St. Thomas energy inc.
We're Your Local Power Distributor

File Number: EB-2014-0113

Date Filed: April 25, 2014

Exhibit 2

RATE BASE

Exhibit 2

Tab 1 of 1

Rate Base

RATE BASE OVERVIEW

This exhibit provides details on St. Thomas Energy Inc.'s distribution rate base forecast for the 2015 Test Year. It also provides an explanation of variances between 2011 Board Approved, 2011 actuals, 2012, 203, 2014 Bridge Year and the 2015 Test Year.

St. Thomas Energy Inc. is seeking approval in this Application, based on a forward test year, for 2015 electricity distribution rates ("EDR") effective January 1, 2015 ("Test Year"). The rate base for purpose of calculating the revenue requirement used in this Cost of Service Application follows Chapter 2 of the Filing Requirements for Electricity Transmission and Distribution Applications issued on July 17th, 2013. In accordance with the Board's Filing Requirements, STEI has calculated the rate based on the average of the opening and closing balance of the 2015TY gross fixed assets and accumulated depreciation and contributed capital, plus a working capital allowance calculated as 13% of the sum of the cost of power and controllable expenses.

Capital assets include those assets that are associated with the activities for the distribution of electricity. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

STEI has provided its rate base calculations for the 2011 COS Application, 2011, 2012 and 2013 actuals, 2014BY and 2015BY. The 2014BY and 2015TY is based upon budget.

STEI rate base for the 2015TY is $31,484,194, an increase of $7,606,522 from the 2011 Board Approved rate base. The following table provides comparative rate base calculations for the 2011 Board Approved, 2011, 2012 and 2013 actuals, 2014BY and 2015 TY.

The 2011 to 2013 years including a working capital allowance of 15%, 2014BY and 2015TY working capital allowance is 13%.

The following Table 2-1 summarizes the increase in rate base from the 2011 Board Approved to the 2015TY.

Table 2-1

Increase in Rate Base from 2011 Board Approved to 2015TY

2011 Approved		**23,877,672**
Increase in working capital	2011 to 2015	112,359
Smart meter transfer - NBV	2012	2,848,778
Restructuring	2012	1,407,734
Stranded meter transfer - NBV	2015	(438,774)
Capital - NBV	2011 to 2015	3,676,426
2015TY Rate Base		**31,484,194**

As provided in the above table, working capital has increased by $112,359, smart meter transfer in 2012 increased NBV of assets by $2,848,778, corporate restructuring resulted in assets transfer of $1,407,737 and "normal" capital additions have increased by $3,676,426 over the period. The 2015TY rate based also includes the removal of the NBV stranded meters $438,774.

SMART METER INITIATIVE

STEI incurred cumulative capital costs of $3,267,776 for the installation of smart meters and the implementation of Time-Of-Use ("TOU") billing for residential and General Service < 50 kW and General Service > 50 kW customers. Smart meters were part of a public policy directive, but will facilitate improved customer service as the functionality associated with the available smart meter data evolves and improves. The recovery of capital costs associated with smart meters was the subject of STEI's Smart Meter Prudence Review Application (EB-2012-0348). The outcome of that application was a Board decision that approved a smart meter incremental revenue rate rider effective until STEI's next cost of service application and historical smart meter costs rate rider effective until April 30, 2014.

RESTRUCTURING

The January 1, 2012 corporate restructuring included assets associated with the Utility operations in the amount of $1,407,734. The transferred assets included; office furniture and equipment, computer hardware, transportation equipment, tools and equipment, communication equipment, mobile substation, system supervisory equipment and vehicle tools.

ALLOWANCE FOR WORKING CAPITAL

OM&A Costs

The controllable OM&A costs used in the working capital allowance calculation are shown in Table 2-2 below:

Table 2-2

Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2011 Board-Approved)	Last Rebasing Year (2011 Actuals)	2012 Actuals	2013 Actuals	2014 Bridge Year	2015 Test Year
Reporting Basis						
Operations	$ 493,406	$ 558,853	$ 958,213	$ 868,543	$ 925,270	$ 977,701
Maintenance	$ 423,276	$ 364,438	$ 324,575	$ 274,855	$ 333,832	$ 340,842
SubTotal	**$ 916,682**	**$ 923,291**	**$ 1,282,788**	**$ 1,143,398**	**$ 1,259,102**	**$ 1,318,543**
%Change (year over year)			38.9%	-10.9%	10.1%	4.7%
%Change (Test Year vs Last Rebasing Year - Actual)						42.8%
Billing and Collecting	$ 1,133,130	$ 982,501	$ 1,039,175	$ 869,044	$ 938,833	$ 965,058
Community Relations	$ 19,513	$ 2,684	$ 32,390	$ -	$ -	$ -
Administrative and General	$ 1,502,109	$ 1,832,734	$ 2,691,486	$ 1,998,931	$ 2,259,284	$ 2,351,019
SubTotal	**$ 2,654,752**	**$ 2,817,919**	**$ 3,763,051**	**$ 2,867,975**	**$ 3,198,117**	**$ 3,316,077**
%Change (year over year)			33.5%	-23.8%	11.5%	3.7%
%Change (Test Year vs Last Rebasing Year - Actual)						17.7%
Total	**$ 3,571,434**	**$ 3,741,210**	**$ 5,045,839**	**$ 4,011,373**	**$ 4,457,219**	**$ 4,634,620**
%Change (year over year)			34.9%	-20.5%	11.1%	4.0%

	Last Rebasing Year (2011 Board-Approved)	Last Rebasing Year (2011 Actuals)	2012 Actuals	2013 Actuals	2014 Bridge Year	2015 Test Year
Operations	$ 493,406	$ 558,853	$ 958,213	$ 868,543	$ 925,270	$ 977,701
Maintenance	$ 423,276	$ 364,438	$ 324,575	$ 274,855	$ 333,832	$ 340,842
Billing and Collecting	$ 1,133,130	$ 982,501	$ 1,039,175	$ 869,044	$ 938,833	$ 965,058
Community Relations	$ 19,513	$ 2,684	$ 32,390	$ -	$ -	$ -
Administrative and General	$ 1,502,109	$ 1,832,734	$ 2,691,486	$ 1,998,931	$ 2,259,284	$ 2,351,019
Total	**$ 3,571,434**	**$ 3,741,210**	**$ 5,045,839**	**$ 4,011,373**	**$ 4,457,219**	**$ 4,634,620**
%Change (year over year)			34.9%	-20.5%	11.1%	4.0%

	Last Rebasing Year (2011 Board-Approved)	Last Rebasing Year (2011 Actuals)	Variance 2011 BA – 2011 Actuals	2012 Actuals	Variance 2012 Actuals vs. 2011 Actuals	2013 Actuals	Variance 2013 Actuals vs. 2012 Actuals	2014 Bridge Year	Variance 2014 Bridge vs. 2013 Actuals	2015 Test Year	Variance 2015 Test vs. 2014 Bridge
Operations	$ 493,406	$ 558,853	-$ 65,447	$ 958,213	$ 399,360	$ 868,543	-$ 89,670	$ 925,270	$ 56,727	$ 977,701	$ 52,431
Maintenance	$ 423,276	$ 364,438	$ 58,838	$ 324,575	-$ 39,863	$ 274,855	-$ 49,720	$ 333,832	$ 58,977	$ 340,842	$ 7,010
Billing and Collecting	$ 1,133,130	$ 982,501	$ 150,629	$ 1,039,175	$ 56,674	$ 869,044	-$ 170,131	$ 938,833	$ 69,789	$ 965,058	$ 26,225
Community Relations	$ 19,513	$ 2,684	$ 16,829	$ 32,390	$ 29,706	$ -	-$ 32,390	$ -	$ -	$ -	$ -
Administrative and General	$ 1,502,109	$ 1,832,734	-$ 330,625	$ 2,691,486	$ 858,752	$ 1,998,931	-$ 692,555	$ 2,259,284	$ 260,353	$ 2,351,019	$ 91,735
Total OM&A Expenses	$ 3,571,434	$ 3,741,210	-$ 169,776	$ 5,045,839	$ 1,304,629	$ 4,011,373	-$ 1,034,466	$ 4,457,219	$ 445,846	$ 4,634,620	$ 177,401
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)											
Total Recoverable OM&A Expenses	$ 3,571,434	$ 3,741,210	-$ 169,776	$ 5,045,839	$ 1,304,629	$ 4,011,373	-$ 1,034,466	$ 4,457,219	$ 445,846	$ 4,634,620	$ 177,401
Variance from previous year				$ 1,304,629		-$ 1,034,466		$ 445,846		$ 177,401	
Percent change (year over year)				35%		-21%		11%		4%	
Percent Change: Test year vs. Most Current Actual						15.54%					
Simple average of %variance for all years						23.88%					7%
Compound Annual Growth Rate for all years											4.4%
Compound Growth Rate (2013 Actuals vs. 2011 Actuals)						2.35%					

COST OF POWER CALCULATION

STEI has calculated the Cost of Power for the 2015 Test Year based upon the 2015 load forecast, adjusted for the impact of Conservation and Demand Management ("CDM") activities, and its proposed loss factor of 1.0367. Detailed calculations are provided in Table 3, 2015 Cost of Power Calculation.

COMMODITY PRICES

In accordance with the Filing Requirements, the commodity price estimate used to calculate the Cost of Power was determined in a way that bases the split between Regulated Price Plan ("RPP") and non-RPP customers on actual data and uses the most current RPP price. The most current non-RPP price was obtained from the Ontario Wholesale Electricity Market Price Forecast Report for the period May 1, 2014 through October 31, 2015 prepared by Navigant Consulting and presented to the Board on April 10, 2014. STEI understands that the commodity charge will be updated to reflect any changes to commodity prices that may become available prior to the approval of its Application.

NON-RPP PRICING

In its report, Navigant estimated that the average Hourly Ontario Energy Price ("HOEP") for the period from May 2014 to April 2015 would be $0.02628 per kWh and the HOEP for the period May 2014 to October 2015 would be $0.02193 per kWh. STEI has the HOEP based on the weighted average HOEP provided by Navigant from January to October 2015 and the assumption that the HOEP in November and December of 2015 will remain at the same level as October 2015. As shown in Table 3-3, the average HOEP price of $0.02301 per kWh was used as the basis for the 2015 cost of power estimate. STEI will update the forecasted HOEP for 2014 once additional information is available. The Global Adjustment is calculated using the forecasted rate of $0.06468 per kWh as provided in the Board's Regulated Price Plan Report dated April 16, 2014 (the "RPP Report").

Table 2-3

Weighted Average HOEP for Non-RPP Customers

Month	HOEP ($ per MWh)
January	29.79
February	23.21
March	23.21
April	23.21
May	21.29
June	21.29
July	21.29
August	22.57
September	22.57
October	22.57
November	22.57
December	22.57
Average	**23.01**

RPP PRICING

In its RPP Report, the Board estimated the RPP price for the period from May 1, 2014 through April 30, 2015 to be $0.09250 per kWh. STEI has used the estimate of $0.09250 per kWh for the 2015 Test Year for customers who are on RPP pricing. STEI will update the RPP price once additional information is available.

WEIGHTED AVERAGE COST OF POWER

In arriving at the weighted average cost of power, the 2013 actual RPP and non-RPP kWh were used as outlined in Table 2-4.

Table 2-4

2013 Actual kWh			
Customer Class Name	**non-RPP**	**RPP**	**Total**
Residential	15,455,793	102,479,231	117,935,024
General Service < 50 kW	8,727,820	30,247,062	38,974,882
General Service > 50 kW	111,231,144	8,791,252	120,022,396
Sentinel Lighting	3,789	56,049	59,838
Street Lighting	334,119	2,790,273	3,124,392
microFit			
TOTAL	**135,752,665**	**144,363,867**	**280,116,532**
%	***48.46%***	***51.54%***	
Forecasted Price			
HOEP ($/MWh)	23.01		
Global Adjustment ($/MWh)	64.68		
Total ($/MWh)	**87.69**	**92.50**	
$/kWh	**0.08769**	**$0.09250**	
%	*48.46%*	*51.54%*	
Weighted Average Price	**$0.04250**	**$0.04767**	**$0.09017**

UNIFORM TRANSMISSION RATES

Oakville Hydro has calculated Retail Transmission charges using the most recent Uniform Transmission Rates ("UTR") approved by the Board (EB-2012-0031), issued on December 20, 2012 and effective January 1, 2013.

- Network Service Rate: $3.82 per kW
- Line Connection Service Rate: $0.82 per kW
- Transformation Connection Service Rate: $1.98 per kW

STEI understands the transmission charges will be updated to reflect any new rates that may become available prior to the approval of its Application.

REGULATORY CHARGES

The Wholesale Market Service ("WMS") costs are calculated based on the current rates and forecasted purchases for the 2015 Test Year. The current rate for WMS and the Rural Rate Assistance ("RRA") are $0.0052 per kWh and $0.0044 per kWh respectively.

SMART METER ENTITY CHARGE

The Smart Meter Entity costs are calculated based on the rate of $0.79 per month for each Residential and General Service < 50 kW customer approved by the Board on March 28, 2013.

2015 COST OF POWER CALCULATION

STEI has calculated the cost of power for the 2015 Test Year as $32,028,491. Table 6, 2015 Cost of Power Calculation provides the detailed calculation of the cost of power for the 2014 Test Year.

DIFFERENCE BETWEEN THIS COST OF POWER, AND COST OF POWER USED

During the final review of STEI's 2015 Cost of Service Rate Application, STEI realized that the commodity price estimate was not calculated per the filing requirements.

STEI recalculated the commodity price estimate in a way that bases the split between Regulated Price Plan ("RPP") and non-RPP customers on actual data and uses the most current RPP price. The most current non-RPP price was obtained from the Ontario Wholesale Electricity Market Price Forecast Report for the period May 1, 2014 through October 31, 2015 prepared by Navigant Consulting and presented to the Board on April 10, 2014.

The difference between the commodity estimate approach in this Application and the Boards identified methodology is that the 2015TY cost of power is overstated by $2,178,036, resulting in the 2015TY revenue requirement being overstated by approximately $18,600 which is well below the materiality level of $50,000.

STEI understands that the commodity charge based upon the filing requirement will be updated to reflect any changes to commodity prices that may become available prior to the approval of this Application.

Table 2-5

Impact of Error in Cost of Power

	Correct	Used In Submission	Difference
Cost of Power	32,028,491	34,206,527	2,178,036
Cost of Power contribution to:			
Rate Base	4,163,704	4,446,849	283,145
Deemed Interest	117,300	125,277	7,977
Deemed Return on Equity	155,889	166,490	10,601
Cost of Power component Revenue Requirement (Pre-Tax)	**273,189**	**291,767**	**18,578**

Table 2-6

Forecasted Purchases	Residential	GS < 50 kW	GS > 50 kW	Sentinel Lighting	Street Lighting	Total
Average Number of Customers (Connections)	15,120	1,737	144	52	4,918	21,971
kWh	125,580,474	42,419,649	121,548,384	23,830	3,253,386	292,825,724
kW			299,044	176	8,685	307,905
Commodity Charges ($0.09017/kWh)	**11,323,591**	**3,824,980**	**10,960,018**	**2,149**	**293,358**	**26,404,095**
Retail Transmission Charges						
Network Rate	0.0071	0.0070	2.8088	1.7656	2.1660	
Network Charges	891,621	296,938	839,955	311	18,812	2,047,636
Connection Rate	0.0054	0.0050	2.0381	1.2803	1.5714	
Connection Charges	678,135	212,098	609,482	225	13,648	1,513,587
Regulatory Charges						
Wholesale Market Service Charges ($0.0052/kWh)	653,018	220,582	632,052	124	16,918	1,522,694
Rural Rate Protection Charges ($0.0013/kWh)	163,255	55,146	158,013	31	4,229	380,673
Smart Metering Entity Charge ($0.79)	143,338	16,467				159,804
Total Cost of Power	**13,852,958**	**4,626,210**	**13,199,519**	**2,840**	**346,964**	**32,028,491**

VARIANCE ANALYSIS OF RATE BASE

Detailed information on the capital expenditure spending in 2011 to 2015 is provided in Exhibit 2.1.5. This information helps to supplement the variance explanations provided below.

2011 Board Approved vs 2011 Actual

As provided in the following Table 2-7, the 2011 actual rate base of $23,415,789 is $461,884 less than the 2011 Board Approved rate base of $23,877,673

Table 2-7

RATE BASE ANALYSIS

	2011 Board Approved	2011 Actual	Variance
Reporting Basis	**CGAAP**	**CGAAP**	
Net Book Value			
Closing gross fixed assets	40,233,778	40,977,689	743,911
Closing accumulated depreciation	(21,293,096)	(22,001,262)	(708,166)
Net Book Value	**18,940,682**	**18,976,427**	**35,745**
Average Net Book Value	**18,940,682**	**18,861,900**	**(78,783)**
Working Capital Allowance			
Cost of power	29,341,836	26,618,052	(2,723,784)
OM&A	3,571,434	3,741,210	169,776
	32,913,270	30,359,262	(2,554,008)
Working capital %	15%	15%	
Working Capital Allowance	**4,936,991**	**4,553,889**	**(383,101)**
Total Rate Base	**23,877,673**	**23,415,789**	**(461,884)**

The average net book value of assets was $78,783 lower and the working capital allowance was $383,101 lower than the 2011 Board Approved.

The rate base reduction is mainly attributed to the reduction in the COP of $2,723,784 which is partially offset by increased OM&A costs of $169,776. The 2011 Cost of Service Settlement process resulted in a reduction of STEI's OM&A costs by $303,642, however, as STEI as a virtual utility with a fixed price MSA was not able to recognize the settlement reduction.

2011 Actual vs 2012 Actual

The 2012 rate base of $27,025,479 is $3,609,690 greater than the 2011 rate base of $23,415,789. Table 2-8 shows the details of the year over year change.

Table 2-8

RATE BASE ANALYSIS

	2011 Actual	2012 Actual	Variance
Reporting Basis	**CGAAP**	**IFRS**	
Net Book Value			
Closing gross fixed assets	40,977,689	48,041,875	7,064,186
Closing accumulated depreciation	(22,001,262)	(23,550,510)	(1,549,248)
Net Book Value	**18,976,427**	**24,491,365**	**5,514,938**
Average Net Book Value	**18,861,900**	**21,733,896**	**2,871,997**
Working Capital Allowance			
Cost of power	26,618,052	30,231,382	3,613,330
OM&A	3,741,210	5,045,839	1,304,629
	30,359,262	35,277,221	4,917,959
Working capital %	15%	15%	
Working Capital Allowance	**4,553,889**	**5,291,583**	**737,694**
Total Rate Base	**23,415,789**	**27,025,479**	**3,609,690**

The increase in the rate based is attributed to the increased net book value of $5,514,938 related to; corporate restructuring of $1,407,734 and the capitalization of $3,627,775 of smart meter cost per STEI's 2012 Smart Meter prudence review (EB-2012-0348) and additional normal capital costs primarily related to system conversion. 2012 amortization included additional smart meter amortization of $418,997 for the 2010 and 2011 years.

The 2012 cost of power of $30,231,382 was $3,612,330 higher than the 2011 amount of $26,618,052 and OM&A of $5,045,839 was $1,304,629 higher than the 2011 amount of $4,019,601. The 2012 OM&A cost reflect the first year operating as an independent operational utility that adopted IFRS capitalization policies. As such, amounts that may have been capitalized under the previous MSA are now considered administrative and expensed.

2012 Actual vs 2013 Actual

The 2013 rate base of $29,688,965 is $2,663,486 greater than the 2012 rate base of $27,025,479. Table 2-9 shows the details of the year over year change.

Table 2-9

RATE BASE ANALYSIS

	2012 Actual	2013 Actual	Variance
Reporting Basis	**IFRS**	**IFRS**	
Net Book Value			
Closing gross fixed assets	48,041,875	49,565,396	1,523,521
Closing accumulated depreciation	(23,550,510)	(24,686,619)	(1,136,109)
Net Book Value	**24,491,365**	**24,878,777**	**387,412**
Average Net Book Value	**21,733,896**	**24,685,071**	**2,951,175**
Working Capital Allowance			
Cost of power	30,231,382	29,347,928	(883,454)
OM&A	5,045,839	4,011,363	(1,034,476)
	35,277,221	33,359,291	(1,917,930)
Working capital %	15%	15%	
Working Capital Allowance	**5,291,583**	**5,003,894**	**(287,690)**
Total Rate Base	**27,025,479**	**29,688,965**	**2,663,486**

The net book value increase of $2,951,175 is primarily related to the capital expenditure increases incurred in 2012 and the capital expenditures in 2013 both of which represent investment in the distribution system to ensure its safe and reliable operation and voltage conversion program.

Cost of power for 2013 of $29,347,928 is $883,454 less than the 2012 amount $30,231,382 and OM&A expenses of $4,011,363 were $1,034,476 less than the amount recorded in 2012, resulting in reduced working capital allowance of $287,690. The 2013 OM&A was lower than 2012 due to the following, but not limited to factors:

- Management fee reduction, $305,000
- Reduced labour, $140,000
- Actuarial gain related to employee post-employment benefits, $175,000
- One-time smart meter costs in 2012, $238,000
- Additional savings are attributed to various building and supplies reductions, bad debt reductions and other efficiency savings such as adopting Paymentus visa payments and reduced substation maintenance costs.

2013 Actual vs 2014 Bridge Year

The 2014BY rate base of $30,350,892 is $661,927 greater than the 2013 rate base of $29,688,965. Table 10 shows the details of the year over year change.

Table 2-10

RATE BASE ANALYSIS	2013 Actual	2014 BY	Variance
Reporting Basis	**IFRS**	**IFRS**	
Net Book Value			
Closing gross fixed assets	49,565,396	52,082,188	2,516,792
Closing accumulated depreciation	(24,686,619)	(25,913,481)	(1,226,862)
Net Book Value	**24,878,777**	**26,168,707**	**1,289,930**
Average Net Book Value	**24,685,071**	**25,523,742**	**838,671**
Working Capital Allowance			
Cost of power	29,347,928	32,674,700	3,326,772
OM&A	4,011,363	4,457,219	445,856
	33,359,291	37,131,919	3,772,628
Working capital %	15%	13%	
Working Capital Allowance	**5,003,894**	**4,827,149**	**(176,744)**
Total Rate Base	**29,688,965**	**30,350,892**	**661,927**

The increased net book value of $838,671 reflects STEI's continued planned investment is STEI's infrastructure, primarily focusing on distribution system replacement and voltage conversion.

The 2014BY COP of $32,674,700 is $3,326,772 greater than the 2013 actual amount of $29,347,928 and 2014BY OM&A of $4,457,219 is $445,856 greater than the 2013 actual amount of $4,011,363. The increase in year over year OM&A expenses is impacted by the one-time employee post retirement gain of $175,000 in 2013 that reduced the Administration costs.

The 2014 working capital allowance of 13% is 2% less than the 2013 rate of 15%, resulting in a net reduction of $176,744.

2014 Bridge Year vs 2015 Test Year

The 2015TY rate base of $31,484,194 is $1,133,303 greater than the 2014BY rate base of $30,350,892. Table 2-11 shows the details of the year over year change.

Table 2-11

RATE BASE ANALYSIS

	2014 BY	2015 TY	Variance
Reporting Basis	**IFRS**	**IFRS**	
Net Book Value			
Closing gross fixed assets	52,082,188	52,262,474	180,286
Closing accumulated depreciation	(25,913,481)	(25,561,490)	351,991
Net Book Value	**26,168,707**	**26,700,984**	**532,277**
Average Net Book Value	**25,523,742**	**26,434,845**	**911,103**
Working Capital Allowance			
Cost of power	32,674,700	34,206,528	1,531,828
OM&A	4,457,219	4,634,619	177,400
	37,131,919	38,841,147	1,709,228
Working capital %	13%	13%	
Working Capital Allowance	**4,827,149**	**5,049,349**	**222,200**
Total Rate Base	**30,350,892**	**31,484,194**	**1,133,303**

The 2015TY average net book value of capital has increased by $911,103 from the 2014TY.The capital additions reflect STEI's continued planned investment is STEI's infrastructure, primarily focusing on distribution system replacement and voltage conversion.

The capital has also been impacted by the removal of stranded meters from rate base from Account 1860 – Meters to Account 1555 - Sub-Account Stranded Meter Costs. The net amount of the transfer is $438,774.

2015TY COP of $34,206,528 is $1,531,828 greater than the 2014TY amount of $32,674,700 and 2015TY OM&A expenses of $4,634,619 are $177,400 greater than the 2014BY amount of $4,457,219, resulting an increased working capital allowance $222,200.

The following Tables are Board Appendix 2-BA2 for the 2011, 2012 and 2013 Actuals, 2014BY and 2015TY

Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2011

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)				$ -				$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)				$ -				$ -	$ -
N/A	1805	Land	$ 6,734	$ -		$ 6,734				$ -	$ 6,734
47	1808	Buildings	$ -			$ -				$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 850,125	$ -		$ 850,125	-$ 826,607	-$ 4,669		-$ 831,276	$ 18,849
47	1825	Storage Battery Equipment	$ -			$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 7,783,183	$ 675,464		$ 8,458,646	-$ 3,571,193	-$ 305,413		-$ 3,876,606	$ 4,582,040
47	1835	Overhead Conductors & Devices	$ 7,161,739	$ 321,075		$ 7,482,814	-$ 3,648,532	-$ 284,619		-$ 3,933,151	$ 3,549,664
47	1840	Underground Conduit	$ 3,822,469	$ 114,143		$ 3,936,612	-$ 1,773,049	-$ 133,232		-$ 1,906,280	$ 2,030,331
47	1845	Underground Conductors & Devices	$ 7,760,134	$ 257,423		$ 8,017,557	-$ 3,453,990	-$ 295,519		-$ 3,749,510	$ 4,268,047
47	1850	Line Transformers	$ 8,846,369	$ 306,820		$ 9,153,189	-$ 4,565,271	-$ 328,136		-$ 4,893,407	$ 4,259,782
47	1855	Services (Overhead & Underground)	$ 5,010,730	$ 194,111		$ 5,204,841	-$ 2,141,523	-$ 194,043		-$ 2,335,566	$ 2,869,274
47	1860	Meters	$ 2,428,925	$ 12,719		$ 2,441,644	-$ 1,443,777	-$ 75,486		-$ 1,519,263	$ 922,381
47	1860	Meters (Smart Meters)				$ -				$ -	$ -
N/A	1905	Land	$ 174,188			$ 174,188				$ -	$ 174,188
47	1908	Buildings & Fixtures	$ 2,385,250			$ 2,385,250	-$ 850,574	-$ 49,633		-$ 900,207	$ 1,485,043
13	1910	Leasehold Improvements				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware				$ -				$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment				$ -				$ -	$ -
8	1935	Stores Equipment				$ -				$ -	$ -
8	1940	Tools, Shop & Garage Equipment				$ -				$ -	$ -
8	1945	Measurement & Testing Equipment				$ -				$ -	$ -
8	1950	Power Operated Equipment				$ -				$ -	$ -
8	1955	Communications Equipment				$ -				$ -	$ -
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	$ 43,592			$ 43,592	-$ 28,788	-$ 2,906		-$ 31,695	$ 11,898
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants	-$ 6,916,641	-$ 266,363		-$ 7,183,004	$ 1,688,377	$ 287,320		$ 1,975,698	-$ 5,207,307
	etc.					$ -				$ -	$ -
						$ -				$ -	$ -
		Sub-Total	$ 39,356,795	$ 1,615,391	$ -	$ 40,972,186	-$ 20,614,926	-$ 1,386,336	$ -	-$ 22,001,262	$ 18,970,924
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	$ 39,356,795	$ 1,615,391	$ -	$ 40,972,186	-$ 20,614,926	-$ 1,386,336	$ -	-$ 22,001,262	$ 18,970,924
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						-$ 1,386,336			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 1,386,336

Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2012

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ -	$ 476,100		$ 476,100	$ -	-$ 97,936		-$ 97,936	$ 378,164
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 6,734	$ 904		$ 7,638	$ -			$ -	$ 7,638
47	1808	Buildings	$			$	$			$	$
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 850,125	$		$ 850,125	$ 831,276	$ 836		$ 832,112	$ 18,013
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,458,646	$ 188,797		$ 8,647,444	-$ 3,876,606	-$ 120,686		-$ 3,997,292	$ 4,650,151
47	1835	Overhead Conductors & Devices	$ 7,482,814	$ 195,298		$ 7,678,113	-$ 3,933,151	-$ 69,636		-$ 4,002,787	$ 3,675,326
47	1840	Underground Conduit	$ 3,936,612	$ 459,743		$ 4,396,355	-$ 1,906,280	-$ 83,919		-$ 1,990,199	$ 2,406,156
47	1845	Underground Conductors & Devices	$ 8,017,557	$ 559,389		$ 8,576,946	-$ 3,749,510	-$ 141,840		-$ 3,891,350	$ 4,685,596
47	1850	Line Transformers	$ 9,153,189	$ 338,735		$ 9,491,924	-$ 4,893,407	-$ 149,108		-$ 5,042,515	$ 4,449,400
47	1855	Services (Overhead & Underground)	$ 5,204,841	$ 158,551		$ 5,363,391	-$ 2,335,566	-$ 87,925		-$ 2,423,491	$ 2,939,900
47	1860	Meters	$ 2,441,644	$ 4,238		$ 2,445,881	-$ 1,519,263	-$ 76,024		-$ 1,595,287	$ 850,594
47	1860	Meters (Smart Meters)	$ -	$ 3,100,869		$ 3,100,869	$ -	-$ 571,777		-$ 571,777	$ 2,529,092
N/A	1905	Land	$ 174,188			$ 174,188	$ -			$ -	$ 174,188
47	1908	Buildings & Fixtures	$ 2,385,250	$ 15,493		$ 2,400,743	-$ 900,207	-$ 36,971		-$ 937,178	$ 1,463,565
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ 71,937		$ 71,937	$ -	-$ 7,194		-$ 7,194	$ 64,743
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ 136,794		$ 136,794	$ -	-$ 40,379		-$ 40,379	$ 96,415
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ -	$ 679,340		$ 679,340	$ -	-$ 136,811		-$ 136,811	$ 542,529
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -	$ 377,239		$ 377,239	$ -	-$ 43,346		-$ 43,346	$ 333,893
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -	$ 12,466		$ 12,466	$ -	-$ 2,493		-$ 2,493	$ 9,973
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ 200,000		$ 200,000	$ -	-$ 13,333		-$ 13,333	$ 186,667
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 43,592	$ 412,316		$ 455,909	-$ 31,695	-$ 31,788		-$ 63,483	$ 392,426
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 7,183,004	-$ 318,521		-$ 7,501,525	$ 1,975,698	$ 162,754		$ 2,138,452	-$ 5,363,073
	etc.		$ -			$ -	$ -			$ -	$ -
						$ -				$ -	$ -
		Sub-Total	**$ 40,972,186**	**$ 7,069,689**	**$ -**	**$ 48,041,875**	**-$ 22,001,262**	**-$ 1,549,248**	**$ -**	**-$ 23,550,510**	**$ 24,491,365**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 40,972,186**	**$ 7,069,689**	**$ -**	**$ 48,041,875**	**-$ 22,001,262**	**-$ 1,549,248**	**$ -**	**-$ 23,550,510**	**$ 24,491,365**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						**-$ 1,549,248**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 1,549,248

Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2013

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 476,100	$ 15,135		$ 491,235	-$ 97,936	-$ 62,933		-$ 160,870	$ 330,366
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 7,638	$ -		$ 7,638	$ -			$ -	$ 7,638
47	1808	Buildings	$			$	$			$	$
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 850,125	$ -		$ 850,125	-$ 832,112	-$ 836		-$ 832,947	$ 17,178
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,647,444	$ 286,820		$ 8,934,264	-$ 3,997,292	-$ 127,060		-$ 4,124,352	$ 4,809,912
47	1835	Overhead Conductors & Devices	$ 7,678,113	$ 192,087		$ 7,870,199	-$ 4,002,787	-$ 72,838		-$ 4,075,625	$ 3,794,574
47	1840	Underground Conduit	$ 4,396,355	$ 284,763		$ 4,681,118	-$ 1,990,199	-$ 91,038		-$ 2,081,236	$ 2,599,881
47	1845	Underground Conductors & Devices	$ 8,576,946	$ 314,373		$ 8,891,318	-$ 3,891,350	-$ 149,699		-$ 4,041,049	$ 4,850,269
47	1850	Line Transformers	$ 9,491,924	$ 347,422		$ 9,839,345	-$ 5,042,515	-$ 157,794		-$ 5,200,309	$ 4,639,036
47	1855	Services (Overhead & Underground)	$ 5,363,391	$ 146,631		$ 5,510,023	-$ 2,423,491	-$ 91,591		-$ 2,515,082	$ 2,994,941
47	1860	Meters	$ 2,445,881	$ 456		$ 2,446,338	-$ 1,595,287	-$ 74,902		-$ 1,670,189	$ 776,140
47	1860	Meters (Smart Meters)	$ 3,100,869	$ 46,475		$ 3,147,344	-$ 571,777	-$ 209,823		-$ 781,599	$ 2,365,744
N/A	1905	Land	$ 174,188			$ 174,188	$ -			$ -	$ 174,188
47	1908	Buildings & Fixtures	$ 2,400,743	$ 17,973		$ 2,418,716	-$ 937,178	-$ 37,826		-$ 975,004	$ 1,443,712
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 71,937	$		$ 71,937	$ 7,194	$ 7,194		$ 14,387	$ 57,550
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 136,794	$ 165,763		$ 302,557	-$ 40,379	-$ 60,511		-$ 100,890	$ 201,667
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 679,340	$ 247,083	-$ 38,000	$ 888,423	-$ 136,811	-$ 85,343	$ 7,600	-$ 214,554	$ 673,869
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 377,239	$ 22,888		$ 400,127	-$ 43,346	-$ 40,013		-$ 83,359	$ 316,769
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$			$	$			$	$
8	1955	Communications Equipment	$ 12,466	$ -		$ 12,466	-$ 2,493	-$ 2,493		-$ 4,986	$ 7,479
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 200,000	$ -		$ 200,000	-$ 13,333	-$ 13,333		-$ 26,667	$ 173,333
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 455,909	$ 69,795		$ 525,704	-$ 63,483	-$ 36,441		-$ 99,925	$ 425,779
47	1985	Miscellaneous Fixed Assets	$			$	$			$	$
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 7,501,525	-$ 596,144		-$ 8,097,669	$ 2,138,452	$ 177,961		$ 2,316,412	-$ 5,781,256
	etc.		$ -			$ -	$ -			$ -	$ -
						$ -				$ -	$ -
		Sub-Total	$ 48,041,875	$ 1,561,521	-$ 38,000	$ 49,565,396	-$ 23,550,510	-$ 1,143,708	$ 7,600	-$ 24,686,619	$ 24,878,777
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	$ 48,041,875	$ 1,561,521	-$ 38,000	$ 49,565,396	-$ 23,550,510	-$ 1,143,708	$ 7,600	-$ 24,686,619	$ 24,878,777
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						-$ 1,143,708			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 1,143,708

Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2014

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 491,235	$ 96,500		$ 587,735	-$ 160,870	-$ 80,234		-$ 241,103	$ 346,632
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 7,638			$ 7,638	$ -			$ -	$ 7,638
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 850,125			$ 850,125	-$ 832,947	-$ 836		-$ 833,783	$ 16,342
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,934,264	$ 337,027		$ 9,271,291	-$ 4,124,352	-$ 134,549		-$ 4,258,901	$ 5,012,390
47	1835	Overhead Conductors & Devices	$ 7,870,199	$ 276,757		$ 8,146,956	-$ 4,075,625	-$ 77,450		-$ 4,153,075	$ 3,993,881
47	1840	Underground Conduit	$ 4,681,118	$ 338,922		$ 5,020,040	-$ 2,081,236	-$ 99,511		-$ 2,180,747	$ 2,839,293
47	1845	Underground Conductors & Devices	$ 8,891,318	$ 291,948		$ 9,183,266	-$ 4,041,049	-$ 156,998		-$ 4,198,047	$ 4,985,219
47	1850	Line Transformers	$ 9,839,345	$ 397,485		$ 10,236,830	-$ 5,200,309	-$ 167,731		-$ 5,368,040	$ 4,868,790
47	1855	Services (Overhead & Underground)	$ 5,510,023	$ 144,843		$ 5,654,866	$ 2,515,082	$ 95,212		$ 2,610,294	$ 3,044,572
47	1860	Meters	$ 2,446,338	$ -		$ 2,446,338	-$ 1,670,189	-$ 71,895		-$ 1,742,084	$ 704,254
47	1860	Meters (Smart Meters)	$ 3,147,344	$ 13,018		$ 3,160,362	-$ 781,599	-$ 210,691		-$ 992,290	$ 2,168,072
N/A	1905	Land	$ 174,188			$ 174,188	$ -			$ -	$ 174,188
47	1908	Buildings & Fixtures	$ 2,418,716	$ 100,000		$ 2,518,716	-$ 975,004	-$ 39,493		-$ 1,014,497	$ 1,504,219
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 71,937	$ 70,000		$ 141,937	$ 14,387	$ 14,194		$ 28,581	$ 113,356
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 302,557	$ 19,500		$ 322,057	-$ 100,890	-$ 64,411		-$ 165,301	$ 156,756
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 888,423	$ 352,792		$ 1,241,216	-$ 214,554	-$ 94,677		-$ 309,231	$ 931,985
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 400,127	$ 28,000		$ 428,127	-$ 83,359	-$ 42,813		-$ 126,171	$ 301,956
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 12,466			$ 12,466	-$ 4,986	-$ 2,493		-$ 7,479	$ 4,986
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 200,000			$ 200,000	-$ 26,667	-$ 13,333		-$ 40,000	$ 160,000
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 525,704	$ 150,000		$ 675,704	-$ 99,925	-$ 41,094		-$ 141,019	$ 534,685
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 8,097,669	-$ 100,000		-$ 8,197,669	$ 2,316,412	$ 180,752		$ 2,497,165	-$ 5,700,504
	etc.		$ -			$ -	$ -			$ -	$ -
						$ -				$ -	$ -
		Sub Total	**$ 49,565,396**	**$ 2,516,792**	**$ -**	**$ 52,082,188**	**$ 24,686,619**	**$ 1,226,862**	**$ -**	**$ 25,913,481**	**$ 26,168,707**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 49,565,396**	**$ 2,516,792**	**$ -**	**$ 52,082,188**	**-$ 24,686,619**	**-$ 1,226,862**	**$ -**	**-$ 25,913,481**	**$ 26,168,707**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						**-$ 1,226,862**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 1,226,862

Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2015

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 587,735	$ 13,000		$ 600,735	-$ 241,103	-$ 65,245		-$ 306,348	$ 294,387
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 7,638			$ 7,638	$ -			$ -	$ 7,638
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 850,125			$ 850,125	-$ 833,783	-$ 836		-$ 834,619	$ 15,506
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 9,271,291	$ 326,655		$ 9,597,946	-$ 4,258,901	-$ 138,179		-$ 4,397,080	$ 5,200,866
47	1835	Overhead Conductors & Devices	$ 8,146,956	$ 268,280		$ 8,415,236	-$ 4,153,075	-$ 79,686		-$ 4,232,761	$ 4,182,475
47	1840	Underground Conduit	$ 5,020,040	$ 329,925		$ 5,349,965	-$ 2,180,747	-$ 103,635		-$ 2,284,382	$ 3,065,583
47	1845	Underground Conductors & Devices	$ 9,183,266	$ 285,377		$ 9,468,643	-$ 4,198,047	-$ 160,565		-$ 4,358,613	$ 5,110,031
47	1850	Line Transformers	$ 10,236,830	$ 385,903		$ 10,622,733	-$ 5,368,040	-$ 172,555		-$ 5,540,595	$ 5,082,138
47	1855	Services (Overhead & Underground)	$ 5,654,866	$ 140,886		$ 5,795,752	-$ 2,610,294	-$ 96,973		-$ 2,707,267	$ 3,088,485
47	1860	Meters	$ 2,446,338		-$ 2,278,507	$ 167,830	-$ 1,742,084	-$ 9,442	$ 1,690,378	-$ 61,148	$ 106,682
47	1860	Meters (Smart Meters)	$ 3,160,362	$ 12,974		$ 3,173,336	-$ 992,290	-$ 211,556		-$ 1,203,846	$ 1,969,490
N/A	1905	Land	$ 174,188			$ 174,188	$ -			$ -	$ 174,188
47	1908	Buildings & Fixtures	$ 2,518,716	$ 100,000		$ 2,618,716	-$ 1,014,497	-$ 40,326		-$ 1,054,823	$ 1,563,893
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 141,937	$ 70,000		$ 211,937	-$ 28,581	-$ 17,694		-$ 46,275	$ 165,662
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 322,057	$ 85,000		$ 407,057	-$ 165,301	-$ 69,857		-$ 235,158	$ 171,899
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 1,241,216	$ 125,000		$ 1,366,216	-$ 309,231	-$ 100,927		-$ 410,158	$ 956,058
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 428,127	$ 20,000		$ 448,127	-$ 126,171	-$ 43,813		-$ 169,984	$ 278,143
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 12,466			$ 12,466	-$ 7,479	-$ 2,493		-$ 9,973	$ 2,493
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 200,000			$ 200,000	-$ 40,000	-$ 13,333		-$ 53,333	$ 146,667
47	1970	Load Management Controls Customer Premises	$			$	$			$	$
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 675,704	$ 100,000		$ 775,704	-$ 141,019	-$ 47,344		-$ 188,363	$ 587,340
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 8,197,669	-$ 100,000	$ 295,793	-$ 8,001,876	$ 2,497,165	$ 165,979	-$ 130,168	$ 2,532,976	-$ 5,468,900
	etc.		$ -			$ -	$ -			$ -	$ -
						$ -				$ -	$ -
		Sub-Total	$ 52,082,188	$ 2,163,000	-$ 1,982,714	$ 52,262,474	-$ 25,913,481	-$ 1,208,480	$ 1,560,210	-$ 25,561,751	$ 26,700,723
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	$ 52,082,188	$ 2,163,000	-$ 1,982,714	$ 52,262,474	-$ 25,913,481	-$ 1,208,480	$ 1,560,210	-$ 25,561,751	$ 26,700,723
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						-$ 1,208,480			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 1,208,480

GROSS ASSETS (PP&E)

STEI's capital spending is categorized in accordance with the Board's Accounting Procedures Handbook. STEI's assets include distribution assets and general plant. In accordance with the Uniform System of Accounts, STEI has included asset accounts 1805 to 1860 in the category of distribution plant, accounts 1915 to 1990 in the category of general plant.

STEI's gross fixed assets for the 2011 Board Approved, 2011, 2012 and 2013 Actual, 2014BY and 2015 TY is presented in the following Table 2-12.

Table 2-12

Gross Assets (PP&E)

GROSS ASSETS by FUNCTION

	2011 Board Approved	2011 Actual	2012 Actual	2013 Actual	2014 BY	2015 TY
Distribution	44,584,859	45,552,161	50,558,685	52,177,712	53,977,712	53,449,204
General	2,603,030	2,603,030	4,984,715	5,485,353	6,302,145	6,815,145
Contributed Capital	(6,954,110)	(7,177,502)	(7,501,525)	(8,097,669)	(8,197,669)	(8,001,876)
Gross Assets excl wip	**40,233,779**	**40,977,689**	**48,041,875**	**49,565,396**	**52,082,188**	**52,262,473**
WIP	-	150,101	114,689	88,742	-	-
Gross Assets incl wip	**40,233,779**	**41,127,790**	**48,156,564**	**49,654,138**	**52,082,188**	**52,262,473**

The detailed amounts categorized according to the Board's Uniform System of Accounts ("USofA") are provided in Table 2-2 on the following page.

Table 2-13

GROSS ASSET DETAILED BREAKDOWN BY MAJOR ACCOUNT

		2011 Board Approved CGAAP	2011 Actual CGAAP	2011 Variance	2012 Actual IFRS	2012 Variance	2013 Actual IFRS	2013 Variance	2014 Actual IFRS	2014 Variance	2015 Actual IFRS	2015 Variance
Distribution												
Land & Buildings												
1806.0000	**Land Rights / Right of Way**	**6,734**	**6,734**	**(0)**	**7,638**	**904**	**7,638**	**-**	**7,638**	**-**	**7,638**	**-**
1820.0000	**Distribution Station Equipment**	**850,125**	**850,125**	**(0)**	**850,125**	**-**	**850,125**	**-**	**850,125**	**-**	**850,125**	**-**
1830.0000	Poles, Towers & Fixtures	7,970,444	8,458,646	488,203	8,647,444	188,797	8,934,264	286,820	9,271,291	337,027	9,597,946	326,655
1835.0000	Overhead Conductors & Devices	7,330,322	7,482,814	152,492	7,678,113	195,298	7,870,199	192,087	8,146,956	276,757	8,415,236	268,280
1840.0000	Underground Conduit	3,880,632	3,936,612	55,980	4,396,355	459,743	4,681,118	284,763	5,020,040	338,922	5,349,965	329,925
1845.0000	Underground Conductors & Devices	7,899,285	8,017,557	118,272	8,576,946	559,389	8,891,318	314,373	9,183,266	291,948	9,468,643	285,377
		27,080,682	**27,895,629**	**814,947**	**29,298,857**	**1,403,228**	**30,376,899**	**1,078,042**	**31,621,553**	**1,244,654**	**32,831,790**	**1,210,237**
Line Transformers												
1850.1000	Underground Transformers	1,488,778	1,607,179	118,401	1,852,760	245,581	2,124,503	271,744	2,403,027	278,524	2,673,659	270,632
1850.2000	Overhead Transformers	7,585,712	7,546,010	(39,702)	7,639,164	93,154	7,714,842	75,678	7,833,803	118,961	7,949,074	115,271
		9,074,490	**9,153,189**	**78,699**	**9,491,924**	**338,735**	**9,839,345**	**347,422**	**10,236,830**	**397,485**	**10,622,733**	**385,903**
Services and Meters												
1855.1000	Overhead Services	3,992,311	4,097,276	104,965	4,179,815	82,539	4,272,209	92,394	4,387,186	114,977	4,498,719	111,533
1855.2000	Underground Services	1,132,735	1,107,564	(25,171)	1,183,576	76,012	1,237,814	54,238	1,267,680	29,866	1,297,033	29,353
1860.1000	Stranded Meters	2,290,880	2,278,507	(12,373)	2,278,507	-	2,278,507	-	2,278,507	-	-	(2,278,507)
1860.1500	Smart Meters	-	-	-	3,100,869	3,100,869	3,147,344	46,475	3,160,362	13,018	3,173,336	12,974
1860.2000	Interval Meters	83,283	89,518	6,235	93,755	4,238	94,212	456	94,212	-	94,212	-
1860.3000	Wholesale Meters	73,619	73,619	-	73,619	-	73,619	-	73,619	-	73,619	-
		7,572,828	**7,646,484**	**73,656**	**10,910,142**	**3,263,657**	**11,103,704**	**193,563**	**11,261,565**	**157,861**	**9,136,918**	**(2,124,647)**
TOTAL DISTRIBUTION		**44,584,859**	**45,552,161**	**967,302**	**50,558,685**	**5,006,524**	**52,177,712**	**1,619,027**	**53,977,712**	**1,800,000**	**53,449,204**	**(528,507)**
General												
Land & Buildings												
1905.0000	Land and General Plant	174,188	174,188	-	174,188	-	174,188	-	174,188	-	174,188	-
1908.0000	Building & Fixtures, General Plant	2,385,250	2,385,250	-	2,385,250	-	2,396,552	11,302	2,496,552	100,000	2,596,552	100,000
1908.1000	Building and Fixtures, Security System	-	-	-	15,493	15,493	22,164	6,671	22,164	-	22,164	-
		2,559,437	**2,559,437**	**-**	**2,574,931**	**15,493**	**2,592,904**	**17,973**	**2,692,904**	**100,000**	**2,792,904**	**100,000**
IT Assets												
1920.0000	Computer Equipment	-	-	-	136,794	136,794	302,557	165,763	322,057	19,500	407,057	85,000
1925.0000	Computer Software	-	-	-	122,966	122,966	138,101	15,135	214,601	76,500	227,601	13,000
1925.1000	Harris/Cayenta Software	-	-	-	353,134	353,134	353,134	-	373,134	20,000	373,134	-
		-	**-**	**-**	**612,894**	**612,894**	**793,792**	**180,898**	**909,792**	**116,000**	**1,007,792**	**98,000**
Equipment												
1915.0000	Office Furniture & Equipmet	-	-	-	71,937	71,937	71,937	-	141,937	70,000	211,937	70,000
1930.0000	Vehicles	-	-	-	679,340	679,340	888,423	209,083	1,241,216	352,792	1,366,216	125,000
1940.0000	Tools and Equipment	-	-	-	377,239	377,239	400,127	22,888	428,127	28,000	448,127	20,000
1955.0000	Communication Equipment	-	-	-	12,466	12,466	12,466	-	12,466	-	12,466	-
1960.1000	Mobile Substation	-	-	-	200,000	200,000	200,000	-	200,000	-	200,000	-
1980.0000	System Supervisory - SCADA	43,592	43,592	-	58,001	14,409	58,001	-	58,001	-	108,001	50,000
1980.1000	GIS System	-	-	-	397,908	397,908	467,702	69,795	617,702	150,000	667,702	50,000
		43,592	**43,592**	**-**	**1,796,890**	**1,753,298**	**2,098,657**	**301,767**	**2,699,449**	**600,792**	**3,014,449**	**315,000**
TOTAL GENERAL		**2,603,030**	**2,603,030**	**-**	**4,984,715**	**2,381,685**	**5,485,353**	**500,638**	**6,302,145**	**816,792**	**6,815,145**	**513,000**
2055.0000	**WIP**	**-**	**150,101**	**150,101**	**114,689**	**(35,412)**	**88,742**	**(25,947)**	**-**	**(88,742)**	**-**	**-**
1995.0000	**Contributed Capital**	**(6,954,110)**	**(7,177,502)**	**(223,392)**	**(7,501,525)**	**(324,023)**	**(8,097,669)**	**(596,144)**	**(8,197,669)**	**(100,000)**	**(8,001,876)**	**195,793**
TOTAL GROSS ASSETS		**40,233,778**	**41,127,790**	**894,011**	**48,156,564**	**7,028,774**	**49,654,138**	**1,497,574**	**52,082,188**	**2,428,050**	**52,262,474**	**180,286**

SUMMARY OF INCREMENTAL CAPITAL MODEL

STEI has not made application for incremental capital expenditures during the IRM period 2012 to 2014.

Reconciliation of Continuity Statements to Calculated Depreciation Expenses

Paragraph 2.5.1.2 of the Filing Requirements requires that the depreciation expense in the fixed asset continuity statements reconcile to the calculated depreciation expenses under Exhibit 4 – Operating Costs and presented by account. In accordance with this requirement there are no reconciling items between the fixed asset continuity statements in this Exhibit and the calculated depreciation expense in Exhibit 4.

GROSS ASSET VARIANCE ANALYSIS

2011 Board Approved vs. 2011 Actual CGAAP

The ending 2011 gross asset balance of $41,127,790 was $894,011 greater than the 2011 Board Approved ending balance of $40,233,778. The 2011 Board Approved application was based upon 2011 capital additions of $1,874,600. STEI's 2011 Application assumed the half-year rule for depreciation costs. However STEI did not adopt the half-year rule which resulted in an increase of $937,300. STEI's decision to not adopt the half-year rule till 2015 did not impact the 2015 Rate Base.

2011 Actual CGAAP vs. 2012 Actual MIFRS

The ending 2012 gross assets balance of $48,156,564 is $7,028,774 greater than the 2011 ending balance of $41,127,790. The increase is attributed to asset transfer from affiliate with respect to corporate restructuring, smart meter transfer, planned distribution system investment and other capital expenditures. Details are as follows:

- The capital additions of $1,407,734 are attributed to the corporate restructuring include office furniture and equipment, computer hardware and software, transportation equipment and tools, communication equipment, mobile substation and supervisory system equipment.

- STEI transferred smart meter costs in the amount of $3,267,775 million from the regulated capital account on December 31, 2012.

- Net distribution capital expenditures of $1,600,014 was net of contributed capital of $324,023 and other capital expenditures were $788,663 with the largest expenditure being related to the GIS system in the amount of $397,908.

2012 capital expenditures did not include administration costs. The 2011 capital expenditures were strictly external costs as STEI had not employees and operated as a virtual utility.

2012 Actual - MIFRS vs. 2013 Actual - MIFRS

The ending 2012 gross asset balance of $49,654,138 was $1,497,574greater than the 2012 ending balance of $48,156,664. The increase is attributed to net distribution capital investments of $1,022,883 and other capital expenditures of $500,638. Details are as follow;

- The distribution investment for 2013 was $1,619,027 which was offset by contributed capital of $596,144. The contributed capital was higher than most years and is not expected to continue at this level. Other capital investments included a new single bucket truck at $247,000 and computer hardware and software investment of $180,000.

2013 Actual - MIFRS vs. 2014 Bridge Year-MIFRS

The 2014 projected ending gross asset balance for the 2014BY of $52,082,188 is $2,428,050 greater than the 2013 year-end amount of $49,654,138. The increase is related to planned distribution system capital expenditures of $1,700,000 million and $816,792 in other capital expenditures, primarily office and building renovations of $170,000, new bucket truck $352,792 and GIS system of $150,000.

2014 Bridge Year-MIFRS vs. 2015 Test Year-MIFRS

The total projected ending gross asset balance for the 2015TY of $42,262,474 is $180,286 greater than the 2014 projected ending amount $52,082,188. Net distribution assets are planned to increase by $1,650,000 and general capital expenditures are planned to increase by $513,000 which includes $170,000 for building and office renovations and vehicle expenditures of $125,000.

The net 2015TY planned capital expenditures of $2,263,000 are reduced by the removal of stranded meters of $2,278,507 resulting in a net reduction of $15,507. This reduction is offset by the change in contributed capital associated with the stranded meters of $195,793, resulting in a net increase of $180,286.

GROSS ASSETS (PP&E)

The calculation of St. Thomas Energy Inc.'s annual amortization until the end of 2015 is consistent with MIFRS, the requirements of the CICA, and the requirements of the OEB. Capital assets are amortized on a straight line basis. STEI is adopting the half-year rule in the in 2015 as in conjunction with the formal adoption of IFRS.

For 2015, St. Thomas Energy Inc.'s amortization will be consistent with MIFRS. Under MIFRS, costs are amortized over the assets useful life, subject to the half-year rule on additions. Due to the transition to MIFRS, St. Thomas Energy Inc. will amortize the opening net book value of assets over their average remaining life.

Annual Amortization Expense for Rate-Setting Purposes

Table 2-13 below shows the 2011 – 2015 Amortization Summary

Table 2-13

AMORTIZATION SUMMARY

			Base	Incremental Smart Meter	Total
2011	**CGAAP**	COS	1,356,340	-	**1,356,340**
2011	**CGAAP**	Actual	1,386,336	-	**1,386,336**
2012	**MIFRS**	Actual - Restructuring	1,130,251	418,997	**1,549,248**
2013	**MIFRS**	Actual	1,143,708	-	**1,143,708**
2014	**MIFRS**	Bridge Year	1,226,862	-	**1,226,862**
2015	**IFRS**	Test Year	1,208,219	-	**1,208,219**

The 2012 actual amortization is $162,912 greater than 2011 CGAAP mainly due to the smart meter capital costs that were moved to capital from Account 1555 – Smart Meter Capital Variance account.

The pre-smart meter amortization cost for 2012 of $1,130,251 is $256,085 less than the amount recorded in 2011. The reduction is attributed to the adoption of MIFRS useful life estimates in conjunction with the 2012 restructuring and the change in capital cost structure. The 2011 capital costs were based upon a management services agreement whereas the 2012 amounts are based upon costs, including labour, directly attributable to the assets.

TREATMENT OF STRANDED ASSETS RELATED TO SMART METER DEPLOYMENT

The Board's Guideline: Smart Meter Funding and Cost Recovery (G-2008-0002) provided two options to distributors regarding the accounting treatment for stranded meters related to the installation of smart meters:

1) Leave them in rate base (i.e. Account 1860); or
2) Record them in "Sub-account Stranded Meter Costs" of Account 1555.

St. Thomas Energy Inc. confirms that it elected option One; Leave them in rate base "Account 1860.

St. Thomas Energy Inc. has completed its smart meter deployments. STEI received a Smart Meter Decision and rate Order effective January 1, 2013. STEI in its application estimated that the stranded meter costs would be $590,000 would be recovered in the 2015 COS rate application. STEI is applying for recovery of $422,504. The difference between the two amounts is the inclusion of residual contributed capital associated with the stranded meters.

Accounting guidance in the December 2010 Accounting Procedures Handbook FAQs (Q and A #15) provides information as to how the Cost of Service rate-setting process may be used to address the recovery by distributors of costs associated with stranded meters.

On December 15, 2011, the Board issued Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition. Section 3.7 and Appendix A-1 provide the most current guidance on the treatment for recovery of costs for stranded meters replaced by smart meters. St. Thomas Energy Inc. hereby files as part of their 2013 application a proposed treatment for the recovery of stranded meters that is in conformity with the approach taken by the Board as follows:

1. The total estimated NBV of the stranded meters as of December 31, 2015, or a revised amount calculated in accordance with the above-noted accounting guidance, has been removed from rate base (see Appendix 2-R attached – E2/T4/S6/Att1). St. Thomas Energy Inc. confirms the 2015 revenue requirement does not include either a cost of capital return or depreciation expense associated with the total estimated stranded meter costs removed from rate base;

2. The total estimated NBV of the stranded meters will be recovered through separate rate riders for the applicable customer classes. St. Thomas Energy Inc. has outlined the manner in which it intends to allocate recovery of the NBV of the stranded meters to the applicable customer rate classes and the rationale for the selected approach (E9/T4/S1);

3. The total estimated stranded meter costs will be tracked in "Sub-account Stranded Meter Costs" of Account 1555; and

4. The associated recoveries from the separate rate riders will also be recorded in this sub-account to reduce the balance in the sub-account.

In order to remain whole St. Thomas Energy Inc. is proposing separate rate riders for the applicable customer classes to recover the amount of the total estimated stranded costs. St. Thomas Energy Inc. expects any residual balance (net of recoveries) will be submitted for review as part of the St. Thomas Energy Inc.'s next Cost of Service.

CAPITAL EXPENDITURES

OVERVIEW

This overview provides background information on the STEI distribution system and a general indication of the types of capital program and project work that is undertaken.

The City of St Thomas is located in Southwestern Ontario approximately 10 km north of Lake Erie and 5 km south of the municipal boundaries of the City of London. STEI's franchise area is primarily contained within the municipal boundaries of the city of St. Thomas and is about 33 square km in area. STEI is largely an urban service territory

STEI's distribution system is supplied by Hydro One Networks Inc. ("HONI") primarily from Edgeware TS at a voltage level of 27.6 kV. There is one remaining industrial customer that is supplied power from St Thomas TS at a voltage level of 13.8 kV.

As of March 2014, STEI has a total of 252.18 circuit kilometers of primary wire and underground cable installed of which 148.67 km, or 59%, is overhead.

The Table 2-14 below shows the breakdown by voltage class for both overhead & underground primary.

Table 2-14: Length of Overhead & Underground Primary Wire and Underground Cable by Voltage Class.

	Overhead (km)			Underground (km)		
Voltage Class	**3 Phase**	**2 Phase**	**1 Phase**	**3 Phase**	**2 Phase**	**1 Phase**
>15 kV	81.6	0	23.4	11.2	0	80.1
> 5kV & < 15 kV	7.4	0	3.4	1.1	0	0
< 5kV	30.4	7.4	0	4.5	1.2	0
Totals	119.4	7.4	26.8	16.8	1.2	80.1

The distribution system has 6 municipal substations remaining used to step down voltage from 27.6 kV to 2.4 kV for the old 2.4kV delta distribution system. There is a 10 year plan in place to convert the 2.4kV delta distribution system to 27.6kV, which when complete will eliminate the municipal substations from the system.

