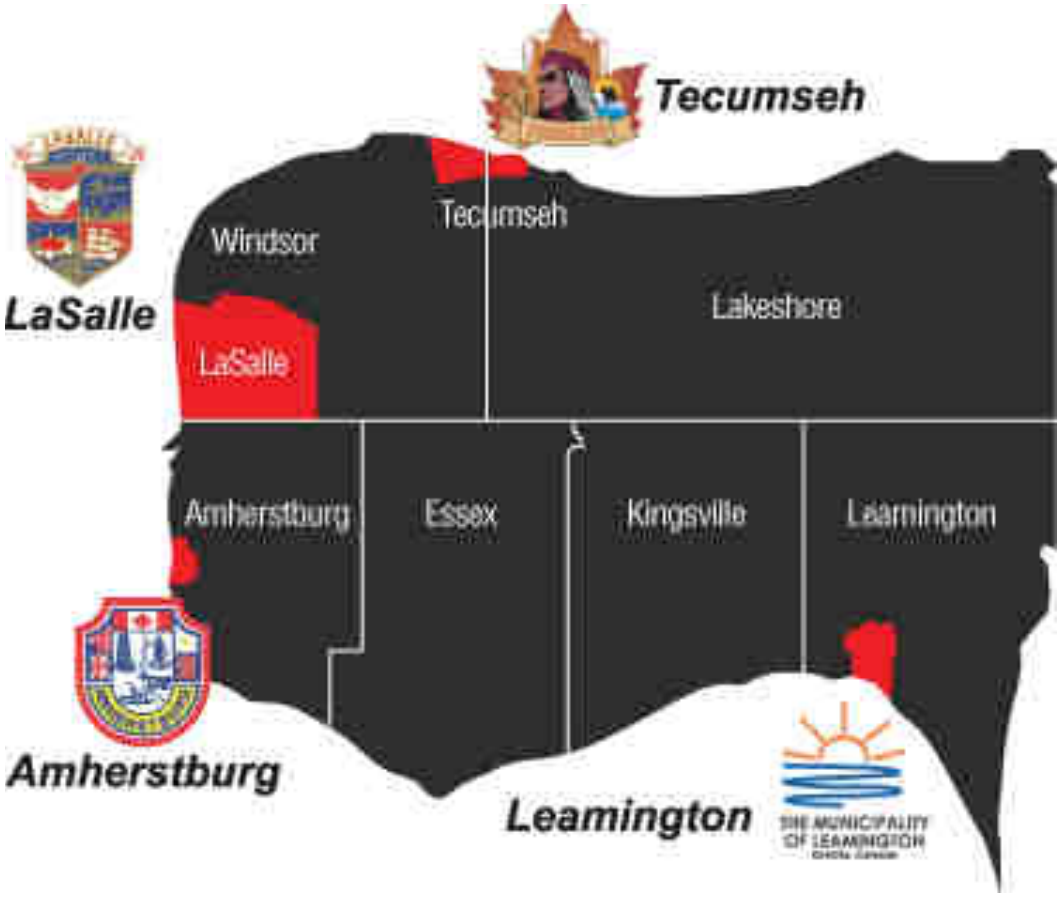


Table of Contents

What is this Consultation About?

Electricity 101

Essex Powerlines' Grid Today

Cost Pressures

What the Plan Means for You

What Is This Consultation?

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

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

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

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

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

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

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

ESSEX POWERLINES CORPORATION

What's the Process that Essex Powerlines Must Follow?

How are electricity rates determined in Ontario?

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

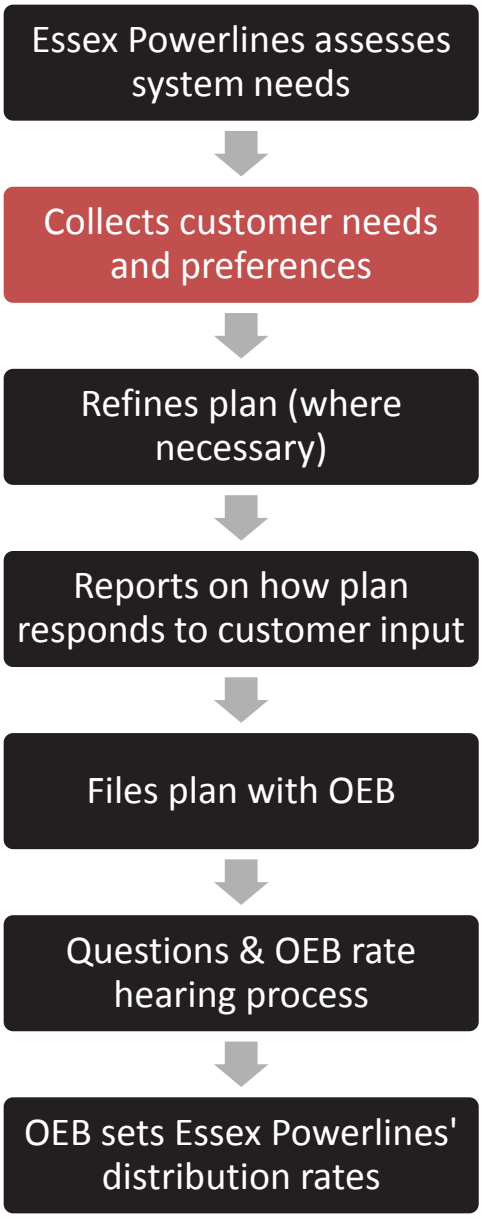
Essex Powerlines is funded by the distribution rates paid by its customers. Periodically, Essex Powerlines is required to file an application with the OEB to determine the funding available to operate and maintain the distribution system. Essex Powerlines must submit evidence to justify the amount of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

As a customer, how are my interests protected?

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

Why is my feedback important?

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



Consumer Feedback on Ontario's Electricity System

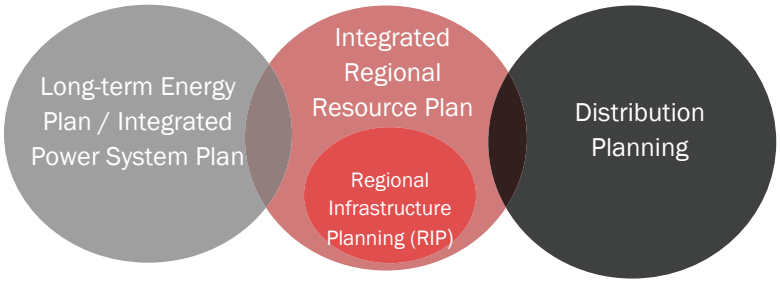
There are a number of ways for consumers to voice their opinions on provincial, regional and local electricity issues. However, this consultation is about your local distribution system and your preferences on how Essex Powerlines Corporation uses your money.

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

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

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

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



Provincial System Planning

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

This includes planning on:

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

Regional Planning

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

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

Distribution System Planning

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

Customer Electricity Bills

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

SAMPLE MONTHLY BILL STATEMENT
Essex Powerlines Corporation

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

Billing Summary Service Address: 1234 Main St.

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

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

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

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

Service Class: RESIDENTIAL **Cycle 0009**

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

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

Understanding Essex Powerlines' Role in Ontario's Electricity System

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

Where Electricity Comes From

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

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

Essex Powerlines Corporation

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

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

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

Essex Powerlines' Overhead System

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

Essex Powerlines' Underground System

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

Electricity Grid:

How is Ontario's Electricity System Regulated?

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

Ontario Ministry of Energy:

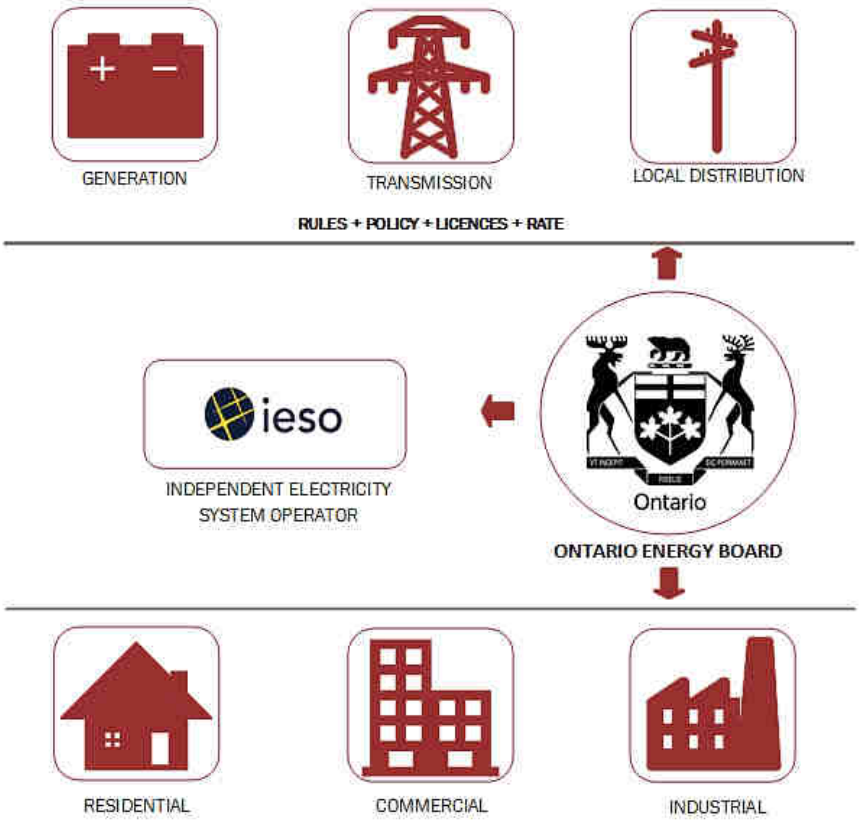
The Ontario Ministry of Energy sets energy policy. It sets the rules and establishes key planning and regulatory agencies through legislation.

Ontario Energy Board:

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

The Independent Electricity System Operator:

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



Customer Feedback

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

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

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

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

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

Essex Powerlines' Grid Today

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

Background on Essex Powerlines' Distribution System

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

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

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

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

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

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

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

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

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

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

Hydro One's Transmission System

High Voltage Transmission – Connects our distribution system to electricity generating stations across the province.
Transmission Station – Reduces high voltage electricity from transmission lines to medium voltage which is fed into Essex Powerlines' distribution stations.

Essex Powerlines' Distribution System:

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

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

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

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

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

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

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

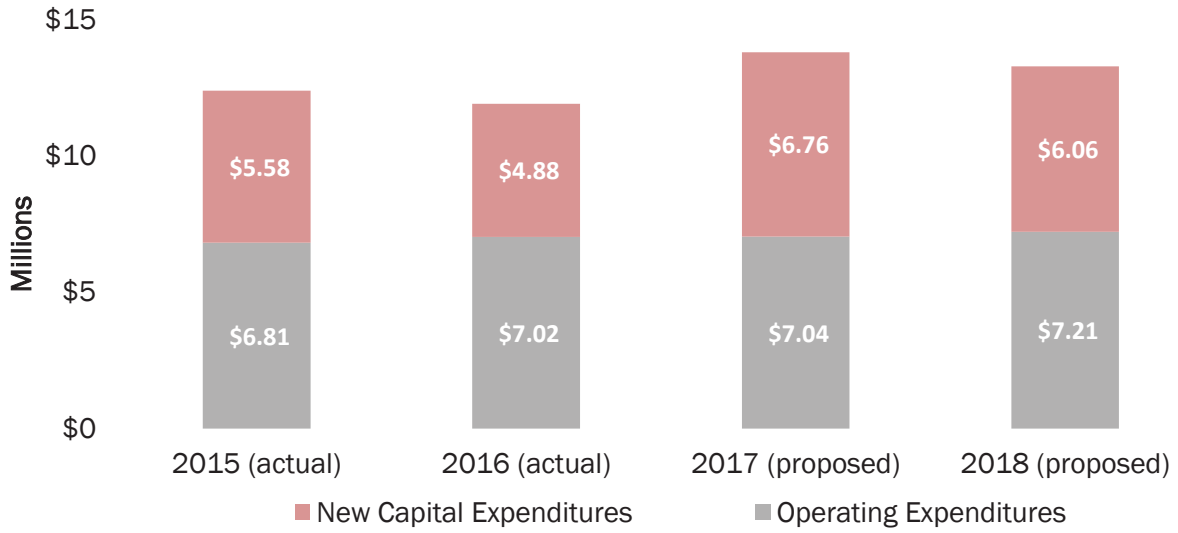
Padmount Transformers – Similar to transformers in the overhead system, these reduce the voltage to a lower level before final connection to customers. In the underground system there are concrete padmounted transformers, which are above ground transformers that are supplied by underground cable, and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

Paying for the Distribution System?

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

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

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



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

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

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

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

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

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

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

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

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

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

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

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

Cost Pressures

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

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

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

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

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

Has Essex Powerlines previously set aside funds for required upgrades?

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

Capital Investment Drivers

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

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

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

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

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

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

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

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

Obsolescence: Asset installations that no longer align with Essex Powerlines' current operating practices or current standards. This can include those assets that:

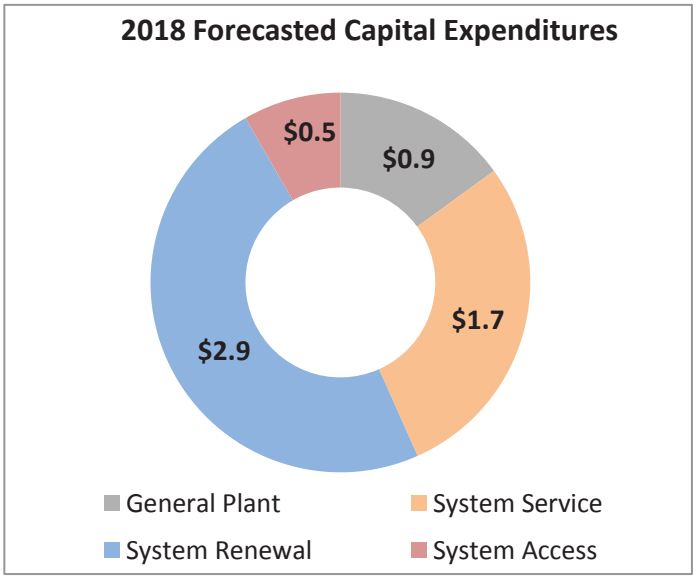
- Are no longer manufactured,
- Lack spare parts,
- Cannot be accessed,
- Lack the ability to have maintenance performed on them,
- Have operational constraints or conflicts, which can result in increased reliability and/or safety related risks.

Aging or Poor Performing Equipment: Where there is the imminent risk of failure due to age or condition deterioration, and these potential failures will result in severe reliability impacts to customers as well as potential safety risks to crew workers or to the public, remediation, through refurbishment or replacement, is required.

Business Support Costs: Essex Powerlines is not just the local electricity distribution system itself, but a company that operates the system. As a company, it needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the system and customer information.

What are the major issues Essex Powerlines needs to address?

Over the years, Essex Powerlines has worked hard to keep its equipment working well beyond its originally expected life, to get maximum value for money. However, Essex Powerlines' key challenge still comes from the need to replace aging equipment.



In 2018, the capital expenditures required to address system renewal, maintain system reliability and invest in other infrastructure priorities are estimated by Essex Powerlines to be $6 million which is consistent with historical spending.

To assist us in prioritizing what needs to be replaced and by when, Essex Powerlines uses an asset management model to drive replacement decisions. Using the information provided by the asset management model, Essex Powerlines plans for four types of capital investment costs:

System Access

Definition: Projects that respond to customer requests for new connections or new infrastructure development. These are usually a high priority, "must do" type of request.

Programs (e.g.): Customer Connections, Relocating assets based on infrastructure needs

System Renewal

Definition: Projects focused on replacing aging equipment in poor condition.

Programs (e.g.): Distribution Station Refurbishment, Voltage Conversion, Underground Cable Replacement, Overhead Wire Replacement

System Service

Definition: Primarily consisting of projects that improve system reliability.

Programs (e.g.): Automated Switches, better distribution system monitoring equipment

General Plant

Definition: Investments in supporting assets, such as tools, vehicles, buildings and information technology (IT) equipment that are needed so that we may perform our task to operate and maintain the distribution system

Programs (e.g.): IT, facilities, fleet

Cost Drivers

Capital Investments

The challenges impacting the Essex Powerlines distribution system can be broken down into 4 broad categories:

Aging Infrastructure

1

- Essex Powerlines completes a variety of field services on a yearly basis to determine the health of its equipment across the four communities that we serve.
- There is a variety of equipment within Essex Powerlines' distribution system that is aging and beyond its useful life requiring replacement ranging from replacements that require immediate action to replacements that need to be addressed in 1-5 years.
- Through its rigorous asset management plan, Essex Powerlines plans to continuously replace aging and equipment in danger of failure through various reactive and preventive maintenance programs.

Voltage Conversion

2

- Essex Powerlines is in the process of finalization its voltage conversion program that will position Essex Powerlines as a single voltage utility in 2017/2018. Instead of supplying electricity at multiple voltages, Essex Powerlines will be supplying its customers with electricity at 27.6kV only. This will reduce inventory, system complexity and system losses; all things that will save Essex Powerlines customers money in the long run.

Economic Development

3

- One of Essex Powerlines' top priorities is to enable economic development in our 4 shareholder communities that we serve through the facilitation of system connection and by keeping our rates at reasonable levels.
- Power quality and reliability has been mentioned by our commercial and industrial customers as a growing concern which is why Essex Powerlines is investing in technology like SmartMAP and the Self-Healing grid to improve visibility of our system and provide faster response times for outages as they incur.

Increasing Cost of Electricity

4

- With energy costs rising and forecasted to continue rising for the foreseeable future, Essex Powerlines has made it a priority to champion Conservation & Demand Management, facilitate customer connection of behind-the-meter generation or simply providing customers with the tools necessary to monitor and control their consumption.

Cost Drivers

Operating Expenses

In addition to its capital budget, Essex Powerlines needs to consider its operating budget which also impacts customer bills.

Cost drivers contributing to the operating budget can largely be attributed to on-going maintenance and management of the distribution system. An example of this cost driver is Essex Powerlines' tree trimming service, designed to lessen the impact of falling tree branches on power lines.

Customer Focus

- It is now an industry requirement for all utilities to demonstrate that they have consulted customers before applying for new rates
- Essex Powerlines embraces this concept and wants to gather ongoing customer feedback and input through website surveys and focus groups.
- Essex Powerlines continues to enhance its online customer service offerings; this has included updating the website as well as increasing social media presence. Essex Powerlines has launched automatic outage updates on our Twitter account. This allows customers to get real-time updates on any outages that they may be experiencing.
- Further, in 2017 Essex Powerlines enhanced the look of the monthly customer bill and made it much easier to read and understand.

Industry Focus

- Industry regulation requires that Essex Powerlines maintain compliance with various regulatory bodies in a complex provincial environment.
- The requirements to implement Smart Meters and to adopt the International Financial Reporting Standard ("IFRS") of accounting are examples of recent industry change.
- Meters are now more complex and require specialized troubleshooting. Essex Powerlines installed many of its Smart Meters in 2009 and 2010. As these meters age, more focus is required on re-verification. Essex Powerlines is now testing groups of these meters at intervals throughout their life span rather than waiting for them to cease operating at end-of-life.
- To ensure that Essex Powerlines is in compliance with all regulatory codes, including new requirements and reporting, additional staffing and support resources have been added since 2010.

Operational Effectiveness & Power Quality

- Consistent with industry best practice, Essex Powerlines has established a formalized asset plan for distribution system assets. This includes asset health assessments and replacement prioritization rules.
- The plan will also include voltage conversion work to modernize the system in order to identify the causes of outages more quickly and reduce line losses.
- Essex Powerlines will incur expenses for additional software and engineering resources as the distribution system plan is continuously updated.

Finding Efficiencies and Cost Savings

Where possible, Essex Powerlines has extended the life of its equipment through rigorous repair and maintenance program in order to get maximum value for money. Some of this aging equipment can be "run to failure", meaning we can replace it after it ceases to function without significant customer impact. However, other end-of-life equipment is more mission critical and cannot be "run to failure" because failure could result in a public safety hazard or an unsupportable economic burden for our customers.

There are several other ways in which Essex Powerlines works to find efficiencies and cost savings in the system:

Enhanced Power Quality Metering: Installing power quality meters at select commercial and industrial sites helps major customers resolve power quality issues so they can better understand and control their energy usage.

Voltage Conversion Program: Converting to a single higher voltage will eliminate antiquated equipment, reduce system losses, and reduce ongoing maintenance costs.

Estimated and Scheduling Tool: A new estimating and scheduling tool means Essex Powerlines can more quickly and more accurately assemble an estimate and lay out work for construction crews.

"Kitting": Warehouse staff pre-assemble parts and equipment needed for specific repairs, which reduces the time needed for crews to complete maintenance and service tasks, thereby reducing costs.

Group Buying Program: Essex Powerlines save money by participating in a group buying program with other local utilities. This means some types of equipment and materials can be purchased much less expensive.

Remote Fault Indication: Allows Essex Powerlines to better diagnose outages before dispatching work crews. Reduces expensive after-hours crew visits.

Labour Saving Equipment: Specialized trucks and other equipment reduce manual labour, which reduces time and costs.

Smart Meter Data: Using Smart Meter data to diagnose outages and power quality issues reduces time and guess work, and helps resolve issues faster.

Targeted Capital Projects: These projects eliminate equipment from the system that is known to be high maintenance.

Outage Management System: Quickly and automatically identifies faults, notifies crews and provides information to help troubleshoot and identify the cause.

SmartMAP: Innovative technology that improves reliability and service and reduces the number of outages as they can be address proactively.

Social Media: Essex Powerlines uses social media to send automated updates to customers about outages and keep them informed about the progress toward restoration.

9. With regards to projects focused on replacing aging equipment in poor condition, which of the following statements best represents your point of view?
   - ☐ Essex Powerlines should invest what it takes to replace the system's aging infrastructure to maintain system reliability, even if that increases my monthly electricity bill by a few dollars over the next few years.
   - ☐ Essex Powerlines should lower its investment in renewing the system's aging infrastructure to lessen the impact of any bill increase, even if that means more or longer power outages.
   - ☐ Not sure

10. As a company, Essex Powerlines needs buildings to house its staff, vehicles and tools to service the power lines and IT systems to manage the system and customer information. Which of the following statements best represents your point of view?
   - ☐ Essex Powerlines should find ways to make do with the buildings, equipment and IT systems it already has.
   - ☐ While Essex Powerlines should be wise with its spending, it is important that its staff have the equipment and tools they need to manage the system safely, efficiently and reliably.
   - ☐ Not sure

11. How well do you feel you understand the cost drivers that Essex Powerlines is responding to?
   - ☐ Very well
   - ☐ Somewhat well
   - ☐ Not very well
   - ☐ Not well at all
   - ☐ Not sure

12. How well do you think Essex Powerlines is managing these cost drivers while meeting customer expectations and keeping rates reasonable?
   - ☐ Very well
   - ☐ Somewhat well
   - ☐ Not very well
   - ☐ Not well at all
   - ☐ Not sure

13. How satisfied are you with the efforts Essex Powerlines has made to find efficiencies and cost savings in the distribution system?
   - ☐ Very satisfied
   - ☐ Somewhat satisfied
   - ☐ Not very satisfied
   - ☐ Not at all satisfied
   - ☐ Not sure

What Essex Powerlines Corporation's Plan Means for You

Residential – 750 kWh per month

In 2018, it is anticipated that residential customers with an average monthly consumption of 750 kWh will see a moderate increase on the distribution portion of their electricity bills. It is expected that – all things being equal – distribution rates will increase in line with the rate of inflation.

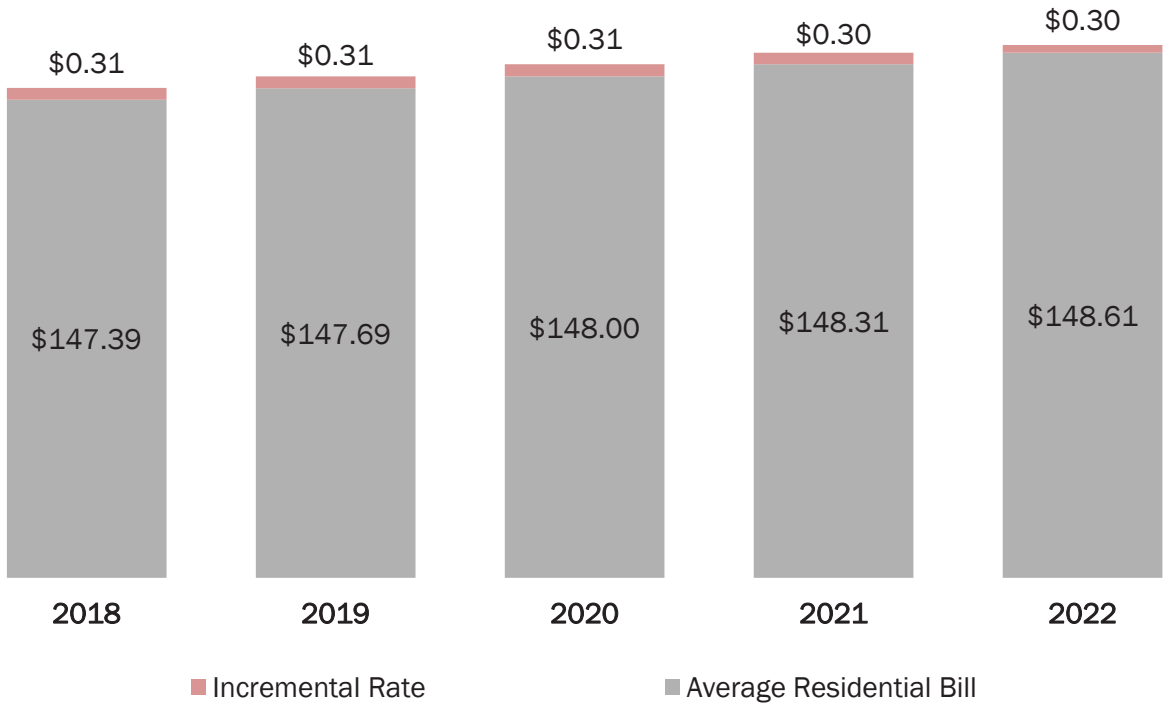
Essex Powerlines considered gradual inflationary increases, consistent with the industry rate-setting process, to determine a one-time rate increase between 2018 until 2022. Essex Powerlines' forecasted increase over the next five years may see an average annual increase of $0.31 per month or 0.2% on the total bill for a residential customer with an average monthly consumption of 750 kWh.

By 2020, Essex Powerlines forecasts that the average residential household will be paying an estimated $1.79 more (6.84%) per month on the distribution portion of their electricity bill; however, this incorporates an average yearly increase of 1.37% each year through 2020.

The illustrations below will provide better understanding of the one-time change in rates.

	Current	Proposed	Increase	5 Year % Increase	Average Yearly Increase
Distribution	$26.16	$27.95	$1.79	6.84%	1.37%
Total Bill	$147.08	$148.61	$1.53	1.04%	0.21%

Estimated Residential Annual Increase in Monthly Bill (5 year forecast)



What Essex Powerlines Corporation's Plan Means for You

GS<50 kW – 2,000 kWh per month

In 2018, it is anticipated that GS<50 kW customers with an average monthly consumption of 2,000 kWh will see a moderate increase on the distribution portion of their electricity bills. It is expected that – all things being equal – distribution rates will increase in line with the rate of inflation.

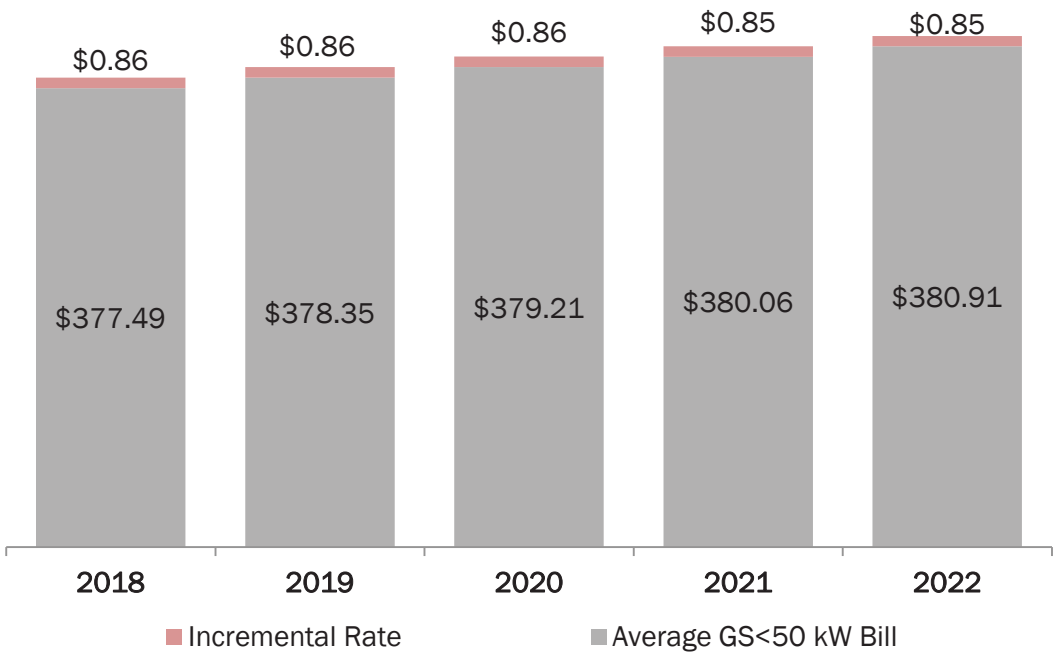
Essex Powerlines considered gradual inflationary increases, consistent with the industry rate-setting process, to determine a one-time rate increase between 2018 until 2022. Essex Powerlines' forecasted increase over the next five years may see an average annual increase of $0.86 per month or 0.2% on the total bill for a GS<50 kW customer with an average monthly consumption of 2,000 kWh.

By 2020, Essex Powerlines forecasts that the average GS<50 kW customer will be paying an estimated $4.92 more (8.32%) per month on the distribution portion of their electricity bill; however, this incorporates an average yearly increase of 1.66% each year through 2020.

The illustrations below will provide better understanding of the one-time change in rates.

	Current	Proposed	Increase	5 Year % Increase	Average Yearly Increase
Distribution	$59.13	$64.05	$4.92	8.32%	1.66%
Total Bill	$376.63	$380.91	$4.28	1.14%	0.23%

Estimated GS<50 kW Annual Increase in Monthly Bill (5 year forecast)



What Essex Powerlines Corporation's Plan Means for You

GS>50 kW – 40,000 kWh & 100 kW per month

In 2018, it is anticipated that GS>50kW customers with an average monthly consumption of 40,000 kWh will see a moderate increase on the distribution portion of their electricity bills. It is expected that – all things being equal – distribution rates will increase in line with the rate of inflation.

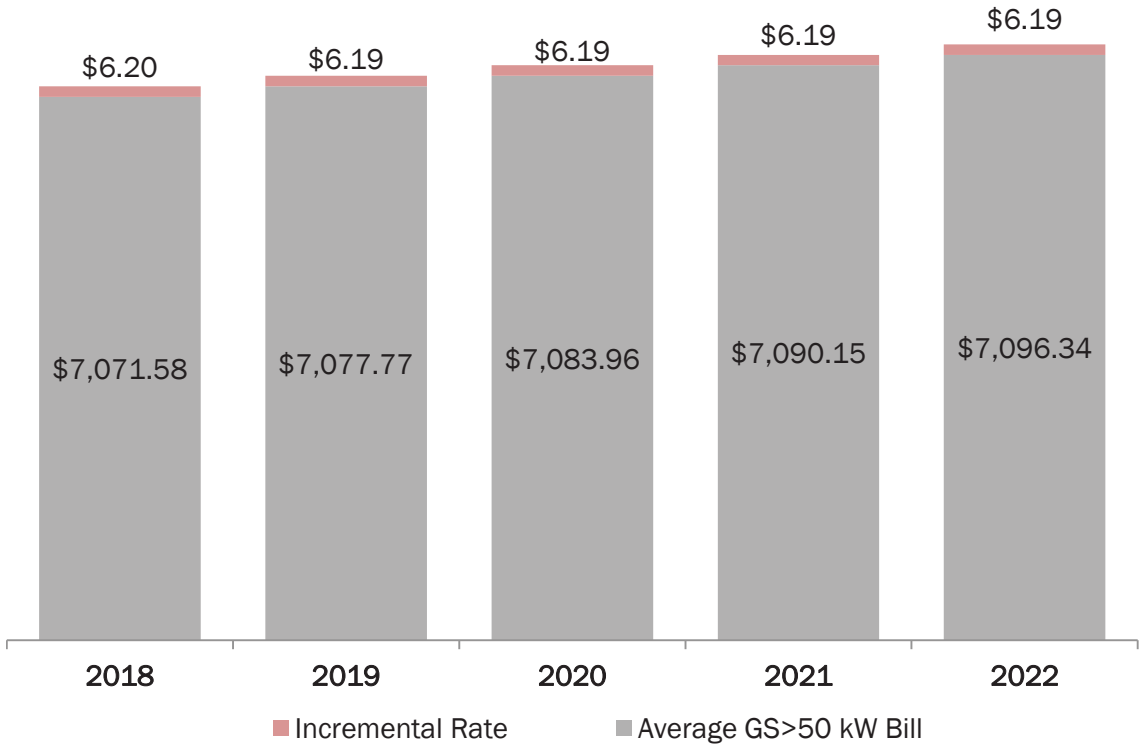
Essex Powerlines considered gradual inflationary increases, consistent with the industry rate-setting process, to determine a one-time rate increase between 2018 until 2022. Essex Powerlines' forecasted increase over the next five years may see an average annual increase of $6.19 per month or 0.08% on the total bill for a GS>50 kW customer with an average monthly consumption of 40,000 kWh.

By 2020, Essex Powerlines forecasts that the average GS>50 kW customer will be paying an estimated $42.67 more (9.40%) per month on the distribution portion of their electricity bill; however, this incorporates an average yearly increase of 1.88% each year through 2020.

The illustrations below will provide better understanding of the one-time change in rates.

	Current	Proposed	Increase	5 Year % Increase	Average Yearly Increase
Distribution	$453.70	$496.37	$42.67	9.40%	1.88%
Total Bill	$7,065.38	$7,096.34	$30.96	0.44%	0.09%

Estimated GS>50 kW Annual Increase in Monthly Bill (5 year forecast)



14. Now that you have a better sense of the operations of Essex Powerlines, including the cost drivers, do you feel the proposed budget is reasonable?
    - ☐ Yes
    - ☐ No
    - ☐ Not sure

15. From what you have read here and what you may have heard elsewhere, does Essex Powerlines' investment plan seem like it is going in the right direction or the wrong direction?
    - ☐ Right direction
    - ☐ Wrong direction
    - ☐ Not sure

16. How well did Essex Powerlines' plan cover the topics you expected?
    - ☐ Very well
    - ☐ Somewhat well
    - ☐ Not very well
    - ☐ Not well at all
    - ☐ Not sure

If not very or not at all, what is missing?

17. How well do you think Essex Powerlines is planning for the future?
    - ☐ Very well
    - ☐ Somewhat well
    - ☐ Not very well
    - ☐ Not well at all
    - ☐ Not sure

18. Considering what you know about the local distribution system, which of the following best represents your point of view?
    - ☐ The rate increase is reasonable and I support it
    - ☐ I don't like it, but I think the rate increase is necessary
    - ☐ The rate increase is unreasonable and I oppose it
    - ☐ Not sure

Final Thoughts

Essex Powerlines values your feedback. This is the first time the utility has conducted a review about its upcoming investment plan in this type of format.

Overall Impression: What did you think about the workbook?

Volume of Information: Did Essex Powerlines provide too much information, not enough, or just the right amount?

Content Covered: Was there any content missing that you would have liked to have seen included?

Outstanding Questions: Is there anything that you would still like answered?

Suggestions for Future Consultations: How would you prefer to participate in these consultations?

Glossary

Breakers: Devices that protect the distribution system by interrupting a circuit if a higher than normal amount on power flow is detected.

Distribution Station: These substations are located near to the end-users. Distribution station transformers change the voltage to lower levels for use by end-users.

Feeder Circuit: Is a wire that connects the transmission station to the broader distribution system in order to deliver electricity to customers.

General Plant: Investments in things like tools, vehicles, buildings and information technology (IT) equipment that are needed to support the distribution system.

Generation Station: A facility designed to produce electric energy from another form of energy, such as fossil fuel, nuclear, hydroelectric, geothermal, solar thermal, and wind.

Kilovolt (kV): 1,000 volts (see volt below).

Kilowatt (kW): 1,000 watts.

Local Distribution Company (LDC): In Ontario, these are the companies that take electricity from the transmission grid and distribute it around a community.

OM&A: Operations, Maintenance and Administration or operating budget.

Substations: Used to change AC voltages from one level to another and to switch generators, equipment and circuits and lines in and out of an electrical system.

Switches: These control the flow of electricity—they direct which supply of electricity is used and which circuits are energized. Distribution systems have switches installed at strategic locations to redirect power flows for load balancing or sectionalizing.

System Access: Projects required to respond to customer requests for new connections or new infrastructure development. These are usually a regulatory requirement to complete.

System Renewal: Projects to replace aging infrastructure in poor condition.

System Service: Primarily projects that improve reliability.

Transmission lines: Transmit high-voltage electricity from the generation source or substation to another substation in the electricity grid.

Transformer: Is an important piece of equipment that reduces the voltage of electricity from a high level to a level that can be safely distributed to your area or to your residence/business.

Underground Cable: A conductor with insulation, or a stranded conductor with or without insulation and other coverings (single-conductor cable), or a combination of conductors insulated from one another (multiple-conductor cable) with an intended use of being buried.

Volt (V): A unit of measure of the force, or 'push,' given the electrons in an electric circuit. One volt produces one ampere of current when acting on a resistance of one ohm.

Watt (W): the unit of electric power, or amount of work (J), done in a unit of time. One ampere of current flowing at a potential of one volt produces one watt of power.

Wire: A conductor wire or combination of wires not insulated from one another, suitable for carrying electric current.

Additional Comments

Appendix G: Infrared Inspection Report

Infrared Inspection

- Electrical Distribution System -

Essex Power Lines

Date

June 15-30, 2015

Report Completed By

Essex Energy Corporation
2199 Blackacre Drive /Suite 2
Oldcastle Ontario N0R 1L0
Tel: 519 946 2000
Fax: 1 866291 5317

FLIR-Systems Ltd. Canada

This identification certifies that

Fred Brefka

has completed the necessary course work and has met or exceeded the established requirements to be an ITC Certified Infrared Thermographer to level as indicated

Examining Officer — 10/24/2016 Expiry Date

ITC – FLIR Canada
920 Sheldon Court
Burlington, Ontario, L7L 5K6

itc INFRARED TRAINING CENTER

Infrared Report Summary

Purpose: Infrared inspection to identify thermal anomalies on electrical distribution equipment that suggest an unwanted condition exists and repairs are required.

Method: Complete infrared inspection of selected Essex Powerlines distribution system equipment. Save infrared images of all noted anomalies. Report on findings.

Conditions: Equipment operating under normal daytime loading conditions.

Inspection Equipment: FLIR model T300 thermal imaging systems, serial #

Observations

Note: Essex Energy Corporation is in no way responsible for any expenses resulting in actions or repair of reported anomalies. This report is not a warranty or guarantee of any equipment condition or reliability.

Please see report for details on all noted suspect conditions. All anomalies classified as follows:
HIGH Priority: High temperature rise over other components. Immediate corrective action required.
Do not ignore. Component temperature over 50 C rise over ambient.

MEDIUM Priority: Intermediate temperature rise. Corrective action required at next opportunity. Do not ignore. Component temperature 20 to 50 C rise over ambient.

LOW Priority: Low temperature rise. Condition should be investigated further and corrected at next convenient opportunity, if applicable.
Do not ignore. Component temperature below 20 C rise over ambient.

No Problems Noted (N/A): No anomalies noted. Condition good.

All reported condition should be investigated further as soon as possible to verify the reported condition. Use all safety procedures. Electrical hazards exist.