The following Tables 2-15 and 16 show a listing of STEI main assets, aside from wire and cable, employed in its distribution system.

Table 2-15

		Distribution by Age (years)				
Asset Category	**Population**	**0 - 19**	**20 - 29**	**30 - 39**	**40 - 44**	**45 +**
Substation Transformers	6			6		
Pad-mount Transformers	563	412	140	8	2	1

Table 2-16

		Distribution by Age (years)				
Asset Category	**Population**	**0 - 19**	**20 - 29**	**30 - 39**	**40 - 44**	**45 +**
Pole-mount Transformers	868	351	383	40	35	59
Distribution Poles	4824	1782	905	371	190	1576
Overhead Switches *	113	42	9			

Further details on STEI's Asset base can be found in its Distribution System Plan (DSP) – attached as Appendix A to this exhibit

Capital Planning Process

STEI has developed a prudent capital budget process and system of prioritization that takes account of its corporate emphasis on business performance and accountability. This system reflects its long term investment strategy, recognizes its shorter term requirements and addresses the ongoing need for STEI to respond to external and internal priority changes. It respects the priorities of a wide range of stakeholders, STEI's corporate strategies and regulatory requirements. The capital budget process also takes into account the relative priorities of the proposed investments primarily as dictated by the amount of discretion afforded to STEI by the various applicable Acts, Regulations and Codes. Required non-discretionary budget items (i.e. having virtually no flexibility) include:

- Projects to accommodate new customers and load growth in order to meet the Company's obligation to connect
- Projects to accommodate Municipal, Region and Ministry requirements

- Expenditures to satisfy regulatory initiatives, environmental or health & safety risks, the
- Green Energy and Green Economy Act, and the Company's Conditions of Service.
- Medium term discretionary budget items (i.e. with some timing flexibility) include:
- Infrastructure renewal projects
- Fleet/tools
- Distribution Automation
- Information technology

In developing its capital investment plans, STEI must satisfy its non-discretionary obligations and balance them with projects that have been evaluated and supported by data from its annual performance review, its Asset Management Strategy (see section 2.1) and the good judgement of its professional management team. Current levels of expenditures on rebuild projects, distribution automation and maintenance have kept STEI's reliability performance at solid North American levels. However, long term planning will identify expenditures for renewals as the distribution system infrastructure ages. This may result in assets remaining in service for longer periods and being subjected to closer condition assessments to minimize performance risks. The following high level inputs are investigated and evaluated in detail and collectively contribute to a final capital investment budget:

- New load growth and development projects
- Municipally driven projects
- Regulatory initiatives
- System reliability
- Distribution Automation
- Infrastructure renewal projects
- Elimination of environmental/health or safety risks
- Fleet/Tools
- Information technology and corporate administration
- Renewable energy generation
- Impact on customer bills

- Customer engagement

Each of these priorities is addressed in the Distribution System Plan filed as Attachment A to this exhibit.

Asset Management Process

STEI's Asset Management Process outlines STEI's good utility practices within its capital/refurbishment program and within its inspection/maintenance program. Further details on STEI's Asset Management Process can be found in its Distribution System Plan (DSP) – attached as Appendix A to this exhibit. The capital/refurbishment program seeks to ensure that the selection between refurbishing assets and replacing them with new capital equipment is made in a manner that minimizes the overall expected lifecycle cost while meeting requisite reliability standards and other mandatory requirements such as health and safety of the public and staff. The inspection/maintenance program allows for an organized approach for inspection, assessment and restoration of assets within the overhead distribution system, underground distribution system and substations – again, in a manner that minimizes the overall expected lifecycle cost and meets all applicable standards.

STEI's capital expenditure main focus is System Renewal activities throughout the historical and forecast period and the replacement of its 50-year old 2,400V system that is rapidly approaching the end of its life and which, because it is overhead, presents a significantly higher safety risk to staff and public when a downed line occurs. The resulting replacement and voltage conversion will provide in an efficient and safer 28kV modern system. Other associated activities in this category relate to associated power line construction and pole replacement.

PLANNING

In accordance with the Filing Requirements, STEI is filing its Distribution System Plan ("DS Plan") as a stand-alone document as Appendix A of this Exhibit. STEI's Distribution System Plan is organized using the headings indicated in Chapter Five of the Board's Filing Requirements for Electricity Distribution and Transmission Applications, entitled Consolidated Distribution System Plan Filing Requirements (the "DS Plan Filing Requirements"). STEI feels it has met the Chapter 5 requirements in all relevant aspects.

REQUIRED INFORMATION

STEI has filed its Capital Expenditure Summary 2010 – 2019 from Chapter 5 Consolidated DS Plan Filing requirements on the following page. Explanatory notes on variances are included in the consolidated DS Plan.

STEI capital additions for the 2015TY are expected to be $2,163,000. Capital additions for the 2015 to 2018 planning period remain fairly stable at approximately the $2,000,000 level and then are forecast to reduce to $1,882,000 in 2019. The decreased is attributed to decreased general capital additions, primarily fleet replacement.

Board Appendices 2-AA and 2-AB are provided on the following pages.

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2015*

CATEGORY	Historical Period (previous plan[1] & actual)														
	2010			2011			2012			2013			2014		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	953,819	693,867	-27.3%	759,731	735,219	-3.2%	551,200	3,943,790	615.5%	719,000	580,417	-19.3%	200,000		-100.0%
System Renewal	872,154	778,473	-10.7%	1,143,467	1,146,535	0.3%	978,700	1,077,181	10.1%	827,423	1,008,816	21.9%	1,600,000		-100.0%
System Service	-	45,076	--	285,510	-	-100.0%	-	-	--	-	-	--	-		--
General Plant	-	-	--	-	-	--	743,500	2,381,685	220.3%	888,000	538,637	-39.3%	728,050		-100.0%
Contributed Capital	- 302,000	- 384,629	27.4%	- 251,000	- 266,363	6.1%	- 230,500	- 318,521	38.2%	- 311,000	- 596,144	91.7%	- 100,000		
TOTAL EXPENDITURE	1,523,973	1,132,787	-25.7%	1,937,708	1,615,391	-16.6%	2,042,900	7,084,134	246.8%	2,123,423	1,531,726	-27.9%	2,428,050	-	-100.0%
System O&M	$ 988,508	$1,085,310	9.8%	$ 916,682	$ 923,291	0.7%	$ 1,371,654	$1,311,270	-4.4%	$1,305,830	$1,224,643	-6.2%	$1,259,102		-100.0%

CATEGORY	Forecast Period (planned)				
	2015	2016	2017	2018	2019
	$ '000				
System Access	200,000	200,000	200,000	200,000	200,000
System Renewal	1,341,250	1,590,000	1,530,000	1,215,000	1,560,000
System Service	208,750	-	-	305,000	-
General Plant	513,000	436,000	458,000	265,000	222,000
Contributed Capital	- 100,000	- 100,000	- 100,000	- 100,000	- 100,000
TOTAL EXPENDITURE	2,163,000	2,126,000	2,088,000	1,885,000	1,882,000
System O&M	$1,318,543	$1,346,233	$ 1,374,503	$1,403,368	$1,432,839

Notes to the Table:
1. Historical "previous plan" data is not required unless a plan has previously been filed
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. histrical budgets by category
2012 actual includes smart meter transfer of $3,267,776 and asset purchased per January 1, 2012 restructuring of $1,407,734

The followig Table 2AA provides the details for the capital projects for the 2010 to 2013 actuals, 2014BY and 2015TY and 2016 – 2019 Foreacast.

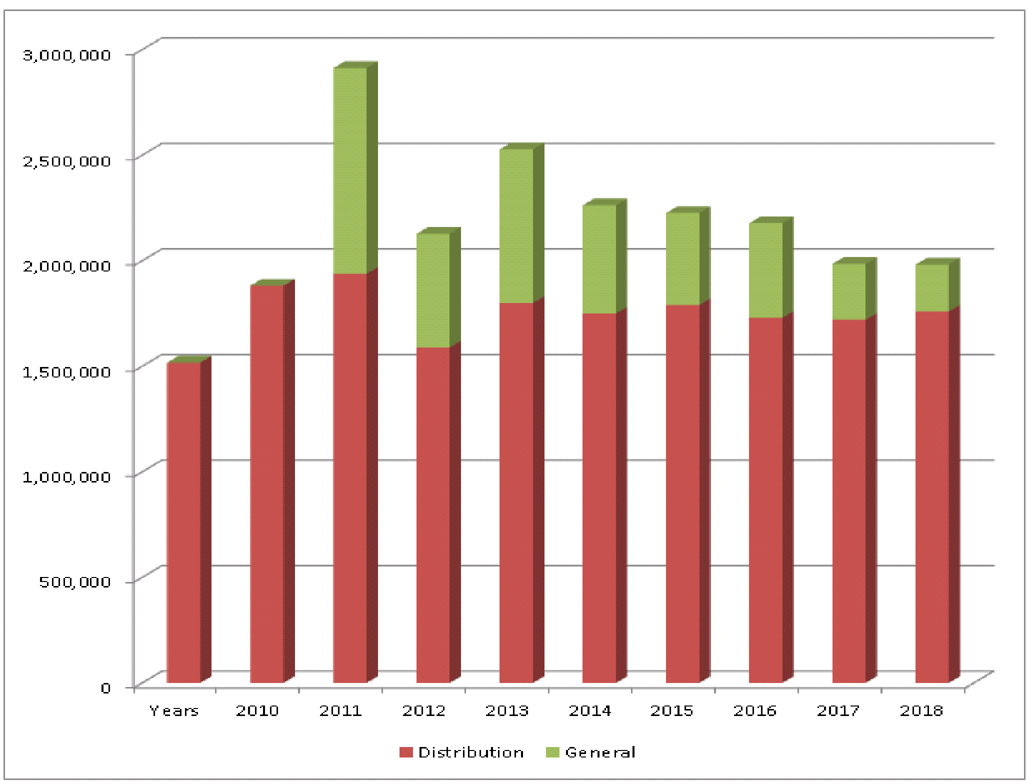
Appendix 2-AA
Distribution Capital Projects

NO.	PROJECT NAME	2010	2011	2012	2013	2014 Bridge Year	2015 Test Year	2016	2017	2018	2019
1	New Subdivision - Lake Margaret, Phase 9	81,487									
2	New Subdivision - Orchard Park, Phase 3	71,980									
3	Voltage Conversion - Chestnut East of Fifth	84,700									
4	Build New OH Powerline - Sutherland Line	45,076									
5	Relocate Poles - Wellington - Princess to Elgin	60,326									
6	New Subdivision - Shaw Valley, Phase 2A	31,896	256,725								
7	New Subdivision - Dalewood Meadows, Phase 4A	151,558	47								
8	New Subdivision - Dalewood Meadows, Phase 4B	92,432	13,335								
9	New Subdivision - Misc	-592		8,087	44,791	200,000	200,000	200,000	200,000	200,000	200,000
10	Voltage Conversion - Misc.	82,120	102,961	33,414	28,188						
11	New Services Residential - Misc	97,510	66,929	40,098	71,033						
12	New Services Commercial - Misc	66,155	66,671	68,969	97,133						
13	Municipal Road Rebuilds - Misc	41,114	23,547	11,755	29,401						
14	Pole Replacement Program	201,630	36,140	19,585	25,202						
15	Voltage Conversion - Locust, Fifth to Third	94,209	-3,638								
16	Voltage Conversion - Fourth, Myrtle, Forest, Erie	170,126	8,347								
17	Voltage Conversion - Forest, Third, Erie, Second	145,687	79,028								
18	New Subdivision - Orchard Park, Phase 4		130,940								
19	Voltage Conversion - Elmina/Churchill Area		271,108								
20	Voltage Conversion - Dieppe, Dunkirk, Churchill		254,658								
21	Upgrade Service - 84 Edward - School		57,405								
22	Upgrade Service - 22 S. Edgeware - School		82,373								
23	New Subdivision - Dalewood Meadows, Phase 5		37,246	110,145							
24	Voltage Conversion - Meehan, Montgomery, Coyne		185,207	113,169	838						
25	Voltage Conversion - Parkview, Pinafore, etc.		212,723	305,096	13,262						
26	Smart Meter Transfer			3,082,487							
27	New Subdivision - Shaw Valley, Phase 2B			161,796	23,591						
28	New Subdivision - Lake Margaret Estates, Phase 11			95,969	763						
29	New Subdivision - Dalewood Meadows, Phase 6			12,115	190,237						
30	New Subdivision - Orchard Park, Phase 5			1,352	119,556						
31	New Subdivision - Orchard Park South			351,017	3,912						
32	Voltage Conversion - Churchill & Chestnut Area			140,125	58						
33	Voltage Conversion - Alma Kains North			46,473	145,134						
34	Voltage Conversion - Stokes & Manor			325,185	330						
35	Voltage Conversion - McLachlin Place			7,827	135,344						
36	Voltage Conversion - Massey & Michener			85,829	3,919						
37	Voltage Conversion - Luton, McLarty, Dyer Area			478	226,098	211,972					
38	Voltage Conversion - Erie, Talequah to Park				50,860	34,140					
39	Voltage Conversion - Highview, Vanbuskirk & McCully Area				379,044	40,956					
40	Voltage Conversion - Steele St.				68	114,932					
41	Voltage Conversion - Locke, Rosemount area				471	700,000					
42	System Upgrade - Bush Line					320,000					
43	Voltage Conversion - Mary St. East					115,000					
44	Voltage Conversion - Warehouse, Park to Fairview					35,000					
45	Voltage Conversion - Mandeville West of First					28,000					
46	Voltage Conversion - Fairview, Sinclair & Talbot Area						298,750				
47	Voltage Conversion - Paulson, Gustin & Paddon Area						358,750				
48	Voltage Conversion - Confederation, Lakeview, Stirling Area						683,750				
49	Build New Powerline - Elmwood Ave						208,750				
50	Voltage Conversion - Hammond, Patricia, Inkerman, Daniel Area							790,000			
51	Voltage Conversion - Highview, Aspen, Chestnut, Croatia, Pol Area							800,000			
52	Voltage Conversion - Tecumseh, Montcalm, Brock, Alma Area								763,335		
53	Voltage Conversion - Park, Mary Bucke, Forest & First Area								463,335		
54	Voltage Conversion - Balaclava & S. Edgeware Area								303,330		
55	Build New Powerline - Centennial, Talbot to Wellington									305,000	
56	Voltage Conversion - Applewood, Lawrence, Butler, Dyer Area									700,000	
57	Voltage Conversion - Major Line West of Sunset Area									285,000	
58	System Upgrade - Edward, Gaylord, East side of Elgin Mall									230,000	
59	Voltage Conversion - First, Thompson, Glanworth, Ashton Area										511,660
60	Voltage Conversion - Aldborough, Airey, Vanier Area										561,670
61	Voltage Conversion - Aldborough, Pullen, Sparta, Parish Area										486,670
62	Asset Transfer - Restructuring			1,407,734	69,795						
63	GIS			397,908		150,000	50,000				
64	New Financial software			353,134							
65	Smart Meter Transfer			185,288							
66	Other			37,621	22,888	28,000	20,000	20,000	20,000	20,000	20,000
67	Computer hardward & software				180,898	116,000	98,000	131,000	98,000	120,000	97,000
68	Fleet				247,083	264,000	125,000	60,000	265,000	20,000	
69	Building, furniture & equipment				17,973	170,000	170,000	175,000	15,000	5,000	5,000
70	SCADA						50,000	50,000	50,000	100,000	100,000
71											
72											
73											
74											
75											
	TOTAL	**1,517,416**	**1,881,754**	**7,402,655**	**2,127,870**	**2,528,000**	**2,263,000**	**2,226,000**	**2,178,000**	**1,985,000**	**1,982,000**
	Less Renewable Generation Facility Assests and Other Non Rate-Regulated Utility Assests (input as negative)										
	TOTAL	**1,517,416**	**1,881,754**	**7,402,655**	**2,127,870**	**2,528,000**	**2,263,000**	**2,226,000**	**2,178,000**	**1,985,000**	**1,982,000**

It should be noted that in its planning process certain STEI capital projects and programs are planned for at a summarized level. The New Services/ Upgrades Residential, New Services / Upgrades Commercial and Road Widening work programs do not have spending forecasts associated with them. There will be spending in these categories in 2014 and 2015 however the level of expenditures for the total capital expenditure work program will not exceed the overall levels shown. STEI is endeavoring to improve its capital budgeting process through its work in the DSP.

The following Chart 1 illustrates STEI's normalized capital expenditures for the years 2010 - 2019. General plant expenditures did not occur until the 2012 restructuring. The normalized spending excludes the 2012 smart meter transfer and the restructuring assets transfer. Distribution capital expenditures remain stable from the 2012 to 2019 years, whereas, the general plant expenditures fluctuates based upon specific planned investments.

Chart 1



CAPITAL EXPENDITURE VARIANCE ANALYSIS – 2011-2015

The following tables summarizes STEI's capital additions by major project by year. A written explanation of variances, including that of actuals versus Board-approved amounts for STEI's last Board-approved cost of service is included below.

Further details on capital additions on the 2011 to 2015 period are provided in Section 3.5.2 of the Distribution system Plan which is in Attachment A to this Exhibit.

2011 CAPITAL ADDITIONS

2011 net capital additions of $1,615,391 were $259,210 less than the Board Settlement amount of $1,874,601. The main difference from 2011 Board Approved to the 2011 Actual is in the System Service area. The 2011 Plan included $285,510 for system expansion work that was not performed. The system expansions are customer driven and the anticipated developments did not occur as expected due to economic conditions.

2012 CAPITAL ADDITIONS

2012 net capital additions of $7,084,134 was $5,468,744 greater than the 2011 Actual spend. The 2012 capital additions included smart meter transfer in the amount of $3,267,776 (as directed by the OEB in its EB-2012-0348) and assets acquired from an affiliate Ascent Energy Services Inc. ("AESI") as part of the corporate restructuring in the amount of $1,407,734. When normalized for these two one-time events the 2012 actual expenditures were $793,235 greater than 2011.

Distribution capital expenditures in 2012 were $56,730 greater than the 2011 amount as the increase in Non-Discretionary/Externally driven expenditures of $126,084 which were partially offset by decreased system access expenditures of $69,354.

General Plant capital expenditures in 2012 were $751,042 greater than the 2011 amount. The increase is related to the GIS system in the amount of $397,908 and new financial software of $353,134. The GIS expenditure includes $150,101 of costs transferred from the 2011 work-in-process account.

Table 2-17 below shows the difference in major capital additions by major project for 2012 vs. 2011

Table 2-17

Capital Additions by Major Project 2012 Actuals vs. 2011 Actuals

Major Project	2011 Actuals	2012 Actuals	Variance
Smart Meter Transfer	0	3,082,487	3,082,487
New Services/Upgrades Residential	66,929	40,098	-26,831
New Services/Upgrades Commercial	206,449	68,969	-137,481
Road Widening (Dependant on Road Work - No Hydro Control)	23,547	11,755	-11,792
New Services Subdivisions	438,293	740,481	302,187
System Access	**735,219**	**3,943,790**	**3,208,571**
Voltage Conversion/System Upgrade	1,110,395	1,057,596	-52,799
Pole Replacement Program	36,140	19,585	-16,555
System Renewal	**1,146,535**	**1,077,181**	**-69,354**
System Service	**0**	**0**	**0**
Asset Transfer - Restructuring	0	**1,407,734**	1,407,734
GIS		**397,908**	397,908
New Financial software		**353,134**	353,134
Smart Meter Transfer		**185,288**	185,288
Other		**37,621**	37,621
General Plant	0	**2,381,685**	**2,381,685**
Grand Total	**1,881,754**	**7,402,655**	**5,520,902**
Normalized Capital Expenditures	**1,881,754**	**2,727,146**	**845,393**
Contributed Capital	**-266,363**	**-318,521**	**-52,158**
Net Capital	**1,615,391**	**7,084,134**	**5,468,744**
Net Capital - Normalized	**1,615,391**	**2,408,625**	**793,235**

2013 CAPITAL ADDITIONS

2013 net capital additions of $1,531,726 were $876,899 less than the 2013 actual amount of $2,408,625 on a normalized basis (i.e. removing the one time impact of the Smart Meter Transfer and the Asset Transfer that occurred in 2012).

Distribution capital expenditures for 2013 were $350,251 less than the 2012 amount as System Access was $280,866 and System Renewal was $68,365 less than the 2012 amounts. Additionally, Contributed capital of $596,144 was $277,623 greater than the 2012 amount of $318,521.

General Plant expenditures for 2013 of $538,637 were $250,026 less than the 2011 amount (excluding restructuring and smart meter) of $788,663. GIS expenditures were $328,113 less than in 2012 as work was carried forward from 2013 to 2014 and financial system software was $353,134 less than 2012. These reductions were offset by increased investment in computer hardware and software and a new bucket truck replacing a 2002 bucket truck. IT capital purchases included:

- Replacements for old firewalls that were no longer being supported to provide network and systems from internal and external threats.

- New core server infrastructure. Old server infrastructure was not performing well and was near its limits for storage. This new system addressed performance issues, provides growth capacity and allows the old equipment to be used for disaster recovery purposes. This server hardware is fully redundant and resilient, providing greater uptime & performance.

- Uninterruptible Power Supplies (UPS) to service new server & storage infrastructure.

- New phone system, previous system was considered end-of-life by the manufacturer. New phone system was needed to continue to receive support and updates.

- Existing backup solution had been outgrown. A new solution was required.

- Stack Switches & Power Supply, existing phone system switches were out of warranty & support; replacement was required.

Table 2-18 below shows the difference in major capital additions by major project for 2013 vs. 2012.

Table 2-18

Capital Additions by Major Project 2013 Actuals vs. 2012 Actuals

Major Project	2012 Actuals	2013 Actuals	Variance
Smart Meter Transfer	3,082,487	0	-3,082,487
New Services/Upgrades Residential	40,098	71,033	30,935
New Services/Upgrades Commercial	68,969	97,133	28,164
Road Widening (Dependant on Road Work - No Hydro Control)	11,755	29,401	17,646
New Services Subdivisions	740,481	382,850	-357,631
System Access	**3,943,790**	**580,417**	**-3,363,373**
Voltage Conversion/System Upgrade	1,057,596	983,614	-73,981
Pole Replacement Program	19,585	25,202	5,617
System Renewal	**1,077,181**	**1,008,816**	**-68,365**
System Service	**0**	**0**	**0**
Asset Transfer - Restructuring	**1,407,734**		-1,407,734
GIS	**397,908**	**69,795**	-328,113
New Financial software	**353,134**		-353,134
Smart Meter Transfer	**185,288**		-185,288
Computer SW & HW		**180,898**	180,898
Fleet		**247,083**	247,083
Building, Office and Fixtures		**17,973**	17,973
Other	**37,621**	**22,888**	-14,733
General Plant	**2,381,685**	**538,637**	**-1,843,048**
Grand Total	**7,402,655**	**2,127,870**	**-5,274,785**
Normalized Capital Expenditures	**2,727,146**	**2,127,870**	**-599,276**
Contributed Capital	**-318,521**	**-596,144**	**-277,623**
Net Capital - normalized	**2,408,625**	**1,531,726**	**-876,899**

2014 CAPITAL ADDITIONS

Forecast 2014BY gross capital additions of $2,428,000 are $896,274 greater than the 2013 actual expenditures of $1,531,726.

The 2014BY distribution capital spending is greater than the 2013 actual amount primarily as STEI continues to focus on the system conversion plan.

The General Plant capital expenditure increase of approximately $190,000 is mainly attributed to the building and office renovation that are planned for 2014 to 2016 period. This project is discussed in more detail in the DSP which is appended as Attachment 1 to this Exhibit. The building is 20 years old and is need of upgrading. There have been a number of issues identified such as water issues, specifically in the northern wall, basement flooding and other items such as elevator upgrades.

Table 2-19 below shows the difference in major capital additions by major project for 2014 vs. 2013.

Table 2-19

Capital Additions by Major Project 2014 Budget vs. 2013 Actuals

Major Project	2013 Actuals	2014 Bridge Year	Variance
New Services/Upgrades Residential	71,033	0	-71,033
New Services/Upgrades Commercial	97,133	0	-97,133
Road Widening (Dependant on Road Work - No Hydro Control)	29,401	0	-29,401
New Services Subdivisions	382,850	200,000	-182,850
System Access	**580,417**	**200,000**	**-380,417**
Voltage Conversion/System Upgrade	983,614	1,600,000	616,386
Pole Replacement Program	25,202	0	-25,202
System Renewal	**1,008,816**	**1,600,000**	**591,184**
System Service	**0**	**0**	**0**
GIS	**69,795**	**150,000**	**80,205**
Computer SW & HW	**180,898**	**116,000**	**-64,898**
Fleet	**247,083**	**264,000**	**16,917**
Building, Office and Fixtures	**17,973**	**170,000**	**152,027**
Tools and Equipment	**22,888**	**28,000**	**5,112**
General Plant	**538,637**	**728,000**	**189,363**
Grand Total	**2,127,870**	**2,528,000**	**400,130**
Normalized Capital Expenditures	**2,127,870**	**2,528,000**	**400,130**
Contributed Capital	**-596,144**	**-100,000**	**496,144**
Net Capital - normalized	**1,531,726**	**2,428,000**	**896,274**

2015 CAPITAL ADDITIONS

2015TY gross capital additions of $2,113,000 are $315,000 less than the 2014BY amount of $2,428,000.

Table 2-20 below shows the difference in major capital additions by major project for 2015 vs. 2014.

Table 2-20

Capital Additions by Major Project 2015 Budget vs. 2014 Budget

Major Project	2014 Bridge Year	2015 Test Year	Variance
New Services Subdivisions	200,000	200,000	0
System Access	**200,000**	**200,000**	**0**
Voltage Conversion/System Upgrade	1,600,000	1,341,250	-258,750
System Renewal	**1,600,000**	**1,341,250**	**-258,750**
Build New Powerline/Expansion	0	208,750	208,750
System Service	**0**	**208,750**	**208,750**
GIS	**150,000**	**0**	**-150,000**
Computer SW & HW	**116,000**	**98,000**	**-18,000**
Fleet	**264,000**	**125,000**	**-139,000**
Building, Office and Fixtures	**170,000**	**170,000**	**0**
Tools and Equipment	**28,000**	**20,000**	**-8,000**
SCADA	**0**	**50,000**	**50,000**
General Plant	**728,000**	**463,000**	**-265,000**
Grand Total	**2,528,000**	**2,213,000**	**-315,000**
Normalized Capital Expenditures	**2,528,000**	**2,213,000**	**-315,000**
Contributed Capital	**-100,000**	**-100,000**	**0**
Net Capital - normalized	**2,428,000**	**2,113,000**	**-315,000**

The reduction of $315,000 in the 2015 Test Year vs the 2014 Bridge Year Forecast is primarily in the general plant expenditures as the core distribution capital expenditures remain relatively consistent.

The general plant reduction is primarily related to the GIS project as 2015TY expenditures are expected to be $150,000 less than the 2014BY amount as the project comes to an end. The GIS project is discussed in more detail in the DSP Exhibit 2, Tab 1, Schedule 11, and Attachment 1. Fleet expenditures are expected to be $139,000 less consistent with the Fleet plan. Partially offsetting this change is the planning expenditures of $50,000 on the new aspects of the development of the SCADA system.

Current SCADA program has been “orphaned” with the planned system conversion and smart grid plans, STEI did not think it would be financially prudent to invest in what could be an obsolete system. Current SCADA resides in the substations that are being phased out. As the conversion program has progressed there is a need for system control infrastructure to enable future smart grid and reduce the length of customer outages and provides trouble shooting information. STEI has planned a conservative implementation over a five year period from 2015 to 2019 to enable STEI to react to potential government initiatives that may impact this type of system.

ACCOUNTING TREATMENT

Treatment of Projects with a Life Cycle Greater than One Year

STEI’s accounting policy is to include projects in fixed assets when they are completed (energized). Capital projects which are not yet completed are included in Work in Progress (‘WIP”). STEI does not have individual projects that are greater than one year. Capital projects that straddle two fiscal years, carried over from one year to the next year, are recorded WIP. Once completed, expenditures are removed from WIP and capitalized to fixed assets.

Treatment of Cost of Funds

STEI’s accounting policy is to expense borrowing costs. STEI does not capitalize interest on capital projects.

Components of Other Capital Expenditures

STEI does not have other capital expenditures, such as non-distribution activities.

CAPITALIZATION POLICY

STEI's capitalization policies and principles are based on Canadian Generally Accepted Accounting Principles ("CGAAP"), and guidelines set out by the Ontario Energy Board, where applicable. Effective January 1st, 2012 STEI as part of the restructuring, developed a new capitalization policy that is consistent with IFRS as property, plant and equipment ("PP&E") expenditures include only directly attributable costs.

The cost of self-constructed assets are recorded and recognized at cost, and include direct labour and benefits, materials, fleet and contractor costs, which are incurred during the development, implementation, or construction phase of the asset.

Assets with a cost in excess of $1,000 expected to provide future economic benefit greater than one year are capitalized. Expenditures that create a physical betterment or improvement of an asset will also be capitalized.

With respect to transportation equipment all costs associated with placing a vehicle into service are capitalized.

Computer software that is acquired or developed by STEI will be capitalized and classified as an intangible asset.

Certain capital assets may be funded or paid by a customer or third party developer through capital contributions. Under IFRS, the capital contributions that are recognized as deferred revenue have been reclassified as a reduction to rate base under MIFRS.

STEI does not anticipate borrowing to fund capital expenditures and as such STEI has not capitalized any interest in the 2015 test year. Historically, STEI has not capitalized interest including the 2011 COS application.

Under IFRS, an entity must present and record separately from PP&E those assets that are within the scope of International Accounting Standard 38 Intangible Assets ("IAS 38").

The Board Report (EB-2008-0408) states the following:

"IFRS requires certain assets to be recorded as intangible assets (e.g. computer software and land rights) that were previously included in PP&E. Utilities shall include such intangible assets in rate base and the amortization expense in depreciation expense for determining the revenue requirement. This reclassification is also necessary to preserve continuity of the rate base."

Based on the above, for MIFRS, St. Thomas Energy Inc. has included intangible assets as PP&E for rate setting purposes. The major differences between IFRS and CGAAP with respect to the accounting for PP&E and intangible assets are outlined below.

GUIDELINE FOR CAPITALIZATION OF ASSETS

Capital Assets

Capital Assets include property, plant, and equipment that are held for use in the production or supply of goods and services and provide a benefit lasting beyond one year. Capital expenditures also include the improvement or "betterment" of existing assets. Intangible assets are also considered capital assets and are defined as assets that lack physical substance. They include goodwill, patents, copyrights and computer software.

Betterment

A betterment is a cost which enhances the service potential of a capital asset and/or increases its value. Betterment includes expenditures which increase the capacity of the asset, lower associated operating costs of the asset, improve the quality of output or extend the asset's useful life. A betterment does not include general maintenance-related actions that seek to sustain an asset's current value.

Repair

A repair is a cost incurred to maintain the service potential of a capital asset. Expenditures for repairs are expensed to the current operating period. Expenditures for repairs and/or maintenance designed to maintain an asset in its original state are charged to an operating account.

Cost

Cost is the amount of consideration to acquire, construct, develop or better a capital asset. The cost of an item of property, plant and equipment includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials and direct labour and any other costs directly attributable to bringing the asset to a working condition for its intended use.

CAPITALIZATION BY COMPONENT

When parts or components of an item of property, plant and equipment have different useful lives, they are accounted for as individual items (major components) of property, plant and equipment. Component costs must be significant in relation to the total cost of the item and depreciated separately over the component's useful life. Components are those which:

- Are significant in relation to the total cost of the item;
- Have different depreciation methods or useful life;
- Components with similar useful lives and depreciation methods are grouped in determining the depreciation charge.
- Parts of the item that are not individually significant (remainder of the items) are combined and categorized as a single component best suited for the sum of the parts.

Capital Spares

STEI recognizes spare inventory as property, plant and equipment. Spare inventory is dedicated specifically as backup for the distribution system. It is expected that these items are not intended for resale, have a longer period of future benefit compare to inventory items intended for resale, are an integral component of the distribution system and are expected to be placed in service.

Depreciation

Depreciation is recognized on a straight-line basis over the estimated useful life of each significant identifiable component of an item of property, plant and equipment. Land is not depreciated. Construction in progress assets are not depreciated until the project is complete and in service. Depreciation of an asset begins in the year when it is available for use, i.e. when it is in the location and condition necessary for it to be capable of operating in the manner intended. Depreciation of an asset ceases at the earlier of the date that the asset is classified as held for sale and the date that the asset is derecognized. Depreciation does not cease when the asset becomes idle or is retired from active use unless the asset is fully depreciated.

Commencing January 1, 2015, depreciation is calculated using the ½ year rule. Under this rule, capital asset additions are assumed to be put into service equally throughout the year, therefore, on average depreciation starts at the midpoint of the acquisition year. Due to the change in estimate of the remaining useful life of many of the assets beginning on January 1, 2012 are amortized over the remaining years of useful life of each component.

Opening Balances

The International Accounting Standards Board ("IASB") amended "IFRS 1 – First-time adoption of IFRS" in May, 2010 to allow rate-regulated entities to use the previous accounting net book value as the IFRS cost on the date of transition to IFRS. This is referred to as the deemed cost exemption.

STEI will elected to use the deemed cost election under IFRS 1 for opening balance sheet values for its capital assets upon transition to IFRS in 2015. Based on paragraph D8B of IFRS 1, entities with operations subject to rate regulations may hold items of PP&E or intangible assets where the carrying amount of such items might include amounts that were determined under previous GAAP but do not qualify for capitalization in accordance with IFRS.

In this case, a first-time adopter may elect to use the previous GAAP carrying amount of such an item at the date of transition to IFRS as deemed cost. For the purposes of paragraph D8B, operations are subject to rate regulation if they provide goods or services to customers at prices (i.e., rates) established by an authorized body empowered to establish rates that bind the customers, and that are designed to recover the specific costs the entity incurs in providing the regulated goods or services, and to earn a specified return. Based on the definition above, STEI qualifies for this exemption.

Under this exemption the deemed cost at the date of transition becomes the new IFRS cost basis. Therefore, on January 1, 2015, the opening accumulated depreciation is $nil under IFRS and the opening cost equates to the closing CGAAP net book value ("NBV").

Capital contribution adjustment represents the adjustment to net book value of distribution system assets. Accumulated customer contribution balance has been set to zero as at January 1, 2015 for IFRS, as the cumulative balance has been offset against the costs of related capital assets for which the contribution was received. Starting in 2015, customer contributions will be recorded as deferred revenue for IFRS.

(This may not be reflected in Proforma results; however, the change in accounting practice is immaterial to this application).

Change of Capitalization Policy

IFRS prescribes which costs can be included as part of the cost of an asset and indicates that only costs that are directly attributable to a specific asset can be capitalized. Indirect overhead costs, such as general and administration costs that are not directly attributable to an asset, that were being capitalized under CGAAP, are not allowed under IFRS.

Based on the Board Report EB 2008-0408, the Board requires utilities to adhere to IFRS capitalization accounting requirements for rate-making and regulatory reporting purposes after the date of adoption of IFRS, and that a utility is required to file a copy of its capitalization policy, as part of its first cost of service rate filing after adopting IFRS.

In light of all the above, STEI, in conjunction with its IFRS advisor and auditor, performed a thorough analysis of all costs that were being capitalized under CGAAP in order to determine if they were eligible for capitalization under IFRS. These costs included materials, labour, benefits, truck, subcontractor, overhead, customer contributions, and borrowing costs. The analysis conducted by STEI has been summarized in the following sections of this evidence.

The following capitalization rules were adopted on January 1, 2012 when STEI restructured from a virtual utility to a self-supporting operating utility that included employee cost.

Material Cost

These costs include stocked items taken from warehouse and issued out to each project as well as direct materials which are purchased and delivered to the job site directly. These costs represent the purchase price and initial delivery/handling costs of the materials.

Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management, hence there will be no impact on the amount of material costs being capitalized for IFRS.

Material Burden

Under CGAAP a fixed percentage or a fixed fee may be allocated to capital projects which represented the cost associated with acquiring, handling, and storing of materials. The material burden also included the labour costs and the associated employee benefits of staff working in Stores Operations and the Procurement department. Since IFRS only allows directly attributable costs to be capitalized, STEI has concluded that material burden will not be capitalized under IFRS as it is impractical for STEI to determine whether these costs are directly attributable to an individual project and even more difficult to attribute them to each inventory item being issued. Therefore, these costs are determined to be general overhead and have been recognized as an expense since restructuring on January 1, 2012 and have no impact on the amount of material costs being capitalized for IFRS.

Labour Costs

The labour costs that are capitalized to PP&E comprise of engineering, design, linemen, construction, and supervision time with working timesheets which record the nature of the actions and activities being undertaken and time spent on each task by each type of employee.

Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management. Therefore, there will be no impact on the amount of labour costs being capitalized under IFRS relating to this cost category.

Benefit Costs

Employee benefit costs represent the costs associated with employee pensions, vacations, etc. For each hour of regular time recorded, via a timesheet, directly to a capital project, St. Thomas Energy Inc. adds a benefit rate per hour that allocates the estimated annual costs per employee type. Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management. St. Thomas Energy Inc. has determined there will be no impact on the amount of employee benefit costs being capitalized under IFRS.

Labour Burden

Under CGAAP, a fixed percentage of overhead and administration costs, referred to as "labour burden", may be allocated to direct labour costs, and forms part of the cost of an asset. These costs include the labour costs, related benefits and other general administrative costs of the senior operations management and directors that cannot be attributed to a specific project. Therefore, these costs are determined to be general overhead and have been recognized as an expense since restructuring on January 1, 2012.

Transportation and Fleet Costs

These costs include the costs associated with maintaining automobiles, trucks and equipment, trailers and other fleet equipment. Some of these costs include fuel costs, repairs, and parts, insurance and all other items of expense necessary to keep the rolling stock in service. These costs can also include the labour costs and the associated benefits of the staff directly involved in rolling stock maintenance.

A fleet rate is determined on an annual basis for each vehicle group by dividing the annual costs accumulated for each vehicle type by their annual usage. When a vehicle is used for a capital project, a fleet rate is charged based on the type of vehicle used multiplied by hourly usage of the vehicle. Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management. St. Thomas Energy Inc. has determined there will be no impact on the amount of transportation costs being capitalized under IFRS.

Fleet Burden

Under CGAAP, a fixed percentage of fleet costs referred to as "truck burden" could be allocated to transportation costs and forms part of the cost of the asset. These costs include general maintenance costs such as salaries and benefits of administration personnel and any other general maintenance activities not directly attributed to each vehicle. Therefore, STEI has concluded that truck burden will not be capitalized under IFRS and there is no impact on the amount being capitalized under IFRS has STEI didn't record these costs previously.

Third Party Costs

Sub-contractor costs are incurred when STEI engages a third party to perform services. Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management. STEI has determined there will be no impact on the amount of third party costs being capitalized under IFRS.

2011 Pre-Restructuring

Prior to January 1, 2012 STEI as a virtual utility, recorded capital costs based upon third party costs including the costs incurred by affiliate companies via the MSA. As of January 1, 2012, STEI as an operating utility adopted IFRS capitalization policies and has not capitalized general overhead costs including labour burdens, general administration, material handling and fleet burdens. The impact of these changes is that restructuring capital costs are lower than under the previous MSA rate.

Capitalization of Borrowing Costs

IAS 23 Borrowing Costs establishes the criteria for the recognition of interest on borrowings as a component of the carrying amount of an acquired or self-constructed item of capital assets.

Borrowing costs that are directly attributable to the acquisition, construction, or production of a qualifying asset form part of the cost of that asset.

Under CGAAP, rate regulated entities were permitted to include an allowance for funds used during construction ("AFUDC") in the cost of an asset that is acquired, constructed, or developed over time. STEI did not and will no longer be able to capitalize AFUDC under IFRS but will be required to capitalize interest as per IAS 23. IAS 23 states that an entity can capitalize borrowing costs only on qualifying assets. A qualifying asset is an asset that takes a substantial period of time to complete. STEI has defined a substantial period of time as being greater than six months, and will capitalize borrowing costs for qualifying asset or project that is expected to take longer than six months to be completed.

STEI does not anticipate borrowing to fund capital expenditures and as such STEI has not capitalized any interest in the 2015 test year. Historically, STEI has not capitalized any interest including the 2011 COS application.

Customer Contributions

Under CGAAP, STEI recorded customer contributions as an offset to the cost of capital asset and amortized as part of the net capital asset. Under IFRS, STEI cannot capitalize these customer contributions as part of its net capital assets, but instead will defer the contributions as a liability and amortize them as revenue.

As outlined in Board Report (EB 2008-0408):

"For regulatory reporting and rate making purposes the amount of customer contributions will be treated as deferred revenue to be included as an offset to rate base and amortized to income over the life of the facility to which it relates".

Consistent with the Board's guidance, St. Thomas Energy Inc. will record customer contributions received after January 1, 2015 as deferred revenue and amortizing them as revenue over the life of the related asset. Customer contributions received prior to this date will be netted against the cost of the related asset as a result of deemed cost election chosen for IFRS 1. For the purpose of this Application, capital contributions are included as an offset to rate base and the related amortized revenue as an offset to depreciation expense.

CAPITALIZATION OF OVERHEAD

Previous to January 1, 2012, STEI capital costs were based upon Master Service Agreement ("MSA") from it affiliates and direct 3rd party costs.

January 1, 2012 upon restructuring STEI, in advance of the transition to IFRS, and in accordance with the Board's requirements, reviewed its overhead costs to determine which costs are directly attributable expenses to capitalize and which should be expensed as part of Operating Maintenance and Administration costs.

STEI determined the following burdens are directly attributable to PP&E and should therefore be capitalized.

Board Appendix 2-DA Overhead Expense is provided below.

BENEFIT BURDEN

The benefit burden rate consists of direct benefits. The burden rate of 44% recovers the employment benefits that employees are entitled to receive such as CPP, EI, medical and dental benefits, OMERS, EHT and WSIB. This burden is applied to hourly labour cost by specific job via payroll input to activity specific job costs.

VEHICLE BURDEN

With respect to repairs and maintenance, IFRS states that the costs of day-to-day servicing of an item of PP&E cannot be recognized in the carrying amount. These costs are expensed as incurred. Therefore the vehicle charge to capital only includes fuel and consumables.

Appendix 2-DA
Overhead Expense

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include overhead costs that are currently capitalized on self-constructed assets under MIFRS.

Nature of the Overhead Costs	(A)[1] Dollar Impact on PP&E Historic Year	(B) Dollar Impact on PP&E Bridge Year	(C) Dollar Impact on PP&E Test Year	(D) Dollar Impact - PP&E Variance Test versus Bridge	(E)[1] Dollar Impact - PP&E Variance Test versus Historic	(F) Directly Attributable? (Y/N)	(G) Reasons why the overhead costs are allowed to be capitalized under MIFRS or an alternate accounting standard given limitations on capitalized overhead
employee benefits	$ 140,425	$ 185,000	$ 189,000	$ 4,000	$ 48,575	Y	alloaction of direct benefits expressed as an overhead percentage applied at payroll time sheet entry
costs of site preparation				$ -	$ -		
initial delivery and handling costs				$ -	$ -		
costs of testing whether the asset is functioning properly				$ -	$ -		
professional fees				$ -	$ -		
				$ -	$ -		
costs of opening a new facility				$ -	$ -		
costs of introducing a new product or service (including costs of advertising and promotional activities)				$ -	$ -		
costs of conducting business in a new location or with a new class of customer (including costs of staff training)				$ -	$ -		
administration and other general overhead costs	$ -	$ -	$ -	$ -	$ -		
				$ -	$ -		
				$ -	$ -		
				$ -	$ -		
Insert description of additional item(s) and new rows if needed.				$ -	$ -		
Total	$ 140,425	$ 185,000	$ 189,000	$ 4,000	$ 48,575		

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include overhead costs that were capitalized on self-constructed assets under CGAAP but are no longer capitalized under MIFRS or an alternate accounting standard and are included in OM&A.

Nature of the Overhead Costs	(A)[1] Dollar Impact on OM&A Historic Year	(B) Dollar Impact on OM&A Bridge Year	(C) Dollar Impact on OM&A Test Year	(D) Dollar Impact - OM&A Variance Test versus Bridge	(E)[1] Dollar Impact - OM&A Variance Test versus Historic	(F) Directly Attributable? (Y/N)	(G) Reasons why the overhead costs are not allowed to be capitalized under MIFRS or an alternate accounting standard given limitations on capitalized overhead
employee benefits	$ 140,425	$ 185,000	$ 189,000	$ 4,000	$ 48,575		alloaction of direct benefits expressed as an overhead percentage applied at payroll time sheet entry
costs of site preparation				$ -	$ -		
initial delivery and handling costs				$ -	$ -		
costs of testing whether the asset is functioning properly				$ -	$ -		
professional fees				$ -	$ -		
costs of opening a new facility				$ -	$ -		
costs of introducing a new product or service (including costs of advertising				$ -	$ -		
costs of conducting business in a new location or with a new class of				$ -	$ -		
administration and other general overhead costs				$ -	$ -		
				$ -	$ -		
				$ -	$ -		
				$ -	$ -		
Insert description of additional item(s) and new rows if needed.				$ -	$ -		
Total	$ 140,425	$ 185,000	$ 189,000	$ 4,000	$ 48,575		

1

COST OF ELIGIBLE INVESTMENTS FOR DISTRIBUTORS

STEI has not incurred any costs for the connection of qualifying generation facilities.

ADDITION OF ICM ASSETS TO RATE BASE

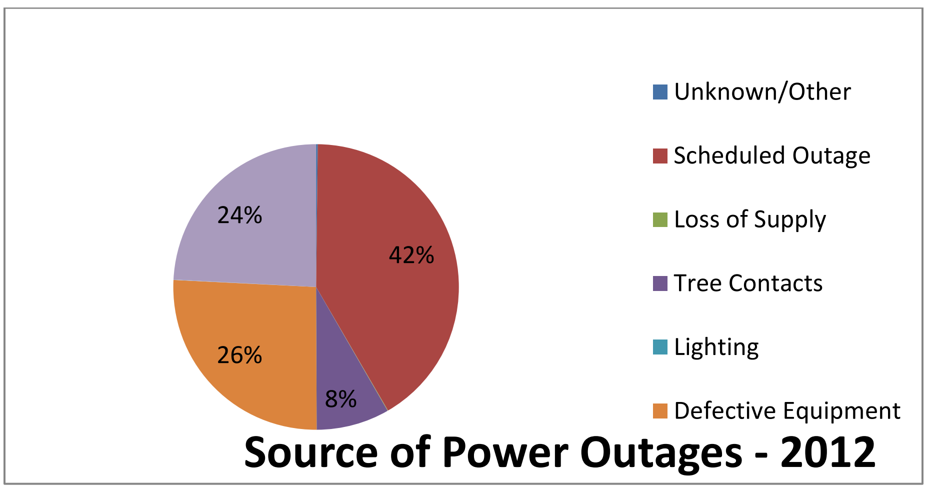
STEI did not file ICM requests during the IRM period from its 2011 Cost of Service Application.

SERVICE QUALITY AND RELIABILITY PERFORMANCE

STEI participates in benchmarking studies to measure service quality, reliability and performance, but is bound by confidentiality and therefore is unable to file these studies.

The following pie chart (Chart 1) summarizes the source of all power outages experienced within STEI's service territory for 2012. 99.7% of the total annual customer-hours of interruption are a result of four items: Scheduled Outages (41.4%), Defective Equipment (25.9%), foreign Interference 24% and tree contacts 8%. The remaining items make up the balance of 0.3%.

Figure 1



STEI tracks service reliability statistics System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), and Customer Average Interruption Duration Index ("CAIDI") including and excluding loss of supply-related incidents and reports these to the Board on an annual basis. Reliability statistics from 2004 to 2013 are shown in Table 2-21 system reliability, Table 2-22; 10 year reliability graph and Table 2-23; 10 year reliability excluding loss of supply below.

Table 2-21: System Reliability

Reliability Statistics - Last 10 Years	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
System Average Interruption Frequency Index (SAIFI)	0.32	0.79	0.74	0.38	2.01	0.65	0.57	1.69	1.05	1.95
System Average Interruption Duration Index (SAIDI)	0.15	0.68	0.19	0.49	0.80	0.28	0.34	1.72	0.22	1.93
Customer Average Interruption Duration Index (CAIDI)	0.46	0.85	0.25	1.29	0.40	0.43	0.60	1.02	0.21	0.99
Index of Reliability	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Excluding Loss of Supply but Includes Significant Events	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
System Average Interruption Frequency Index (SAIFI)	0.32	0.79	0.13	0.38	0.39	0.39	0.57	1.00	1.05	1.42
System Average Interruption Duration Index (SAIDI)	0.15	0.66	0.13	0.49	0.45	0.13	0.34	0.99	0.22	0.99
Customer Average Interruption Duration Index (CAIDI)	0.46	0.83	0.95	1.29	1.16	0.32	0.60	0.98	0.21	0.70
Index of Reliability	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Table 2-22: 10 year Reliability Graph

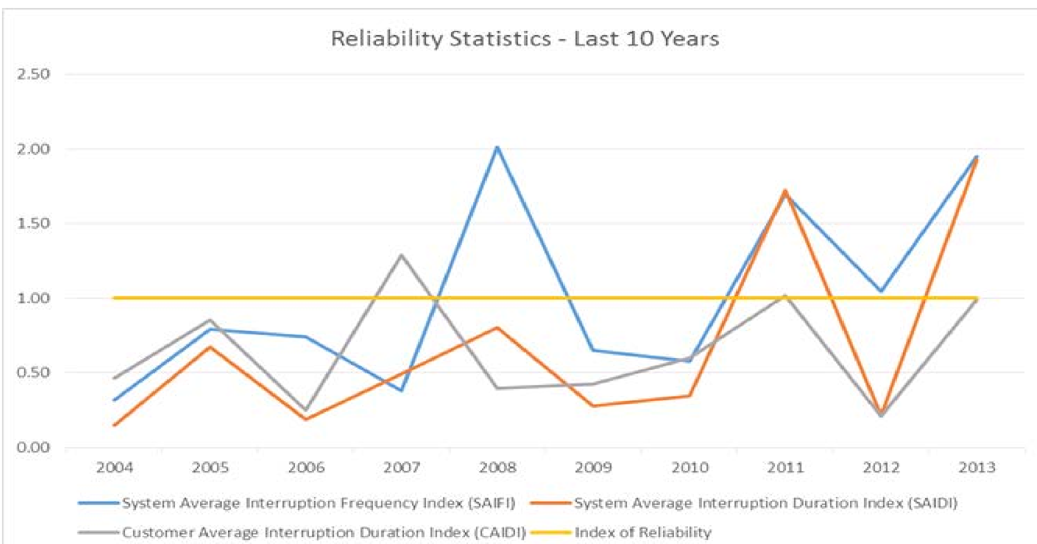
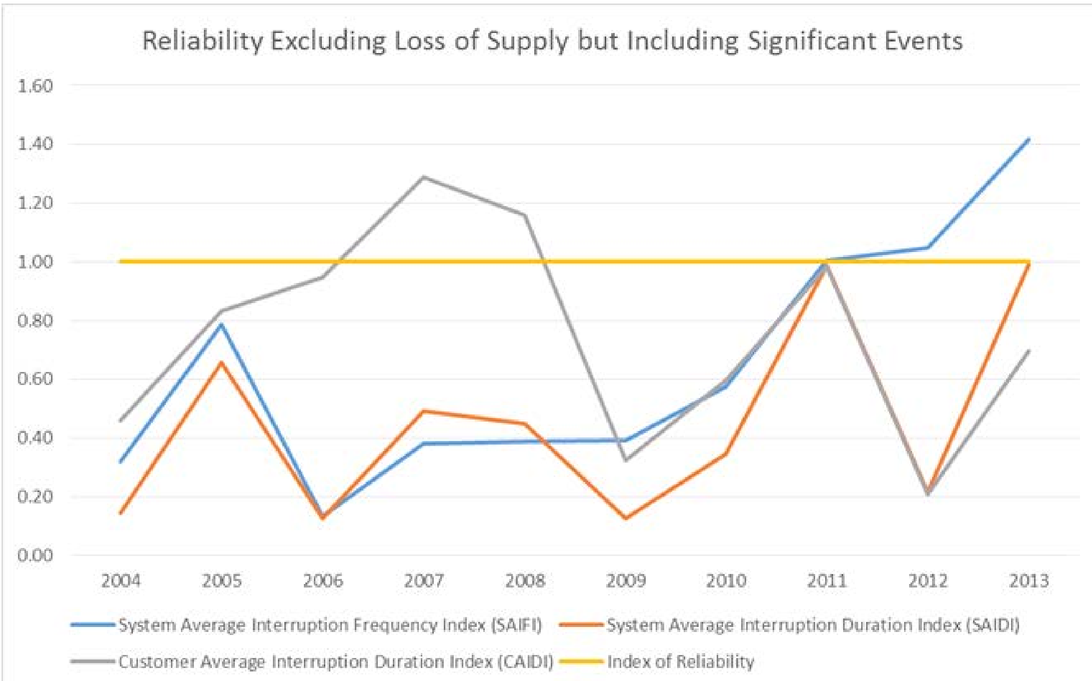


Table 2-23: 10 Year Reliability Graph, excluding Loss of Supply



STEI's performance is within the range of acceptable performance over the previous five years and no corrective action is required. The following Table 2-G sets out the service reliability indicators for the last five years (2008-2012).

Appendix 2-G
Service Reliability Indicators
2008 - 2012

Index	Includes outages caused by loss of supply					Excludes outages caused by loss of supply				
	2008	2009	2010	2011	2012	2008	2009	2010	2011	2012
SAIDI	0.800	0.280	0.340	1.720	0.220	0.450	0.126	0.343	0.987	0.217
SAIFI	2.010	0.650	0.570	1.690	1.050	0.389	0.392	0.575	1.004	1.047

5 Year Historical Average

SAIDI		0.672		0.425
SAIFI		1.194		0.681

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

STEI's service quality indicators for the years 2009 to 2013 are provided in the Table 2-24 Service Quality Indicators below:

Table 2-24: Service Quality Indicators

Reported Service Quality Indicators (SQIs)							
Indicator	**Minimum Standard**	**2009**	**2010**	**2011**	**2012**	**2013**	**Average**
Connection of New Services - Low Voltage (LV)	90% or Better	100.0%	98.8%	99.4%	100.0%	100.0%	**99.6%**
Connection of New Services - High Voltage (HV)	90% or Better	n/a	n/a	n/a	n/a	n/a	**n/a**
Appointment Scheduling	90% or Better	94.3%	97.2%	95.0%	94.5%	91.9%	**94.6%**
Appointments Met	90% or Better	99.3%	99.7%	100.0%	100.0%	100.0%	**99.8%**
Rescheduling a missed appointment	100%	50.0%	50.0%	n/a	n/a	n/a	**50.0%**
Telephone Accessibility	65% or Better	81.6%	89.5%	82.6%	83.8%	76.5%	**82.8%**
Telephone Call Abandon Rate	less than 10%	1.1%	2.1%	1.9%	1.5%	2.7%	**1.9%**
Written Responses to Inquiries	80% or Better	100.0%	98.4%	95.3%	100.0%	100.0%	**98.7%**
Emergency Response - Urban Areas	80% or Better	100.0%	100.0%	100.0%	100.0%	100.0%	**100.0%**
Emergency Response - Rural Areas	80% or Better	n/a	n/a	n/a	n/a	n/a	**n/a**
Reconnection Performance Standard	85% or Better	n/a	n/a	100.0%	100.0%	100.0%	**100.0%**

Attachment 1 of 4

STEI Consolidated DSP

St. Thomas energy inc.
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Distribution System Plan

Index to Distribution System Plan

The relationship between the sections of St. Thomas Energy Inc.'s Distribution System Plan and the Chapter 5 Filing Requirements is shown below.

1 Distribution System Plan (Ch.5.2)

On March 28, 2013 the Ontario Energy Board (the "Board") issued Chapter 5 of the Board's Filing Requirements for Electricity Transmission and Distribution Applications, entitled "Consolidated Distribution System Plan Filing Requirements" ("DS Plan Filing Requirements" or "Chapter 5 Filing Requirements"). The filing requirements provide a standard approach to a distributor's filing of asset management and capital expenditure plan information in support of a rate application. St. Thomas Energy Inc.'s ("St. Thomas Energy" or "STEI" or "the Company") Distribution System Plan ("DS Plan") has been prepared in accordance with the DS Plan Filing Requirements. St. Thomas Energy has organized the required information using the section headings in the DS Plan Filing Requirements.

St. Thomas Energy's DS Plan is an integrated document that supports the cost-effective planning and operation of the electricity distribution network – a network that is efficient, reliable, sustainable, and provides value for customers. The DS Plan documents the practices, policies and processes that are in place to ensure that investment decisions support St. Thomas Energy's desired outcomes in a cost effective manner and provides value to the customer. St. Thomas Energy is committed to adhering to its DS Plan in order to provide the valued outcomes to the customer. Electricity distributors are capital intensive in nature and prudent capital investments and maintenance plans are essential to ensure the sustainability of the distribution network.

1.1 Distribution System Plan Overview (Ch.5.2.1)

a) Key elements of the DS Plan affecting rates

High level guidance

This Distribution System Plan is driven by STEI's Vision Statement; i.e. "To be the industry leader in energy solutions and services." One measure of the company's seriousness in meeting this vision is that it is registered as a participant in the internationally-recognized ISO 9001 program that seeks to demonstrate the highest level of continuous improvement and customer satisfaction.

In striving to secure this vision for the company, STEI is guided by the four target performance outcomes identified by the Board: Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance. This requires conformance with all laws and applicable regulations, codes, standards, etc.

It therefore follows that to help achieve the foregoing, STEI's asset management objective is to continue "to meet all regulated requirements ***in a manner that minimizes the overall cost to STEI customers*** when staff acquire and subsequently maintain assets in order to provide service at required performance standards."

This DS Plan is guided strictly by that asset management objective.

Long-Term Direction

It is with this asset management objective in mind that some 5 years ago STEI carefully examined its distribution system to determine the direction the utility should take over the following 10 years in the renewal/replacement of its physical assets.

The most evident characteristic of STEI's distribution system was that it was then almost 50 years old and designed to engineering standards of that vintage. With significant effort focused on preventive and corrective maintenance, the rapidly aging system was still essentially achieving the high level of reliability that STEI's customers were demanding but it was quite apparent that as the equipment continued to age and deteriorate that the then-current situation would not remain viable for long. Maintenance costs were accelerating and obtaining spares from manufacturers for the old technology was becoming much more difficult. Since the distribution system was a "floating delta" design whereby a backyard circuit could touch the ground and the circuit not trip, the increasing risk of downed lines and the likelihood of other equipment failures as the components of the system further aged placed the public at elevated danger from live wires. Also, the larger number of maintenance events meant increasing equipment face time for repair crews who had to work with a dangerous ungrounded system.

Only two engineering solutions were on offer: continue to operate and maintain the 50-year old system indefinitely or upgrade the system to contemporary standards. No other practical engineering alternative could be identified.

Detailed analysis showed that continuing to operate and maintain the existing aged system indefinitely would result in a progressively more expensive maintenance program, increasing difficulty in sourcing spare parts, a greater number of outages, a drop from the expected high reliability standards, progressively more exposure by the public and STEI crews to live wires and STEI's inability to meet individual customers' increased capacity requirements.

The alternative to this would be to totally replace the existing system. This presented a severe financial challenge since the cost for this alternative was expected to be in the $10 million to $15 million range which, for STEI, was a decade-long commitment. Nevertheless, moving to a modern 27.6 kV system was seen to meet the lowest lifecycle cost through reduced outage and preventive maintenance costs; the opportunity to obtain reduced operating costs and improved equipment efficiencies; removal of a number of sub-stations and elimination of multiple kilometers of cable; the ability to continue to achieve the customer-demanded reliability standards for the foreseeable future; enhanced public and staff safety and the ability to meet customers' needs for adequate capacity delivery.

STEI management firmly concluded at that time that the only truly viable and practical choice was the 2400 V to 27.6 kV "voltage conversion" alternative.

STEI began progressively implementing the new distribution system in 2010, balancing in each year the need to fully implement the system as soon as possible to obtain the identified cost, efficiency and safety improvements with the conflicting requirement to minimize customer bill increases and the need to implement other smaller renewals/replacements.

In preparation for the development of this current DS Plan, STEI management reviewed its previous plan to ensure the earlier decision continued to be the optimal solution. A careful analysis of all the factors led to the firm conclusion that completing the replacement of the 2,400 V system with the modern 27.6 kV system was indeed the correct approach.

Since there was a 22% decrease in load in the 2005 – 2012 period due to plant closures (though the load has since levelled and is showing small positive signs) and there is spare capacity available to STEI at the Edgeware transmission station, there are no other major claims for STEI's capital. Similarly, there are no significant external drivers or other prospective business conditions driving the size and mix of capital investments needed to achieve STEI's planning objectives. Hence, this DS Plan is essentially the completion of STEI's Voltage Conversion program.

Capital expenditures over the 10-year period

In allocating funds each year in the 2015 to 2019 forecast period, in this DS Plan STEI has continued to balance the desire to fund the Voltage Conversion program to the maximum extent possible with the need to perform other smaller refurbishment/replacement work together with the strong desire to keep the bill impacts as level as possible and within a reasonable range.

Examination of proposed expenditures will show that STEI's capital expenditures in each investment category over the 10 year period have been fairly stable with a slight upward normalized trend of approximately 3% per year in total expenditure; also, after normalization, there is otherwise no marked change in the share of total investment represented by any investment category.

During the 5-year future period, the majority (i.e. 13) of the material projects are part of the Voltage Conversion program; these material projects total $7.0 million. In addition, there are 2 related New Powerline projects and 1 System Upgrade project summing to $0.7 million. In total, these 16 material projects directly or indirectly enabling the voltage conversion cost 73% of all capital expenditures during the 2015 to 2019 period.

The balance of the $10.6 million capital expenditure in the 5-year period is made up of a few miscellaneous material projects (i.e. New Subdivisions, I.T. and Fleet) and a number of minor capital projects.

b) Sources of cost savings

The conversion from the 50-year old 2400 V system to a modern 27.6 kV system will continue to provide cost savings resulting from reduced operating costs including line losses, improved equipment efficiencies, removal of a number of sub-stations, the elimination of multiple kilometers of cable and reduced maintenance costs.

The forecast impact of system investments on system O&M costs is shown in Section 3.4 of this report. Despite escalating costs in general, this report shows a modest 2% p.a. reduction in the plan cost for O&M in the forecast period compared to the planned cost of O&M in the historical period.

c) Period covered by the DS Plan

This DS Plan covers the required 10 years as set out in the Chapter 5 Filing Requirements; specifically, the 5-year historical period of 2010 to 2014, the 2015 Test Year and the remaining four years of the forecast period 2016 to 2019.

d) Vintage of Information

The majority of the information presented in this report has 2013 currency though 2014 data has been incorporated where this is available. The key documents used to inform this DS Plan are:

- OPA's review of regional and renewable energy generation: 2014
- Asset Management Plan: 2013
- Management System Manual: 2013
- Asset Condition Assessment report: 2011

e) Important Changes to the Asset Management Process

STEI has made a number of important changes recently to its Asset Management Process which outlines the company's good utility practices within the replacement/refurbishment program and within its inspection/maintenance program. These advances include:

- Update of the Asset Management Plan which documents policies, strategies and objectives and provides specific information used by STEI to establish capital and maintenance requirements that form the basis for its 5-year investments.
- Formalization of the Asset Management Strategy. This is a set of guidelines that STEI staff are required to follow in making all asset management decisions – both long term and day-to-day.
- Development of ***draft*** asset lifecycle optimization policies and practices to encourage the foregoing asset management strategy being adhered to and utilized on a day-to-day basis. (The policies are currently being evaluated for their day-to-day practicality and are therefore shown as "draft"):
    - Policy on System Access, Renewal and Service Investments
    - Policy on the Evaluation of Asset Replacement and Refurbishment
    - Policy on Optimal Maintenance Planning Practices
- Comprehensive update of the Management System Manual complete with work forms and other document to assist in safe day-to-day work performance.

f) Contingency Events

There is no significant aspect of the DS Plan that relates to or is contingent upon the outcome of ongoing activities or future events. Minor contingent considerations relate to the delays that may occur by causing a project to be delayed due to the emergence of a more urgent unplanned project.

1.2 Coordinated Planning with Third Parties (Ch.5.2.2)

a) Description of the Consultations

STEI's only neighbouring distribution system is that of Hydro One Networks Inc. Regular communications between our companies occur for operational activities and to jointly plan our system changes to reduce costs. Examples of these regional planning activities are:

1. The Transmission Connection Agreement that outlines system operation responsibilities, communication details, ownership and emergency operations
2. Coordination of connection impact assessments for common feeders
3. Joint use of Hydro One's poles by STEI along Sutherland Line
4. STEI joint use offer of its hydro poles to Hydro One along Southdale Line
5. Joint use of Hydro One's poles by STEI along Centennial Avenue
6. Joint discussions regarding future plans for Hydro One's transformers / lines in and around STEI
7. Discussions concerning long term load transfers

In addition to the items relating to the activities between STEI and Hydro One, there is a Mutual Assistance Plan between eight distribution companies in the EDA Western District. This Mutual Assistance Plan provides a framework for a coordinated repair and restoration effort by participating utilities. It provides a process to deal with an emergency of a magnitude that requires outside assistance. STEI also has a mutual agreement with Erie Thames Powerlines to support trouble calls on a 24 hour – 7 day/week basis.

The benefits of the above final deliverables are currently being enjoyed by STEI and its joint planning partners. The benefits from the consultations are incorporated in this DS Plan.

b) Final Deliverable to the Regional Planning Process

The OPA conducts regional planning through its Integrated Regional Resource Planning (IRRP) process, where local stakeholders collaborate in the development of integrated solutions for maintaining a reliable supply of electricity to Ontario communities.

The objective of the IRRP process is to develop long-term electricity plans that thoughtfully integrate all relevant resource options, such as conservation and demand management, distributed generation, large-scale generation, transmission and distribution.

In its Letter of Comment (attached), the OPA notes that STEI is part of “Group 2” and the London area for the regional planning process prioritized for 2014 and 2015. At this time however, neither a Regional Infrastructure Plan, nor an Integrated Regional Resource Plan (“IRRP”) has commenced for STEI’s service territory. As a result, the OPA is unable to comment on whether any renewable energy generation investments would be consistent with a Regional Infrastructure Plan.

c) Comment Letter provided by OPA

STEI submitted its Renewable Energy Generation plan to the OPA for comment on February 11, 2014. This letter provided information about regional planning that STEI carried out with neighbouring utilities and contained detailed information about the renewable energy generation projects and planning that impact STEI’s service territory.

The Letter of Comment from the OPA is attached as “Appendix A to Section 1.2”

APPENDIX A to Section 1.2

LETTER OF COMMENT PROVIDED BY OPA

OPA Letter of Comment

St. Thomas Energy Inc.

Renewable Energy Generation Investments Plan

March 13, 2014

ONTARIO POWER AUTHORITY

Introduction

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

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

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

St. Thomas Energy Inc. – Distribution System Plan

On February 12, 2014 St. Thomas Energy Inc. ("STEI") provided its Renewable Energy Generation Investments Plan ("Plan") to the OPA as part of its 5-year Distribution System Plan. The OPA has reviewed STEI's Plan and has provided its comments below.

OPA FIT/microFIT Applications Received

During a review of its Plan, and in discussions with the OPA to clarify the Plan information, STEI indicates that it has successfully connected 33 microFIT projects totalling 278.2 kW of capacity, and 2 FIT projects totalling 600 kW of capacity. In addition to connected projects, STEI also identifies what it describes as "pending projects" consisting of 10 microFIT projects totalling 85 kW of capacity, and 4 FIT projects totalling 360 kW of generation capacity, as part of its Plan.

According to OPA's information, as of January 2014, the OPA has offered contracts to 32 microFIT projects totalling 270 kW of capacity, and 3 FIT projects totalling 638 kW of capacity. The 3 FIT projects consist of the 2 FIT projects connected in STEI's distribution area totalling 600 kW of capacity, and 1 FIT project with a capacity of 38 kW that is pending connection to STEI's distribution system.

The OPA's and STEI's information on renewable energy generation applications is reasonably consistent. The small difference in the number of microFIT projects could be due to differences in the date of data collection. It is also possible that STEI is aware of potential FIT applications which have not yet received FIT contracts, for example, based on pre-FIT consultations and which it describes as pending projects.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 1-800-797-9604 Toll Free
info@powerauthority.on.ca www.powerauthority.on.ca

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

The OPA notes that STEI is part of “Group 2” and the London area for the regional planning process prioritized for 2014 and 2015. At this time however, neither a Regional Infrastructure Plan, nor an Integrated Regional Resource Plan (“IRRP”) has commenced for STEI’s service territory. As a result, the OPA is unable to comment on whether any renewable energy generation investments would be consistent with a Regional Infrastructure Plan.

On page 6 of their letter, STEI indicates that “[its] working assumption is that future levels of installation will be similar to the past projects and it is expected that STEI has ample capacity for renewable generation for the foreseeable future. Based on STEI’s analysis as submitted to the OPA on current and future REG projects, STEI does not expect to make any network investments within the 5- year planning period.”

As noted above, the regional planning process has not yet been initiated for the London area and no regional planning meetings have yet been held with STEI. The OPA looks forward to working further with St. Thomas Energy Inc. once the planning process begins for its area, and appreciates the opportunity to comment on the information provided as part of its Distribution System Plan.

1.3 Performance Measurement for Continuous Improvement (Ch.5.2.3)

Monitoring system performance, both field assets and information systems, provides STEI with the information to appropriately adjust its plans and/or to identify remedial steps to ensure that distribution system assets achieve their design life and are capable of serving under peak demand conditions. STEI's performance monitoring is geared to achieving desired results on its four target performance outcomes, specifically:

- Customer Focus,
- Operational Effectiveness,
- Public Policy Responsiveness and
- Financial Performance.

The Service Quality Requirements within section 7 of the Distribution System Code indicate a prescribed measurement and expected level of performance that defines a baseline for the quality of service delivered by electricity distributors. These are important indicators that generally reflect day-to-day performance of direct customer contacts. STEI monitors and reports on the successful meeting of these requirements on a yearly basis.

In addition to the metrics mandated by the OEB, STEI is evaluating a number of additional performance measures that may potentially assist in the utility's continuous improvement activities.

Please note: These additional performance measures are being considered by STEI on a <u>trial basis</u> only and may not be subsequently incorporated into STEI's set of approved performance measures.

The established and additional performance measures are discussed below.

a) System Planning Process Performance

STEI evaluates the performance of its distribution system planning process using a set of metrics that address the following:

- **Customer Oriented performance**

The measure of customer satisfaction is, in many cases, unique to the particular customer and the specific nature of their concern. STEI achieves customer satisfaction through a culture that prioritizes and focuses on providing strong customer service that is embedded in all aspects of STEI's day-to-day operations. STEI planning, budgeting and program implementation practices all focus on customer satisfaction (e.g. by investing prudently in infrastructure improvements to reduce outages, by avoiding costs of duplication that may result from poor planning, or high costs that accumulate when activities coincide and create undue overtime and the associated charges).

- **Consumer Bill Impacts**

The purpose of including the “Asset Additions per Customer” metric is to indicate the net capital expenditures incurred by a typical customer each year; this type of expenditure is often viewed as the largest element of discretionary spending. The reported value for any one year is calculated as (1) the total of the system access, system renewal, system service, general plant costs plus contributions and grants, divided by (2) the number of metered customers. The metric is under review as a potentially useful year-over-year planning indicator of the impact on the customer’s annual bill for capital additions. Historical performance is reported in Section (b) below.

- **Reliability**

Reliability – together with cost – is widely reported as the customers’ ongoing prime concern and, when power is unavailable whether for reasons within STEI’s control or not, this makes STEI highly visible and places it in a negative light. STEI’s investments in modern technology have been made in an effort to provide the customer-expected high level of reliability in a cost-effective way. Close examination is paid to system reliability indices and other system behavioural indicators and, through diligent monitoring and analysis of system behaviour, attention is given to the performance of specific feeders and recommendations for maintenance or capital investments.

The result of the continuous monitoring and analysis provides a comprehensive overview of the performance of STEI’s distribution system. This contributes to STEI’s Asset Management Program by identifying future maintenance and capital budget priorities to maintain the reliability and performance of the distribution system. The following specific attributes are reviewed and addressed:

1) Substation and Feeder performance
2) Underground Distribution
3) System demand and critical loading issues
4) System maintenance activities and priorities
5) Reliability statistics and observations
6) Future maintenance recommendations
7) Future Capital Budget recommendations

The analysis highlights specific performance issues in a given year and identifies trends that require attention over the longer term. A review at each voltage level assists in planning longer-term distribution automation.

Major investments are required to replace and renew the underground portion of STEI’s distribution system as it ages and as the risk of significant outages increase. The analysis of cable failures on specific feeders within specific neighbourhoods focuses and prioritizes capital investments.

STEI's close attention to system demands and related critical loading issues triggered the regional planning exercise it undertook with Hydro One (then Ontario Hydro) in the 1980s that culminated in the construction of the Edgeware transmission station. STEI continues to monitor the loading on the current feeders from the station in order to maintain reliability standards and to reduce any incidents of critical loading.

STEI's maintenance and inspection programs comply with the requirements of the Distribution System Code. STEI reviews its routine maintenance programs to ensure consistency with good utility practices and confirm its aim for compliance with all inspection requirements (e.g. legislation, warranties, etc.).

All of the above culminate in recommendations for maintenance and capital expenditures that are considered within the annual budgeting process and resourcing plan development.

In accordance with Section 7.3.2 of the OEB Electricity Distribution Rate Handbook, STEI records and reports annually the following Service Reliability Indices:

- SAIDI: System Average Interruption Duration Index
  $= \dfrac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customers Served}}$
- SAIFI: System Average Interruption Frequency Index
  $= \dfrac{\text{Total Customer-Interruptions}}{\text{Total Customers Served}}$
- CAIDI: Customer Average Interruption Duration Index
  $= \dfrac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customer-Interruptions}}$
- Index of Reliability: the per-unit of annual customer-hours that service is available
  $= \dfrac{\text{8,760 hours/year - SAIDI}}{\text{8,760 hours/year}}$

In addition, as part of its consideration of additional performance measures, STEI also records two very straightforward and informative indicators of reliability that provide staff with an ongoing year-over-year snapshot:

- Number of unplanned customer system outages, and
- Number of momentary customer interruptions.

The above set of four indices provides STEI with an annual statement of its service performance for internal benchmarking and for comparisons with other distribution companies. The tables and graphs following in Section (b) record historical performance.

- **Power Quality**

Because the rate of occurrence of these issues is so low, STEI does not find it useful to record the incident rate of power quality problems. Power Quality issues are often eliminated by good robust electrical design (e.g. that analyzes for voltage drop limitations, unwanted frequency harmonics). Experience has shown that STEI may investigate less than 2 / year such power quality issues in a typical year and that the majority prove to be the result of internal customer issues. For residential customers, the few power quality items in STEI's service territory are usually associated with issues that have been already identified and are scheduled for imminent replacement or refurbishment. For commercial customers, power issues are invariably the result of the customers installing equipment that has been acquired overseas and which is not designed to operate within Ontario's voltage limits. STEI offers its customers appropriate guidance on potential solutions. In accordance with STEI's Conditions of Service, STEI works with customers to perform investigative analysis to identify the underlying cause. Depending on the circumstances, this may include review of relevant power interruption data, trend analysis, and/or use of diagnostic measurement tools.

- **Customer Satisfaction**

Another metric that STEI is considering for inclusion into its formal set of performance measurements is the percent of electricity bill payers who, when interviewed as part of the bi-annual UtilityPULSE survey, report that they are "very or fairly" satisfied with their LDC. The trend provided by this metric together with a comparison of the Provincial average is perhaps the ultimate indicator of customer oriented performance as sought by the OEB as part of the Renewed Regulatory Framework for Electricity Distributors. The graph in Section (b) demonstrates historical performance.

- ## Cost Efficiency and Effectiveness

STEI monitors its expenditures on all capital projects against the original budget. Any increases or decreases are reviewed for cause and accuracy. Very close attention is then given to the total capital budget to ensure there is no material over-expenditure. Similarly, unanticipated projects may have to be accommodated; this may result in the re-allocation of funds or the postponement of some projects. STEI is currently evaluating a number of metrics to measure cost efficiency and effectiveness.

- **Extending the Useful Life of Equipment**

The purpose of the potential cost efficiency metric "Total Capital Expenditures spent on System Renewal" is to provide an indication of the utility's success in extending the useful life of its existing equipment. The metric is calculated as (1) the amount spent on system renewal divided by (2) the total capital expenditures plus contributions and grants; the result is expressed as a percentage. The year-over-year metric is designed as a planning aid to STEI's system planning staff in their continuous improvement activities. The graph in the Section (b) demonstrates historical performance.

- **Resolving Billing Issues**

Within the industry, one of the biggest concerns said to be expressed by customers is the frequency with which they discover billing errors. As an element within the bi-annual UtilityPULSE survey, STEI records the number of such errors and has initiated an effectiveness initiative focused on slashing such occurrences. Two specific measures are being considered on a trial basis:

- Percent of respondents indicating they had a billing problem in the last 12 months; and
- Percent of STEI bills cancelled and subsequently reissued.

The graphs in Section (b) present historical performance of STEI billing issues.

- **Addressing Customer Concerns**

For the past few years STEI has taken the approach to review individual customer concerns on a monthly base and follow up directly with the customer as warranted. As the graph indicates in Section (b), the volume of customer concerns is statistically very low in comparison to the overall customer count of 16,694.

- ### Asset and/or System Operations Performance

  - **Blackouts and Outages**

While the distribution industry may have sophisticated metrics for measuring system operations performance, customers readily assess the performance of system operations by the occurrence or non-occurrence of blackouts and outages. As part of the bi-annual UtilityPULSE survey, customers are asked if they had a blackout or outage in the last 12 months. STEI is currently recording this performance measure with a view to including it in its official performance measures. The graph in Section (b) records STEI's success in providing continuous power.

b) Performance and Performance Trends

- ### Customer Oriented Performance

Following is a summary of the performance and performance trends of the metrics described above.

- **Customer Bill Impacts**

  <u>Asset Additions per Customer ($):</u>

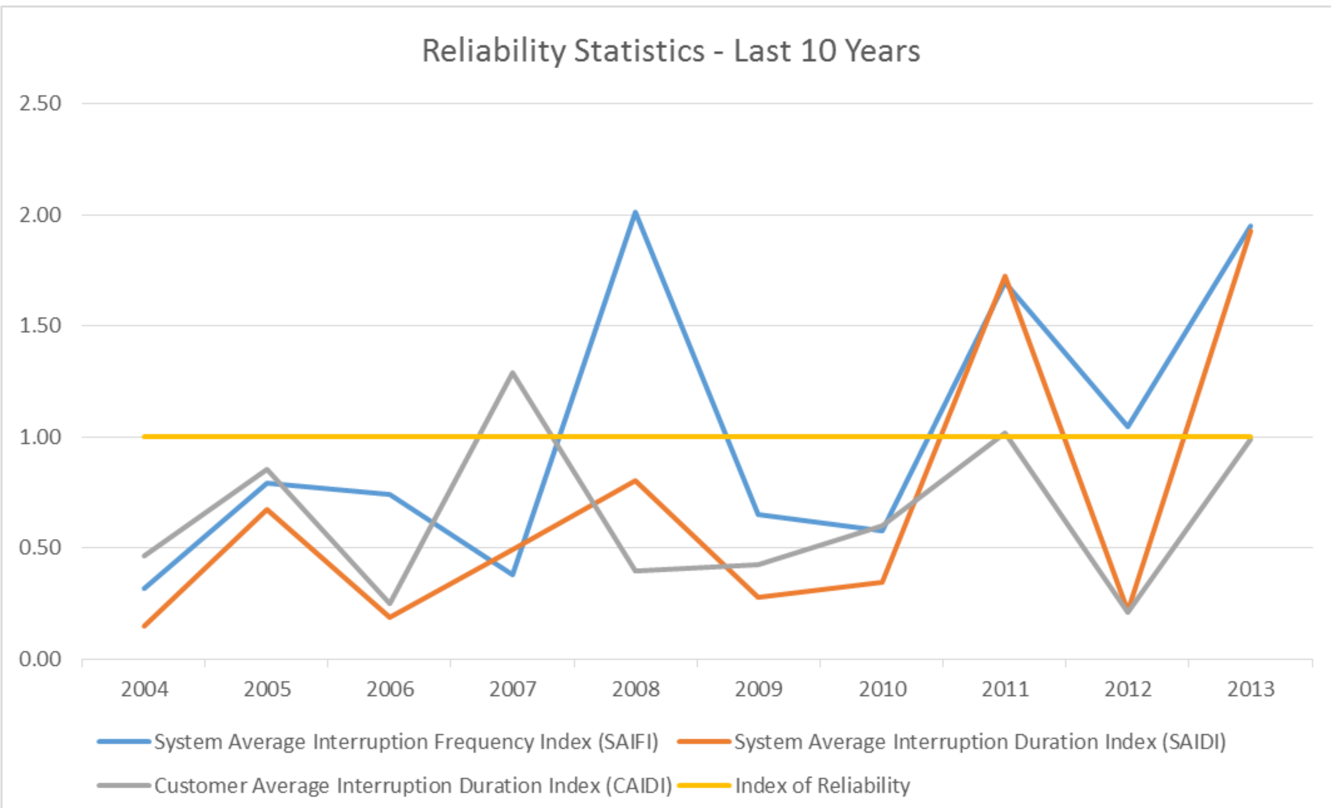
2010	2011	2012	2013
$66.10	$98.31	$428.10	$91.78

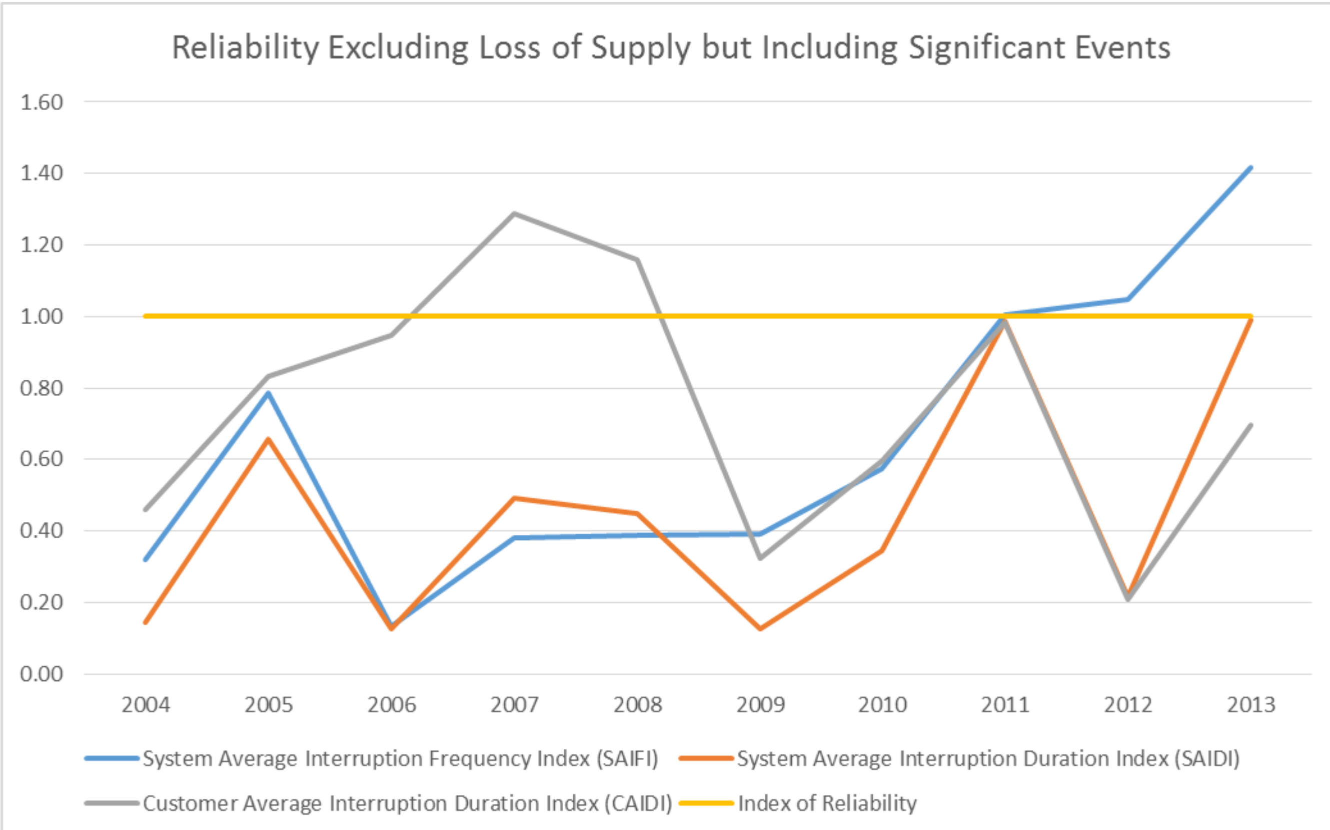
Net of contributed capital, 2012 normalized = $145.55.

- **Reliability**

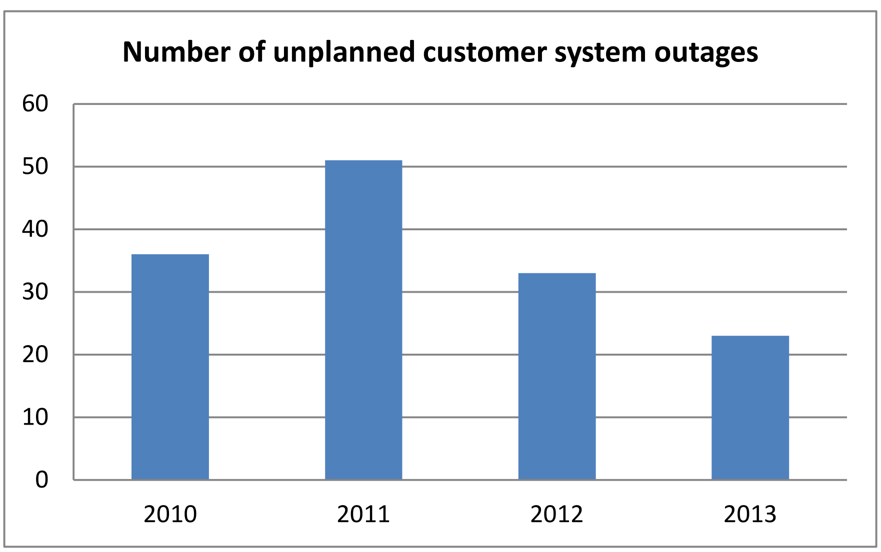
Reliability Statistics - Last 10 Years	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
System Average Interruption Frequency Index (SAIFI)	0.32	0.79	0.74	0.38	2.01	0.65	0.57	1.69	1.05	1.95
System Average Interruption Duration Index (SAIDI)	0.15	0.68	0.19	0.49	0.80	0.28	0.34	1.72	0.22	1.93
Customer Average Interruption Duration Index (CAIDI)	0.46	0.85	0.25	1.29	0.40	0.43	0.60	1.02	0.21	0.99
Index of Reliability	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Excluding Loss of Supply but Includes Significant Events	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
System Average Interruption Frequency Index (SAIFI)	0.32	0.79	0.13	0.38	0.39	0.39	0.57	1.00	1.05	1.42
System Average Interruption Duration Index (SAIDI)	0.15	0.66	0.13	0.49	0.45	0.13	0.34	0.99	0.22	0.99
Customer Average Interruption Duration Index (CAIDI)	0.46	0.83	0.95	1.29	1.16	0.32	0.60	0.98	0.21	0.70
Index of Reliability	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

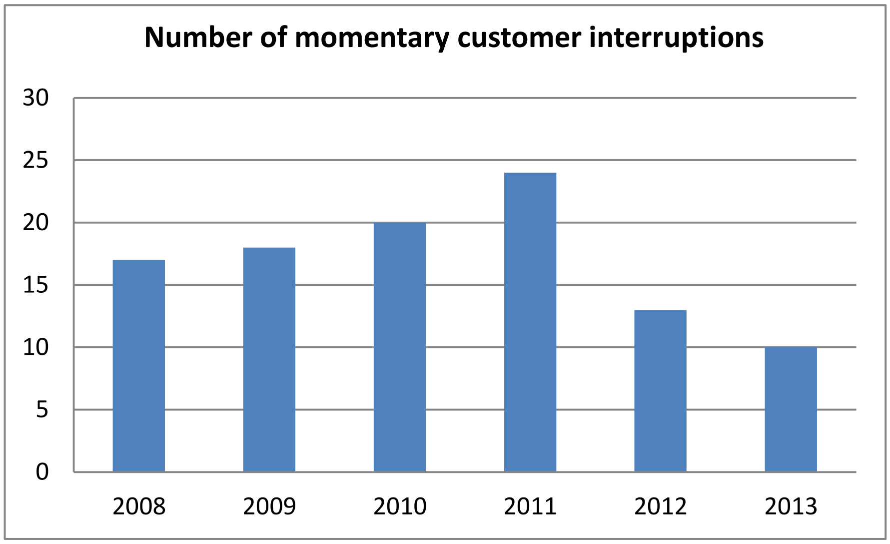




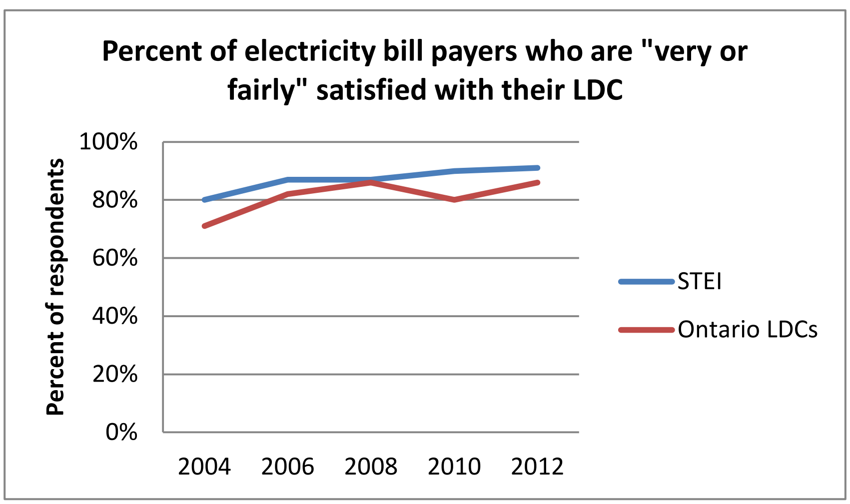
- **Unplanned customer system outages**



<u>Momentary customer interruptions</u>



- **Customer Satisfaction**



- **Power Quality**

As discussed above, because of the low occurrence of power quality issues, STEI has not found it useful to record the incident rate of such problems.

- **Cost Efficiency and Effectiveness**

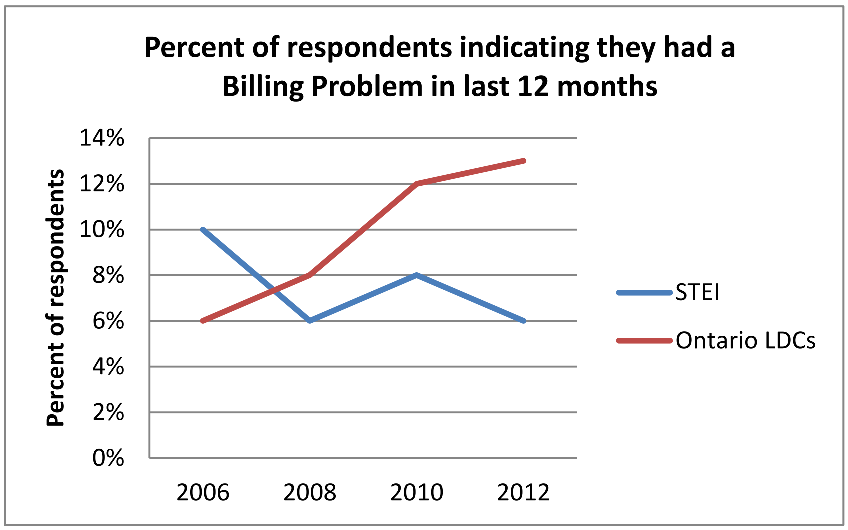
Following is a summary of the annual performance and performance trends of the metrics described above.

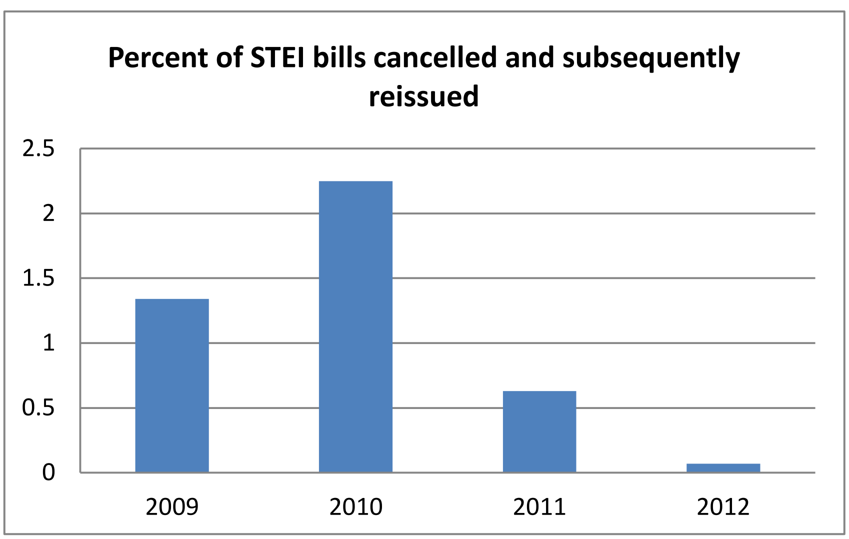
- **Total Capital Expenditures spent on System Renewal (%)**

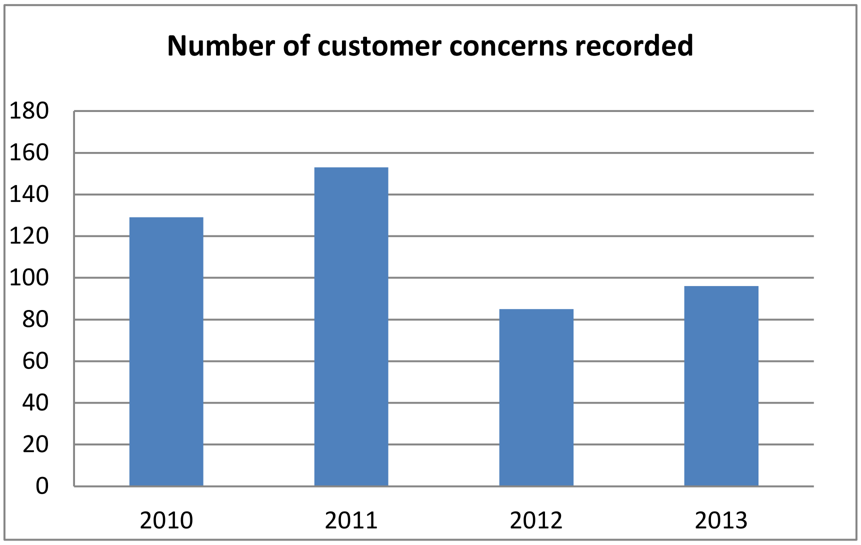
2010	2011	2012	2013
53.0	60.9	14.6	55.4

2012 normalized for smart meter and asset transfer 39.5%

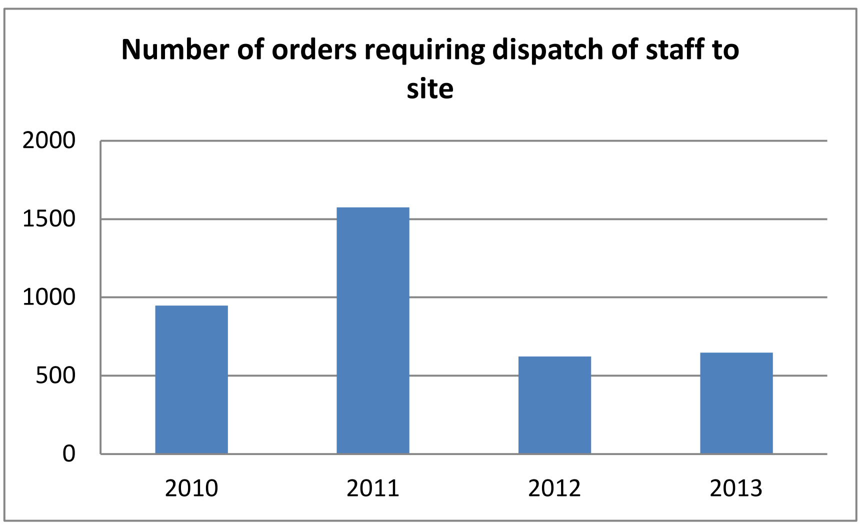
- **Customers with a billing problem**





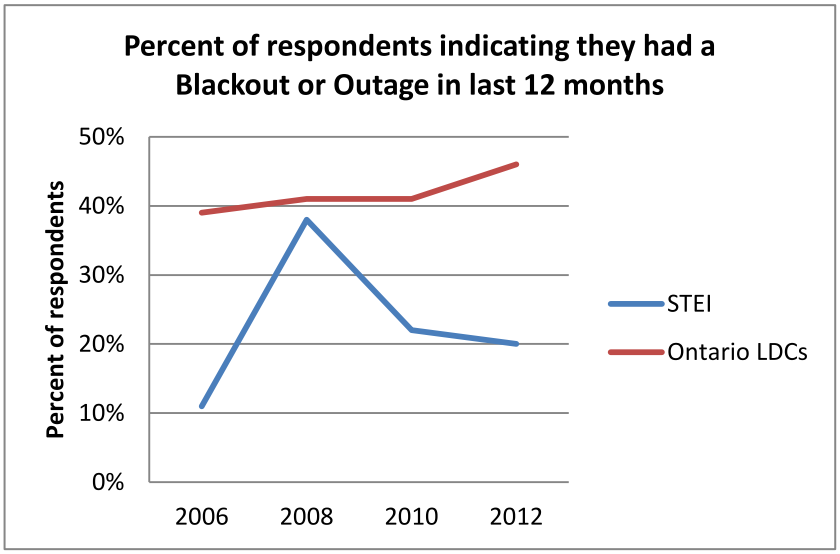


- **Orders requiring a site visit**



- **Asset and/or Systems Operations Performance**

    - **Customers experiencing blackouts or outages**



c) Effect of Information on the Plan

The foregoing information has been instrumental in assisting STEI staff in their system planning activities and helping them focus resources. For example;

- The relatively flat "Asset Additions per Customer" metric over the 4 year period (2010 – 2013) (as displayed above) provides confidence to STEI staff that their system design strategy is successfully leveraging earlier infrastructure investments and is extracting longer useful life from equipment.
- The steady 10-year overall performance in system reliability as demonstrated by the above SAIDI, SAIFI and CAIDI statistics shows that no significant additional expenditure is needed to improve service area reliability but that a level of capital expenditure should be made to simply maintain current reliability levels. This is reinforced by the 55% reduction over the past three years in the number of unplanned customer outages and 58% reduction in the number of momentary customer outages over the same period.
- The steady increase in the number of STEI customers who have responded in the bi-annual UtilityPULSE survey that they are either "very or fairly" satisfied – and at a level consistently above the Provincial average – provides STEI management with confidence in their continuous improvement strategy.
- The essentially flat "Percentage Total Capital Expenditures spent on System Renewal" provides strong support for STEI's push to extract the optimal lifecycle from its investments.
- The plummeting number of customers having billing problems (less than half the Provincial average) and number of bills cancelled and subsequently reissued (only 3% of the number recorded just three years previously) provides total confidence in the investment made in STEI's billing systems.
- The 37% drop in the number of expressed customer concerns and the 59% drop in the number of orders requiring the dispatch of staff to site over the 2011-2013 period is, among others, solid proof of the wisdom of multi-year investment to replace underground cables in much of the service area.
- With the level of STEI customers having had a blackout or outage in the past 12 months being less than half of the Provincial average (20% outages vs. 46%) proof is established of the quality of the company's maintenance activities and the quality of its equipment investments.

2 Asset Management Process (Ch.5.3)

2.1 Asset Management Process Overview (Ch.5.3.1)

a) Asset Management Process Objectives, Goals and Priorities

STEI's Asset Management Process outlines the company's good utility practices within its capital/refurbishment program and within its inspection/maintenance program. The capital/refurbishment program seeks to ensure that the selection between refurbishing assets and replacing them with new capital equipment is made in a manner that minimizes the overall expected lifecycle cost while meeting requisite reliability standards and other mandatory requirements such as health and safety of the public and staff. The inspection/maintenance program allows for an organized approach for inspection, assessment and restoration of assets within the overhead distribution system, underground distribution system and substations – again, in a manner that minimizes the overall expected lifecycle cost and meets all applicable standards.

In order for the Asset Management Process to be implemented optimally, it must support the company's Corporate Objectives and the company's subordinate asset management objectives.

STEI's Corporate Objectives are represented by its Vision Statement and Values:

<u>Vision Statement</u>:

To be the industry leader in energy solutions and services.

<u>Values</u>:

- Honesty
- Attitude
- Respect
- Teamwork

To help achieve the foregoing, STEI's asset management objective is to continue "to meet all regulated requirements ***in a manner that minimizes the overall cost to STEI customers*** when staff acquire and subsequently maintain assets in order to provide service at required performance standards."

To assist with achieving its asset management objective, STEI has developed its distribution system strategy which is the set of long-term policies, rules, guidelines, etc. that STEI utilizes to transition from its current system into its desired future system. An integral part of this strategy is a mechanism that ensures the appropriate ranking of the various asset management aims so that competing proposed investments are prioritized consistent with achieving the overall asset management objective. Hence, the strategy described in this Distribution System Plan provides the integrated rationale for capital expenditures and supporting activities planned for the 2014-2019 period.

Any effective strategy requires, as the starting point, a clear recognition of the strengths and weaknesses of the current system together with a realistic vision of the desired future system. In order to provide context and rationale for the strategy, it is first necessary to sketch out the current and future distribution systems together with the key drivers and other major influencers expected to impact the transition.

The Present Distribution System

STEI has pursued the best practices of the electricity distribution industry for many years. This has included adhering to the OEB's Distribution System Code that sets out both good utility practice and minimal performance standards for electricity distribution systems in Ontario, and minimal inspection requirements for distribution equipment. In addition STEI is registered for:

- ISO 9001 – Establishing a framework for continual improvement and customer satisfaction, providing assurance about quality in supplier/customer relationships, harmonizing quality requirements, qualifying suppliers and providing technical support for regulators
- OHSAS 18001 – Establish an OH&S management system to eliminate or minimize risk to employees and other interested parties, assure conformance with stated OH&S policy, implement/maintain and continually improve an OH&S management system

Consistent with best practices, over the years STEI has diligently maintained its equipment in safe and reliable working order and, only when economically justified, has refurbished or replaced the equipment. The diligent maintenance of its equipment has permitted STEI to extract an extended useful working life from its assets; moreover, while the average age of the distribution equipment has thus increased, the reliability of the equipment has also often increased to meet the expectations of STEI's customers.

By carefully controlling renewal expenditures and therefore moderating any increases in its customers' bills, the distribution system has evolved into an array of equipment of different vintages spanning a number of technological eras; that is, STEI did not spend funds on replacing functioning equipment in order to simply have more modern technologies in place.

This is evidenced by the technology of its distribution equipment as it existed 5 years ago and to a lesser degree now; specifically, large areas of the St. Thomas service area are still being supplied by the original 2,400 V floating delta distribution system which provides significant maintenance challenges and places lines-people at elevated risk when carrying out repair work. With the construction of the 230 kV Edgeware Transformer Station in the early 80s, STEI was provided with the opportunity to upgrade the distribution system to the modern 4-wire wye 27.6 kV system as the floating delta feeders reached the end of their life; the higher supply voltage also results in lower line losses. This modernization project that began in 2010 continues as the original 2,400 V equipment's condition further degrades. Reliability in those parts of the City with the older equipment continues to deteriorate and upgrades become cost justified for STEI's customers.

In addition, in order to increase safety and reliability, all primary overhead 2,400 V distribution is being progressively removed from backyards and being replaced with 27.6 kV underground distribution from the street and 240 V backyard distribution which includes neutrals and insulation. The overhead secondary service wire remains in the backyards but are supplied by underground supplied pad-mounted transformers from the street.

While the company's "technology conservative" practices have resulted in reduced capital expenditures in the past as noted above, the now-needed upgrading presents a significant challenge to today's management; that is, to maintain and operate the distribution system and to accelerate specific and potentially obsolete equipment to current technological standards within the new lower IFRS-driven capital expenditure envelope.

The City of St. Thomas has experienced economic downturn in recent years with a 22% decrease in load over the 2005 to 2012 period. The decrease in load which is primarily due to plant closures (primary examples being Sterling Truck, Canadian Timken and Schulman Canada) has resulted in the LDC's costs being spread over a much smaller customer base and thus placing additional upward pressure on customers' rates.

As a key player in the regional supply of electricity, STEI continues to participate with Hydro One in detailed Regional Planning. An earlier joint study resulted in the construction and commissioning of the aforementioned Edgeware TS in the early 80s. The current detailed Regional Planning process with Hydro One is in its early stage of development but, since there is one remaining HONI-unallocated breaker at the Edgeware TS and the STEI load has dropped significantly in recent years, no major change is anticipated for STEI's electricity supply in the near future.

The Desired Future Distribution System

STEI's customers have been surveyed over the past few years to ensure that the utility spent its limited resources consistent with its customers' needs and wishes. The vision of STEI's desired future distribution system has been informed by its customer feedback.

Consistent with meeting all regulatory and statutory requirements, the envisaged future distribution system is being designed to deliver power at the quality and reliability levels required by customers and will minimize the lifetime cost by balancing preventive maintenance, life-extending refurbishment and end-of-life replacement; in short, the system will *meet the customers' needs for quality and reliability of power at the minimal cost to the customer.*

The envisaged system in place in 10 to 20 years will be one where there is even greater emphasis on condition monitoring in order to direct preventive maintenance to specific at-risk equipment and extend further the safe reliable useful life of all equipment. Consequently, equipment is expected to have longer in-service lives.

To operate effectively, the future system should have sufficient capital available to it to permit the lowest cost solution to be implemented; this would involve, however, smoothing the financial blips brought about with the bulk replacement of certain equipment that has exceeded its cost-effective life. (While extending the useful working life of equipment is intuitively desirable, life-extension "at any cost" such as that necessitated by shortage of capital, produces a sub-optimal more-costly solution.)

In order to leverage the efficiencies that are possible through emerging new technologies, the distribution system would employ smart grid equipment.

Underground connections are envisaged as the norm in the more densely populated parts of the service area.

Distribution-connected renewable generation and electric vehicle charging are expected to be much more commonplace in STEI's service area. Also, CDM would continue to be an integral part of the system.

In order to achieve the foregoing desired distribution system, sufficient well-trained and well-equipped staff will be required. This may require a temporary increase in staff levels in some departments in order to accommodate apprenticeship schedules to replace retiring employees.

Drivers and influencers

Perhaps the factor exhibiting the greatest "influence" on achieving the desired future system is the legacy of the in-situ equipment noted above; this legacy severely restricts the options available to current management to achieve the desired future within funding limits.

STEI's regulatory obligation to connect all potential customers represents a significant challenge to manage its resources. This regulatory obligation includes not just new residential and commercial properties but projects conducted by the City, Region or the Ministry; for example, relocating poles to accommodate road re-alignment work. The draw on STEI's resources is not just the resources required in total but typically the lack of certainty as to when the project will be ordered to proceed and the almost immediate attention it demands when the order to proceed is given.

With the sharp rise in electricity commodity prices experienced in the past few years and the forecast that this trend will continue for a number of years, there is a major emphasis on utilities maintaining current rates if possible or, at least, seeking only minimal increases. This situation has been exacerbated by the OEB requirement that utilities move to Modified International Financial Reporting Standards (MIFRS) and the adoption of extended useful lives.

Another influence resulting from the rapidly increasing cost of electricity and the consistently improving reliability is that, generally, current reliability standards are adequate. However, for some high-technology customers, even the current excellent reliability standards are insufficient because of the very high cost of lost production from even a momentary outage or a minor power quality variation.

The continued effect of the Green Energy Act and the requirement to give priority connection to solar, wind and other renewable energy sources will place a continuing demand on the utility's manpower and financial resources.

Provided Conservation and Demand Management ("CDM") activities continue to be financed by the OPA and lost revenue is reimbursable to the LDC, the CDM effect on the distribution system is expected to be mildly positive as load continues to be dampened.

Continuing to address environmental challenges such as the removal of all PCBs from transformers presents a short-term need for funding from the limited financial resources available. While STEI has no transformers with contaminants above the mandatory threshold, these remaining transformers need to be replaced in due course.

Emerging smart grid technologies offer opportunities to reduce operations cost over the longer term. While such technologies have the immediate effect of improving reliability, the technology can also bring about efficiency improvements by assisting the system to self-heal and thus reduce the number of occasions when line crews are required to respond to outages. Customers benefit from shorter outage response times and lower operating costs. However, the potential role of smart grid technologies within the STEI service area requires to be better understood before any significant investment is made.

In order to achieve its desired future distribution system, STEI prioritizes its investments by first addressing those objectives that are mandatory, followed by those where some discretion may be applied. In summary, the priority ranking is:

1. Meet legislated and mandatory requirements
2. Maintain current operational standards by performing essential upgrades and refurbish in-situ where economic
3. Invest prudently by leveraging and/or early harvesting of previous investments; invest in customer service and economic/efficiency improvements
4. Accelerate replacement of critical over-aged items where affordable and optimal

Further details are provided in the following Asset Management Strategy and later in "Appendix A to Section 2.3".

The company's prioritization of investments is reflected in its Asset Management Strategy and subsequently in its Asset Management Plan.

Asset Management Strategy

The following are the actions that STEI plans to take over the next 5-10 years in order to bring about the desired future – albeit, at a reduced rate in view of the short term limitations on funding.

- ***Priority will be given*** to STEI's legislated/mandatory requirements; for example:
    - System access including the obligation to connect customers - Residential, Commercial and Industrial.
    - Accommodate City, Region and Ministry mandatory projects.
    - Embrace the requirements of the Green Energy Act for the implementation of renewable energy generation and to fully meet the CDM conditions of the company's license, and in order to fully support public policy directives.
    - Meet the OEB's – and other regulatory bodies' – quality, reliability, health, safety, environmental, etc. performance standards.
    - Generally, funds will be spent to simply maintain the current reliability level and not enhance it above the current level; where a higher level of reliability is genuinely required by the customer, the additional cost will be allocated only to the specific customer(s) or customer class by some appropriate OEB-approved mechanism.
- In order to safeguard major investments already made, continue to upgrade as necessary advanced technology systems. This would include the Data Acquisition equipment that has been acquired in preparation for future SCADA investments.
- Enhance specific existing systems in order to harvest operational efficiency improvements. These investments include the full implementation of the GIS system in order to assist in the preparation of electronic documentation in support of the asset management system. Also, additional IT investments may be made so as to leverage the existing investment in smart meters in order to improve outage management.
- Continue to invest prudently in modern information technology in order to provide customers with clear meaningful bills that are able to assist them in managing their electricity usage.
- Optimize life extension. For example:
    - Intensify condition monitoring to minimize uncertainty regarding decisions relating to equipment maintenance, renewal and replacement.
    - Where economically viable, refurbish distribution equipment in-situ to extend their reliable working lives.
- When eventually needed, leverage the additional supply capacity available from the Edgeware transformer station.
- Where the optimal life has already been reached and to the extent that funding is available, undertake the accelerated replacement of the over-aged items and equipment that present an increased safety risk to the public or staff; e.g. continue to replace STEI's 2,400 V floating delta feeders and install underground pad-mounted transformers with street access.

- Prudently acquire smart grid equipment when its role within the STEI system has been fully defined and where there will be direct economic/efficiency benefits.
- Continue with the cost effective replacement of service vehicles to ensure the utility has a reliable fleet for maintenance and for response to system outages.
- Acknowledge that some desirable changes are realistically not affordable at present.
    - Retain, and simply maintain in good operating condition – perhaps after 2019 – half of the remaining six distribution stations and the remaining components of the original 2,400 V floating delta distribution system until the voltage conversion is complete for the applicable sections of the service area.
    - When the need eventually arises, undertake the $1 million liability to acquire the remaining Edgeware breaker.

To encourage the foregoing asset management strategy being adhered to and utilized on a day-to-day basis, STEI has recently developed asset lifecycle optimization policies and practices as attached in "Appendix A to Section 2.3" of this DS Plan. **The policies are currently being evaluated for their day-to-day practicality and are therefore shown as "draft".**

- Policy on System Access, Renewal and Service Investments
- Policy on the Evaluation of Asset Replacement and Refurbishment
- Policy on Optimal Maintenance Planning Practices

STEI recognizes that no matter how comprehensive any documented strategies, policies or practices may be, they cannot address every situation or eventuality; moreover, overly-strict adherence to such rules will inevitably result is decision-making errors with a consequential cost to the customer. Therefore, the application of all the above directives are constantly checked by management and staff to ensure the resulting day-to-day decisions meet the highest level of professional judgement and common sense in every situation faced.

The resulting STEI Distribution System Plan presents a fully integrated and optimized approach to capital expenditure planning. It recognizes the utility's responsibilities to provide its customers with reliable service that is acknowledged as excellent value for money, by ensuring that its asset management activities maintain a focus on customers, operational effectiveness, public policy responsiveness and financial performance.

Inspection, performance reporting and maintenance

STEI has established a comprehensive system of inspection and performance reporting programs to provide for continuous assessments of its distribution assets and to achieve consistency with its corporate mission and value statements. These programs present information that is also relied on to satisfy the reporting requirements of the Distribution System Code. However, STEI has also developed reporting mechanisms that go beyond these regulatory obligations and are focused on continuous performance improvements (ISO 9001, OHSAS 18001, Quarterly Quality Management Reviews) to ensure the availability of long term capacity to meet the needs of the community, all of which contribute to effective and successful utilization of the distribution system assets; i.e. providing STEI's customers with a reliable, safe and adequate supply of electricity in a manner that meets the customers' needs ***at the lowest cost***.

While capital expenditure planning and implementation is arguably the most crucial aspect of STEI's Asset Management Process, the inspection and maintenance of equipment and systems is another key activity to help achieve the distribution system's minimal lifecycle cost. STEI's Asset Management Process that has evolved over a number of years takes advantage of its up-to-date records management system and uses information technology to facilitate the efficient collection of inspection data in support of both its capital and O&M planning.

For a discussion of the information used in preparing both the capital expenditure plan and the inspection and maintenance, please see "Components (Inputs/Outputs) of the Asset Management Process" below.

For a discussion of the inspection and maintenance activities contributing to the achievement to minimal lifecycle, please see "2.3 Asset lifecycle optimization policies and practices" also below**.**

Commitment and organization to achieve Asset Management Process objectives

STEI regards all aspects of asset management as a foundation for the performance of its distribution system. Senior management is committed to the continual improvement process and ensures that sufficient resources are allocated to implement the strategy. This requires an upfront investment in personnel - both internal and outsourced – to create and establish the strategy and the long term resources to complete the annual planning, inspecting, reporting and implementation of activities. The quality and consistency of the reporting data is paramount to a successful Distribution System Plan. The responsibility for the continuous management of the strategy is assigned to the Director of Engineering and Operations.

The Director's responsibilities primarily involve risk management i.e. ensuring that:

- The inspection process is organized with assets identified in reasonable zones and segments.
- Inspections and follow up maintenance is continuously being effectively organized and performed
- Records are accurate and current
- Condition analysis is completed correctly
- Potential Maintenance and Capital Budget recommendations are captured from annual inspections and the Asset Management Plan.
- The condition of the distribution system, for the short, medium and long term periods, is reviewed to maintain and enhance the reliability of the system in the most cost effective manner

This up-to-date information provides key inputs to the maintenance budget and capital investment proposals.

b) Components (Inputs/Outputs) of the Asset Management Process

The information inputs/outputs of the asset management process used to prepare STEI's capital expenditure plan are described in the Asset Management Plan which is attached as "Appendix A to Section 2.1". These information components include:

1. Inspections per 2.3
2. Asset Condition Assessment report
3. Quarterly Quality Management Reviews
4. Performance considerations
5. Innovative and new technology
6. Risk analysis and recommendations

STEI has developed a comprehensive Management System Manual to manage the quality of the work performed by staff on a day-to-day basis. The quality system applies to all core and support processes associated with design, development, construction, operation and maintenance of electrical distribution systems, electrical revenue metering, as well as meter reading, billing and collecting services. All clauses of ISO 9001:2008 apply except for 7.5.2 as all products are verified and/or tested.

The manual defines all mandatory aspects of the system and includes a cross reference matrix to ISO 9001to illustrate the relationship of this system to the standard. The manual is supported by procedures and work instruction where detailed specific process information may be more appropriately conveyed. The manual interfaces with the H & S system at various reference points defined herein (i.e. internal audit & corrective action).

The Management System Manual is attached as "Management System Manual – part 1" Appendix B to Section 2.1.

The supporting procedures and work instructions are attached as "Management System Manual – part 2" Appendix C to Section 2.1.

APPENDIX A to Section 2.1

ASSET MANAGEMENT PLAN

St. Thomas energy inc.
We're Your Local Power Distributor
a division of Ascent

Asset Management Plan

Prepared by STEI & Kinectrics Inc. December 2011

Updated by St. Thomas Energy March 2013

Table of Contents

1 EXECUTIVE SUMMARY

1.1 Objective

St Thomas Energy Inc. ("STEI") Asset Management Plan documents policies, strategies and objectives and provides specific information used by STEI to establish capital and maintenance requirements that form the basis for the 5-year STEI Investment Plan.

The Investment Plan provided in this Asset Management Plan summarizes estimated investments portfolio, including major capital and maintenance programs, for the first year (2011) and investment totals for each Capital and O&M investment category for the next 4 years based.

The Asset Management Plan also provides information about STEI that, when shared with customers, shareholder, regulators, potential business partners, general public etc., allows them to understand what STEI is all about and what is the rational for the work to be carried under the Investment Plan over the next 5 years.

1.2 AMP Components

The Asset Management Plan consists of several sections. Following is a brief description of contents for each:

<u>About St Thomas Energy Inc. – Section 2</u>

This section provides a brief description of company history, shareholder, geographic location, customer base, and historical and forecast information regarding demand and energy consumption.

<u>Corporate Information – Section 3</u>

This section provides corporate information that governs corporate decision making at a high level, such as mission and vision statements, business values and customer service performance comparison to the OEB's Electrical Distribution Service Quality Requirements (ESQRS).