CONTENTS OF REPORT

Priority H= High M= Medium L= Low N/A= Not Applicable

Equipment	Area	Problem	Priority	Page
HYDRO ONE Substation	LaSalle	Heating Contact	M	4
TX7B140	LaSalle	Heating Secondary Connections	M	5
TX7B425	LaSalle	Heating Secondary Connections	H	6
FS10073	Tecumseh	Heating Primary Connection	M	7
P01810	Tecumseh	Heating Connection	M	8
TX10528	Tecumseh	Heating Secondary Connection	M	9
TX10619 (New TX installed)	Tecumseh	Heating Secondary Connections	M	10
TX10902	Tecumseh	Heating Secondary Connections	M	11
TX31537	Leamington	Heating Secondary Connection	H	12

Identification:	HYDRO ONE Substation	Date
Area:	LaSalle	15/06/2015

Description: Line Switch

INFRARED IMAGE:

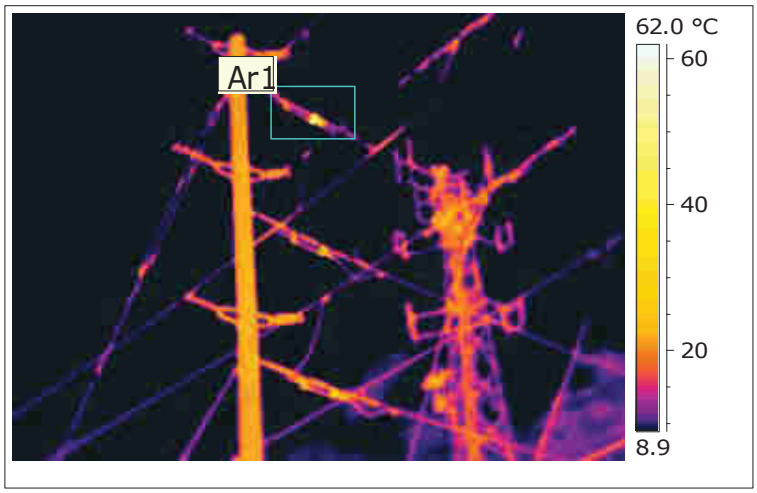
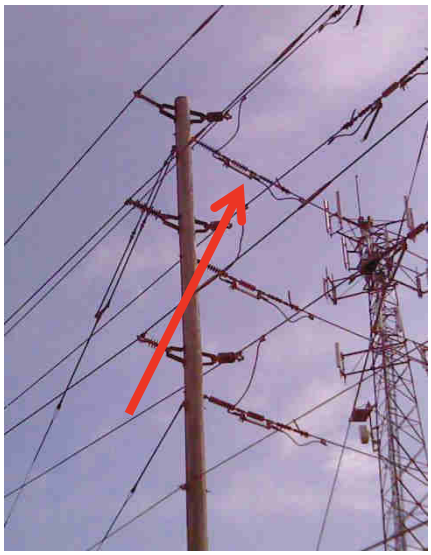


Photo:



Temperature rise: 40.8 °C (over ambient)

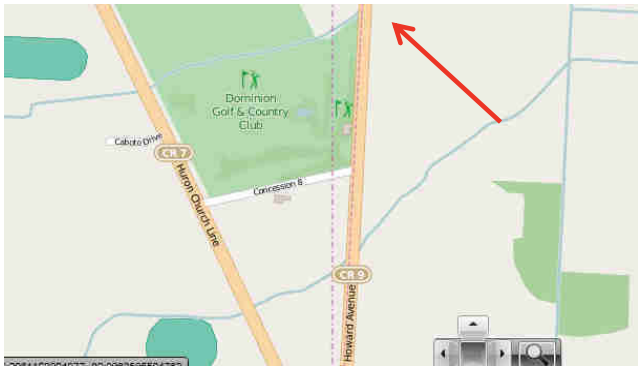
IR Information	
Date of creation	6/15/2015
Time of creation	8:35:30 AM
Object parameter	
Ambient temperature	20.0 °C
Label	
Ar1.Max	60.8 °C

Status:

Repair Date:

Notes:

Map:



Details:
Infrared image of Hydro One Substation Line Switch.
At Pole # 86HMM6
Located at Howard Ave in LaSalle
Heating noted at Line Switch connection at arrow in photo.
See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium X Low

ANOMALY: Heating contact

Identification:	TX7B140	Date
Area:	LaSalle	19/06/2015

Description: O/H Transformer Bushing

INFRARED IMAGE:

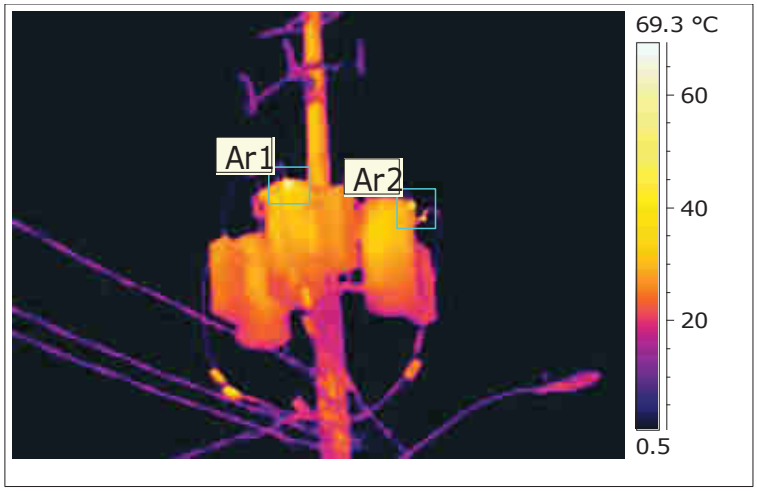


Photo:

Temperature rise: 42.6 & 20.9°C (over ambient)

IR Information	
Date of creation	6/19/2015
Time of creation	9:55:21 AM
Object parameter	
Ambient temperature	24.0 °C
Label	
Ar1.Max	66.6 °C
Ar2.Max	44.9 °C

Status:

Repair Date:

Notes:

Map:

Details:
Infrared image of transformer TX7B140. On Hydro One pole.
Located at 6260 Morton Industrial Road in Lasalle.
Heating noted at the center & road-side secondary bushing connection.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR1 AR2 Max).

PRIORITY: High Medium X Low

ANOMALY: Heating Secondary Connections

Identification:	TX7B425	Date
Area:	LaSalle	19/06/2015

Description: O/H Transformer Bushing

INFRARED IMAGE:

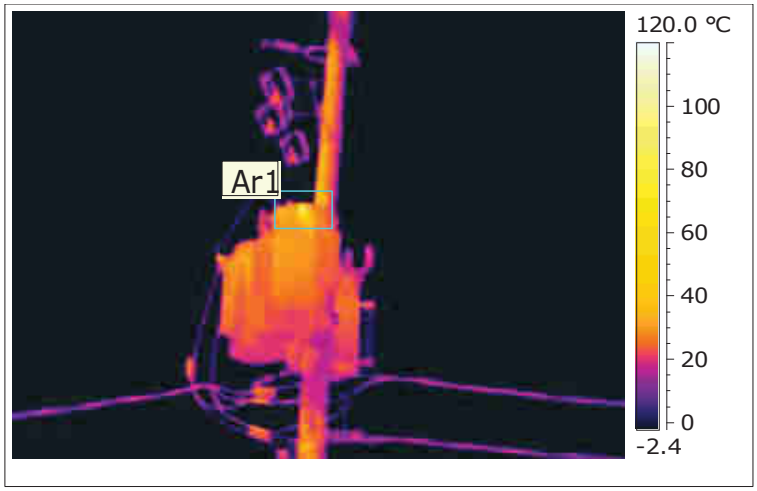


Photo:

Temperature rise: 95.3 °C (over ambient)

IR Information	
Date of creation	6/19/2015
Time of creation	9:40:32 AM
Object parameter	
Ambient temperature	24.0 °C
Label	
Ar1.Max	119.3 °C

Status:

Repair Date:

Notes:

Map:

Details:
Infrared image of transformer TX7B425. On Hydro One pole.

Located at 6280 Morton Industrial Road in LaSalle. Heating noted at the road-side secondary bushing connection. At arrow in photo.

See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High X Medium Low

ANOMALY: Heating Connection

Identification:	FS10073	Date
Area:	Tecumseh	25/06/2015

Description: Primary Fuse Connection

INFRARED IMAGE:

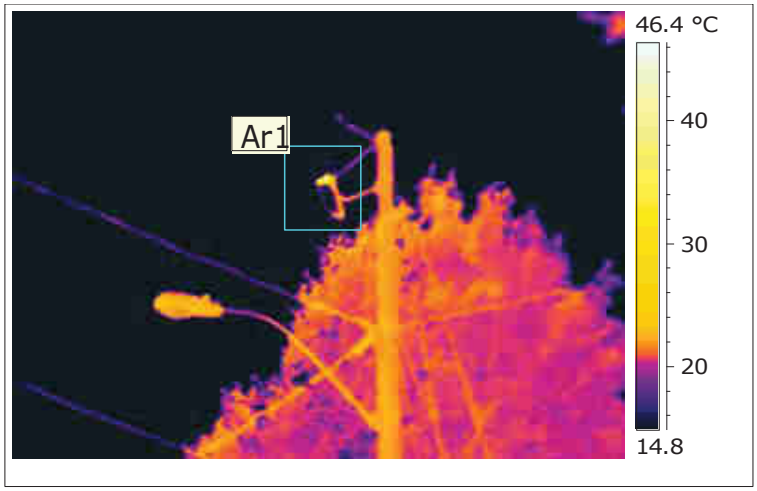


Photo:

Temperature rise: 24.4 °C (over ambient)

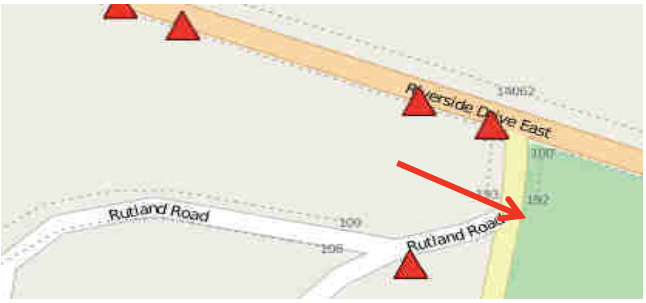
IR Information	
Date of creation	6/25/2015
Time of creation	12:44:54 PM
Object parameter	
Ambient temperature	20.0 °C
Label	
Ar1.Max	44.4 °C

Status:

Repair Date:

Notes:

Map:



Details:
Infrared image of Fuse FS10073
Located at Rutland Rd and Kensington Boulevard in Tecumseh

Heating noted at Fuse upper primary connection.
At arrow in photo.

See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium X Low

ANOMALY: Heating Primary Connection

Identification:	P01810 (TX10527 not in use)	Date
Area:	Tecumseh	25/06/2015

Description: Line Switch

INFRARED IMAGE:

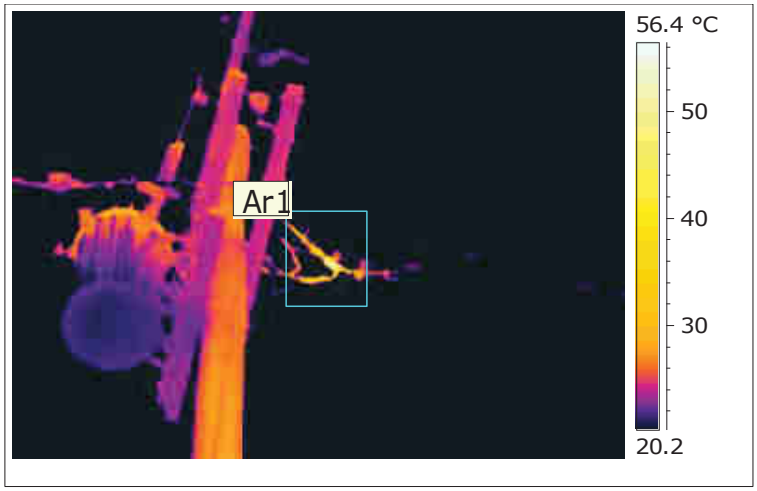


Photo:

Temperature rise: 33.1 °C (over ambient)

IR Information	
Date of creation	6/25/2015
Time of creation	2:35:15 PM
Object parameter	
Ambient temperature	22.0 °C
Label	
Ar1.Max	55.1 °C

Status:

Repair Date:

Notes:

Map:

Details:
Infrared image of transformer TX10527.
Located at 12417 Arbour Sreet in Tecumseh

Heating noted at secondary connection at arrow in photo. It is an Ampact point on Wire. TX is disconnected

See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium X Low

ANOMALY: Heating Connection

Identification:	TX10528	Date
Area:	Tecumseh	25/06/2015

Description: O/H Transformer Bushing

INFRARED IMAGE:

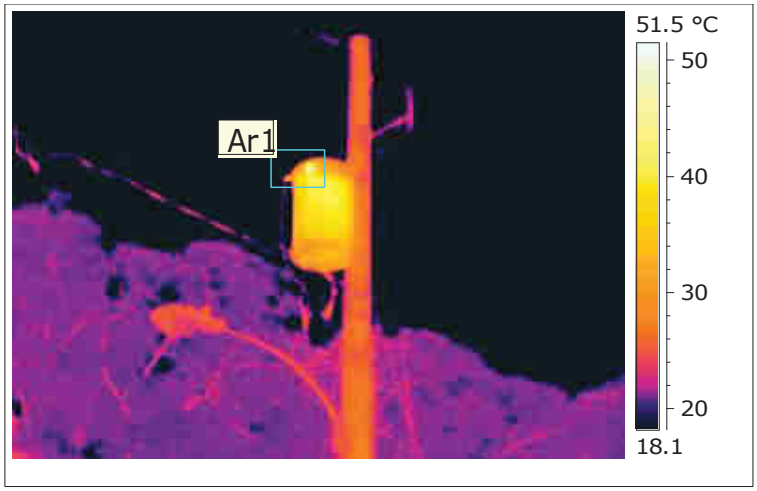


Photo:

Temperature rise: 29.1 °C (over ambient)

IR Information	
Date of creation	6/25/2015
Time of creation	2:30:29 PM
Object parameter	
Ambient temperature	22.0 °C
Label	
Ar1.Max	51.1 °C

Status:

Repair Date:

Notes:

Map:

Details:
Infrared image of transformer TX10528.
Located at 12425 Renaud Street in Tecumseh

Heating noted at secondary bushing connection at arrow in photo.

See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium X Low

ANOMALY: Heating Secondary Connection

Identification:	TX10619 (New TX installed)	Date
Area:	Tecumseh	25/06/2015

Description: O/H Transformer Bushings

INFRARED IMAGE:

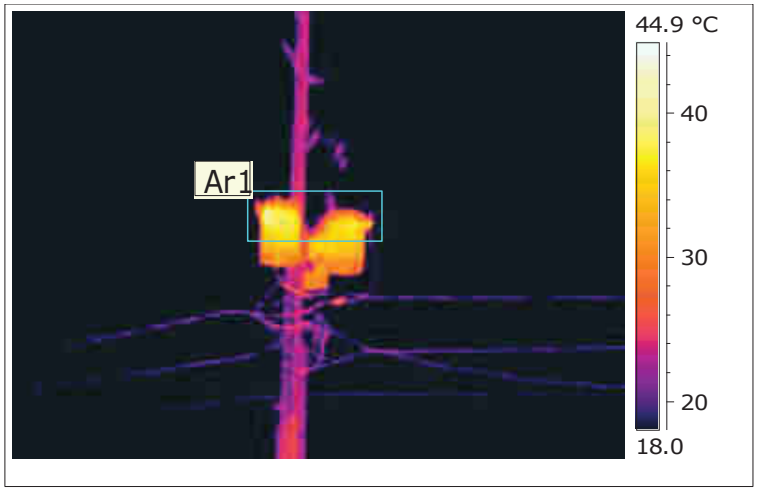
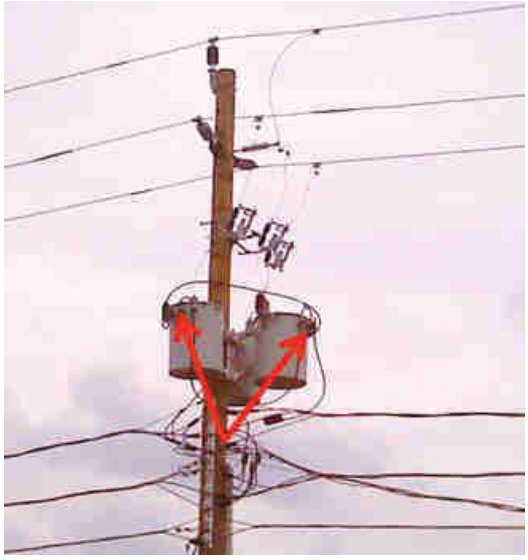


Photo:



Temperature rise: 23.3 °C (over ambient)

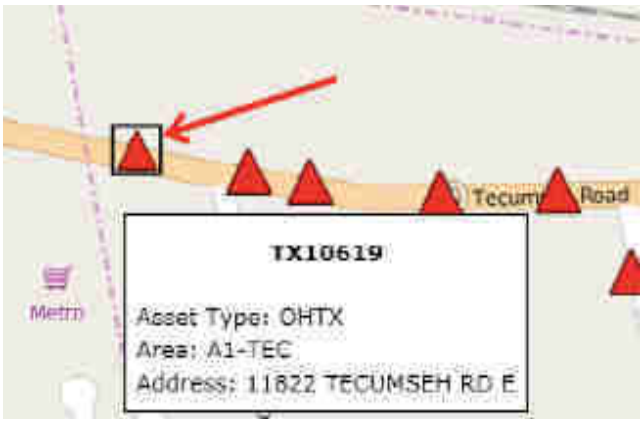
IR Information	
Date of creation	6/25/2015
Time of creation	2:07:23 PM
Object parameter	
Ambient temperature	22.0 °C
Label	
Ar1.Max	45.3 °C

Status:

Repair Date:

Notes:

Map:



Details:
Infrared image of transformer TX10619 new.
Located at 11822 Tecumseh Road in Tecumseh

Heating noted at two secondary bushing connection at arrow in photo.

See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium X Low

ANOMALY: Heating Secondary Connections

Identification:	TX10902	Date
Area:	Tecumseh	25/06/2015

Description: O/H Transformer Bushings

INFRARED IMAGE:

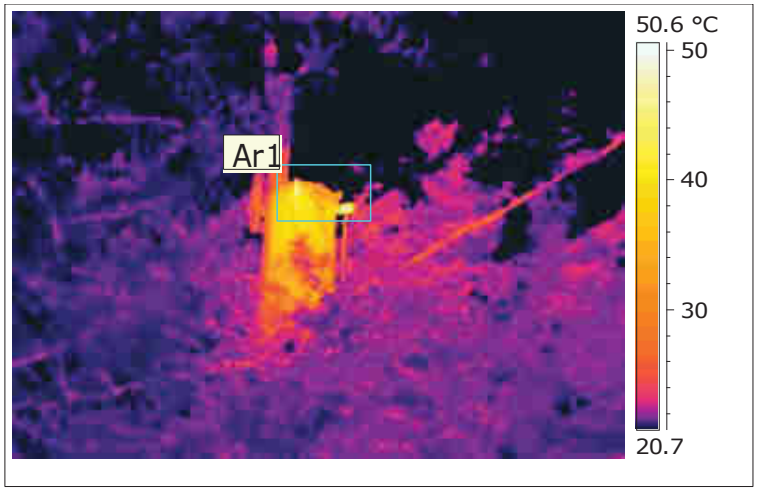


Photo:

Temperature rise: 30.8 °C (over ambient)

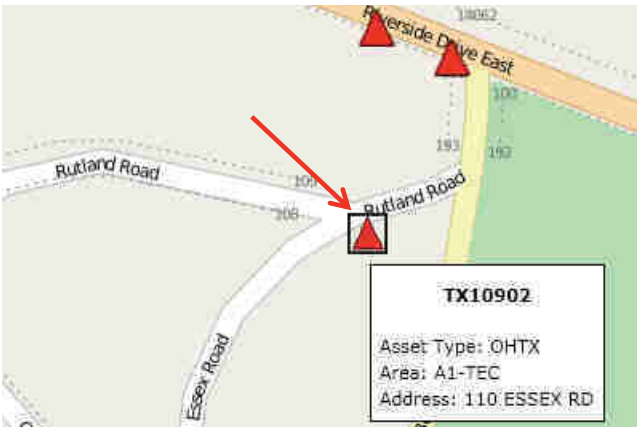
IR Information	
Date of creation	6/25/2015
Time of creation	12:48:22 PM
Object parameter	
Ambient temperature	20.0 °C
Label	
Ar1.Max	50.8 °C

Status:

Repair Date:

Notes:

Map:



Details:
Infrared image of transformer TX10902.
Located at 110 Essex Road in Tecumseh

Heating noted at two secondary bushing connections and Tree trimming is required at arrow in photo.

See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium X Low

ANOMALY: Heating Secondary Connections

Identification:	TX31537	Date
Area:	Leamington	29/06/2015

Description: **O/H Transformer Bushings**

INFRARED IMAGE:

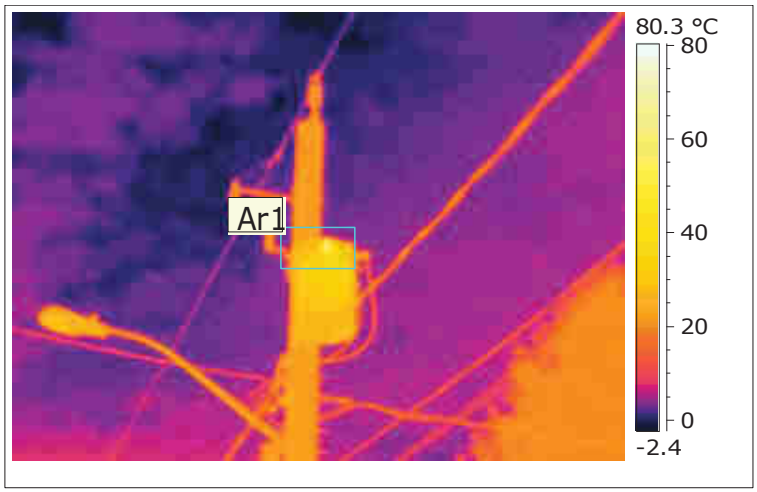
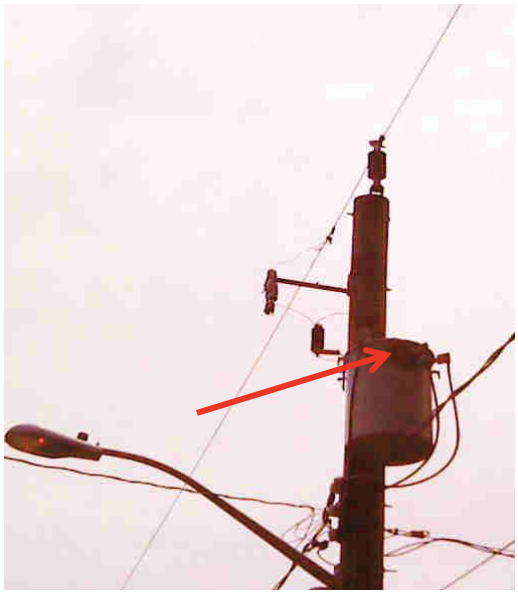


Photo:



Temperature rise: 59.6 °C (over ambient)

IR Information	
Date of creation	6/29/2015
Time of creation	12:23:07 PM
Object parameter	
Ambient temperature	20.0 °C
Label	
Ar1.Max	79.6 °C

Status:

Repair Date:

Notes:

Map:

Details:
Infrared image of transformer TX31537.
Located at 88 Setterington Street in Leamington

Heating noted at secondary bushing connection at arrow in photo.

See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High X Medium Low

ANOMALY: Heating Secondary connection

Infrared Inspection

- Electrical Distribution System -

Essex Power Lines

Date

July, 2015

Report Completed By

Essex Energy Corporation
2199 Blackacre Drive /Suite 2
Oldcastle Ontario N0R 1L0
Tel: 519 946 2000
Fax: 1 866291 5317

FLIR-Systems Ltd. Canada
This identification certifies that
Fred Brefka
has completed the necessary course work and has met or exceeded the established requirements to be an ITC Certified Infrared Thermographer to level as indicated

Examining Officer — 10/24/2016 Expiry Date

iTC – FLIR Canada
920 Sheldon Court
Burlington, Ontario, L7L 5K6

itc INFRARED TRAINING CENTER

Infrared Report Summary

Purpose: Infrared inspection to identify thermal anomalies on electrical distribution equipment that suggest an unwanted condition exists and repairs are required.

Method: Complete infrared inspection of selected Essex Powerlines distribution system equipment. Save infrared images of all noted anomalies. Report on findings.

Conditions: Equipment operating under normal daytime loading conditions.

Inspection Equipment: FLIR model T300 thermal imaging systems, serial #

Observations

Note: Essex Energy Corporation is in no way responsible for any expenses resulting in actions or repair of reported anomalies. This report is not a warranty or guarantee of any equipment condition or reliability.

Please see report for details on all noted suspect conditions. All anomalies classified as follows:
HIGH Priority: High temperature rise over other components. Immediate corrective action required.
Do not ignore. Component temperature over 50 C rise over ambient.

MEDIUM Priority: Intermediate temperature rise. Corrective action required at next opportunity. Do not ignore. Component temperature 20 to 50 C rise over ambient.

LOW Priority: Low temperature rise. Condition should be investigated further and corrected at next convenient opportunity, if applicable.
Do not ignore. Component temperature below 20 C rise over ambient.

No Problems Noted (N/A): No anomalies noted. Condition good.

All reported condition should be investigated further as soon as possible to verify the reported condition. Use all safety procedures. Electrical hazards exist.

CONTENTS OF REPORT

Priority H= High M= Medium L= Low N/A= Not Applicable

Equipment	Area	Problem	Priority	Page
TX50440	Amherstburg	Heating Secondary Connection	M	4
TX50446	Amherstburg	Heating Secondary Connection	M	5
TX50925	Amherstburg	Heating Connection	L	6
TX30597	Leamington	Heating Contact	H	7
TX31010	Leamington	Heating Connection	L	8
TX31011	Leamington	Heating Secondary Connection	M	9
TX30083	Leamington	Heating Secondary Connection	M	10

Identification:	TX50440	Date
Area:	Amherstburg	06/07/2015

Description: Secondary Terminal Strip

INFRARED IMAGE:

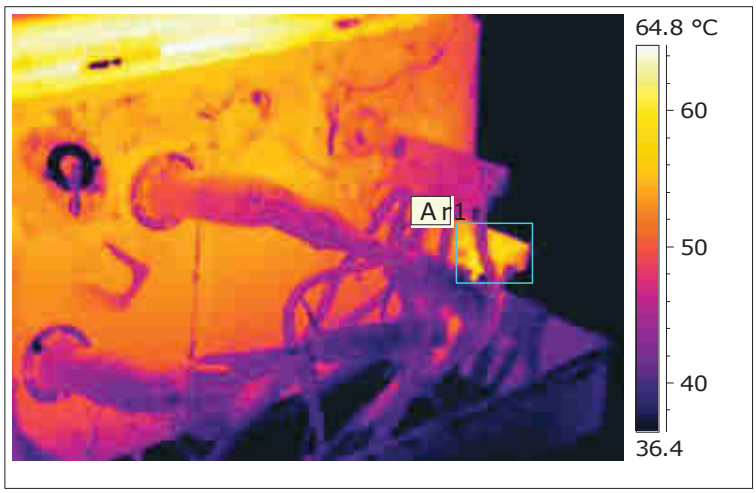
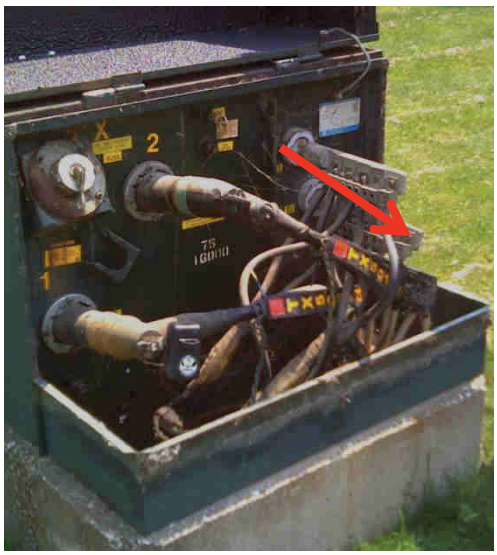


Photo:



Temperature rise: 34.1 °C (over ambient)

IR Information	
Date of creation	7/6/2015
Time of creation	3:01:47 PM
Object parameter	
Ambient temperature	26.0 °C
Label	
Ar1.Max	60.1 °C

Status:

Repair Date:

Notes:

Map:

Details:
Infrared image of TX50440
Located at Virginia Ave in Amherstburg
Heating noted at one off the secondary Terminal Strips on the centre Terminal Strip indicated by the red arrow in photo.
See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium X Low

ANOMALY: Heating Secondary Connection

Identification:	TX50446	Date
Area:	Amherstburg	06/07/2015

Description: Secondary Terminal Strip

INFRARED IMAGE:

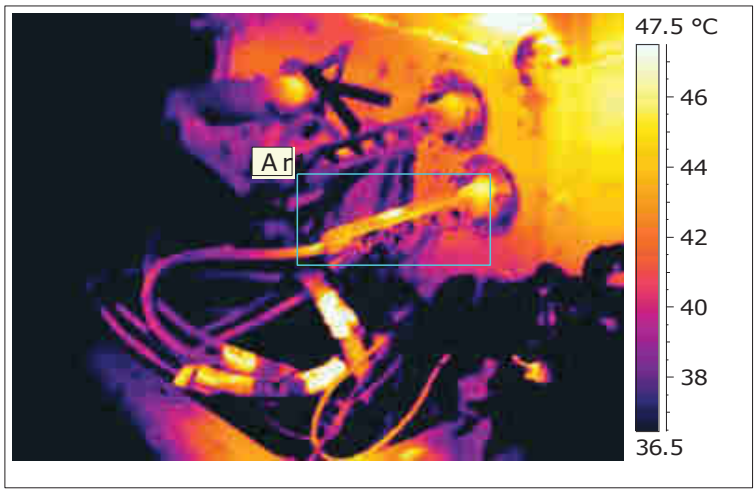
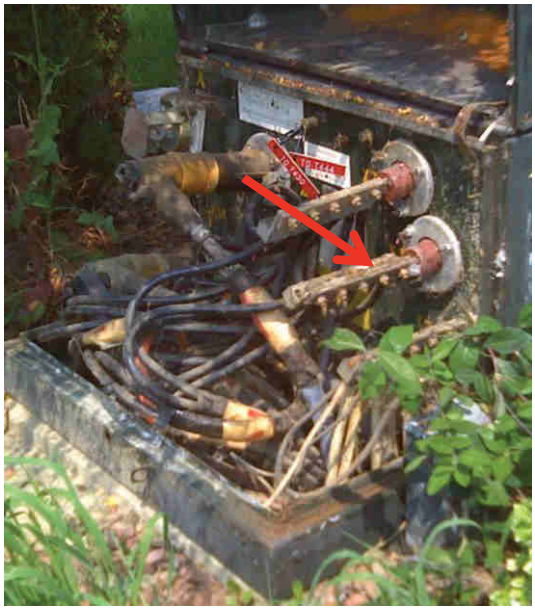


Photo:



Temperature rise: 21.6°C (over ambient)

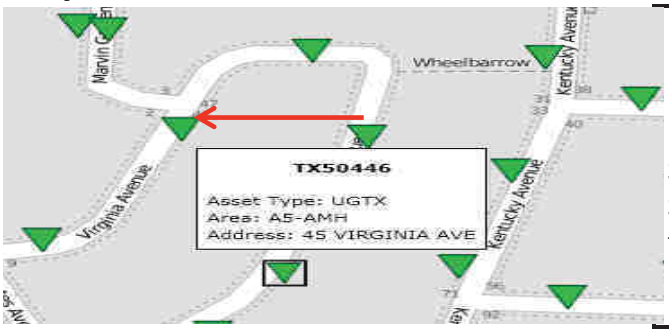
IR Information	
Date of creation	7/6/2015
Time of creation	3:38:01 PM
Object parameter	
Ambient temperature	26.0 °C
Label	
Ar1.Max	Ar1.Max Temperature 47.6 °C

Status:

Repair Date:

Notes:

Map:



Details:
Infrared image of TX50446
Located at 45 Virginia Ave in Amherstburg
Heating noted at one off the secondary Terminal Strips on the centre Terminal Strip at arrow in photo.
See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium X Low

ANOMALY: Heating Secondary Connection

Identification:	TX50925	Date
Area:	Amherstburg	07/07/2015

Description: Secondary Terminal Strip

INFRARED IMAGE:

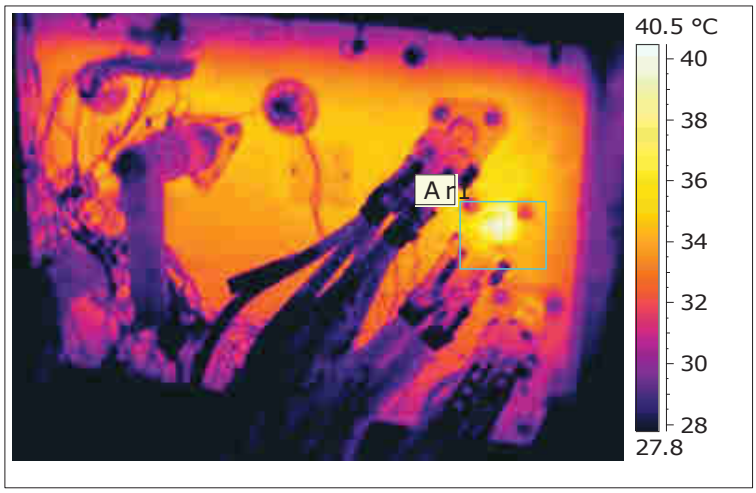


Photo:

Temperature rise: 16.2°C (over ambient)

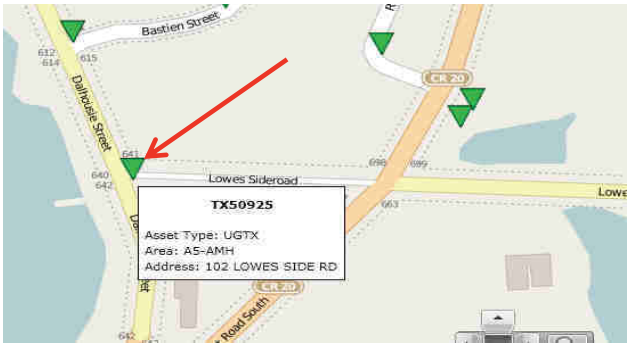
IR Information	
Date of creation	7/7/2015
Time of creation	2:37:33 PM
Object parameter	
Ambient temperature	24.0 °C
Label	
Ar1.Max	40.2 °C

Status:

Repair Date:

Notes:

Map:



Details:
Infrared image of TX50925
Located at 102 Lowes Sdrd in Amherstburg
Heating noted at one off the secondary bushing identified by the red arrow in photo.
See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium Low X

ANOMALY: Heating Connection

Identification:	TX30597	Date
Area:	Leamington	07/10/2015

Description: Secondary fuse for streetlight

INFRARED IMAGE:

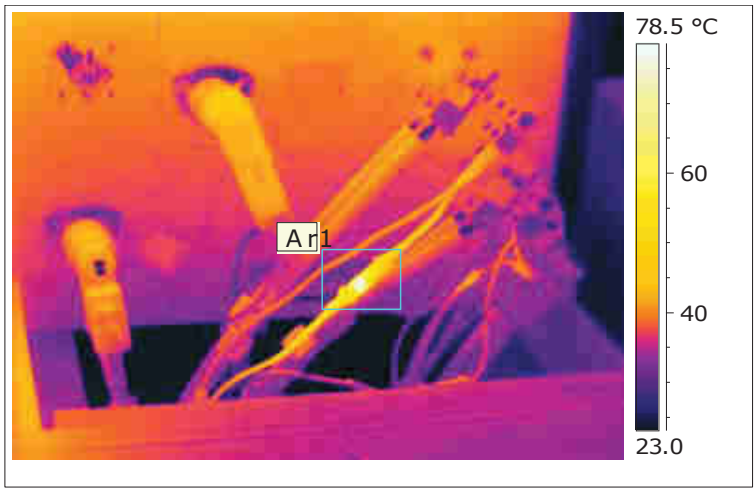


Photo:

IR Information	
Date of creation	7/10/2015
Time of creation	1:13:23 PM
Object parameter	
Ambient temperature	23.0 °C
Label	
Ar1.Max	78.7 °C

Temperature rise: 55.1°C (over ambient)

Status:

Repair Date:

Notes:

Map:

Details:
Infrared image of TX30597
Located at 9 Albert ST in Leamington
Heating noted at secondary wire in the streetlight fuse (indicated by red arrow).
See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High X Medium Low

ANOMALY: Heating Contact

Identification:	TX31010	Date
Area:	Leamington	07/10/2015

Description: Secondary Bushing

INFRARED IMAGE:

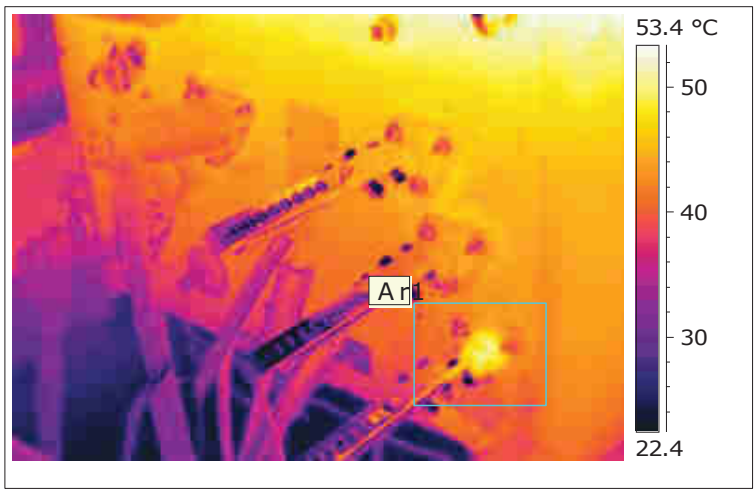
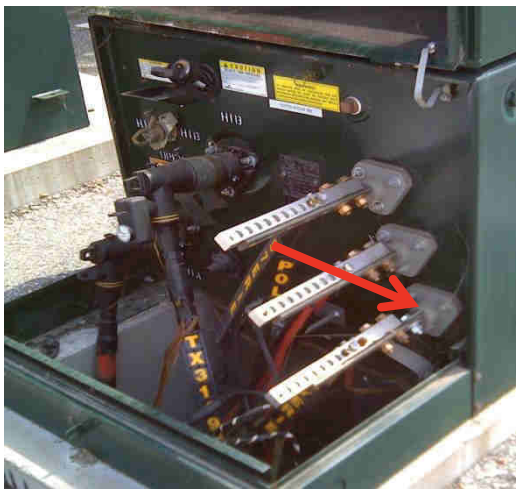


Photo:



IR Information	
Date of creation	7/10/2015
Time of creation	11:39:24 AM
Object parameter	
Ambient temperature	23.0 °C
Label	
Ar1.Max	51.0 °C

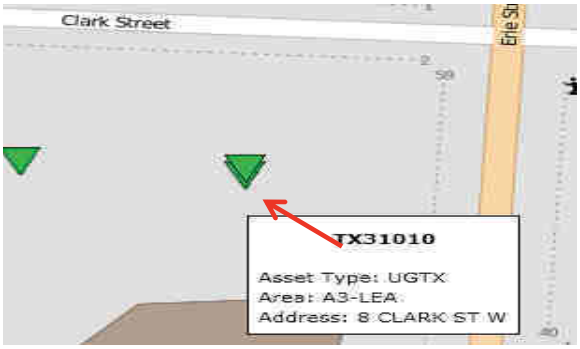
Temperature rise: 28°C (over ambient)

Status:

Repair Date:

Notes:

Map:



Details:
Infrared image of TX31010
Located at 8 Clark St W in Leamington
Heating noted at one off the secondary bushing at arrow in photo.
See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium Low X

ANOMALY: Heating Connection

Identification:	TX31011	Date
Area:	Leamington	07/10/2015

Description: Secondary Terminal Strip

INFRARED IMAGE:

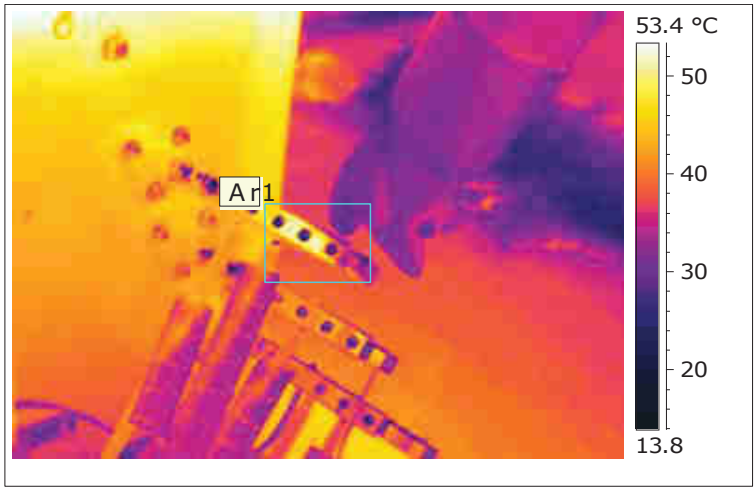
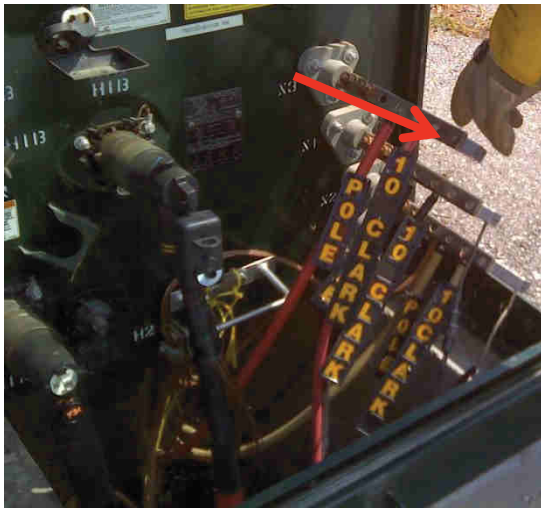


Photo:



IR Information	
Date of creation	7/10/2015
Time of creation	11:24:51 AM
Object parameter	
Ambient temperature	23.0 °C
Label	
Ar1.Max	52.4 °C

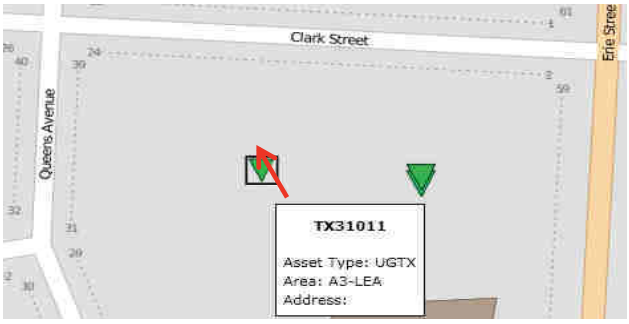
Temperature rise: 29.4°C (over ambient)

Status:

Repair Date:

Notes:

Map:



Details:
Infrared image of TX31011
Located at Clark Street in Leamington
Heating noted at one off the secondary Terminal Strips at arrow in photo.
See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium X Low

ANOMALY: Heating Secondary Connection

Identification:	TX30083	Date
Area:	Leamington	07/15/2015

Description: Secondary Terminal Strip

INFRARED IMAGE:

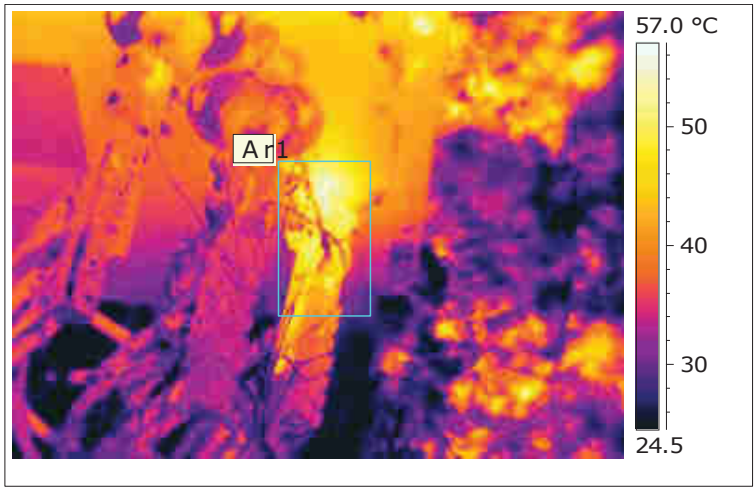
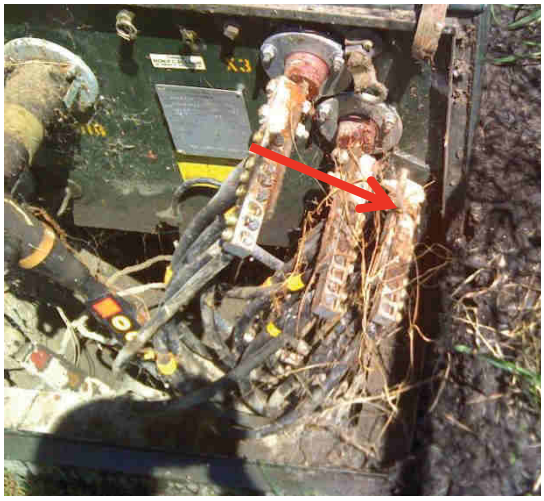


Photo:



IR Information	
Date of creation	7/15/2015
Time of creation	3:01:00 PM
Object parameter	
Ambient temperature	28.0 °C
Label	
Ar1.Max	55.1 °C

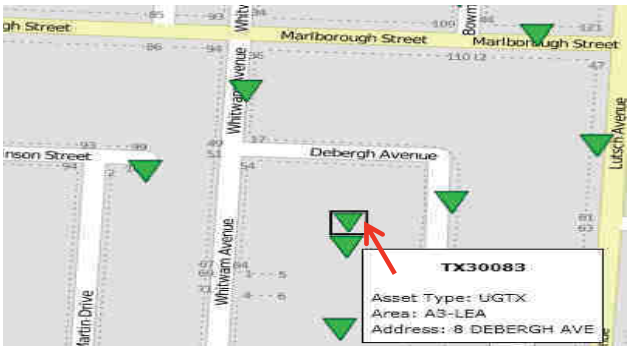
Temperature rise: 27.1°C (over ambient)

Status:

Repair Date:

Notes:

Map:



Details:
Infrared image of TX30083
Located at 8 Debergh Ave in Leamington
Heating noted at one off the secondary Terminal Strips at arrow in photo.
See IR information chart above for maximum temperature inside area box (AR1 Max).

PRIORITY: High Medium X Low

ANOMALY: Heating Secondary Connection

Infrared Inspection
- Electrical Distribution System -

Essex Power Lines

Date : May, 2016

Report Completed By:

Essex Energy Corporation
2199 Blackacre Drive / Suite 2
Oldcastle Ontario N0R 1L0
Tel: 519 946 2000
Fax: 1 866291 5317

Sheldon Tracey

HAS SUCCESSFULLY COMPLETED
THE FOLLOWING REQUIREMENTS FOR CERTIFICATION:
ATTENDING OUR TRAINING COURSE,
PASSING THE REQUIRED EXAMS, AND
SUBMITTING A PRACTICAL FIELD ASSIGNMENT.

Certified Instructor

CERTIFICATION NO. CDN-2016177
EXPIRATION DATE: 2021-03-07

Infrared Training Center – FLIR Canada

Infrared Summary Report

Purpose: Infrared inspection to identify thermal anomalies on electrical distribution equipment that suggest an unwanted condition exists and repairs are required.

Method: Complete infrared inspection of selected Essex Powerlines distribution system equipment. Save infrared images of all noted anomalies. Report on findings.

Conditions: Equipment operating under normal daytime loading conditions.

Inspection Equipment: FLIR model T300 thermal imaging systems, serial # 453000429

Observations

Note: Essex Energy Corporation is in no way responsible for any expenses resulting in actions or repair of reported anomalies. This report is not a warranty or guarantee of any equipment condition or reliability.

Please see report for details on all noted suspect conditions. All anomalies classified as follows:
HIGH Priority: High temperature rise over other components. Immediate corrective action required.
Do not ignore. Component temperature over 50 C rise over ambient.

MEDIUM Priority: Intermediate temperature rise. Corrective action required at next opportunity. Do not ignore. Component temperatures 20 to 50 C rise over ambient.

LOW Priority: Low temperature rise. Condition should be investigated further and corrected at next convenient opportunity, if applicable.
Do not ignore. Component temperatures below 20 C rise over ambient.

No Problems Noted (N/A): No anomalies noted. Condition good.

All reported conditions should be investigated further as soon as possible to verify the reported condition. Use all safety procedures. Electrical hazards exist.

CONTENTS OF REPORT

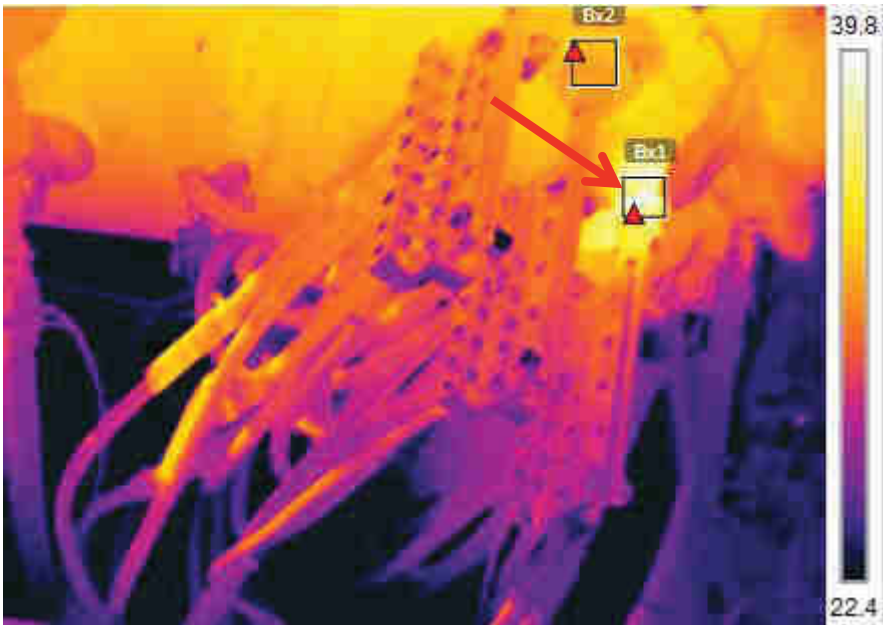
Priority H= High M= Medium L= Low N/A= Not Applicable

Equipment	Area	Problem	Priority	Page
TX7P511	Lasalle	Secondary Bushing	L	4
TX7P454	Lasalle	Secondary Bushing	L	5
TX7P169	Lasalle	Secondary Connection	L	6
TX7P421	Lasalle	Secondary Bushing	L	7
TX7P121	Lasalle	Secondary Connection	L	8
TX7P120	Lasalle	High Voltage Elbow / Bushing Well	L	9
TX7P540	Lasalle	Secondary Connection	L	10
TX7P341	Lasalle	Secondary Bushing	L	11
TX72000	Lasalle	High Voltage Elbow	L	12
TX700P3	Lasalle	Secondary Bushing	L	13
TX7P568	Lasalle	Secondary Bushing / Terminal	L	14
TX7P239	Lasalle	Secondary Wire	L	15

Asset ID: TX7P511
Address: 2955 Brooklyn Avenue, Lasalle
Date: 16-05-25

ANOMALY: SECONDARY BUSHING

INFRARED IMAGE:



IR INFORMATION:

Ambient	22 °C
Bx 1 Temp	39.9 °C
Bx 2 Temp	33.7 °C
ΔTemp	6.2 °C
IR Image(s)	IR #12366-70

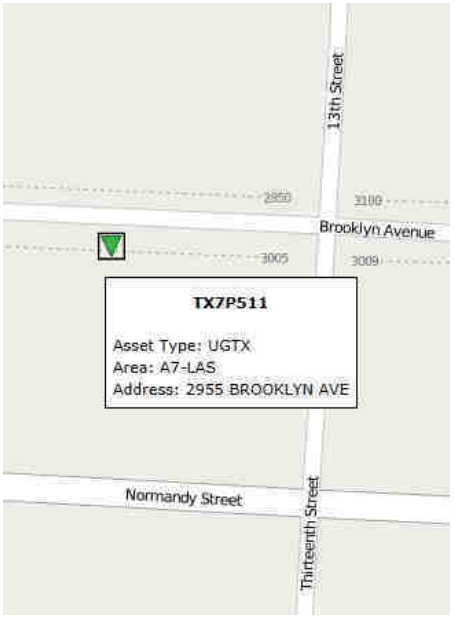
DETAILS:

There was an increase in temperature noted on the bottom secondary bushing. A qualitative comparison between the other secondary bushing indicates an issue. The issue is identified by the red arrow in each image.

For another view of issue, please review IR image # 12368 & 12370.

DIGITAL IMAGE:

MAP:

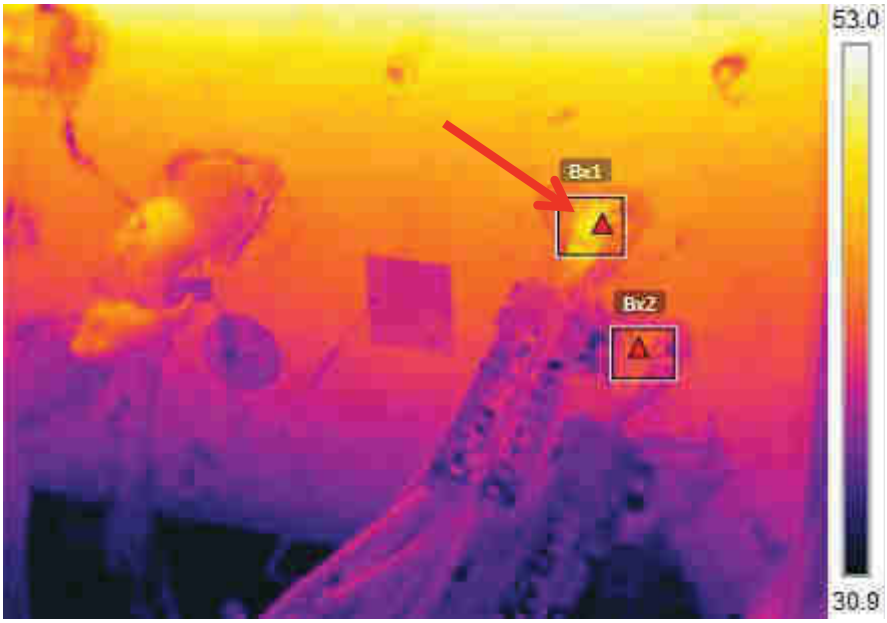


PRIORITY: HIGH MEDIUM LOW - X

Asset ID: TX7P454
Address: 2565 Skinner St., Lasalle
Date: 16-05-25

ANOMALY: SECONDARY BUSHING

INFRARED IMAGE:



IR INFORMATION:

Ambient	25 °C
Bx 1 Temp	49.3 °C
Bx 2 Temp	43.4 °C
ΔTemp	5.9 °C
IR Image(s)	12482-84

DETAILS:

There was an increase in temperature noted on the top secondary bushing. A qualitative comparison between the other secondary bushing indicates an issue. The issue is identified by the red arrow in each image.

For another view of issue, please review IR image # 12484.

DIGITAL IMAGE:

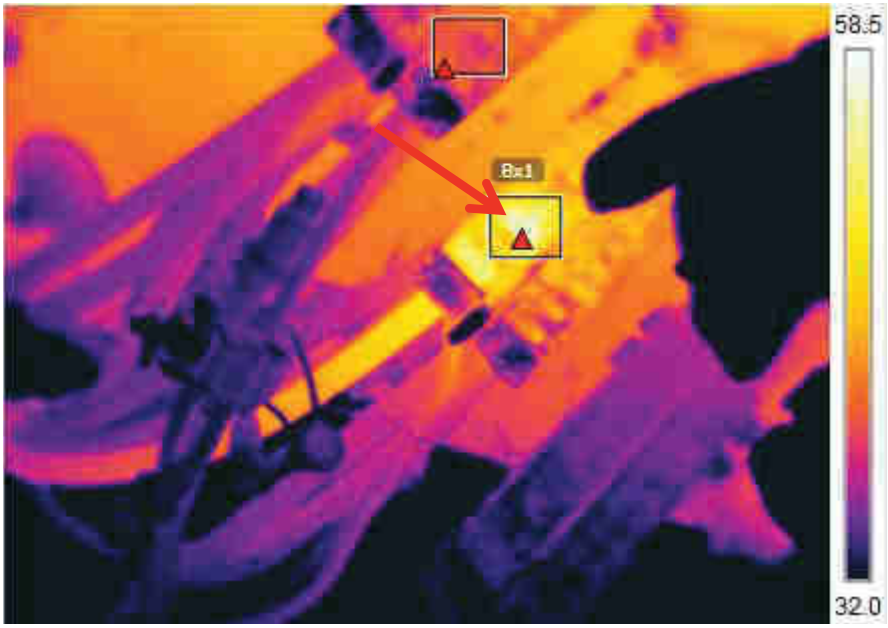
MAP:

PRIORITY: HIGH MEDIUM LOW - X

Asset ID: TX7P169
Address: 5909 Baxter Cres., Lasalle
Date: 16-05-26

ANOMALY: SECONDARY CONNECTION

INFRARED IMAGE:



IR INFORMATION:

Ambient	20 °C
Bx 1 Temp	58.4 °C
Bx 2 Temp	42.8 °C
ΔTemp	15.6 °C
IR Image(s)	12580-82

DETAILS:

There was an increase in temperature noted on a secondary connection. A quantitative comparison between the other secondary connections indicates that there is an issue on the secondary connection indicated by the red arrow.

For another view of issue, please review IR image # 12582.

DIGITAL IMAGE:

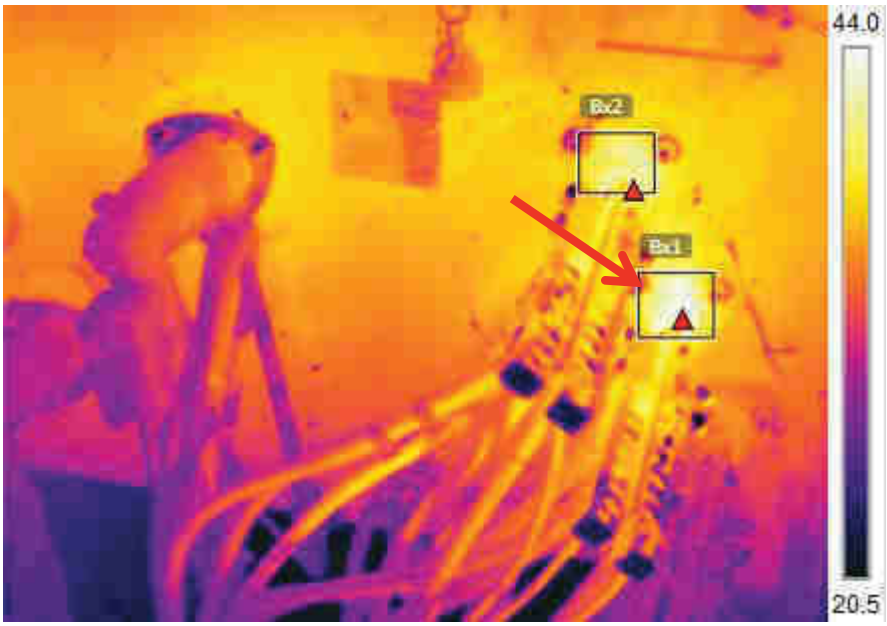
MAP:

PRIORITY: HIGH MEDIUM LOW - X

Asset ID: TX7P421
Address: 231 Tyler Rd., Lasalle
Date: 16-05-26

ANOMALY: SECONDARY BUSHING

INFRARED IMAGE:



IR INFORMATION:

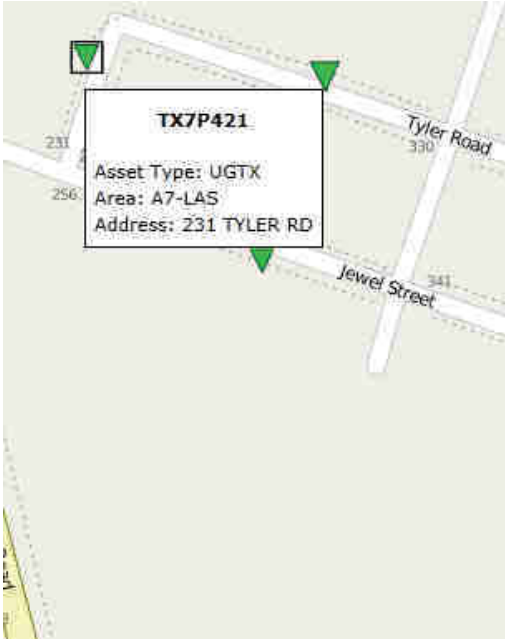
Ambient	18 °C
Bx 1 Temp	43.9 °C
Bx 2 Temp	42.4 °C
ΔTemp	1.5 °C
IR Image(s)	12824-26

DETAILS:

There was an increase in temperature noted on the middle secondary bushing. A qualitative comparison between the other secondary bushing indicates an issue. The issue is identified by the red arrow in each image.

DIGITAL IMAGE:

MAP:

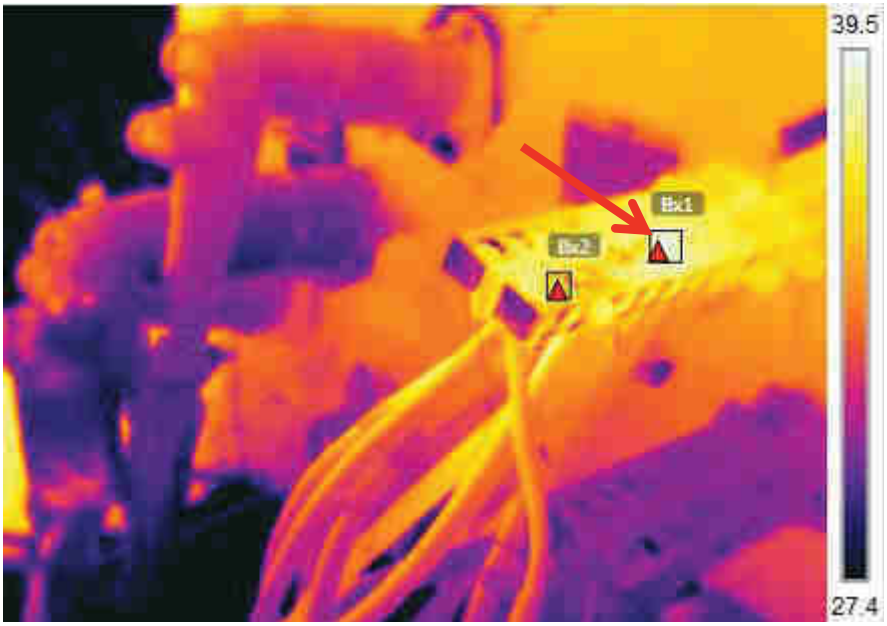


PRIORITY: HIGH MEDIUM LOW - X

Asset ID: TX7P121
Address: 892 Huron St., Lasalle
Date: 16-05-26

ANOMALY: SECONDARY CONNECTION

INFRARED IMAGE:



IR INFORMATION:

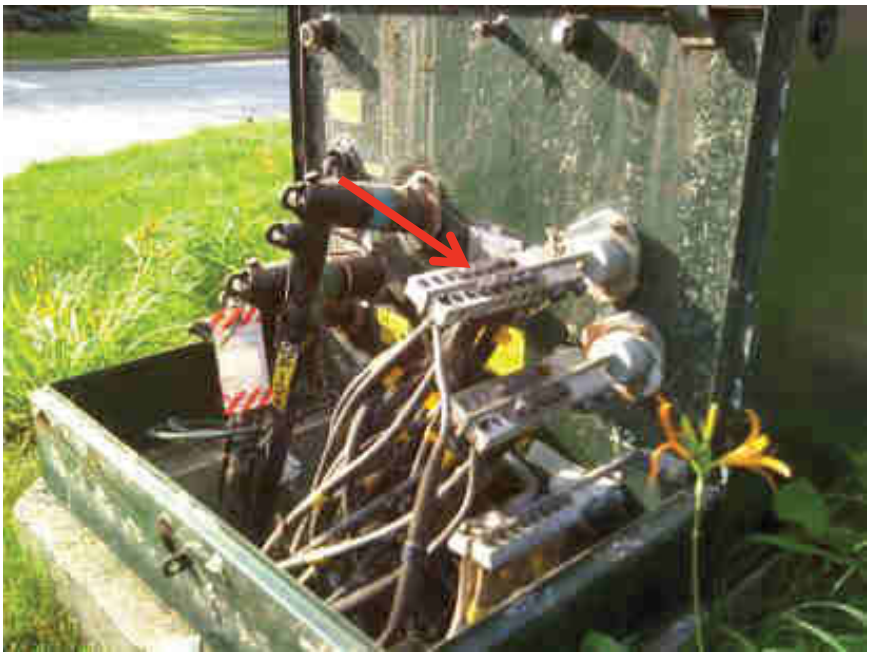
Ambient	19 °C
Bx 1 Temp	40.1 °C
Bx 2 Temp	37.3 °C
ΔTemp	2.8 °C
IR Image(s)	13052-56

DETAILS:

There was an increase in temperature noted on one of the secondary connections. A qualitative comparison between the other secondary connections indicates an issue. The issue is identified by the red arrow in each image.

For another view of issue, please review IR image # 13052 & 13054.

DIGITAL IMAGE:



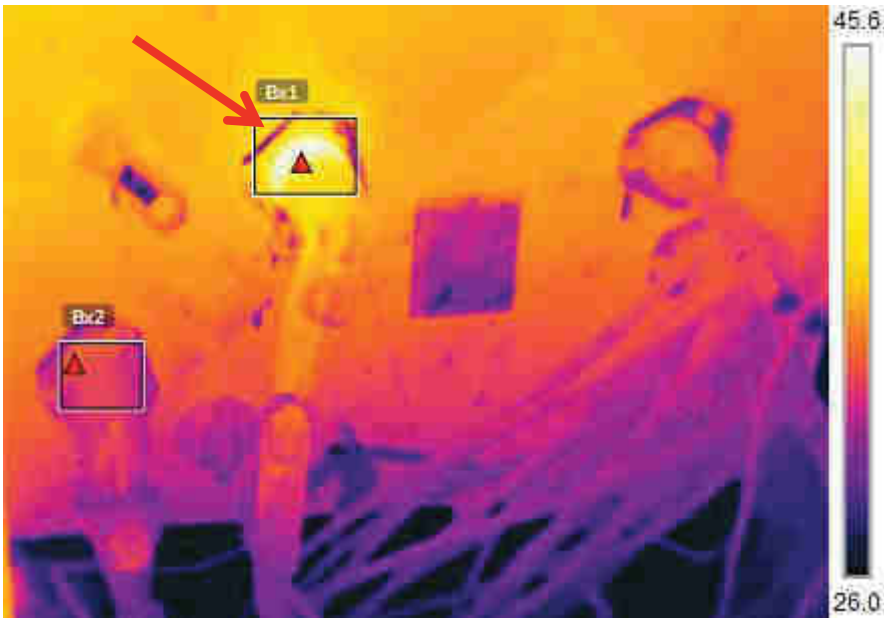
MAP:

PRIORITY: HIGH MEDIUM LOW - X

Asset ID: TX7P120
Address: 944 Huron St., Lasalle
Date: 16-05-28

ANOMALY: HIGH VOLTAGE ELBOW / BUSHING WELL

INFRARED IMAGE:



IR INFORMATION:

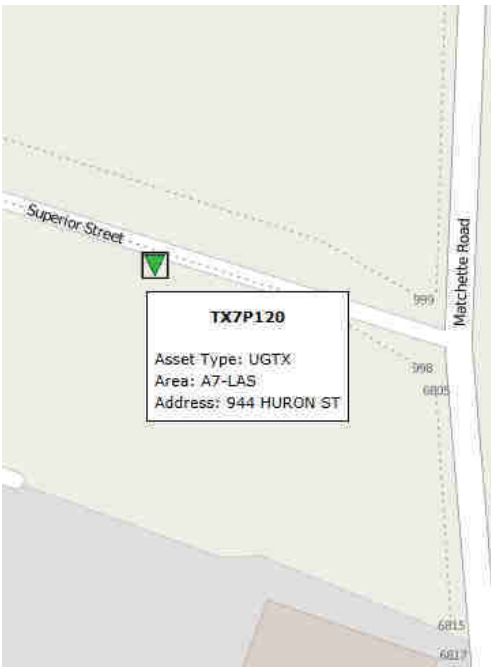
Ambient	19 °C
Bx 1 Temp	45.6 °C
Bx 2 Temp	34.6 °C
ΔTemp	11 °C
IR Image(s)	13064-66

DETAILS:

There was an increase in temperature noted on one of the high voltage elbows. A quantitative comparison between the other high voltage connections indicates an issue. The issue is identified by the red arrow in each image.

DIGITAL IMAGE:

MAP:

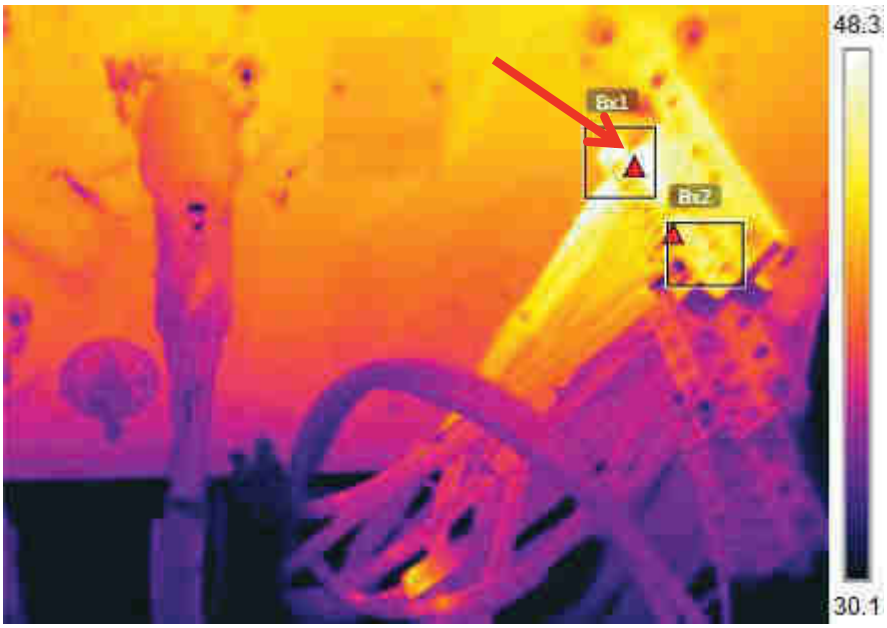


PRIORITY: HIGH MEDIUM LOW - X

Asset ID: TX7P540
Address: 1140 Deerview Dr., Lasalle
Date: 16-05-28

ANOMALY: SECONDARY CONNECTION

INFRARED IMAGE:



IR INFORMATION:

Ambient	25 °C
Bx 1 Temp	52.7 °C
Bx 2 Temp	45.9 °C
ΔTemp	6.8 °C
IR Image(s)	13130-32

DETAILS:

There was an increase in temperature noted on one of the secondary connections. A qualitative comparison between the other secondary connections indicates an issue. The issue is identified by the red arrow in each image.

For another view of issue, please review IR image # 13130.

DIGITAL IMAGE:

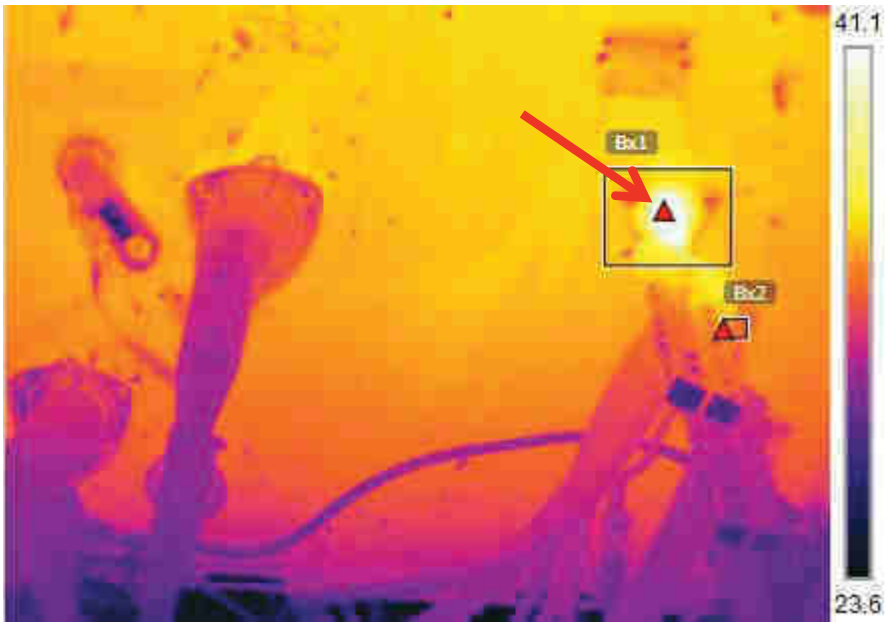
MAP:

PRIORITY: HIGH MEDIUM LOW - X

Asset ID: TX7P341
Address: 165 Rivervilla Crt., Lasalle
Date: 16-05-28

ANOMALY: SECONDARY BUSHING

INFRARED IMAGE:



IR INFORMATION:

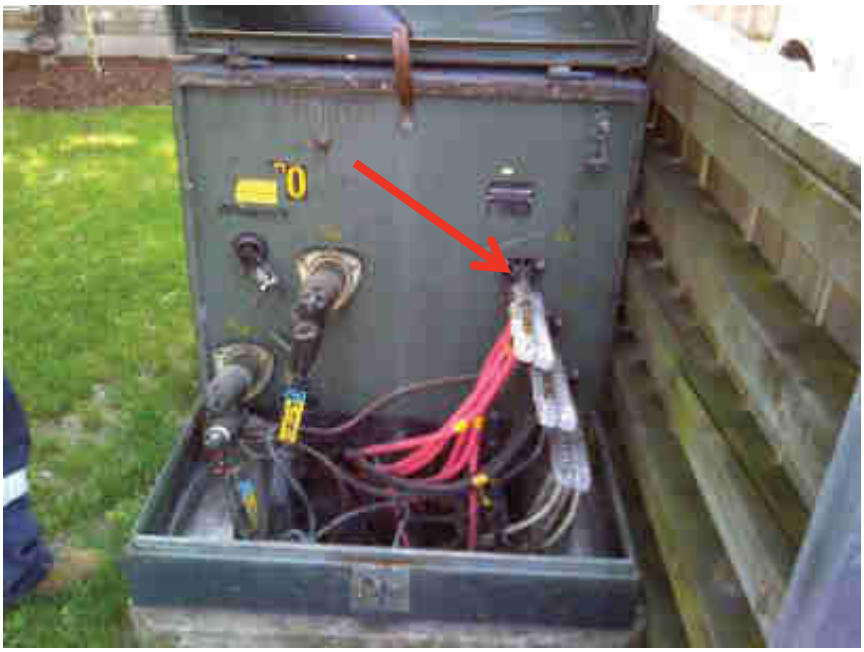
Ambient	25 °C
Bx 1 Temp	47 °C
Bx 2 Temp	34.9 °C
ΔTemp	12.1 °C
IR Image(s)	13162-64

DETAILS:

There was an increase in temperature noted on the top secondary bushing. A quantitative comparison between the other secondary bushings indicates an issue. The issue is identified by the red arrow in each image.

For another view of issue, please review IR image # 13162.

DIGITAL IMAGE:



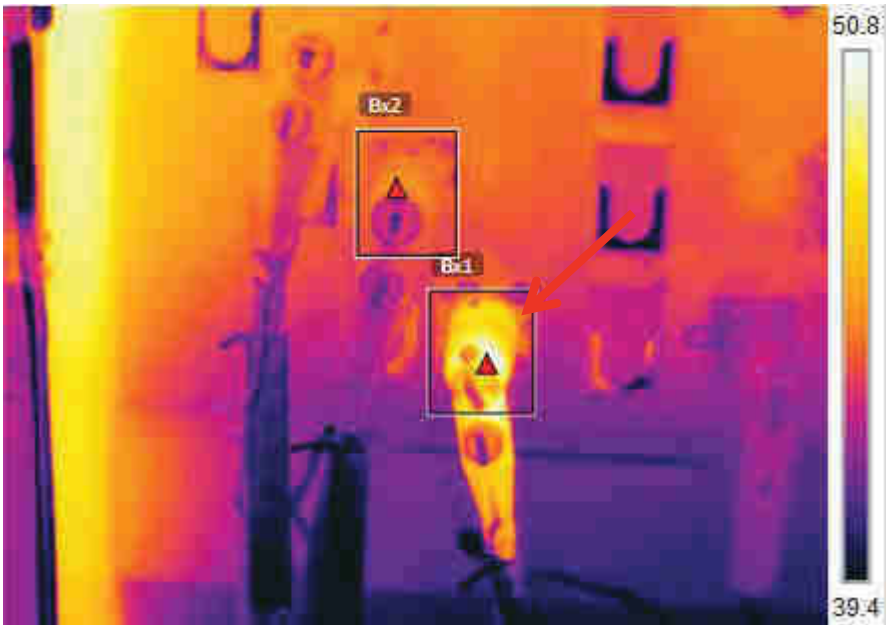
MAP:

PRIORITY: HIGH MEDIUM LOW - X

Asset ID: TX72000
Address: 415 Morton Dr., Lasalle
Date: 16-05-28

ANOMALY: HIGH VOLTAGE ELBOW

INFRARED IMAGE:



IR INFORMATION:

Ambient	25 °C
Bx 1 Temp	50.6 °C
Bx 2 Temp	45.3 °C
ΔTemp	5.3 °C
IR Image(s)	13168-70

DETAILS:

There was an increase in temperature noted on the bottom-left high voltage elbow. A quantitative comparison between the other high voltage elbows indicates an issue. The issue is identified by the red arrow in each image.

For another view of issue, please review IR image # 13170.

DIGITAL IMAGE:

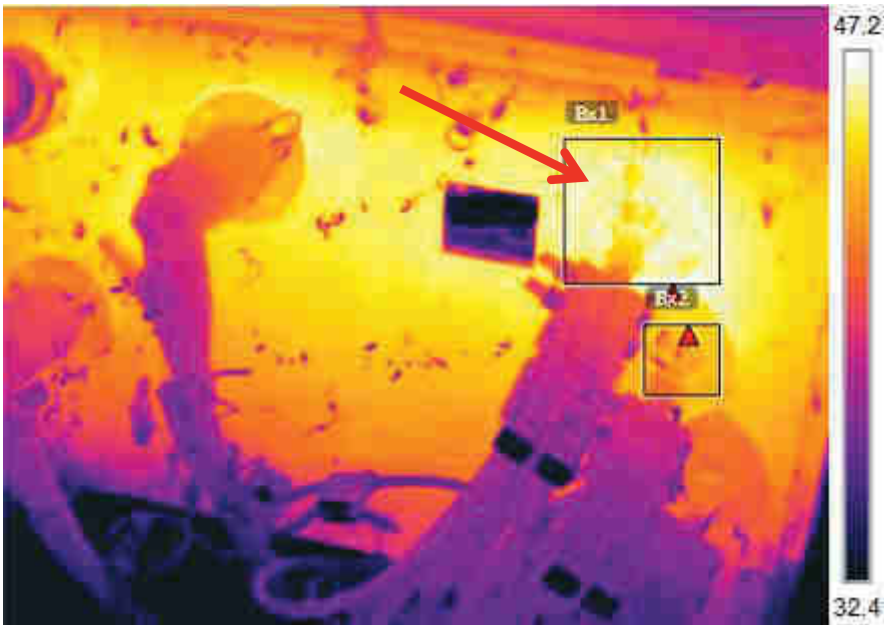
MAP:

PRIORITY: HIGH MEDIUM LOW - X

Asset ID: TX700P3
Address: 437 Darlene Pl., Lasalle
Date: 16-05-28

ANOMALY: SECONDARY BUSHING

INFRARED IMAGE:



IR INFORMATION:

Ambient	25 °C
Bx 1 Temp	47.1 °C
Bx 2 Temp	44.9 °C
ΔTemp	2.2 °C
IR Image(s)	13180

DETAILS:

There was an increase in temperature noted on the top secondary bushing. A quantitative comparison between the other secondary bushings indicates an issue. The issue is identified by the red arrow in each image.

DIGITAL IMAGE:

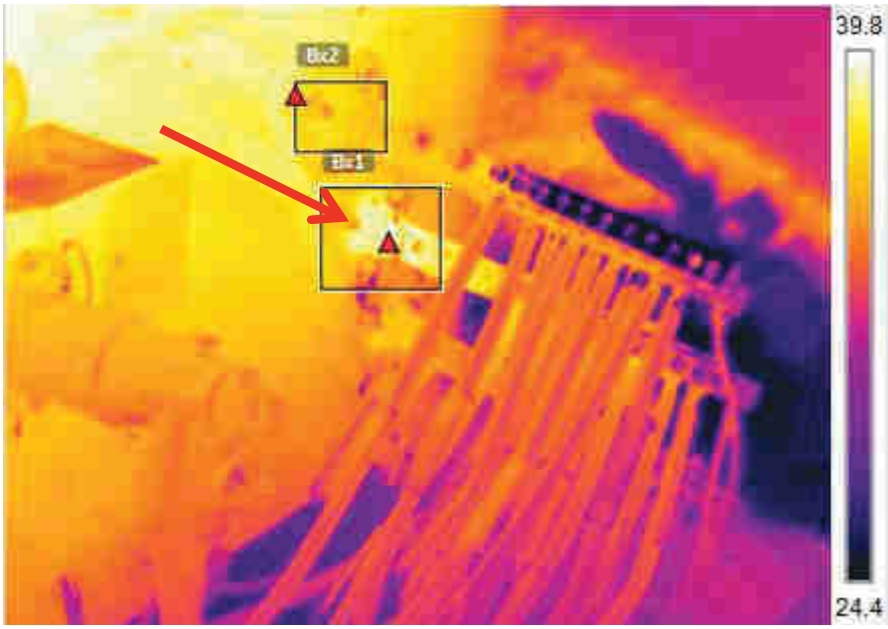
MAP:

PRIORITY: HIGH MEDIUM LOW - X

Asset ID: TX7P568
Address: 1252 Naccarato St., Lasalle
Date: 16-06-01

ANOMALY: SECONDARY BUSHING / TERMINAL

INFRARED IMAGE:



IR INFORMATION:

Ambient	25 °C
Bx 1 Temp	40 °C
Bx 2 Temp	38 °C
ΔTemp	2 °C
IR Image(s)	13410-12

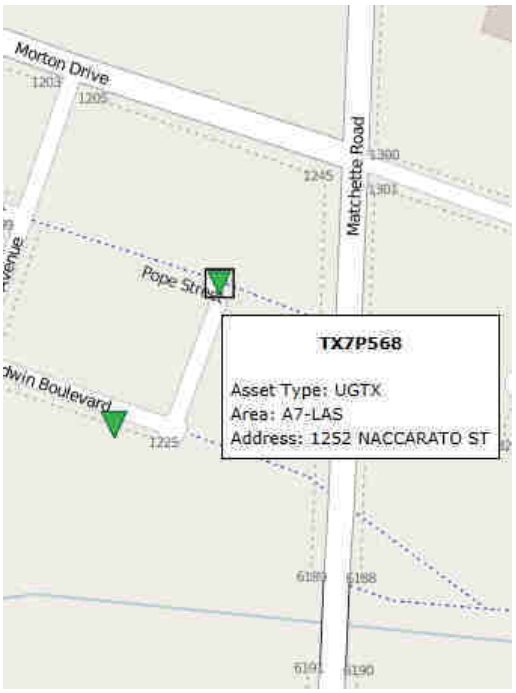
DETAILS:

There was an increase in temperature noted on the middle secondary bushing. A qualitative comparison between the other secondary bushings indicates an issue. The issue is identified by the red arrow in each image.

For another view of issue, please review IR image # 13412.

DIGITAL IMAGE:

MAP:

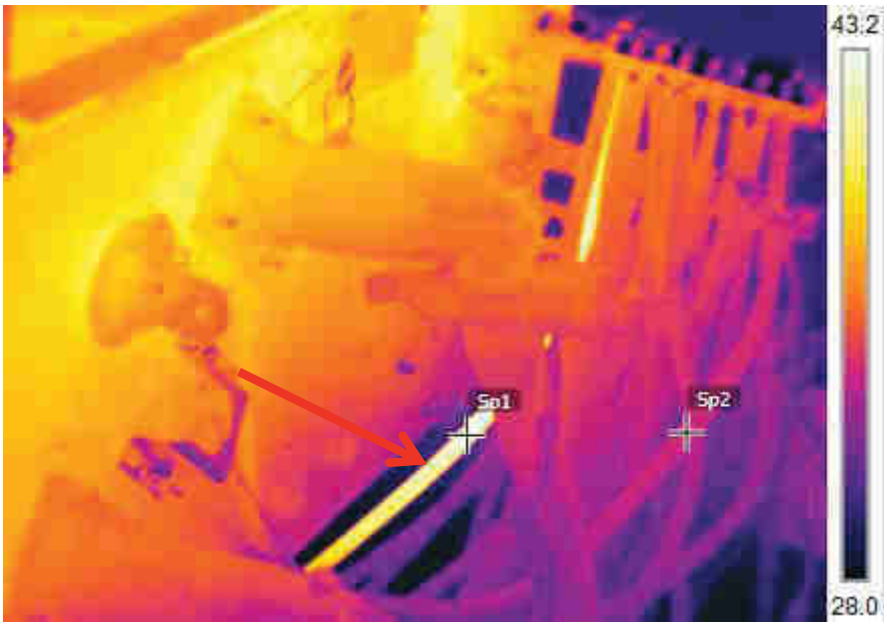


PRIORITY: HIGH MEDIUM LOW - X

Asset ID: TX7P239
Address: 750 River Ave., Lasalle
Date: 16-06-01

ANOMALY: SECONDARY WIRE

INFRARED IMAGE:



IR INFORMATION:

Ambient	26 °C
Sp 1 Temp	42.7 °C
Sp 2 Temp	34.1 °C
ΔTemp	8.6 °C
IR Image(s)	13424-26

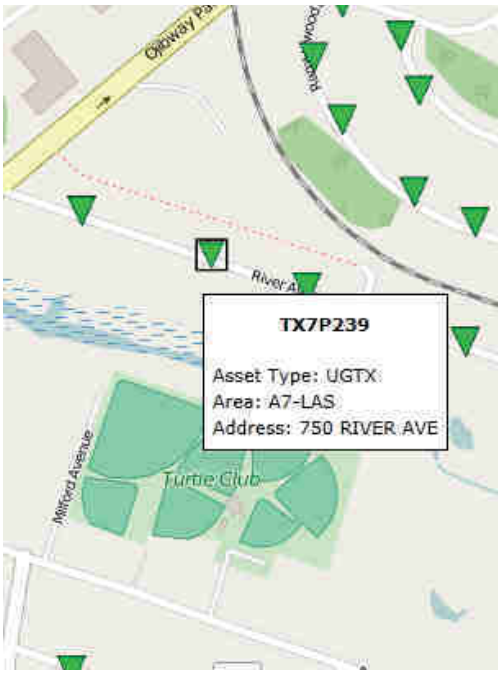
DETAILS:

There was an increase in temperature noted on one of the secondary wires. A quantitative comparison between the other secondary wires indicates an issue. The issue is identified by the red arrow in each image.