<u>System Description and Performance – Section 4</u>

This section provides description of STEI's distribution system, including supply points, overhead and underground feeders, municipal stations ("MSs") and SCADA facility. Historic reliability performance of STEI's system over the last 5 years is also shown in this section.

<u>Maintenance Practices – Section 5</u>

This section provides an overview of STEI's maintenance practices and compares them with the Distribution System Code ("DSC") requirements

External Challenges – Section 6

This section provides a brief description of external challenges facing STEI, specifically road widening projects, and industrial, commercial and residential developments. These represent non-discretional projects that will require a significant financial commitment by STEI.

Internal Initiatives – Section 7

This section provides a brief description of internally driven initiatives aimed at improving reliability of supply to customers at the most cost-efficient manner, specifically voltage conversion of the area supplied by Substation 6.

Asset Strategy – Section 8

This section outlines STEI’s long-term strategy of rebuilding primary and secondary rear lot

overhead lines to reduce maintenance cost and improve both reliability of supply and appearance.

Continuous Improvement – Section 9

This section provides actions that STEI intends to undertake in order to improve its business processes to be better aligned with best Asset Management practices

Asset Condition Assessment Results – Section 10

This section presents a summary of results from the Asset Condition Assessment performed by Kinectrics Inc.

2013 Investment Plan – Section 11

This section provides a summary of the 2013 Investment Plan and includes major investment categories.

2013-2016 Investment Plans – Section 12

This section shows Investment Plans for 2013-2016 divided into 4 major investment buckets: Capital Non-Discretionary, Capital Sustainment, Operating and Maintenance.

2 ABOUT STEI

St. Thomas Energy Inc. (STEI) is a local distribution company under license and regulated by the Ontario Energy Board.

The company distributes electricity to about 16,500 customers and owns assets with a net book value of $18,694,765 as at the end of October 2011.

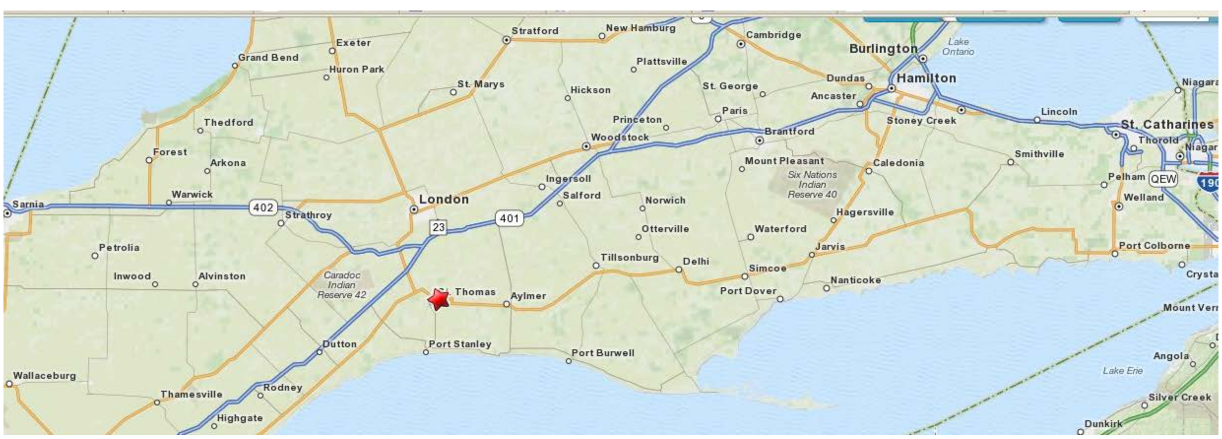
2.1 Company History

STEI is the successor company of St. Thomas PUC which was originally created in 1906. Following deregulation in the 1990s, St. Thomas Holding Inc. (now Ascent) was officially incorporated as a for-profit entity and became the parent company of St. Thomas Energy Inc. -- wholly owned by the City of St. Thomas."

2.2 Geographic Location

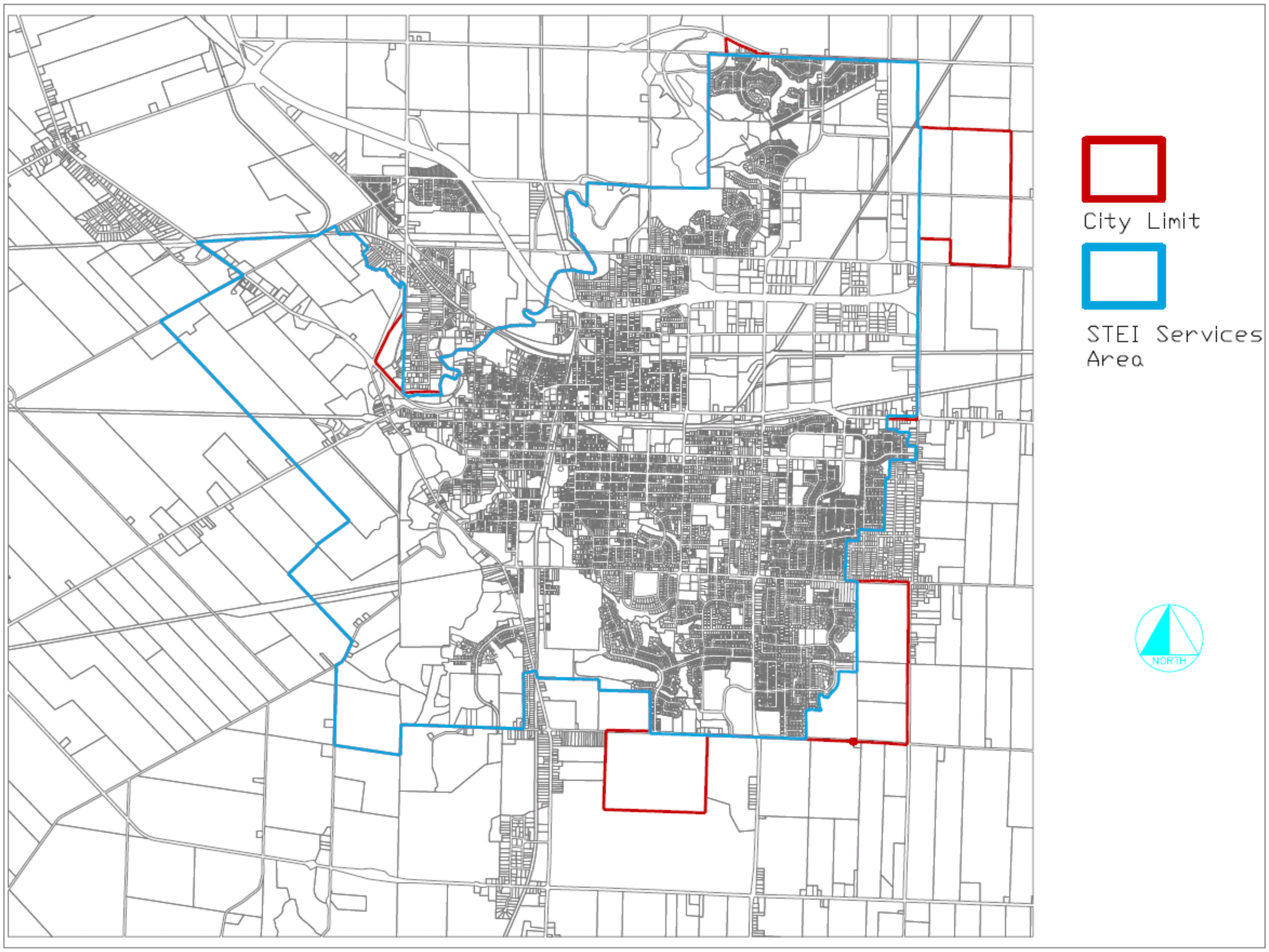
The City of St Thomas is located in Southwestern Ontario approximately 10 km north of Lake Erie and 5 km south of the municipal boundaries of the City of London.

<u>Figure 2.2A</u> – Location of the City of St Thomas.



STEI's franchise area is primarily contained within the municipal boundaries of the city of St. Thomas and is about 33 square km large (see figure 2.2B). The area is also embedded within the Aylmer area of Hydro One Networks Inc.

Figure 2.2B – STEI Franchise Area.



2.3 Customer Base

As of October 2011, the customer segmentation within the STEI franchise area consists of 14,641 residential customers and 1,861 commercial customers. The commercial customers are further segmented into 1,665 General Service customers less than 50kW of demand and 196 General Service customers greater than 50kW.

2.4 Demand and Energy Forecast

Table 2.4A itemizes the total monthly MW peak and the monthly energy usage for the period January 1, 2006 to Dec 31, 2012.

Table 2.4A – Summarized monthly Peak Demand and Energy for STEI.

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	
2006	33.0	30.6	31.7	28.2	30.3	31.9	36.4	34.9	29.1	30.4	30.3	31.5	Energy (GWh)
	58.1	56.8	55.4	51.2	69.1	64.2	75.4	76.9	54.3	52.4	54.6	60.1	Demand (MW)
2007	33.5	32.0	32.5	28.8	29.2	32.1	31.5	35.2	30.2	30.0	30.0	31.7	Energy (GWh)
	58.1	60.7	57.8	50.8	60.1	68.3	70.0	73.6	67.9	56.4	57.5	59.0	Demand (MW)
2008	33.3	31.2	31.0	27.3	27.4	30.2	32.0	30.1	27.4	26.5	26.6	29.1	Energy (GWh)
	58.4	58.2	53.2	48.4	47.1	67.0	65.5	64.7	61.0	46.9	50.4	52.6	Demand (MW)
2009	30.2	26.0	23.1	23.1	21.7	23.3	24.3	27.4	23.9	23.8	23.8	27.0	Energy (GWh)
	52.1	50.2	43.3	43.3	39.7	55.8	47.3	61.9	42.1	46.0	46.0	51.5	Demand (MW)
2010	27.9	24.7	24.8	22.2	24.3	25.9	29.7	29.1	23.6	23.6	23.9	27.2	Energy (GWh)
	48.9	47.3	43.8	39.5	54.0	54.0	62.0	60.9	59.1	46.2	44.0	50.0	Demand (MW)
2011	27.7	24.9	26.2	23.2	23.4	25.0	30.7	28.4	24.4	23.4	23.6	25.5	Energy (GWh
	47.8	47.5	44.5	41.0	53.7	57.3	65.5	56.5	58.0	40.0	44.8	45.5	Demand (MW)
2012	26.6	24.5	24.2	22.0	23.7	26.0	30.2	27.5	23.5	23.2	24.0	25.2	Energy (GWh)
	46.9	43.3	42.9	38.7	51.1	59.7	63.1	58.4	54.5	42.6	45.9	46.0	Demand (MW)

Tables 2.4B & 2.4C present actual and forecast information regarding electricity usage. Data up to 2012 is from historical records and 2013 to 2015 data has been forecasted by STEI using Table 2.4D.

Table 2.4B – Actual and Forecast Annual Demand (MW) by Rate Class for 2005 to 2015.

Rate Class	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
GS>50	408.2	419.0	410.8	377.5	343.0	353.2	340.7	359.1	344.1	345.8	347.6
Street Ltg	8.1	8.2	8.3	8.3	8.4	8.5	8.5	8.6	8.6	8.7	8.8
Sentinel Ltg	0.24	0.12	0.12	0.14	0.16	0.17	0.17	0.15	0.17	0.17	0.17
GS>5000	68.1	65.7	66.2	60.4	15.8	0.0	0.0	0.0	0.0	0.0	0.0

Table 2.4C – Actual and Forecast Electricity Consumption in GWh for 2005 to 2015.

Rate Class	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Residential	112.4	115.2	115.2	120.2	121.3	120.9	119.0	117.5	120.2	120.8	121.4
GS<50	38.6	39.0	40.4	40.9	40.9	36.7	36.5	36.2	36.7	36.8	36.9
GS>50	176.2	174.1	170.7	151.5	127.2	137.3	136.4	134.2	137.8	138.5	139.2
GS>5000	38.4	36.9	33.3	28.4	6.5	0.0	0.0	0.0	0.0	0.0	0.0
Street Ltg	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.2	3.2
Sentinel Ltg	0.09	0.05	0.05	0.04	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Total	368.7	368.1	362.6	344.1	299.0	298.0	295.0	300.5	297.9	299.3	300.7

Table 2.4D Forecast Annual Growth Rate by Rate Class for 2013 to 2015.

	Forecasted Yearly Growth Rate (%)		
Rate Class	2013	2014	2015
Residential	0.50	0.50	0.5
GS<50	0.30	0.30	0.3
GS>50-4999	0.50	0.50	0.5
Street Ltg	0.75	0.75	.75
Sentinel Ltg	0.00	0.00	0.00

3 CORPORATE INFORMATION

3.1 Mission & Vision

MISSION STATMENT
- Provide maximum financial return to our stakeholders and to the corporation
- Optimize operational efficiencies and synergies across all companies
- Achieve recognition as a leader in service provider and an employer of choice
- Ensure employee and public safety
- Support effective communications both internally and eternally
- Foster innovation
- Ensure environmental impacts are a key consideration in out decision-making
- Achieve a stable, sustainable organization

VISION STATEMENT
To be the industry leader in energy solutions

3.2 Business Values

- Financial Stability
- Employee & Public Safety
- System Reliability
- Quality Salutations
- Customer Service

3.2.1 Financial Stability

STEI is financially stable and has provided payments in the form of interest and dividends to the sole shareholder, the City of St. Thomas, since 2001.

3.2.2 Employee & Public Safety

STEI measures Employee and Public Safety by incident & accident frequency, lost time due to Injury and our level of commitment to Occupational Health & Safety ("OHS") practices and training. It has been over 16 years since STEI has had a compensable injury. Corporate policies are also in place to ensure the health and welfare of our staff, visitors and customers.

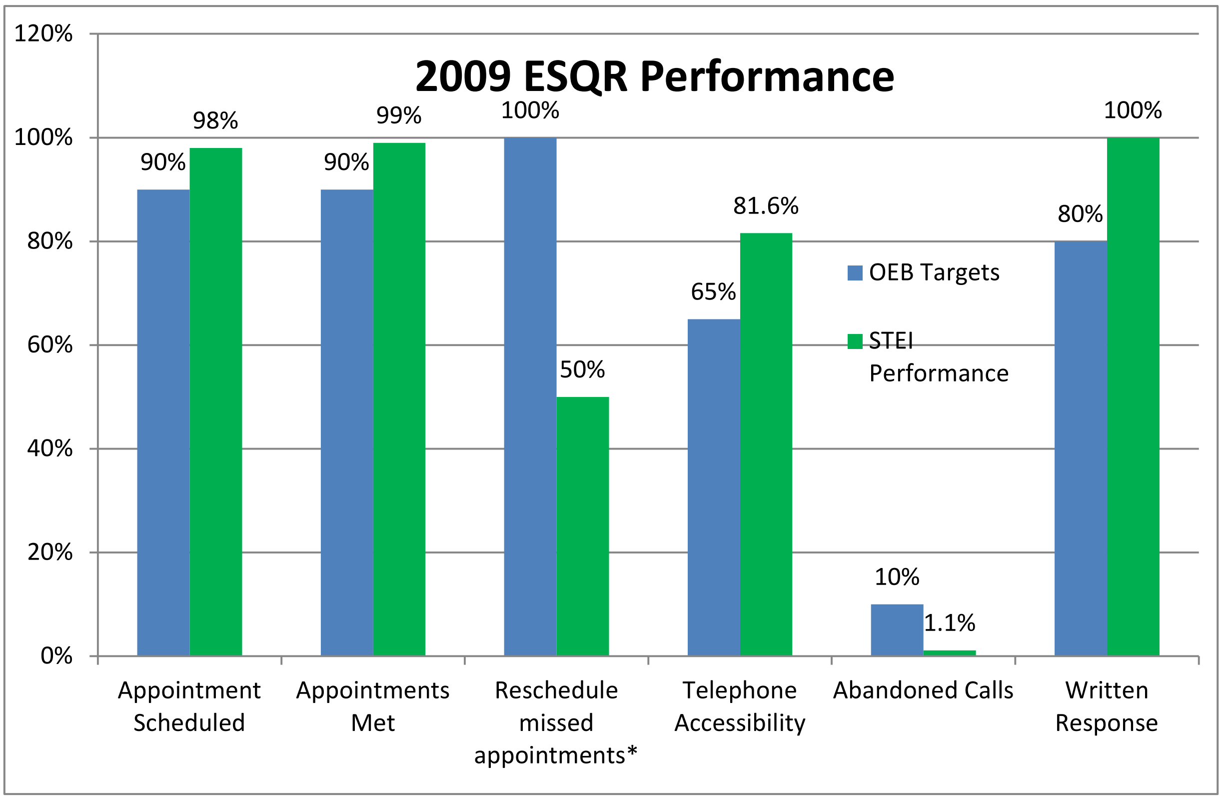
3.2.3 System Reliability

For the last decade, STEI has participated annually in the Canadian Electrical Association (CEA) Reliability Study to benchmark service quality against its peers in Ontario and internationally. STEI's goal is to remain a top quartile performer benchmarked against the other LDCs in the province of Ontario.

3.2.4 Customer Service

Since 2009, STEI has consistently met and exceeded the primary service quality indices established by the Ontario Energy Board ("OEB").

Figure 3.2.4A – 2009 ESQR Performance.



Only 4 calls required rescheduling all year

For 2009, the OEB made changes to the customer service statistics that LDCs were to report with the introduction of its Electric Distribution Service Quality Requirements ("ESQR"). STEI continued to perform well as presented in the next chart:

Figure 3.2.4B – 2010 ESQR Performance.

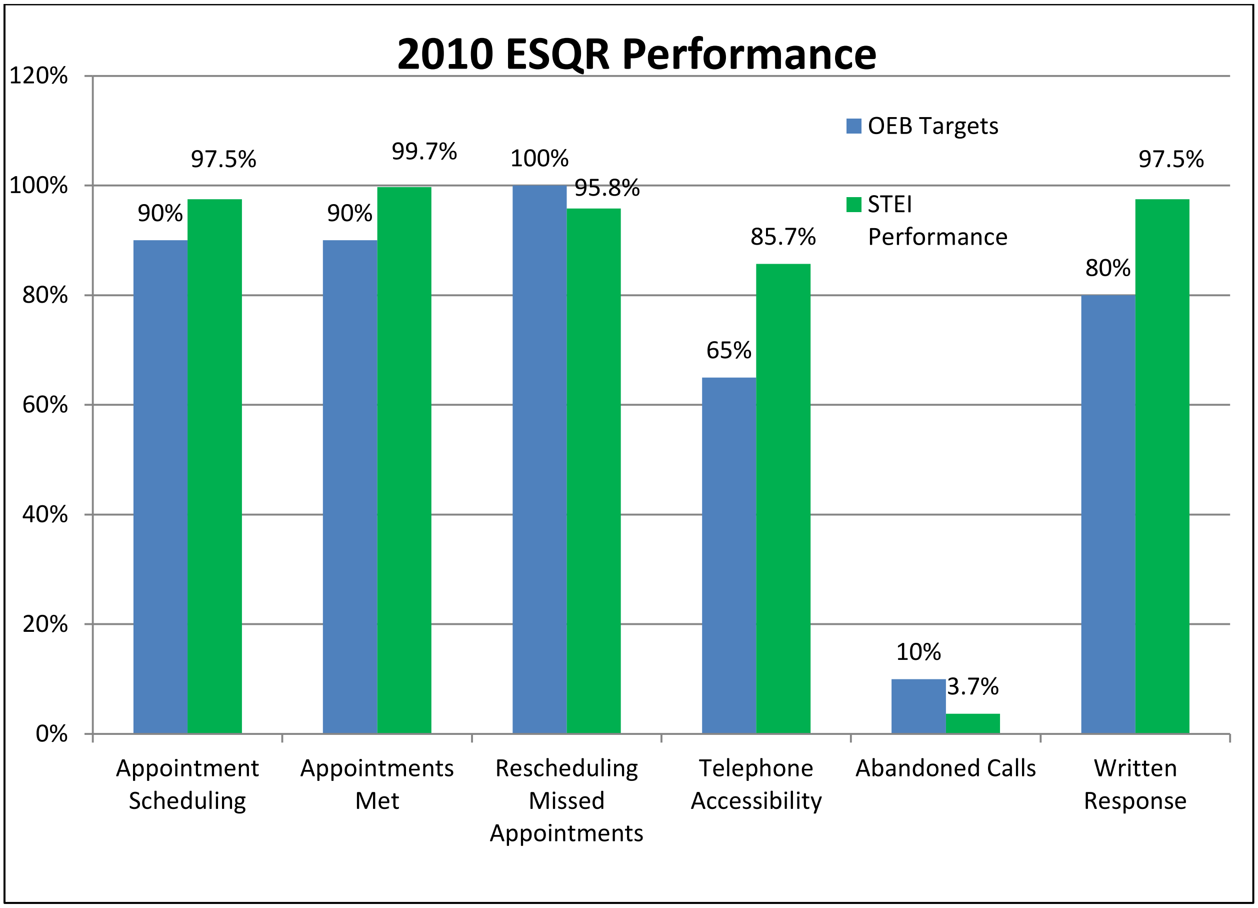


Figure 3.2.4C – 2011 ESQR Performance.

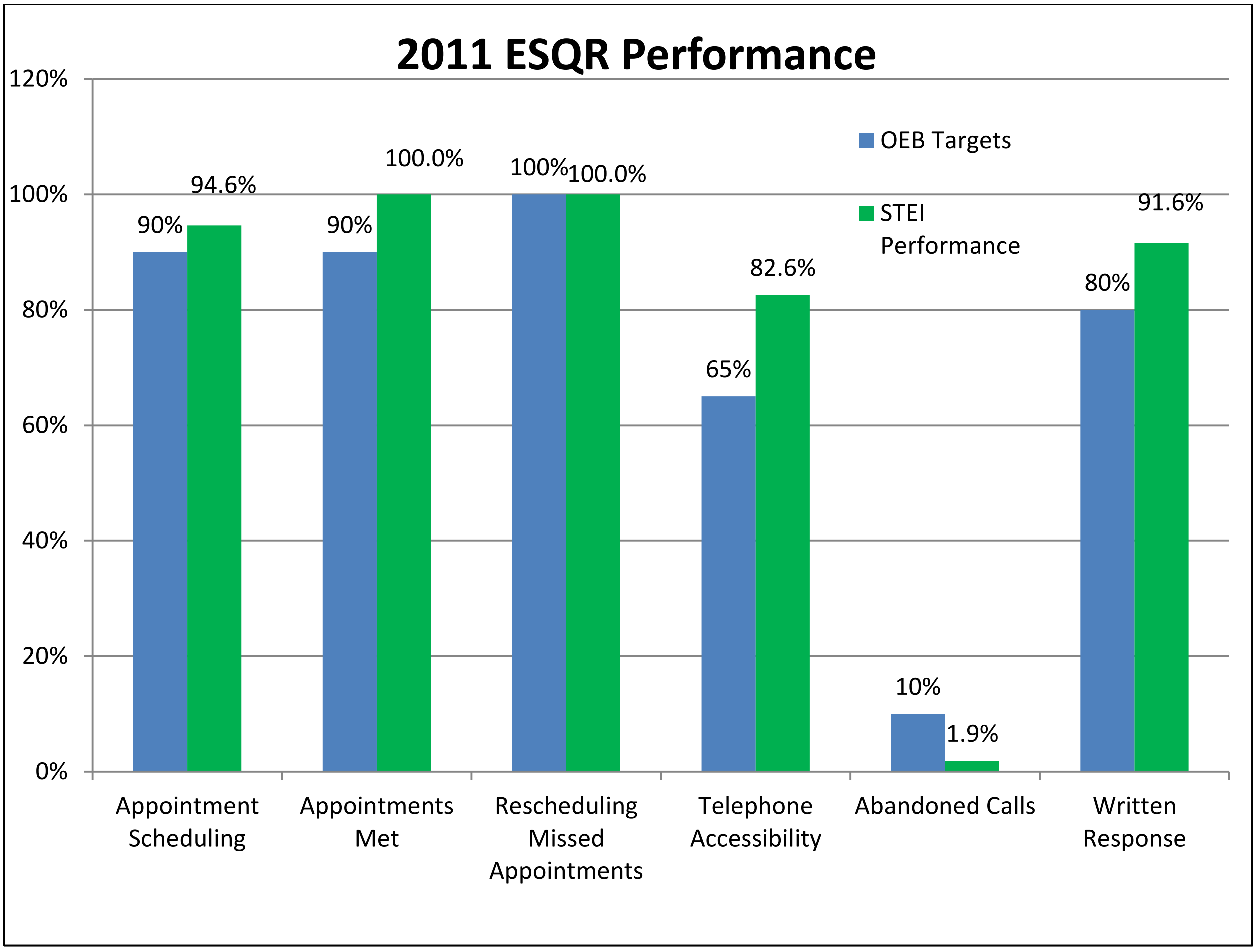
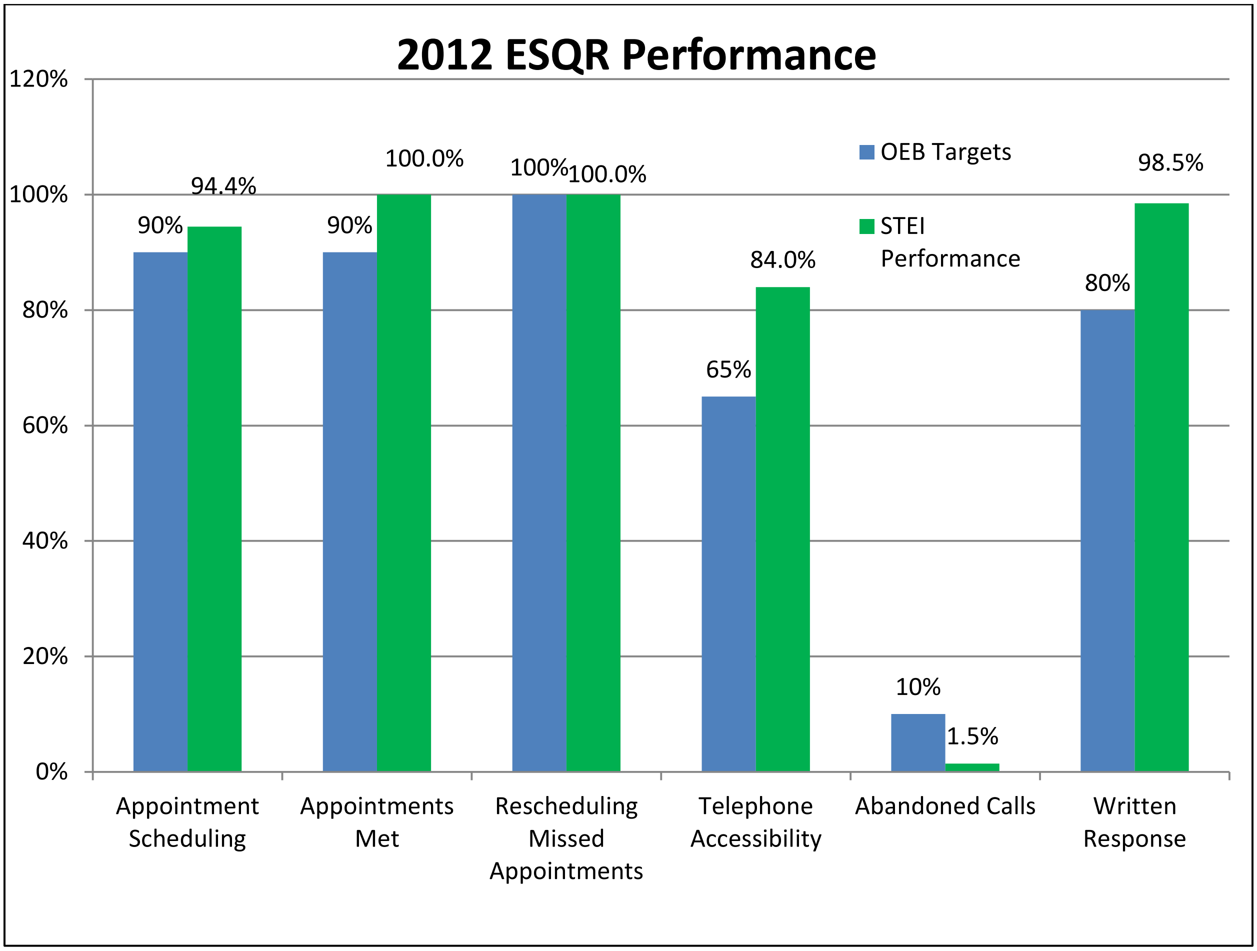


Figure 3.2.4D – 2012 ESQR Performance.



4 SYSTEM DESCRIPTION AND PERFORMANCE

4.1 System Description

STEI's distribution system is supplied by Hydro One Networks Inc ("HONI") primarily from Edgeware TS at a voltage level of 27.6 kV. There is one remaining industrial customer that is supplied power from St Thomas TS at a voltage level of 13.8 kV.

As of December 31, 2012, STEI has a total of 251.7 circuit kilometers of primary wire and cable installed. Table 4.1 shows the breakdown by voltage class for both overhead & underground primary.

Table 4.1 – Length of Overhead & Underground Primary Conductor by Voltage Class.

	Overhead (km)			Underground (km)		
Voltage Class	**3 Phase**	**2 Phase**	**1 Phase**	**3 Phase**	**2 Phase**	**1 Phase**
>15 kV	81.6	0	23.4	11.2	0	80.1
> 5kV & < 15 kV	7.4	0	3.4	1.1	0	0
< 5kV	30.4	7.4	0	4.5	1.2	0
Totals	119.4	7.4	26.8	16.8	1.2	80.1

The distribution system has 6 municipal substations remaining used to step down voltages from 27.6 kV to 2.4 kV for the old 2.4kV Delta distribution system. There is a 10 year plan in place to convert the 2.4kV Delta distribution system to 27.6kV which when complete will eliminate the municipal substations from the system.

STEI monitors the status of all four 27.6 kV feeders that supply its' service territory and all 2.4 kV municipal substation feeders from a SCADA facility located in the main office. This helps STEI respond to power system interruptions in an efficient manner.

A listing of other major assets is provided in Section 10 of the document, "Asset Condition Assessment".

4.2 System Performance

Annual System Performance indices since 2006 have been provided in the following graphs.

Figure 4.2A – SAIDI - 2006 to 2012

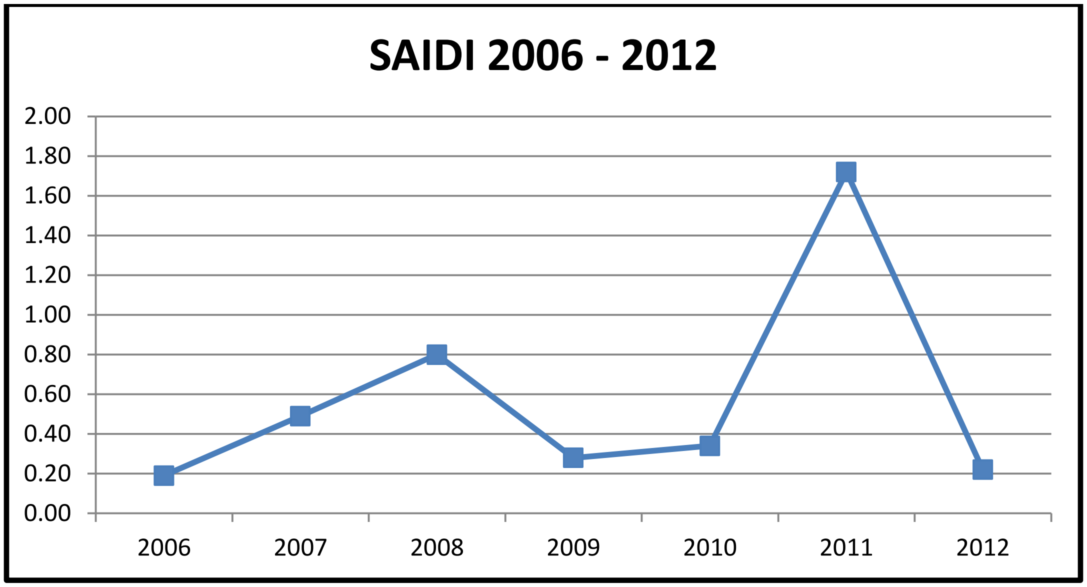


Figure 4.2B – SAIFI - 2006 to 2012.

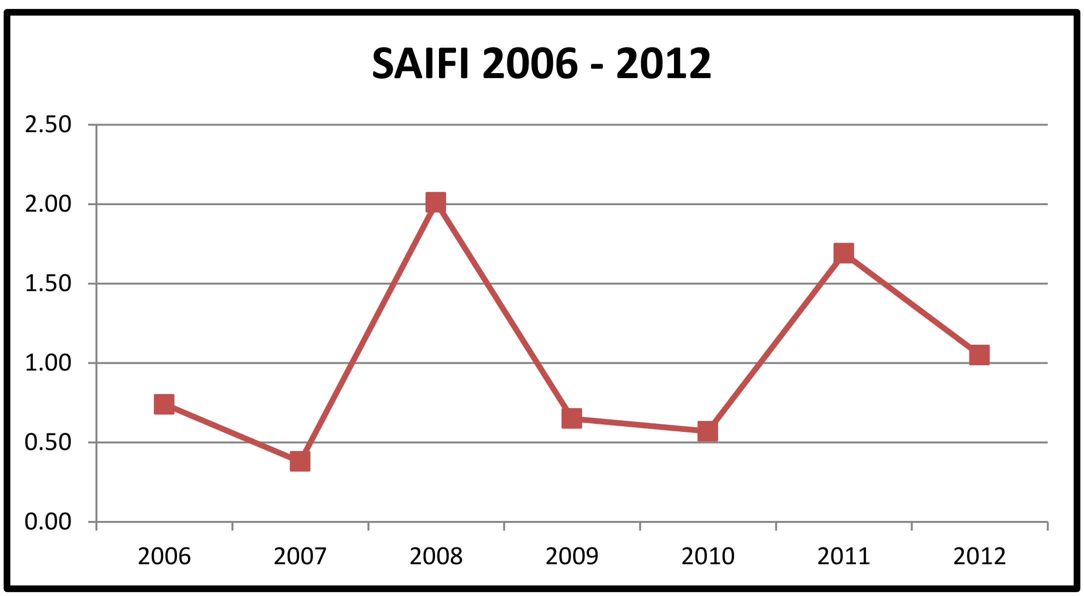
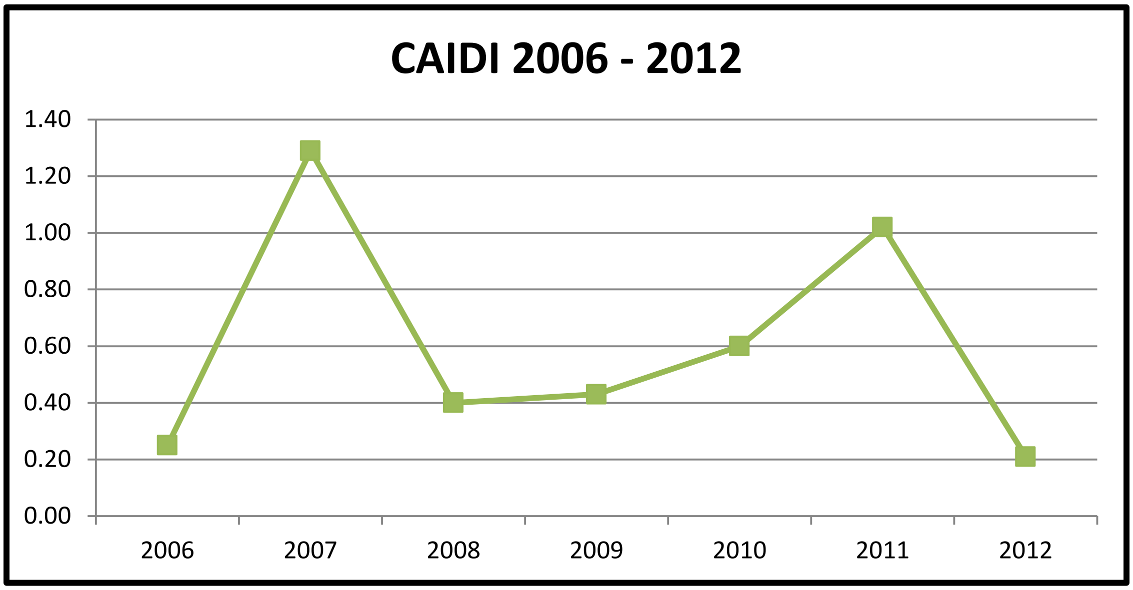


Figure 4.2C – CAIDI - 2006 to 2012.



5 MAINTENANCE PRACTICES

STEI's time-based maintenance practices, as illustrated in Table 5.1, meet or exceed all the minimum requirements contained in the Distribution System Code (DSC).

Table 5.1 STEI's Time Based maintenance Practices

FEEDER/EQUIPMENT	**1.1 *CYCLE***	**1.2 *METHOD***
Overhead Circuits - 27600/16000V System	Annual	Infrared Thermographic Survey & Visual Inspection
Overhead Circuits - 27600/16000V System – Backyards	3 Years	Visual Inspection
Overhead Circuits - 13800V System	Annual	Infrared Thermographic Survey & Visual Inspection
Overhead Circuits – 4800/8320V System	3 Years	Visual Inspection
Overhead Circuits - 2400V System – Backyards	3 Years	Visual Inspection
Load Interrupter Switches	Annual	Infrared Thermographic Survey
Load Interrupter Switches	5 Years	Preventative Maintenance
Distribution Station	Monthly	Visual Inspection
Distribution Station	2 Year	"Gas in Oil" Analysis
Distribution Station	2 Year	Substation Inspection & Cleaning
Distribution Station Pot-head Risers	Annual	Infrared Thermographic Survey & Visual Inspection
Transformers (Padmount) – Three Phase	3 Years	Infrared Thermographic Survey & Visual Inspection
Transformers (Padmount) – Single Phase	3 Years	Visual Inspection
Transformers (Polemount)	3 Years	Infrared Thermographic Survey & Visual Inspection
Padmounted Switchgear & Junctions	3 Years	Infrared Thermographic Survey & Visual Inspection
Poles & Structures	3 Years	Visual Inspection
Poles & Structures	5 Years	Wood Rot Test
Vegetation Management	3 years	Tree trimming Brush clearing

6 EXTERNAL CHALLENGES

Road Widening

Periodically, the municipality requires infrastructure to be relocated due to road widening's. The city and the MTO has identified a number of rehabilitation projects in 2013 but none of these have a significant impact on STEI infrastructure. Relocations for new Road Works is expected to be in the $50,000 range.

Industrial/Commercial Development

STEI works closely with the city's economic development office on any major industrial/commercial developments that may be relocating to St. Thomas. Potential commercial projects for 2013 are; Elgin Health Unit Talbot Street, RV World Talbot Street, 877 Talbot St new commercial mall, L&PS Train Depot.

Residential Development

New Subdivision developments resulting in load growth for 2013 are: Orchard Park Phase 5 - 42 Services, Dalewood Meadows Phase 6 - 79 Services.

7 INTERNAL INITIATIVES

Distribution System replacement and Voltage conversion is a primary driver for STEI's capital spend. Areas of conversion for 2013 include: Manor & Vanbuskirk Area, McLachlin & First Area, Erie Street and the associated capital spend is about $1M.

Work continued on the conversion of St. Thomas Energy's Electronic Operation Maps and Electronic Equipment Databases into a Geographical Information System (GIS) System.

8 ASSET STRATEGIES

Conversion of Rear Lot Lines

Between one half to two thirds of the 2.4 kV distribution system supplying residential customers consists of rear yard overhead primary & secondary lines. STEI will be continuing the conversion of rear yard overhead primary to 27.6 kV underground in the front boulevards
and rebuilding the overhead in rear yards

9 CONTINUOUS IMPROVEMENT

The following are to be implemented over the next 3 years:

- Prioritization of investments (projects and programs) in a cost effective manner
- Closing the gaps in collecting required ACA data
- Putting in place Performance Metrics to help prioritize investments
- Implement formal capital planning process

10 ASSET CONDITION ASSESSMENT RESULTS

STEI retained Kinectrics Inc. (“Kinectrics") to carry out an Asset Condition Assessment (“ACA”) of the STEI’s distribution key assets. The assets were divided into several Asset Groups. For each of these Asset Groups, the ACA included the following tasks:

- Derive Health Indexes
- Conduct Field Surveys
- Provide Capital Replacement Plan
- Provide recommendations for prioritized data gap closure

The ACA report summarizes the methodology, demonstrates specific approaches used in this project, and presents the resultant findings and recommendations.

Information Availability and Health Index Methodology

The general methodology for ACA is described, while each Asset Group is presented in detail in its own section. The information for each Asset Group includes the Health Index (“HI”) formula and distribution.

Where appropriate, the results were modified based on the expert opinion of STEI staff. Field observations generally supported the Health Index distribution derived using Kinectrics’ methodology. Some differences could be attributed to the fact that the field survey observations weigh all the condition parameters equally while the Health Index formulation used a weighted sum of condition parameters scores.

Health Index Results Summary

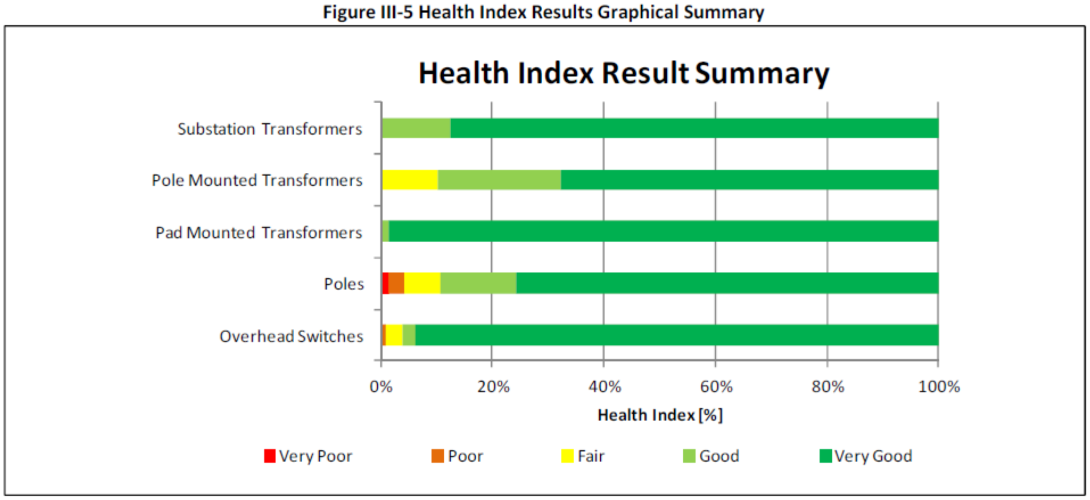
For five Asset Groups there was sufficient asset information to calculate Health Indexes. Table 10.1 shows, for each of the five Asset Group, the total number of assets, sample size, and Health Index distribution. This data is from the 2011 ACA.

Table 10.1 Health Index Results Summary

Table III-4 Health Index Results Summary

Asset Category	Population	Sample Size	Health Index Distribution (% of Sample Size)					Total in Poor and Very Poor	Average Health Index	Average Age
			Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)			
Substation Transformers	8	8	0.0%	0.0%	0.0%	12.5%	87.5%	0.0%	95%	29
Pole Mounted Transformers	894	892	< 1%	< 1%	10.3%	21.9%	67.4%	< 1%	90%	19
Pad Mounted Transformers	499	499	0.0%	0.0%	< 1%	1.4%	98.2%	0.0%	97%	12
Poles	4857	4855	1.5%	2.8%	6.4%	13.5%	75.8%	4.3%	90%	27
Overhead Switches	105	98	0.0%	1.0%	3.1%	2.0%	93.9%	1.0%	97%	13

Figure III-5 Health Index Results Graphical Summary



The Overall Capital Replacement Plan is the total replacement projections for all the assets over the next ten (10) years. This is shown on Figure 10.1.

<u>Figure 10.1</u> Ten (10) Year Capital Replacement Plan

ACA Conclusions and Recommendations from 2011 ACA

1. An Asset Condition Assessment was conducted for five of STEI's key distribution assets, namely Substation Transformers, Pole Mounted Transformers, Pad Mounted Transformers, Poles, and Overhead Switches.

2. Approximately 11% of Poles are in "fair" or worse condition. Of these, over 4% were found to be "poor" or "very poor".

3. While very little units were considered to be "poor" or "very poor", over 10% of Pole Mounted Transformers were found to be "fair".

4. The vast majority of Substation Transformers, Pad Mounted Transformers, and Overhead Switches were in "good" or "very good" condition.

5. STEI's most significant expected replacements were found to be for Wood Poles. Approximately 80 poles are expected to be replaced in year the first year; this amounts to approximately $800,000 in required capital, assuming the cost of replacing each pole is $10,000.

6. Approximately 13 Pole Mounted Transformers are expected to be replaced in the first year. Assuming a replacement cost of $6,375 per unit, the total replacement cost for the first year is

$82,875. The expected number of replacements increases by approximately 1 unit per year in the next 10 years.

7. Good condition data is being collected for Substation Transformers. Assessment of insulation condition may be improved by collecting and incorporating winding power dissipation factor test results (winding Doble).

8. The data gaps for Pole Mounted Transformers are inspection records related to overall life grade, oil leaks, and tank condition. It is recommended that such information be collected and incorporated into future assessments.

9. Collecting information on the overall life grade condition would improve the assessment of Pad Mounted Transformers. It is recommended that such information be collected and incorporated into future assessments.

10. While detailed inspections of Poles are routinely conducted at STEI, the results of the most recent inspections were not available for this asset condition assessment. As such, the assessment for this asset class was based solely on age. It is recommended that the detailed inspections be used in future assessments of this asset class.

11. More granular inspection ratings should be considered, where applicable, to produce more informative Health Index results. For example, for a pad mounted transformer, an inspection item called “corrosion” with a ranking system of “As New”, “Wear/Monitoring Required”, and “Poor/Replacement Required” will result in more informative Health Indexes than a ranking system of “okay” and “not okay”. Recommendations for improved scoring systems are given for parameters of the following asset classes: Pole Mounted Transformers, Pad Mounted transformers, and Overhead Switches. These can be found in the Data Analysis section of each asset category.

11 2013 INVESTMENT PLAN

Table 11.1 – STEI Investment plan for 2013.

Year	Project	Reason	Poles	OH conductor	UG conduit	UG conductor	Services	Trans.	Metering	Eng/Admin	
			1830	1835	1840	1845	1855	1850	1860	40%	Total
2013	Install UG system for residential subdivision	Residential development for approx. 200 lots		0.00	100,000.00	120,000.00	22,000.00	140,000.00		152,800.00	534,800.00
										-	-
2013	Convert existing 2.4kV system in Sub 11 area Sparta St., Pullen Ave. and Frances St. (Primary and trans - front yard UG. Secondary to remain rear yard overhead)	Replace due to age and condition, numerous outages due to old cable. Ongoing voltage conversion program)	8,200.00	11,800.00	48,000.00	72,000.00		40,000.00		72,000.00	252,000.00
										-	-
2013	Convert existing 2.4kV system in Sub 14 area (North of El St.) Manor Rd., Vanbuskirk Dr. and McCully Dr. (Primary and trans - front yard UG. Secondary to remain rear yard	Replace due to age and condition, numerous outages due to old cable. Ongoing voltage conversion program)	8,200.00	11,800.00	48,000.00	72,000.00		40,000.00		72,000.00	252,000.00
2013	Miscellaneous Capital - New UG Services	Customer demand work					88,411.50				88,411.50
2013	Miscellaneous Capital - New OH Services	Customer demand work					101,411.50				101,411.50
										-	-
2013	Miscellaneous Capital Work	Customer demand work	10,000.00	15,000.00	5,000.00	10,000.00	2,000.00	30,000.00		28,800.00	100,800.00
										-	-
2013	Miscellaneous Capital Work	Utility Projects	20,000.00	5,000.00	15,000.00	20,000.00	15,000.00	20,000.00	0.00	38,000.00	133,000.00
										-	-
2013	Capital Revenue Metering	New installations and upgrades							60,000.00	24,000.00	84,000.00
										-	-
			46,400.00	43,600.00	216,000.00	294,000.00	228,823.00	270,000.00	60,000.00	387,600.00	**1,546,423.00**

APPENDIX B to Section 2.1

MANAGEMENT SYSTEM MANUAL – PART 1

St. Thomas energy inc.
We're Your Local Power Distributor

MANAGEMENT SYSTEM MANUAL

Re-release: October 2011; Rev 0
Rev 1 - January 31, 2012
Rev 2 - May 8, 2012
Rev 3 - August 7, 2012
Rev 4 – November 26, 2013

Contents

Company background and profile:

St. Thomas Energy Inc. is an electrical distribution utility company whose roots date back to 1906 when our predecessor company, Public Utilities Commission of St. Thomas was established.

St. Thomas Energy Inc. is located in St. Thomas, a city of approximately 35,000 people, situated in southwestern Ontario. We provide design, construction, operation and maintenance of electrical distribution systems; electrical revenue metering; as well as meter reading, billing and collecting services. Our customers include residents, commercial establishments and the municipality of St. Thomas.

Our most important resource is our highly skilled group of employees, numbering in the range of 30- 35, whose first priority is our customers.

We are proud to be a corporate member of the community and we strive to provide a high level service to our customers.

Scope of Quality System:

The quality system applies to all core and support processes associated with design, development, construction, operation and maintenance of electrical distribution systems, electrical revenue metering, as well as meter reading, billing and collecting services. All clauses of ISO 9001:2008 apply except for 7.5.2 as all products are verified and/or tested.

This manual defines all mandatory aspects of the system and includes a cross reference matrix to ISO 9001to illustrate the relationship of this system to the standard. This manual is supported by procedures and work instruction where detailed specific process information may be more appropriately conveyed. This manual interfaces with the H & S system at various reference points defined herein (I.E. Internal audit & corrective action).

Quality Policy:

In addition to the requirements of ISO 9001 the following policy is underpinned by the following core values:

- Financial Stability
- Employee and Public Safety
- Quality Solutions
- Customer Service
- System Reliability

Our processes, structures, systems and facilities will be designed to…

1. Provide maximum financial return to our stakeholders and to the corporation
2. Optimize operational efficiencies and synergies across all companies
3. Achieve recognition as a leading service provider and an employer of choice
4. Ensure employee and public safety
5. Support effective communication both internally and externally
6. Foster innovation
7. Ensure environmental impacts are a key consideration in our decision-making
8. Achieve a stable, sustainable organization

It is the Policy of St. Thomas Energy Inc. to provide its customers with a safe and reliable electrical power distribution system and strive for their complete satisfaction with our company products and services. The foregoing is conducted in compliance with governing statutes and regulations. Our commitment also includes the resolve to continually improve the effectiveness of our quality management system, enhance the value of our products and services and monitor our quality objectives.

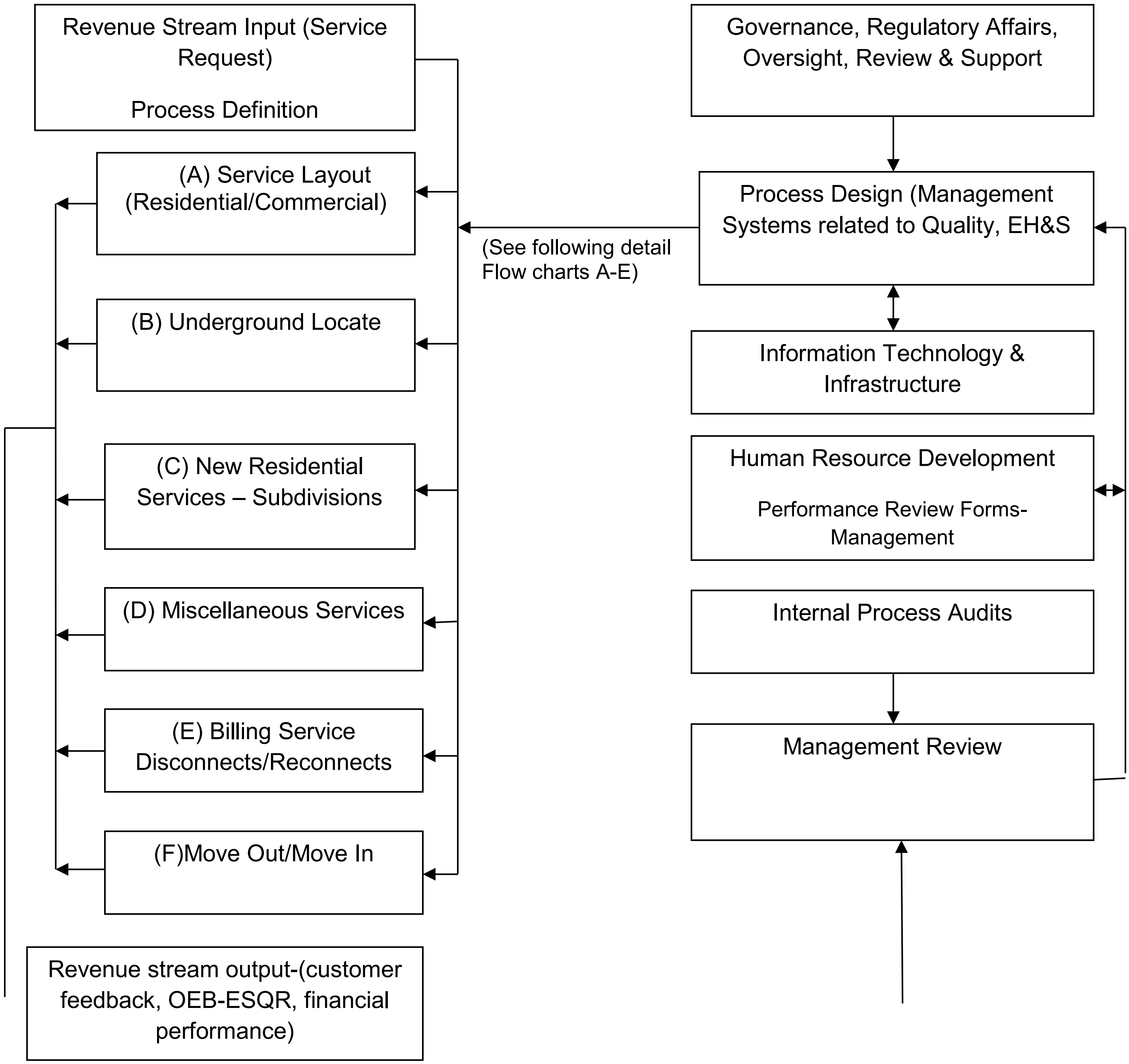
Roles & Responsibilities:

The organization chart depicts the structure. It may be accessed via the link or by viewing in the Quality System folder on the server.

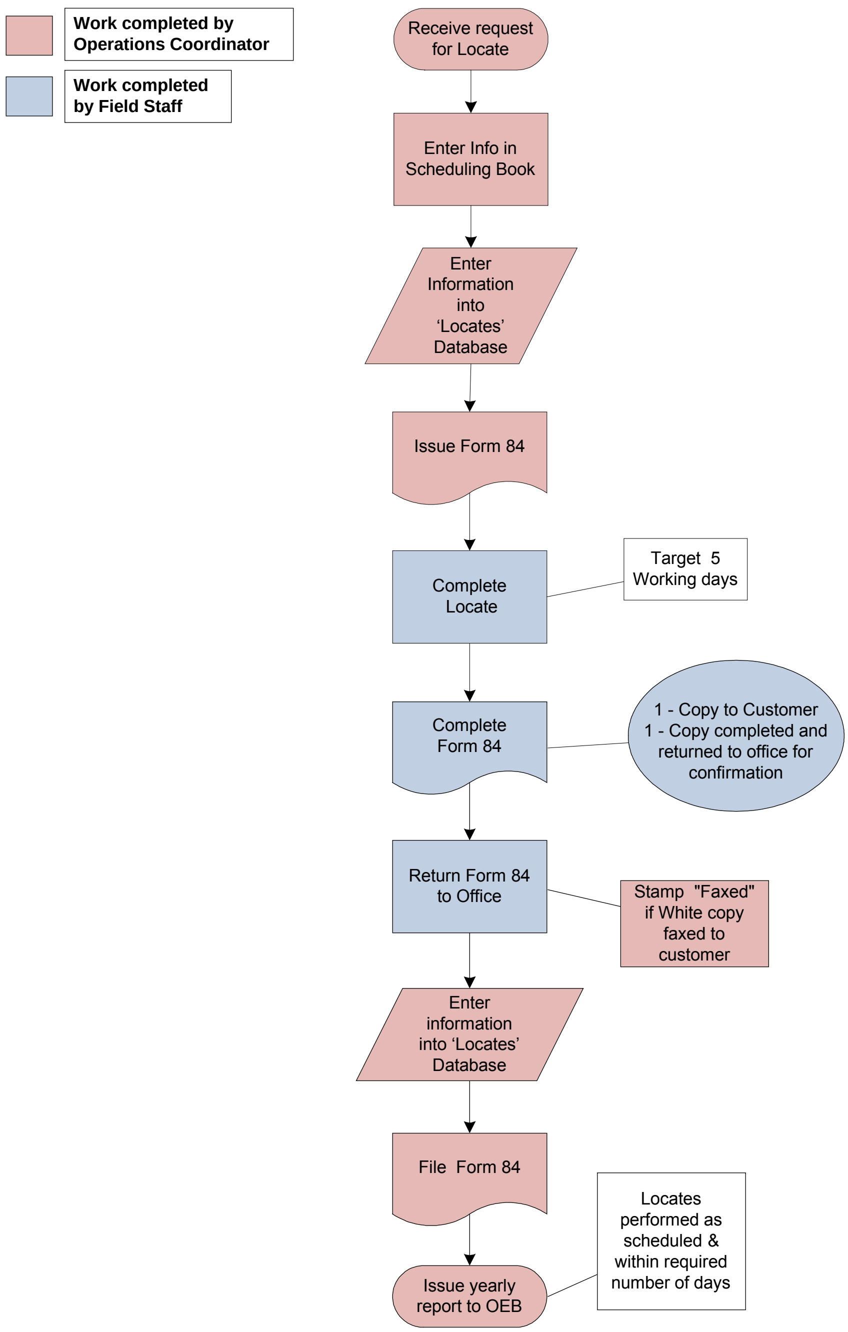
Each position defined on the organization chart is supported with a job description which provides an overall description of the responsibilities of each position.

The Director of Engineering & Operations is also the Management Representative for the quality management system. In this regard the Director of Engineering & Operations is responsible for assuring the efficiency and effectiveness of the system, providing data to management on the performance of the system, pushing quality concepts, with a focus on the customer, through the enterprise, assuring management reviews and internal audits are conducted. The Director of Engineering & Operations, at his/her discretion, may delegate coordination and oversight of day to day management system activities at his/her discretion.