For another view of issue, please review IR image # 13426.

DIGITAL IMAGE:

MAP:



PRIORITY: HIGH MEDIUM LOW - X

Infrared Inspection
- Electrical Distribution System -

Essex Power Lines

Date : April 18, 2017

Report Completed By:

Essex Energy Corporation
2199 Blackacre Drive / Suite 2
Oldcastle Ontario N0R 1L0
Tel: 519 946 2000
Fax: 1 866291 5317

Austin Crough
Engineering Support
acrough@essexenergy.ca

Infrared Summary Report

Purpose: Infrared inspection completed to identify thermal anomalies on electrical distribution equipment that suggest an unwanted condition exists and repairs are required.

Method: Completed infrared inspection of selected Essex Powerlines distribution system equipment. Save infrared images of all noted anomalies. Report on findings.

Conditions: Equipment operating under normal daytime loading conditions.

Inspection Equipment: FLIR model T300 thermal imaging systems, serial # 453000429

Observations

Note: Essex Energy Corporation is in no way responsible for any expenses resulting in actions or repair of reported anomalies. This report is not a warranty or guarantee of any equipment condition or reliability.

Please see report for details on all noted suspect conditions. All anomalies classified as follows:
HIGH Priority: High temperature rise over other components. Immediate corrective action required. Do not ignore. Component temperature was over 50° C higher than properly working equipment.

MEDIUM Priority: Intermediate temperature rise. Corrective action required at next opportunity. Do not ignore. Component temperature was 20 to 50° C higher than properly working equipment.

LOW Priority: Low temperature rise. Condition should be investigated further and corrected at next convenient opportunity, if applicable. Do not ignore. Component temperature was less than 20° C higher than properly working equipment

No Problems Noted (N/A): No anomalies noted. Condition good.

All reported conditions should be investigated further as soon as possible to verify the reported condition. Use all safety procedures. Electrical hazards exist.

CONTENTS OF REPORT

Priority: H= High / M= Medium / L= Low / N/A= Not Applicable

Equipment	Area	Problem	Priority	Page
TX10180	Tecumseh	High Voltage Elbow	L	4
TX10508	Tecumseh	High Voltage Elbow	L	5
TX10936	Tecumseh	High Voltage Wire Connection	L	6
TX10102	Tecumseh	High Voltage Elbow	L	7
TX10909	Tecumseh	Secondary Connection	L	8
TX10390	Tecumseh	Secondary Connection	L	9
TX10389	Tecumseh	Secondary Connection	L	10
TX10021	Tecumseh	High Voltage Elbow	L	11
TX10404	Tecumseh	Secondary Connection	L	12
TX10079	**Tecumseh**	**Secondary Wire**	**H**	**13**
TX10398	Tecumseh	Secondary Bushing / Terminal	L	14
TX10059	Tecumseh	Secondary Terminal	L	15
TX10016	Tecumseh	High Voltage Elbow	L	16
TX10308	Tecumseh	Secondary Wire	L	17

Asset ID: TX10180
Address: 1499 Heatherglen Cres, Tecumseh
Date: 17-03-07

ANOMALY: HIGH VOLTAGE ELBOW
PRIORITY: LOW

INFRARED IMAGE:

IR INFORMATION:

Ambient	10 °C
Bx 1 Temp	26.1 °C
Bx 2 Temp	14.4 °C
ΔTemp	11.7 °C
IR Image(s)	IR #14159, 14160

DETAILS:

There was an increase in temperature noted on the left high voltage elbow. A quantitative comparison with the other high voltage elbow indicated an issue. The issue is identified by the white arrow in each image.

For another view of the issue, please review IR image # 14157 & 14158.

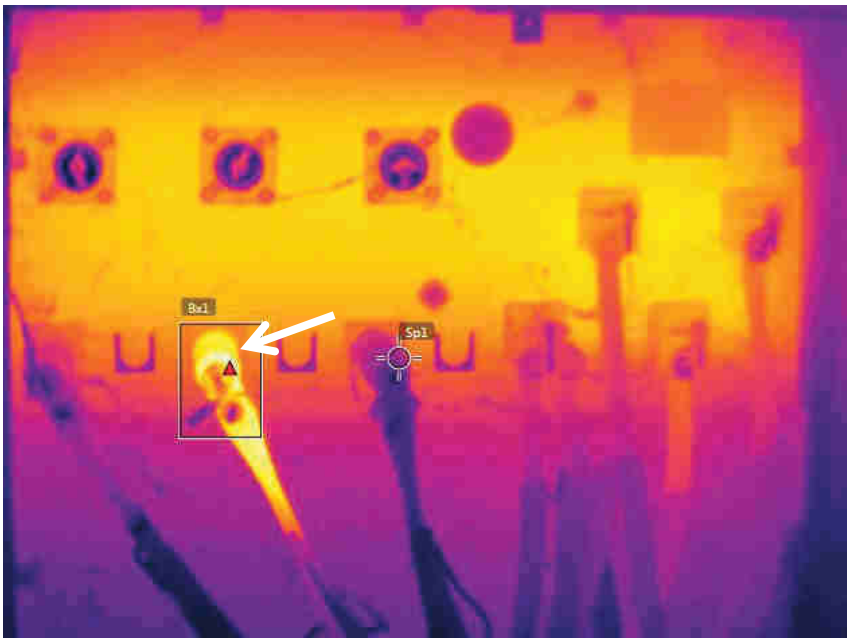
DIGITAL IMAGE:

MAP:

Asset ID: TX10508
Address: 11873 Tecumseh Rd E, Tecumseh
Date: 17-03-07

ANOMALY: HIGH VOLTAGE ELBOW
PRIORITY: LOW

INFRARED IMAGE:



IR INFORMATION:

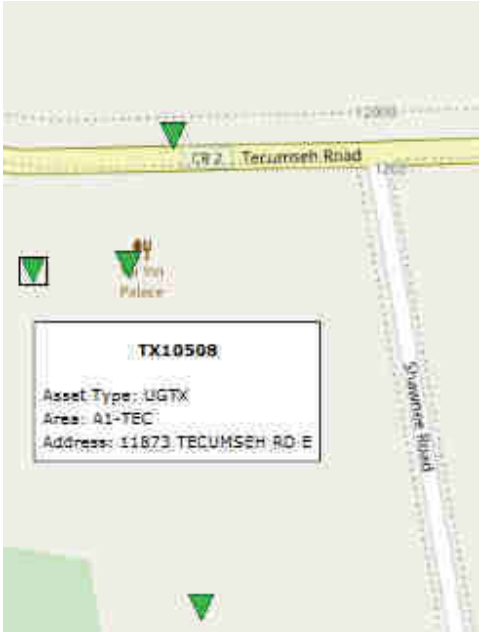
Ambient	11 °C
Bx 1 Temp	23.8 °C
Sp 1 Temp	12.7 °C
ΔTemp	11.1 °C
IR Image(s)	14205, 14206

DETAILS:

There was an increase in temperature noted on the center high voltage elbow. A quantitative comparison with another high voltage elbow indicated an issue. The issue is identified by the white arrow in each image.

DIGITAL IMAGE:

MAP:

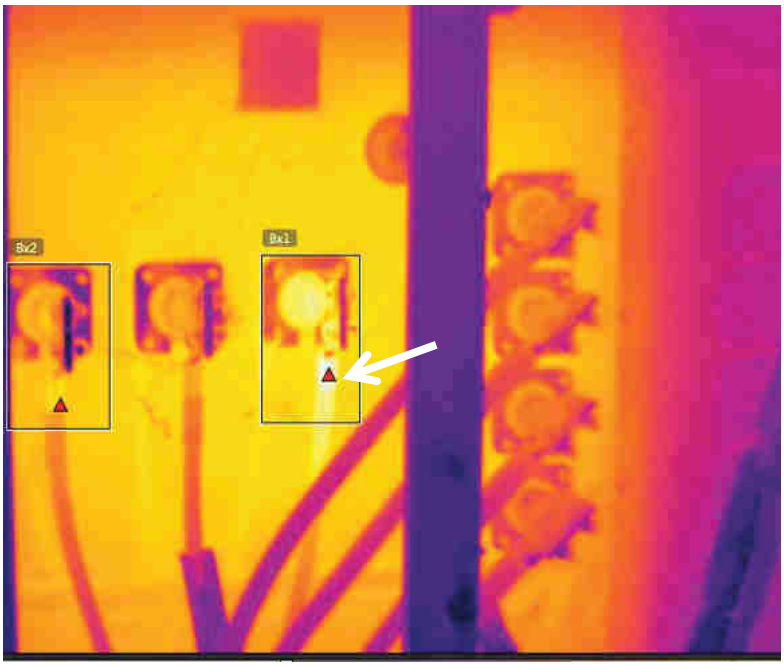


Asset ID: TX10936
Address: 917 Lesperance Rd, Tecumseh
Date: 17-03-07

ANOMALY: HIGH VOLTAGE WIRE CONNECTION

PRIORITY: LOW

INFRARED IMAGE:



IR INFORMATION:

Ambient	11 °C
Bx 1 Temp	22.8 °C
Bx 2 Temp	17.8 °C
ΔTemp	5.0 °C
IR Image(s)	14217, 14218

DETAILS:

There was an increase in temperature noted on the wire connection of the right high voltage elbow. A quantitative comparison with another connection indicated that there was an issue. The issue is identified by the white arrow in each image.

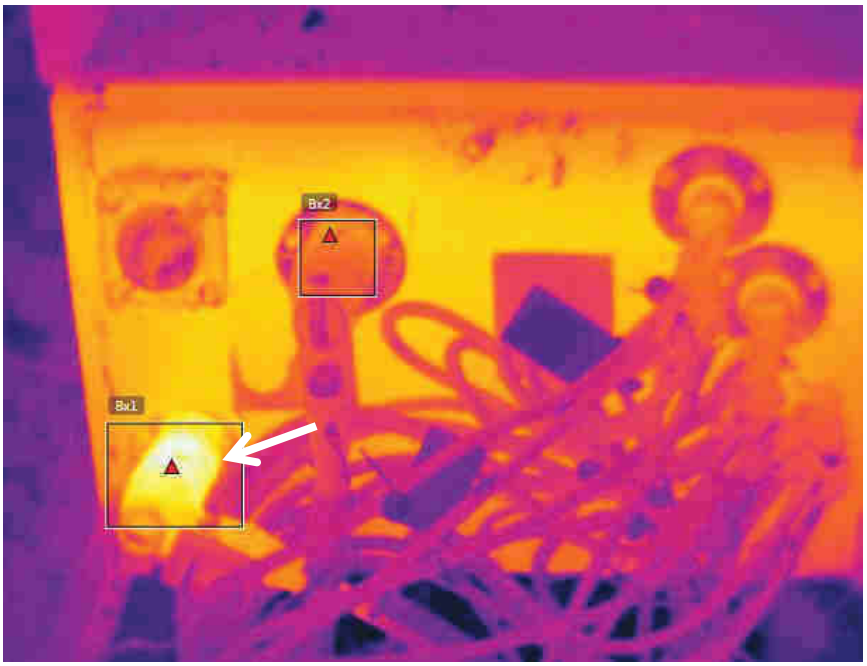
DIGITAL IMAGE:

MAP:

Asset ID: TX10102
Address: 12229 Valente Crt, Tecumseh
Date: 17-03-07

ANOMALY: HIGH VOLTAGE ELBOW
PRIORITY: LOW

INFRARED IMAGE:



IR INFORMATION:

Ambient	12 °C
Bx 1 Temp	33.5 °C
Bx 2 Temp	19.4 °C
ΔTemp	14.1 °C
IR Image(s)	14287, 14288

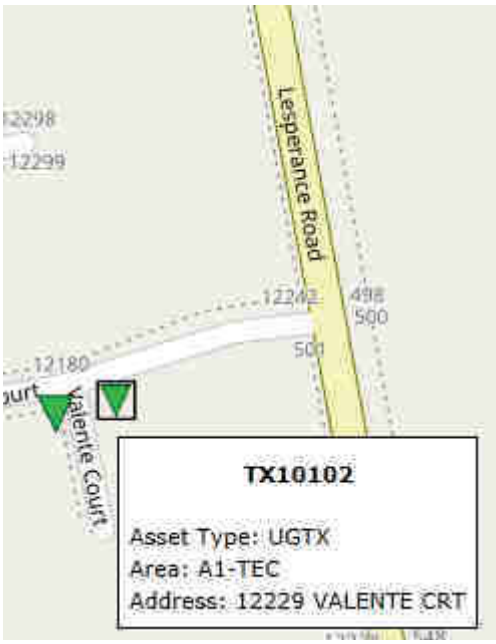
DETAILS:

There was an increase in temperature noted on the left high voltage elbow. A quantitative comparison with another high voltage elbow indicated an issue. The issue is identified by the white arrow in each image.

For another view of the issue, please review IR image #14285 & 14286

DIGITAL IMAGE:

MAP:



Asset ID: TX10909
Address: 13275 Tecumseh Rd, Tecumseh
Date: 17-03-08

ANOMALY: SECONDARY CONNECTION
PRIORITY: LOW

INFRARED IMAGE:

IR INFORMATION:

Ambient	10 °C
Bx 1 Temp	16.3 °C
Bx 2 Temp	10.6 °C
ΔTemp	5.7 °C
IR Image(s)	14479, 14480

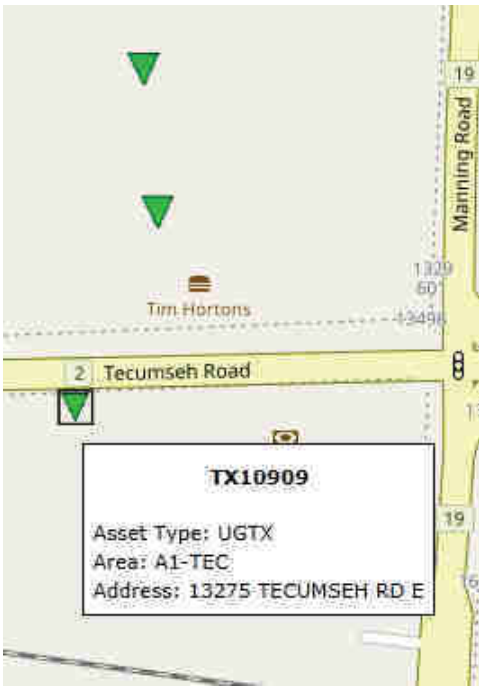
DETAILS:

There was an increase in temperature noted on the bottom right secondary connection. A quantitative comparison between the other secondary connections indicated an issue. The issue is identified by the white arrow in each image.

For another view of the issue, please review IR image # 14481 &14482.

DIGITAL IMAGE:

MAP:



Asset ID: TX10390
Address: 595 Michael Dr, Tecumseh
Date: 17-03-08

ANOMALY: SECONDARY CONNECTION
PRIORITY: LOW

INFRARED IMAGE:

IR INFORMATION:

Ambient	11 °C
Bx 1 Temp	25.9 °C
Sp 1 Temp	13.7 °C
ΔTemp	12.1 °C
IR Image(s)	14509, 14510

DETAILS:

There was an increase in temperature noted on one of the secondary connections. A quantitative comparison between the other secondary connections indicated an issue. The issue is identified by the white arrow in each image.

For another view of the issue, please review IR image #14507 &14508.

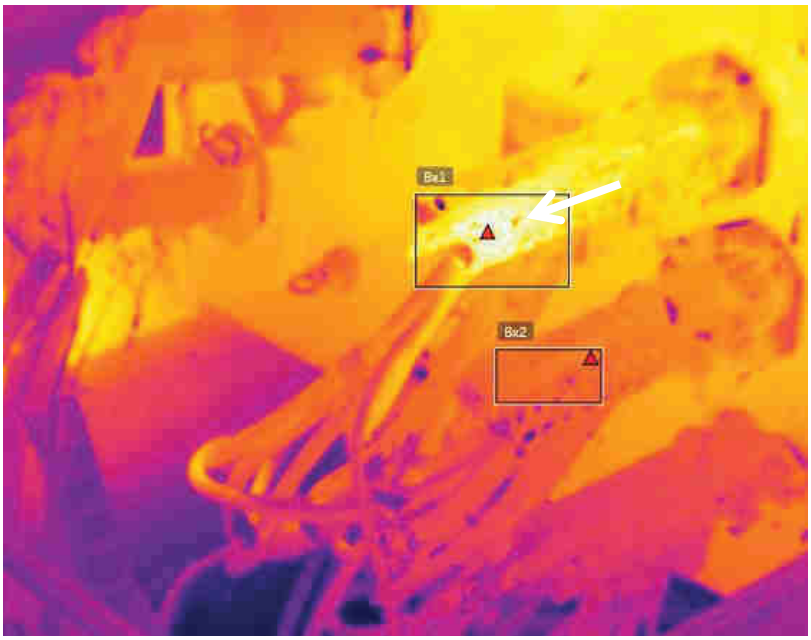
DIGITAL IMAGE:

MAP:

Asset ID: TX10389
Address: 555 Michael Dr, Tecumseh
Date: 17-03-08

ANOMALY: SECONDARY CONNECTION
PRIORITY: LOW

INFRARED IMAGE:



IR INFORMATION:

Ambient	11 °C
Bx 1 Temp	23.3 °C
Bx 2 Temp	15.4 °C
ΔTemp	8.0 °C
IR Image(s)	14513,14514

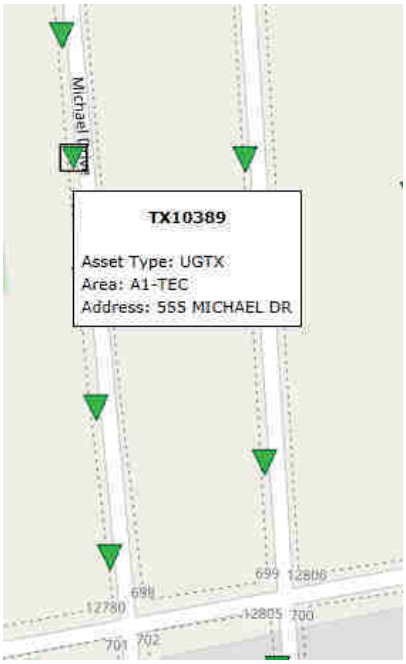
DETAILS:

There was an increase in temperature noted on one of the secondary connections. A quantitative comparison between the other secondary connections indicated an issue. The issue is identified by the white arrow in each image.

For another view of the issue, please review IR image # 14511 & 14512.

DIGITAL IMAGE:

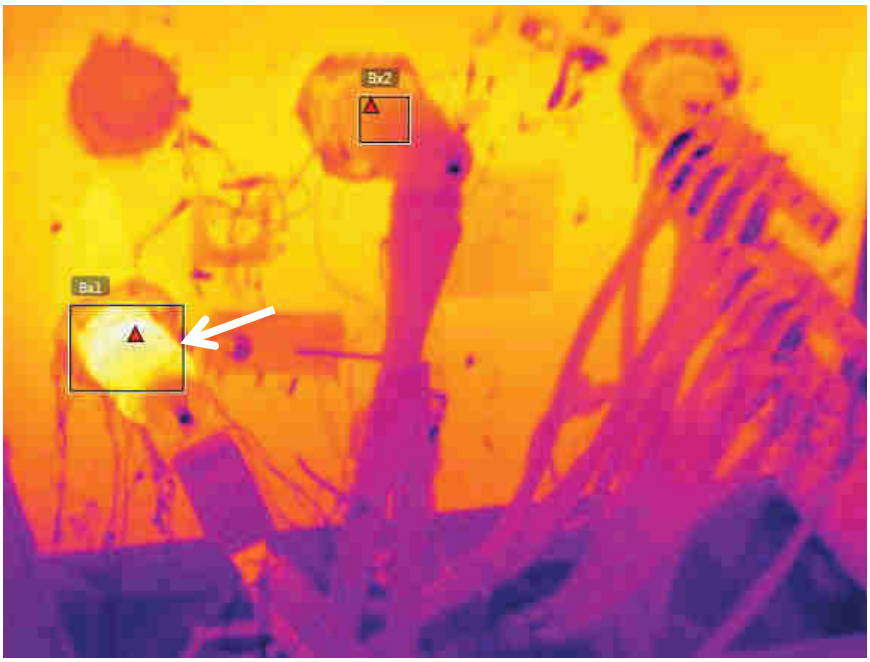
MAP:



Asset ID: TX10021
Address: 512 Collier Cres, Tecumseh
Date: 17-03-09

ANOMALY: HIGH VOLTAGE ELBOW
PRIORITY: LOW

INFRARED IMAGE:



IR INFORMATION:

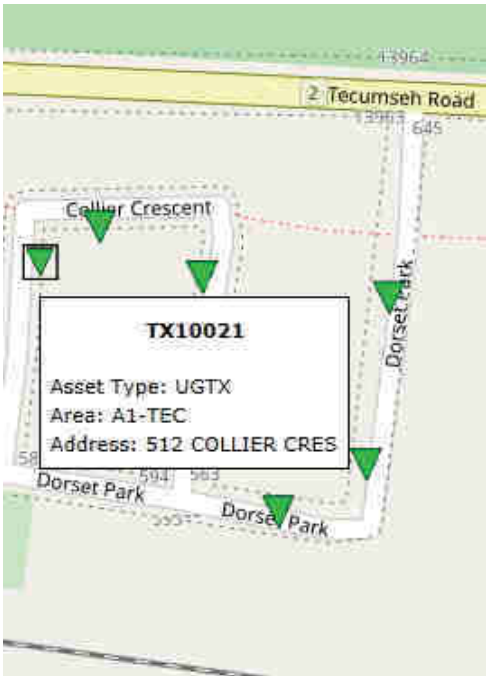
Ambient	4 °C
Bx 1 Temp	27.7 °C
Bx 2 Temp	15.1 °C
ΔTemp	12.6 °C
IR Image(s)	14599, 14600

DETAILS:

There was an increase in temperature noted on the left high voltage elbow. A quantitative comparison with the other high voltage elbow indicated an issue. The issue is identified by the white arrow in each image.

DIGITAL IMAGE:

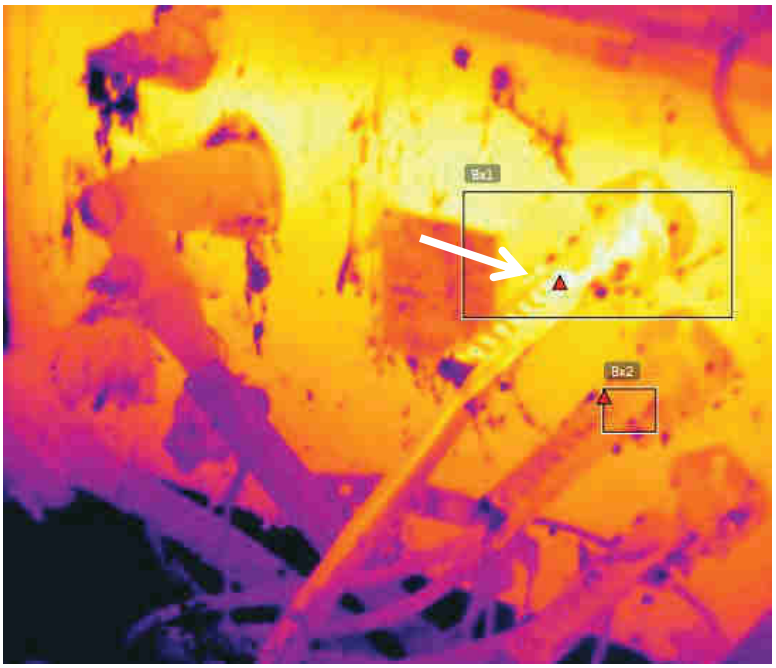
MAP:



Asset ID: TX10404
Address: 260 Clovelly Rd, Tecumseh
Date: 17-03-09

ANOMALY: SECONDARY CONNECTION
PRIORITY: LOW

INFRARED IMAGE:



IR INFORMATION:

Ambient	4 °C
Bx 1 Temp	18.7 °C
Bx 2 Temp	14.4 °C
ΔTemp	4.3 °C
IR Image(s)	14675, 14676

DETAILS:

There was an increase in temperature noted on a secondary connection on the top terminal. A quantitative comparison with another secondary connection indicated an issue. The issue is identified by the white arrow in each image.

For another view of issue, please review IR image # 14677 &14678.

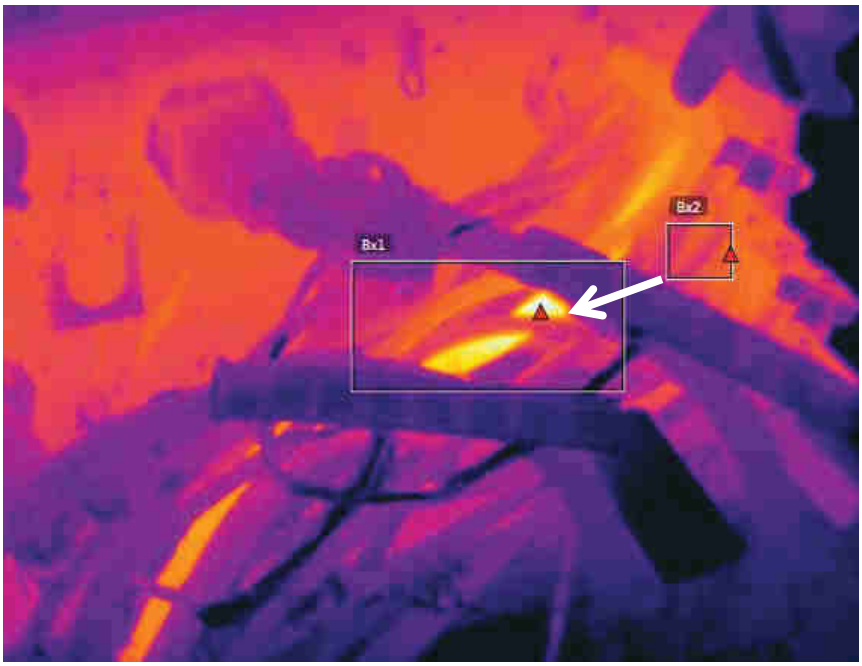
DIGITAL IMAGE:

MAP:

Asset ID: TX10079
Address: 310 Cada Cres, Tecumseh
Date: 17-03-09

ANOMALY: SECONDARY WIRE
PRIORITY: HIGH

INFRARED IMAGE:



IR INFORMATION:

Ambient	4 °C
Bx 1 Temp	107.4°C
Bx 2 Temp	23.9 °C
ΔTemp	83.5 °C
IR Image(s)	14693, 14694

DETAILS:

There was an increase in temperature noted on a secondary wire on the top terminal. A quantitative comparison between the other secondary wires indicated an issue. The issue is identified by the white arrow in each image.

For another view of the issue, please review IR image # 14695, 14696.

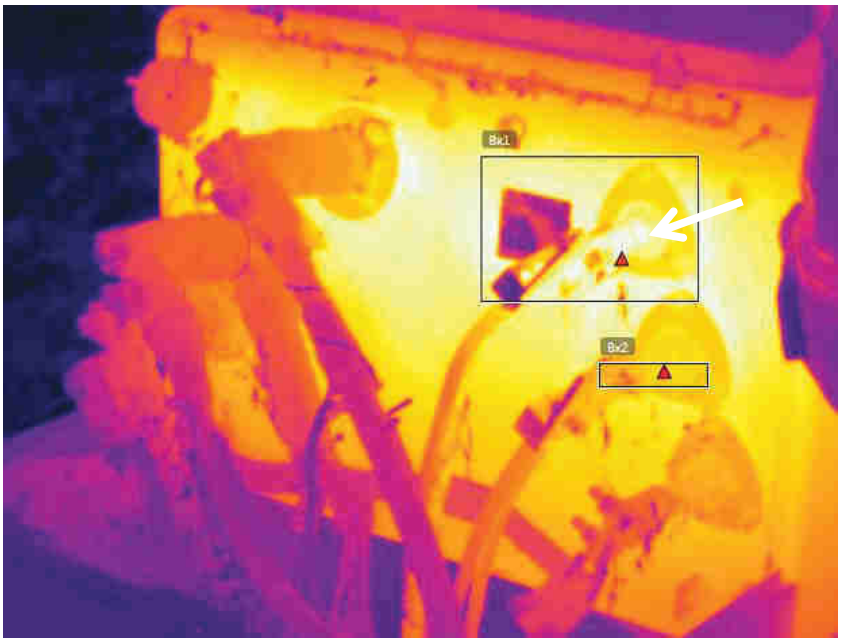
DIGITAL IMAGE:

MAP:

Asset ID: TX10398
Address: 184 Hayes Ave, Tecumseh
Date: 17-03-09

ANOMALY: SECONDARY BUSHING / TERMINAL
PRIORITY: LOW

INFRARED IMAGE:



IR INFORMATION:

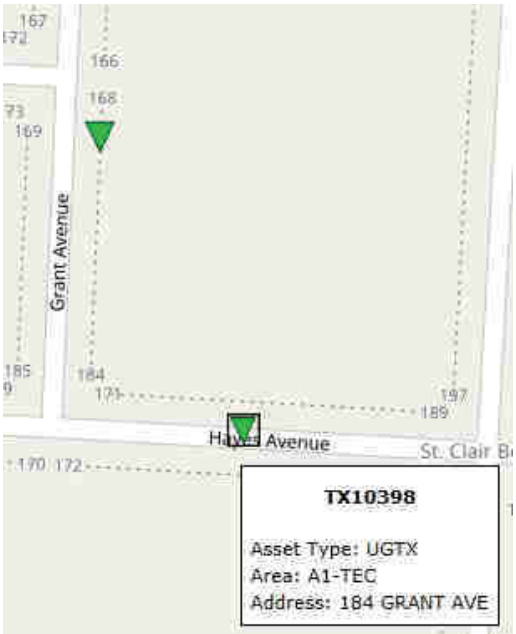
Ambient	3 °C
Bx 1 Temp	25.6 °C
Bx 2 Temp	21.9 °C
ΔTemp	3.7 °C
IR Image(s)	14729,14730

DETAILS:

There was an increase in temperature noted on the top secondary terminal. A qualitative comparison with another secondary terminal indicated an issue. The issue is identified by the white arrow in each image.

DIGITAL IMAGE:

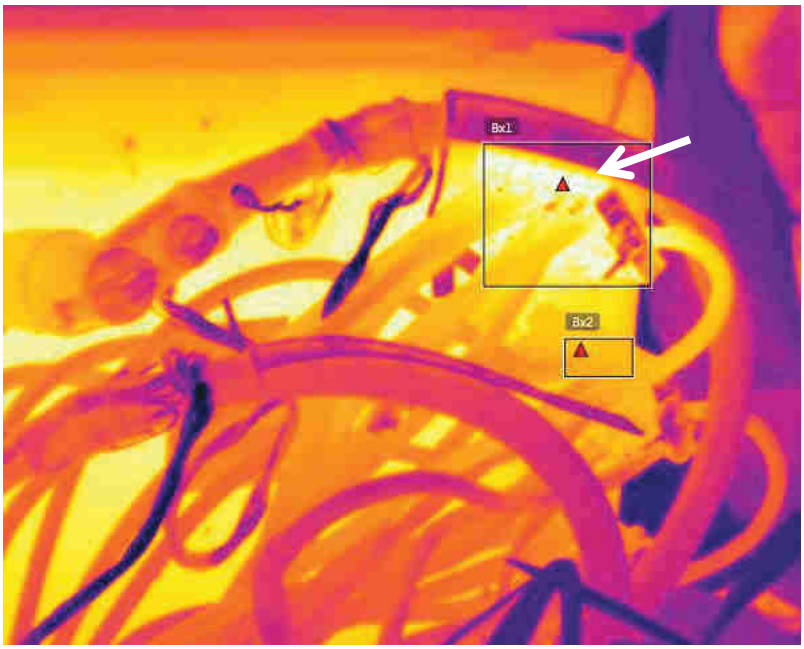
MAP:



Asset ID: TX10059
Address: 160 David Cres, Tecumseh
Date: 17-03-09

ANOMALY: SECONDARY TERMINAL
PRIORITY: LOW

INFRARED IMAGE:



IR INFORMATION:

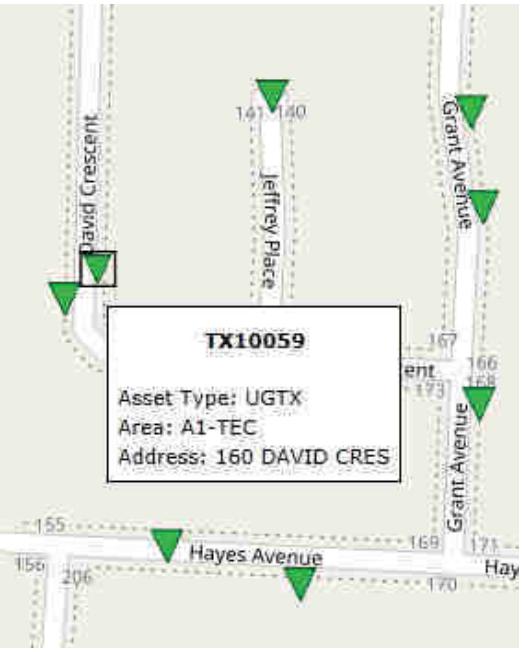
Ambient	5°C
Bx 1 Temp	25.1 °C
Bx 2 Temp	18.8 °C
ΔTemp	6.3 °C
IR Image(s)	14745,14746

DETAILS:

There was an increase in temperature noted on the top secondary terminal. A quantitative comparison with another secondary terminal indicated an issue. The issue is identified by the white arrow in each image.

DIGITAL IMAGE:

MAP:



Asset ID: TX10016
Address: 503 Harbourne Cres, Tecumseh
Date: 17-03-10

ANOMALY: HIGH VOLTAGE ELBOW
PRIORITY: LOW

INFRARED IMAGE:

IR INFORMATION:

Ambient	1°C
Bx 1 Temp	18.3 °C
Bx 2 Temp	5.7 °C
ΔTemp	12.6 °C
IR Image(s)	14589, 14590

DETAILS:

There was an increase in temperature noted on the top high voltage elbow. A quantitative comparison with the other high voltage elbow indicated an issue. The issue is identified by the white arrow in each image.

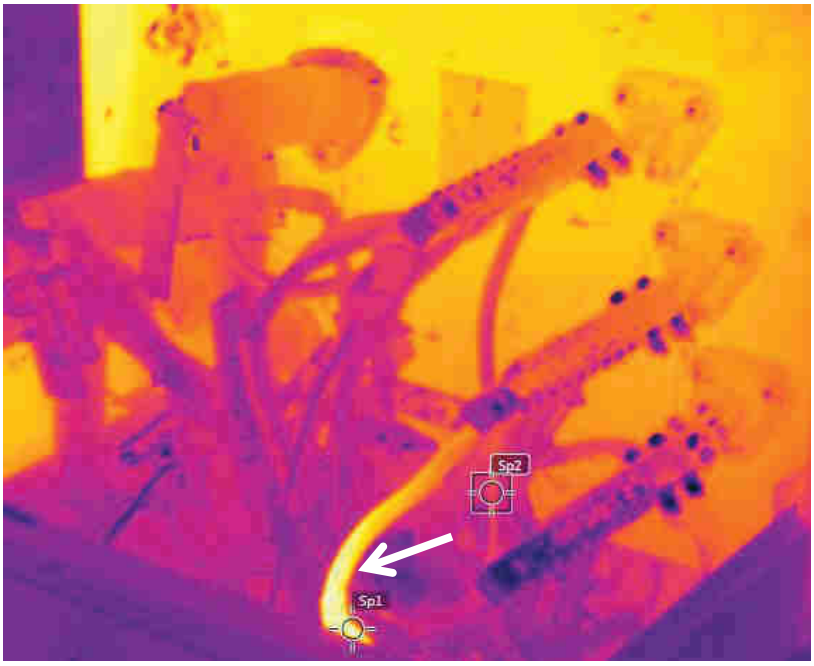
DIGITAL IMAGE:

MAP:

Asset ID: TX10308
Address: 441 Green Valley Dr, Tecumseh
Date: 17-03-10

ANOMALY: SECONDARY WIRE
PRIORITY: LOW

INFRARED IMAGE:



IR INFORMATION:

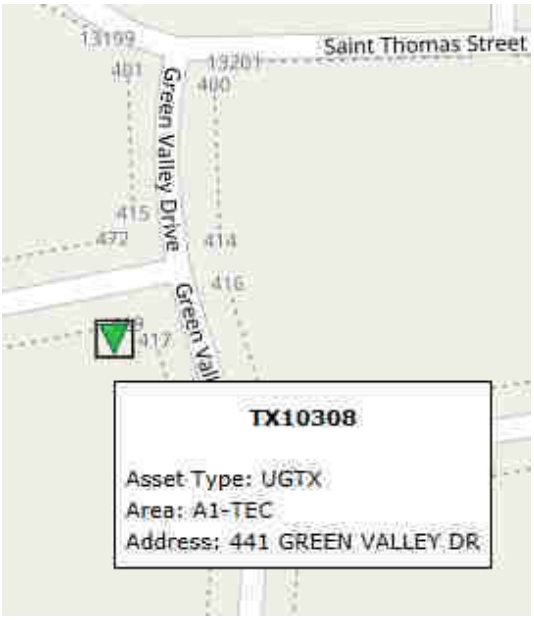
Ambient	1°C
Sp 1 Temp	19.9 °C
Sp 2 Temp	1.8 °C
ΔTemp	18.1 °C
IR Image(s)	14853, 14854

DETAILS:

There was an increase in temperature noted on a secondary wire of the middle terminal. A quantitative comparison between the other secondary wires indicated an issue. The issue is identified by the white arrow in each image.

DIGITAL IMAGE:

MAP:



Appendix H: Building Condition Review

Essex Powelines Building Condition Review

Cover

November 3

2730
Highway 3

2016

Revised - Nov 9, 2016

BUILDING
CONDITION
REPORT

Submission by:
ROAstudio inc.

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Submission to:

ESSEX POWERLINES CORPORATION

2730 Highway 3
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2730 Highway 3

Building Condition Review

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Executive Summary

ROA Studio Inc, along with associated consultants, was engaged to provide observations and report the physical conditions of the property located at 2730 Highway 3, Oldcastle Ontario. This review addresses item that are significant for the continued operations of the facility in its current usage and occupancy, consistent with comparable properties of similar age.

The report observes the general physical condition of the subject property, material systems and components, and identifies deficiencies and any unusual features or inadequacies.

The consultant team visited the site on various September 7, 2016 and conducted a visual inspection of building systems.

The following building systems were reviewed and the following is our professional opinion of the found condition of the building:

Site	☐ Good	☑ fair	☐ Poor
Building Exterior	☑ Good	☐ fair	☐ Poor
Windows & Doors	☑ Good	☐ fair	☐ Poor
Roofing | Skylight	☐ Good	☑ fair	☐ Poor
Interior finishes	☑ Good	☐ fair	☐ Poor
Structural systems	☑ Good	☐ fair	☐ Poor
Fire Protection	☑ Good	☐ fair	☐ Poor
Plumbing Systems	☑ Good	☐ fair	☐ Poor
Natural Gas	☑ Good	☐ fair	☐ Poor
HVAC	☐ Good	☑ fair	☐ Poor
Electrical Systems	☑ Good	☐ fair	☐ Poor
Lighting Systems	☑ Good	☐ fair	☐ Poor
Fire Alarm System	☑ Good	☐ fair	☐ Poor
Security Systems	☑ Good	☐ fair	☐ Poor
Works Garage	☑ Good	☐ fair	☐ Poor

Opinions of Probable Costs

These opinions of probable costs are to assist the client in developing a general understanding of the physical condition of the subject property.

The following summarizes the cost per building systems.

Site ....$	477,000.00
Building Exterior....$	3,000.00
Windows & Doors ....$	14,500.00
Roofing | Skylights....$	229,000.00*
Interior finishes....$	4,000.00
Structural Systems ....$	10,000.00
Fire Protection....$	0.00
Plumbing Systems ....$	0.00
Natural Gas Systems....$	1,000.00
HVAC..... ....$	18,000.00
Electrical Systems ....$	1,000.00
Lighting Systems....$	0.00
Fire Alarm Systems....$	0.00
Security Systems....$	0.00
Works Garage....$	0.00
Total....$	757,500.00

*Refer to report, Roof Replacement of 220,000.00 will be required in 5 to 7 years.

The following summaries the cost for floor drains in the works garage:

Floor Drains....$	75,000.00

Opinions of probable costs should only be construed as preliminary budgets.

SECTION 1 PROJECT DETAILS

1.1 Purpose

ROA Studio I nc, along with associated consultants, were engaged to provide observations and report the physical conditions of the property located at 2730 Highway 3, Oldcastle Ontario. This review addresses item that are significant for the continued operations of the facility in its current usage and occupancy, consistent with comparable properties of similar age. The intent of this report is to determine anticipated capitol and maintenance cost over a five (5) to ten (10) year period. All inspections were non-destructive and based on visual inspections of representative portions of the various systems. This report should not be considered a guarantee or warranty of any kind. Unexpected repairs should still be anticipated.

1.2 Scope of Work

Observe the general physical condition of the subject property, observe material systems and components, and identify deficiencies and any unusual features or inadequacies observed by conducting specific or representative observations, as appropriate. Visually inspect the building systems based on representative samples to be review include but not limited to:

Site - Asphalt Paving, Concrete Curbing and sidewalks, Parking and exterior egress. Conduct a site inspection related to the existing servicing infrastructure and trench drain system. Determine possible causes of sewer back-ups into trench drain system and offer possible solutions to correct existing problems.

Building Envelope - facades and curtain wall system, glazing system, exterior sealants, exterior loading docks, doors, stairways, etc.

Roofing - Identify and observe the roof systems (exposed membrane and flashings) including, parapets, slope, drainage, etc. Observe for evidence and/or the need for material repairs, evidence of significant ponding, or evidence of roof leaks.

Interior Elements - common areas including, but not limited to, lobbies, corridors, assembly areas, offices and restrooms. Identify and observe typical finishes for flooring, ceilings, and walls.

Structural Systems - Perform structural design spot checks. Observe the building substructure, building's superstructure and structural framing (floor framing system).

Mechanical Systems - Heating, ventilating and air conditioning systems, plumbing fixtures, exhaust systems and other mechanical systems.

Electrical Systems - Main electrical service, electrical panels, emergency lighting, fire alarm systems and emergency power systems.

Written Report - Subsequent to the visual inspection, prepare a comprehensive list of deficiencies and provide photo evidence of such deficiencies. A estimated budget cost to be associated with any corrective work required over a 5-10 year period.

Opinions of Probable Costs - are to be prepared for the suggested remedy of the material physical deficiencies observed. These opinions of probable costs are to assist the client in developing a general understanding of the physical condition of the subject property.

Opinions of probable costs are provided for material physical deficiencies and not for repairs or improvements that could be classified as: (1) cosmetic or decorative; (2) part or parcel of a building renovation program or tenant improvements/finishes; (3) enhancements to reposition the subject property in the marketplace; (4) for warranty transfer purposes; or a combination thereof.

Opinions of probable costs should only be construed as preliminary budgets. Actual costs may vary from the consultant's opinions of probable costs depending on such matters as type and design of suggested remedy, quality of materials and installation, manufacturer and type of equipment or system selected, field conditions, whether a physical deficiency is repaired or replaced in whole, phasing of the work (if applicable), quality of contractor, quality of project management exercised, market conditions, and whether competitive pricing is solicited.

1.3 Exclusions to Scope of Work

Providing an environmental assessment or opinion on the presence of any environmental issues such as asbestos, hazardous wastes, toxic materials, the location and presence of designated substances or mould.

Preparing engineering calculations (civil, structural, mechanical, electrical, etc.) to determine any system's, component's, or equipment's adequacy or compliance with any specific or commonly accepted design requirements or preparing designs or specifications to remedy any physical deficiency.

1.4 Conventions Used in this Report

GOOD - Indicates the component is functionally consistent with its original purpose but may show signs of normal wear and tear and deterioration.

FAIR - Indicates the component will probably require repair or replacement anytime within five years.

POOR - Indicates the component will need repair or replacement now or in the very near future.

MAJOR CONCERNS - A system or component that is considered significantly deficient or is unsafe and in need of prompt attention.

1.5 Documents Provided

The documents made available to the consultants by Essex Powerlines to assist in the preparations of this report are as follows:

- Architectural Drawings by Sfera Architectural Associates Inc. dated March 16, 2012

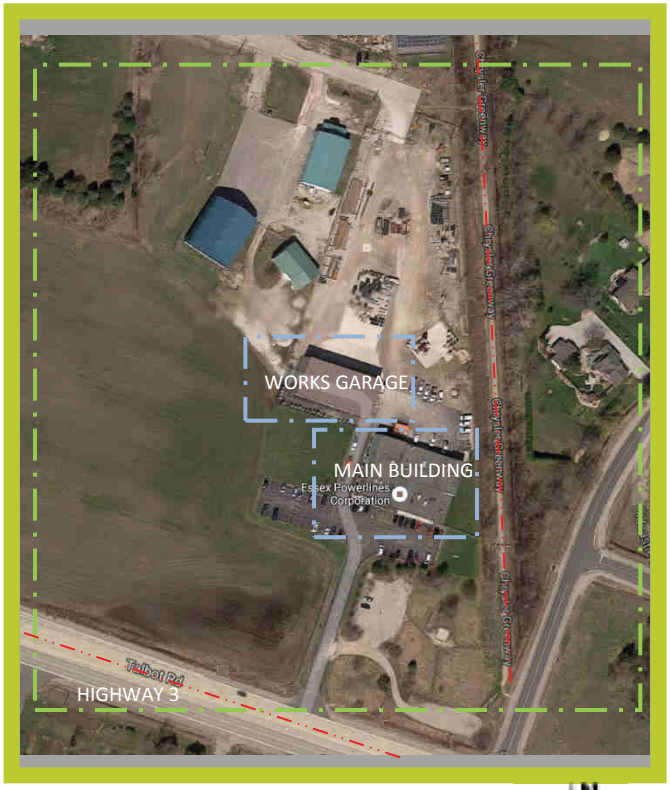
1.6 Interview of Associated Persons

At various time through during the site visit on September 7, 2015. Mr. Brandon Chartier was made available to provide information regarding history of work on premises.

1.7 Project Site & Building History

The project site is located on the North side of Highway 3 in Oldcastle, Ontario. The site neighbors teh Chrysler Greenway to the east and agricultural land to west. The site has three (2) main structures, the main office facility, and works garage.

The Main Office building is a partial 2 storey facility and has been added numerous time. The facility was converted from the old Tecumseh fire hall. Major renovations were completed in 2012 along with the construction of the Works garage. The training room was renovated in 2016.



1.8 Building Description | Data

Main Office

- First floor contains admin space, warehouse space and staff areas
- Second floor contains Administrative office areas
- The facility is constructed of masonry load bearing walls and structural steel roof system.

Building Areas

Main Floor	1,365 m²
Second Floor	400 m²
Total	1,765 m²

OBC Classification

Group D - Office
Group F Division 3 Warehouse

Works Garage

- Constructed in 2012
- 1 single storey, slab on grade construction containing truck storage garage. The facility was constructed as a Pre-Eng building with concrete block infill.

Building Areas

Total 618 m2

OBC Classification

Group F Division 2 - Garage

1.9 Site Survey Date & Conditions.

ROA Studio, along with consultants, visited the site on September 7, 2016. Temperatures ranged from 32°C as a high to 23°C. While on site, it was mostly sunny skies.

SECTION 2 BUILDING SURVEY

2.1.1 Site

Description
This section will review the exterior site work including sidewalks, pavement, drainage, and parking systems in general.

Sidewalks	☑ Good	☐ fair	☐ Poor
Asphalt pavement Front	☐ Good	☐ fair	☑ Poor
Asphalt pavement Back Lot	☑ Good	☐ fair	☐ Poor
Curbing	☐ Good	☑ fair	☐ Poor
Drainage	☐ Good	☐ fair	☑ Poor

General Comments
The overall site condition was reviewed to the south of the building (front parking lot) and along the north of the building to the edge of the asphalt within the service yard. A review of the pavement around the pre-engineered storage building was also undertaken. The current configuration provides parking for staff and visitors to the south of the building with a driveway access extending to Highway 3 to the north. Currently, this parking area is abutted on most sides by concrete curb, changing to parking bumpers along the easterly limit. Extending to the north, along the west side of the building is a service access way (paved) which provides gated access to the rear (north) service yard. Within the service yard, asphalt pavement is provided around the pre-engineered storage building and for a distance to the north of the main administration building. Areas north of the edge of the asphalt are granular and were not evaluated

Specific to the south parking lot (front of building), the current pavement structure is viewed as being at the extent of its service life. The current pavement is cracked significantly with the presence of vegetation growing up between these cracks. Where present, the existing catch basin system has settled. With regard to the curbs, several cracks and areas of damage were identified. While not at a point that mandates full replacement at this time, consideration should be given to their replacement during re-pavement especially if consideration is given to upgrading the storm water management system.

With regard to the sidewalks along the front (south) of the building, while limited in overall footprint the only notable issue related to its separation from the pavement could be addressed during asphalt work.

In reviewing the paved area to the north of the building, its overall condition is poor. At some point during its service life a trench has been cut into the pavement along the east edge. This repair appears to be extending to a pump chamber. Much like the front parking area, the pavement is cracked and in need of full replacement. It is important to note a settled catch basin in the south-east corner of this service parking area. This catch basin has settled to such a point it now possess a fall/tripping risk due to its sudden elevation change.

Recommendations | Observations

- It is recommended that all asphalt pavements (north and South) be removed inclusive of the granular layer and reconstructed to ensure maximum design life.
- It is recommended that the site drainage be upgraded to ensure maximum longevity of the pavement structure
- Should the storm water management strategy require the curb, it can be replaced, otherwise local repairs should be made during any new construction activities.

Opinion of Probable Cost
Allow $397,000 for Pavement Replacement
Allow $65,000 for storm water system upgrades
Allow $15,000 for local curb repair

Images

Catch Basin
Location: South Parking Area

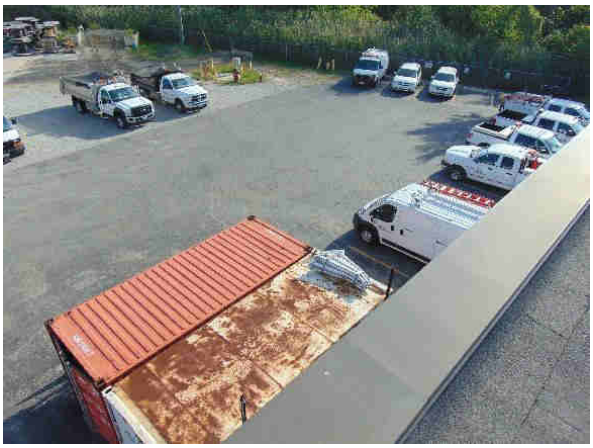
Asphalt to Sidewalk interface
Location: Main Entrance

Images

Catch Basin Settlement
Location: North Service Area

View of South-West Parking Lot

View of South-East Parking Lot



North Service Area facing East

2.2.1 Building Exterior

Description
This section reviews the exterior cladding including wall coverings, eaves, soffits and flashings.

Masonry Block	☐ Good	☑ fair	☐ Poor
Pre-fin Metal Siding	☐ Good	☑ fair	☐ Poor
EIFS	☑ Good	☐ fair	☐ Poor
Sealants & Caulking	☑ Good	☐ fair	☐ Poor
Works Garage	☑ Good	☐ fair	☐ Poor

General Comments
The exterior of the building is in generally good condition. Area of concern is along the west and south facade where there appears to be moisture in the masonry units. Recommendation would be to clean and monitor block for suture discoloring. The pre-fin metal siding is in fair condition. The Exterior Insulation Finish System (EIFS) is in good condition with no visible signs of damage. The works Garage is in good condition.

Recommendations | Observations

- Possible moisture intrusion into the masonry block in various locations.
- Asphalt is paved above Metal Siding
- Grade is above Metal Siding,
- A penetration is not sealed in Storage room (Interior side)

Opinion of Probable Cost

Allow $3,000 to clean and monitor Masonry Block

Images

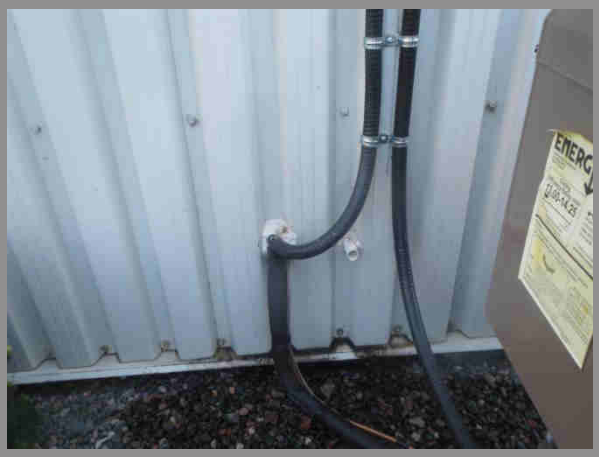
Monitor: Possible moisture intrusion
Location: Front Entrance

Monitor: Possible moisture intrusion
Location: Southwest Wall

Sample: Metal Siding, EFIS and Masonry Facade
Location: Looking at Main Entrance

Images

Repair: Abandoned penetration not sealed
Location: Inventory Storage Room



Repair: Penetrations Sealed at HVAC Equipment
Location: West Wall

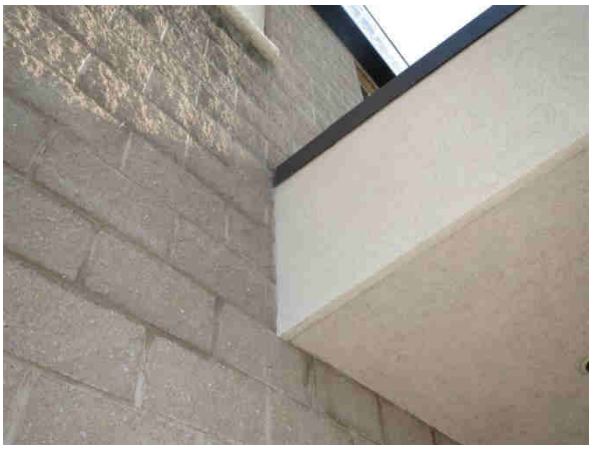
Repair: Minor holes in Masonry
Location: West Wall

Sample: South Façade, EFIS and Masonry
Location: South Facade

Sample: Caulking at Metal Siding | Masonry
Location: West Wall

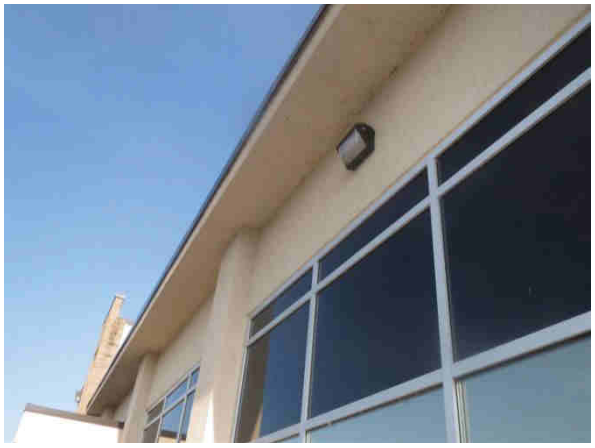
Sample Metal Siding
Location: West Wall

Images



Sample: EFIS and Masonry Joint
Location: Main Entrance

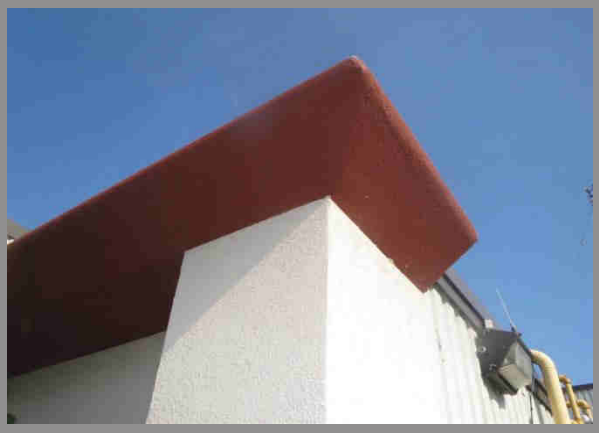
Sample: Masonry Pier | Sidewalk
Location: South Wall



Sample: EFIS in good condition
Location: South Wall

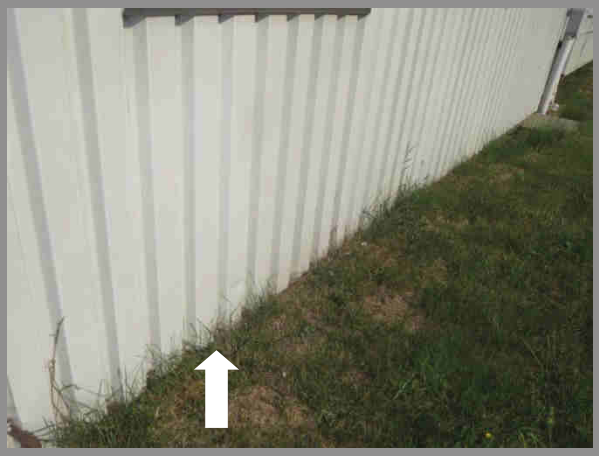
Sample: EFIS in good condition
Location: South Wall

Sample: EFIS in good condition
Location: South Wall



Sample: EFIS in good condition
Location: South Wall

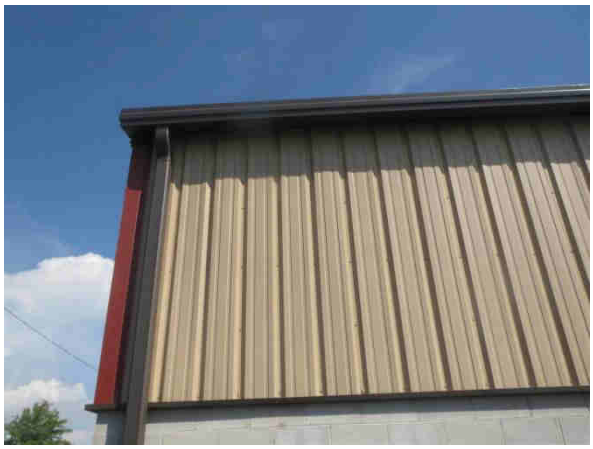
Images



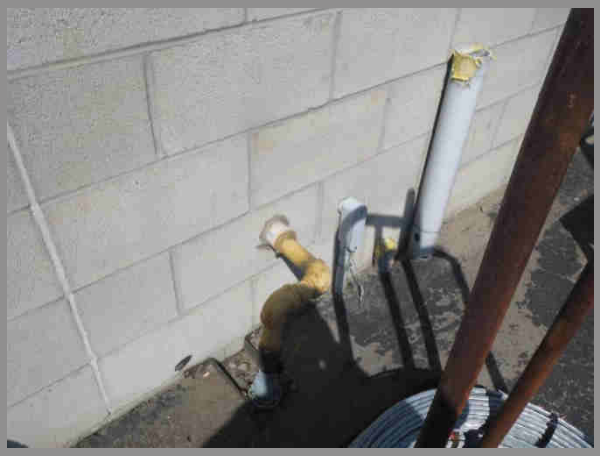
Repair: Grade over Metal Siding
Location: Outside Training Room

Repair: Asphalt over Metal Siding
Location: outside Meter Shop

Front View of Works Garage
Location: Works Garage



Sample: Siding in good Condition
Location: Works Garage



Sample: Penetration sealed
Location: Works Garage

Sample: Conc. Block, Louver
Location: Works Garage

2.2.2 Windows | Exterior Doors

Description
This section reviews current state of the windows and doors in the buildings. This includes a visual inspection of the frames, sealing, glazing and hardware.

Window Frames	☑ Good	☐ fair	☐ Poor
Glazing	☑ Good	☐ fair	☐ Poor
Door & Frames	☑ Good	☐ fair	☐ Poor
Over Head Door & Frames	☐ Good	☑ fair	☐ Poor
Sealants | caulking	☐ Good	☑ fair	☐ Poor

General Comments
The main building has all new aluminum frames and glazing. The majority of the frames and thermal units were installed in 2012 and most recently 2016 in the Training room. The frames and glazing are generally in good condition. 2 window's gaskets are failing on the west wall (in a Private offices) and a window in a second floor office show water damage.

The Exterior doors are a mix of hollow metal and aluminum entrance framing. The shipping and receiving door on the west wall has damaged weatherstripping and does not close properly. Weatherstripping should be replaced. The frames at Stair No. 3 and Stair to gym are starting to rust at the bottom frame.

The Overhead doors were installed about 20 years ago however are in fair working order and condition. There is minor rusting on the steel frame at the inventory storage door. Regular maintenance is recommended to extend the life of the doors.

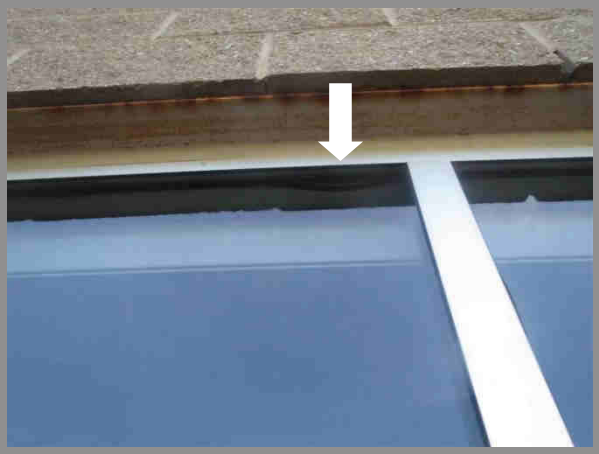
The Caulking in and sealants are in fair shape. The caulking at the southwest corner windows has or starting to fail. There is no caulking around the employee entrance door.

Recommendations | Observations
- Overhead Door Jamb rusting - monitor.
- Door Frames rusting on north wall. Items consider in poor condition.
- Shipping | Receiving weatherstripping damaged.
- 2 Window units need gaskets repaired | replaced
- 1 Window on Second floor shows signs of leaking
- Sealant | caulking around doors & windows starting to deteriorate.
- Works Garage Metal Frames are not sized for Opening. Potential for water infiltration – Monitor.

Opinion of Probable Cost
Allow $6,000 for new caulking | sealants
Allow $8,500 for new door and frames and new weatherstriping

Images

Repair: Caulking failing
Location: Southwest Wall



Repair: Gasket Failing and lintel rusting
Location: west Wall

Repair: Window Leaking
Location: Second Floor Office

Images

Sample: Window and Caulking in Good shape
Location: Southwest Wall

Sample: Window and Flashing in good condition
Location: west Wall of Main Building

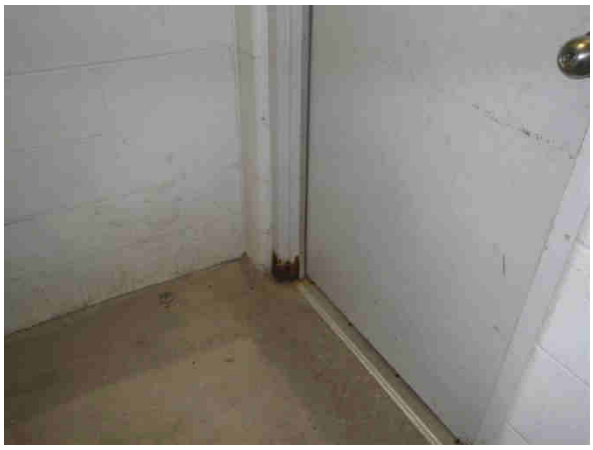
Repair: Weatherstripping missing
Location: Shipping & Receiving

Sample: New window at Training Room
Location: New Training Room

Repair: Weatherstripping Damaged
Location: Shipping & Receiving

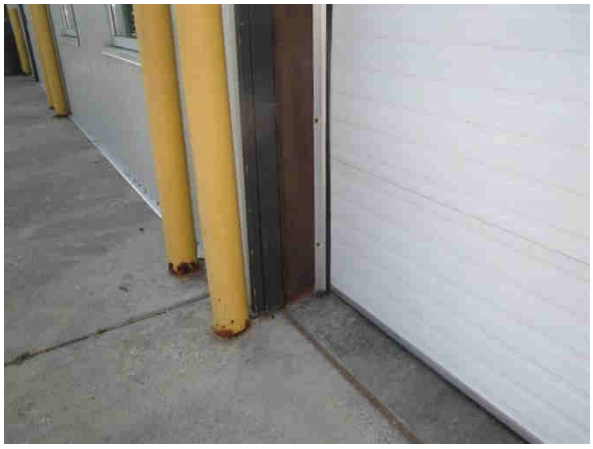
Repair: No Caulking around door frame
Location: Employee Entrance

Images



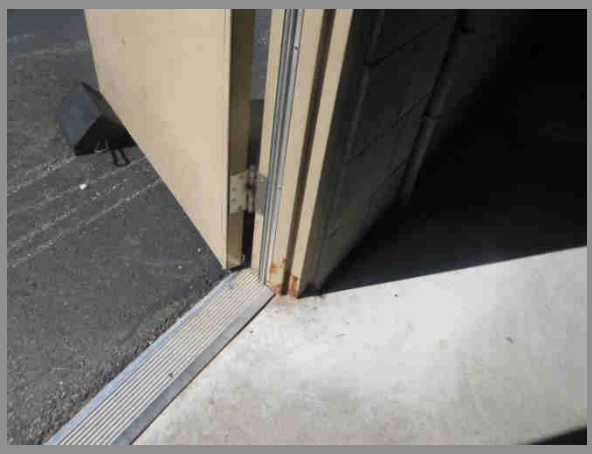
Repair: Door Frame starting to rust
Location: Stair No 3

Repair: Frame does not suit masonry opening
Location: Works Garage

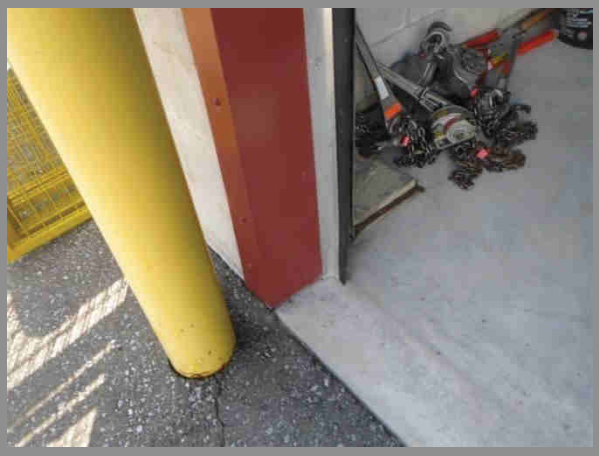


Repair: Rust at overhead doors
Location: Inventory door (No. 5)

Repair: Door Frame starting to rust
Location: Stair by Gym



Repair: Door Frame rusting – frame does not fit masonry opening
Location: Works Garage



Weatherstripping in good condition
Location: Works Garage

2.2.3 Roofing | Skylights

Description
This section reviews current state of roofing including the roofing material, parapets and drainage.

Mod-Bit Roof	☐ Good	☑ fair	☐ Poor
Roof Hatch	☐ Good	☐ fair	☑ Poor
Parapets	☑ Good	☐ fair	☐ Poor
Roof Drains	☑ Good	☐ fair	☐ Poor
Skylights	☐ Good	☑ fair	☐ Poor

General Comments - Main Office

The roof system is a mob-bit roofing membrane. The roof is in fair condition with some cracking of the top surface starting to show. The roof has a few areas where there it is starting to bubble. The roof may need to be replaced in the next 5 to 7 years. The roof hatch is in poor condition at requires immediate attention. The original roof hatch was damaged and a makeshift cover was installed without proper handle and opening | hold open hardware. This is a safety concern. The parapets are in good condition with no signs of leaking or damage. The roof drains are in good working order. The skylights are older but do not show signs of leaking. Flashing of high wall showing oxidization, requires painting or to be replaced.

Recommendations | Observations

- Roof membrane showing age | cracks
- Roof Drains clear and appear working
- Few visual sign of leaks in building. Staff indicated no roof leaks present.
- Skylights did not show evidence of leaking.
- Counter flashing at High wall starting to rust

General Comments - Works Garage

The roof of the works garage addition was inaccessible, visually inspected from Main Office. Sloped Steel roof in good condition.

Opinion of Probable Cost

<u>Immediate Actions</u>	
New roof Hatch	$5,000.00
Paint | Replace Flashing at High Wall	$4,000.00
<u>Within 5-7 years</u>	
New roof	$220,000.00

Images

Roof Hatch
Location: Over second Storey Office

Roof starting to Bubble
Location: One Storey Office Area - By Training Room

Roof inFair Condition – Cracking on surface
Location: Over Second Floor Office

Images

Roof Drain Clear – Small Ponding
Location: Over Second Floor Office

Roof Drain Clear – small ponding
Location: Over Meter Bay

Exhaust fan c\w new seals on curbing
Location: Over First Floor Office Area

Skylight
Location: Over Second Floor Office

Rusted Counter Flashing at High Wall Transition
Location: At Meter Shop – Office

Pitched metal roof
Location: Works Garage

2.3.1 Interior Finishes

Description
This section reviews the current state of interior finishes including ceilings, walls, flooring and interior doors.

Flooring	☑ Good	☐ fair	☐ Poor
Ceilings	☐ Good	☑ fair	☐ Poor
Doors	☑ Good	☐ fair	☐ Poor
Walls	☑ Good	☐ fair	☐ Poor

General Comments - Main Office

As an overview, the interior finishes of the building are in good condition. The office space has been renovated throughout the building approximately 4 years ago. The flooring is a carpet, and sheet flooring for the office, concrete for the warehouse and ceramic tile in the washrooms. The walls consist stud partitions and some demountable walls in the office areas while the warehouse space is concrete block. The floors are relatively level and the walls are relatively plumb. The ceilings are comprised of suspended acoustical ceiling systems with some minor staining. The doors are in good condition and the barrier free door operators are in working condition. Office Washrooms have been renovated in the past few year and are in good condition. The shower room ceiling is paint on precast concrete planks, the paint is peeling significantly in this area.

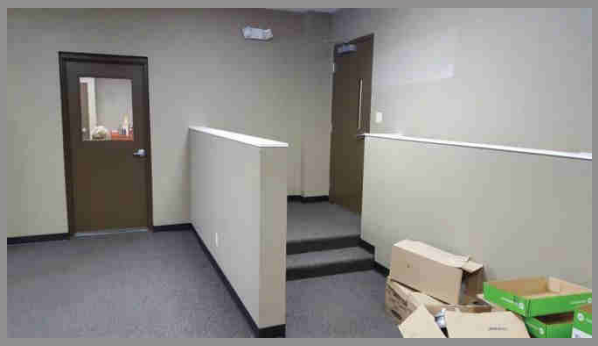
The interior finishes of the works garage are in good condition.

Recommendations | Observations

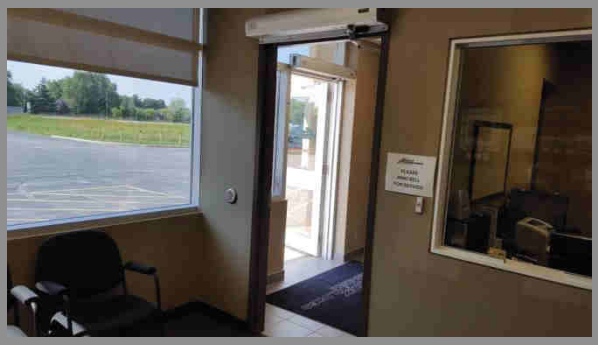
- Finishes are in good condition (recently renovated)
- Some Ceiling tiles to be replaced due to water damage
- Monitor for Roof Leaks at Damaged Ceiling Tiles
- Ceiling paint in Men's Change Room and Shower in poor condition
- Penetrations in Mechanical room not Fire Caulked
- Works Garage in good Condition

Opinion of Probable Cost
Allow $500 for ceiling Tile Replacement
Allow $3000 to scrape and paint change room | shower ceiling
Allow $500 for misc Fire Caulking

Images



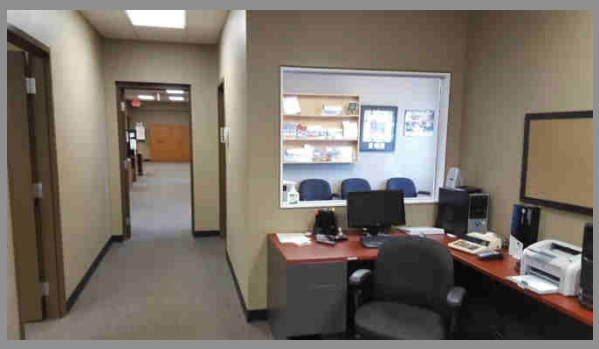
Sample: Doors, Walls and carpet in good condition
Location: Front Open Office



Door Operator In working Condition
Location: Customer Entrance

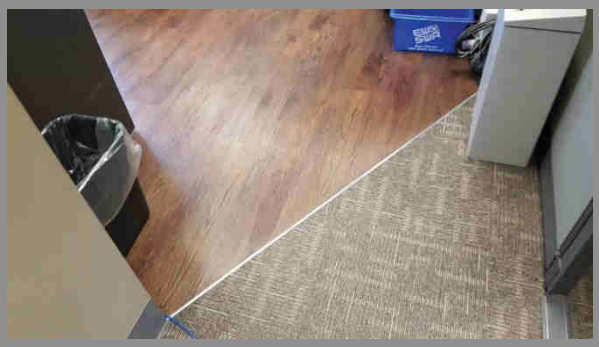
Penetration not fire caulked.
Location: Mechanical Room

Images



Sample: Flooring, Walls, in good condition
Location: Reception

Sample: Floor level Transition
Location: Stair No. 1



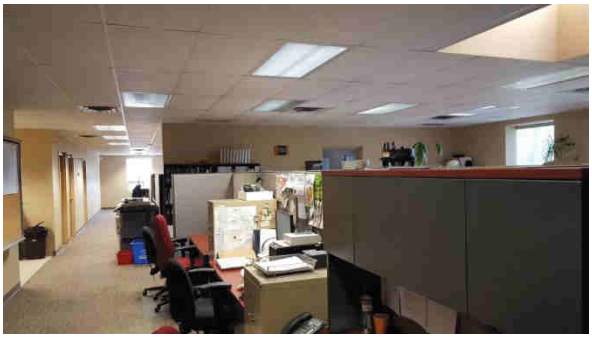
Sample: Floor transition in good condition
Location: First Floor Open Office

Sample: flooring in good condition
Location: First Floor Open Office Area

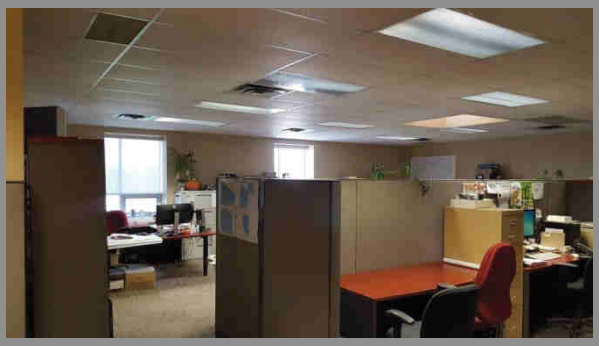
Sample: Demountable partition in good condition.
Location: Second Floor Office

Sample: Block Walls and Concrete floor in good condition.
Location: Stores

Images



Sample: Interior Finishes in good condition
Location: Second Floor Office Area



Sample: Interior Finishes in good condition
Location: Second Floor Office Area

Ceiling tiles water damage
Location: Office Space

Sample: Ceiling tiles water damage
Location: 1 storey First Floor

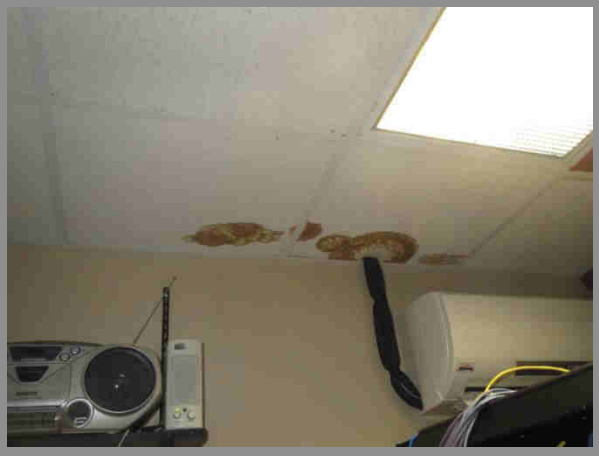
Concrete slab in good condition
Location: Truck Bay

Sample- Cleanout missing cap – trip hazard
Location: First Floor Kitchen

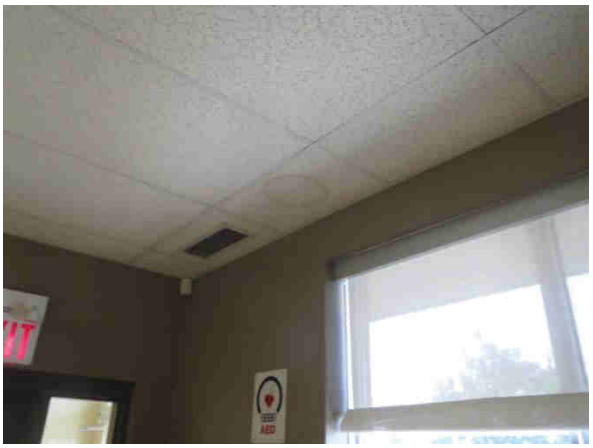
Images

Partition Damaged due to plumbing repair
Location: Office -Men's Washroom

Repair: Paint peeling
Location: Men's Shower | Change Room



Sample- Ceiling tile damaged (condensation from HVAC Equipment)
Location: Second Floor Communication Room



Repair: Water damaged ceiling tiles
Location: Second Floor

Repair: Paint peeling
Location: Men's Shower | Change Room

Sample: Interior
Location: Works Garage

2.4.1 Structural Elements

Description
This section will review the overall structural condition of the building based on a visual inspection

Framing Elements	☑ Good	☐ fair	☐ Poor
Masonry	☐ Good	☑ fair	☐ Poor
Exterior Facade	☑ Good	☐ fair	☐ Poor
Misc Metals	☐ Good	☑ fair	☐ Poor
Decking	☑ Good	☐ fair	☐ Poor

General Comments - Main Office

The current site contains two buildings which were reviewed, specifically the main building (administration) and a detached pre-engineered storage building to the west of the main building. The following will outline the observations made for each building.

While reviewing the pre-engineered building, it was noted that this building is relatively new in its construction and does not exhibit any structural defects. It was noted that there is no floor drainage which could allow for winter time icing which could damage the concrete surface.

The main administrative building is made up of various phases of construction. In general each phase demonstrates itself to be in good to fair condition. Only minor issues in general were observed overall while touring this building. The construction of the building was a combination of masonry, steel and precast systems to form the single storey and the two storey portion to the building. Each of the main gravity and lateral loading components appeared to be in good condition with no visible signs of distress.

The Works Garage was in good condition.

While touring the administrative building the following minor defects were observed:

- Various hairline cracks were observed within the masonry joints.
- Within the north stairwell to the second floor area it was noted that the masonry wall (west) has sheared likely due to the movement of the roof diaphragm. The specific cause of this appears to be during construction the masonry was placed tight to the roof framing preventing free movement.
- At the second floor landing of the north stairwell the concrete fill at the precast core has broken free and can be freely moved by hand.
- Roof ladders have signs of rusting on their connection to the building structure.
- Within the maintenance bay at the north end of the building a chain fall has been secured to the center roof beam. There is no markings or signage on the beam to indicate that it has been rated for this additional load.
- Within the storage area located at the north end of the building, interior masonry walls extended from the second floor to the roof within the high bay area of the storage area appear to be missing any form of lateral connection to the roof deck.
- Around the exterior of the building, various cracks in the masonry façade were observed.
- At the second floor mezzanine, a door opens to the service garage area. Currently on the garage side wood framing is used to create a railing system to prevent falls. However, in its current condition it is unable to support the loads required of a guard.

Recommendations and Observations

- It is recommended that all existing cracks in the masonry, inclusive of those in the façade be monitored on a regular basis. Should the cracks worsen, a licensed Professional Engineer should re-evaluate the condition and recommend any repairs deemed appropriate.
- All roof ladders should be painted as part of the maintenance protocol for the building to ensure longevity.
- The crack in the wall at the north stairwell should be remediated immediately, with mortar around the cross-bracing and joist being cut back to avoid reoccurrence.
- The loose fill in the hollow core plank at the north stairwell should be removed and replaced with new when maintenance staff can address this issue.
- A detailed review of the lateral connection of all walls should be undertaken with use of lifts as required to access the areas noted.
- The railing system present at the mezzanine doors should be replaced with a system able to carry the loads or the doors should be permanently sealed.
- The chain fall in the service garage should be removed until the beam is analyzed and certified by a licensed Professional Engineer for the additional load.

Opinion of Probable Cost
Allow $10,000 Engineering Services
Note: Miscellaneous repairs per maintenance staff value undefined.

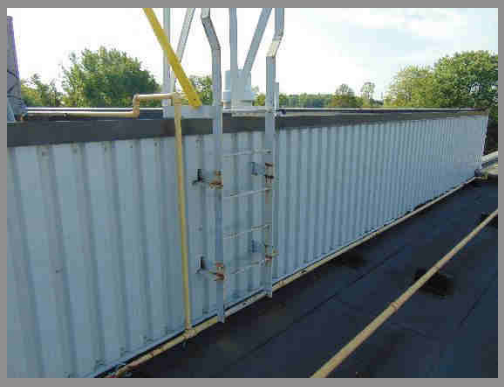
Images

Cracking in Exterior Facade
Location: South Wall

Cracking in Wall
Location: North Stairwell

Possible Lateral stability issue
Location: Storage Area

Cracking in Wall
Location: North Stairwell



Typical Roof Ladder
Location: Roof

2.5.1 Fire Protection

Description
This section reviews Fire Protection related systems, including sprinkler, standpipe and fire extinguishers.

Fire Extinguishers	☑ Good	☐ fair	☐ Poor

General Comments - Main Office

The building is not sprinklered nor does it have a standpipe system with fire hose cabinets.

There are fire extinguishers installed throughout the building. Fire extinguishers are ABC dry chemical type, 10lb and are well marked and appropriate for the areas they serve. Inspection tags were attached to each extinguisher.

Recommendations | Observations
No Comment

Opinion of Probable Cost
No Comment

2.5.2 Plumbing - General

Description
This section reviews general plumbing systems including plumbing fixtures.

Plumbing Systems	☑ Good	☐ fair	☐ Poor

General Comments

The existing plumbing systems appear to be in good condition reflective of the age of the building. The water distribution is primarily copper with some PEX piping added recently to service a new sink in the Board Room.

There is a variety of plumbing fixtures throughout the building and appear in good condition. Water closets are floor mounted, tank type, urinals are wall mounted flush valve type.