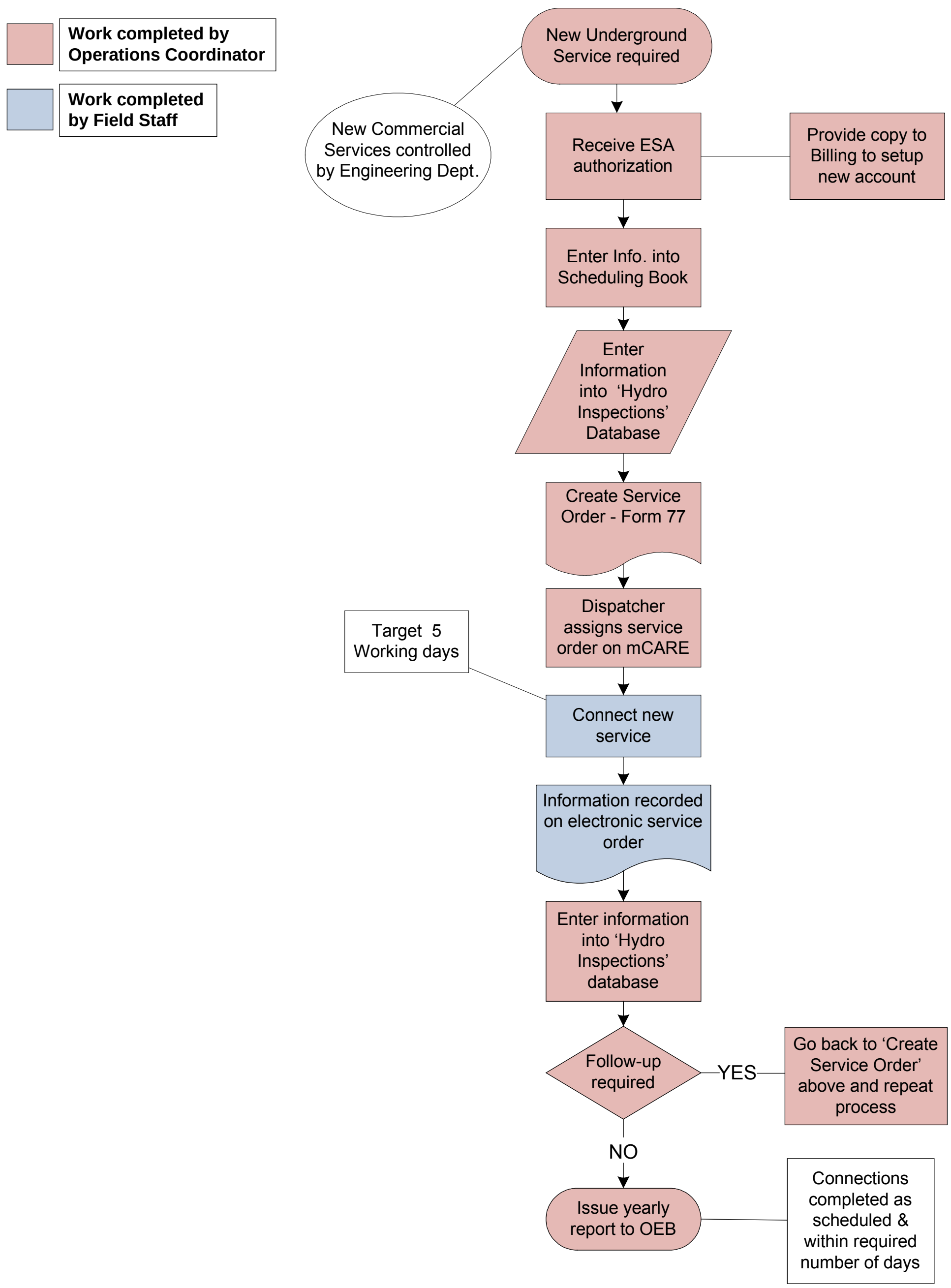
Process Interrelationships:



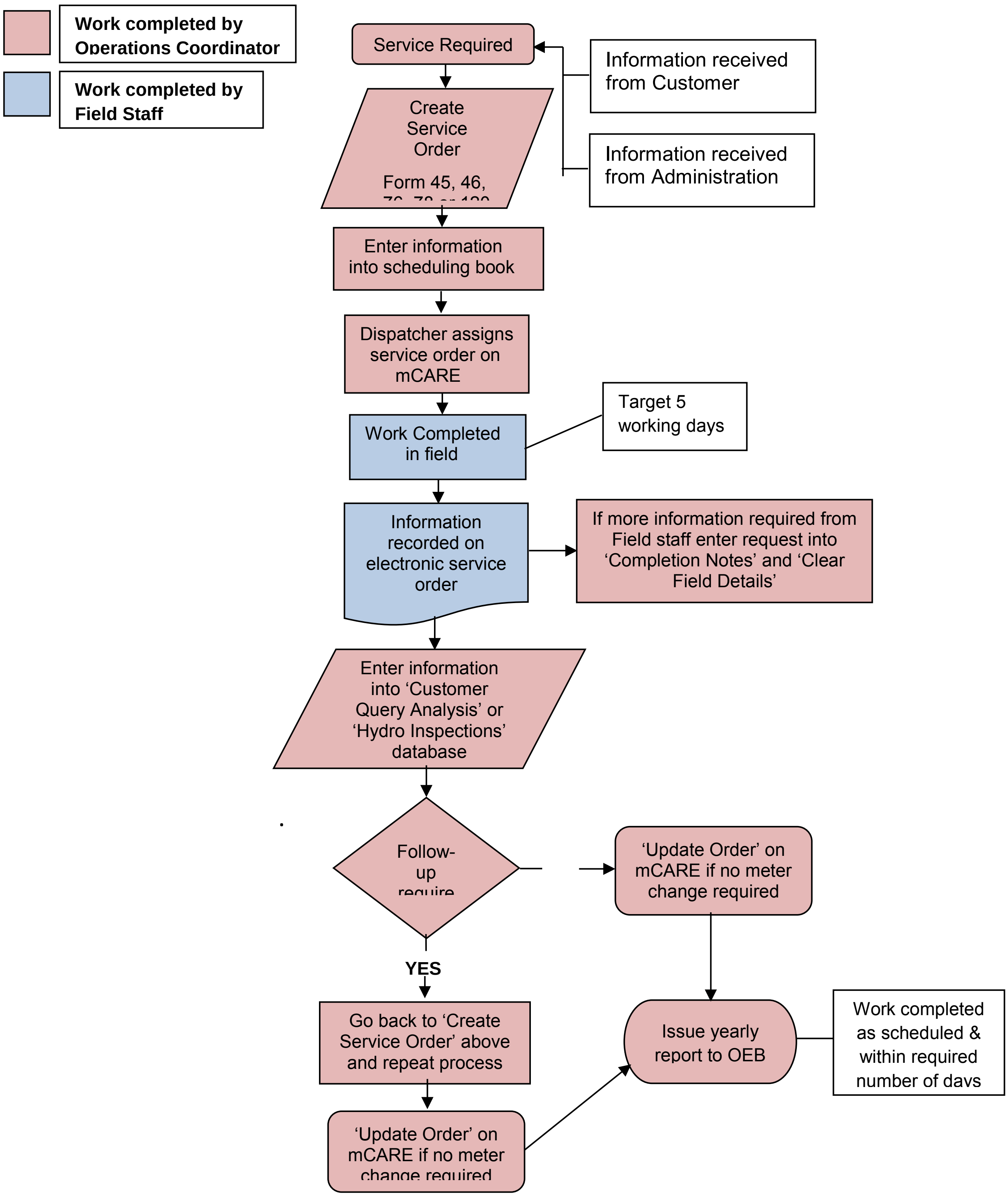
Process B: Underground Locate



Process C: New Residential Service - Subdivisions

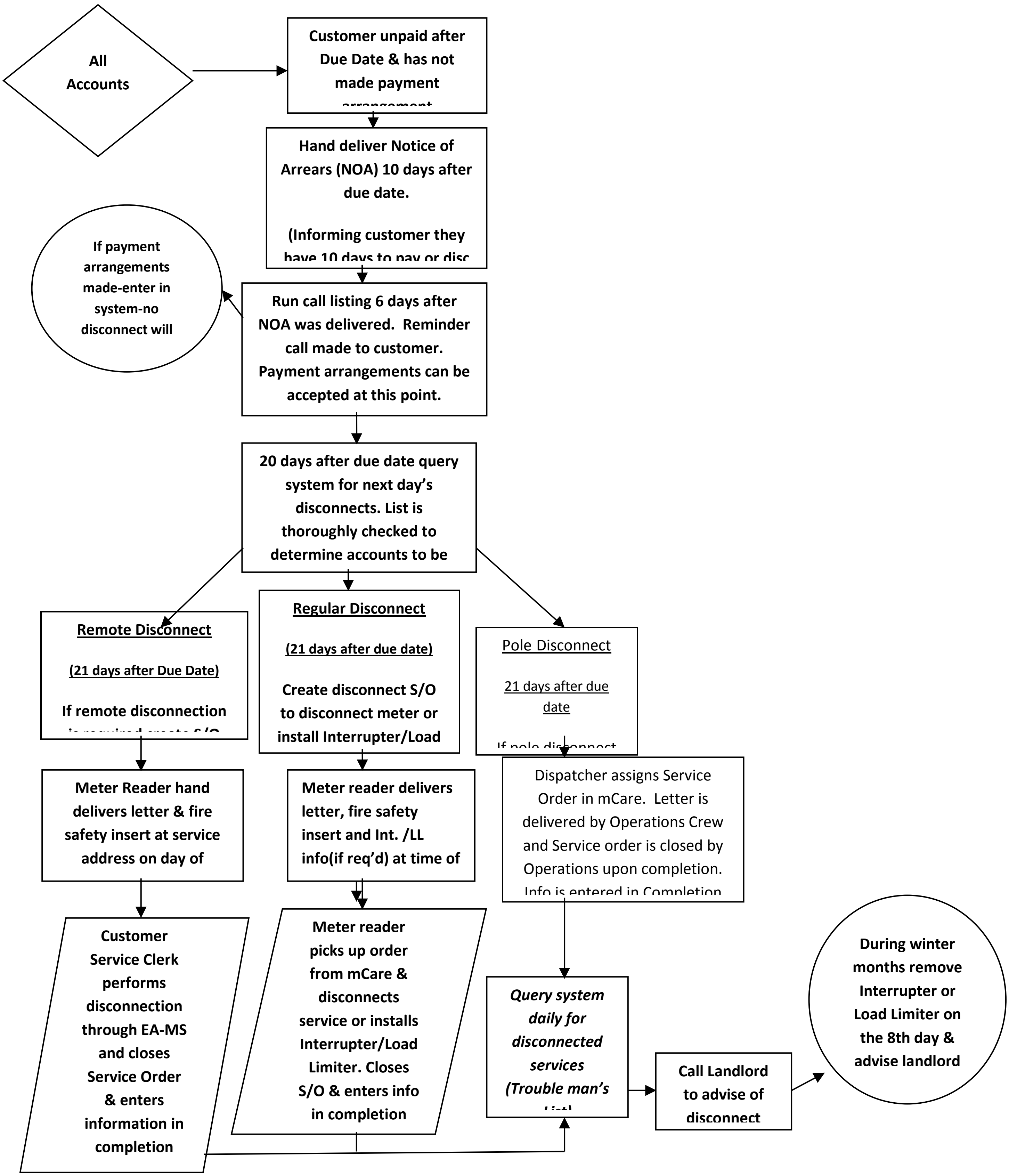


Process D: Miscellaneous Services



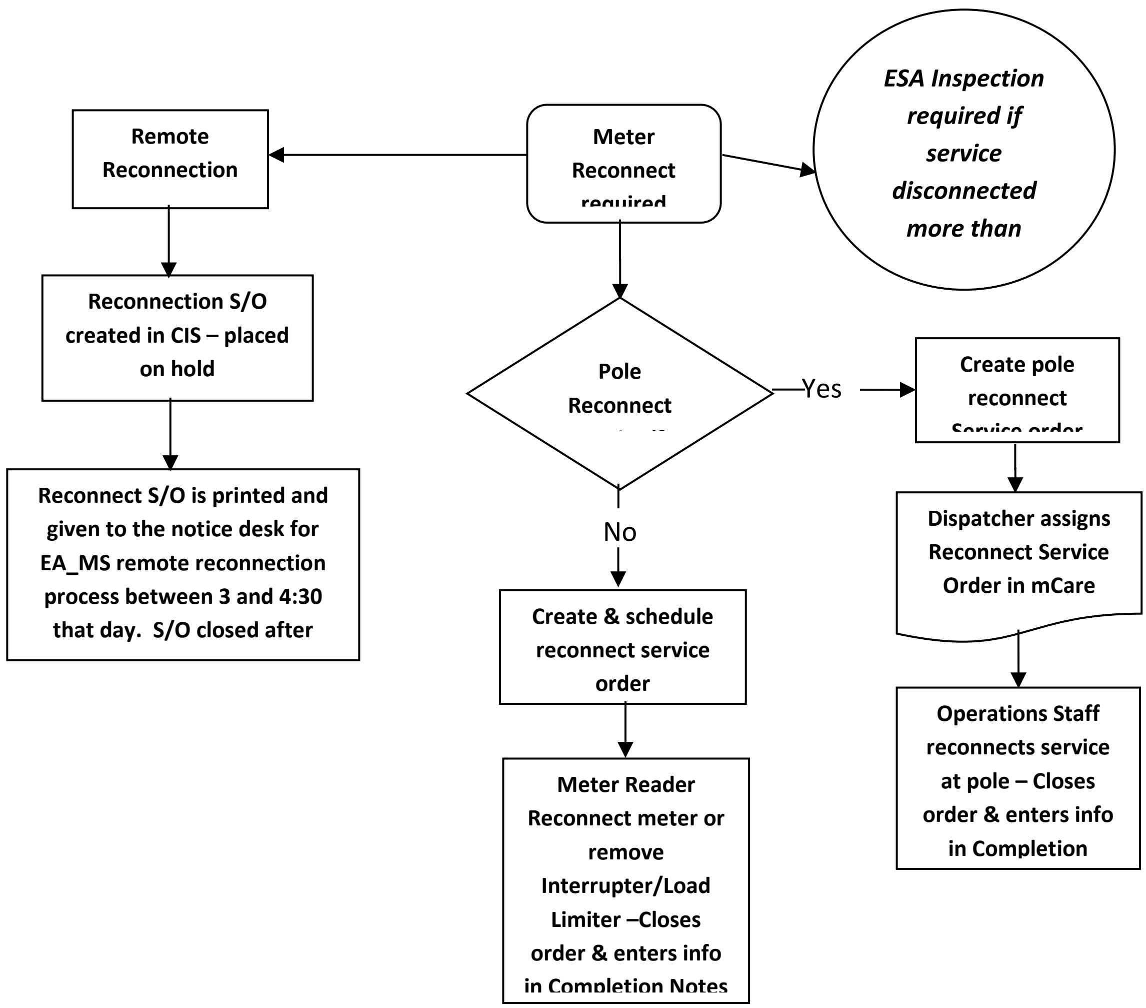
Process E: Billing Service Disconnects/Reconnects

Meter or Service Disconnect

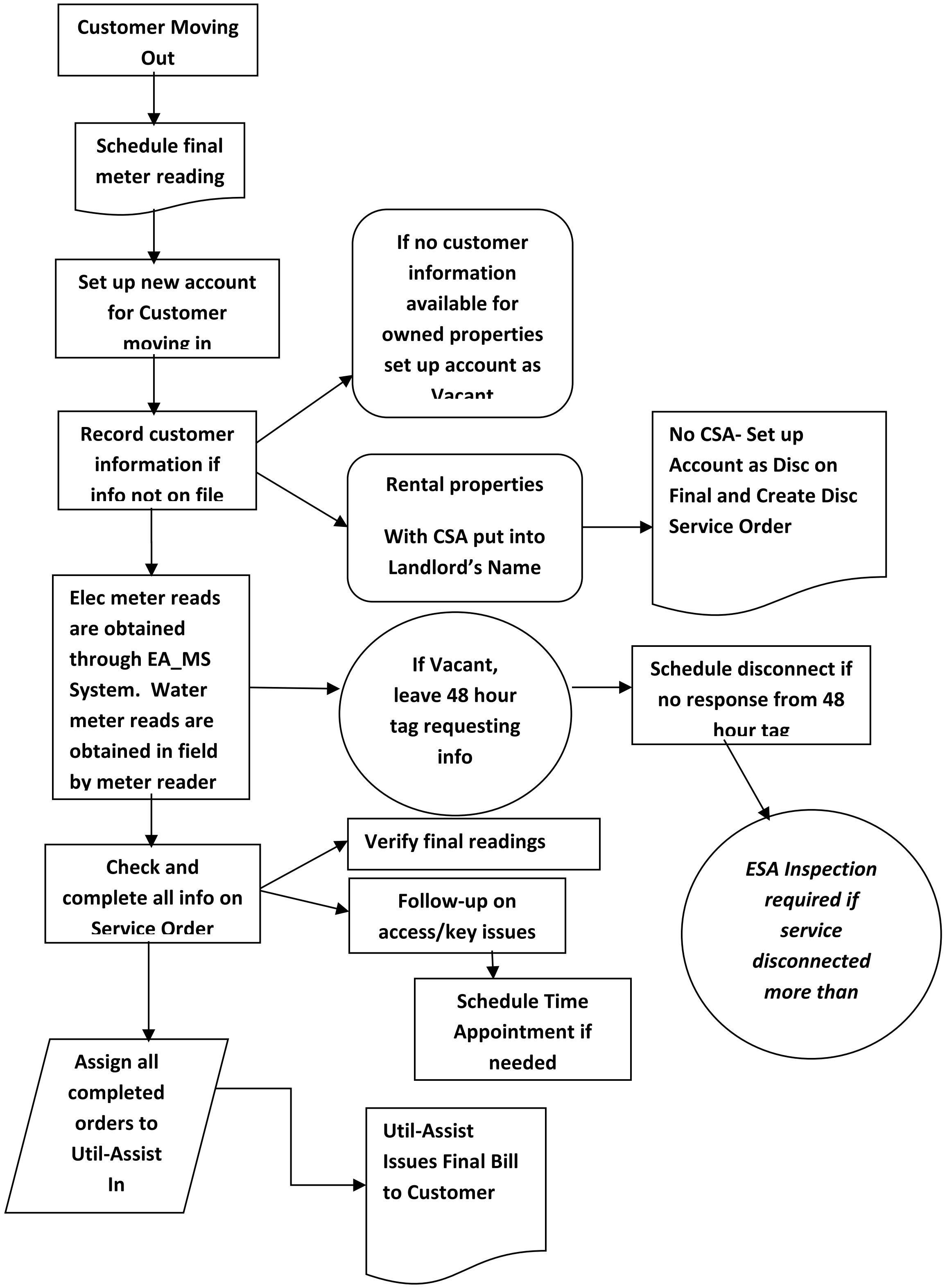


Process E: Billing Service Disconnects/Reconnects

Meter or Service Reconnect



Process F: Move Out – Move In



Control of Documents:

General: The purpose of this procedure is to ensure that all members of St. Thomas Energy Inc. (STEI) are provided with documented information that is current, valid and approved. This relates to any procedures, instructions or regulations with which personnel are expected to comply.

Pertaining to internal documents: Internal documents are those documents that STEI designs and composes to (either or both) ensure business objectives are met and to ensure regulatory compliance is maintained. STEI Documentation Master List - Appendix A provides a full listing of such documents. Documents developed to define procedures, act as work instructions or provide operational guidance in any form that are intended to be for ongoing use, must be included on the list and are subject to the controls defined herein.

Internal documents use a standard header with the STEI logo. The title of the document must be clearly indicative of the content and will be similar to the file name. Date of original release, revision level and date of revision must also appear. Pages must indicate "X of X". Departments may adopt a numbering system germane to their requirements.

Masters of all the documents listed on the index are located in write protected folders on the shared drive. Write access is granted to the approval authority and/or to a direct delegate of the approval authority. Positions with write access are indicated on the index in the header bar for each population of documents. Default write access is the Director of Engineering & Operations or direct delegate. Default is indicated in the absence of a name on the index. The folder name heads the list of documents, by file name, residing in the folder.

The placement of a document in the write protected folders denotes approval.

Read access is granted liberally throughout the operation to ensure personnel have ready access to relevant documentation. Personnel are encouraged to have "desk top" short cuts to facilitate access to frequently accessed documents.

Personnel may print copies of documents for convenience however such copies are not controlled or updated. (NOTE—see caution flag under "Revision Process" regarding forms)

The Director of Engineering & Operations is accountable for control and security of server access and is ultimately responsible for server access profiles. This activity may be delegated to a competent IT professional. Requests for access privileges must originate from a Management member with justification. Director of Engineering & Operations, or direct IT delegate, approves and indicates so by granting the requested access. If access is denied the rational is explained. Requests/responses are completed electronically (e-mail). Such are saved, by Director of Engineering & Operations or IT delegate for evidence and audit trail.

Revision Process:

When, for whatever reason, it becomes necessary to revise a document initiate the change in the following manner:

- Save a copy of the document on the server at S:\ISO 9000\Document Revisions - In Process and add your initials to the file name.
- Edit the document as you see fit. NOTE: It is of great assistance to the reviewer/approver if you make your edits appear as different text style, color or use of the "Track Changes" options.
- E-mail a hyperlink to the revised document on the server to the individual responsible for the document as indicated in Appendix A.

Upon receipt of the proposed changes the responsible authority will:

- Review the proposed changes and either respond as to why the changes are not acceptable or will proceed with:
- Adjust any format or text issues and any other minor edits or tidy up required
- Make sure the revision is moved up a level and the revision date is correct in the header.
- Provide a brief synopsis as to the nature of the change in the document history section (forms accepted) NOTE: some documents, in existence at the time of the release of this procedure did not have History Sections. These will be added as such documents are otherwise updated)
- Move the previous version of the document to the corresponding archive folder.
- Update STEI Documentation Master List - Appendix A
- Update Document Review Log
- Post the updated document on the server, available for viewing by all.
- Decide on one of 3 approaches to communicating the change, based on the nature of the change, as follow:
    A)- Very minor editorial clean up with no impact on intent or process—do nothing
    B)-Simple change or update: send a notification e-mail, indicating the gist of the change, to all relevant parties. Save such e-mails.
    C)-Significant change to policy, practice or process: set up a meeting/training session. Save the sign in sheet for the record.

NOTE: In cases where write access is limited to the Director of Engineering & Operations, or delegate, the responsible authority may send the changes to the Director of Engineering & Operations, or delegate, who will provide support in formatting, revision block updating and other details as outlined above.

CAUTION NOTE RE FORMS: It is common for personnel to print a small stock pile of frequently used forms for convenience. Ensure that when forms are updated a reminder is sent to destroy all existing stockpiles.

Documents of External Origin

Documents of external origin include such as Industry Regulations & Standards, Ministry acts and regulations related to Health & safety as well as quality system governing documents.

EH&S Related: STEI maintains membership in AEUSP. Via regular meeting, newsletters and updates STEI ensures all related standards, regulations and statutory updates are reviewed and promulgated to the operation via the Health & Safety Manual. The Health & Safety manual, as an internally developed document, is controlled as described in the above section. The responsible authority is named on the index list of documents.

Governing Quality Standards: The Quality System Coordinator maintains access to the web site of the International Organization for Standardization to monitor any updates that may occur in the standards. The QSC is supported in maintaining knowledge of updates via the 3rd party registrar and various consulting bodies. Any updates are reviewed and promulgated via this manual, and associated documents, which are subject to the controls for internal documents as described above.

Quality standards and/or specifications imposed by customers are reviewed at quotation/contract initiation by the associated project control authority with support by appropriate technical staff as warranted. Such may drive adjustment to existing documents or contract specific plans or instructions. Such are subject of the internal controls described above.

Technical Standards: The Engineering Manager is responsible for ensuring STEI complies with up to date input. Such regulations & standards are promulgated into the STEI "Electrical Distribution, Design & Construction Standards" manual. This manual, as an internally created document, is controlled as described in the foregoing section with the following caveats:

- At the time of the release of this procedure, October 2011, the contents of the "Electrical Distribution, Design & Construction Standards" manual were verified as being valid and current.
- There currently is no revision date or level indicated on the various components of the manual and therefore, as of the release of this procedure, are deemed to be at Revision 0, dated October, 2011.
- As various components of the manual are updated, revision block will be added; starting with "1" and the date the revision completed will also be added. For audit purposes the "date modified" may be reconciled with revision dates.
- The Engineering department maintains 1 printed copy of the manual in the department. As components of the manual are updated the hard copy is also updated and previous outdated hard copy sections are destroyed.
- Relevant portions of the manual are provided with work packages for use of the field crews executing the work. In such instance the copies may be edited/adjusted/summarized or otherwise to ensure they are relevant to the specific job. Such issued and adjusted portions of the "Electrical Distribution, Design & Construction Standards" manual are NOT further controlled and the provided hard copies may be discarded after the job is complete

Industry Standards: Examples include CSA, ESA, and MOL. Input from such organizations in the form of updates, bulletins and other communiqués are typically received by e-mail, and regular mail. Such are routed to the appropriate manager who reviews and updates or creates any internal controls as warranted. If there is doubt as to where such input is to be routed, the Director of Engineering & Operations directs.

Engineering Drawings

Internally generated drawings and material lists (design output) are managed per work instruction WI 7.3.1

Control of Records:

There are 2 formats for records, hard copy and electronic (ie: 'Soft Copy'). The majority of records are hard copy. In some cases hard copy records are replicated in soft copy. Notwithstanding the back-up protocol described below the hard copy record is considered as "the record".

The RMS Retention Schedule lists the record, department, retention time per legend on the RMS retention schedule, has provision for comments germane to changes in retention and approval authority for such changes. All records are stored in a manner that precludes deterioration or abuse.

Hard Copy: Current records are retained in office environment filing cabinets until capacity has been achieved and records are sufficiently dated to be archived. This varies with volume and nature but there is typically a minimum of 1 year retention in current record files.

Work instruction 4.2.4.1 provides details regarding archival and destruction of hard copy records.

Soft Copy: Incremental backup of all servers is conducted automatically each night and stored on an off site server. The Information Technology Supervisor is responsible for this process. Back up is tested periodically by recalling archived records.

If documents have not been revised for 36 months they will be reviewed and updated as required.

Non Conforming Product

Non conforming product (NCP) is defined as product that does not conform to specified criteria. In the case of STEI "product" relates to physical items that we install as well as our service.

Physical Items: Other than obvious signs of transit damage or tampering defective product is typically not discovered until point of install. In some instances rudimentary tests may be performed to provide a degree of assurance of functionality before an item is transported (E.G. a transformer).

When an item is found at receipt, or early rudimentary test, to be defective it is returned to the vendor for replacement and or credit. Such events may be tracked, via credits in the AP system, in the event it appears that such instances are becoming frequent. Any chronic vendor concerns highlighted in this manner are reviewed during Management review process. Such vendor issues may precipitate the issue of a corrective action request (see next section) by the Quality Manager.

If an item is discovered to be defective during or after installation the field team retrieves the item, replacing as required) and returns it to the shop. Such items will also be returned for credit/replacement as indicated above. If the event causes more than 2 hours of effort to resolve, a nonconformance is raised however discretion of the Quality Manager prevails based on the risk and nature of the problem.

In instances where STEI personnel cause an item to become nonconforming the item will be evaluated by the Operations Manager to determine if it is repairable or must be scrapped. Such events will trigger a corrective action if the item is costly or if the resolution requires more than 2 hours labor.

NOTE: In any case related to above events where an item must be held at STEI, while reviews or return logistics are being sorted out, the item will be clearly identified as defective (I.E. yellow caution tape with a sign or placed in a designated area) by any clearly evident means suitable to the size and configuration of the item.

Service Problems: Customer complaints or concerns are captured in the CIS data base. Events are resolved on a real time basis with the primary focus being on immediate satisfaction of the customer. CIS data base is analyzed and results are reviewed at Management Review meetings. Chronic or repeat problems may precipitate a corrective action.

NOTE: "Incidents" are also a form of nonconformance. In this context incidents are handled via the H & S protocols. Chronic H & S issues may result in invoking the corrective action process (see next section).

Corrective & Preventive Action

The following section describes the method for dealing with Corrective Action & Preventive Action.

Corrective Action is necessary when a problem has occurred or something or some process does not meet expectations. The root of the problem must be uncovered and action must be taken that is designed to prevent the problem from happening again. The effort put into analyzing the problem and correcting the root cause must be compatible with the size of the problem and the risk associated with the problem.

Corrective action initiatives may be precipitated by input from the H&S system. (E.G. via: Oil Spill, FM 58; Records of Evacuations, FM 19; un addressed work orders from safety tours or other sources)

Preventive Action is necessary when a potential problem has been uncovered. Action must be taken to prevent the anticipated problem from occurring. The effort invested in preventing the problem must be based on the probability that the problem will occur and the risk associated with it. Preventive action activities are typically identified via planning meetings, implementation of new technologies or processes or engaging new customers. Document trails for such preventive actions may be found in:

- Approved capital budget plans
- Project plans (I.E. for upgrades to software, equipment, technologies,)
- Opportunities for improvement identified during audits.
- Risk management plans and controls resulting from hazard analysis from the 18001 system.
- Near miss mitigation plans stemming from analysis of near miss events identified via the H&S system.

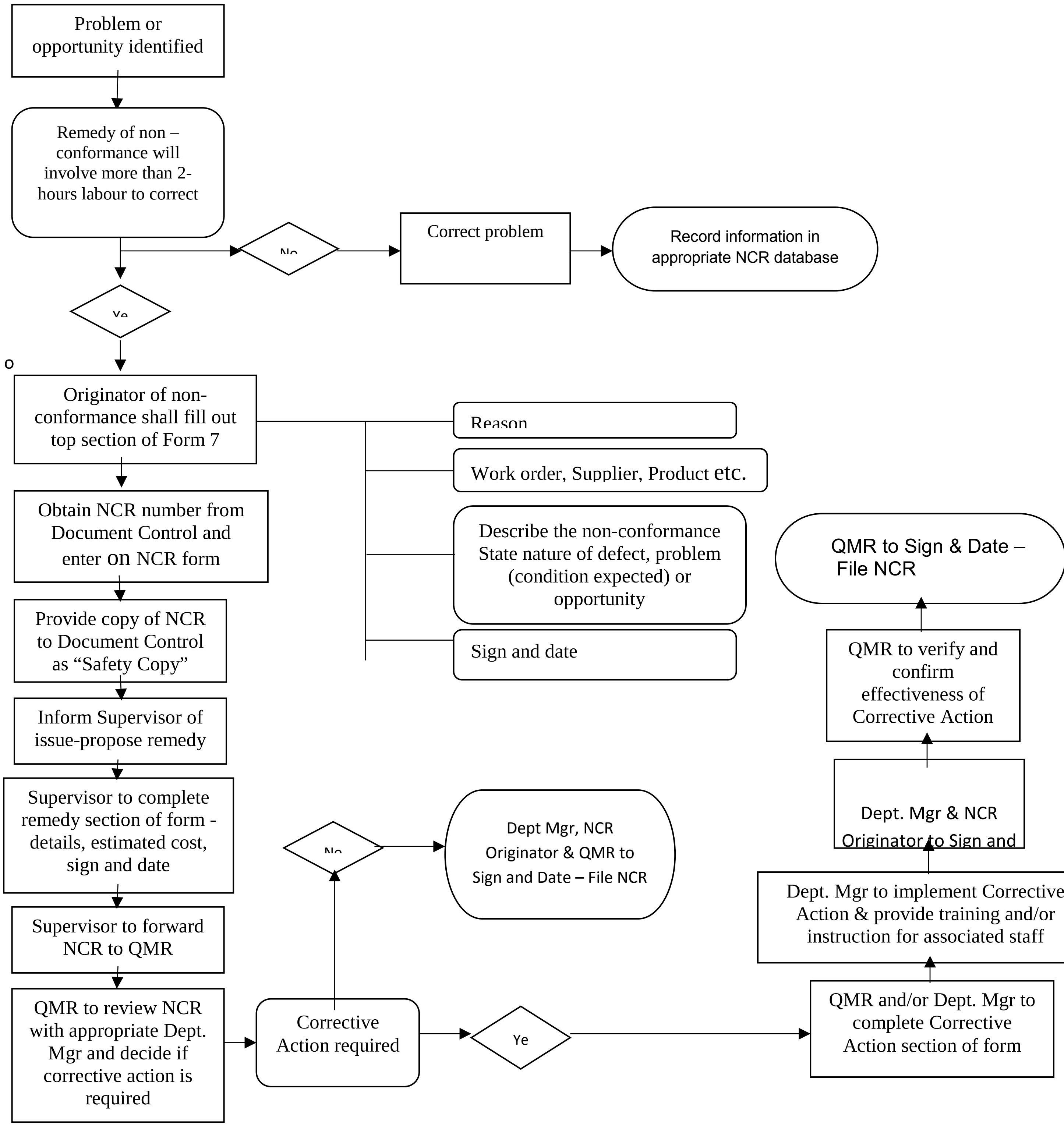
Preventive action opportunities may also be identified during the normal course of the working day by any person on the company. Personnel are encouraged to document the potential problem (opportunity) on the NCR form, checked as “OFI”. In such instance the CAPA process described below if followed.

The CAPA process:

The corrective (and preventive for issues identified via the NCR form) action process involves the use of “Form 7” which is annotated to indicate if the issue is corrective or preventive in nature.

The process, from initiation through to follow up, is described in the flow chart on the following page.

The flow chart below outlines the process to follow when completing a Form # 7.



Internal Audit

The following section describes the process for conducting internal audits. The internal audit process is controlled and directed by the Directory of Engineering & Operations. The Directory of Engineering & Operations assures that the audit process is orchestrated by competent personnel, either within STEI or sub-contracted. Audit planning activities assure that:

- Designated auditors are independent of the processes they audit.
- All processes indicated in the process flow charts in the “Process Interrelationships” section of this manual are audited at least once per year.
- Audit frequency of particular processes is adjusted to reflect the process status (I.E. new technology, new process, new personnel, detected level of compliance)
- Process review covers H &S requirements as stipulated in the H & S Manual.
- Audit plan is updated annually and may be adjusted through the year as process status warrants.
- Audit planning activities cover both ISO 9001 & 18001 based documentation and processes.

To prepare for an audit the auditor:

- Assures familiarity with the process to be audited
- Reviews associated policy, procedures, instructions or other relevant governing documentation
- Reviews previous audit results and any known performance issues.
- Prepares audit “memory joggers” or checklists. These may be in the form of printed copies of procedures; hand written prompts or whatever combination suits the style of the auditor. The above are used to guide the auditor through the audit to ensure the entire process is audited.

To conduct the audit the auditor:

- Interviews personnel, reviews associated files and records
- Summarizes results on form 201 (Audit Summary)
- Reviews the results with the leader of the audited process who also signs form 201

NOTE: Any non conformances or opportunities for improvement uncovered during the audit are to be recorded on the NCR/CAR Form (form 7). The corrective action process, described in the preceding section of this manual, then ensues. The Director of Engineering & Operations, or delegated audit coordinator, decides if the audit frequency needs to be adjusted for the subject process once the corrective measures have been verified.

“nonconformances” are defined as specific issues found that are contrary to stipulated expectations.

“opportunities for improvement” are defined as potential problems or weaknesses that would benefit from some improved method or approach (akin to “preventive action” described in the corrective and preventive action section)

Cross Reference Matrix to ISO 9001, 2008

ISO 9001, 2008 Clause reverence	Where or how addressed at STEI
4.1 General requirements	This manual and this matrix
4.2 Documentation requirements	This manual
4.2.1 General	This manual
4.2.2 Quality manual	This manual
4.2.3 Control of documents	Document control section this manual
4.2.4 Control of records	Records control section this manual
5.1 Management commitment	This manual and via regulatory compliance and performance reviews and management reviews
5.2 Customer focus	Follows: OEB Electricity Service Quality Requirements
5.3 Quality policy	Policy section this manual
5.4 Planning	This manual and related process definitions and organizational structure.
5.4.1 Quality objectives	OEB Electricity Service requirements, service quality data base.
5.4.2 Quality management system planning	This manual
5.5.1 Responsibility and authority	As defined in the organization chart linked to this manual and job descriptions referenced in this manual
5.5.2 Management representative	Director of Engineering & Operations—see “Roles & Responsibilities” section of this manual.
5.5.3 Internal communication	Regular departmental meetings (Customer Service, Engineering, Safety, Finance) are held by departmental leaders-approximately monthly—not less than 6 per year. Agendas are created and actions and/or minutes recorded.
5.6.1, .2, .3 Management review –input-output	Review meetings approximately 1/4ly—not less than 3 times per year. Standard Agenda prompts discussion on required subject matter
6.1 Provision of resources	
6.2.1 General	Resource requirements—human and physical, are subject of Management Review.
6.2.2 Competence awareness and training	Job descriptions exist for each position outlining responsibilities and qualification criteria. All employees have an annual review which includes identification of training or development needs and a review of the effectiveness of previous training. Any identified such needs are tracked, scheduled and prompted by the Executive Administrator who also tracks mandatory training such as WHIMIS reviews, first aid, fall arrest and related.

	NOTE: Apprentice programs exist for: Power Line Maintenance; Electricians & Meter Technicians. Personnel are advanced through the program per the program requirements, business needs and the collective agreement.
6.3 Infrastructure	Upgrades assessed and planned during annual capital budget planning process. Decided by the board. Reviewed and discussed at 1/4ly Management reviews.
6.4 Work environment	As above-also reviewed monthly by Health & Safety committee—see H&S Manual.
7.1 Planning of product realization	Process flows defined customer interface process also WI 7.3.2 relates.
7.2.1 Determination of requirements related to the product	At quote/service order stage—refer to above noted process flows and work instruction.
7.2.3 Customer communication	Customer Service Reps—CIS Database
7.3 Design and development	Engineering Department-standards & instructions, PRO 7.3
7.3.1 Planning	3 drivers for the process: Customer, Capitol Plan, Maintenance—all projects are defined on a list—reviewed regularly—progress reported on each project against timeline and budget.
7.3.2 Input	Regulatory: Ontario Reg 22/04 Customer Driven: via form 91 –WI 7.3.2 Capitol Plan: approved annually by the board-scope of project defined in plan Maintenance: reactive-inputs defined on WO
7.3.3 Output	Drawings & material list—see WI 7.3.1
7.3.4 Review	By Manager—WI 7.3.2
7.3.5 Verification	Per Reg 22/04
7.3.6 Validation	Per Reg 22/04
7.4.1 Purchasing process	See: Pro 7.4
7.4.2 Purchasing information	See: Pro 7.4
7.4.3 Verification of purchased product	See Pro 7.4
7.5.1 Control of product and service provision	Core processes are depicted flow chart—see “Process Interrelationship” section of this manual.
7.5.2 Validation for product and service provision	Not applicable-see stated exclusion in scope section of this manual.
7.5.3 Identification & traceability	WI 7.5.1 relates (electrical meter control)
7.5.4 Customer property	Main interaction with customer property is during provision of service. Any damage or problems reported via the CIS system and monitored per OEB requirements. Other customer property:
7.5.5 Preservation	WI 7.5.1 relates (electrical meter control)
7.6 Control of monitoring and measuring devices	See Pro 7.6 & W.I. 7.6.1

8.1 General-measurement, analysis and improvement	Management review of data & targets at 1/4ly (not less than 3 times per year) meetings.,
8.2.1 Customer satisfaction	Service delivery is monitored per OEB Electricity Service Quality Requirements. Customer feedback/input is garnered from Service Quality Database and reported at 1/4ly Management Meetings. Feedback is input to the database via general call ins, water heater surveys and sub-station feedback.
8.2.2 Internal audit	Internal Audit section this manual
8.2.3 Monitoring & measurement of process	Service quality database
8.2.4 Monitoring & measurement of product	Service quality database & OEB requirements report.
8.3 Control of nonconforming product	See NCP section of this manual.
8.4 Analysis of data	Reviewed at 1/4ly management meetings. CIS & ESQR data report generated monthly
8.5.1 Continual improvement	Via review and establishment/review/adjustment of targets at 1/4ly Management Reviews.
8.5.2 Corrective action	See CAPA section of this manual
8.5.3 Preventive action	See CAPA section of this manual

Document History Section:

Manual was rewritten October 2011 and released as revision “0”. The rewrite streamlined and consolidated procedures to simplify structure. Material changes to the control system were negligible. The most significant change related to the simplification of the document management process.

Jan. 31, 2012 – Completed final revisions to manual before implementation

May 8, 2012 – Updated ‘Process D: Meter Control Processes’ and ‘Process E: Move Out – Move In’

August 7, 2012 – ‘Process B: Order Entry Processes – 1’ create separate pages for Underground locates and New Residential Service flow charts, colour code and revise names of flow charts; ‘Process C: Order Entry Processes 2 – Meters and Others’, colour code flow chart and change name to ‘Process D: Miscellaneous Services’; revise ‘Process E: Move Out – Move In’ to clarify how water readings are obtained and change to Process F

APPENDIX C to Section 2.1

MANAGEMENT SYSTEM MANUAL – PART 2

St.Thomasenergyinc.

We're Your Local Power Distributor

MANAGEMENT SYSTEM MANUAL

Re-release: October 2011; Rev 0
Rev 1 -January 31, 2012
Rev 2- May 8, 2012
Rev 3- August 7, 2012
Rev 4– November 26, 2013

St.Thomasenergyinc. We're Your Local Power Distributor	St. Thomas Energy Inc.

Contents

St. Thomas energy inc.
We're Your Local Power Distributor

Driver Truck Log

Driver Responsibility

Notify Supervisor if less than 8 hours consecutive off-duty time prior to shift start

Employee	
Month	Year

Daily	Minimum 10 hours off duty – 8 hours consecutive Maximum 13 hours driving No driving after 14 hours on duty	**7 Day cycle rule**	No driving after 70 hours on duty All drivers require 24 consecutive hours off-duty in preceding 14 days
Work Shift	No driving after 16 hours elapsed from end of most recent 8 hours consecutive off period	**Emergency**	Responding to a situation, or impending situation, that constitutes, or could constitute, an imminent danger to life, property or the environment.

Odometer Reading: ____________

Date	Duty Status	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Totals
MONDAY	Off-Duty																									
	Driving																									
	On-Duty-Not-Driving																									
	Emergency-TroubleCall																									

Odometer Reading: ____________

Date	Duty Status	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Totals
TUESDAY	Off-Duty																									
	Driving																									
	On-Duty-Not-Driving																									
	Emergency-TroubleCall																									

Odometer Reading: ____________

Date	Duty Status	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Totals
WEDNESDAY	Off-Duty																									
	Driving																									
	On-Duty-Not-Driving																									
	Emergency-TroubleCall																									

Odometer Reading: ______________

Date	Duty Status	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Totals
	Off-Duty																									
THURSDAY	Driving																									
	On-Duty-Not-Driving																									
	Emergency-TroubleCall																									

Odometer Reading: ______________

Date	Duty Status	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Totals
	Off-Duty																									
FRIDAY	Driving																									
	On-Duty-Not-Driving																									
	Emergency-TroubleCall																									

Odometer Reading: ______________

Date	Duty Status	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Totals
	Off-Duty																									
SATURDAY	Driving																									
	On-Duty-Not-Driving																									
	Emergency-TroubleCall																									

Odometer Reading: ______________

Date	Duty Status	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Totals
	Off-Duty																									
SUNDAY	Driving																									
	On-Duty-Not-Driving																									
	Emergency-TroubleCall																									

Comments ____

____

FORKLIFT OPERATOR'S DAILY CHECK LIST

Date:	Operator:
Engine Hours:	

Indicate an X where a problem is detected and a check mark to indicate no problems visible

VISUAL INSPECTION		
1.	Rear Tire	
2.	Engine Compartment	
	Oil	
	Radiator	
	Air Filter	
	Fan Belt	
3.	Overhead Guard	
4.	Front Tire	
5.	Tilt Cylinder	
6.	Carriage	
7.	Fork Locking Pine (Left)	
8.	Fork (Left)	
	Attachment (If applicable)	
9.	Mast	
10.	Lift Cylinder	
11.	Lift Chains	
12.	Fork (Right)	
13.	Fork Locking Pin (Right)	
14.	Carriage	
15.	Tilt Cylinder	
16.	Front Tire (Right)	
17.	Hydraulic Oil	
18.	Battery Connections	
19.	Seat and Belt	
20.	Fire Extinguisher	
21.	Operators Compartment	
22.	Overhead Guard	
23.	Rear Tire (Right)	

OPERATIONAL INSPECTION		
A)	Listen for Unusual Noise	
B)	Check Parking Brake	
C)	Lifting Control	
D)	Tilt Control	
E)	Forward Driving	
	Accelerator	
	Steering	
	Braking	
F)	Reverse Driving	
	Accelerator	
	Steering	
	Braking	
G)	Lights	
H)	Horn	
I)	Gauges	
J)	Oil Spots of Floor	

COMMENTS:

All comments made in reference to any problems should be made on this page and handed to the supervisor immediately.

CAUTION: This is not a complete list of all items which may require attention. Operators are responsible for ensuring that the lift truck is in proper working condition in accordance with the manufacturer's specifications.

Signed:

DO NOT operate lift truck if problem is detected. Park truck, remove key and tag truck disabled.

honesty attitude respect teamwork

TAILBOARD CONFERENCE

Date:	Work Order #:
Supervisor:	Job Description:
Work Location:	

TRAFFIC CONTROL PLAN

1. **Volume of Traffic** ☐ Low (≤ 10 vehicles in a 3 minute period) ☐ High (> 10 vehicles in a 3 minute period)
2. **Work Duration** ☐ Mobile Operations ☐ Very Short Duration (up to 30 minutes) ☐ Short Duration (< 1 day) ☐ Long Duration (> 1 day)
3. **Reference to Book 7** Typical Layout – Figure TL# _______
4. **Protective Devices** ☐ Barricades ☐ Cones ☐ Blocker Truck ☐ Warning Signs ☐ Flashing Lights / Arrows
5. **Traffic Control Person** ☐ Yes ☐ No (Note: Person must be a trained TCP)
6. **Reviewed With Group** ☐ Rescue Methods ☐ Set Up Measures ☐ Removal

Traffic Protection Diagram (If Necessary)

HAZARD IDENTIFICATION

Environment – Have We Considered:

☐ Private Property	☐ Terrain	☐ Weather Conditions	☐ Non Standard Framing
☐ Proximity of Live Apparatus	☐ Suspect Insulators	☐ Climbing Hazards	☐ Broken Ties
☐ Pole Deterioration	☐ Locates	☐ Underground Utilities	☐ Adjacent Structures
☐ Cross Arm Deterioration	☐ #4/#6 Primary	☐ Locates	☐ Wood Pins

Equipment and Hardware – Have We Considered:

☐ Temporary Support of Pole	☐ Safe Loads for Rigging	☐ Vehicle Stability	☐ Climbing Hazards
☐ Proper Vehicle for Job	☐ Inspection of Tools and Equipment		

People – Have We Considered:

☐ Qualification of Personnel	☐ General Public	☐ Other Work Groups	☐ PPE

Procedures – Have We Considered:

☐ Isolation of Apparatus	☐ Need for Hold Off	☐ Limits of Approach	☐ Live Line Techniques
☐ Equipment Grounding	☐ Distribution Standards	☐ Safe Practice Guides	☐ Test for Isolation
☐ Back Feeds	☐ Cover Up	☐ Vehicle Ground	

Form 38 Issue 4

TAILBOARD CONFERENCE

Today's Tasks – Job Planning Worksheet

Major Job Steps	Associated Hazards	Applied Barriers
1		
2		
3		
4		
5		
6		
Hold Offs Feeder # ____ _____ Established ____ _____ Surrendered ____ _____	**Work Protection Req'd** Work Protection _________ Self _________	**Boom Current Leakage Test Req'd** No _____ Yes _____ Reading ______

Supervisor Site Visit

Time _________

Initial _________

Talk about the job
Assign specific tasks
Identify Hazards
Let crew know what is expected
Beware of changes
Observe all safety rules
Allow time to complete the job
Review protective equipment
Determine if crew members understand their duties

honesty attitude respect teamwork

CREW SIGN OFF

1. I was present during the tailboard discussion
2. I understand the job plan and tasks assigned
3. I can perform the task assigned
4. I agree with the job plan

PRINT NAMES	SIGNATURE
Person in Charge:	

Form 38 Issue 4

St. Thomas Energy Inc.

DAILY VEHICLE & EQUIPMENT INSPECTION

Period From: (Date) ____________________ To (Date) ________________________

Type of Vehicle _________ Make of Chassis ___________ Vehicle # _____ Odometer __________ Hrs ________

Date: _________ Time: ________ Inspection Person Name: _______________ Signature: ____________________

Date: _________ Time: ________ Inspection Person Name: _______________ Signature: ____________________

Date: _________ Time: ________ Inspection Person Name: _______________ Signature: ____________________

Date: _________ Time: ________ Inspection Person Name: _______________ Signature: ____________________

Date: _________ Time: ________ Inspection Person Name: _______________ Signature: ____________________

CHECK ALL ITEMS AND NOTE ANY DEFECTS: S = SATISFACTORY U = UNSATISFACTORY

	M	T	W	T	F		M	T	W	T	F
1. Oil Level						14. Battery Connections					
2. Coolant Level						15. Belts					
3. Power Steering Fluid						16. Leaks					
4. Washer Fluid						17. Mirrors					
5. Lights and Flashers						18. Towing Attachments					
6. Tires						19. Air Brake Tank(s)					
7. Suspension						20. Wheel Chocks					
8. Parking Brake						21. Air Pressure					
9. Brake Failure Warning						22. Warning Signal/Low Air					
10. Horn						23. Heater/Defroster					
11. Fire Extinguisher						24. First Aid Kit					
12. Fuel						25. All Gauges					
13. Seat Belts						26. Windshield Wipers					

AERIAL DEVICES **RADIAL BOOM DERRICKS**

	M	T	W	T	F		M	T	W	T	F
1. Hydraulic Oil Level						1. Hydraulic Oil Level					
2. Reservoir Breather Cap						2. Reservoir Breather Cap					
3. Bucket Leveling System						3. Winch Cable/Rope					
4. Boom, Bucket(s) & Liner(s)						4. Welds, Pins & Bolts					
5. Welds, Pins & Bolts						5. Outriggers & Pads					
6. Outriggers & Pads						6. Grounding Lead/Clamp					
7. Grounding Lead/Clamp						7. Auger Stow Cable					
8. Jib, Winch & Rope						8. Auger Teeth & Point					
9. Current Leak Reading						9. Manual Auger Locking Pins					

	Operator's Initials	Comments:	Foreman's Initials
M			
T			
W			
T			
F			

Foreman's Signature: ______________________ Date Repairs Completed: ______________________

Form 67 Issue 3

DAILY HYDRAULIC UNIT SYSTEM CHECK

(ALL BUCKET AND RBD TRUCKS)

PERIOD: FROM ________________________ TO ________________________

OPERATOR ______________________________ UNIT ______________________________

COMPLETE THESE CHECKS AT THE JOB SITE PRIOR TO FIRST DAILY USE. NOTE: FOR EACH MOTION CHECK, HOLD FOR 15 SECONDS. NO MOTION SHOULD BE VISIBLE. ENGINE RPM SHOULD BE MINIMUM 1,000.

CHECK ALL ITEMS AND NOTE ANY DEFECTS: S = SATISFACTORY U = UNSATISFACTORY

M	T	W	T	F	
					1. POSITION TRUCK IN WORKING LOCATION
					2. ENGINE PTO AND WARM-UP
					3. CHECK HYDRAULIC OIL LEVEL
					4. CHECK BUCKET(S) – ARE THEY SECURE? ARE THERE ANY CRACKS?
					5. OUTRIGGER CONTROL AND HOLDING VALVES:
					- LOWER ALL OUTRIGGERS AND LEVEL TRUCK
					- DISENGAGE PTO
					- OPERATE ALL OUTRIGGERS CONTROLS UP & DOWN AND CHECK MOTION
					6. CHECK HYDRAULIC SELECTOR VALVE:
					- SWITCH TO MAINFRAME, TRY TO RAISE OUTRIGGERS
					- SWITCH TO OUTRIGGERS, TRY TO RAISE BOOM
					7. BUCKET TRUCK CONTROLS AND HOLDING VALVES:
					- USE LOWER CONTROLS ONLY
					- OPERATE ALL FUNCTIONS: LOWER BOOM UP/DOWN, UPPER BOOM FOLD/UNFOLD, ROTATION CW/CCXW
					- PLACE LOWER BOOM OFF REST, PLACE UPPER BOOM JUST OFF REST
					- DISENGAGE PTO
					- TRY TO FOLD UPPER BOOM – CHECK MOTION
					- TRY TO LOWER LOWER BOOM – CHECK MOTION
					- PLACE LOWER BOOM ON REST, PLACE UPPER BOOM AT 180° TO LOWER
					- DISENGAGE PTO
					- TRY TO UNFOLD UPPER BOOM – CHECK MOTION
					- RAISE LOWER BOOM TO 80°, UNFOLD UPPER BOOM TO HORIZONTAL
					- DISENGAGE PTO
					- TRY TO RAISE LOWER BOOM – CHECK MOTION
					8. RBD BOOM CONTROLS AND HOLDING VALVES:
					- OPERATE ALL FUNCTIONS: BOOM UP/DOWN, EXTEND/RETRACT, WINCH OUT/IN
					- RAISE BOOM TO 60°, EXTEND BOOM PARTIALLY
					- DISENGAGE PTO
					- TRY TO RETRACT – CHECK MOTION
					- TRY TO LOWER – CHECK MOTION

	Operator's Initials	**Comments:**	**Foreman's Initials**
M			
T			
W			
T			
F			

Foreman's Signature: ________________________ Date Repairs Completed: ________________________

Form 67 Issue 3

St. Thomas energy inc.
We're Your Local Power Distributor

DATE : ____________________

DAILY OPERATIONS LOG

Answering Service Checked for Messages ◎

Weather: AM ________________ ____°C

PM ________________ ____°C

Troubleman on Duty ______________________

TIME	EMPLOYEE or CUSTOMER	TRUCK	LOCATION	DETAILS OF WORK	FEEDER	Hold off Established	Hold off Surrendered

TIME	DETAILS OF WORK

CREW LOCATIONS

TIME	EMPLOYEES	TRUCKS	LOCATION	DETAILS OF WORK

TEMPERATURE READINGS - HOT/COLD WEATHER PLAN

EMPLOYEE	TIME	TEMPERATURE	OPERATOR	EMPLOYEE	TIME	TEMPERATURE	OPERATOR

CALL FORWARDING ESTABLISHED & TESTED ◯

AFTER HOUR MESSAGES FROM PREVIOUS NIGHT(S): ◯ YES (messages attached) ◯ NO

Form 55 Issue 3

St. Thomas energy inc.

We're Your Local Power Distributor

HEALTH and SAFETY POLICY and PROCEDURES MANUAL

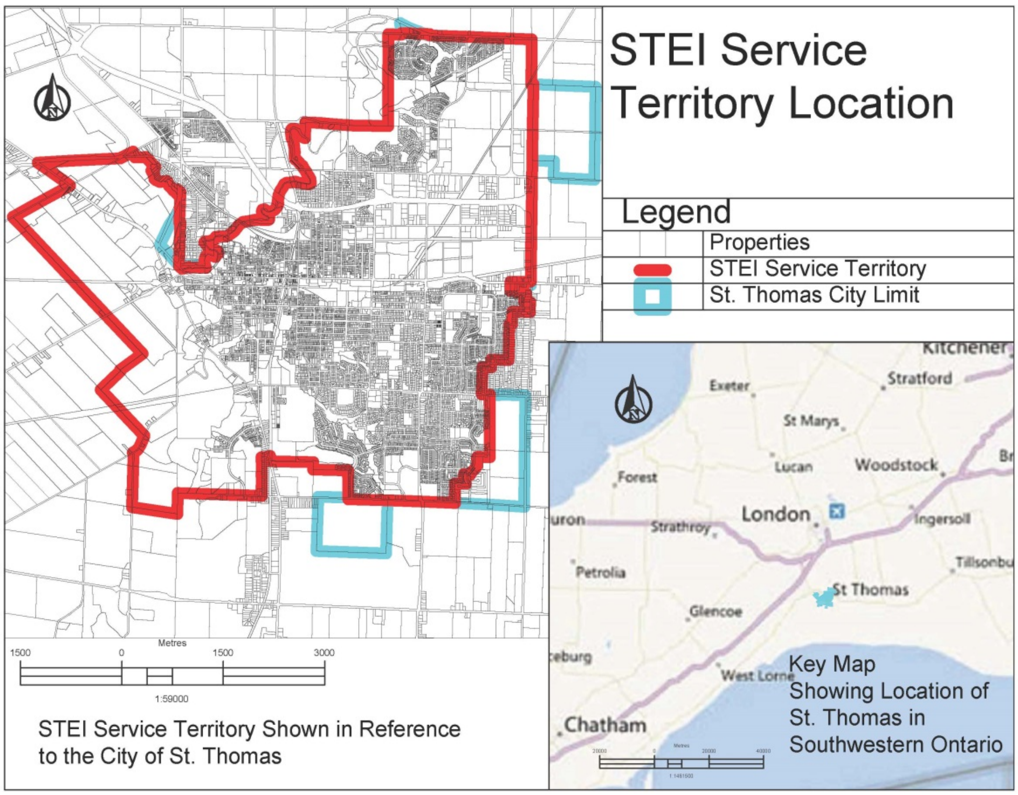
TABLE OF CONTENTS

Section

2.2 Overview of Assets Managed (Ch.5.3.2)

Geographic Location

The City of St Thomas is located in Southwestern Ontario approximately 10 km north of Lake Erie and 5 km south of the municipal boundaries of the City of London. STEI's franchise area is primarily contained within the municipal boundaries of the city of St. Thomas and is about 33 square km in area. STEI is largely an urban service territory, though it does service some rural areas as shown in the following map.



a) Distribution Service Territory Features

Temperature and Weather

The load forecasting equations used to normalize and forecast STEI's weather sensitive load use monthly heating degree days and cooling degree days as measured at London to take into account temperature sensitivity. Environment Canada defines heating degree days and cooling degree days as the difference between the average daily temperature and 18°C for each day (below for heating, above for cooling).

This area has a humid continental climate according to the Köppen climate classification system. A humid continental climate is a climatic region typified by large seasonal temperature differences, with warm to hot (and often humid) summers and cold (sometimes severely cold) winters. In summer July has an average temperature of 20.8 °C, and temperatures above 30 °C occur on average 7 days per year. In 2012, however, temperatures at or above 30 °C occurred a total of 27 times. This area is affected by thunderstorms more than any other location in Canada. Annual precipitation averages about 101 centimeters, and winter snowfall totals are heavy, averaging 194 centimeters per year.

Economic Growth

Excerpts from the St. Thomas & District Chamber of Commerce, Regional Economic Outlook – London, obtained via web on March 18, 2014:

> "Economic indicators paint a mixed picture but essentially one of a slow growing economy continuing to adjust to considerable challenges in its manufacturing base. With this key export sector providing a smaller boost to the domestic economy, consumer and housing activity have down-shifted though federal government policy changes to reduce mortgage insurance availability have also contributed to housing's sluggish performance.
>
> Economic growth will remain below average through 2014 and into 2015, held down by weak gains in consumer spending, personal income and residential investment as well as declining government investment and spending. Slow population growth through 2015 as net in-migration remains subdued due to relatively high unemployment. Business investment in plant and equipment expands fairly robustly with manufacturing and other firms seeking efficiencies and adapting to changing market conditions. Industries contributing most to economic growth through 2015 are manufacturing, professional-scientific-managerial services, finance-insurance-real estate services and retail-wholesale trade. Public administration, accommodation-food services and construction contribute only marginally to forecast growth. Education services output declines slightly with the school-aged population.
>
> Population growth will remain sluggish through 2015 and will not accelerate noticeably until more plentiful job opportunities emerge. The regional economy continues to grind out of its most severe recession since the early 1980s. Total employment is well above its 2009 recession low but remains below pre-recession levels. Job growth will pick up slightly in 2014 but remains modest through 2015, with most of the increases in health-social services, retail-wholesale trade and various other service industries. Manufacturing employment will do well to hold at current levels. Construction employment is range-bound. The forecast unemployment rate declines to 7.6 percent in 2015 from 8.1 percent in 2013. The declining labour force participation rate observed during and since the recession lowered the measured unemployment rate, despite

modest job growth. An upshift in the participation rate due to improving job opportunities could result in a higher unemployment rate or one that does not decline significantly.