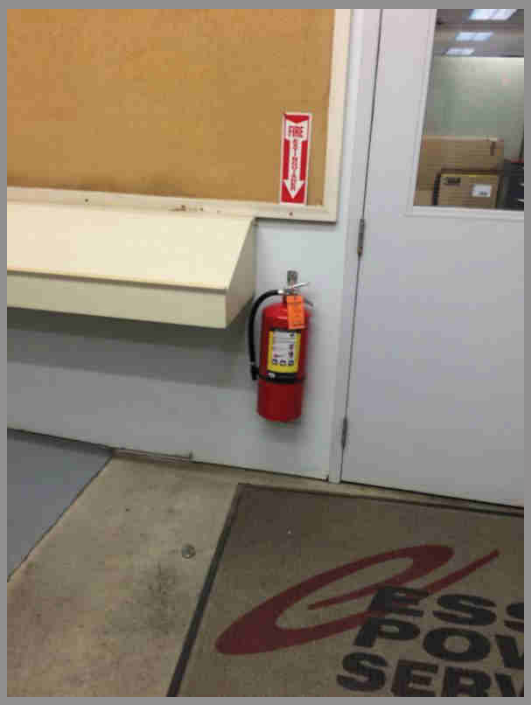
The lavatories are wall or counter mounted and there are counter mounted stainless steel sinks in local kitchenettes.

Recommendations | Observations

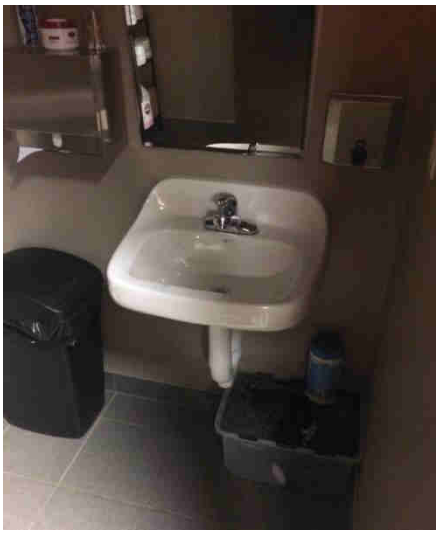
- The fixtures are not low flow consumption nor are they accessible for barrier free standards.
- Hot and cold water line are insulated and some minor repairs to insulation is recommended.
- The plumbing systems are in good working condition.

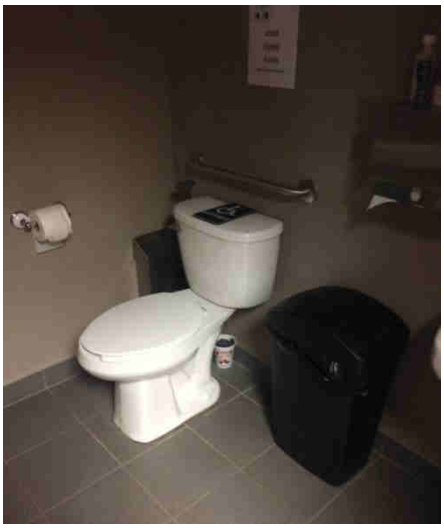
Opinion of Probable Cost
No Comment

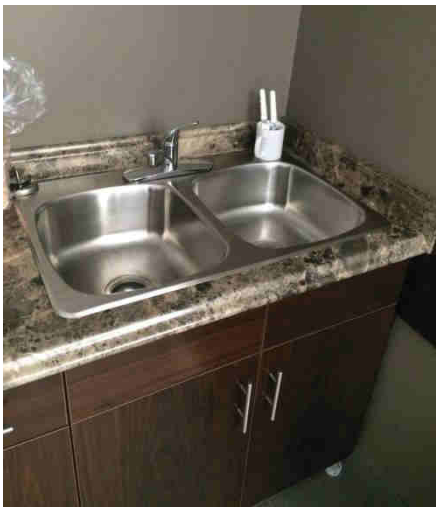
Images



Images







2.5.3 Plumbing | Domestic Water

Description
This section reviews Domestic Water related systems, including Domestic Cold Water, Domestic Hot Water and Domestic Hot Water Re-Circulation systems.

Dom. Cold Water	☑ Good	☐ fair	☐ Poor
Dom. Hot Water	☑ Good	☐ fair	☐ Poor
Dom. HW Re-Circ	☑ Good	☐ fair	☐ Poor

General Comments - Main Office

Incoming water service is 1-¼" diameter and enters the building at the Mechanical/Electrical Room.

The 1-1/4" service is complete with shutoff valve, water meter and backflow preventer.

Water is distributed to the hot water heater, plumbing fixtures and hose bibbs.
Cold water is extended to the separate Garage Building. Water piping throughout the building is copper with one fixture served by PEX piping. Water piping has a life expectancy of 35 to 40 years.

Domestic hot water supply is provided by a conventional gas fired hot water heater which appears to have been in service for some time. The heater is A.O. Smith Model BTR-120 with 71 gallons of storage.

Recommendations | Observations
- The water heater may require replacing in the next two to four years.

Opinion of Probable Cost
No Comment

2.5.4 Sanitary Drainage System

Description
This section reviews Sanitary Drainage systems

Sanitary System	☑ Good	☐ fair	☐ Poor

General Comments - Main Office

Sanitary and vent piping is a mix of cast iron, copper & small portions of PVC piping. It appears to be mainly original piping with small amounts of new piping in areas where washrooms were renovated and where new fixtures have been added. Sanitary systems appear to be gravity fed with a sanitary lift pump serving new sink in training room.

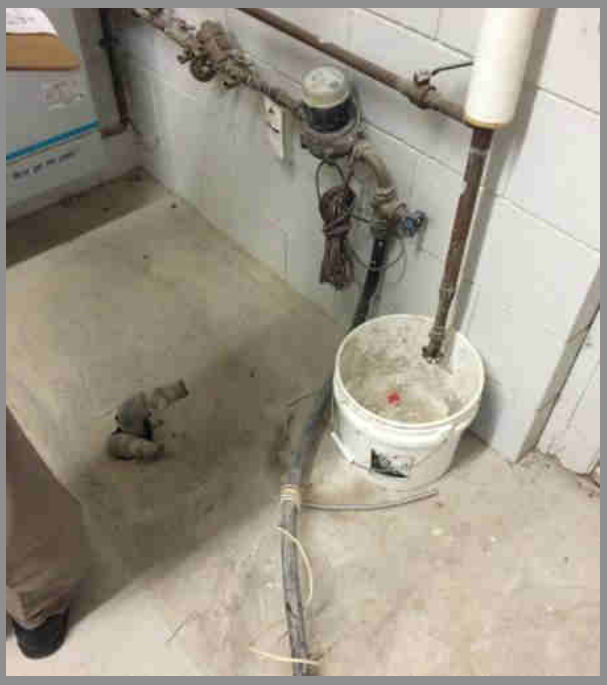
Underground sanitary piping condition is hard to evaluate. Typically, an estimate of 35-40 year replacement life is found to be acceptable with buildings of this type. Through our discussions with the maintenance staff it appears there has not been any reported back-ups in the system.

Original building included a septic system and this has been replaced by connection to municipal sanitary sewer. It is unclear were the sanitary leaves the building or the size of the piping.

Recommendations | Observations
No Comment

Opinion of Probable Cost
No Comment

Images



2.5.5 Storm Drainage System

Description
This section reviews Storm Drainage systems

Storm Systems ☑ Good ☐ fair ☐ Poor

General Comments - Main Office

The building is primarily drained with the use of roof drains and scuppers which are piped to rain water leader inside the building. The storm piping is mostly concealed so condition could not be assessed.

The storm water from office area is discharged to underground storage tank and is pumped to nearby creek.

Maintenance staff report that this is in good working order.

Recommendations | Observations
No Comment

Opinion of Probable Cost
No Comment

2.5.6 Gas Service

Description
This section reviews Gas Service and distribution.

Gas Systems ☑ Good ☐ fair ☐ Poor

General Comments - Main Office

The building is provided with an outdoor gas pressure regulating station with gas meter which is located on the South-East corner of the building adjacent to Highway 3. Pressure is currently being reduced down to 7" to 14 W.C. and is distributed with dedicated branch lines to the mechanical room and to the roof.

Three gas lines rise from the manifold to the roof of the building where the distribution piping is located.

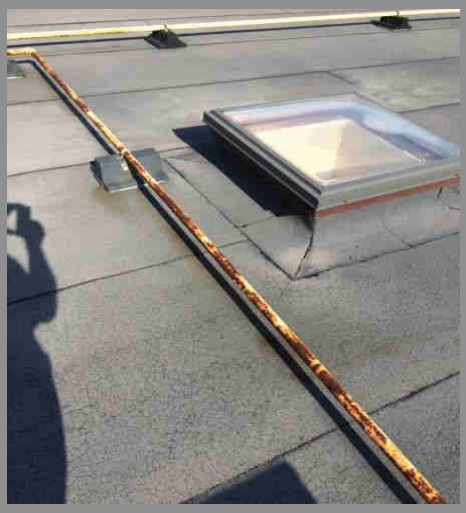
Gas piping is either threaded or welded depending on the pipe size.
Gas is distributed to all roof mounted HVAC units, water heater, gas fired unit heaters located inside the building. In addition to the original piping system a newer dedicated gas line feeds the new garage building.

In general, the original gas piping has come deterioration of the yellow paint identification.

Recommendations | Observations
- Paint gas piping

Opinion of Probable Cost
Allow $1,000.00 for gas line painting

Images



2.6.1 Heating Ventilating and Air Conditioning

Description

Roof Top Units	☐ Good	☑ fair	☐ Poor
Controls	☑ Good	☐ fair	☐ Poor
Split Systems	☑ Good	☐ fair	☐ Poor
Exhaust Fans	☑ Good	☐ fair	☐ Poor

General Comments

The office building is served by roof mounted packaged, gas fired HVAC units of various manufacturers and ages.

The conditioned air is distributed to the occupied areas served and is introduced to the conditioned space through ceiling mounted diffusers. Return grilles, also ceiling mounted transfer room air into the ceiling space which is utilized as a return air plenum.

A split HVAC system consisting of a fan coil unit and condensing unit mounted on grade serve the Inventory Storage Area. A second split system serves the computer/I.T. Room.

All roof mounted units and split system are controlled through local master thermostats.

The renovated ground floor has further sub zoning thermostats controlling local motorized volume dampers.

Unconditioned Meter Repair Room is heated and ventilated by gas fired unit heaters, roof ventilators and ante-stratification paddle fans.

Electric cabinet heaters are located at entrance vestibules.

Local roof mounted exhaust fans serve washrooms.

The Vehicle Storage Garage is heated and ventilated by gas fired vacuum tube type radiant heaters.

Ventilation consists of two wall mounted propeller fans and related fresh air intakes.

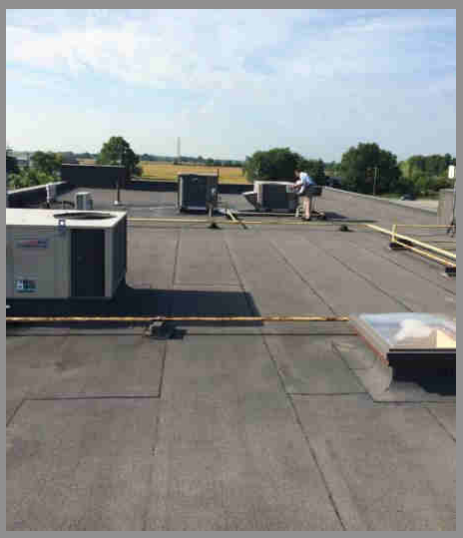
Anti-stratification paddle fans circulate the air within the garage.

<u>Roof Top Units</u>

There are eight roof mounted, packaged gas fired heating, electric cooling units serving the building.

A list of the units with name plate information is provided in Appendix A. The roof plan is schematically drawn to locate approximate location of the units.

Images



The units range in size and capacity according to the requirements of the area served.
As there were no mechanical drawings available we contacted the company who have serviced the equipment

Cardinal Service Group has serviced and replaced units as they became problematic or exceeded their service life cycle.
Cardinal Service Group reported that six units have been replaced and those are in excellent operating condition.

Recommendations | Observations

- Two remaining units need to be replaced within the next budget year.

Opinion of Probable Cost
Allow $18,000.00 to replace two remaining units.

Controls

The building controls are standalone master thermostats controlling each roof top unit.

In the ground floor renovated office area there are local thermostats providing sub-zone temperature control.

The ductwork distribution serving the rooftop units distribute supply air through ceiling mounted diffusers. Return grilles in the ceiling transfer return air fan the occupied space to the ceiling space which is utilized as a return air plenum.

The condensing unit is connected via refrigeration piping to a fan coil filter unit located in the Inventory Storage Area.

Supply air from the fan coil unit is ducted to supply air grilles which area exposed within the room.

A local thermostat controls the cooling.
This equipment is in good working condition.

The Meter Repair Room is not air conditioned. The space is heated by local thermostats.

There are ceiling mounted, anti-stratification paddle fans throughout this space.
Roof mounted gravity ventilators provide summer ventilation.

Recommendations | Observations

- The systems serving the Meter Repair Room are in good operating condition.

Opinion of Probable Cost
No Comment

Images

Split Systems

There are two split systems serving the building. One system serves the I.T. Room. It consists of a room mounted Mr. Slim condenser unit as manufactured by Mitsubishi connected via refrigeration piping to a wall mounted fan coil terminal in the I.T. Room.

The second split system serves the Inventory Storage Area. The condenser unit is located on grade.

York Manufacture
Model YCD60B215A
Serial WIB6352679
Cooling Capacity 60,000 BTUH

The condensing unit is connected via refrigeration piping to a fan coil filter unit located in the Inventory Storage Area.

Supply air from the fan coil unit is ducted to supply air grilles which area exposed within the room.

A local thermostat controls the cooling.
This equipment is in good working condition.

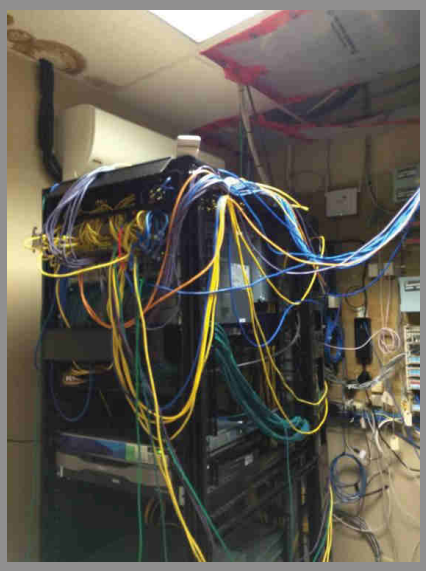
The Meter Repair Room is not air conditioned. The space is heated by local thermostats.

There are ceiling mounted, anti-stratification paddle fans throughout this space.
Roof mounted gravity ventilators provide summer ventilation.

Recommendations | Observations

- The systems serving the Meter Repair Room are in good operating condition.

Images



Exhaust Fans

There are local roof mounted exhaust fans serving washrooms and some general areas, locker rooms etc.

Recommendations | Observations

- Exhaust systems are in good working condition.

Opinion of Probable Cost
No Comment

The Vehicle Storage/Work Garage

The Vehicle Storage/Work Garage is heated by gas fired vacuum tube type radiant heaters.
This is an efficient method of heating large open spaces which have overhead doors.

Ventilation of this area is provided by two sidewall propeller type exhaust fans and related louvered fresh air intake.

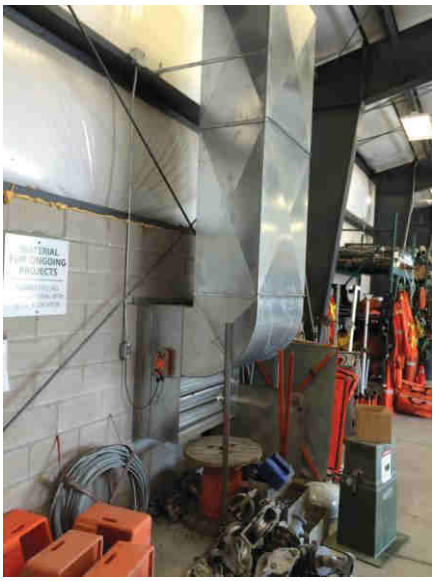
Ceiling mounted anti-stratification paddle fans circulate the air within the Garage.

Recommendations | Observations

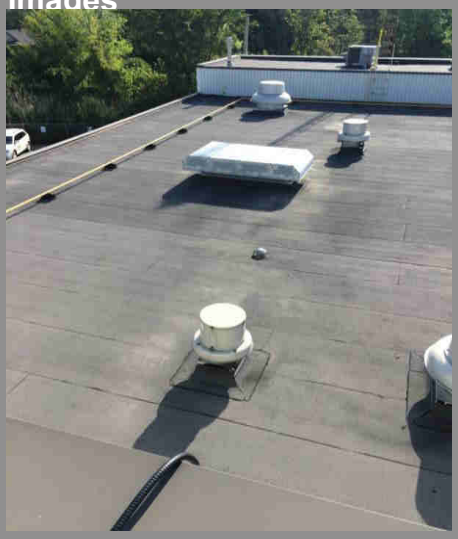
- The building was constructed in 2012 and the mechanical equipment is in good working condition.

Opinion of Probable Cost
No Comment

Images



Images



2.7.1 Electrical Service & Distribution

General Comments

The electrical service to the building comes via an underground feeder from the east side of the building.

The electrical service is rated at 100 Amp, 347/600 Volt, three phase. Revenue metering is provided. The peak demand is not known but since historically there has never been any over load tripping and service breakdown it can safely be assumed the existing is withing the 100A Service capacity.

Service & Distribution	☑ Good	☐ fair	☐ Poor

Recommendations | Observations
The main service equipment consists of a 100A 600 Volts 3 pole 4 wire Siemens Disconnect switch, integrated revenue meter, and a 150A, 600V 3 pole, 4 wire Thompson Technology Automatic Transfer Switch.

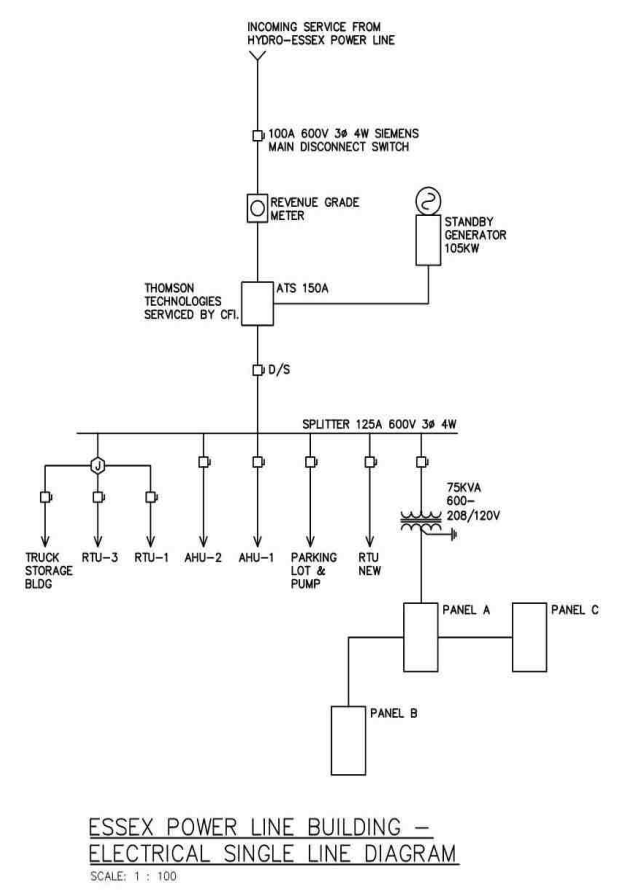
There is a 105 kW (131kVA) Diesel engine driven standby generator set located outside in a weather proof mobile enclosure. The standby power supports the entire building load.

The rest of the distribution is configured through a splitter and multiple fused disconnect switches.

The electrical equipment is generally in good operating condition with no obvious signs or problems such as heating of terminations, excessive corrosion, or rust. Building maintenance personnel reported no overloading or unusual tripping of breakers. Cabling runs also appeared to be in good condition. Only the well pump control panel located remotely outdoors appears to be rusted and needs replacement.

Opinion of Probable Cost
No Comment

Images



2.7.2 Emergency Power

Description
This section reviews the emergency power systems.

Emergency Power	☑ Good	☐ fair	☐ Poor

General Comments

There is a 105 kW (131 kVA), Kohler, 600V, 3 phase diesel engine driven standby generator supporting the entire building load. This unit is in good working condition and is maintained and serviced by CF Industrial, Leamington.

Recommendations | Observations
The generator and the associated 150A Automatic Transfer Switch by Thomson Technologies is expected to support the maximum demand load of the building. The generator is in a weather proof enclosure and is on wheels with a socket-plug arrangement.

Opinion of Probable Cost
No comment

2.7.3 Electrical Room & Generator Room

Description
This section reviews electrical transformers, electrical room equipment and generator room equipment.

Equipment	☑ Good	☐ fair	☐ Poor
Dry Transformers	☑ Good	☐ fair	☐ Poor

General Comments
The main Electrical Room is to be provided with 1-hour fire separation ratings from the remainder of the building. It would be prudent to ascertain this is provided in the existing block walls and steel roof deck.

There are no Motor Control Centres in the facility, however, there are several smaller enclosed magnetic starters provided for the ON-OFF control of fans and pumps which appears to be original equipment.

There are two (2) dry type transformers manufactured by FPE and seem to be in good operating condition and did not feel hot to the touch; which signifies that they are not over loaded.

Wiring is a combination of wire in conduit installations and BX cable installations. Some feeders are TECK cable installation strapped directly to walls and other structural supports

Panelboards are Siemens and generally have spaces available, other smaller ones appear to be fully utilized with little spare circuits except where noted.

Panel A has 19 spaces available (28%).

Panel C has 12 spaces available (18%)

Panelboards in the metering room appear to be new and are utilized for the purpose of testing of meters.

Recommendations | Observations
No Comment

Opinion of Probable Cost
No Comment

Images

2.7.4 Lighting

Description
This section reviews lighting systems

Lighting	☑ Good	☐ fair	☐ Poor

General Comments

Most of the original lighting has been replaced with T8 or T5 linear fluorescent and compact fluorescent in the Main Building and the existing remote garage. Generally, the lighting level is good between 400-600 lux in offices and general circulation areas. Where the lighting level is less it was at the preference of the users of the spaces.

There are a few fluorescent fixtures with small cell egg crate diffusers. These appear to be old and do not allow regular cleaning, therefore are recommended for replacement.

There are a few (six only) building mounted Metal Halide fixtures which are not as efficient as the new LED sourced fixtures. These fixtures must be replaced.

Recommendations | Observations
No Comments

Opinion of Probable Cost
No Comments

2.7.5 Emergency Lighting

Description
This section reviews Emergency lighting systems

Emergency Lighting	☑ Good	☐ fair	☐ Poor

General Comments

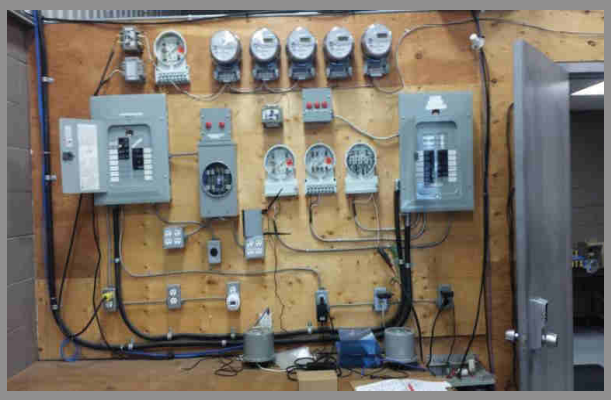
The entire building lighting is supported by standby power generator. This more than meets the standards.

Exit sign lighting is present and these are Red LED sign lights. Emergency battery operated lighting is also present in the Electrical room and I.T. Room in conformance with the code. Exit sign lighting is of the RED EXIT fixture which is no longer in conformance with the current code, where the green running man pictograph is required.

Recommendations | Observations
No Comments

Opinion of Probable Cost
No Comments

Images



2.7.6 Fire Alarm System

Description
This section reviews fire alarm systems

Fire Alarm ☑ Good ☐ fair ☐ Poor

General Comments

Fire Alarm System is not required for this facility, however there are smoke and heat detectors installed at selected location and rooms and connected to security systems. There are horns to sound when smoke and heat detection initiate FA condition. This system does not conform to Fire Alarm installation code.

Recommendations | Observations
No Comments

Opinion of Probable Cost
No Comments

2.7.7 Security Access and Surveillance System

Description
This section reviews Security Access and Surveillance System

Security System ☑ Good ☐ fair ☐ Poor

General Comments

There appears to be CCTV Cameras and motion detectors networked together to provide a security system for the building. A “terago” Antenna was installed on the roof appeared to be in good condition and installed recently in the life of the building.

Recommendations | Observations
No Comments

Opinion of Probable Cost
No Comments

2.7.8 Storm Water Storage Pump Alarm

Description
This section reviews the Pump Alarms.

Pump Alarm ☑ Good ☐ fair ☐ Poor

General Comments

This is a remote storm water storage with pump control panel outdoors over the well. The control panel enclosure is old and rusted, and is recommended for replacement. There is a pump failure alarm located in the truck storage area.

Recommendations | Observations
No Comments

Opinion of Probable Cost
No Comments

Images

2.7.9 Communications

Description
This section reviews the communication systems.

Communications	☑ Good	☐ fair	☐ Poor

General Comments

Voice and Data: Communication is provided via Cat 6 structural cabling between IT Closets and voice/data drop. Rack and switching equipment belongs to the Owner.

Recommendations | Observations
No Comments

Opinion of Probable Cost
No Comments

2.7.10 Remote Garage

Description
This section reviews the remote Garage doors

Remote Garage	☑ Good	☐ fair	☐ Poor

General Comments

This is a separate building built of steel and insulated and provided with a steel deck roof. This is built to the south of the main building. Being only 10 years old, most of the electrical equipment including lighting appears to be in order. Lighting is high-bay T5 sourced pendant luminaries, providing adequate lighting.

Recommendations | Observations
No Comments

Opinion of Probable Cost
No Comments

2.7.11 Receptacles & Switches

Receptacles & Switches	☑ Good	☐ fair	☐ Poor

General Comments

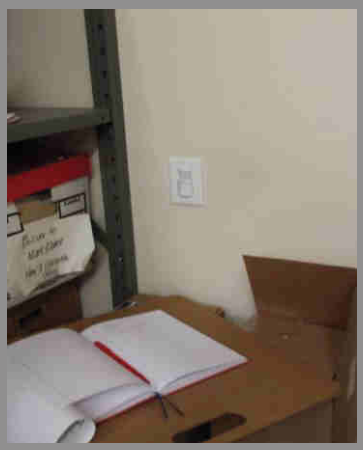
Grounded receptacles are installed throughout the building. Receptacles are recesses with the exception of garage and service rooms. These appear to be sufficient in number as not many power cords extensive were observed on site.

There are manual toggle switches as well as occupancy sensor switches on site. Bulk lighting in garages and truck parking is controlled via manual switches.

Recommendations | Observations
No Comment

Opinion of Probable Cost
No Comment

Images



SECTION 3 Statement of Limitations

3.1 Statement of Limitations

The building condition assessment conducted was a visual assessment only. No physical, destructive testing or measurements of existing building structure were taken during the site visit. No assessment can be made where building structure and elements were either not exposed or easily accessible. Connections, fastenings and anchorage of building structure were not reviewed in detail. Existing structural and architectural drawings were provided for review but may not reflect the actual built construction. Comments and conclusions are therefore based on the visual and/or the apparent physical condition of the building elements. Any design and/or construction deficiencies that are not recorded in this report were not evident given the level of study undertaken.

The costing information presented here has been prepared from the engineers' experience and from past projects of a similar nature. The amount given are opinions only and must not be taken as a guarantee of price. If guaranteed pricing is required then the full scope of work needs to be detailed and appropriate contractor(s) approached for a quotation.

This study is intended for the client named and should not be distributed further without our consent.

SECTION 4 Works Garage Floor Drains

2.8.1 Works Garage - Floor Drains

Description
This section reviews the requirement to have a floor drain for the existing Works Garage Slab.

General Comments

Floor Drains are not required by the Ontario Building Code for the Works Garage. It is good practice to have floor drains due to the use of the facility. The powerline trucks will have snow melt and rain drip onto the floor as well as potential for washing of the vehicles.

Recommendations | Observations

If Client requires | requests floor drains to be installed the following would be recommended.

- (1) Catch basin installed in each bay and piped to exterior of building.
- If washing | repair of vehicles required in bays, an Oil interceptor is required

Opinion of Probable Cost
Allow $55,000.00 for installation of Catch Basins and associated work.
Allow $20,000.00 for installation of Oil interceptor.

Images

APPENDIX 'A'

SECTION 5

Roof Top Unit Schedule

RTU No. 1 On Upper Roof
Carrier 48TFE006-A-111HQ
Serial 4902G10127
Natural Gas / Electric Cooling
Heating
Input 115,000 BTUH
Output 92,000 BTUH
Cooling
48,000 BTUH

RTU No. 2 On Upper Roof
York Model ZXG075SC1AA1A111A2
Serial N1M5169256
Natural Gas / Electric Cooling
Heating
Input 145,000 BTUH
Output 116,000 BTUH
Cooling
72,000 BTUH

RTU No. 3 On Upper Roof
Allied Commercial - No Name Plate
Natural Gas /Electric Cooling Estimated
Capacities 3 to 4 Ton Cooling
65000 to 100,000 BTUH
Input – Heating

RTU No. 4 On Low Roof
Lennox KGA 036S4DMIJ
Serial 5611GO1963
Natural Gas / Electric Cooling
Heating
Input 105,000 BTUH
Output 84,000 BTUH
Cooling
36,000 BTUH

RTU No. 5 On Low Roof
Lennox KGA060S4DH3J
Serial 5612C08673
Natural Gas / Electrical Cooling
Heating
Input 150,000 BTUH
Output 120,000 BTUH
Cooling
59,000 BTUH

Appendix I: Fleet Purchasing Policy

Approved by: Dan Charron P. Eng, Operations Manager	Approval date: Reviewed date: March 3, 2017
Joe Barile, General Manager Reviewed by:	
Brandon Chartier, Facility Operations & Risk Mitigation Supervisor	

I. Purpose

The purpose of this procedure is to describe Essex Powerlines' (EPL) policy with regards to when new vehicle are to be purchased and existing vehicles should be considered for replacement.

II. Scope

This policy applies to all of departments within EPL who use EPL vehicles as part of their assigned work.

III. Responsibilities

1. Risk Mitigation Supervisor is responsible for:
   (a) Filing a current version of this policy
   (b) Periodically reviewing and updating this policy as required.
   (c) Making copies available to any Operational personnel, upon request.
   (d) Disseminating copies to all impacted employees whenever this policy is revised.
2. *Managers* and *Supervisors* of the organization are responsible for:
   (a) Providing input for periodic review of this policy.
   (b) Approving any amendments to this policy.
3. *Senior Management* of the organization is responsible for:
   (a) Ensuring this policy is periodically revised.
   (b) Providing oversight over any and all policy changes.

IV. Process

As of Jan 1st 2017, EPL has a fleet of 23 vehicles that range in age from 1996 to 2016. Of the 23 vehicles, 10 are greater than 4500kgs and 13 are under 4500Kgs
EPL uses the following criteria when a vehicle needs to be replaced, either for sale or replacement.

1. Fleet (Diesel Engines)

   a. Single/Double Truck/RBD Line Truck/Dump Trucks/Service Trucks (all having diesel engines)

- Recorded mileage of 300,000 kilometers and/or more than 15 years of service
- Maintenance costs
- Its usefulness to the organization
- Annual test results (i.e. electrical and stress testing)
- The impact of new technology that may greatly decrease the vehicles usefulness/productivity
- Changing emission, weight and road safety regulations
- Departmental needs
- Operating costs are more than 50% of a year's depreciation value. (e.g. Chassis condition/Body condition/Boom condition and technical assessment)

If a vehicle with 15 years of service has considerably less than 300,000 kilometers logged, consideration will be made to refurbish the unit only if an assessment determines a remaining useful life of at least 5 years.

In order to cap annual capital expenditures, generally only one large truck (over 4500kg) will be replaced in any given fiscal year, unless an emergency occurs in the fleet.(i.e. incident/accident)

If there are two trucks that need replacing in the same year, the truck with the greater mileage will be first and the second truck will come the following year.

b. Gas Powered Vehicles (Pickups/Mini Vans/Cars)(Under 4500Kgs)
   - Recorded mileage of 200,000 kilometers and/or more than 7 years of service

If a vehicle with 7 years of service has considerably less than 200,000 kilometers logged, consideration will be made to refurbish the unit only if an assessment arranged, by the Facility Operations & Risk Mitigation Supervisor, determines a remaining useful life of at least 3 years.

ESSEX POWERLINES FLEET

TYPE	UNIT #	JOB #	ACT	YEAR	DESCRIPTION	PLATE #	VIN #	TOTAL WEIGHT (KG)	GVW (KG)	FUEL	LIKELY REPLACEMENT DATE	Petro Canada Card #	PETRO LOG IN #
SINGLE BUCKET	100	80	9072	2006	INTERNATIONAL SINGLE BUCKET-42' POSI	6273RT	1HTMKAAR66H319947	17,000		DIESEL	2020	993-145-132-3-0002	8906
SINGLE BUCKET	103	392	9072	2007	INTERNATIONAL SINGLE BUCKET-55' POSI	9918WX	3HTWGAAR47N484204	15,072		DIESEL	2022	993-145-132-3-0007	7343
SINGLE BUCKET	107	1127	9072	2011	FREIGHTLINER - 46' SINGLE BUCKET	4165ZJ	1FVACYBS9BHBA2347	12,078		DIESEL	2026	993-145-132-3-0005	2400
SINGLE BUCKET	108	12-1185	9072	2012	FREIGHTLINER - 42' SINGLE BUCKET	AC68159	1FVACYBS6CHBS3730	17,000		DIESEL	2027	993-145-132-3-0044	
SINGLE BUCKET	111	14-1281	9072	2014	FREIGHTLINER - 46' SINGLE BUCKET	AH17507	1FVACYCDEHFU9211	18,000		DIESEL		993-145-132-3-0001	7521
DOUBLE BUCKET	351	86	9072	1996	FRHT DOUBLE BUCKET - 57' TELECT	8867AF	1FVXJLBB1TL556949	19,000		DIESEL	2016	993-145-132-3-0008	5322
RBD	110	12-1198	9072	2013	FREIGHTLINER RBD - 50 '	AE13684	1FVHCYBS0DHFE3673	27,250		DIESEL	2028	993-145-132-3-0009	2107
RBD	104	88	9072	1996	INTERNATIONAL LINE TRUCK	8568CF	1HTSDAAR8TH343650	15,000		DIESEL	2015	993-145-132-3-0040	1445
RBD	113	14-1404	9072	2015	FREIGHTLINER RBD - 50 '	AL 92881	3ALHCYCY4FDGR7982	27,250		DIESEL	2030	993-145-132-3-0011	8924
PICK-UP	65	502	9072	2009	GMC SIERRA-EXT CAB	AM46588	1GTEC19X592149337	3,000		GAS	2017	993 145 132 3 0030	2308
PICK-UP	66	507	9072	2010	FORD-150 SUPER CAB 2 X 4	408-8YD	1FTEX1C85AFB19881	3,000		GAS	2018	993 145 132 3 0031	1267
PICK-UP	67	717	9072	2010	FORD-250 CREW CAB 4 X 4	465-6YF	1FTSW2BR3AEB22886	4,400		DIESEL	2018	993 145 132 3 0033	4677
PICK-UP	68	718	9072	2010	FORD-250 CREW CAB 4 X 4	AF 48094	1FTSW2BR3AEB22887	4,400		DIESEL	2018	993 145 132 3 0026	1777
PICK-UP	69	719	9072	2010	FORD-250 CREW CAB 4 X 4	AL 48283	1FTSW2BR3AEB22888	4,400		DIESEL	2018	993 145 132 3 0035	1777
PICK-UP	76	1032	9072	2016	CHEV SILVERADO 2500HD	AN 82039	1GC1KUEG0GF198940	3,022		GAS	2024	993 145 132 3 0012	76
VAN	70	1024	9072	2010	DODGE JOURNEY	BKNN-044	3D4PG5FV3AT217267			GAS	2018	993 145 132 3 0036	8481
VAN	71	1025	9072	2010	DODGE JOURNEY	BKNN-045	3D4PG5FV3AT217266			GAS	2018	993 145 132 3 0037	1492
VAN	72	12-1165	9072	2012	DODGE RAM 1500 4X4	AK 24845	1C6RD7FTOCS226772	3,000		GAS	2020	993 145 132 3 0024	4277
VAN	73	13-1439	9072	2014	DODGE RAM CV	AF 34706	2C4RRGAG4ER179710	3,000		GAS	2022	993 145 132 3 0004	5023
VAN	74	1030	9072	2016	RAM PROMASTER	AN85444	3C6TRVAG4GE129086	2,061		GAS	2024		
VAN	75	1026	9072	2016	RAM PROMASTER	AN85445	3C6TRVAG8GE130029	2,061		GAS	2024		
DUMP TRUCK	109	12-1184	9072	2012	DODGE RAM 3500 DUMP	AC 28214	3C7WDTAL6CG240813	8,000		DIESEL	2022	993 145 132 3 0038	4677
DUMP TRUCK	112	14-1291	9072	2015	FORD SUPER DUTY F550 DUMP	AH 65653	1FDUF5HT2FEA19524			DIESEL	2025	993 145 132 3 0038	4677
TRAILER	730	107	9072	1930	UTILITY TRAILER	E9209L	FILE #165984361	760	6,401				
TRAILER	731	108	9072	1992	TRAILER	L45405	2F9PR6426NF043005	1,660	5,443				
TRAILER		13-1085	9072	2013	LANDSCAPE TRAILER	K2350Y	2CPUSD2D6DA019085	977	4,491				
POLE TRAILER	735	111	9072	1997	60' FREIBURGER POLE TRAILER	S36022	2F9PT6516VF043010						
POLE TRAILER	736	112	9072	1997	POLE/REEL TRAILER	S94733	ZF9PR6426VF043012	1,740	5,443				
REEL TRAILER	733	110	9072	1968	REEL TRAILER	E9212L	13523	1,510	4,535				
BACKHOE	740	14-1351	9072	2014	CASE FARMALL 95C					DIESEL			
CHIPPER	361	242	9070	``	VEERNEER 12	E9210L	FILE #292343032			GAS			
PORTABLE TRANS.	737	113	9072	1961	PORTABLE TRANSFORMER	11953C	154TRANS	1,020					
GENERATOR	362	352	9072	2000	VILTECH	B89-03C	T5193512646049603						
PICK-UP	61	98	9072	2006	CHEV PICKUP	2283RX	3GCE14X36G153387	3,000		G	2014	993 145 132 3 0041	7608
PICK-UP	62	99	9072	2006	4 X 4 CHEV SIVERADO QUAD PICKUP	6984TA	1GCHK23DX6F224597	3,500		DIESEL	2014	993 145 132 3 0016	1154
PICK-UP	62	1062	9072	2006	CHEVY SILVERADO	698-4TA	1GCHK23DX6F224597	3,000		DIESEL	2015	993 145 132 3 0012	
VAN	63	100	9072	2007	GMC SAVANA	9951TS	1GTFG15X571150014	3,000		G	2015	993 145 132 3 0042	6694
VAN	64	101	9072	2007	GMC SAVANA	AM46587	1GTGG25V671140116	3,000		G	2015	993 145 132 3 0028	6711

Table 1 : Fleet Inventory - April - 2017

Appendix J: Asset Condition Assessment Report

Essex Powerlines Corporation
Asset Condition Assessment

Prepared by METSCO Energy Solutions Inc.

Report no. P-17-133-001-R0

August 11, 2017

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Summary

The Asset Condition Assessment is based on data compiled in June 2017 and covers the following classes of fixed assets owned by Essex Powerlines Corporation (EPL):

- Wood poles
- Concrete poles
- Steel poles
- Pad-mounted distribution transformers
- Pole-mounted distribution transformers
- Pad-mounted switchgear
- Dip poles (primary risers)
- Primary underground cables

Table 0-1 summarizes the assessment criteria and Typical Useful Life (TUL) for each asset class. Age demographics are not tracked for dip poles. The condition was determined for all asset classes except primary underground cables, for which only age demographics are known. Statistics for primary underground cable failures were used to support an age-based replacement plan.

Table 0-1: Assessment Criteria and TUL for each Asset Class

Asset Class	Assessment Criteria	TUL (years)
Wood poles	Test results (Resistograph), visual inspection results, service age	50
Concrete poles	Visual inspection results, service age	50
Steel poles	Visual inspection results, service age	60
Pad-mounted distribution transformers	Visual inspection results, service age	40
Pole-mounted distribution transformers	Visual inspection results, service age	40
Pad-mounted switchgear	Visual inspection results, service age	30
Dip poles (primary risers)	Visual inspection results	N/A
Direct-buried primary underground cables	Service age, reliability statistics	30
Primary underground cables in conduit	Service age, reliability statistics	40

The assets are assessed to be in one of five conditions: Very Good, Good, Fair, Poor, or Very Poor. The results of the Asset Condition Assessment, including the number of assets in each class, are summarized in Figure 0-1.