Housing sales and prices see modest growth while housing construction remains range-bound. Private sector investment in non-residential building construction, mostly stores and offices, is forecast to expand. Public sector investment continues to shrink in the short term, reversing the post-recession fiscal stimulus."

Customer Base

As of December 2013 the customer breakdown within the STEI franchise area consists of 14,828 residential customers, 1,862 commercial/industrial customers, 2 sentinel light accounts and 2 streetlight accounts. The commercial/industrial customers are further divided into 1,720 General Service customers less than 50 kW of demand and 142 General Service customers greater than 50 kW.

b) Description of the System Configuration

STEI's distribution system is supplied by Hydro One Networks Inc ("HONI") primarily from Edgeware TS at a voltage level of 27.6 kV. There is one remaining industrial customer that is supplied power from St Thomas TS at a voltage level of 13.8 kV.

As of March 2014, STEI has a total of 252.18 circuit kilometers of primary wire and underground cable installed of which 148.67 km, or 59%, is overhead. The table below shows the breakdown by voltage class for both overhead & underground primary.

Primary Wire

Underground Cable

Length of Overhead & Underground Primary Wire and Underground Cable by Voltage Class.

	Overhead (km)			**Underground (km)**		
Voltage Class	**3 Phase**	**2 Phase**	**1 Phase**	**3 Phase**	**2 Phase**	**1 Phase**
17 - 40 kV	81.11		24.55	10.77		86.78
6 - 16 kV	6.93		3.43	1.06		
1- 5 kV	26.44	6.21		4.07	0.83	
Totals	114.48	6.21	27.98	15.90	0.83	86.78

The distribution system has 6 municipal substations remaining used to step down voltage from 27.6 kV to 2.4 kV for the old 2.4kV delta distribution system. There is a 10 year plan in place to convert the 2.4kV delta distribution system to 27.6kV, which when complete will eliminate the municipal substations from the system.

c) Service Profile: Age and Condition of Assets

The following tables show a listing of the main assets, aside from wire and cable, employed in the distribution system.

		Distribution by Age (years)				
Asset Category	**Population**	**0 - 19**	**20 - 29**	**30 - 39**	**40 - 44**	**45 +**
Substation Transformers	6			6		
Pad-mount Transformers	563	412	140	8	2	1

Substation Transformer

Pad-mount Transformer

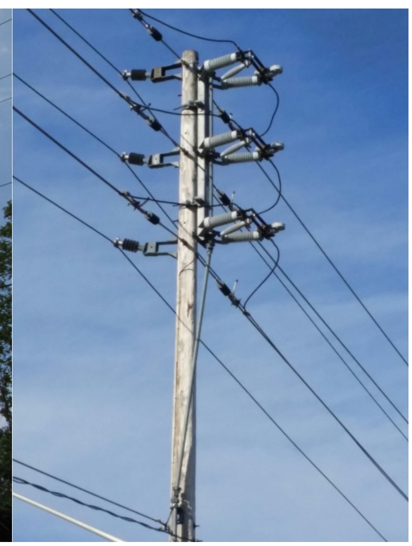
		Distribution by Age (years)				
Asset Category	**Population**	**0 - 19**	**20 - 29**	**30 - 39**	**40 - 44**	**45 +**
Pole-mount Transformers	868	351	383	40	35	59
Distribution Poles	4824	1782	905	371	190	1576
Overhead Switches *	113	42	9			

* Age data not available for 62 Overhead Switches

Pole-mount Transformers

Distribution Poles

Overhead Switch



STEI monitors the status of all four 27.6 kV feeders that supply its service territory and all 2.4 kV municipal substation feeders from a SCADA facility located in the main office. This helps STEI respond to power system interruptions in an efficient manner.

d) Capacity Utilization of Existing System Assets

Power Supply Configuration

St. Thomas Energy's distribution system is supplied by Hydro One's Edgeware Transformer Station at the north east corner of the City. Edgeware Transformer Station is supplied by two 230KV transmission lines. Presently there are nine 27.6 kV distribution feeders supplied by Edgeware Transformer Station. The Substation is designed for 12 feeder positions. Based on the summer transformer limited ten day rating (LTR) each feeder position can be allocated a load capacity of: 198 MW / 12 = 16.5 MW per feeder.

St. Thomas Energy owns six feeders. Four are used to supply the City of St. Thomas and two are used to supply the Formet Plant. The two feeders that are used for the Formet Plant are dedicated to that plant and cannot be used to supply the city.

Under emergency situations, feeders can be loaded up to about 25 MW, which will allow the maximum capacity of 4 feeders (66 MW) to be supplied by only 3 feeders. St. Thomas Energy's design criteria is to be able to supply the allocated capacity of 4 feeder (66 MW) with only three feeder without significantly affecting the supply to the city.

St. Thomas Energy Feeder Loading Criteria

Edgeware Transformer Station Loading Criteria is based on the capacity of the high voltage 230 kV transmission lines supplying it and on the 230 kV power transformer's limited ten day rating (LTR).

Edgeware Transformer's limited ten day rating (LTR):

- Transformer Rating (No Fans & Pumps/Fans/Fans &Pumps): 75/100/125 MVA
- Summer Limited Ten (10) Day Rating (LTR): 198 MW
- Winter Limited Ten (10) Day Rating (LTR): 216 MW

If the capacity for Edgeware TS is based on the rating of only one transformer with the second transformer for redundancy in case one fails or has to be taken out of service for maintenance, the maximum capacity limited ten day rating (LTR) for summer is 198MW and for winter is 216MW

Base on the summer transformer limited ten day rating (LTR) each feeder position can be allocated a load capacity of: 198MW/12 = 16.5MW per feeder.

Under normal operating conditions, all four of St. Thomas Energy's 27.6KV feeders are configured to be less than 10 km in length. Each of the four main feeder back bones are made up of 336 AL, 556 AL and some 795AL near the transformer station. There are some 4/0 CU sections that can be considered equivalent to 336 AL.

The taps or loops connected to the main feeders are limited to about 2 km in length. A tap is basically a radial connection to the main feeder and a loop is a tap that can have either end connected to the main feeder. Only one of the loop ends is normally connected to the main feeder. For the purposes of determining feeder capacities, taps and loops can be considered a load at the point that they are connected to the main feeder. Overhead 27.6 kV taps and loops are typically 3/0 ACSR and underground loops are typically 2/0 AL cable. Loading for 27.6 kV overhead taps are limited to about 100 Amps. Loading for underground 27.6 kV loops are limited to about 60 Amps (twenty 50KVA single phase pad-mounted transformers (1000 kVA) per single phase loop).

The operating voltage at the Edgeware TS is typically 3% above a nominal value of 27.6 kV which is about 28.4 kV. The maximum allowable voltage drop at the end of a feeder is about 3% below the nominal value of 27.6 kV which is about 26.8 kV. This is a total voltage drop of about 6%.

For the purpose of determining feeder capacity, it is assumed that the feeder conductor size is completely made up of 336 AL and a load of 16.5 MW 335 amperes is at the end of the feeder. For the voltage to drop 6% at the end of the feeder, the feeder can be 8.6 kilometres long. If the load was equally distributed along the feeder, the feeder can be about twice as long at about 17.2 kilometers. Since the load is never really equally distributed along a feeder, the length can be estimated to be somewhere between 8.6 km and 17.2 km which is about 12.9 km.

The maximum manufactures thermal rating for 336 AL for conductor temperature of 75 degrees Celsius, ambient temperature 25 degrees Celsius in the sun, emissivity 0.5, wind speed 2.2 km / hr. is about 510 amperes. For a 500 ampere or 25 MW load with a 6% voltage drop at the end of the feeder, the feeder can be 5.8 km long if all the load is at the end or 11.6 km if the load is equally distributed along the feeder. Since the load is really never equally distributed along a feeder, the length can be estimated to be somewhere between 5.8 km and 11.6 km which is about 8.7 km.

Under emergency situations or planned maintenance outages, feeders can be loaded up to about 25 MW or 500 amperes, which will allow the maximum capacity of 4 feeders (4 x 16.5 MW = 66 MW) to be supplied by only three feeders. St. Thomas Energy's design criteria is to be able to supply the allocated capacity of four feeder (66 MW) with only three feeders without "significantly" affecting (there may be some reduced voltages) the supply to the city.

As long as St. Thomas Energy's peak demand does not exceed 66 MW, the design criteria is satisfied. When peak demand is projected to exceed 66 MW, St. Thomas Energy will apply to Hydro One for a new feeder position at Edgeware Transformer Station.

Fault current levels at Edgeware TS are approximately 12,500 amperes. For more detail fault current levels, please refer to Hydro One's Threshold CIA Reports Number 20740 and Number 21350. The fault levels along the feeders start dropping off the further downstream from the transformer station. At the end of the feeders about 10 km from the Transformer Station the fault current drops of to about 3000 amperes

2.3 Asset Lifecycle Optimization Policies and Practices (Ch.5.3.3)

a) Lifecycle policies and practices

The application of lifecycle optimization policies and practices is an essential component of STEI's Asset Management Process. STEI's recently-developed asset lifecycle optimization policies and practices are attached as "Appendix A to Section 2.3" of this DS Plan. The policies are currently being evaluated for their day-to-day practicality and are therefore shown as "draft".

The analysis of the data in STEI's Inspection Program supports STEI staff in exercising good judgment when assessing items of concern resulting from the "annual" inspection process. (While usually referred to as an annual event, some equipment is inspected more frequently while other equipment is on a longer inspection cycle.) The recommendations for major asset refurbishments or replacements are made by the senior engineering and operations personnel to senior management in consideration of all the available information including the inspection information, the capital and repair cost implications, the resulting reduction in O&M costs, the high-level guidance provided by the asset lifecycle optimization policies and practices and the potential effect on customers' bills.

The purpose of such an inspection program is to determine asset condition, identify any risk to safety, reliability and/or the environment and subsequently address findings through prudent capital, operations and maintenance expenditures, as necessary. STEI carried out a system wide Asset Condition Assessment and the report was presented as part of its 2010 Electricity Distribution Rate Application. A subsequent Asset Condition Assessment report was performed by Kinectrics Inc. in 2011 with the report being issued in June 2012. This is used to support the annual Asset Management Plans. The inspection cycles and patrol inspections for each of the major distribution facilities are described the table below. STEI aims to meet or exceed these requirements.

STEI considered updating the report in preparation for this DS Plan but concluded because of the minimal change in overall condition of its equipment that would be expected during a 1 to 2 year period, this would not be a prudent expenditure.

The Asset Condition Assessment is attached as "Appendix B to Section 2.3" of this DS Plan.

FEEDER/EQUIPMENT	CYCLE	METHOD
Overhead Circuits - 27600/16000V System	Annual	Infrared Thermographic Survey & Visual Inspection
Overhead Circuits - 27600/16000V System – Backyards	3 Years	Visual Inspection
Overhead Circuits - 13800V System	Annual	Infrared Thermographic Survey & Visual Inspection
Overhead Circuits – 4800/8320V System	3 Years	Visual Inspection
Overhead Circuits - 2400V System – Backyards	3 Years	Visual Inspection
Load Interrupter Switches	Annual	Infrared Thermographic Survey
Load Interrupter Switches	5 Years	Preventative Maintenance
Distribution Station	Monthly	Visual Inspection
Distribution Station	2 Year	"Gas in Oil" Analysis
Distribution Station	2 Year	Substation Inspection & Cleaning
Distribution Station Pot-head Risers	Annual	Infrared Thermographic Survey & Visual Inspection
Transformers (Padmount) – Three Phase	3 Years	Infrared Thermographic Survey & Visual Inspection
Transformers (Padmount) – Single Phase	3 Years	Visual Inspection
Transformers (Polemount)	3 Years	Infrared Thermographic Survey & Visual Inspection
Padmounted Switchgear & Junctions	3 Years	Infrared Thermographic Survey & Visual Inspection
Poles & Structures	3 Years	Visual Inspection
Poles & Structures	5 Years	Wood Rot Test
Vegetation Management	3 years	Tree trimming Brush clearing

- **Wood pole testing and replacement**

  STEI has taken a proactive approach to the testing and replacement of wood poles; the testing uses specialized test equipment. Defective poles are identified for replacement and critical poles are replaced immediately with a high priority placed on those equipped with transformers or underground cable connections.

- **Infrared Thermography of the Overhead system and Municipal Substations**

  Annual inspection and scanning of the overhead system and substations is an important and very effective part of a STEI's preventative maintenance program.

- **PCB Testing and Replacement of Distribution Transformers**

  STEI has approximately 1,440 distribution transformers within its system. As a result of environmental legislation, only those units manufactured prior to 1980 are candidates for PCB contamination. STEI had tested all its transformers and those with PCB content over the legal threshold have now been replaced in accordance with the legislation.

- **Tree Trimming**

  STEI's tree trimming is completed in accordance with its established 3 year cycle; this is usual utility practice.

- **Vault Inspection and Cleaning**

  Customer owned vaults that contain STEI distribution equipment are inspected with an eye on condition of equipment, operational and public safety.

By preparing periodic Asset Condition Assessment reports STEI is able to track the performance of its distribution system and review recommendations for maintenance and capital expenditures. This often results in a re-prioritization of activities and investments based on the most recent performance data.

Similarly, while pole replacements are a continuous requirement due to the population age, the results of the pole testing can re-prioritize expenditures by accelerating or decelerating the program accordingly.

STEI's recently-developed asset lifecycle optimization policies and practices are attached as "Appendix A to Section 2.3" of this DS Plan.

The policies are currently being evaluated for their day-to-day practicality and are therefore shown as "draft".

- Policy on System Access, Renewal and Service Investments,
- Policy on the Evaluation of Asset Replacement and Refurbishment, and
- Policy on Optimal Maintenance Planning Practices.

This set of documents addresses how, among other factors, system renewal spending is optimized, prioritized and scheduled within budget envelopes together with the impact on routine O&M; maintenance planning criteria and assumptions; and risk assessment and mitigation.

b) Lifecycle risk management

STEI regards risk identification and mitigation as an integral part of its asset lifecycle optimization activities. Consequently, rather than having a separate set of risk management policies and practices to address risk, STEI has fully integrated risk management considerations into the set of three formal policies and practices just identified.

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APPENDIX A to Section 2.3

ASSET LIFECYCLE OPTIMIZATION POLICIES AND PRACTICES

DRAFT

St. Thomas Energy Inc.

Asset Lifecycle Optimization Policies and Practices

Purpose

The purpose of these policies and practices is to provide direction to St. Thomas Energy Inc. (STEI) staff when they are acquiring and maintaining assets in order to provide service at required performance standards; the goal is to ***minimize the overall cost to STEI customers***

Introduction

The lifecycle cost for an asset includes, but is not limited to, the acquisition, operating, maintenance, disposal, refurbishment and replacement costs over the lifetime of the asset.

The required performance standards include both the technical performance standards necessary for the asset to correctly perform its inherent task (e.g. for distribution system equipment this would include meeting reliability and power quality standards among others) together with other mandatory and required performance standards[1] (e.g. system and physical security, environmental, etc.).

The asset's optimal lifecycle cost is the minimal total cost over the long-term of acquiring, maintaining and utilizing the assets. Establishing the true optimal lifecycle cost for any specific asset is a very complex exercise and requires substantial amounts of data that are not always available. Consequently, as a practical consideration, the policies and practices set out in this document provide direction for STEI staff to minimize refurbishment and replacement costs collectively, and to separately minimize maintenance costs; all this is done while meeting required minimal performance standards.[2] As STEI continually refines its industry-leading expertise in establishing optimal practices, the directives in this document will, from time to time, be revised to reflect that expertise.

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[1] Unless there is inherent value to the customer by STEI exceeding the required *minimal* performance standards (i.e. the enhanced performance standard is something the customer would willingly pay for), then no additional value can be attributed to this factor in the cost analyses described in this document.

[2] The overall optimum for a system is not necessarily the sum of the optima for the individual sub-systems. Thus, the overall minimal lifecycle cost is not necessarily achieved by separately achieving the sum of the minimal long-term refurbishment and replacement cost, and separately achieving the minimal long-term maintenance cost. Nevertheless, because of the disparity in the magnitude of costs involved together with practical considerations, this sub-optimization is considered to be a reasonable approximation at this time.

Policy on System Access, Renewal and Service Investments

Purpose

The purpose of this policy is to ensure that in making system access, system renewal and system service investments, STEI staff appropriately optimizes, prioritizes and schedules the candidate investments consistent with the available budget envelopes.

Details of the Policy

a) *Optimizing Lifecycle Costs*

When contemplating significant expenditure decisions, STEI staff shall:

- Perform the selection decision in recognition of the fact that the goal of STEI's asset lifecycle optimization policies and practices is *to strike the best balance from the customers' perspective.* This is acknowledgement that it is the customer who ultimately pays for the assets and receives the associated benefits.
- Consider the full lifecycle cost of all the practical and reasonable alternatives that could meet the identified need.
- Seek to identify the alternatives that comply with all design, construction and safety standards and has the lowest lifecycle cost. The expected lowest lifetime cost will be *one* of the factors considered when making the ultimate decision.
- Use the most accurate quantitative and qualitative information available to them when making their analyses and in coming to their determination, will use both corporate and individual staff's technical knowledge and experience and, most importantly, will use their *professional best judgment*.
- Give careful consideration to the possibility of refurbishing existing facilities rather than replacing them and thus seek to achieve lifecycle cost optimization. (The attached STEI document ***"Policy on the Evaluation of Asset Replacement and Refurbishment"*** provides specific direction to staff faced with a replacement/refurbishment decision.)
- Consider lease options when viable.
- Ensure pertinent information is recorded and added to the database of information so as to be available for future lifecycle optimizing analyses.

b) *Prioritizing Expenditures*

In deciding which expenditures should be made within the established budget envelope, STEI staff shall pay particular consideration to the following:

Legislated and Mandatory Requirements

- The company's legislated and mandatory requirements including:
    - System access in order to meet the obligation to connect customers.
    - Accommodating City, Region, Ministry, etc. mandatory projects.
    - The Green Energy Act.

  - The company's CDM conditions of license.
  - Meeting the OEB's – and other regulatory bodies' – quality, reliability, health, safety, environmental, etc. performance standards.

Maintenance of Current Standards

- Safeguarding major investments already made by continuing to maintain and perform essential upgrades in order to keep the systems reasonably current.
- Intensify condition monitoring where practical in order to minimize uncertainty regarding decisions relating to equipment maintenance, renewal and replacement.
- Refurbish distribution equipment in-situ where economically viable in order to extend the equipment's reliable working life.
- Just maintaining current reliability levels where minimal required standards are already being met.

Investments

- Leverage additional supply capacity etc. by utilizing investments previously made.
- Invest in opportunities to permit early harvesting of operational efficiency improvements from established investments.
- Consider the lifecycle cost of all reasonable alternatives in decisions regarding replacement vs. refurbishment.
- Continue to invest prudently in modern information technology in order to improve both customer service and communications with customers.
- Prudently acquire smart grid equipment where the need has been established and there will be direct economic/efficiency benefits.

Affordability

- To the extent that funding is available, consider accelerated replacement of critical over-aged items for that equipment where the optimal life has already been reached.
- Acknowledge that some desirable investments are realistically not immediately affordable within the budget envelope.

c) Scheduling Investments

Having performed the required in-depth analyses and having decided on the investments that are to be pursued, careful attention must be given to scheduling the selected expenditures.

- Seek to schedule investments in such a way so as to minimize year-to-year fluctuations in total expenditure and thus minimize fluctuations in customers' rates; this scheduling should be utilized to the extent that quality of service will not suffer, legislated and mandatory requirements are met, and that other key factors have been considered.
- Consider implementing the highest priority investments early in the period in order to protect these investments from an unforeseen funding shortage later in the year. This is in

recognition that despite the best planning, unexpected and unfunded contingencies can arise that demand funding priority. In such situations, some planned expenditures in the year may require to be cancelled in favour of the new contingency.

DRAFT

Policy on the Evaluation of Asset Replacement and Refurbishment

Purpose

The purpose of this policy is to ensure that in determining whether a major item of equipment should be replaced or refurbished, STEI staff has an accurate understanding of the lifecycle costs of the various alternatives available.

Details of the Policy

When determining whether a *major* item of equipment should be replaced or refurbished, STEI staff shall:

- Perform an economic evaluation (sometimes called a cost comparison) on the various alternatives that meet the technical needs. For the purpose of this Policy, a major item of STEI equipment is deemed to be an item of equipment costing $50,000 or more. (This threshold follows from the definition of a *material investment* as contained in OEB Filing Requirements.)
- Fully justify selecting any alternative with a lifecycle cost that is higher than the minimal lifecycle cost alternative.
- Conduct the economic evaluation using established costing and economic evaluation principles.
- Perform the economic evaluation over a sufficient number of years so that all the significant costs are identified and captured in the comparison of costs.
    - The period over which the comparison will take place will generally be the expected life of a new item of the subject equipment.
    - If there are other replacement equipment options that are expected to have a longer life than a new version of the equipment being considered for replacement, then consideration should be given to choosing a longer comparison period.
    - In the relatively rare circumstance that the equipment is not expected to be needed for the full duration of its life (and therefore may be sold or scrapped after the period it is needed for), then the shorter period for which the equipment will be needed should be selected.
- Give consideration in the economic evaluation to all reasonable alternatives that, as a minimum, meet the required performance standards.
    - Every effort should be made to include as the base case, a “do nothing” alternative; that is, the existing equipment is envisaged as being maintained with minimal investment for the selected duration without replacement or substantial refurbishment. (While in many circumstances this may not be a truly practical

alternative nor may not result in the minimal cost alternative even if it is practical, it nevertheless provides a reference point in the decision making process.)
    - In addition to the base case, at least one replacement alternative and one refurbishment alternative shall be included if such options are physically possible and practical.
- Factor in the full lifecycle costs for every alternative into the evaluation. The lifecycle cost will include but not be limited to:
    - Removal and sale (or scrap) of existing equipment together with any site reclamation.
    - Purchase of new replacement equipment.
    - Refurbishment of the existing equipment. (During a long evaluation period it may be necessary to include more than one refurbishment.)
    - Lifetime operating and maintenance.
    - At the end of evaluation period, the removal and sale (or scrap) of refurbished/new equipment together with any site reclamation.
- Ensure the legitimacy of any indirect costs or attributing monetary benefits to superior performance of any alternative.
- Discount cash flows using time-value-of-money factors provided by the Accounting Department.

DRAFT

Policy on Optimal Maintenance Planning Practices

Purpose

The purpose of this policy is to ensure that STEI assets are maintained in an appropriate condition to perform their intended purpose and that they are maintained in such a way that the selected balance of preventive and repair maintenance minimizes cost to the customer.

The optimal degree of maintenance is that which strikes the best balance between the cost of STEI performing work on an asset in order to prevent a possible failure, and the cost and consequences of a failure of the asset[3].

Details of the Policy

When deciding on a maintenance strategy, procedure or practice, STEI staff will seek to determine the optimal balance of preventive and breakdown activity and shall:

- Consider both the *probability* and *consequences* of a failure. The probability of a failure may be based on historical data and/or professional experience. The consequences may include the impact on public or staff safety, loss of supply, inability to respond to an outage, causing a hazardous spill, etc.
- Consider both the *frequency* and *intensity* of the preventive maintenance contemplated.
- Take into account both the cost of performing the anticipated preventive work and, in the event of a failure, the cost to rectify the failure. The cost shall include the labour and material costs for STEI staff, contractors, out-sourced personnel, etc. These costs may include, but need not be limited to, performing asset-conditioning monitoring, adjusting equipment settings, acquiring replacement parts, refurbishing equipment components, clean-up of a hazardous spill, full replacement of a failed item, etc.
- Consider adoption of minimal preventive maintenance approach for those assets for which these expenditures will not significantly affect the equipment or the system. Examples *may* include depending on the specific situation:
    - Pole mounted transformers
    - Overhead line switches
    - Pad mounted transformers
    - Pad mounted switchgear

[3] "Failure" of an asset includes both the inability of the asset to actually perform its role and the gradual deterioration of the asset resulting in a loss of efficiency often with cost-impacting consequences.

- Give due regard to the equipment manufacturer's recommendations in selecting the frequency and intensity of preventive maintenance. However, manufacturer's recommendations should only be considered a guide since equipment operates under a wide range of conditions and environments.
- Ensure that they are familiar with, and diligently follow, the checklists, worksheets, logs, etc. that have been provided to facilitate day-to-day operations including:
  - Forklift Operator's Daily Checklist
  - Tailboard Conference Worksheet – Traffic Control Plan and Job Planning
  - Daily Vehicle and Equipment Inspection Sheet
  - Daily Hydraulic Unit System Check Sheet
  - Daily Operations Log Sheet
  - Driver Truck Log Sheet

  Samples of the above items are included in STEI's System Management Manual.
- Perform all work with careful attention to safety as set out in the Health and Safety Policy and Procedures Manual (the index is attached as "Addendum 1 to Policy on Optimal Maintenance Planning Practices") and Health and Safety Policy Manual (the index is attached as "Addendum 2 to Policy on Optimal Maintenance Planning Practices").

Addendum 1

to

Policy on Optimal Maintenance Planning Practices

Health and Safety Policy and Procedures Manual

Addendum 2

to

Policy on Optimal Maintenance Planning Practices

Health & Safety Policy Manual

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APPENDIX B to Section 2.3

ASSET CONDITION ASSESSMENT

ST. THOMAS Energy Inc.
2011 ASSET CONDITION ASSESSMENT

June 20, 2012

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Toronto, ON
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ST. THOMAS Energy Inc
2011 ASSET CONDITION ASSESSMENT

Kinectrics Report: K-418037-RA-0002-R00

June 20, 2012

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Director – Asset Management

Dated: June 20, 2012

To: St. Thomas Energy Inc
135 Edward Street, St. Thomas, Ontario
N5P 4A8

Revision History

Revision Number	Date	Comments	Approved
R00	June 20, 2012	Final	Yury Tsimberg

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I INTRODUCTION

St. Thomas Energy Inc. (STEI) is a local distribution company that provides electricity to over 14,600 residential customers in St. Thomas, Ontario. It is regulated by the Ontario Energy Board (OEB). Following deregulation in the 1990s, St. Thomas Holding Inc. (now Ascent) was officially incorporated as a for-profit entity and became the parent company of STEI, wholly owned by the City of St. Thomas.

Kinectrics Inc. (Kinectrics) is an independent consulting engineering company with the advantage of nearly 100 years of expertise gained as being part of one of North America's largest integrated electric power companies. Kinectrics has a depth of experience in the area of transmission and distribution systems and has become a prime source of Asset Management and Asset Condition services to some of the largest power utilities in North America.

In 2011, STEI selected and engaged Kinectrics Inc (Kinectrics) to perform an Asset Condition Assessment (ACA) on STEI's key distribution assets.

The Asset Condition Assessment Report summarizes the methodology, demonstrates specific approaches used in this project, and presents the resultant findings and recommendations.

I.1 Scope of Work

The asset categories included in this study are as follows:

- Substation Transformers
- Pad Mounted Transformers
- Pole Mounted Transformers
- Poles
- Overhead Line Switches

I.2 Deliverables

The deliverable in this study is a Report that includes the following information:

- Description of methodology for condition assessment of replacement plan (Section II)
- Description of the data assessment procedure (Section II.3)
- For each asset category the following are included (Appendix A: Results for Each Asset Category):
  - Age distribution
  - Health Index distribution
  - Condition-based replacement plan
  - Data gap analysis

II ASSET CONDITION ASSESSMENT METHODOLOGY

The Asset Condition Assessment (ACA) Methodology involves the process of determining asset Health Index, as well as developing a Condition-Based Replacement Plan for each asset group. The methods used are described in the subsequent sections.

II.1 Health Index

Health Indexing quantifies equipment condition based on numerous condition parameters that are related to the long-term degradation factors that cumulatively lead to an asset's end of life. The Health Index is an indicator of the asset's overall health and is typically given in terms of percentage, with 100% representing an asset in brand new condition. Health Indexing provides a measure of long-term degradation and thus differs from defect management, whose objective is finding defects and deficiencies that need correction or remediation in order to keep an asset operating prior to reaching its end of life.

Condition parameters are the asset characteristics or properties that are used to derive the Health Index. A condition parameter may be comprised of several sub-condition parameters. For example, a parameter called "Oil Quality" may be a composite of parameters such as "Moisture", "Acid", "Interfacial Tension", "Dielectric Strength" and "Colour".

In formulating a Health Index, condition parameters are ranked, through the assignment of weights, based on their contribution to asset degradation. The condition parameter score for a particular parameter is a numeric evaluation of an asset with respect to that parameter.

Health Index (HI), which is a function of scores and weightings, is therefore given by:

$$HI = \frac{\sum_{m=1}^{m} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{m} \alpha_m (CPS_{\max} \times WCP_m)} \times DR$$

where Equation 1

$$CPS = \frac{\sum_{n=1}^{n} \beta_n (CPF_n \times WCPF_n)}{\sum_{n=1}^{n} \beta_n (CPF_{\max} \times WCPF_n)} x CPS_{\max}$$

Equation 2

CPS	Condition Parameter Score
WCP	Weight of Condition Parameter
α_m	Data availability coefficient for condition parameter
CPF	Sub-Condition Parameter Score
WCPF	Weight of Sub-Condition Parameter
β_n	Data availability coefficient for sub-condition parameter
DR	De-Rating Multiplier

The scale that is used to determine an asset's score for a particular parameter is called the condition criteria. For this project, a condition criteria scoring system of 0 through 4 is used. A score of 0 represents the worst score while 4 represents the best score. I.e. $CPF_{max} = 4$.

II.1.1 Health Index Example

Consider the asset class "Substation Transformer". The condition and sub-condition parameters, as well as their weights are shown on Table II-1.

Table II-1 Substation Transformers Condition and Sub-Condition Parameters

Health Index Formula for Substation Transformers			
Condition Parameters		Sub-Condition Parameters	
Name	Weights (WCP)	Name	Weights (WCPF)
Insulation	2	Oil Quality	1
		Oil DGA	2
		Power Dissipation Factor	2
Sealing and Connection	1	Tank Oil Leak	2
		Oil Conservator	2
		Grounding	1
		Tank Condition	1
Service Record	1	Age	3
		Loading	5

Assume a parameter scoring system of 0 though 4, where 0 and 4 represent the "worst" and "best" scores respectively. The maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is therefore "4".

Scores are determined using condition criteria. The criterion defines the score of a particular parameter. Consider, for example, the age criteria given on Table II-2. An asset that is 35 years old will receive a score of "2" for "Age".

Table II-2 Age Criteria

Parameter Score	Condition Description
4	0-19
3	20-29
2	30-39
1	40-44
0	45+

Table II-3 shows a sample Health Index evaluation for a particular transformer. The sub-condition parameter scores (CPFs) shown are assumed values between 0 through 4.

The Condition Parameter Score (CPS) is evaluated as per Equation 2. The Health Index (HI) is calculated as per Equation 1. As no de-rating factors are defined, there is no multiplier for the final Health Index.

Table II-3 Sample Health Index Calculation

Insulation			Sealing and Connection			Service Record		
Sub-Condition Parameter	CPF	Weight	Sub-Condition Parameter	CPF	Weight	Sub-Condition Parameter	CPF	Weight
Oil Quality	3	1	Tank Oil Leak	3	2	Age	4	3
Oil DGA	2	2	Oil Conservator	3	2	Loading	3	5
Power Dissipation Factor	2	2	Grounding	4	1			
			Tank Condition	2	1			
Insulation CPS = [(3*1+2*2+2*2) / (4*1+4*2+4*2)]*4 = 2.2			Sealing and Connection CPS = [(3*2+3*2+4*1+2*1) / (4*2+4*2+4*1+4*1)]*4 = 3.6			Service Record CPS = (4*3+3*5) / (4*3+4*5) = 3.375		
Weight = 2			Weight = 1			Weight = 1		
$HI = \frac{(2.2*2+3.6*1+3.375*1)}{(4*2+4*1+4*1)} = 71\%$								

II.1.2 Health Index Results

As stated previously, an asset's Health Index is given as a percentage, with 100% representing "as new" condition. The Health Index is calculated only if there is sufficient condition data. The subset of the population with sufficient data is called the sample size. Results are generally presented in terms of number of units and as a percentage of the sample size. If the sample size is sufficiently large and the units within the sample size are sufficiently random, the results may be extrapolated for the entire population.

The Health Index distribution given for each asset group illustrates the overall condition of the asset group. Further, the results are aggregated into five categories and the categorized distribution for each asset group is given. The Health Index categories are as follows:

Very Poor	Health Index < 25%
Poor	25 ≤ Health Index < 50%
Fair	50 ≤ Health Index <70%
Good	70 ≤ Health Index <85%
Very Good	Health Index ≥ 85%

Note that for critical asset groups, such as Station Transformers, the Health Index of each individual unit is given.

II.2 Condition-Based Replacement Methodology

The Condition-Based Replacement plan outlines the number of units that are projected to be replaced or refurbished in the next 10 years. The numbers of units are estimated using either a proactive or reactive approach. In the proactive approach, units are considered for replacement prior to failure, whereas the reactive approach is based on expected failures per year.

Both approaches consider asset failure rate and probability of failure. The failure rate is estimated using the method described in the subsequent section.

II.2.1 Failure Rate and Probability of Failure

Where failure rate data is not available, a frequency of failure that grows exponentially with age provides the best model. This is based on the Gompertz-Makeham law of mortality. The original form of the failure function is:

$$f = \gamma e^{\beta t}$$

Equation 3

f = failure rate per unit time
t = time
γ, β = constant that control the shape of the curve

Depending on its application, there have been various forms derived from the original equation. Based on Kinectrics' expertise in failure rate study of multiple power system asset groups, the following variation of the failure rate formula is adopted:

$$f(t) = e^{\beta(t-\alpha)}$$

Equation 4

f = failure rate of an asset (percent of failure per unit time)
t = age (years)
α, β = constant parameters that control the rise of the curve

The corresponding probability of failure function is therefore:

$$P_f(t) = 1 - e^{-(f - e^{-\alpha\beta})/\beta}$$

Equation 5

P_f = cumulative probability of failure

Different asset groups experience different failure rates and therefore different probabilities of failure. As such, the shapes of the failure and probability curves are different. The parameters α and β are used to control the location and steepness of the exponential rise of these curves. For each asset group, the values of these constant parameters were selected to reflect typical useful lives for these assets.

Consider, for example, an asset class where at the ages of 10 and 70 the asset has cumulative probabilities of failure of 10% and 90% respectively. It follows that when using Equation 5, α and β are calculated as 84 and 0.102 respectively. As such, for this asset class the cumulative probability of failure equation is:

$$P_f(t) = 1 - e^{-(e^{\beta(t-\alpha)} - e^{\alpha\beta})/\beta} = 1 - e^{-(e^{0.102(t-84)} - e^{-8.568})/0.102}$$

The failure rate and probability of failure graphs are as shown:

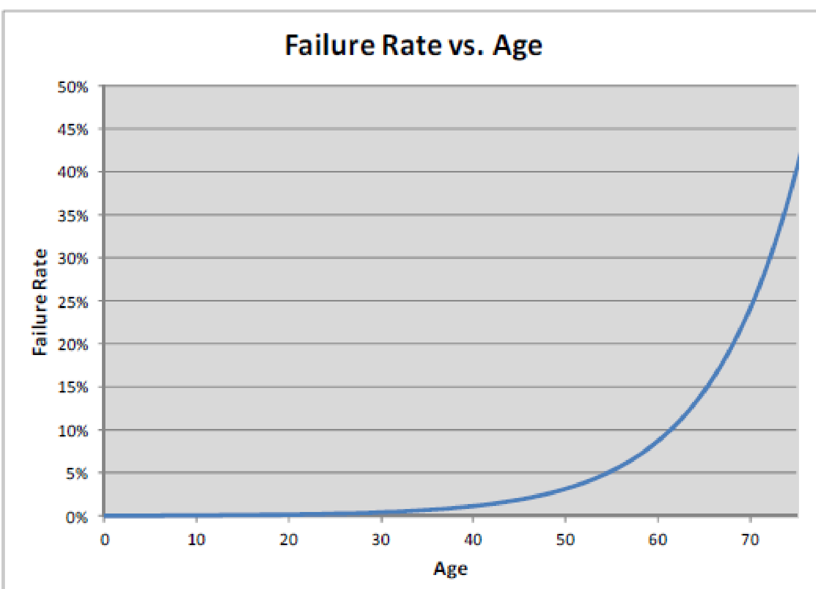


Figure II-1 Failure Rate vs. Age

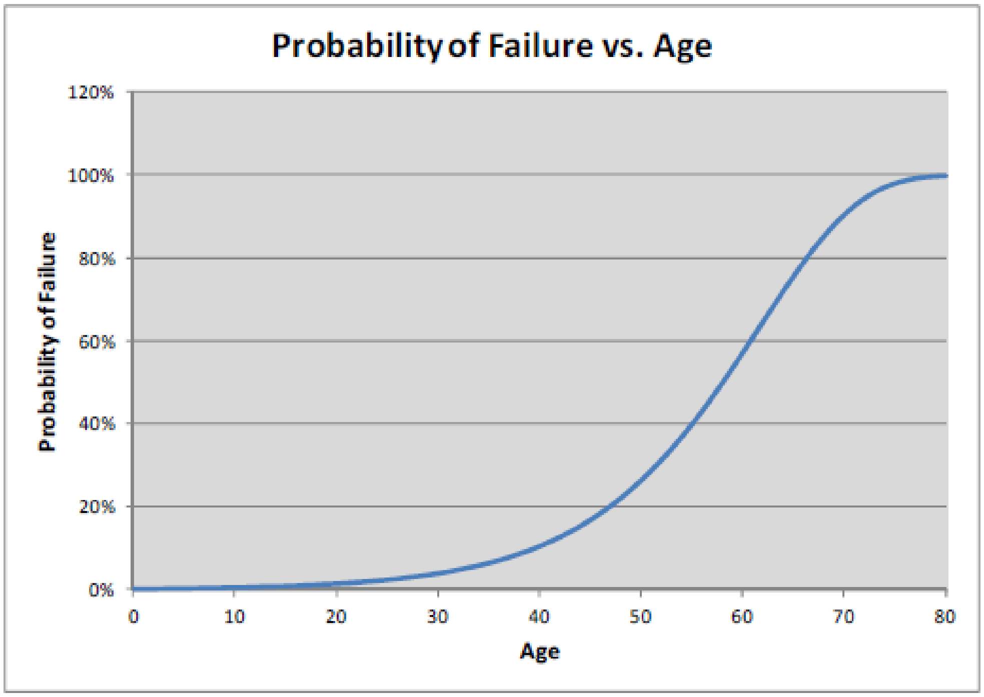


Figure II-2 Probability of Failure vs. Age

II.2.2 Projected Replacement Plan Using a Reactive Approach

Because their consequences of failure are relatively small, many types of distribution assets are reactively replaced.

For such asset types, the number of units expected to be replaced in a given year are determined based on the asset's failure rates. The number of failures per year is given by Equation 4:

$$f(t) = e\beta(t - \alpha)$$

With α and β determined from the probability of failure of each asset class

An example of such a replacement plan is as follows: Consider an asset distribution of 100 five (5) year old units, 20 ten (10) year old units, and 50 twenty (20) year old units. Assume that the failure rates for 5, 10, and 20 year old units for this asset class are f_5 = 0.02, f_{10} = 0.05, f_{20} = 0.1 failures / year respectively. In the current year, the total number of replacements is 100(f_5) + 20(f_{10}) + 50(f_{20}) = 100(.02) + 20(0.05) + 50(0.1) = 2 + 1 + 5 = 8.

In the following year, the expected asset distribution is, as a result, as follows: 8 one (1) year old units, 98 six (6) year old units, 19 eleven (11) year old units, and 45 twenty-one (21) year old units. The number of replacements in year 2 is therefore 8(f_1) + 19(f_6) + 45(f_{11})+ 45(f_{21}).

Note that in this study the "age" used is in fact "effective age", or condition-based age, as opposed to the chronological age of the asset.

II.2.3 Projected Replacement Plan Using a Proactive Approach

For certain asset classes, the consequence of asset failure is significant, and, as such, these assets are proactively replaced prior to failure. The proactive replacement methodology involves relating an asset's Health Index to its probability of failure by considering the stresses to which it is exposed.

RelatingHealthIndexandProbabilityofFailure

Failure of an asset occurs when the stress to which an asset is exposed exceeds its strength. Assuming that stress is not constant, and that stress is normally distributed, the probability of stress exceeding asset strength leads to the probability of failure. This is illustrated in the figure below. A vertical line represents condition or strength (Health Index) and the area under the curve to the right of the Health Index line represents the probability of failure.

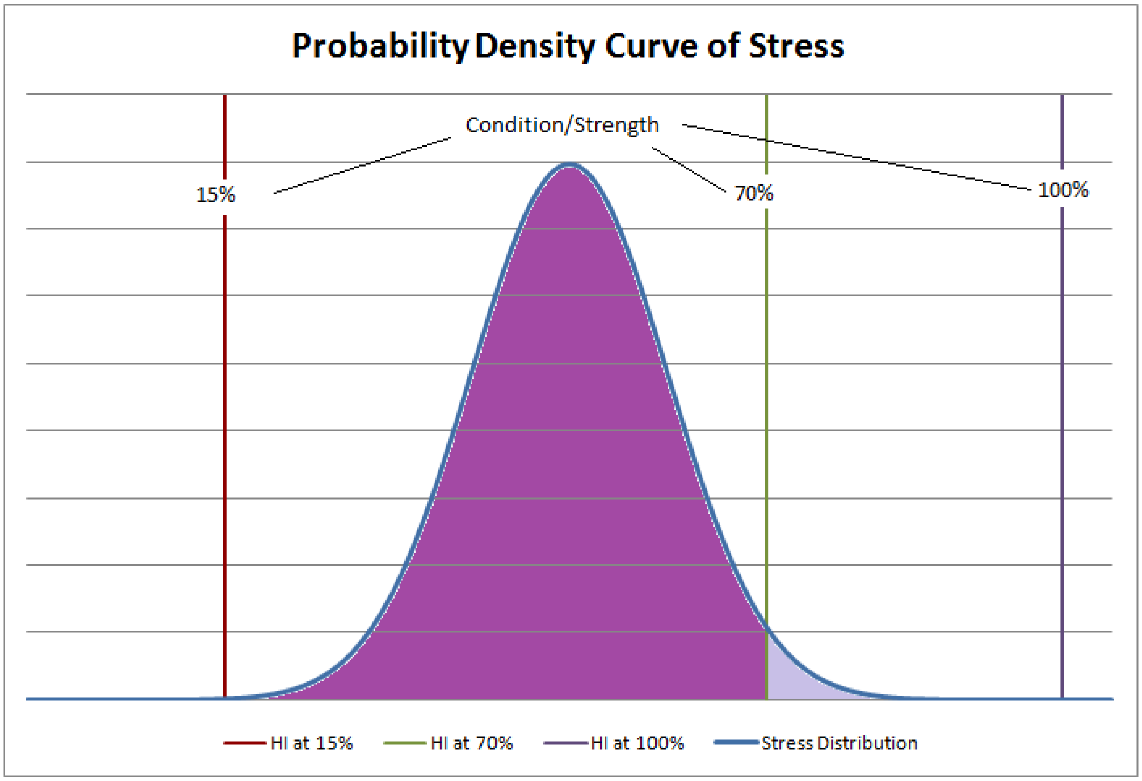


Figure II-3 Stress Curve

Two points of Health Index and probability of failure are needed to generate the probability of failure at other Health Index values. A Health Index of 100% represents an asset that is in brand new condition and a Health Index of 15% represents the asset's end of life. The 100% and 15% conditions are plotted on the stress curve by finding the points at which the areas under the stress curve are equal to $P_{f\ 100\%}$(age at 100% Health Index) and $P_{f\ 15\%} = P_f$(age at 15% Health Index). By moving the vertical line left from 100% to 15%, the probabilities of failure for other Health Indices can be found.

The probability of failure at a particular Health Index is found from plotting the Health Index on the X-axis and the area under the probability density curve to the right of the Health Index line on the Y-axis as shown on the graph of the figure below.

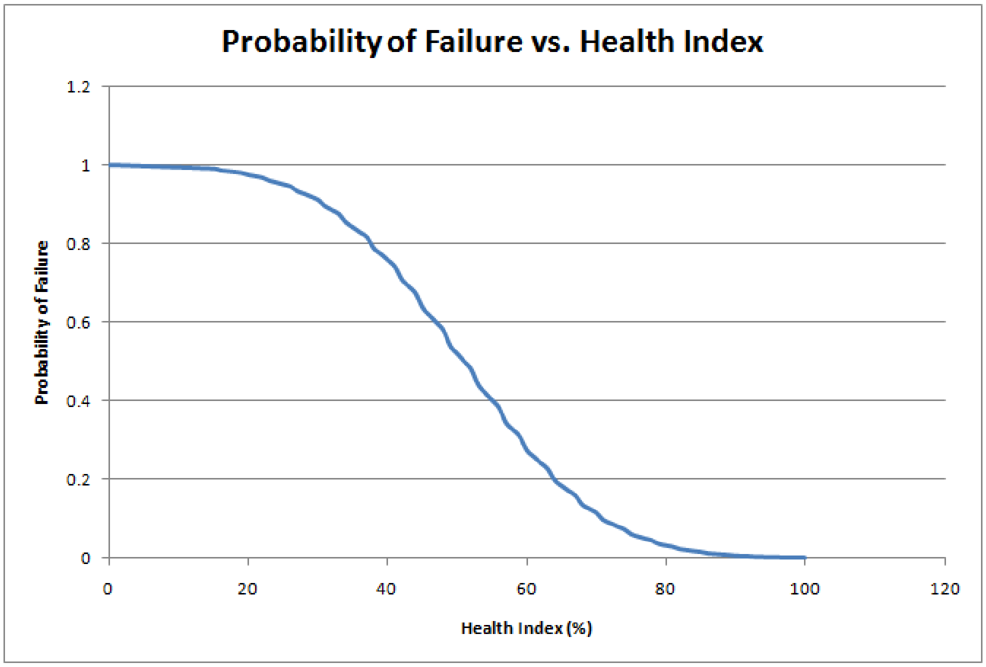


Figure II-4 Probability of Failure vs. Health Index

<u>Condition-BasedReplacementPlan</u>

In this study, a proactively replaced unit is flagged for intervention (e.g. replacement or major refurbishment) when its probability of failure, as defined by its Health Index, is greater than or equal to 80%.

II.3 Data Assessment

The condition data used in this study were obtained from St. Thomas Energy and included the following:

Asset Properties (e.g. age, location information)
Test Results (e.g. Oil Quality, DGA)
Inspection records

There are additional parameters or tests that STEI may not collect but nonetheless are important indicators of the deterioration and degradation of assets. The set of unavailable data are referred to as data gaps. I.e. A data gap is the case where none of the units in an asset group has data for a particular item. The situation where data is provided for only a sub-set of the population is not considered as a data gap.

As part of this study, the data gaps of each asset category are identified. In addition, the data items are ranked in terms of importance. There are three priority levels, the highest being most indicative of asset degradation:

Priority	Description
P1 (Highest Priority)	Critical data; most useful as an indicator of asset degradation
P2 (Medium Priority)	Important data; can indicate the need for corrective maintenance or increased monitoring
P2 (Lowest Priority)	Helpful data; least indicative of asset deterioration

III RESULTS

This section summarizes the findings of this study.

Health Index Results

A summary of the Health Index evaluation results is shown in Table III-4 and graphically summarized in Figure III-5. The population and sample size, or number of assets with sufficient data for Health Indexing, are given. For each group the Health Index distribution, total percentage in "poor" and "very poor" condition, and average Health Index are shown. Also given is the average age of each group.

It can be seen from the results that over 4% of Wood Poles are in "poor" or "very poor" condition. Very few, 1% or less, Overhead Switches and Pole Mounted Transformers are considered "poor" or "very poor". There are no Substation Transformers or Pad Mounted Transformers that are in "poor" or "very poor" condition.

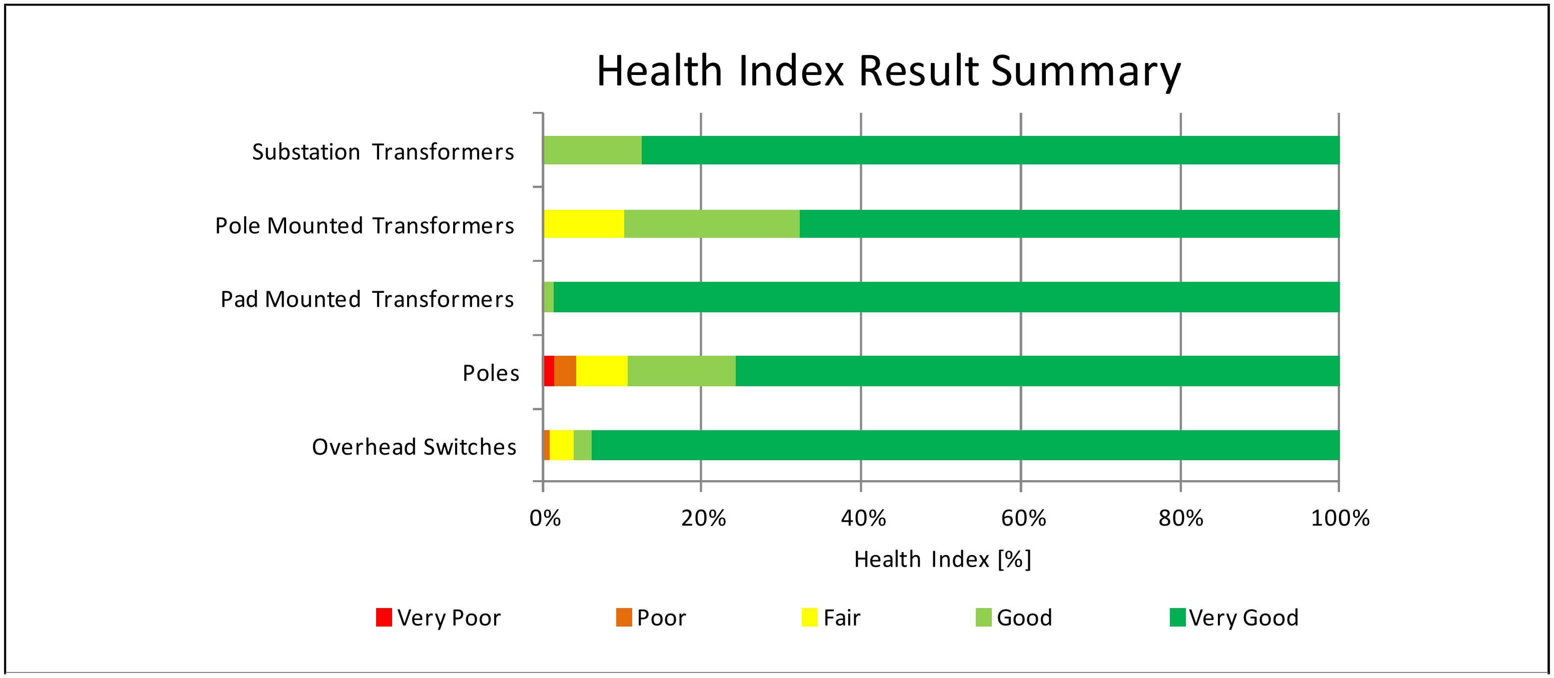
It should be noted that over 6% of Wood Poles are in "fair" condition, making the total percentage of poles that are "fair" or worse nearly 11%.

Similarly, the percentage of Pole Mounted Transformers in "fair" or worse condition is just over 10%.

Table III-4 Health Index Results Summary

Asset Category	Population	Sample Size	Health Index Distribution (% of Sample Size)					Total in Poor and Very Poor	Average Health Index	Average Age
			Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)			
Substation Transformers	8	8	0.0%	0.0%	0.0%	12.5%	87.5%	0.0%	95%	29
Pole Mounted Transformers	894	892	< 1%	< 1%	10.3%	21.9%	67.4%	< 1%	90%	19
Pad Mounted Transformers	499	499	0.0%	0.0%	< 1%	1.4%	98.2%	0.0%	97%	12
Poles	4857	4855	1.5%	2.8%	6.4%	13.5%	75.8%	4.3%	90%	27
Overhead Switches	105	98	0.0%	1.0%	3.1%	2.0%	93.9%	1.0%	97%	13

Figure III-5 Health Index Results Graphical Summary



Condition Based Replacement Plan

The assumed asset cost and replacement strategy is shown in Table III-5. Table III-6 shows a 10 Year Condition-Based Replacement Plan in terms of number of units and costs; Table III-7 graphically shows the plan in terms of cost.

It is important to note that the replacement plan suggested in this study is based solely on asset condition. It uses a probabilistic, non-deterministic, approach and as such can only show expected failures or probable number of units for replacement. While the Condition-Based Replacement Plan can be used as a guide or input to STEI's Asset Management Plan, it is not expected that it be followed precisely in developing final capital replacement plans. There are numerous other factors and considerations that will influence STEI's asset management decisions. Among these are obsolescence, municipal initiatives, and functional requirements.

STEI's most significant expected replacements were found to be for Wood Poles. Approximately 80 poles are expected to be replaced in the first year; this amounts to approximately $800,000 in required replacement capital, assuming the cost of replacing each pole is $10,000.

It is also worth noting that 13 pole mounted transformers are expected to be replaced in the first year. Assuming a replacement cost of $6,375 per unit, the total replacement cost for the first year is $82,875. The expected number of replacements increases by approximately 1 unit per year in the next 10 years.

Very little pad mounted transformers and overhead switches are expected to be replaced in the next 10 years. No substation transformers have been identified for replacement or refurbishment in the next 10 years.

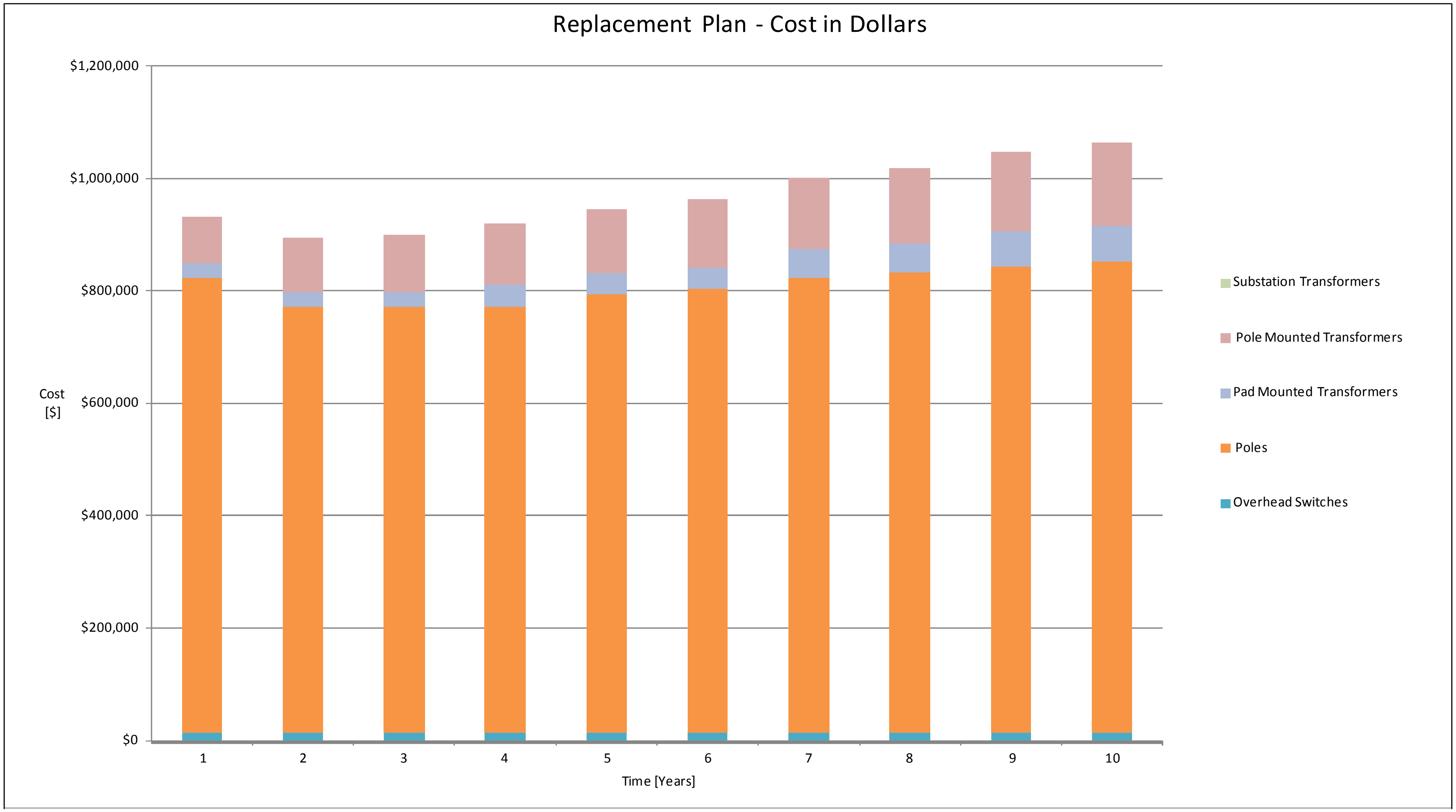
Table III-5 Assumed Asset Cost and Replacement Strategy

Asset	Assumed Replacement Cost	Replacement Strategy
Substation Transformers	$300,000	proactive
Pole Mounted Transformers	$6,375	reactive
Pad Mounted Transformers	$12,750	reactive
Poles	$10,000	proactive
Overhead Switches	$13,000	reactive

Table III-6 Ten Year Condition Based Replacement Plan

Ten Year Condition-Based Replacement Plan											
Asset	Item	Years									
		1	2	3	4	5	6	7	8	9	10
Substation Transformers	Number of Units	0	0	0	0	0	0	0	0	0	0
	Cost [$]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Pole Mounted Transformers	Number of Units	13	15	16	17	18	19	20	21	22	23
	Cost [$]	$82,875	$95,625	$102,000	$108,375	$114,750	$121,125	$127,500	$133,875	$140,250	$146,625
Pad Mounted Transformers	Number of Units	2	2	2	3	3	3	4	4	5	5
	Cost [$]	$25,500	$25,500	$25,500	$38,250	$38,250	$38,250	$51,000	$51,000	$63,750	$63,750
Poles	Number of Units	81	76	76	76	78	79	81	82	83	84
	Cost [$]	$810,000	$760,000	$760,000	$760,000	$780,000	$790,000	$810,000	$820,000	$830,000	$840,000
Overhead Switches	Number of Units	1	1	1	1	1	1	1	1	1	1
	Cost [$]	$13,000	$13,000	$13,000	$13,000	$13,000	$13,000	$13,000	$13,000	$13,000	$13,000

Table III-7 Ten Year Condition Based Replacement Plan Graphical Summary



Data Assessment Results

For Substation Transformers, the following types of data are being collected: oil quality test results, DGA test results, transformer loading, and inspection records related to bushings, temperature, tank leaks, tank condition, and grounding. The information related to the insulation may be improved by collecting winding power dissipation factor (e.g. winding Doble) test results.

The data gaps identified for the Pole Mounted Transformers asset class are inspection records related to overall life grade (end of life assessment), oil leaks, and tank condition.

Inspection type information is currently being collected for Pad Mounted Transformers. Collecting information on the overall life grade of each unit would improve the assessment of this asset class.

While STEI routinely performs detailed inspections of its wood poles, the detailed inspection records were not available for this year's assessment. As such, the condition assessment for this asset class was based on age only. The required condition data for Poles can be found in the detailed inspection records (e.g. pole strength, specific type of pole damage, split, hollow heart).