Figure 0-1: Asset Condition Summary

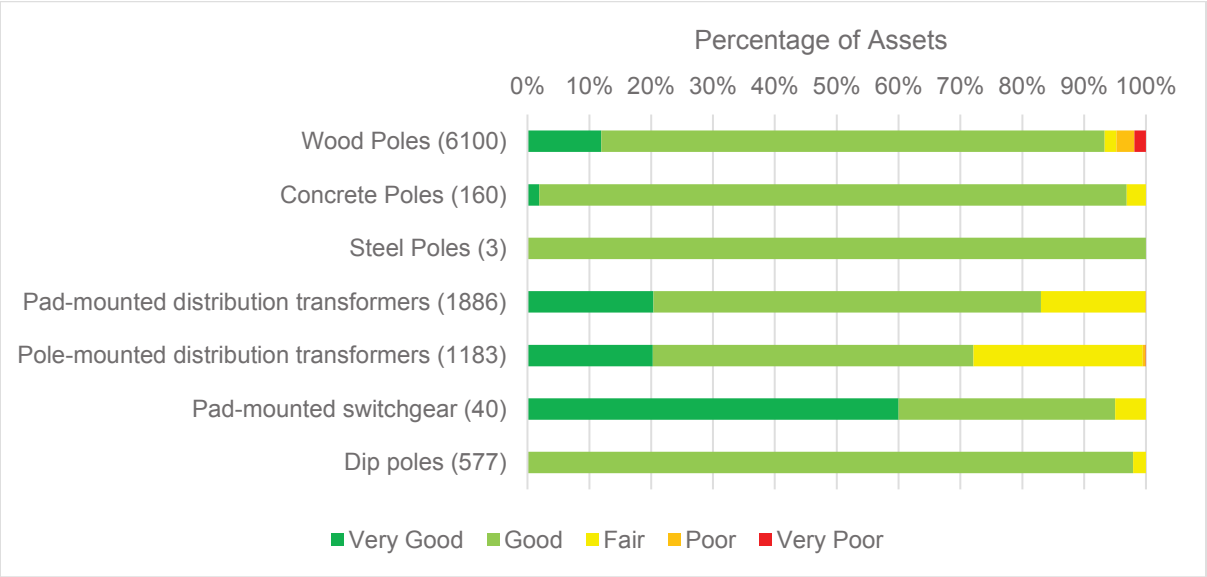
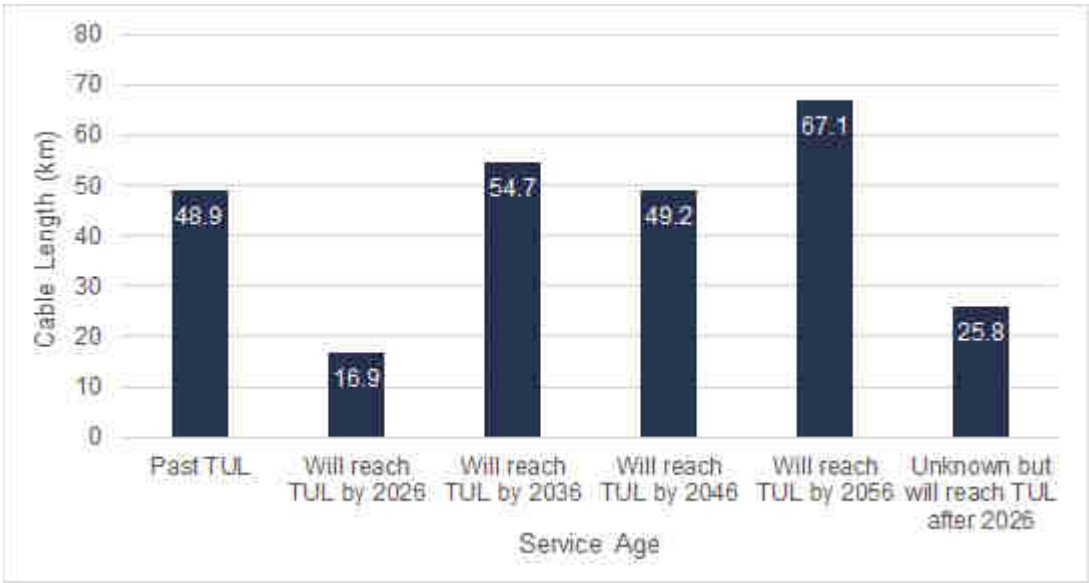


Figure 0-2 presents the service age of EPL's primary underground cables with respect to the TUL. A total of 48.9 km of cables are past TUL and an additional 16.9 km will reach TUL by 2026 (a ten-year planning window). Cables installed in conduits for which the exact installation date is unknown are presumed to have been installed after 1986 and are, therefore, not expected to require replacement before 2026. The approximate age of these cables should be determined and subsequent analyses.

Figure 0-2: Service Age of Primary Underground Cables Relative to TUL



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1 Introduction

This report summarizes the results of an Asset Condition Assessment study carried out by METSCO Energy Solutions Inc. (METSCO) on behalf of Essex Powerlines Corporation (EPL), with the objective of establishing the health and condition of fixed assets employed in the distribution systems.

The Asset Condition Assessment methodology was applied for different categories of fixed assets that are employed on EPL's distribution system. Adoption of this methodology would require periodic asset inspections and recording of their condition to identify the assets most at risk, requiring focused investments into risk mitigation.

Computing the Health Index for distribution assets requires developing end-of-life criteria for various components associated with each individual asset type. Each criterion represents a factor that is critical in determining the component's condition relative to potential failure. These components and tests shown in the tables are weighted based on their importance in determining the assets end-of-life.

For the purpose of scoring the condition assessment, the letter condition ratings are assigned the following numbers shown as "factors":

- A = 4
- B = 3
- C = 2
- D = 1
- E = 0

These condition rating numbers (i.e., A = 4, B = 3, etc.) are multiplied by the assigned weights to compute weighted scores for each component and test. The weighted scores are totaled for each asset.

Totaled scores are used in calculating final Health Indices for each asset. For each component, the Health Index calculation involves dividing its total condition score by its maximum condition score and expressing it as a percentage. This step normalizes scores by producing a number from 0 to 100% for each asset. For example, a transformer in perfect condition would have a Health Index of 100% while a completely degraded transformer would have a Health Index of 0. The condition of the asset based on the Health Index is interpreted using Table 1-1.

Table 1-1: Description and Interpretation of Asset Condition

Health Index	Condition	Description	Interpretation
[85%, 100%]	Very Good	Asset is in “like-new” condition; some aging or minor deterioration	Normal maintenance
[70%, 85%)	Good	Significant deterioration of some components	Normal maintenance
[50%, 70%)	Fair	Widespread significant deterioration or serious deterioration of specific components	Possible remedial work or replacement depending on criticality
[30%, 50%)	Poor	Widespread serious deterioration	Start planning process to replace or refurbish depending on criticality
[0%, 30%)	Very Poor	Extensive serious deterioration	Asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

The assets covered in the report include the following fixed assets:

- Wood poles
- Concrete poles
- Steel poles
- Pad-mounted distribution transformers
- Pole-mounted distribution transformers
- Pad-mounted switchgear
- Dip poles (primary risers)
- Primary underground cables

The information contained within this report was compiled based on data available in June 2017.

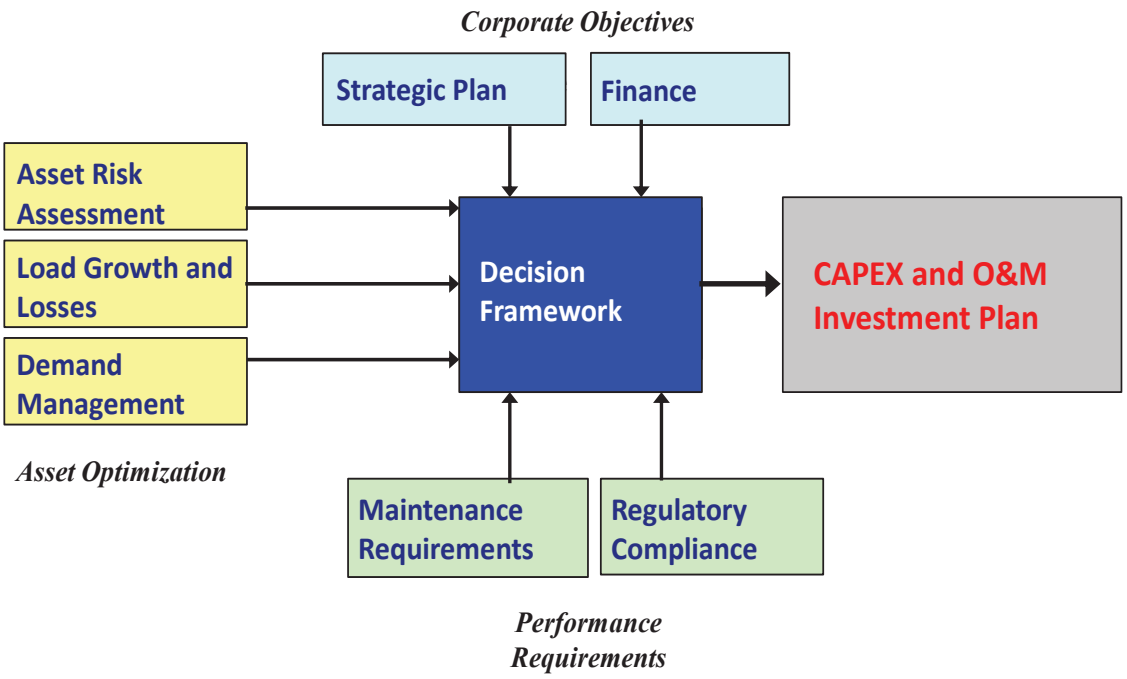
2 Strategic Management of Distribution Fixed Assets

Decisions involving investment into fixed assets play a major role in determining the optimal performance of distribution system fixed assets. A majority of the investments in fixed assets are triggered by declining performance in the areas of supply system reliability, power quality or safety; or increasing operating and maintenance costs associated with aging assets; or anticipated growth in demand requiring capacity upgrades. In any case, investments that are either oversized or made too far in advance of the actual system need may result in non-optimal operation. On the other hand, investment not made on time when warranted by the system needs raise the risk of performance targets not being achieved and would also result in non-optimal operation. Optimal operation of the distribution system is achieved when “right sized” investments into renewal and replacement (capital investments) and into asset repair, rehabilitation, and preventative maintenance are planned and implemented based on a “just-in-time” approach. In summary, the overarching objective of the Asset Management Strategy is to find the right balance between capital investments in new infrastructure and operating and maintenance costs so that the combined total cost over the life of the asset is minimized.

A risk-based Asset Management Strategy, therefore, determines the risk of asset failure based on the condition of the asset – commonly using Health Indices – computes the valuation of the risk based on consequences of asset failure, and identifies the optimal risk mitigation alternative through an evaluation of all available options. Asset management covers the full lifecycle of a fixed asset, from preparation of the asset specification and installation standards, to the scope and frequency of preventative maintenance during the asset’s service life, and finally to the determination of the assets end-of- life and retirement from service. At each stage of an asset’s lifecycle, decisions are made to achieve the right balance between achieving maximum life expectancy, highest operating performance, lowest initial investment (capital costs), and lowest operating costs. The best-in-class asset management strategies employ integrated processes that allow optimal levels of financial and operating performance to be achieved, using transparent and objective criteria that can easily be audited and inspected by regulators.

The overarching objective is to develop capital and preventative maintenance investment plans, which could be implemented over a period of ten to twenty-five years to achieve optimal system performance by placing appropriate weights on corporate objectives and performance requirements, as shown in Figure 2-1.

Figure 2-1: Multi-Point Decision Framework



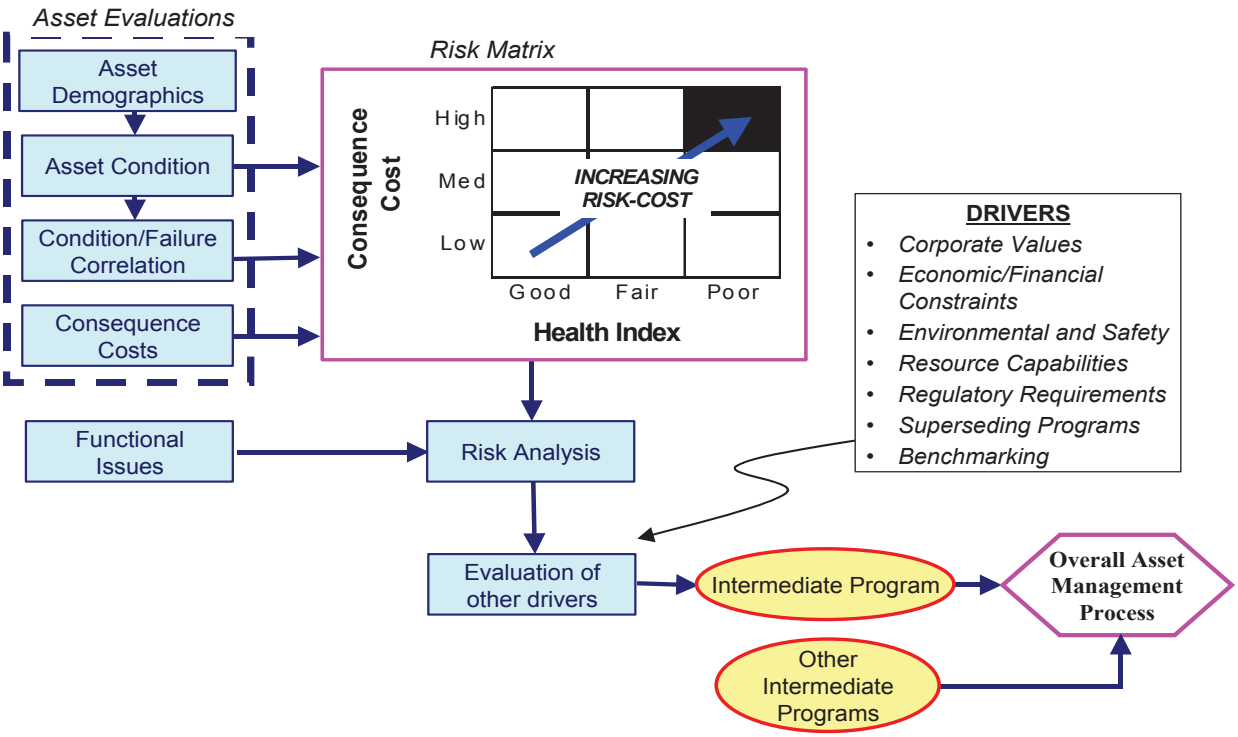
For regulated transmission and distribution (T&D) businesses, the key considerations in development of a Strategic Asset Management Plan include:

a) Public and Employee Safety
b) Regulatory Compliance
c) Protecting Brand Name and Image
d) Operating Efficiency
e) Reliability and Supply System Security
f) Customer Service Quality
g) Minimizing Asset Life Cycle Costs
h) Minimizing Environmental Risks
i) Getting Full Life out of Assets
j) Return on Investment
k) Risk Based Maintenance Strategy
l) Minimizing Risk of Premature Failures

Figure 2-2 summarizes a practical matrix to sift through a large number of assets, typically employed on T&D systems to objectively identify assets that present the highest risk of in-service

failures so that the investments could be targeted into assets that present the highest risk. Numeric Health Indices, typically normalized to a scale of 100, are commonly used to express the health and condition of assets, differentiating the assets in good condition that require minimal risk mitigation from those in poor condition, requiring a higher level of investments. This exercise allows development of an investment plan that could be implemented over a medium- or long-term planning hoizon.

Figure 2-2: Model to Identify Assets with Highest Risks



3 Health Indices

3.1 Wood Poles

3.1.1 Condition Assessment Methodology

3.1.1.1 Health Index Calculation

The Health Index for wood poles is calculated by considering a combination of service age, visual inspection results, and pole testing results (cavity and decay determined from a Resistograph test). Table 3-1 summarizes the methodology to combine these criteria into an overall Health Index for wood poles. The methodology employs a "gateway" if the pole fails the cavity test, forcing the pole condition to Very Poor by halving the Health Index.

Table 3-1: Wood Poles – Health Index

Condition Criteria	Weight	Possible Ratings	Possible Scores	Max Grade
Cavity test (Resistograph)*	8	A,B,C,D,E	4,3,2,1,0	32
Decay test (Resistograph)	6	A,B,C,D,E	4,3,2,1,0	24
Outstanding issues (visual inspection)	4	A,B,C,D,E	4,3,2,1,0	16
Service age	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	84

*If E, divide Health Index by two.

EPL considers a Typical Useful Life (TUL) of fifty years for wood poles, which is consistent with common industry practice. Table 3-2 is used to translate age into a condition rating.

Table 3-2: Wood Poles – Age Condition Grading

Condition Rating	Age
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 50 years
E	51 years or older

Visual inspections are performed on a three-year cycle, checking for:

- Hollow pole sound when struck with hammer
- Bent, cracked, or broken poles
- Pole positioned in hazardous location
- Leaning pole in unstable soil
- Loose or unattached guy wires or studs
- Slack, broken, or damaged guys
- Guy positioned close to primary conductors or equipment
- Guy strain insulators pulled apart or broken

- Guy guards missing or out of position
- Loose, cracked, or broken crossarms and brackets
- Woodpecker, bird nests, or insect damage
- Grading changes or washouts
- Other problems (e.g. dirty insulators, crossarm damage)

The pole inspector ranks the issues as high, medium, or low priority depending on the severity. High priority issues generally require immediate follow-up, while other identified issues are prioritized accordingly. If an issue is resolved via corrective maintenance or capital replacement, the inspection database is updated. Table 3-3 presents the condition rating based on the outstanding issues for the wood pole.

Table 3-3: Wood Poles – Outstanding Issues Condition Grading

Condition Rating	Corresponding Condition
A	No outstanding issues
B	One low priority issue outstanding
C	Multiple low priority issues or one medium priority issue outstanding
D	Multiple medium priority issues outstanding
E	One or more high priority issues outstanding

EPL started its pole testing program in 2014. Poles are drilled using a Resistograph to determine the amount of decay and size of cavities within the wood. Each pole is tested twice: once at the groundline and once five feet from the ground. The Resistograph automatically determines the percentage of decay and cavity relative to the size of the pole. If the cavity exceeds 40% of the pole, then the pole requires immediate replacement in accordance with CSA C22.3 No.1-15. Both test locations are compared to ensure the worst condition poles are prioritized for replacement. Table 3-4 summarizes the condition rating based on the tested cavity size. Decay percentages obtained from the Resistograph tests are also used to assess the condition of wood poles as presented in Table 3-5.

Table 3-4 Wood Poles – Cavity Test Condition Grading

Condition Rating	Corresponding Condition
A	Cavity < 10% for both tests
B	Cavity ≥ 10% for either test
C	Cavity ≥ 20% for either test
D	Cavity ≥ 30% for either test
E	Cavity ≥ 50% for one test and ≥ 40% for second test

Table 3-5: Wood Poles – Decay Test Condition Grading

Condition Rating	Corresponding Condition
A	Decay < 10% for both tests
B	Minor decay ≥ 10% for one test
C	Significant decay ≥ 20% for one test
D	Major decay ≥ 30% for one test
E	Severe decay ≥ 40% for one test

3.1.1.2 Translating Health Index into Asset Condition

The condition of each wood pole is determined based on its Health Index and service age. As noted in Table 3-6, service age is only used to distinguish between Good and Very Good condition poles when the Health Index is 85% or greater. When the Health Index is less than 85%, it is directly translated into asset condition. If the age is unknown, then the pole is assumed to be in Good condition if the Health Index is greater than or equal to 70%.

Table 3-6: Wood Pole Condition Determined Using Health Index and Service Age

Health Index	Service Age	Wood Pole Condition
≥ 85%	≤ 10 years	Very Good
≥ 85%	> 10 years	Good
≥ 70%, < 85%	-	Good
≥ 50%, < 70%	-	Fair
≥ 30%, < 50%	-	Poor
< 30%	-	Very Poor

3.1.2 Results of Analysis

3.1.2.1 Age Demographics

EPL owns 6100 wood poles across its four service territories. The service age is known for 2903 – or 48% – of EPL's wood poles. Figure 3-1 presents the age distribution of the known set. The distribution is skewed towards newer poles since modern data collection processes are more accurate.

Figure 3-1: Consolidated Age Demographics of Wood Poles

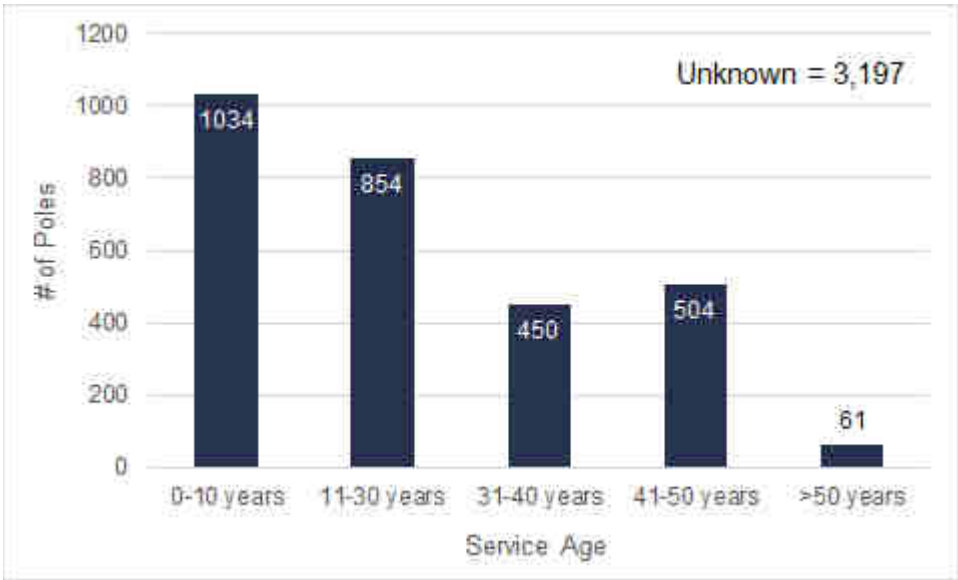


Table 3-7 presents the wood poles age demographics by community. The percentage of poles with unknown service ages varies between communities depending on the pre-amalgamation records.

Table 3-7: Wood Pole Age Demographics by Community

Age	Number of Poles				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
0-10 years	98	211	100	625	**1034**
11-30 years	134	237	48	435	**854**
31-40 years	50	226	27	147	**450**
41-50 years	25	382	27	70	**504**
>50 years	2	3	17	39	**61**
Unknown	649	502	438	1608	**3197**
Total	**958**	**1561**	**657**	**2924**	**6100**

3.1.2.2 Condition Assessment

Pole testing commenced in 2014 and EPL has tested 4146 of its in-service poles to date (68%). The Health Index is calculated for all wood poles that have been tested and translated into condition using Table 3-6. If the age is unknown, then the Health Index is calculated based on the test results and the results of visual inspections. The condition is calculated for 4146 wood poles (the known set), as summarized in Table 3-8, and then extrapolated to the entire population, as shown in Table 3-9.

Table 3-8: Wood Pole Asset Condition – Known Set

Condition	Number of Poles				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
Very Good	66	61	34	333	**494**
Good	609	465	221	2086	**3381**
Fair	16	10	3	54	**83**
Poor	42	24	8	34	**108**
Very Poor	26	16	6	32	**80**
Unknown	199	985	385	385	**1954**
Total	**958**	**1561**	**657**	**2924**	**6100**

Table 3-9: Wood Pole Asset Condition – Extrapolation

Condition	Number of Poles*				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
Very Good	83	165	82	383	**714**
Good	769	1260	534	2402	**4965**
Fair	20	27	7	62	**117**
Poor	53	65	19	39	**177**
Very Poor	33	43	14	37	**128**
Total	**958**	**1561**	**657**	**2924**	**6100**

*Integers may be off by 1 due to extrapolation.

The pole testing results includes failed poles from 2015 and 2016 that were changed out; therefore, the extrapolation must be adjusted to reflect these change-outs. Table 3-10 presents the extrapolated pole condition as of 2017 after the adjustments.

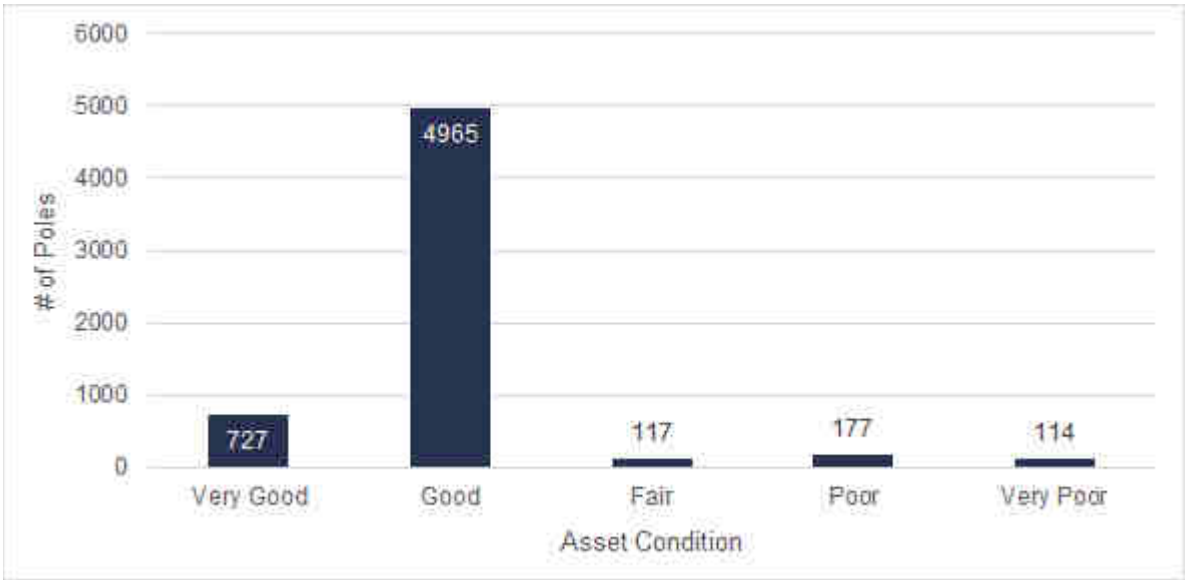
Table 3-10: Wood Pole Asset Condition – 2017 Extrapolation

Condition	Number of Poles*				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
Very Good	83	165	84	394	**727**
Good	769	1260	534	2402	**4965**
Fair	20	27	7	62	**117**
Poor	53	65	19	39	**177**
Very Poor	33	43	12	26	**114**
Total	**958**	**1561**	**657**	**2924**	**6100**

*Integers may be off by 1 due to extrapolation.

The overall distribution consolidated between the four service areas is presented in Figure 3-1. The results suggest a pole replacement rate of 1.5-2% per year, depending on the final results of the risk analysis, which is reflective of a fifty-year TUL.

Figure 3-2: Condition Assessment Results for Wood Poles



3.2 Concrete/Steel Poles

3.2.1 Condition Assessment Methodology

3.2.1.1 Health Index Calculation

The Health Index for both concrete and steel poles is calculated by considering a combination of service age and visual inspection results. Table 3-11 summarizes the methodology to combine these criteria into an overall Health Index for concrete and steel poles. Concrete and steel poles are not tested.

Table 3-11: Concrete/Steel Poles – Health Index

Condition Criteria	Weight	Possible Ratings	Possible Scores	Max Grade
Outstanding issues (visual inspection)	4	A,B,C,D,E	4,3,2,1,0	16
Service age	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	28

EPL considers a TUL of fifty years for concrete poles, which is consistent with common industry practices. Table 3-12 is used to translate the concrete pole service age into a condition rating.

Table 3-12: Concrete Poles – Age Condition Grading

Condition Rating	Age
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 50 years
E	51 years or older

EPL owns just three metal poles, which have a TUL of sixty years based on common industry practice. Table 3-13 is used to translate the steel pole service age into a condition rating.

Table 3-13: Steel Poles – Age Condition Grading

Condition Rating	Age
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 60 years
E	61 years or older

Visual inspections are performed on a three-year cycle, checking for:

- Guy guards missing or out of position
- Guy strain insulators pulled apart or broken
- Leaning pole in unstable soil
- Loose or unattached guy wires or studs
- Slack, broken, or damaged guys
- Other problems (e.g. discoloured insulators, grounding issues)

The pole inspector ranks the issues as high, medium, or low priority depending on the severity. High priority issues generally require immediate follow-up, while other identified issues are prioritized accordingly. If an issue is resolved via corrective maintenance or capital replacement, the inspection database is updated. Table 3-14 presents the condition rating based on the outstanding issues for the concrete or steel pole.

Table 3-14: Concrete/Steel Poles – Outstanding Issues Condition Grading

Condition Rating	Corresponding Condition
A	No outstanding issues
B	One low priority issue outstanding
C	Multiple low priority issues or one medium priority issue outstanding
D	Multiple medium priority issues outstanding
E	One or more high priority issues outstanding

3.2.1.2 Translating Health Index into Asset Condition

The condition of each concrete and steel pole is determined based on its Health Index and service age. As noted in Table 3-6, service age is only used to distinguish between Good and Very Good condition poles when the Health Index is 85% or greater. When the Health Index is less than 85%, it is directly translated into asset condition. If the age is unknown, then the pole is assumed to be in Good condition if the Health Index is greater than or equal to 70%.

Table 3-15: Concrete/Steel Pole Condition Determined Using Health Index and Service Age

Health Index	Service Age	Pole Condition
≥ 85%	≤ 10 years	Very Good
≥ 85%	> 10 years	Good
≥ 70%, < 85%	-	Good
≥ 50%, < 70%	-	Fair
≥ 30%, < 50%	-	Poor
< 30%	-	Very Poor

3.2.2 Results of Analysis

3.2.2.1 Age Demographics

EPL owns 160 concrete poles across its four service territories. The service age is known for 136 – or 85% – of the concrete poles. Figure 3-3 presents the age distribution of the known set of concrete poles. There have been very few concrete pole installations in the past ten years.

Figure 3-3: Consolidated Age Demographics of Concrete Poles

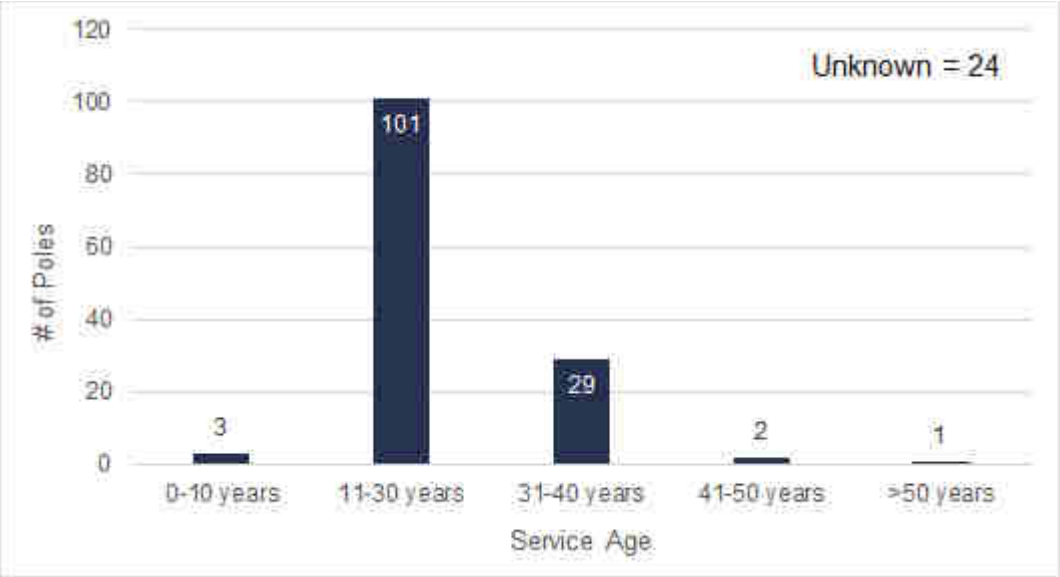


Table 3-16 presents the concrete pole age demographics by community. Over half of the concrete poles are located in LaSalle and most are less than thirty years old.

Table 3-16: Concrete Pole Age Demographics by Community

Age	Number of Poles				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
0-10 years	0	0	0	3	**3**
11-30 years	24	9	15	53	**101**
31-40 years	0	1	0	28	**29**
41-50 years	0	2	0	0	**2**
>50 years	0	0	1	0	**1**
Unknown	2	6	11	5	**24**
Total	**26**	**18**	**27**	**89**	**160**

EPL owns three steel poles: two in LaSalle and one in Leamington. The service age is known for just one of the poles, which is thirty-seven years old and situated in LaSalle.

3.2.2.2 Condition Assessment

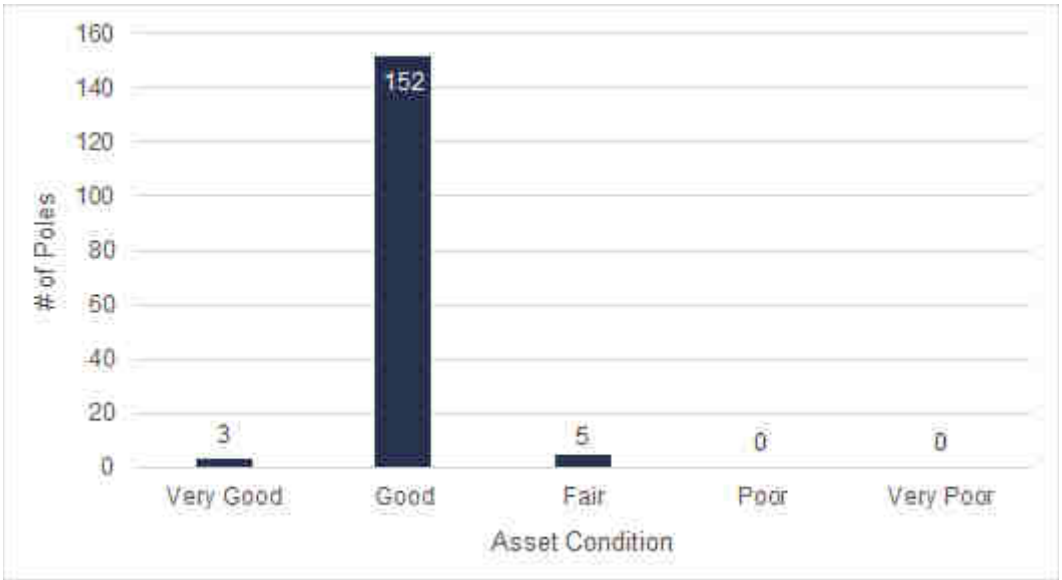
The Health Index is calculated for all concrete and steel poles and translated into condition using Table 3-15. If the age is unknown, then the Health Index is calculated solely based on the visual inspection results.

Table 3-17: Concrete Pole Asset Condition by Community

Condition	Number of Poles*				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
Very Good	0	0	0	3	**3**
Good	26	16	25	85	**152**
Fair	0	2	2	1	**5**
Poor	0	0	0	0	**0**
Very Poor	0	0	0	0	**0**
Total	**26**	**18**	**27**	**89**	**160**

The overall distribution of concrete pole condition consolidated between the four service areas is depicted in Figure 3-4. The results suggest that there are no immediate replacement needs for concrete poles, which is reflective of the visual inspection results that identified only a few low priority issues and no medium or high priority issues.

Figure 3-4: Condition Assessment Results for Concrete Poles



The three steel poles were all assessed to be in good condition. The results suggest that there are also no immediate replacement needs for steel poles, which is reflective of the fact that no issues were identified during visual inspections.

3.3 Distribution Transformers

3.3.1 Condition Assessment Methodology

3.3.1.1 Health Index Calculation

The pole-mounted and pad-mounted transformers on EPL's system step voltages down from primary (27.6/16.0 kV) to secondary (typically 120/240 V, but up to 600 V). The Health Index for both pole-mounted and pad-mounted distribution transformers is calculated by considering a combination of service age and inspection results. For pad-mounted transformers, the inspection includes an infrared scan. Table 3-18 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-18: Distribution Transformers – Health Index

Condition Criteria	Weight	Possible Ratings	Possible Scores	Max Grade
Outstanding issues (inspection results)	4	A,B,C,D,E	4,3,2,1,0	16
Service age	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	28

EPL considers a TUL of forty years for distribution transformers, which is consistent with common industry practices. Table 3-19 is used to translate the distribution transformer service age into a condition rating.

Table 3-19: Distribution Transformer – Age Condition Grading

Condition Rating	Age
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 50 years
E	51 years or older

Visual inspections are performed on a three-year cycle for both pad-mounted and pole-mounted transformers. Pad-mounted transformers are assessed for:

- Pad or vault secured in proper location
- Paint condition acceptable
- Corrosion
- Leaking oil
- Flashed or cracked insulators
- Damaged elbows
- Pad-mount lid damage, public security lock damage assembly
- Vegetation problem
- Access problem
- Other issues (e.g. grounding)

Pole-mounted transformers are checked for:

- Contamination/discolouration of bushings
- Issues with H1 primary bushing
- Rust
- Leaking oil
- Issues with ground lead attachment
- Switch contact not properly closed
- Ground wires on arrestors unattached
- Issues with lightning arrestor
- Issues with bird/animal nests
- Vine/bush growth interface
- Tree trimming required
- Access problem
- Other issues (e.g. wire cover, secondary services)

The inspector ranks the issues as high, medium, or low priority depending on the severity. High priority issues generally require immediate follow-up, while other identified issues are prioritized accordingly.

Pad-mounted transformers also undergo infrared scanning on a three-year cycle. As with visual inspections, detected hotspots are prioritized as high, medium, or low issues by the inspector.

Table 3-20 presents the condition rating based on the outstanding issues for the pad-mounted or pole-mounted distribution transformer.

Table 3-20: Distribution Transformers – Outstanding Issues Condition Grading

Condition Rating	Corresponding Condition
A	No outstanding issues
B	One low priority issue outstanding
C	Multiple low priority issues or one medium priority issue outstanding
D	Multiple medium priority issues outstanding
E	One or more high priority issues outstanding

3.3.1.2 Translating Health Index into Asset Condition

The condition of each distribution transformer is determined based on its Health Index and service age. As noted in Table 3-21, service age is only used to distinguish between Good and Very Good condition poles when the Health Index is 85% or greater. When the Health Index is less than 85%, it is directly translated into asset condition. If the age is unknown, then the pole is assumed to be in Good condition if the Health Index is greater than or equal to 70%.

Table 3-21: Transformer Condition Determined Using Health Index and Service Age

Health Index	Service Age	Wood Pole Condition
≥ 85%	≤ 10 years	Very Good
≥ 85%	> 10 years	Good
≥ 70%, < 85%	-	Good
≥ 50%, < 70%	-	Fair
≥ 30%, < 50%	-	Poor
< 30%	-	Very Poor

3.3.2 Results of Analysis

3.3.2.1 Age Demographics

EPL owns 1886 pad-mounted distribution transformers across its four service territories. The service age is known for 1785 – or 95% – of the pad-mounted transformers. Figure 3-5 presents the age distribution of the known set of pad-mounted transformers, while Table 3-22 presents the age demographics of pad-mounted transformers by community.

Figure 3-5: Consolidated Age Demographics of Pad-mounted Transformers

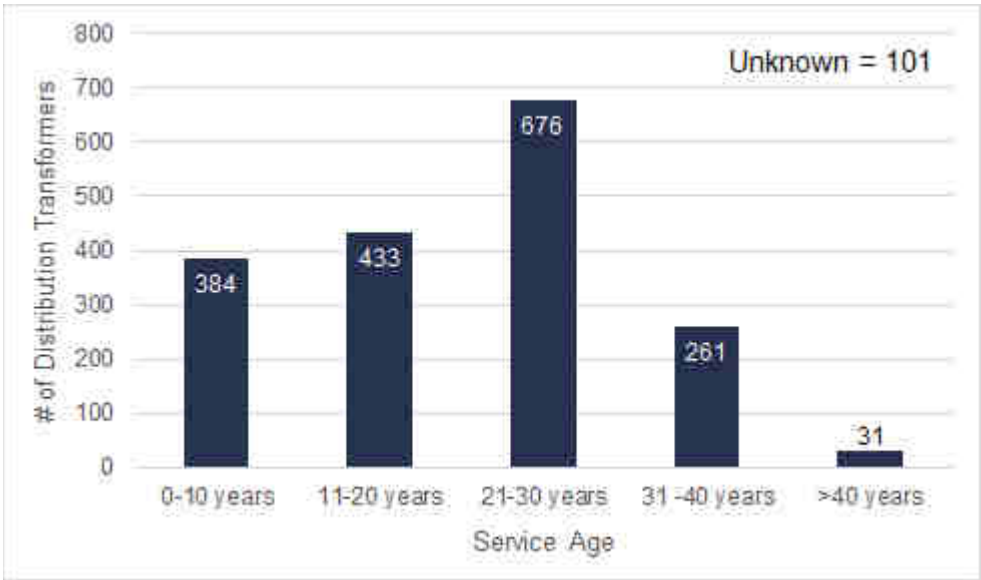


Table 3-22: Pad-mounted Transformer Age Demographics by Community

Age	Number of Distribution Transformers				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
0-10 years	69	80	88	147	**384**
11-30 years	53	114	60	206	**433**
31-40 years	177	132	129	238	**676**
41-50 years	112	87	10	52	**261**
>50 years	15	10	4	2	**31**
Unknown	70	4	15	12	**101**
Total	**496**	**427**	**306**	**657**	**1886**

EPL owns 1183 pole-mounted distribution transformers across its four service territories. The service age is known for 991 – or 84% – of the pole-mounted transformers. Figure 3-6 presents the age distribution of the known set of pole-mounted transformers, while Table 3-22 presents the age demographics of pole-mounted transformers by community.

Figure 3-6: Consolidated Age Demographics of Pole-mounted Transformers

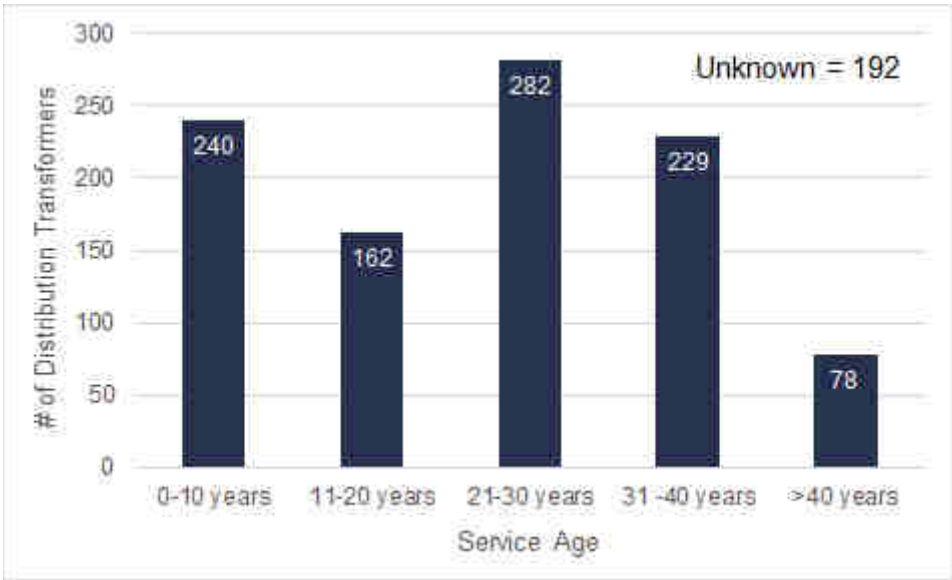


Table 3-23: Pole-mounted Transformer Age Demographics by Community

Age	Number of Distribution Transformers				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
0-10 years	12	45	25	158	**240**
11-30 years	14	49	10	89	**162**
31-40 years	31	73	6	172	**282**
41-50 years	31	71	3	124	**229**
>50 years	6	49	0	23	**78**
Unknown	75	11	89	17	**192**
Total	**169**	**298**	**133**	**583**	**1183**

3.3.2.2 Condition Assessment

The Health Index is calculated for all pad-mounted and pole-mounted distribution transformers and then translated into condition using Table 3-21. If the age is unknown, then the Health Index is calculated solely based on the inspection results. Table 3-24 presents the pad-mounted transformer condition assessment for each community.