There were no data gaps for Overhead Switches. Good information is being collected during inspections.

IV CONCLUSIONS AND RECOMMENDATIONS

1. An Asset Condition Assessment was conducted for five of STEI's key distribution assets, namely Substation Transformers, Pole Mounted Transformers, Pad Mounted Transformers, Poles, and Overhead Switches.

2. Approximately 11% of Poles are in "fair" or worse condition. Of these, over 4% were found to be "poor" or "very poor".

3. While very little units were considered to be "poor" or "very poor", over 10% of Pole Mounted Transformers were found to be "fair".

4. The vast majority of Substation Transformers, Pad Mounted Transformers, and Overhead Switches were in "good" or "very good" condition.

5. STEI's most significant expected replacements were found to be for Wood Poles. Approximately 80 poles are expected to be replaced in year the first year; this amounts to approximately $800,000 in required capital, assuming the cost of replacing each pole is $10,000.

6. Approximately 13 Pole Mounted Transformers are expected to be replaced in the first year. Assuming a replacement cost of $6,375 per unit, the total replacement cost for the first year

is $82,875. The expected number of replacements increases by approximately 1 unit per year in the next 10 years.

7. Good condition data is being collected for Substation Transformers. Assessment of insulation condition may be improved by collecting and incorporating winding power dissipation factor test results (winding Doble).

8. The data gaps for Pole Mounted Transformers are inspection records related to overall life grade, oil leaks, and tank condition. It is recommended that such information be collected and incorporated into future assessments.

9. Collecting information on the overall life grade condition would improve the assessment of Pad Mounted Transformers. It is recommended that such information be collected and incorporated into future assessments.

10. While detailed inspections of Poles are routinely conducted at STEI, the results of the most recent inspections were not available for this asset condition assessment. As such, the assessment for this asset class was based solely on age. It is recommended that the detailed inspections be used in future assessments of this asset class.

11. More granular inspection ratings should be considered, where applicable, to produce more informative Health Index results.

    For example, for a pad mounted transformer, an inspection item called “corrosion” with a ranking system of “As New”, “Wear/Monitoring Required”, and “Poor/Replacement Required” will result in more informative Health Indexes than a ranking system of “okay” and “not okay”. Recommendations for improved scoring systems are given for parameters of the following asset classes: Pole Mounted Transformers, Pad Mounted transformers, and Overhead Switches. These can be found in the Data Analysis section of each asset category.

V APPENDIX A: RESULTS FOR EACH ASSET CATEGORY

This section shows detailed results and findings for each asset category. The following are given for each asset category:

- Age distribution
- Health Index distribution
- Condition-based replacement plan
- Data gap analysis

1 Substation Transformers

STEI has a total of 8 Substation Transformers, ranging in size from 3 MVA to 5 MVA.

1.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for STEI Substation Transformers. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 though 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

1.1.1 Condition and Sub-Condition Parameters

Table 1-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	$CPS_{m.max}$
1	Insulation	6	4
2	Cooling	0*	4
3	Sealing & connection	3	4
4	Reliability	3	4

*note that “Cooling” was set with a weight of zero because 2010 data was not available

Table 1-2 Insulation (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	CPF lookup table	$CPF_{n.max}$
1	Oil Quality	4	Table 1-7	4
2	Oil DGA	10	Table 1-8	4
3	Winding Doble	0*	Table 1-9	4
4	Bushing	1	Table 1-10	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

Table 1-3 Cooling (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	CPF lookup table	$CPF_{n.max}$
1	Temp gauge operation	1	Table 1-10	4
2	Fan/Pump operation	1	Table 1-11	4

Table 1-4 Sealing & Connection (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	CPF lookup table	$CPF_{n.max}$
1	Tank oil leak	2	Table 1-10	4
2	Oil conservator	2	Table 1-11	4
3	Grounding complete	1	Table 1-10	4
4	Transformer tank condition	1	Table 1-10	4

Table 1-5 Reliability (m=5) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	CPF lookup table	$CPF_{n.max}$
1	Loading	5	Table 1-12	4
2	Age	3	Figure 1-1	4

Table 1-6 Other (m=5) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	CPF lookup table	$CPF_{n.max}$
1	Dirt/Debris	1	Table 1-10	4
2	Tree branches	1	Table 1-10	4
2	Weeds in fence	1	Table 1-10	4

1.1.2 Condition Parameter Criteria

<u>Oil Quality</u>

Table 1-7 Oil Quality Test Criteria

CPF	Description
4	Overall factor is less than 1.2
3	Overall factor between 1.2 and 1.5
2	Overall factor is between 1.5 and 2.0
1	Overall factor is between 2.0 and 3.0
0	Overall factor is greater than 3.0

Where the Overall factor is the weighted average of the following gas scores:

Oil Quality Test	Voltage Class [kV]	Scores				
		1	2	3	4	Weight
Water Content (D1533) [ppm]	V ≤ 69	< 30	30-35	35-40	> 40	5
	69 < V < 230	< 20	20-25	25-30	> 35	
	V ≥ 230	< 15	15-20	20-25	> 25	

Select the row applicable to the equipment rating

Dielectric Strength (D1816 - 2 mm gap) [kV]	V ≤ 69	> 40	35-40	30-35	< 30	4
	69 < V < 230	> 47	42-47	35-42	< 35	
	V ≥ 230	> 50	50-45	40-45	< 40	
Dielectric Strength (D877) [kV]	All	> 40	30-40	20-30	< 20	
IFT (D971) [dynes/cm]	V ≤ 69	> 25	20-25	15-20	< 15	4
	69 < V < 230	> 30	23-30	18-23	< 18	
	V ≥ 230	> 32	25-32	20-25	< 20	
Color	All	< 1.5	1.5-2.0	2.0-2.5	> 2.5	1
Acid Number (D974) [mg KOH/g]	V ≤ 69	< 0.05	0.05-0.1	0.1-0.2	> 0.2	4
	69 < V < 230	< 0.04	0.04-0.1	0.1-0.15	> 0.15	
	V ≥ 230	< 0.03	0.03-0.07	0.07-0.1	> 0.1	
Dissipation Factor (D924 - 25^{0}C)	All	< 0.5%	0.5%-1%	1-2%	> 2%	5
Dissipation Factor (D924 - 100^{0}C)	All	< 5%	5%-10%	10%-20%	> 20%	

Select the row applicable to the equipment rating

Overall Factor = $\frac{\sum Score_i \; Weight_i}{\sum Weight}$

For example if all data is available, overall Factor = $\frac{\sum Score_i \; Weight_i}{12}$

Oil DGA

Table 1-8 Oil DGA Criteria

CPF	Description
4	DGA overall factor is less than 1.2
3	DGA overall factor between 1.2 and 1.5
2	DGA overall factor is between 1.5 and 2.0
1	DGA overall factor is between 2.0 and 3.0
0	DGA overall factor is greater than 3.0

*In the case of a score other than 4, check the variation rate of DGA parameters. If the maximum variation rate (among all the parameters) is greater than 30% for the latest 3 samplings or 20% for the latest 5 samplings, overall Health Index is multiplied by 0.9 for score 3, 0.85 for score 2, 0.75 for score 1 and 0.5 for score 0.

Where the DGA overall factor is the weighted average of the following gas scores:

2.5 MVA to 10 MVA

Dissolved Gas	Scores						
	1	2	3	4	5	6	Weight
H2	<=70	<=100	<=200	<=400	<=1000	>1000	4
CH4 (Methane)	<=70	<=120	<=200	<=400	<=600	>600	3
C2H6 (Ethane)	<=75	<=100	<=150	<=250	<=500	>500	3
C2H4 (Ethylene)	<=60	<=100	<=150	<=250	<=500	>500	3
C2H2 (Acetylene)	<=3	<=7	<=35	<=50	<=100	>100	5
CO	<=750	<=1000	<=1300	<=1500	<=1700	>1700	2*
CO2	<=7500	<=8500	<=9000	<=12000	<=15000	>15000	2*
CO2/CO	3 - <10	<12	<15 Or <3	<18	<20	>20	4*

*If CO $\geq$ 500 ppm and CO2 $\geq$ 5000 ppm, use CO2/CO ratio (e.g. CO and CO2 weights = 0, CO2/CO weight = 4)
If CO < 500 ppm and CO2 < 5000 ppm, use CO2 and CO limits (e.g. CO and CO2 weights = 4, CO2/CO weight = 0)

10 MVA and Higher

Dissolved Gas	Scores						
	1	2	3	4	5	6	Weight
H2	<=40	<=100	<=300	<=500	<=1000	>1000	4
CH4(Methane)	<=80	<=150	<=200	<=500	<=700	>700	3
C2H6(Ethane)	<=70	<=100	<=150	<=250	<=500	>500	3
C2H4(Ethylene)	<=60	<=100	<=150	<=250	<=500	>500	3
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=80	>80	5
CO	<=350	<=500	<=600	<=1000	<=1500	>1500	2*
CO2	<=3000	<=4500	<=5700	<=7500	<=10000	>10000	2*
CO2/CO	3 - <8	< 10	<13 Or <3	<14	<15	>15	4*
*If CO ≥ 500 ppm and CO2 ≥ 5000 ppm, use CO2/CO ratio (e.g. CO and CO2 weights = 0, CO2/CO weight = 4) If CO < 500 ppm and CO2 < 5000 ppm, use CO2 and CO limits (e.g. CO and CO2 weights = 4, CO2/CO weight = 0)							

$$\text{Overall Factor} = \frac{\sum Score_i \times Weight_i}{\sum Weight}$$

Winding DobleTest

Table 1-9 Winding Doble Test Criteria

CPF	Description
4	%PF < 0.5%
3	0.5% < %PF < 0.7%
2	0.7% < %PF < 1%
1	1.0% < %PF < 2.0%
0	%PF > 2.0%

Age

Assume that the failure rate for Substation Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f - e^{\alpha\beta})/\beta}$$

S_f	= survivor function
P_f	= cumulative probability of failure

Assuming that at the ages of 30 and 60 years the probability of failures (P_f) for this asset are 10% and 99% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below.

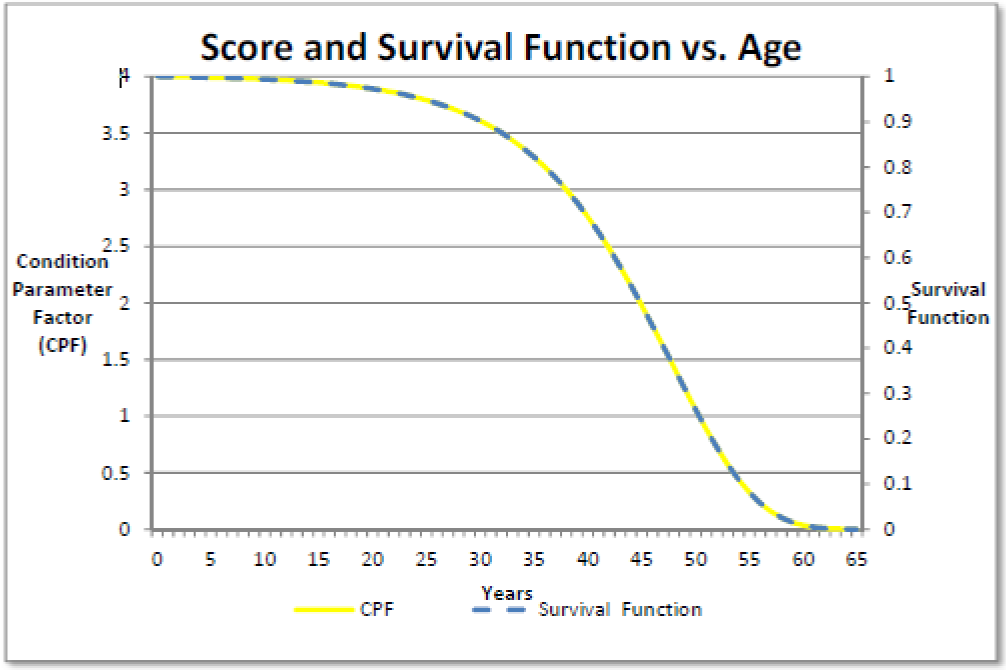


Figure 1-1 Substation Transformers Age Condition Criteria

<u>Defect Counts</u>

Table 1-10 Average Defect Count in 4 Years

CPF	Condition Description
4	Excellent Working Condition
3	Minor Wear, Working as Required
2	Wear or Failed, Repaired During Inspection/Regular Monitoring Required
1	Major Wear or Failed, Repaired During Inspection
0	Immediate Replacement or Emergency Repair Required

<u>OK or Not OK</u>

Table 1-11 Satisfactory or Not Satisfactory

CPF	Condition Description
4	Satisfactory
0	Not Satisfactory

<u>Loading History</u>

Table 1-12 Loading History

Data: S1, S2, S3, …, SN recorded data (monthly 15 min peak)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 CPF = $\frac{NA\ \ 4\ \ \ NB\ \ 3\ \ \ NC\ \ 2\ \ \ ND\ \ 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then CPF should be multiplied by 0.6 to show the effect of overheating.

1.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 29 years.

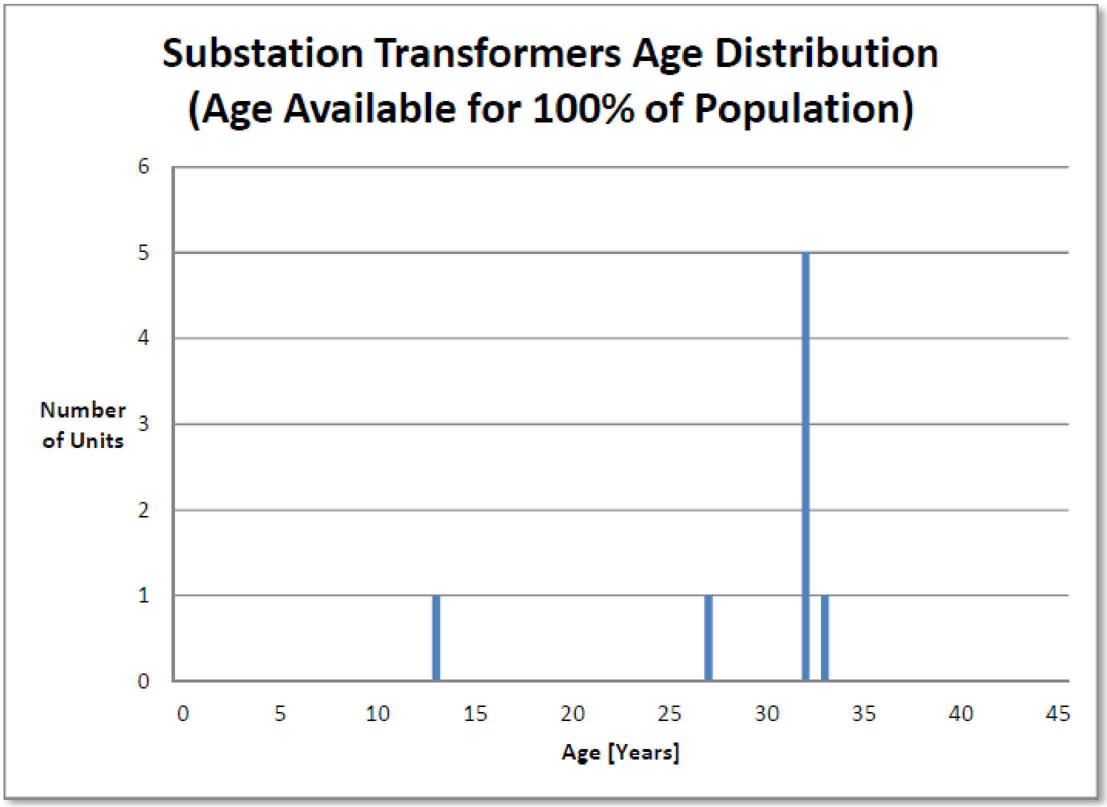


Figure 1-2 Substation Transformers Age Distribution

1.3 Health Index Results

There are 8 in-service Substation Transformers at STEI. Of these, 8 units had sufficient data for assessment. The average Health Index for this asset group is 95%. The Health Index Distribution is shown in Figure 1-3 and Figure 1-4.

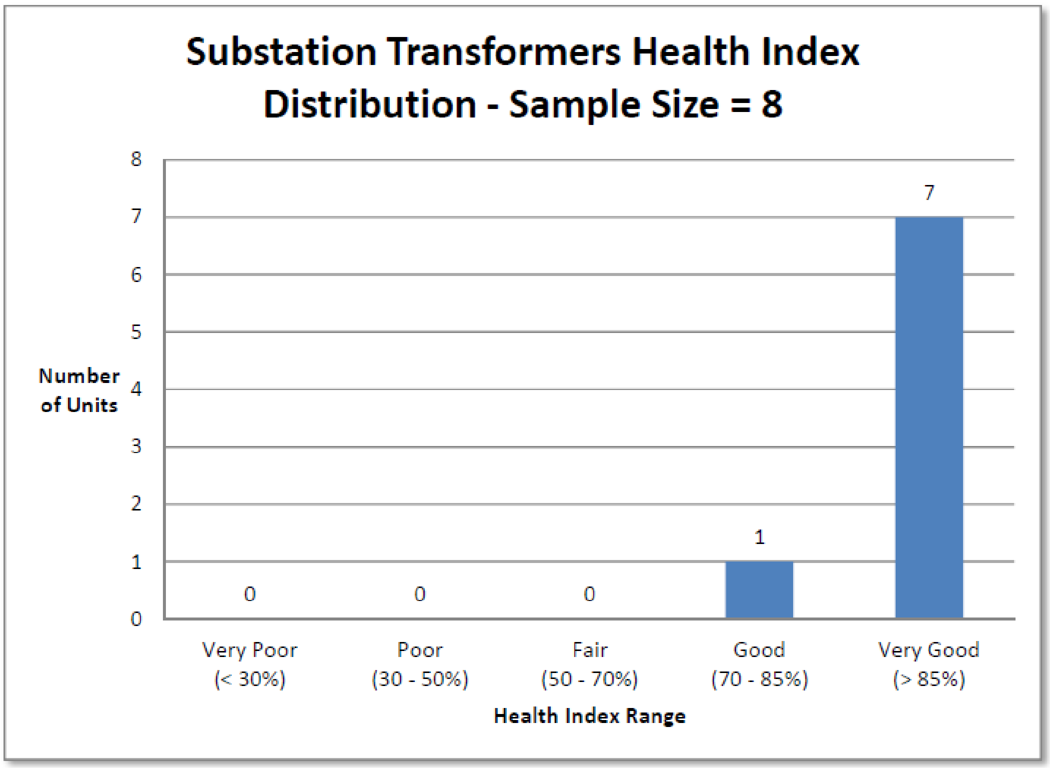


Figure 1-3 Substation Transformers Health Index Distribution (Number of Units)

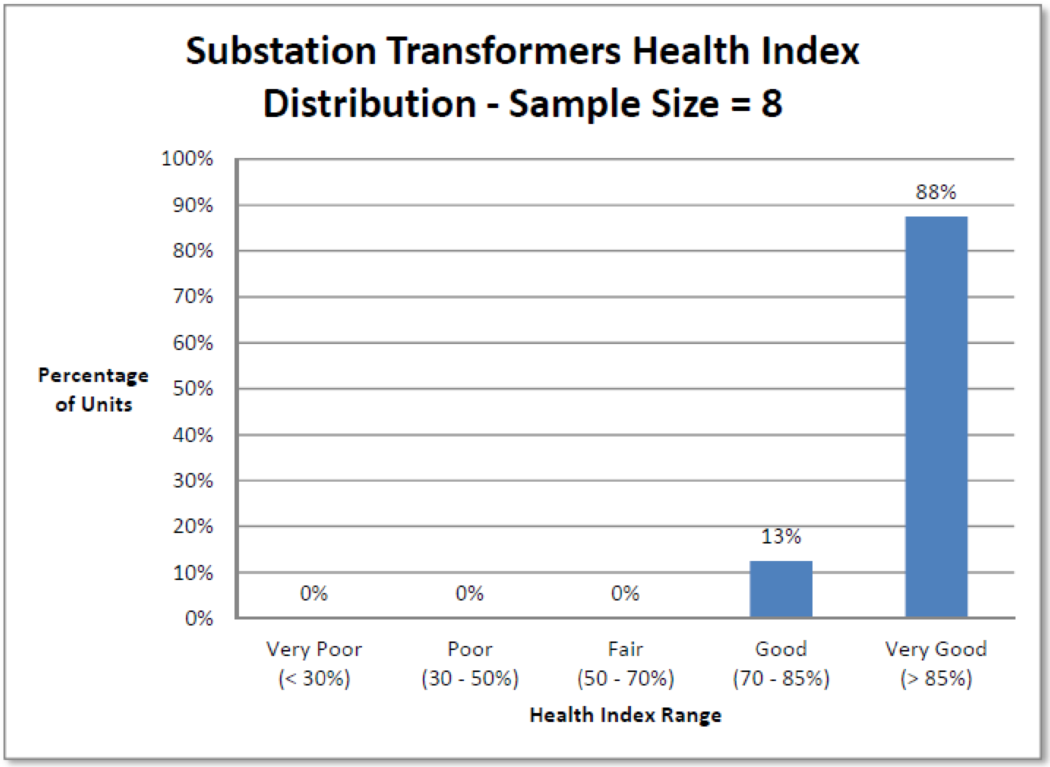


Figure 1-4 Substation Transformers Health Index Distribution (Percentage of Units)

The detailed results, from lowest to highest Health Index are shown below:

Table 1-13 Health Index Results for Each Substation Transformers Unit

Transformer Name	Age	Health Index
Sub 11	32	80.1%
Sub 9	32	94.9%
Sub 14	32	96.6%
Mobile	13	96.7%
Sub 15	32	98.0%
Sub 13	33	98.3%
Sub 10	32	98.9%
Sub 6	27	98.9%

1.4 Condition-Based Replacement Plan

As it is assumed that Substation Transformers are proactively replaced, the risk assessment and replacement procedure described in Section II.2.3 was applied for this asset class.

No units were flagged for intervention (replacement or refurbishment) in the next 10 years.

1.5 Data Analysis

The data available for Substation Transformers includes age, inspection results, oil quality, dissolved gas analysis, and Doble tests as per the GE tests and inspections.

The data gap is shown below:

Data Gap	
Condition Parameter	Priority
Power Dissipation Factor (winding Doble) test	P1

2 Pole-Mounted Transformers

At the time of this assessment there were 894 Pole-Mounted Transformers at STESI. This includes transformers with the following properties:

Status = "In Service"
Type = "Polemount" or ""Polemount Step Down"

2.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for STEI Pole-Mounted Transformers. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

2.1.1 Condition and Sub-Condition Parameters

Table 2-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m	$CPS_{m.max}$
1	Physical Condition	1	4
2	Connection & Insulation	1	4
3	Service Record	4	4
DR*	Manufacturer	0.8 if criteria is met; 1 otherwise	

*It is STEI's experience that transformers from a certain manufacturer are prone to failure. To reflect this risk, the calculated Health Indices of these types of transformers are de-rated by 80%.

Table 2-2 Physical Condition (m=1) Weights and Maximum CPF

n	Sub-condition parameter	$WCPF_n$	CPF lookup table	$CPF_{n.max}$
1	Tank Corrosion	0*	Table 2-6	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

Table 2-3 Connection & insulation (m=2) Weights and Maximum CPF

n	Sub-condition parameter	$WCPF_n$	CPF lookup table	$CPF_{n.max}$
1	Oil Leaks	0*	Table 2-5	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

Table 2-4 Service Record (m=3) Weights and Maximum CPF

n	Sub-condition parameter	$WCPF_n$	CPF lookup table	$CPF_{n.max}$
1	Overall	0*	Table 2-6	4
2	Age	1	Figure 2-1	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

2.1.2 Condition Parameter Criteria

Yes or No

Table 2-5 Yes or No Criteria

CPF	Condition Description
4	Yes
1	No

Life Grade

Life grade gives information related to an asset's remaining life. This scoring system is used for parameters that can affect equipment replacement. Life grade is an assessment based on non-refurbishable or maintainable conditions that lead to asset end of life.

Table 2-6 Inspection Condition Criteria

CPF	Condition Description
4	As new condition
2	Wear, regular monitoring required
0	Poor condition, replacement required
1	Major Wear or Failed, Repaired During Inspection
0	Immediate Replacement or Emergency Repair Required

Age

Assume that the failure rate for Pole-Mounted Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 30 and 60 years the probability of failure (P_f) for this asset are 10% and 99% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

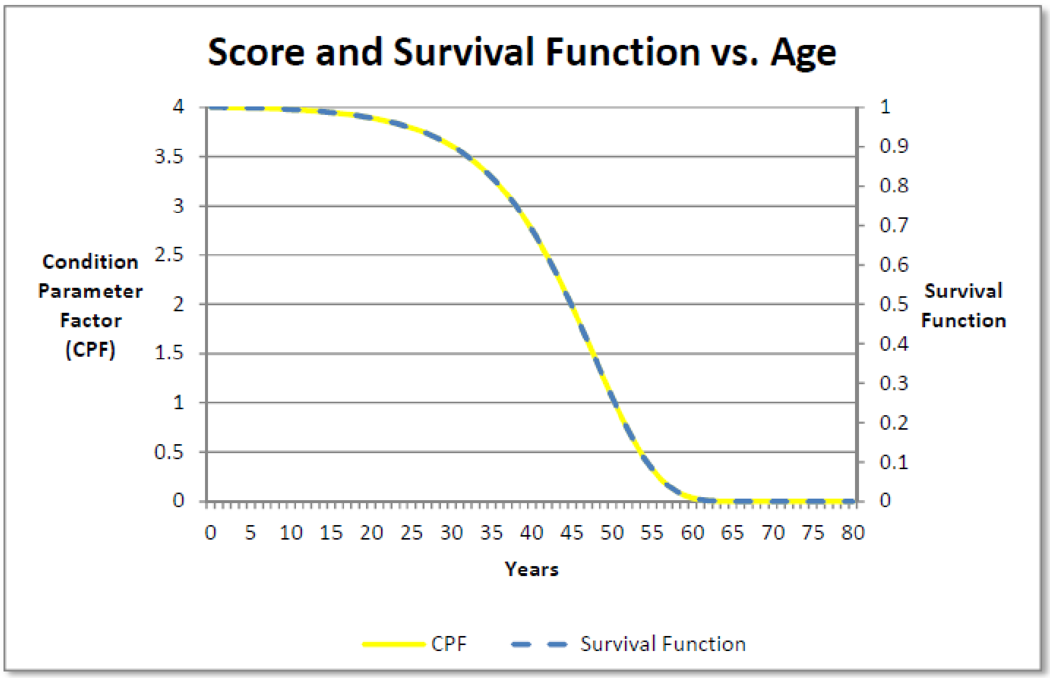


Figure 2-1 Pole-Mounted Transformers Age Condition Criteria

2.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 19 years.

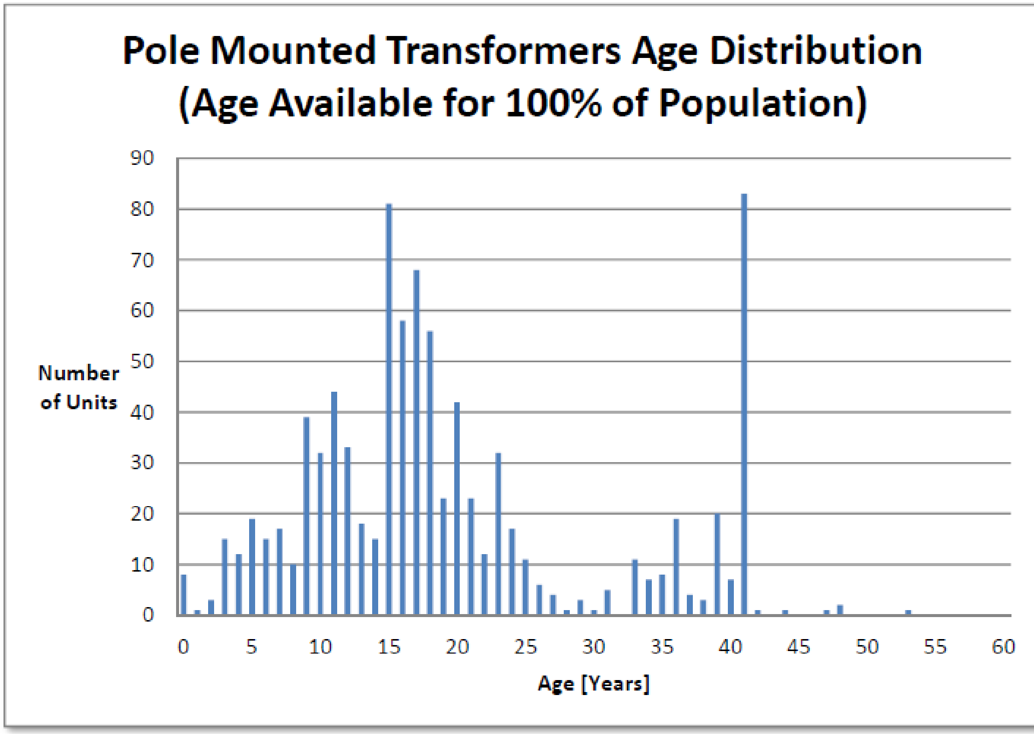


Figure 2-2 Pole-Mounted Transformers Age Distribution

2.3 Health Index Results

There are 894 in-service Pole-Mounted Transformers at STEI. Of these, 892 units were assumed to have had sufficient data for assessment. The average Health Index for this asset group is 90%. The Health Index Results are as follows.

Note that the earliest install year was assumed to be the transformer age. For example, if the transformer was installed in three locations in the years 1980, 1990, and 2000, the transformer age is assumed to be 2010 – 1980 = 30 years. If no installation date is given, the year of purchase is used as the basis for age.

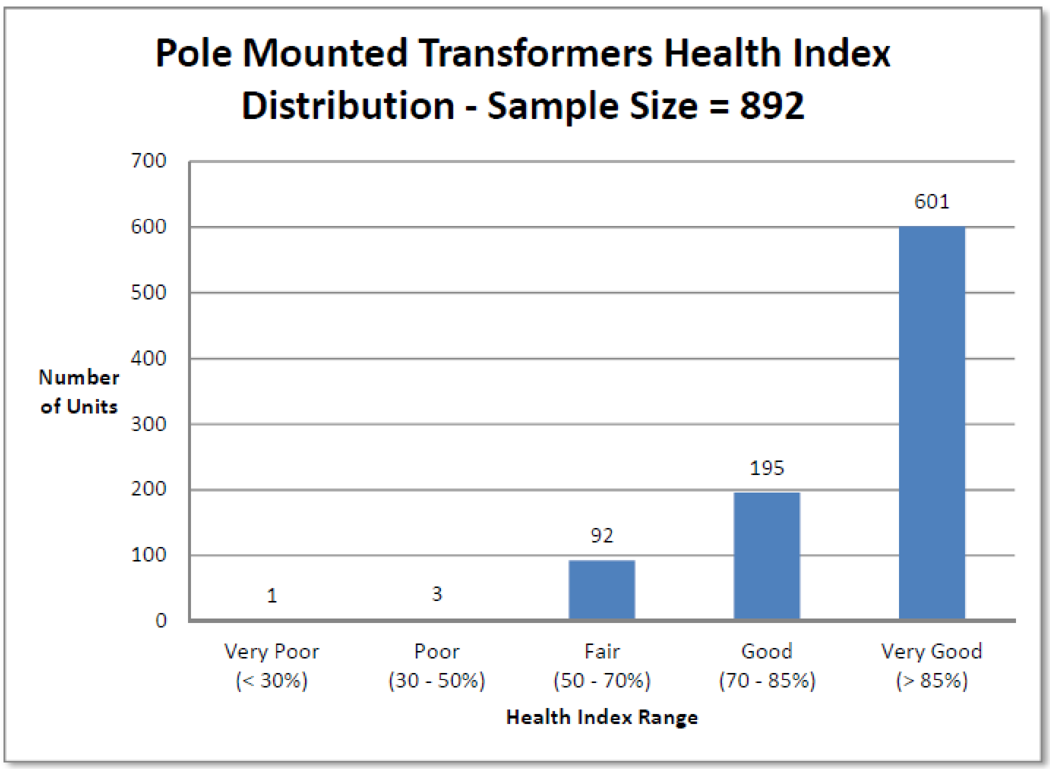


Figure 2-3 Pole-Mounted Transformers Health Index Distribution (Number of Units)

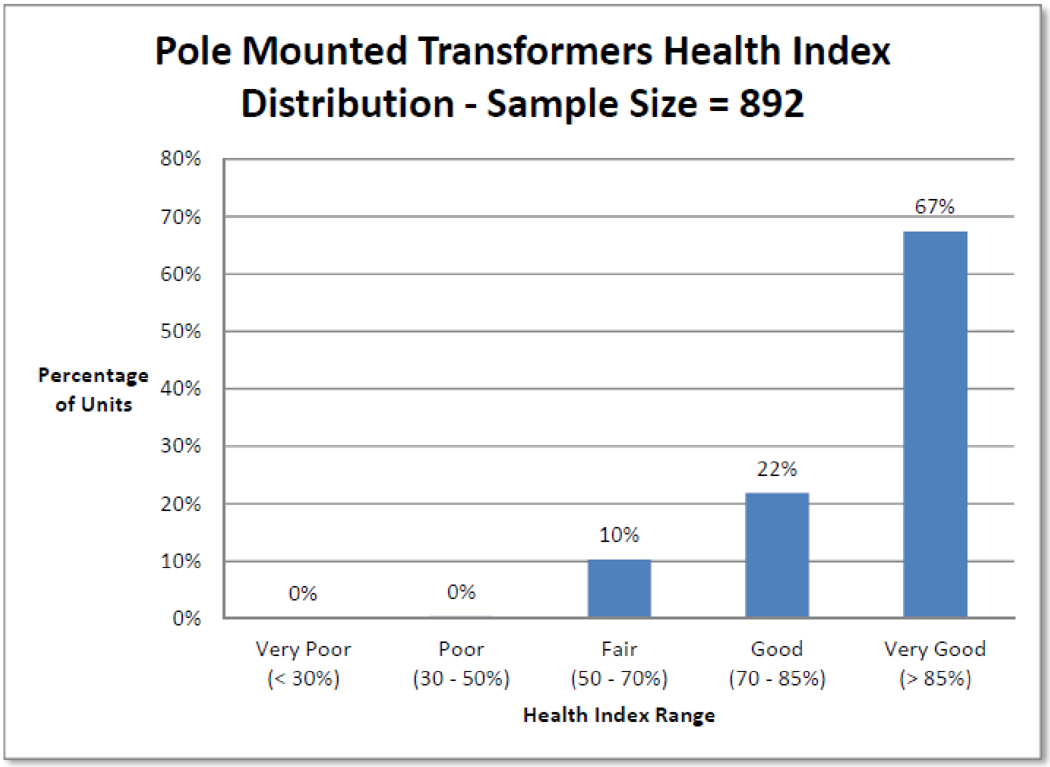


Figure 2-4 Pole-Mounted Transformers Health Index Distribution (Percentage of Units)

2.4 Condition-Based Replacement Plan

As it is assumed that Pole-Mounted Transformers are reactively replaced, the replacement plan is based on asset failure rate f(t), as described in Section II.2.2. Note that the failure rate curve used in the analysis use the same assumptions as POF assumptions as is shown in the Age condition criteria.

The 10 year plan is as follows:

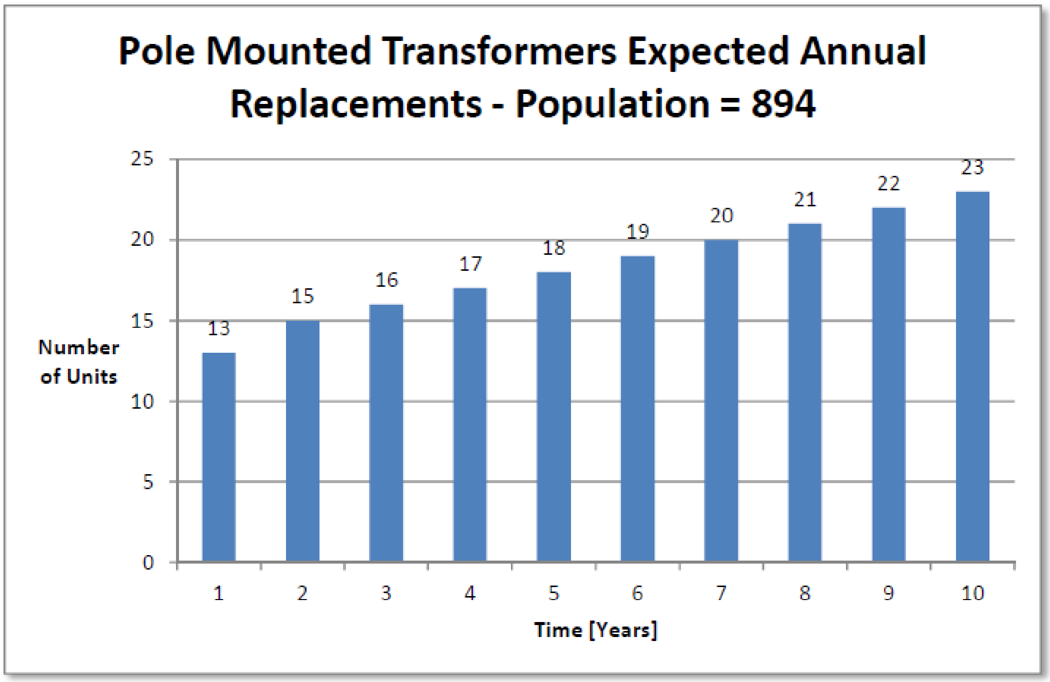


Figure 2-5 Pole-Mounted Transformers Condition-Based Replacement Plan

2.5 Data Analysis

The only available data for pole-mounted transformers are age and manufacturer. As such, the Health Index distribution is based primarily on age distribution.

The data gaps and priorities for filling them are as follows:

Data Gap	
Condition Parameter	Priority
Overall Condition	P1
Oil Leak	P2
Tank Corrosion	P2

The parameters outlined above can be collected through periodic inspections and will allow for a more comprehensive, condition-based assessment. Oil Leak is a yes/no assessment, whereas Overall and Tank Corrosion conditions are end-of-life, or life grade, assessments. Section 2.1.2 details possible inspection score systems for these parameters.

3 Pad-Mounted Transformers

The total Pad-Mounted Transformers population is 499. This includes transformers with the following properties:

Status = “In Service”
Type = “Padmount”, “Padmount Loop & Fuses”, "Padmount Loop Fuses & 4PSwitch" "Padmount Loop Fuses & Switch", "Padmount Radial “, "Padmount Radial & Fuses", or "Padmount Radial & Switch"

3.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for STEI Pad-Mounted Transformers. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows:

Assume a parameter scoring system of 0 though 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

Health Index condition and sub-condition parameters and condition criteria are as follows:

3.1.1 Condition and Sub-Condition Parameters

Table 3-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m	$CPS_{m.max}$
1	Physical condition	3	4
2	Connection & insulation	5	4
3	Service Record	5	4

Table 3-2 Physical Condition (m=1) Weights and Maximum CPF

n	Sub-condition parameter	$WCPF_n$	CPF lookup table	$CPF_{n.max}$
1	Tank Corrosion	3	Table 3-5	4
2	Access	1	Table 3-5	4
3	Trans Base Grade & Level	1	Table 3-5	4
4	Transformer Base	2	Table 3-5	4
5	Debris	1	Table 3-5	4

Table 3-3 Connection & Insulation (m=2) Weights and Maximum CPF

n	Sub-condition parameter	$WCPF_n$	CPF lookup table	$CPF_{n.max}$
1	Secondary connection	1	Table 3-5	4
2	Oil leaks	2	Table 3-5	4
3	Primary Bushing & Elbows	2	Table 3-5	4
4	Grounding	1	Table 3-5	4

Table 3-4 Service Record (m=3) Weights and Maximum CPF

n	Sub-condition parameter	$WCPF_n$	CPF lookup table	$CPF_{n.max}$
1	Overall	2	Table 3-6	4
2	Age	1	Figure 3-1	4

3.1.2 Condition Parameter Criteria

<u>OK or Not OK</u>

Table 3-5 OK or Not OK Criteria

Assuming that at the ages of 30 and 60 years the probability of failure (P_f) for this asset are 10%

CPF	Condition Description
4	OK
1	Repair / Not OK

Life Grade

Life grade gives information related to an asset's remaining life. This scoring system is used for parameters that can affect equipment replacement. Life grade is an assessment based on non refurbish-able or maintainable conditions that lead to asset end of life.

Table 3-6 Life Grade Criteria

CPF	Condition Description
4	As new condition
2	Wear, regular monitoring required
0	Poor condition, replacement required

Age

Assume that the failure rate for Pad-Mounted Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{\alpha\beta})/\beta}$$

S_f	= survivor function
P_f	= cumulative probability of failure

and 99% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

Assuming that at the ages of 30 and 60 years the probability of failure (P_f) for this asset are 10% and 99% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

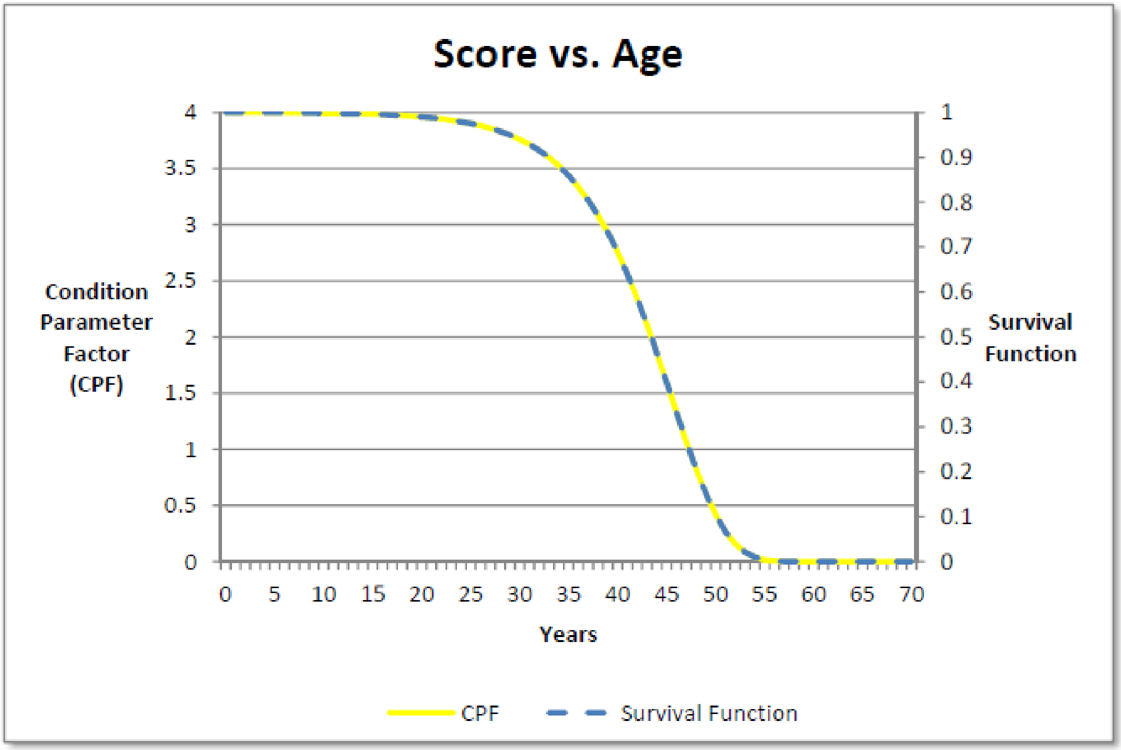


Figure 3-1 Pad-Mounted Transformers Age Condition Criteria

3.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 12 years.

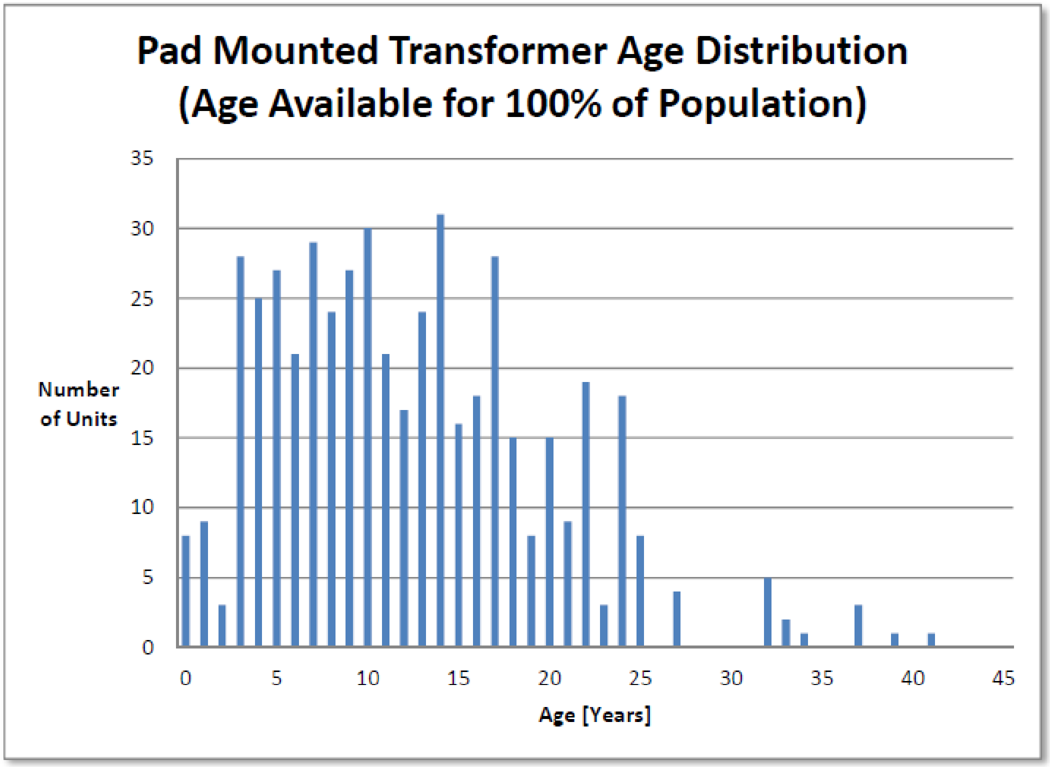


Figure 3-2 Pad-Mounted Transformers Age Distribution

3.3 Health Index Results

There are 499 in-service Pad-Mounted Transformers at STEI. Of these, 499 units were assumed to have had sufficient data for assessment. The average Health Index for this asset group is 97%. The Health Index Results are as follows.

Note that the earliest install year was assumed to be the transformer age. For example, if the transformer was installed in three locations in the years 1980, 1990, and 2000, the transformer age is assumed to be 2010 – 1980 = 30 years. If no installation date is given, the year of purchase is used as the basis for age.

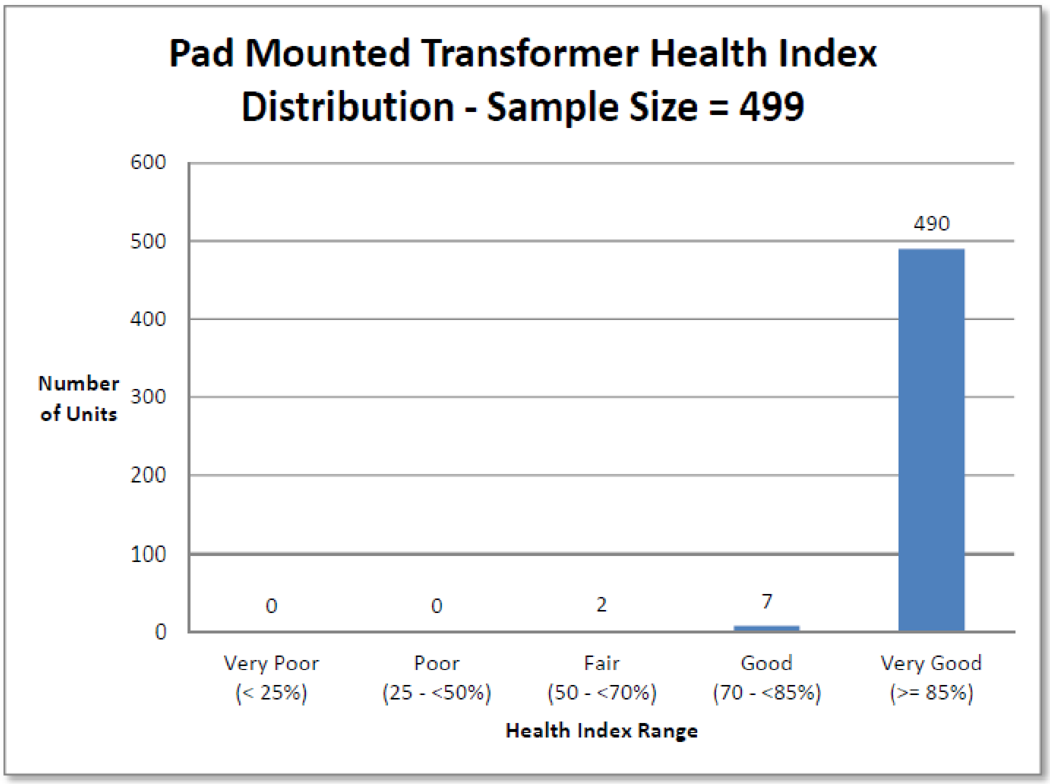


Figure 3-3 Pad-Mounted Transformers Health Index Distribution (Number of Units)

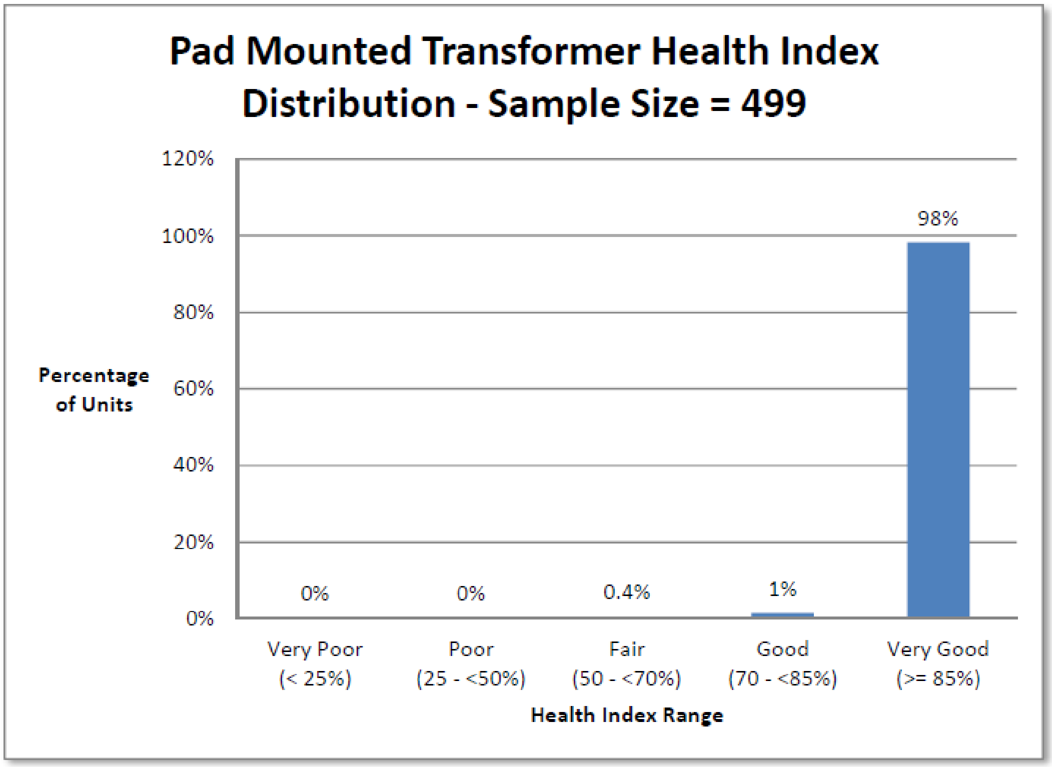


Figure 3-4 Pad-Mounted Transformers Health Index Distribution (Percentage of Units)

3.4 Condition-Based Replacement Plan

As it is assumed that Pad-Mounted Transformers are reactively replaced, the replacement plan is based on asset failure rate f(t), as described in Section II.2.2. Note that the failure rate curve used in the analysis use the same assumptions as POF assumptions as is shown in the Age condition criteria.

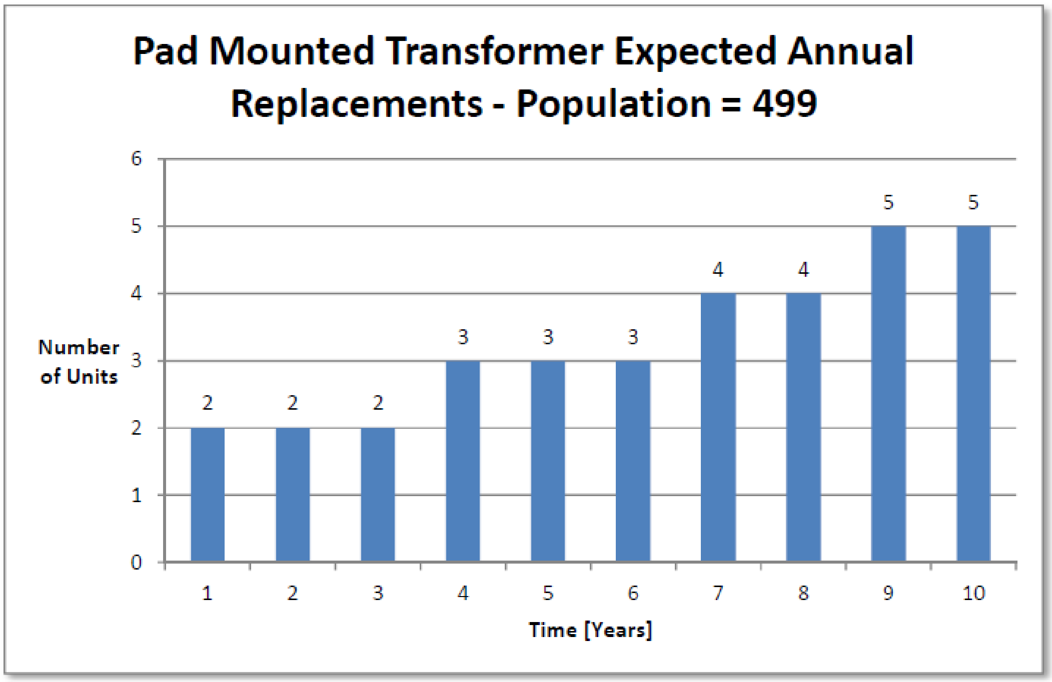


Figure 3-5 Pad-Mounted Transformers Condition-Based Replacement Plan

3.5 Data Analysis

The data available for Pad-Mounted Transformers includes age and inspections.

The data gaps and priorities for filling them are as follows:

Data Gap	
Condition Parameter	Priority
Overall Condition	P2

An Overall life grade assessment is important in giving a general end-of-life assessment for this asset class. Section 3.1.2 details the inspection score system for this parameter.

The granularity of the scoring system used in STEI's inspection forms should be reviewed. Although numerous parameters are accounted for during inspections, all are scored using an "Okay / Repair" system (as shown on the tables in Section 3.1.2). Certain parameters can better reflect end of life by using the scoring system given below. The criteria are detailed on the tables in Section 3.1.2.

Parameter	Current Score System	Recommended Possible Scoring System
Tank Corrosion	Okay/Repair (Table 3-5)	Life Grade (Table 3-6)
Transformer Base	Okay/Repair (Table 3-5)	Life Grade (Table 3-6)
Primary Bushing and Elbows	Okay/Repair (Table 3-5)	Life Grade (Table 3-6)

4 Wood Poles

At the time of this assessment there were 4857 Wood Poles at STESI.

4.1 Health Index Formulation

This section presents the Health Index Formula developed and used for wood, concrete, steel, and aluminum poles. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 though 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

4.1.1 Condition and Sub-Condition Parameters

Table 4-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m	$CPS_{m.max}$
1	Mechanical & electrical	5	4
2	Pole physical	3	4
3	Pole accessories	1	4
4	Overall	4	4

Table 4-2 Mechanical & Electrical (m=1) Weights and Maximum CPF

n	Sub-condition parameter	$WCPF_n$	CPF lookup table	$CPF_{n.max}$
1	Pole Strength	0*	Table 4-9	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

Table 4-3 Pole Physical (m=2) Weights and Maximum CPF

n	Sub-condition parameter	$WCPF_n$	CPF lookup table	$CPF_{n.max}$
1	Shell Rot	0*	Table 4-8	4
2	Brown Cubicle Rot	0*	Table 4-8	4
3	Dry Rot	0*	Table 4-8	4
4	Ring Rot	0*	Table 4-8	4
5	Upper Roof Rot	0*	Table 4-8	4
6	Internal Decay	0*	Table 4-8	4
7	White Heart Rot	0*	Table 4-8	4
8	Fire damage	0*	Table 4-8	4
9	Lighting Damage	0*	Table 4-8	4
10	Mechanical Damage	0*	Table 4-8	4
11	Rodent Damage	0*	Table 4-8	4
12	Wood Borer Damage	0*	Table 4-8	4
13	Wood Pecker Damage	0*	Table 4-8	4

14	Shell Separation	0*	Table 4-8	4
15	Split Top	0*	Table 4-8	4
17	Excessive Checking	0*	Table 4-8	4
18	Spur Cut	0*	Table 4-8	4
19	Enclosed Pocket	0*	Table 4-8	4
20	Hollow Heart	0*	Table 4-8	4
21	Ant Activity	0*	Table 4-8	4
22	Ant Evidence	0*	Table 4-8	4
23	Lean	0*	Table 4-8	4
24	Pole in Water	0*	Table 4-8	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

Table 4-4 Pole Accessory (m=3) Weights and Maximum CPF

n	Sub-condition parameter	$WCPF_n$	CPF lookup table	$CPF_{n.max}$
1	Trees in Wire	0*	Table 4-8	4
2	Guy Wire	0*	Table 4-8	4
3	Defective Ground	0*	Table 4-8	4
4	Crossarm	0*	Table 4-8	4
5	Fire Guard	0*	Table 4-8	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

Table 4-5 Overall (m=4) Weights and Maximum CPF

n	Sub-condition parameter	$WCPF_n$	CPF lookup table	$CPF_{n.max}$
1	Roof Overall	0*	Table 4-7	4
2	Body Overall	0*	Table 4-7	4
3	Age	1	Figure 4-2	4

*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively not included in the formulation.