Table 3-24: Pad-mounted Transformer Asset Condition by Community

Condition	Number of Poles*				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
Very Good	69	80	88	147	**384**
Good	297	241	199	445	**1182**
Fair	128	106	19	65	**318**
Poor	2	0	0	0	**2**
Very Poor	0	0	0	0	**0**
Total	**496**	**427**	**306**	**657**	**1886**

The overall distribution of pad-mounted transformer condition consolidated between the four service areas is depicted in Figure 3-7. The majority of the pad-mounted distribution transformers are in Good condition, while just two are in Poor condition.

Figure 3-7: Condition Assessment Results for Pad-mounted Transformers

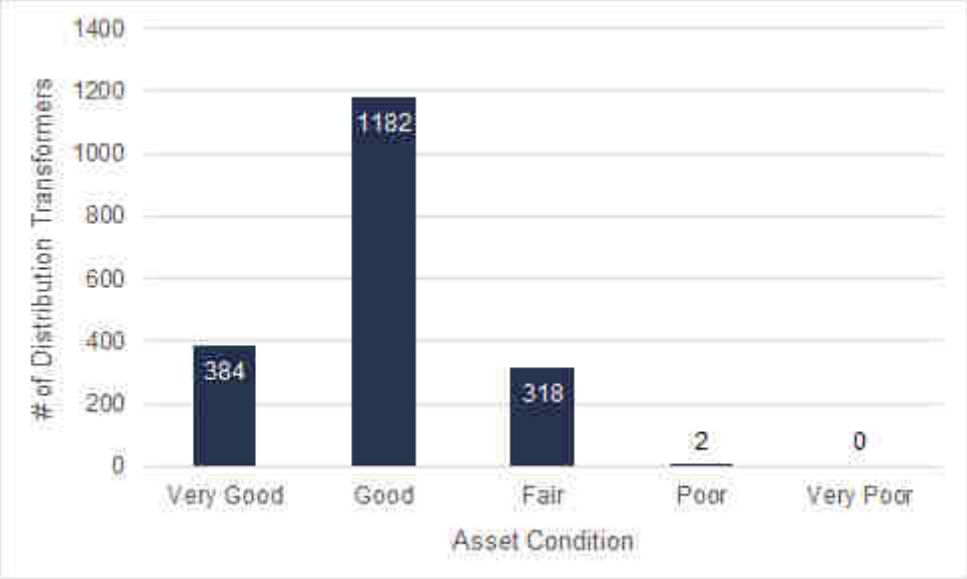
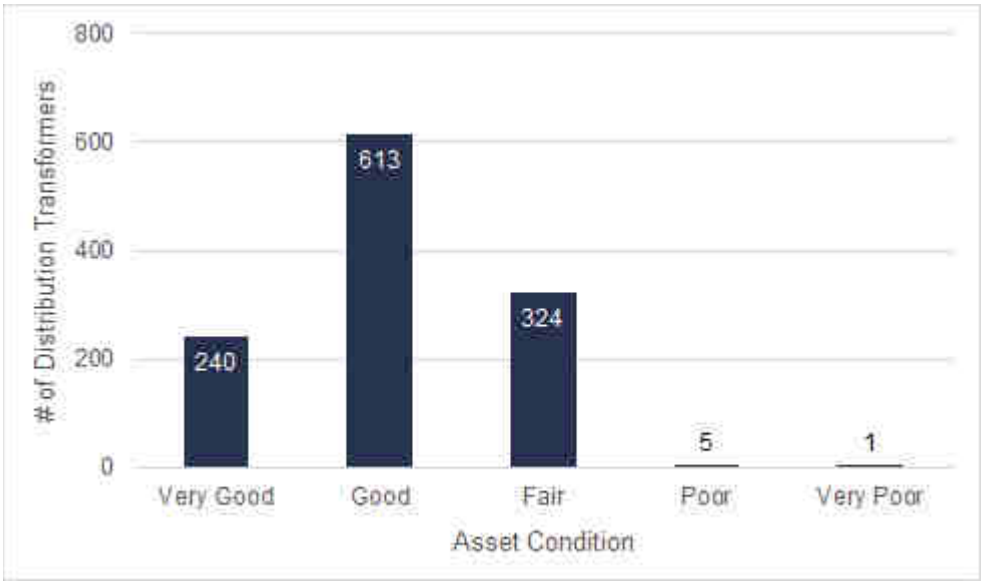


Table 3-25 presents the pole-mounted transformer condition assessment for each community, while Figure 3-8 depicts the overall distribution of pole-mounted transformer condition consolidated between the four service areas. Five pole-mounted distribution transformers are in Poor condition and one is in Very Poor condition. Similar to the pad-mounted transformers, the majority of the pole-mounted distribution transformers are in Good condition.

Table 3-25: Pole-mounted Transformer Asset Condition by Community

Condition	Number of Poles*				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
Very Good	12	45	25	158	**240**
Good	120	127	96	270	**613**
Fair	37	124	12	151	**324**
Poor	0	1	0	4	**5**
Very Poor	0	1	0	0	**1**
Total	**169**	**298**	**133**	**583**	**1183**

Figure 3-8: Condition Assessment Results for Pole-mounted Transformers



3.4 Pad-mounted Switchgear

3.4.1 Condition Assessment Methodology

3.4.1.1 Health Index Calculation

The Health Index for pad-mounted switchgear is calculated by considering a combination of service age and inspection results. For pad-mounted transformers, the inspection includes an infrared scan. Table 3-26 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-26: Pad-mounted Switchgear – Health Index

Condition Criteria	Weight	Possible Ratings	Possible Scores	Max Grade
Outstanding issues (inspection results)	4	A,B,C,D,E	4,3,2,1,0	16
Service age	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	84

EPL considers a TUL of thirty years for pad-mounted switchgear, which is consistent with common industry practices. Table 3-27 is used to calculate the condition rating based on the service age of the pad-mounted switchgear.

Table 3-27: Pad-mounted Switchgear – Age Condition Grading

Condition Rating	Age
A	0 to 10 years
B	11 to 20 years
C	21 to 25 years
D	26 to 30 years
E	31 years or older

Visual inspections are performed on a three-year cycle for pad-mounted switchgear, checking for:

- Overall condition of the pad/foundation
- Paint on metal surfaces of the gear
- Cabinet doors bolted shut
- Switches, fuses, and other internal equipment
- Vegetation problem
- Access problem
- Other issues (e.g. hotspots)

The inspector ranks the issues as high, medium, or low priority depending on the severity. High priority issues generally require immediate follow-up, while other identified issues are prioritized accordingly. Table 3-28 presents the condition rating based on the outstanding issues for the pad-mounted or pole-mounted distribution transformer.

Table 3-28: Pad-mounted Switchgear – Outstanding Issues Condition Grading

Condition Rating	Corresponding Condition
A	No outstanding issues
B	One low priority issue outstanding
C	Multiple low priority issues or one medium priority issue outstanding
D	Multiple medium priority issues outstanding
E	One or more high priority issues outstanding

3.4.1.2 Translating Health Index into Asset Condition

The condition of each distribution transformer is determined based on its Health Index and service age. As noted in Table 3-21, service age is only used to distinguish between Good and Very Good condition poles when the Health Index is 85% or greater. When the Health Index is less than 85%, it is directly translated into asset condition. If the age is unknown, then the pole is assumed to be in Good condition if the Health Index is greater than or equal to 70%.

Table 3-29: Switchgear Condition Determined Using Health Index and Service Age

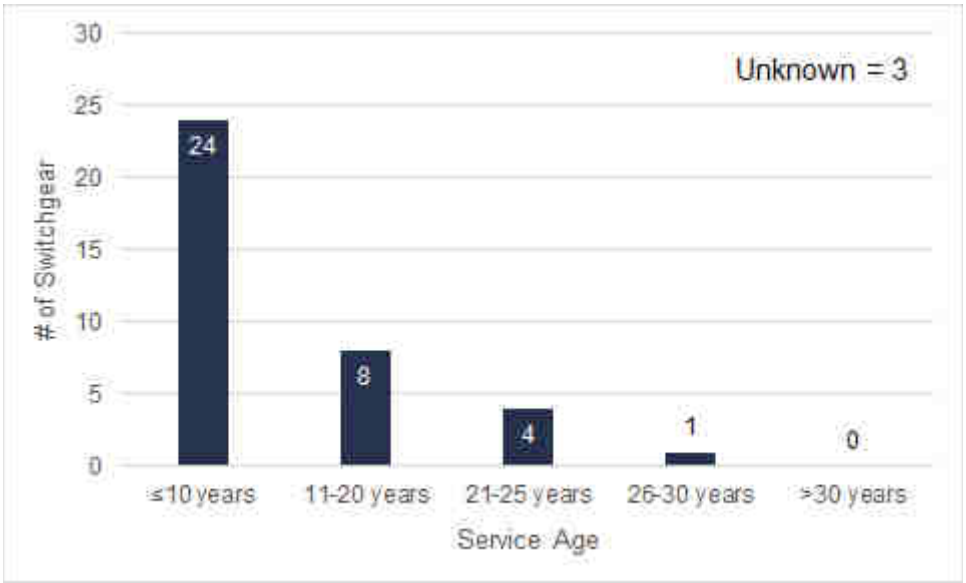
Health Index	Service Age	Wood Pole Condition
≥ 85%	≤ 10 years	Very Good
≥ 85%	> 10 years	Good
≥ 70%, < 85%	-	Good
≥ 50%, < 70%	-	Fair
≥ 30%, < 50%	-	Poor
< 30%	-	Very Poor

3.4.2 Results of Analysis

3.4.2.1 Age Demographics

EPL owns forty pad-mounted switchgear and the service age is known for thirty-seven of them. Figure 3-9 presents the age distribution of the known set of pad-mounted switchgear.

Figure 3-9: Consolidated Age Demographics of Pad-mounted Switchgear

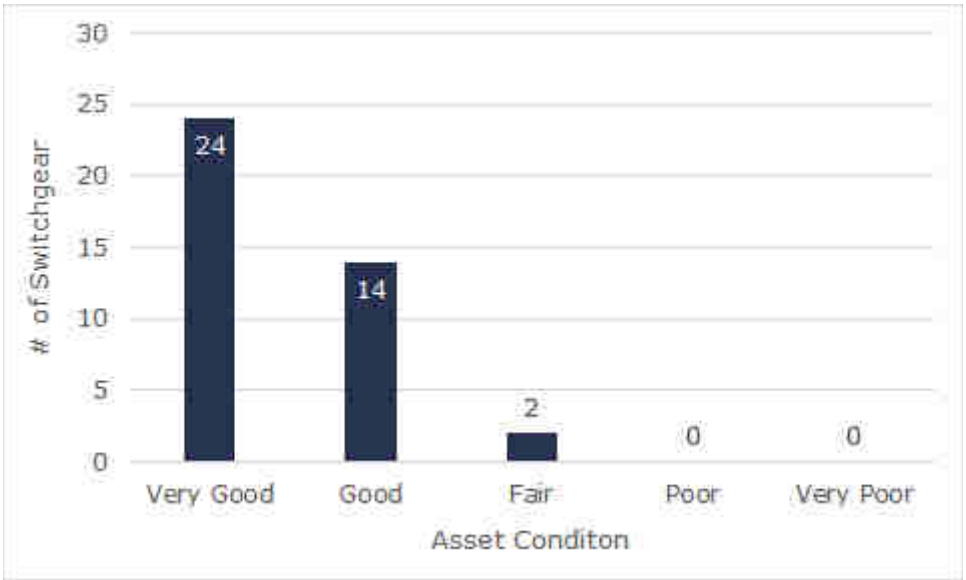


3.4.2.2 Condition Assessment

The Health Index is calculated for all pad-mounted switchgear and then translated into condition using Table 3-29. If the age is unknown, then the Health Index is calculated solely based on the inspection results. The condition assessment results for pad-mounted switchgear are presented

in Figure 3-10. Two of the switchgear are in Fair condition, while the rest are in Good or Very Good condition.

Figure 3-10: Condition Assessment Results for Pad-mounted Switchgear



3.5 Dip Poles (Primary Risers)

3.5.1 Condition Assessment Methodology

Dip poles include the protective equipment, cable potheads/terminations, and hardware installed on primary risers (the transition point between the overhead and underground system). EPL does not track age demographics for the dip poles. Instead, the condition of the asset is assessed based on the inspection results. Visual inspections are performed on a three-year cycle for dip poles, checking for:

- Insulator condition
- Problematic switch bracket
- Metal/PVC cable guard condition
- Concerns with lightning arrestors
- Concerns with riser cable and potheads/termination
- Concerns with grounding condition
- Concerns with disconnect switches and/or fused cut-outs
- Concerns with concentric neutral and arrestors
- Leads intact
- Other issues (e.g. vegetation)

The inspector ranks the issues as high, medium, or low priority depending on the severity. High priority issues generally require immediate follow-up, while other identified issues are prioritized

accordingly. Table 3-30 presents the condition rating based on the outstanding issues for the pad-mounted or pole-mounted distribution transformer.

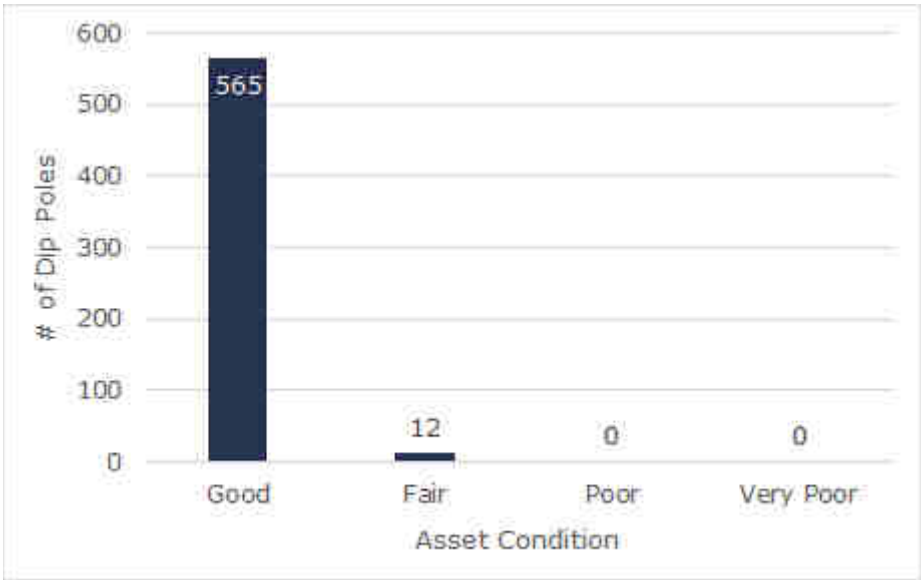
Table 3-30: Dip Poles – Condition Assessment Methodology

Asset Condition	Inspection Results
Good	No outstanding issues
Fair	One/two low priority issue(s) outstanding
Poor	More than two low priority issues or one/two medium priority issue(s) outstanding
Very Poor	One or more high priority issues or more than two medium priority issues outstanding

3.5.2 Results of Analysis

EPL has dip poles at 577 locations. Figure 3-11 presents the results of the condition assessment. Twelve dip poles are in Fair condition, while the rest are in Good condition.

Figure 3-11: Condition Assessment Results for Dip Poles



3.6 Primary Underground Cables

3.6.1 Age Demographics

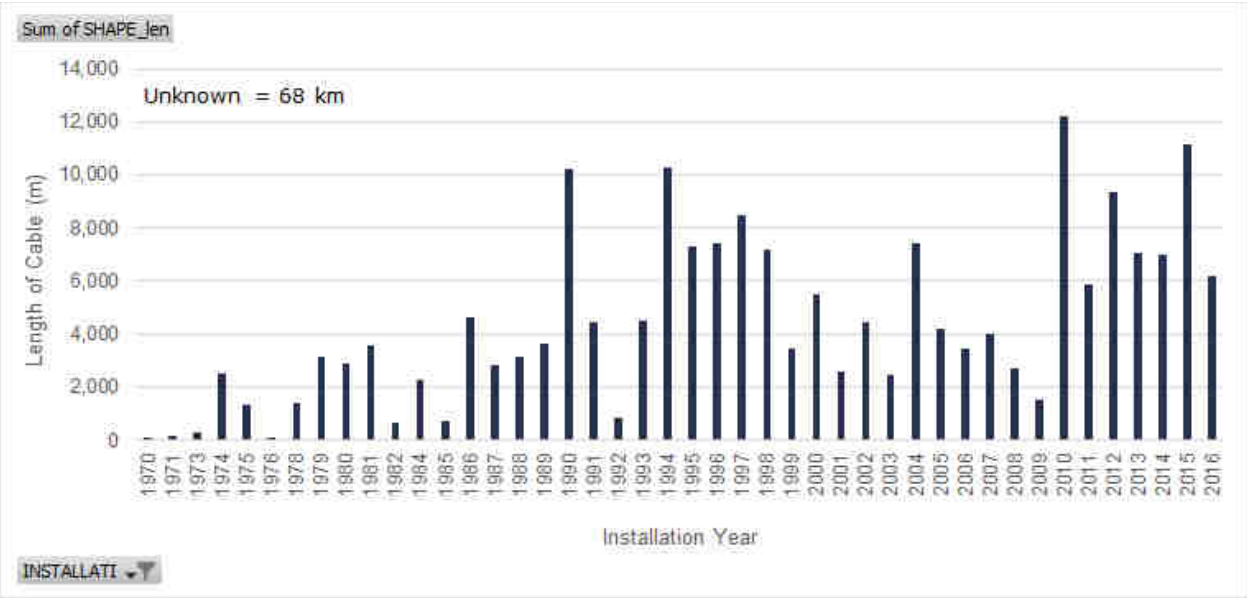
Underground cable length is measured in kilometres of circuit, where a 1-km run of three-phase cable is measured as 1 km rather than 3 km. EPL owns 263 km of primary underground cables across its four service areas. The installation year is known for 194.9 km of the cables – or 74%. Table 3-31 presents the length and number of phases of primary underground cable for each service area.

Table 3-31: Primary Underground Cable Length by Area and Number of Phases

Number of Phases	Length of Cable (km)				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
Single-phase	62.4	40.4	33.7	90.8	**227.3**
Three-phase	7.5	8.3	9.0	10.5	**35.3**
Total	**69.9**	**48.7**	**42.7**	**101.3**	**262.6**

Figure 3-12 presents the cable length by installation year. EPL uses a TUL of thirty years for direct-buried cables and forty years for cables in conduits, which is consistent with common industry practices for primary TR XLPE cables. Since 1986, all primary cables were installed in conduits; therefore, the significant amount of cable installed in 1990 and from 1994 to 1997 will reach their TUL beginning in 2030.

Figure 3-12: Installation Year of Primary Underground Cable



Out of the 67.7 km for which the installation date is unknown, 25.8 km was installed in conduit and is most likely less than thirty years old. The remaining 41.9 km direct-buried cable was presumably installed prior to 1986 and has exceeded its TUL. Based on this analysis, 48.9 km – or 19% – of EPL's underground cable have exceeded TUL. Table 3-32 summarizes the service age of EPL's primary underground cable relative to TUL.

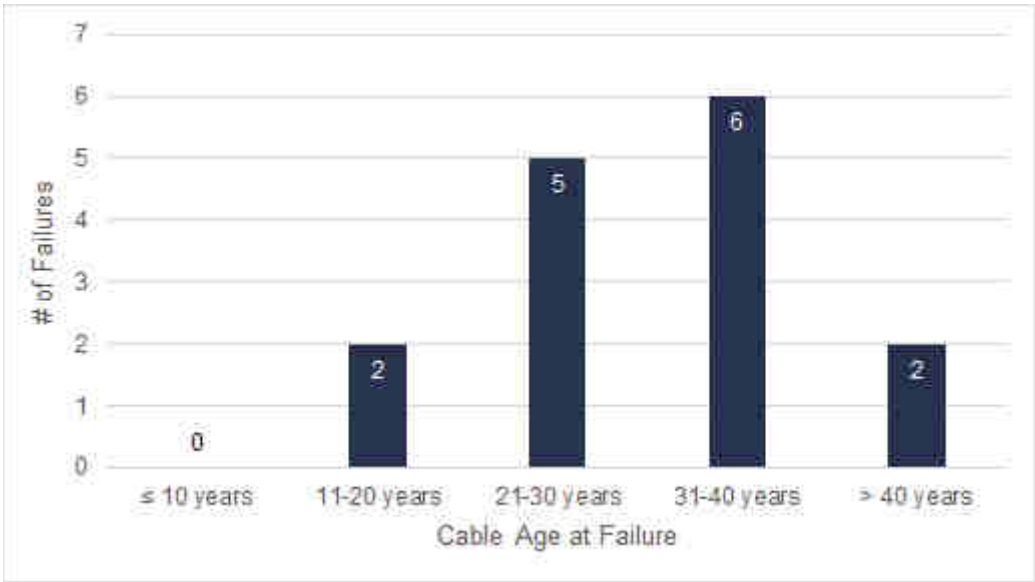
Table 3-32: Primary Underground Cable Service Age Relative to TUL

Service Age	Cable Length (km)
Past TUL	48.9
Will reach TUL by 2026	16.9
Will reach TUL by 2036	54.7
Will reach TUL by 2046	49.2
Will reach TUL by 2056	67.1
Unknown but will reach TUL after 2026	25.8
Total	262.6

3.6.2 Failure History

EPL has experienced eighteen primary cable failures over the past five years (2012 through 2016). The cable's age at failure is known for fifteen of the failures. Figure 3-13 summarizes the age distribution of failed cables. Most of the failed cabled segments were direct-buried cables, especially since cables installed in conduits starting in 1986 have been in service for thirty-one years or less. The failure history supports a TUL of thirty years for direct-buried cables.

Figure 3-13: Age of Primary Underground Cable at Failure



3.6.3 Levelized Cable Replacement

Although 49 km of underground cable has exceeded TUL, replacement should be spread out over many years to avoid rate shock. Adequately addressing this backlog of underground cable replacements over the next ten years will prepare EPL for the significant length of cable that will reach TUL by 2030. A ten-year replacement plan (2017 through 2026) should also consider the 16.9 km of cable that has not yet reached TUL, but will do so by 2026.

Table 3-33: Levelized, Ten-year Replacement Plan of Primary Underground Cables

Year	2017	2018	2019	2020	2021
Cable Length (km)	6.6	6.6	6.6	6.6	6.6
Year	2022	2023	2024	2025	2026
Cable Length (km)	6.6	6.6	6.6	6.6	6.6
Total Length of Cable Replacement (km)					66.0

Attachment 2-D

Capital Expenditure Summary

File Number:	EB-2017-0039
Exhibit:	2
Attachment	2-D
Page:	1 of 1
Date:	August 28th, 2017

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2018*

CATEGORY	Historical Period (previous plan[1] & actual)																								Forecast Period (planned)				
	2010			2011			2012			2013			2014			2015			2016			2017			2018	2019	2020	2021	2022
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	*$ '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	--	1,746	1,781	1,816	1,853	1,835
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	--	2,693	1,362	2,304	2,248	2,195
System Service	Note 1	693	--	Note 1	940	--	Note 1	885	--	Note 1	185	--	Note 1	177	--	Note 1	2,196	--	Note 1	1,005	--	Note 1	787	--	707	2,186	1,126	1,243	1,342
General Plant	Note 1	960	--	Note 1	251	--	Note 1	1,272	--	Note 1	450	--	Note 1	487	--	Note 1	547	--	Note 1	384	--	Note 1	1,504	--	1,037	856	976	927	968
TOTAL EXPENDITURE	-	5,255	--	-	4,526	--	-	6,572	--	-	5,513	--	-	6,208	--	-	7,779	--	-	5,274	--	-	6,658	--	6,183	6,185	6,222	6,270	6,339
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	--	$ 3,067	$ 3,116	$ 3,162	$ 3,213	$ 3,264

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year): 0

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category

1. Historical "previous plan" data is not required unless a plan has previously been filed

Notes on year over year Plan vs. Actual variances for Total Expenditures

Notes on Plan vs. Actual variance trends for individual expenditure categories

Attachment 2-E

Capital Projects Table

Appendix 2-AA
Capital Projects Table

Projects	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017 Bridge Year**	**2018 Test Year**
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access								
Subdivisions	$ 540,677	$ 728,506	$ 240,014	$ 150,424	$ 1,020,249	$ 446,196	$ 375,000	$ 382,500
Residential Connection/Extension	$ 188,901	$ 471,954	$ 429,496	$ 677,866	$ 872,062	$ 1,050,696	$ 386,636	$ 394,369
Municipal Requests	$ 721,963	$ 140,953	$ 1,048,671	$ 1,577,009	$ 311,344	$ 12,336	$ 600,000	$ 612,000
New Service Upgrades - C&I	$ 120,392	$ 226,150	$ 100,871	$ 21,124	$ 3,767	$ 99,080	$ 349,960	$ 356,959
Miscellaneous	-$ 69,558	$ 149,705	-$ 53,546	$ 105,509	$ 133,539	$ 150,961	$ -	$ -
Sub-Total	$ 1,502,375	$ 1,717,268	$ 1,765,507	$ 2,531,933	$ 2,340,960	$ 1,759,269	$ 1,711,596	$ 1,745,828
System Renewal								
Pole Replacement Program	$ 115,417	$ 194,333	$ 478,275	$ 193,281	$ 335,898	$ 513,973	$ 460,478	$ 114,062
O/H Reactive Replacements	$ 110,554	$ 6,908	$ -	$ 6,145	$ -	$ 104,563	$ 80,784	$ 82,400
U/G Reactive Replacements	$ 8,785	$ 53,159	$ 10,765	$ -	$ 6,890	$ -	$ 63,690	$ 64,964
Install/Replace Load Breaks	$ 34,236	$ 3,612	$ -	$ -	$ -	$ 64,119	$ 58,752	$ 59,927
Direct Buried Cable Replacement Program	$ 346,712	$ 1,100,768	$ 851,290	$ 299,670	$ 88,733	$ 43,582	$ 1,229,416	$ 2,224,410
PMH Replacement Program	$ 162,024	$ 27,180	$ 122,012	$ 63,630	$ 55,209	$ 135,236	$ 144,432	$ 147,321
Single Voltage Utility - Conversion	$ 423,196	$ 929,490	$ 935,091	$ 852,182	$ 547,174	$ 85,942	$ 617,735	$ -
Replacement - Lithgow Livefront Transformers	$ -	$ -	$ 389,704	$ -	$ -	$ -	$ -	$ -
Conversion - Monopoly Subdivisions	$ -	$ -	$ -	$ 675,210	$ 259,837	$ 312,264	$ -	$ -
Insulator Replacement	$ -	$ -	$ -	$ -	$ 132,486	$ 145,399	$ -	$ -
Conversion - Howard/6th Concession	$ -	$ -	$ -	$ -	$ 744,587	$ -	$ -	$ -
Primary Cable Replacement	$ 522,882	$ 24,495	$ -	$ 713,295	$ 113,618	$ 93,316	$ -	$ -
Transformer Replacement Program	$ 57,308	$ 47,978	$ 108,721	$ 143,405	$ 178,078	$ 424,720	$ -	$ -
Miscellaneous	$ 51,431	$ 310,092	$ 216,870	$ 65,157	$ 232,675	$ 202,228	$ -	$ -
Sub-Total	$ 1,832,545	$ 2,698,015	$ 3,112,729	$ 3,011,974	$ 2,695,184	$ 2,125,343	$ 2,655,287	$ 2,693,082
System Service								
FIT & Generation Connections	$ 463,599	$ 30,227	$ 91,689	$ 25,824	$ 67,577	$ 80,085	$ 188,892	$ 181,370
HONI Asset Purchases	$ 468,859	$ 232,123	$ 13,222	$ 89,077	$ 21,142	$ -	$ 170,360	$ 89,474
Metering Upgrade & Replacement Program	$ -	$ 56,878	$ 100,139	$ 7,712	$ 8,460	$ 156,282	$ 163,037	$ 166,297
Smart Metering Initiative	$ -	$ 515,559	$ -	$ -	$ 2,051,075	$ 87,921	$ -	$ -
Self Healing Grid Reclosers	$ -	$ -	$ -	$ 61,005	$ -	$ 633,057	$ 264,843	$ 270,140
Miscellaneous	$ 7,314	$ 50,649	-$ 20,282	-$ 7,117	$ 47,571	$ 48,019	$ -	$ -
Sub-Total	$ 939,772	$ 885,435	$ 184,769	$ 176,502	$ 2,195,825	$ 1,005,363	$ 787,132	$ 707,281
General Plant								
Bldgs & Fixtures	$ 13,214	$ 844,622	$ 21,981	$ -	$ 48,914	$ 42,469	$ 286,800	$ 370,000
Office Furniture/Equip	$ -	$ 29,967	$ 6,711	$ 876	$ 5,980	$ 20,672	$ 10,000	$ 10,000
Computer Equipment HW	$ 27,112	$ -	$ 13,501	$ 25,333	$ 5,837	$ 117,329	$ 356,150	$ 161,809
Computer Software	$ 17,981	$ 34,572	$ 52,989	$ 166,960	$ 17,043	$ 4,632	$ 254,500	$ 115,000
Transportation Equip	$ 156,970	$ 198,529	$ 307,516	$ 248,438	$ 401,244	$ 136,662	$ 487,000	$ 270,000
Tools & Equipment	$ 35,577	$ 163,983	$ 47,415	$ 45,486	$ 68,451	$ 62,365	$ 110,000	$ 110,000
Miscellaneous	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total	$ 250,855	$ 1,271,673	$ 450,112	$ 487,094	$ 547,468	$ 384,129	$ 1,504,450	$ 1,036,809
Miscellaneous								
Total	**$ 4,525,547**	**$ 6,572,392**	**$ 5,513,117**	**$ 6,207,502**	**$ 7,779,437**	**$ 5,274,104**	**$ 6,658,465**	**$ 6,183,000**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***								
Total	**4,525,547**	**6,572,392**	**5,513,117**	**6,207,502**	**7,779,437**	**5,274,104**	**6,658,465**	**6,183,000**

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

Attachment 2-F

Capitalization Policy & Amortization Policy

Essex Powerlines Corporation
Capital Assets – Amortization Policy
For the year ending December 31, 2015 (IFRS adoption on Jan 1, 2015) ***updated April 16, 2016*** **MP**

Process Owner – Max Picco (EPL) – this policy is for Essex Powerlines

Distribution system assets that are self-constructed are recorded in a job costing system (Wennsoft Job Cost now Signature Job Cost), and the process followed is outlined below:

1. job is created in job cost to capture the costs associated with the creation of the asset:
    a. Labour (Code 1)
        i. When employees work on the job they code their time into the job through the Penny Timesheet entry system.
    b. Material (Code 2)
        i. When materials are taken from inventory, or purchased directly to be used for a project it is coded to the job through either an inventory entry or an accounts payable entry.
    c. Equipment (Code 3)
        i. When a vehicle is used for a job the time it was used is coded into the job through the Penny Timesheet entry system.
    d. Sub-Contractors (Code 4)
        i. If sub-contractors are used for a job their invoice is entered into the job through the Accounts Payable module.
    e. Other (Code 5)
        i. If other A/P vendor charges are used for a job the invoice is entered into the job through the Accounts Payable module.
    f. Consultants (Code 6)
        i. If consultants are used for a job their invoice is entered into the job through the Accounts Payable module.

2. Once the job is completed the job is analyzed by supervisors and the Senior clerk (Usually by using the WSJC reporting tool to compare the Estimate created by the estimator in UTILIDE to the actual Job Costs) by both the Operations Supervisor and by the senior clerk to ensure that the costs entered into the job are valid.

3. The Senior Clerk then closes the job in WennSoft which transfers the associated WIP job costs carried in the WIP G/L account to the Fixed Asset Acquisition Clearing G/L account. This posting is summarized by Job and by charge type (the 6 codes noted above).

4. At month-end, the FAAC (fixed asset auto creator) is used to pull the amounts out of the Fixed Asset Acquisition Clearing G/L account and redistribute the capital amounts based on component types or fixed asset classes (e.g. poles, wire, conduit, etc) to the appropriate G/L accounts. At the same time the individual assets are created in the Fixed Asset Books (New IFRS & OEB, etc.) depending on the class (e.g. poles, wire, conduit, etc) and will have the appropriate life and depreciation rate attributed to the assets for future monthly depreciation calculations.

Summary

All assets meeting the definition of a fixed asset shall be considered a long-term asset and shall be recorded in the GP Fixed Asset Module. Such assets shall be systematically and accurately recorded; properly classified; and adequately documented in the GP Fixed Asset Module using Book "NEW IFRS" starting January 1, 2015. Since IFRS is being adopted effective January 1, 2015 the new fixed asset book "NEW IFRS" will be created with gross asset values that reflect the Net Book Value of the original asset costs less accumulated amortization less a pro-rata allocation of the contributed capital (net of amortization) as of December 31, 2014.

Policy

Asset Valuation

Fixed assets shall be recorded at historic cost (not to include administrative overhead) after December 31, 2014. All costs shall be documented, including methods and sources used to establish any estimated costs.

1. Purchased Assets – The recording of purchased assets shall be made on the basis of actual costs, including all ancillary costs, based on vendor invoice or other supporting documentation.
2. Constructed Assets – All direct costs (including labor, but not administrative overhead as was the practice until December 31, 2014 under CGAAP) associated with the construction project shall be included in establishing the asset valuation.

Asset Decommissioning Costs and Salvage Value

The company maintains that any endo of life decommissioning costs net of any salvage value amount to immaterial amounts when discounted to present. As such Essex Powerlines does not add decommissioning costs to capitalized assets.

Asset Classification and amortization periods

Fixed assets should be categorized and amortized as follows:

		FA Module Book Class set-up	
		Useful Lives	
		Used till Dec 2014 = Book ID "OEB"	New starting Jan 1, 2015 = Book ID "NEW IFRS"
1612	Land Rights (intangible)	50	50
1830	Poles	25	50
1835	O/H Conductor	25	50
1840	U/G Conduit	25	40
1845	U/G Conductor	25	30
1850	U/G Transf	25	40
1850	O/H Transf	25	40
1855	Services (Overhead/Underground)	25	50 & 40
1860	Meters Std.	25	25
1860	Meters Interval	25	25
1860	Meters Wholesale	25	25
1860	Meters - Smart	25	15
1865	Other Insall on Cust. Premises	25	25
1908	Buildings & Fixtures	25	50
1915	Office Furniture/Equipment	10	10
1920	Computer Equipment	5	5
1611	Compter Software (intangible)	5	5
1930	Transportation Equipment (Small/Large)	5 & 8	7 & 10
1935	Stores Equipment	10	10
1940	Tools & Equip	10	10
1945	Pwr Measure & Test Equip	10	10
1955	Communication Equipment	10	10
2075	Non-Utility Prop Owned (solar)	20	20

General Policy for Capitalization

Fixed assets should be capitalized as follows:

- All land acquisitions
- All buildings/facilities acquisitions and new construction
- Facility renovation and improvement projects costing more than $1,000
- Equipment and assets costing more than $500 with a useful life beyond a single reporting period (generally one year)
- Purchases of equipment and facilities acquired through a debt financing arrangement meeting the capital lease
- Intangible assets of purchased or internally generated computer software and all other intangible assets costing more than $500 with a useful life beyond a single reporting period (generally one year)
- Construction in Progress (CIP) for capital projects with a budget in excess of $500 shall be presented as part of PP&E but not amortized

Capitalized Interest Costs:

As per IAS 16, the company capitalizes any directly attributable borrowing costs for qualifying assets (construction period in excess of 1 year). The objective of capitalizing interest is to obtain a measure of the acquisition cost that more closely reflect the total investment in the asset.

The capitalization period begins when the following four considerations are present:

- Expenditures for the capital asset have been made.
- Activities necessary to get the capital asset ready for its intended use are in progress.
- Interest costs are being incurred.
- The construction period of cost accumulation exceeds 1 year.

A weighted average of the rates on other borrowings is to be applied to expenditures not covered by specific new borrowings.

Intangible Assets

Intangible assets are those that lack physical substance, are non-financial in nature and have an initial useful life extending beyond a single reporting period (land use rights or easements, and software). Software costing more than $500 with a useful life beyond a single reporting period (generally one-year) should be capitalized.

General and administrative costs and overhead expenditures associated with intangible assets are not to be capitalized as part of the cost.

Construction in Progress (CIP)

A listing of CIP assets reflect the cost of construction work undertaken, but not yet completed. For construction in progress assets, no depreciation is recorded until the asset is placed in service. When construction is completed, the assets are reclassified under the appropriate categories, capitalized and amortized over their useful lives.

Amortization Method

Essex Powerlines has established the straight-line methodology for amortizing all fixed assets using the half-year convention.

Asset Retirement or Disposition and the Derecognition of those Assets

Asset retirement will be transacted when assets are prematurely replaced or there are no more future economic benefits expected from use or planned disposal. Retiring an entire asset will require the removal of the entire asset and related accumulated depreciation from the fixed asset module in GP. Any undepreciated balance will be reported as a loss on disposition.

Disposition of an entire asset will require the removal of the entire asset and related accumulated depreciation from the fixed asset module in GP. Any proceeds will be applied against the NBV and a gain or loss on disposition recorded.

Attachment 2-G

Overhead Expense

Appendix 2-D
Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	**2011 Historical Year**	**2012 Historical Year**	**2013 Historical Year**	**2014 Historical Year**	**2015 Historical Year**	**2016 Historical Year**	**2017 Bridge Year**	**2018 Test Year**
Distribution	$ 2,311,983	$ 2,769,624	$ 2,288,897	$ 2,573,946	$ 2,768,874	$ 2,489,996	$ 2,112,492	$ 2,200,339
Billing & Collecting	$ 1,131,257	$ 1,174,568	$ 1,329,771	$ 1,158,128	$ 1,229,676	$ 1,348,249	$ 1,499,880	$ 1,550,150
Community Relations	$ 11,394	$ 8,539	$ 8,451	$ 10,016	$ 12,013	$ 6,482	$ 23,442	$ 23,396
Administrative & General	$ 2,092,295	$ 2,240,566	$ 2,400,175	$ 2,962,130	$ 2,753,655	$ 3,136,895	$ 3,579,949	$ 3,796,390
Labour Burden	$ 229,006	$ 293,809	$ 370,247	$ 375,867	$ 420,809	$ 426,466	$ 486,528	$ 496,528
Material Burden	$ 415,547	$ 451,614	$ 117,111	$ 94,162	$ 92,905	$ 79,266	$ 88,476	$ 90,246
Vehicle Burden	$ 153,393	$ 234,821	$ 251,570	$ 216,004	$ 263,029	$ 228,808	$ 240,000	$ 250,000
Total OM&A Before Capitalization (B)	$ 6,344,875	$ 7,173,540	$ 6,766,223	$ 7,390,252	$ 7,540,961	$ 7,716,163	$ 8,030,767	$ 8,407,049

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	**2011 Historical Year**	**2012 Historical Year**	**2013 Historical Year**	**2014 Historical Year**	**2015 Historical Year**	**2016 Historical Year**	**2017 Bridge Year**	**2018 Test Year**	**Directly Attributable? (Yes/No)**	**Explanation for Change in Overhead Capitalized**
Labour Burden	$ 229,006	$ 293,809	$ 370,247	$ 375,867	$ 420,809	$ 426,466	$ 486,528	$ 496,528	Yes	Training no longer capitalized under IFRS/MIFRS.
Material Burden	$ 415,547	$ 451,614	$ 117,111	$ 94,162	$ 92,905	$ 79,266	$ 88,476	$ 90,246	Yes	Removed the Admin OH layer of our burdens due to IFRS/MIFRS
Vehicle Burden	$ 153,393	$ 234,821	$ 251,570	$ 216,004	$ 263,029	$ 228,808	$ 240,000	$ 250,000	Yes	No changes necessary under MIFRS/IFRS.
Total Capitalized OM&A (A)	$ 797,946	$ 980,244	$ 738,928	$ 686,033	$ 776,743	$ 734,540	$ 815,004	$ 836,774		
% of Capitalized OM&A (=A/B)	13%	14%	11%	9%	10%	10%	10%	10%		

Attachment 2-H

Service Reliability Indicators

Appendix 2-G
Service Reliability and Quality Indicators
2011 - 2015

Service Reliability

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply					Excluding Major Event Days				
	2012	2013	2014	2015	2016	2012	2013	2014	2015	2016	2012	2013	2014	2015	2016
SAIDI	4.530	5.370	3.820	2.230	2.540	0.890	2.240	1.160	1.340	0.630	4.530	5.370	3.820	2.230	2.540
SAIFI	3.830	3.580	2.460	1.840	3.200	0.610	1.120	0.660	0.830	0.500	3.830	3.580	2.460	1.840	3.200

5 Year Historical Average

SAIDI		3.698		1.252		3.698
SAIFI		2.982		0.744		2.982

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

Service Quality

Indicator	OEB Minimum Standard	2012	2013	2014	2015	2016
Low Voltage Connections	90.0%	93.2%	92.7%	93.0%	92.3%	90.5%
High Voltage Connections	90.0%	N/A	N/A	N/A	N/A	N/A
Telephone Accessibility	65.0%	68.5%	66.4%	78.0%	79.2%	73.6%
Appointments Met	90.0%	95.7%	94.3%	94.7%	94.8%	90.8%
Written Response to Enquires	80.0%	93.9%	91.2%	91.7%	84.7%	96.3%
Emergency Urban Response	80.0%	91.2%	92.9%	96.3%	100.0%	97.7%
Emergency Rural Response	80.0%	N/A	N/A	N/A	N/A	N/A
Telephone Call Abandon Rate	10.0%	7.0%	1.7%	1.2%	1.4%	0.8%
Appointment Scheduling	90.0%	96.8%	96.5%	95.5%	98.5%	98.8%
Rescheduling a Missed Appointment	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Reconnection Performance Standard	85.0%	96.7%	93.3%	95.3%	93.7%	97.5%