4.1.2 Condition Parameter Criteria

DamageGrading

Table 4-6 Inspection Condition Criteria

CPF	Condition Description
4	None
3	Minor
2	Moderate
0	Extreme
4	None

LifeGrade

Table 4-7 Life Grade Criteria

CPF	Condition Description
4	GOOD
3	FAIR TO GOOD
2	FAIR
1	FAIR TO POOR
0	POOR

YesorNo

Table 4-8 Yes or No Criteria

CPF	Condition Description
4	Yes
0	No

PoleStrength

Table 4-9 Pole Strength Test Results

CPF	Condition Description
4	100%
2	67%
1	33%
0	0

Age

Assume that the failure rate for Wood Poles exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - \ P_f = e^{-(f-e^{\alpha\beta})/\beta}$$

S_f	= survivor function
P_f	= cumulative probability of failure

Assuming that at the ages of 40 and 75 years the probability of failures (Pf) for this asset are 10% and 99% respectively results in the survival curve shown below. If follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age for wood poles is also shown in the figure below:

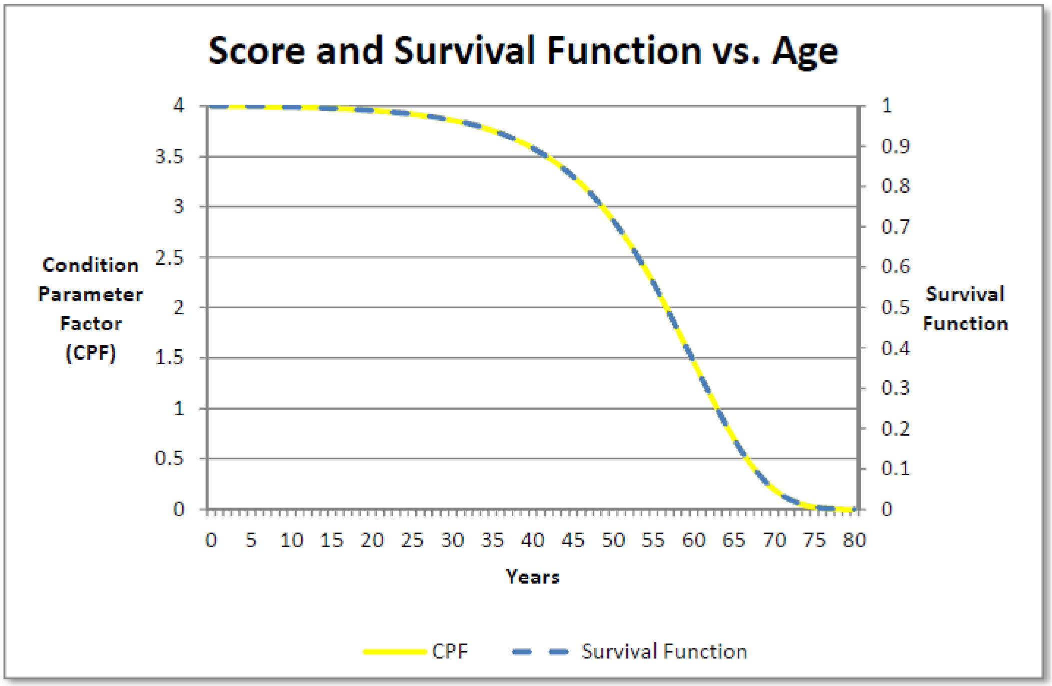


Figure 4-1 Wood Pole Age Condition Criteria

4.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 99.96% of the population. The average age was found to be 27 years.

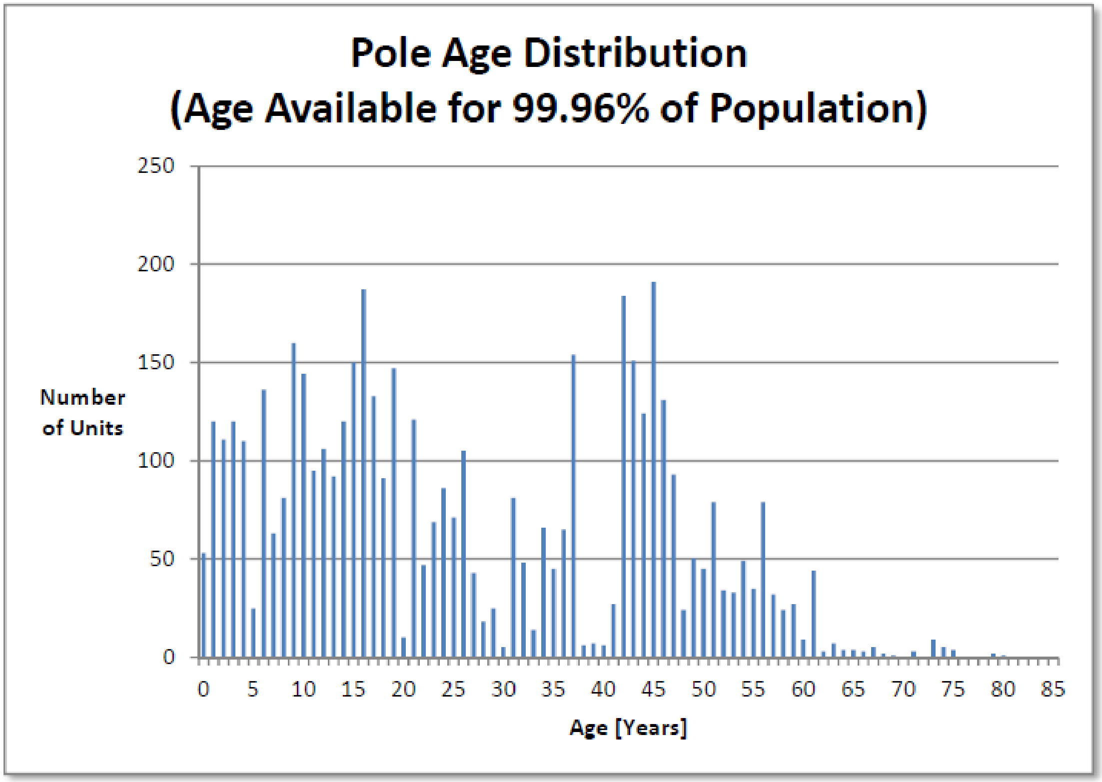


Figure 4-2 Wood Pole Age Distribution

4.3 Health Index Results

There are 4857 installed Wood Poles at STEI. Of these, 4855 units were assumed to have had sufficient data for assessment. The average Health Index for this asset group is 90%. The Health Index Results are as follows.

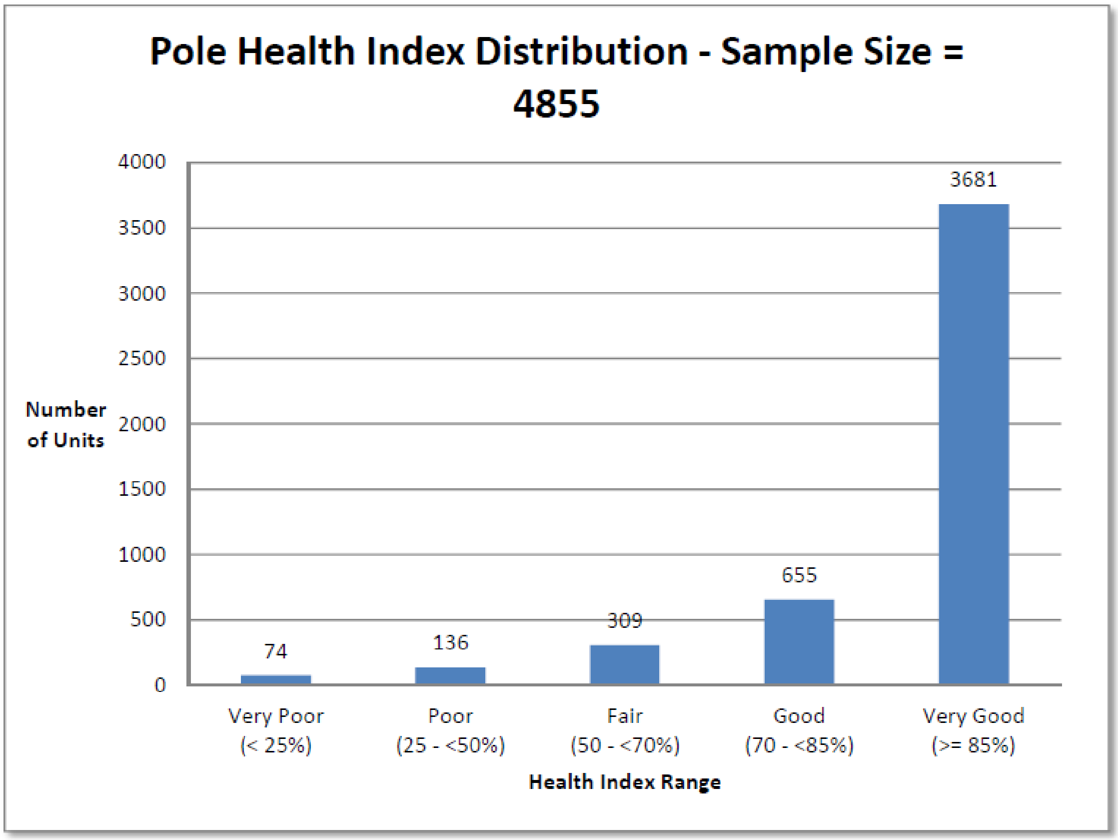


Figure 4-3 Wood Poles Health Index Distribution (Number of Units)

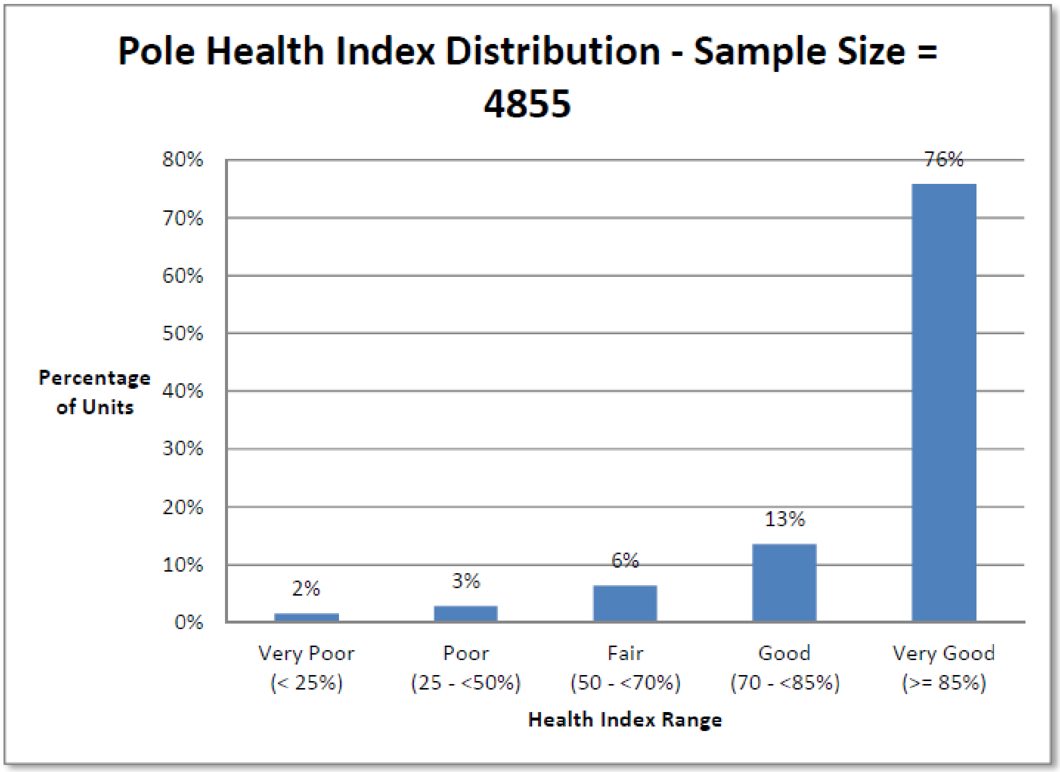


Figure 4-4 Wood Poles Health Index Distribution (Percentage of Units)

4.4 Condition-Based Replacement Plan

Although Wood Poles are generally proactively replaced, the number of expected replacements is estimated using the asset failure rate f(t), as described in Section II.2.2. Note that the failure rate curve used in the analysis use the same assumptions as POF assumptions as is shown in the Age condition criteria.

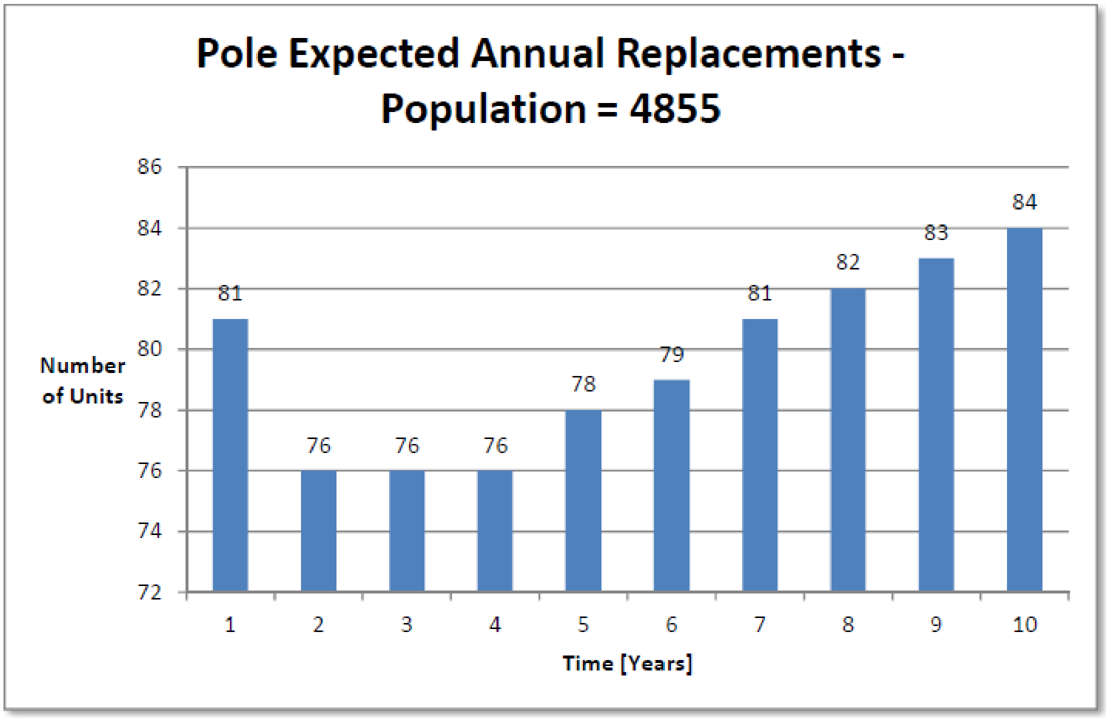


Figure 4-5 Wood Poles Condition-Based Replacement Plan

4.5 Data Analysis

While STEI routinely performs detailed inspections of its wood poles, the detailed inspection records were not available for this year's assessment. As such, the condition assessment for this asset class was based on age only. The required condition data for Poles can be found in the detailed inspection records (e.g. pole strength, specific type of pole damage, split, hollow heart).

5 Overhead Line Switches

At the time of this assessment the Overhead Line Switches population at STESI was 105. The total asset population is 105. This includes transformers with the following properties:

Underground <> "yes"
Type = "Load Interrupter Switch"

5.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for STEI Overhead Line Switches. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows:

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

5.1.1 Condition and Sub-Condition Parameters

Table 5-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	$CPS_{m.max}$
1	Operating Mechanism	14	4
2	Contact Performance	7	4
3	Arc Extinction	5	
4	Insulation	2	4
5	Service Record	7	4

Table 5-2 Operating Mechanism (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	CPF Lookup table	$CPF_{n.max}$
1	Mechanism	9	Table 5-7	4
2	Connectors	1	Table 5-7	4

Table 5-3 Contact Performance (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	CPF Lookup table	$CPF_{n.max}$
1	Switch Blade	1	Table 5-7	4
2	Switch Blade Closure	1	Table 5-7	4

Table 5-4 Arc Extinction (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	CPF Lookup table	$CPF_{n.max}$
1	Arc Suppressor	2	Table 5-7	4
2	Contacts	1	Table 5-7	4

Table 5-5 Insulation (m=4) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	CPF Lookup table	$CPF_{n.max}$
1	Insulator	1	Table 5-7	4

Table 5-6 Service Record (m=5) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	CPF Lookup table	$CPF_{n.max}$
1	Age	3	Figure 5-1	4

5.1.2 Condition Parameter Criteria

Good or Not Good

Table 5-7 Good / Not Good Criteria

CPF	Condition Description
4	Good (Satisfactory)
0	Not-Good

Life Grade

Table 5-8 Life Grade Condition Criteria

CPF	Condition Description
4	As new condition
2	Wear, regular monitoring required
0	Poor condition, replacement required

Age

Assume that the failure rate for Overhead Line Switches exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{\alpha\beta})/\beta}$$

S_f	= survivor function
P_f	= cumulative probability of failure

Assuming that at the ages of 30 and 55 years the probability of failure (P_f) for this asset are 10% and 99% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

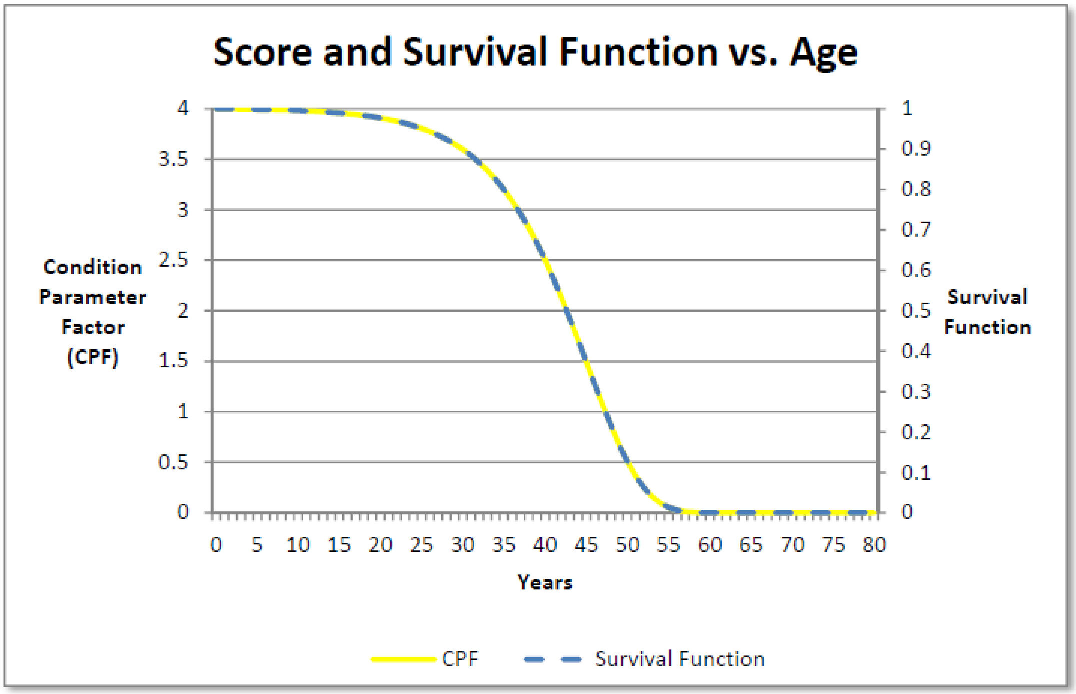


Figure 5-1 Overhead Line Switches Age Condition Criteria

5.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 51% of the population. The average age was found to be 13 years.

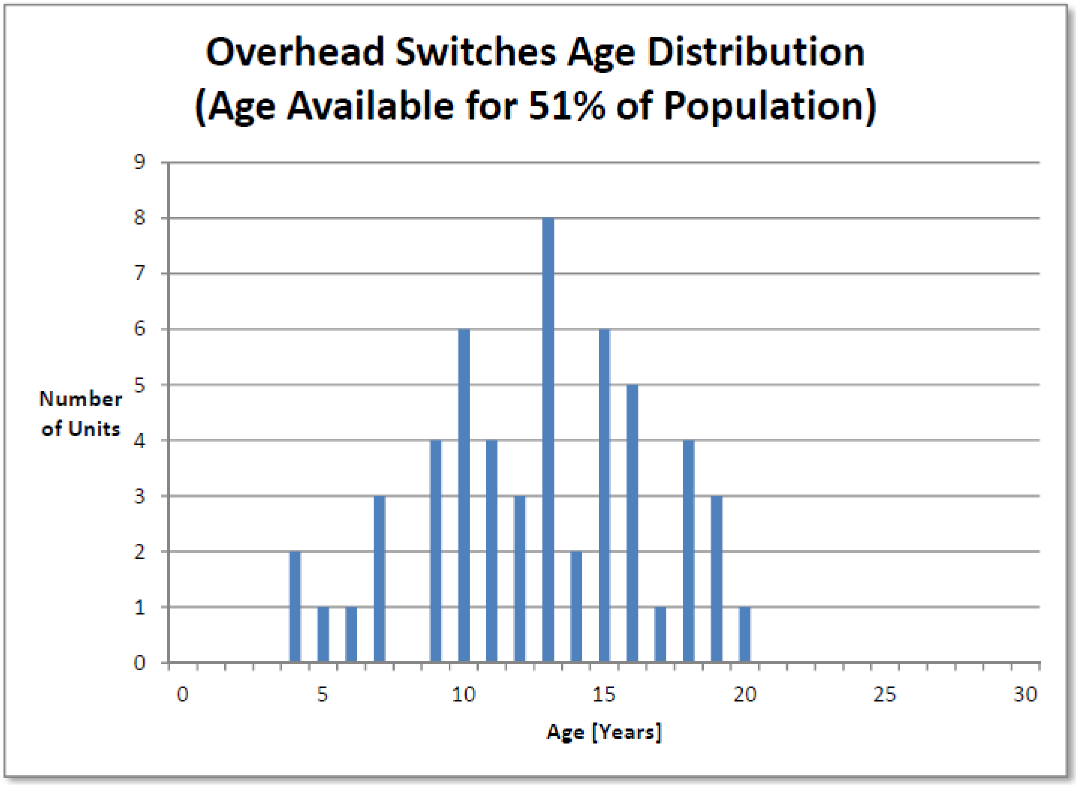


Figure 5-2 Overhead Line Switches Age Distribution

5.3 Health Index Results

There are 105 in-service Overhead Line Switches at STEI. Of these, 98 units were assumed to have had sufficient data for assessment. The average Health Index for this asset group is 97%. The Health Index Results are as follows.

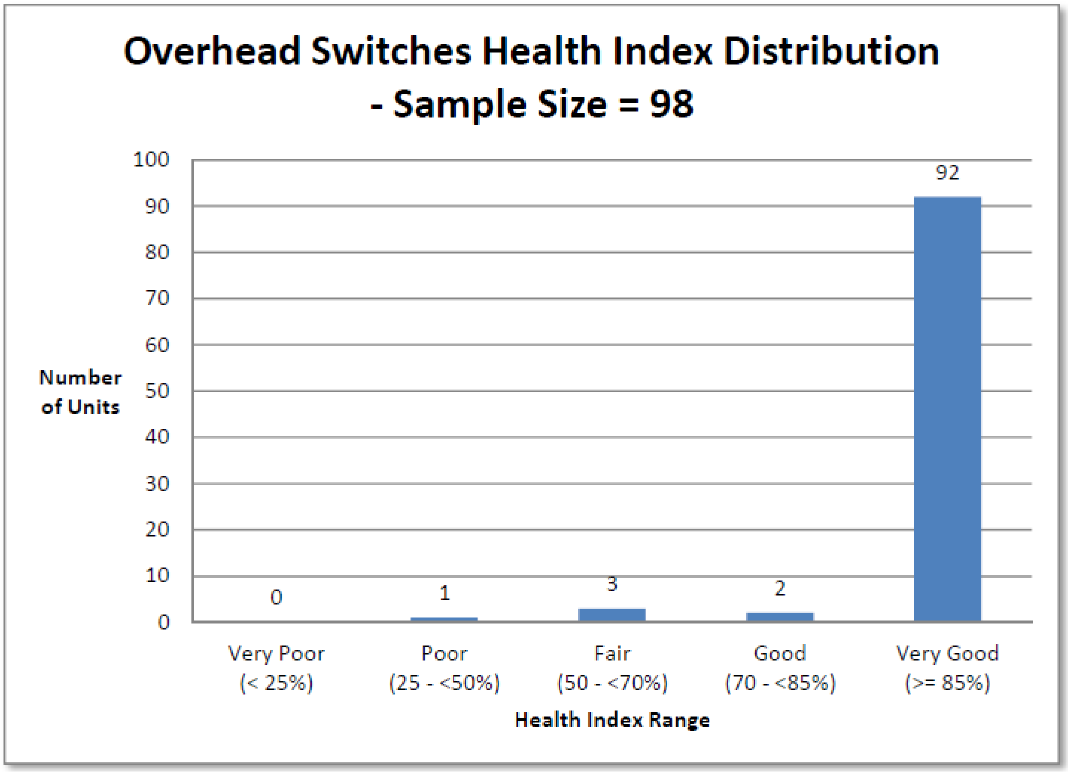


Figure 5-3 Overhead Line Switches Health Index Distribution (Number of Units)

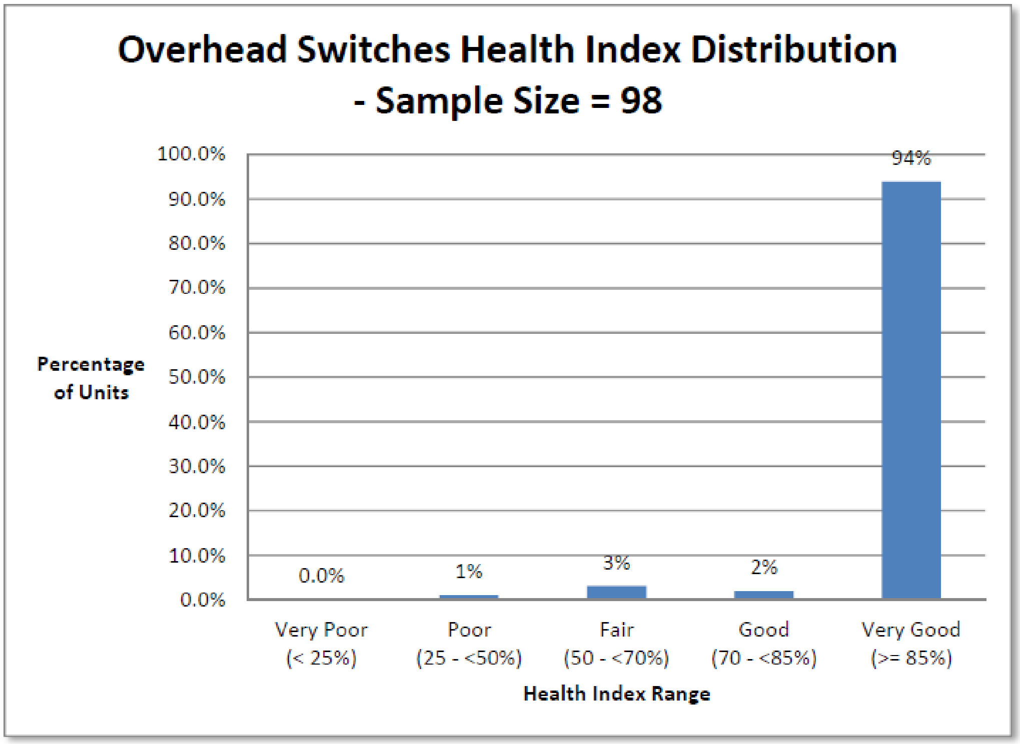


Figure 5-4 Overhead Line Switches Health Index Distribution (Percentage of Units)

5.4 Condition-Based Replacement Plan

As it is assumed that Overhead Line Switches are reactively replaced, the replacement plan is based on asset failure rate f(t), as described in Section II.2.2. Note that the failure rate curve used in the analysis use the same assumptions as POF assumptions as is shown in the Age condition criteria.

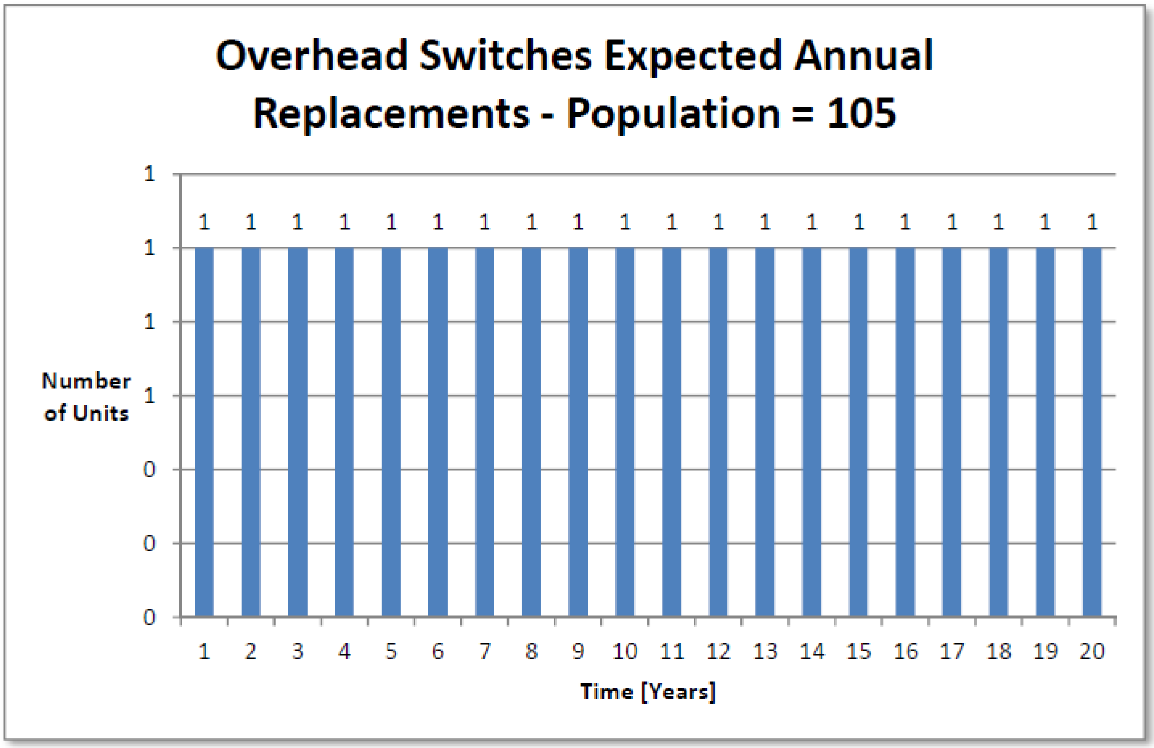


Figure 5-5 Overhead Line Switches Condition-Based Replacement Plan

5.5 Data Analysis

There were no data gaps for this asset class. Good information is being collected during inspections.

The granularity of the scoring system used for the parameter Insulator should be reviewed. A Life Grade scoring system would better reflect end of life conditions. The life grade criterion is detailed on Table 5-8.

Parameter	Current Score System	Recommended Scoring System
Insulator	Good (Satisfactory) / Not Good (Table 5-7)	Life Grade (Table 5-8)

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3 Capital Expenditure Plan (Ch.5.4)

3.1 Summary (Ch.5.4.1)

a) Capability to connect new load or generation

STEI is forecasting that the current system has ample capacity for renewable generation and new customer loads for the foreseeable future and as such, STEI does not expect to make any network investments within the 5-year planning period. STEI's distribution system capital program continues to focus on distribution system replacement and voltage conversions. Residential rear yard 2,400 V overhead and secondary lines are being converted to 27.6 kV underground in the front boulevards and rebuilding the overhead in rear yards.

It is also worth noting that the voltage conversion work, while driven mainly by equipment reaching the end of its useful life, will result in more system capacity on the primary and secondary distribution systems. This will support more energy intensive applications such as electric vehicles and allow the system to accept more renewable energy generation. The increase of capacity on the primary side is in the range of 40% – 50% while the secondary side will allow about 67% more energy movement.

b) Total Annual Capital Expenditures

Section 3.4 Appendix 2-AA Capital Projects Table (attached) lists STEI's capital projects in the 10-year period 2010 to 2019 and shows, by year, the actual capital expenditure for projects in the historical period together with the planned capital expenditure for projects in the bridge year and forecast period.

c) Effect of Planning Process on Capital Expenditures

STEI has developed a prudent capital budget process and system of prioritization that takes account of its corporate emphasis on business performance and accountability. This system reflects its long term investment strategy, recognizes its shorter term requirements and addresses the ongoing need for STEI to respond to external and internal priority changes. It respects the priorities of a wide range of stakeholders, STEI's corporate strategies and regulatory requirements.

The capital budget process also takes into account the relative priorities of the proposed investments primarily as dictated by the amount of discretion afforded to STEI by the various applicable Acts, Regulations and Codes. Specifically:

Required non-discretionary budget items (i.e. having virtually no flexibility) include:

- Projects to accommodate new customers and load growth in order to meet the Company's obligation to connect
- Projects to accommodate Municipal, Region and Ministry requirements
- Expenditures to satisfy regulatory initiatives, environmental or health & safety risks, the Green Energy and Green Economy Act, and the Company's Conditions of Service.

Medium term discretionary budget items (i.e. with some timing flexibility) include:

- Infrastructure renewal projects
- Fleet/tools
- Distribution Automation
- Information technology

The capital expenditures have been allocated to the following categories;

System Access expenditures and variances

The planned annual capital expenditures during the 2010 to 2013 period for connecting new sub-divisions and providing other *ongoing* power system access have been in the $0.5 million to $1.0 million range. During the bridge year and throughout the forecast period because of the smaller number of new sub-divisions expected, the plan amount is constant at $0.2 million

System Renewal expenditures and variances

The main thrust of STEI's System Renewal activities throughout the historical and forecast period is replacement of its 50-year old 2,400 V system that is rapidly approaching the end of its life and which, because it is ungrounded, presents a significantly higher safety risk to staff and public when a downed line occurs. (When a single energized conductor contacts the ground or other items like fences/homes, it will not trip the line). The planned expenditure each year over the historical period falls in the $0.8 million to $1.1 million range with larger planned expenditures in the $1.2 million to $1.6 million range in the bridge year and forecast years as the renewal/conversion program is accelerated towards completion.

System Service expenditures and variances

Expenditures in this investment category were planned for only four years in the 10-year DS Plan period; i.e. historical year 2011, bridge year 2014, and forecast years 2015 and 2018; no expenditures were planned in the balance of the years. All four planned expenditures were in the $0.2 million to $0.3 million range.

General Plant expenditures and variances

In the 2012 to 2014 period planned expenditures were in the $0.7 million to $0.9 million range; during the forecast period, planned expenditures decrease from $0.5 million to $0.2 million.

d) Total Capital Cost of Material Expenditures

Section 3.4 Appendix 2-AB, i.e. Table 2 – Capital Expenditure Summary (attached), consolidates the information in Appendix 2-AA by investment category for each year and, in addition to the actual and planned capital expenditures already noted, includes the plan amount and variance amount for each project in the historical period.

e) Information Related to Regional Planning

From the Ontario Power Authority's Letter of Comment March 13, 2014: "The OPA notes that STEI is part of "Group 2" and the London area for the regional planning process prioritized for 2014 and 2015. At this time however, neither a Regional Infrastructure Plan, nor an Integrated Regional Resource Plan ("IRRP") has commenced for STEI's service territory."

f) Customer Engagement

STEI continually engages its customers in various forums and assesses the effectiveness of these activities. Specifically, STEI has engaged in independent 3rd party customer surveys, internal surveys, web surveys, bill inserts, bill messages, Home Shows and Business Expos. STEI is also in the process of working collaboratively with other utilities to provide a Roving Energy Manager to assist customers with load reduction.

STEI has engaged UtilityPULSE to conduct independent customer satisfaction surveys since 2002. These bi-annual customer satisfaction surveys provide information that supports discussions surrounding improving customer service at all levels and departments within STEI. The survey asks customers questions on a wide range of topics, including: overall satisfaction, reliability, trust, customer care, outages, billing, management operations and corporate image. The results help determine what is being done well and what needs improvement.

Historically, STEI surveys have identified the importance of good system reliability to customers. This input was one of the key factors in STEI adopting the Voltage Conversion program which is the core of the current DS Plan. Also as a result of customer feedback, STEI has recently introduced a new web site – see details later in this section.

g) System Development over Next 5 Years

In developing its 5 year capital investment plans, STEI must satisfy its non-discretionary obligations and balance them with projects that have been evaluated and supported by data from its annual performance review, its Asset Management Strategy (see section 2.1) and the good judgement of its professional management team. Current levels of expenditures on rebuild projects, distribution automation and maintenance have kept STEI's reliability performance at solid North American levels. However, long term planning will identify expenditures for renewals as the distribution system infrastructure ages. This may result in assets remaining in service for longer periods and being subjected to closer condition assessments to minimize performance risks. Nevertheless, the biggest change to STEI's system expected over the next 5 years is the completion of the Voltage Conversion program.

In preparation for the development of this current DS Plan, management reviewed its previous plan to ensure the decision made some 5 years ago continued to be the optimal solution. A careful analysis of all the factors led to the firm conclusion that completing the replacement of the 2,400 V system with the modern 27.6 kV system was indeed the correct approach. In allocating funds each year in the 2015 to 2019 forecast period, STEI has continued to balance the desire to fund the Voltage Conversion program to the maximum extent possible with the need to perform other smaller refurbishment/replacement work together with the desire to keep the bill impacts as level as possible and within a reasonable range.

When reviewing capital investments in the City of St. Thomas residential, commercial and industrial load growth continues to be a feature – albeit at a reduced level; a modest load growth has recently been experienced after a 22% drop in load in the 2005-2012 period due to industrial closures. The analysis of the distribution system for renewable energy generation does not indicate a requirement for any significant capital expenditures for the connections proposed by customers and the amount of proposed REG (FIT and microFIT projects).

h) Customer Driven Projects/Programs

In response to customer preferences STEI introduced a new user friendly web site in early 2012. It is intended to be an informative tool to provide updates, news items and assist our customers 24x7. Customers can learn about latest news items as related to STEI; electricity rates, safety programs, various OPA initiatives and conservation tips as well as offering many on line services. Customers can easily navigate by way of the web site to Customer Connect a web portal tool that allows customers to view and monitor;

- TOU price period indicator
- TOU usage as recent as the day before and going back as far as 2012
- TOU usage charts with weather overlay
- Usage chart with associated cost
- Billing and payment transaction history going back to 2000
- Electric meter reading history going back to 2000
- Usage comparison from bill to bill, year to year
- E-Bill presentment
- Customer set notifications and alerts based on usage or dollars
- All data is available for downloading

To take advantage of technology-based opportunities and to support the energy efficiency needs of the larger customers, STEI has applied to the Ontario Power Authority for a Roving Energy Manager (REM). The REM will be an important element in assisting STEI in meeting its goals associated with the Ontario Power Authority Conservation Demand Management Program. The REM will be responsible for assisting STEI commercial and industrial customers to overcome traditional barriers related to energy management. The REM is expected to assist in the identification, reporting, and implementation of energy saving opportunities, and become a significant resource of knowledge to larger STEI consumers.

STEI works closely with our local social agency, St Thomas-Elgin Ontario Works. St Thomas Elgin Ontario Works ("OW") provides financial and employment assistance to people in financial need. OW and STEI staff work together almost daily to resolve collection type issues and concerns of customers.

To demonstrate innovative technologies, STEI is considering the installation of small renewable energy generation (REG) equipment at STEI's head office in order to encourage customer REG adoption.

St. Thomas Energy, keeping true to the corporate vision ***"To be the industry leader in the provision of energy solutions and services,"*** is helping to green Ontario's highways by installing the first public electric vehicle (EV) charging station in St. Thomas and Elgin County.

3.2 Capital Expenditure Planning Process Overview (Ch.5.4.2)

3.2.1 High Level Inputs to the Capital Expenditure Planning Process

STEI has developed a prudent capital budget process and system of prioritization that takes account of its corporate emphasis on business performance and accountability. This system reflects its long term investment strategy, recognizes its shorter term requirements and addresses the ongoing need for STEI to respond to external and internal priority changes. It respects the priorities of a wide range of stakeholders, STEI's corporate strategies and regulatory requirements.

The capital budget process also takes into account the relative priorities of the proposed investments primarily as dictated by the amount of discretion afforded to STEI by the various applicable Acts, Regulations and Codes. Specifically:

Required non-discretionary budget items (i.e. having virtually no flexibility) include:

- Projects to accommodate new customers and load growth in order to meet the Company's obligation to connect
- Projects to accommodate Municipal, Region and Ministry requirements
- Expenditures to satisfy regulatory initiatives, environmental or health & safety risks, the Green Energy and Green Economy Act, and the Company's Conditions of Service.

Medium term discretionary budget items (i.e. with some timing flexibility) include:

- Infrastructure renewal projects
- Fleet/tools
- Distribution Automation
- Information technology

In developing its capital investment plans, STEI must satisfy its non-discretionary obligations and balance them with projects that have been evaluated and supported by data from its annual performance review, its Asset Management Strategy (see section 2.1) and the good judgement of its professional management team. Current levels of expenditures on rebuild projects, distribution automation and maintenance have kept STEI's reliability performance at solid North American levels. However, long term planning will identify expenditures for renewals as the distribution system infrastructure ages. This may result in assets remaining in service for longer periods and being subjected to closer condition assessments to minimize performance risks.

The following high level inputs are investigated and evaluated in detail and collectively contribute to a final capital investment budget:

- New load growth and development projects
- Municipally driven projects
- Regulatory initiatives
- System reliability
- Distribution Automation

- Infrastructure renewal projects
- Elimination of environmental/health or safety risks
- Fleet/Tools
- Information technology and corporate administration
- Renewable energy generation
- Impact on customer bills
- Customer engagement

Each of these priorities is addressed below. In addition, on-going assessments of the health and performance of the distribution system are captured on a regular basis. Both of these items contribute significantly to the development and prioritization of budgets with particular attention to the impact on customer's bills.

(a) New load growth and development projects

STEI has its obligations to connect defined in section 28 of the *Electricity Act:*

> 28.1 *A distributor to whom section 28 applies shall connect a building to its distribution system in such manner as may be prescribed by regulation, under such circumstances as may be prescribed by regulation, for such properties or classes of properties as may be prescribed by regulation, and for such consumers or classes of consumers as may be prescribed by regulation. 2010, c. 8, s. 37 (3).*

This reinforces the importance of good planning and capital investments in the City of St. Thomas where residential and commercial/industrial development continues to be a feature – albeit at a reduced level; a modest load growth has recently been experienced after a 22% drop in load in the 2005-2012 period due to industrial closures. Through close cooperation with staff from the City and the Region, STEI has consistently met the required expansion of its distribution system by providing the supply infrastructure and capacity. This requires capital investments and realistic estimates of load growth for system planning. Back in the 1980s at a time of significant growth in the area, Regional planning with Ontario Hydro identified the requirement for a new Transformer Station (Edgeware T.S.) which was subsequently constructed and commissioned.

Capital expenditures for new load growth are not discretionary and STEI's budgeting process treats them as priority items. However, they are part of the long term planning process and the timing of these expenditures can sometimes be shifted as the rate of growth fluctuates (e.g. with economic conditions). The provision for built-in reliability also has to be accommodated and this has to be consistent with customers' high expectations and regulatory requirements.

(b) Municipally driven projects

These projects are driven primarily by the City of St. Thomas and the Region with additional requirements from the Ministry of Transportation. In these circumstances, the relocation of STEI facilities is required in accordance with the *Public Service Works on Highways Act*. These projects are planned and funded within municipal, regional and provincial budgets but historically they are often difficult to schedule for LDCs as they rely on multiple schedules for funding, engineering, approvals and construction schedules outside of their control.

The act prescribes a formula for the apportionment of costs that allows for the road authority to contribute 50% of the “cost of labour” towards the relocation costs. Specifically:

> *Apportionment of costs of taking up:*
> *The road authority and the operating corporation may agree upon the apportionment of the cost of labour employed in such taking up, removal or change, but, subject to section 3, in default of agreement such cost shall be apportioned equally between the road authority and the operating corporation, and all other costs of the work shall be borne by the operating corporation. R.S.O. 1990, c. P.49, s. 2 (2).*
>
> > *“cost of labour” means,*
> >
> > *(a) the actual wages paid to all workers up to and including the foremen for their time actually spent on the work and in travelling to and from the work, and the cost of food, lodging and transportation for such workers where necessary for the proper carrying out of the work,*
> >
> > *(b) the cost to the operating corporation of contributions related to such wages in respect of workers’ compensation, vacation pay, unemployment insurance, pension or insurance benefits and other similar benefits,*
> >
> > *(c) the cost of using mechanical labour-saving equipment in the work,*
> >
> > *(d) necessary transportation charges for equipment used in the work, and*
> >
> > *(e) the cost of explosives; (“coût de la main-d’oeuvre”)*

Due to the uncertainties of the municipal planning, the scheduling and funding for these projects are often very speculative from STEI’s planning perspective. Municipal funding can become available at very short notice or conversely projects become delayed through the approvals process. However, close communications with the road authorities are maintained to minimize problems with schedules.

At the time of budgeting and with the best information available from the respective road authorities, STEI’s capital investment budget carries provision for these projects. STEI retains flexibility to accommodate changes identified by the municipal authorities.

(c) Regulatory initiatives

This is a newer feature of STEI’s planning and capital investment processes. STEI’s obligation to install and commission Smart Meters throughout its service area is a prime example of a non-discretionary project initiated by the government. STEI successfully deployed Smart Meters and met the government’s target completion date while maintaining normal day-to-day operations.

The Green Energy and Green Economy Act (GEGEA) requires distributors to accommodate a wide variety of renewable energy generation projects under the Ontario Power Authority's FIT and microFIT programs. STEI has embraced the prospects for this new electricity supply model though it introduces a new set of unknowns into the local supply planning equation and therefore into the capital budgeting process. Within the bounds of land use approvals and realistic business models, uncertainty remains as to where and when renewable energy generation projects may be proposed as well as the relative size of the proposals.

While this uncertainty creates complexity from a planning perspective it is also capable of bringing supply opportunities to market that may result in reduced capital expenditures and improvements to the overall efficiency of the distribution system. To date, STEI has connected 2 FIT and 36 microFIT projects.

All licenced distributors in Ontario have to comply with Ontario Regulation 22/04 Electrical Distribution Safety and compliance with this regulation is subject to an annual external audit. Section 4 of the regulation sets the public safety standards and includes the statement:

> *"All distribution systems and the electrical installations and electrical equipment forming part of such systems shall be designed, constructed, installed, protected, used, maintained, repaired, extended, connected and disconnected so as to reduce the probability of exposure to electrical safety hazards. O. Reg. 22/04, s. 4 (2)."*

To confirm compliance with the above, the auditors reference the Distribution System Code, specifically the section on System Inspection Requirements and Maintenance. This reinforces STEI's commitment to maintaining its system in accordance with good utility practice and performance standards that could result in unscheduled capital expenditure priorities.

(d) System reliability

STEI's priority and close monitoring of its reliability is a prime feature of its annual performance. Attention is given to the annual performance of every feeder at all voltage levels. Feeder outage times and momentary interruptions are reviewed and analyzed for trends and potential recommendations for improvement. For example, such reviews have highlighted reliability issues that are directly related to tree limbs or animal interference. This has resulted in more intensive tree trimming in some areas and the introduction of insulator guards to reduce wildlife contacts.

In accordance with Section 7.3.2 of the OEB's Electricity Distribution Rate Handbook, STEI records and reports the overall Service Reliability Indices for its distribution system. By this measure, STEI's reliability performance has been maintained consistent with industry expectations and regulatory requirements.

In planning expenditures based on reliability, consideration is also given to the nature of specific customers whose needs may be different from other customers. For example, the priorities for a single residential customer and an industrial customer employing hundreds of staff with production reliance on electrical power require different evaluation criteria when being factored into the budget allocation process.

(e) Distribution Automation

Distribution automation is a general term covering a wide range of technology applications that can enhance the operation and reliability of a distribution system.

Within the distribution industry today, automation is generally only applied to the larger voltage feeders; the smaller numbers of customers on the lower voltage feeders do not usually justify similar expenditures and these feeders are well protected by the circuit breakers at the respective substations. The installation of a Supervisory Control and Data Acquisition (SCADA) system in any LDC is a major step forward in responding to serious system outages in that the installation of this equipment improves response times and enhances the flexibility of the system resulting in increased reliability to a large number of customers.

The precise role of distribution automation within the STEI service area is currently being evaluated together with developing a clear understanding the optimal cost-benefit investment balance for STEI's customers. Until that picture is clear, no large-scale automation investments will be made for STEI.

Nevertheless, the sub-role of Data Automation within the STEI service area is clear and STEI has acquired Data Automation equipment as a step in its eventual coupling with a SCADA system in order to assist with the remote monitoring and control of its main feeders. The experience gained by the distribution industry in Ontario will help position STEI well for the installation of distribution automation equipment; this shared learning approach is consistent with the government's emphasis on Smart Grid technologies within the GEGEA.

(f) Infrastructure renewal projects

STEI has an on-going commitment to infrastructure renewal through its asset management strategy. The key infrastructure renewal projects in the LDC are mainly in support of moving from the original 13.8kv delta sub-transmission system to the safer and more efficient 4-wire Wye 27.7kv system.

The following items provide a high level summary of its approach to infrastructure renewal projects.

Overhead

In order to increase safety and reliability, all primary 2.4kv distribution is progressively being removed from backyards and being replaced with 27.6kv underground distribution from the street. The overhead secondary services bus and overhead service wire remain in the backyards but are supplied by underground pad-mounted transformers from the street.

In addition, pole testing and pole replacements are ongoing priorities and are continuously addressed in those areas where the supply is expected to remain overhead for some period of time. For example, spot replacements are identified and addressed through an annual pole replacement program. A number of areas in the City of St. Thomas continue to have rear-lot construction where access is a major issue due to the presence of trees. These are encountered frequently and require attention from an operational and safety standpoint. The timing and amount of expenditure for renewal of the overhead system are items for continuous consideration within the capital budget process.

Underground

Similar to many LDCs in southern Ontario, some years back STEI made a commitment to underground residential distribution (URD) construction in specific parts of the City. This infrastructure has exhibited its own signs of aging. Primary cable failures have increased and are tracked annually. Submersible transformers are also a feature of some older neighbourhoods and are an expensive legacy. Underground system rebuilds are very capital intensive and have become an important priority that is evaluated annually and is a significant feature of the long term infrastructure renewal plans.

Substations

STEI owns and operates six municipal substations within its distribution system that transform 27.6 kV supply down to lower distribution voltages. These substations were all built in 1978 or 1979. While providing good reliability in the older neighbourhoods, the substations are an expensive legacy; they require on-going maintenance and renewal of major components such as power transformers and switchgear. These renewals are a function of condition and age and must be factored into the long term capital budget process.

Buildings

Many of STEI's substations are housed within custom buildings, designed specifically for high voltage equipment with the appropriate public safety and security elements built into the designs. Maintaining a high standard of safety and functionality requires continual and planned upkeep and may on occasion require capital investment.

The STEI office facilities were originally constructed in 1992. While enhancements have been made over the years, it will continue to require capital investments to maintain its physical integrity and so that STEI can provide suitable working conditions for all its employees. A further upgrade is planned for 2014.

Summary

Infrastructure renewal projects, buildings, overhead, underground and substations are an essential component of STEI's investment strategies. The ratio of residential underground to overhead installations is continuing to increase in accordance with current practices as just discussed. Inherently this will increase the future capital investments in infrastructure renewal due to the additional costs of underground projects. The timing of all renewal investments can be somewhat discretionary, allowing for some flexibility in the capital budget process, but renewals cannot be ignored in the long term investment strategy.

(g) Elimination of environmental/health or safety risks

STEI has always respected environmental/health or safety issues and addresses them through the appropriate budget allocations.

For a number of years, the most significant environmental issue for LDCs has been the elimination of Polychlorinated Byphenyls (PCB) contaminated transformers. STEI has completed its entire transformer testing work and has replaced all units with a PCB level above the mandatory threshold. In due course, though it is not a legislated requirement but in order to exercise an abundance of caution, all transformers containing even a very small amount of PCB will be replaced.

(h) Fleet/Tools

The nature of STEI's business requires the use of very specialized vehicles and tools to build, operate and maintain the distribution system. They are necessary to work effectively under live high voltage situations, often under extreme weather conditions where worker and public safety are the prime consideration.

STEI has built up its fleet of vehicles and equipment to deal with all aspects of its work environments. Maintaining this fleet in safe and reliable operating conditions is a continuous process requiring annual commitments for replacement or upgrades under a planned budgetary process.

(i) Information technology and corporate administration

Information technology (IT) is an essential investment in any utility business. The applications include sophisticated customer information and work management systems, personal computing, Geographic Information System (GIS) and Data Acquisition systems. They are all major capital expenditures requiring periodic upgrades or replacements that are carefully reviewed and prioritized, with input from all stakeholders within the company.

(j) Renewable energy generation

While the new filing requirements no longer require the preparation of a formal GEA Plan, STEI has documented its capability to accommodate renewable energy generation facilities (REG); this analysis is included in Section 3.3 of this Distribution System Plan. The analysis does not indicate a requirement for any significant capital expenditures for the connections proposed by customers and the amount of proposed REG (FIT and microFIT projects) does not offer any significant capacity contribution to STEI's distribution system.

(k) Impact on customer bills

In the annual budgeting process, care is taken to introduce only gradual increases in capital expenditures to minimize the impact on customer bills and to ensure smooth changes year-to-year. Mechanisms used in reviewing proposed budget increases include determining the reliability and quality of service improvements to customers, changes in revenue requirement from one year to the next (which is a proxy for the expected change in distribution rates) and impacts on STEI's resources (e.g., workforce, capital, etc.).

(l) Customer engagement

STEI has a wide range of customer engagement activities that communicate on items of interest and importance. These are communicated through community events, retail locations, a web portal, local newspapers and bill inserts. Items include energy conservation, financial assistance programs, time-of–use pricing and e-billing.

In 2012, STEI engaged UtilityPULSE to conduct a Customer Survey. The results of the survey contribute to the annual Electric Utility Customer Satisfaction Survey that reports on benchmark scores from electric utility customers across Canada. The survey covers a wide range of issues relating to customer satisfaction, service levels, business operations, reliability, conservation, smart meters and smart grid. In 2014, STEI plans to engage UtilityPULSE again to conduct the every-two-year study. In addition, STEI intends to conduct its own telephone survey to further assist in understanding how it can better serve its customers.

The results of the 2012 UtilityPULSE survey showed that 91% of STEI's customers were either "fairly satisfied" or "very satisfied" with the service they receive from the LDC; the Province-wide average across all LDCs was 86%. Even more telling, *52%* of STEI's customers reported they were *very satisfied* compared to *40%* across the Provincial. This is truly a testament to the care and attention that STEI gives to meeting its customers' needs.

As a result of this type of feedback, the importance of maintaining the high level of reliability in the service area was identified by customers. This feedback was subsequently reflected in the current capital expenditure plan; the resulting planned expenditures include the replacement of the original 13.8kv delta sub-transmission system.

Further details of STEI's customer engagement activities are provided in Exhibit 1, Tab 3, Schedule 1 "Overview of Customer Engagement".

3.2.2 Elements of the Capital Expenditure Planning Process

a) Objectives, Criteria and Assumptions used and relationship to the Asset Management Objectives

The objective for STEI's capital expenditure planning process is twofold:

1. As a minimum, select that equipment that is to be refurbished and that equipment that is to be purchased/leased such that STEI's legislated/mandatory obligations are met and
2. To the extent possible, select that equipment that will enable economic/efficiency improvements to be made and/or enhance customer communications and service.

The two-fold objective is to be achieved subject to certain constraints including:

- All capital expenditures are to be made within the available resources envelope
- Expenditures to increase reliability will be made only where the required standard is not being met
- The plan should provide flexibility to accommodate unplanned and unexpected contingencies

The often-conflicting multiple criteria in effect include:

- Minimize the system lifecycle cost
- Minimize the increase in customers' bills – both short term and long term

The assumptions applicable to the development of the plan include:

- Expected change in number of customers, load, location, etc. and that the anticipated legislated, regulatory and other changes will occur as expected

The relationship between:

- the foregoing capital planning objective, constraints, criteria and assumptions and
- the asset management objectives

is that STEI's capital planning forms just one component (albeit often the largest) of its asset management process. Consequently, STEI makes every attempt to optimally plan the capital expenditures in an attempt to achieve overall optimization of its asset management activities.

STEI's outlook and objectives for accommodating the connection of renewable energy generation (REG) facilities is discussed in depth in its renewable energy generation analysis in Section 3.3 of this DS Plan. Since all REG potentially reduces the need for infrastructure enhancements within the service area, it is STEI's objective to connect all REG offerings as quickly as possible. The analysis notes that the STEI distribution system can accommodate all known projects, as is. At present, there are no particularly significant REG and connection capital projects planned.

b) STEI policy and procedures on incorporating non-distribution system alternatives

As just noted, it is STEI's policy to actively seeks opportunities to connect all REG projects since they have the potential to relieve system capacity constraints; these offerings include both FIT and microFIT projects. Also, STEI is, and has been for several years, extremely active in implementing conservation and demand management (CDM) load and energy savings; CDM savings make an immediate contribution to relieving system capacity and/or operational constraints. In addition, STEI's Regional Planning activities with neighbouring LDCs and Hydro One may produce some currently unidentified opportunities.

c) Processes used to identify projects in each investment category

The processes, tools and methods employed to identify, select, prioritize and pace the execution of projects in each investment category utilize a broad spectrum of STEI staff across multiple disciplines - in particular engineering and finance. STEI's "Asset Lifecycle Optimization Policies and Practices" (attached as "Appendix A to Section 2.3") sets out for STEI staff the processes, tools and methods to be used. In summary, the key elements are:

- Identify the range of renewal/refurbishment/purchase/lease options that meet each identified need or issue. This step involves experienced engineering staff that is able to differentiate between those theoretically possible options and those options that, in their professional best judgement, offer a solid practical solution.
- Again, for each identified need or issue, determine the full lifecycle cost of all identified practical and reasonable alternatives. The primary tool used here for major potential investments is an economic evaluation utilizing the discounted cash flow technique. This analysis would be performed with the assistance of finance staff.
- Select the best alternative for addressing each identified need or issue. This involves identifying the alternative with the lowest lifetime cost that complies with all design, construction and safety standards.
- Projects in each investment category are prioritized to ensure that STEI meets all legislated and mandatory requirements, maintains current operational standards by performing essential upgrades and refurbishments in-situ where economic, invests prudently by leveraging and/or early harvesting of previous investments, invests in customer service and economic/efficiency improvements, and accelerates replacement of critical over-aged items where affordable and optimal.
- Projects are scheduled so as to balance the number and skills of resources needed for each project, likely weather conditions, delivery of materials and equipment, etc. Consideration is also given to scheduling projects in such a way that if a major unplanned and unfunded contingency were to occur, funding and resources could be swapped to respond to the emergency circumstances.

d) Customer feedback and impact on plan

STEI carefully utilizes the feedback it receives from its customers. In addition to feedback it receives throughout the year in response to operational issues, STEI conducts specific events and surveys. As described fully in Exhibit 1. Tab 3 Schedule 1 “Overview of Customer Engagement” these customer-oriented activities include:

- Since 2007 STEI has provided their Commercial and Industrial Interval Metered customers with an on-line web portal 3rd party solution, called “C&I EnergyManager”. The C&I EnergyManager is a secure portal offering reports that allow customer to better manage their energy use.
- Specifically, STEI has engaged in independent 3rd party customer surveys, internal surveys, web surveys, bill inserts, bill messages, Home Shows and Business Expos.
- STEI is in the process of working collaboratively with other utilities to provide a Roving Energy Manager to assist large customers with load reduction.
- STEI has engaged UtilityPULSE to conduct independent customer satisfaction surveys since 2002. These bi-annual customer satisfaction surveys provide information that supports discussions surrounding improving customer service at all levels and departments within STEI.

The feedback obtained from customers through these events is utilized throughout the planning cycle and is used by system planning staff to adjust the priority of projects and to fine-tune the selection of projects to be undertaken.

A specific example of customer feedback regarding the importance of maintaining the high level of reliability in the service area was subsequently reflected in the current capital expenditure plan; that project was the replacement the 13.8kv sub-transmission system.

e) Methods and criteria used to prioritize REG investments

These methods and criteria are discussed in detail in the analysis of STEI’s REG present and future activities (see Section 3.3). In summary: STEI does not receive an inordinate number of requests to connect REG investments; consequently, given the benefit that accrues to the distribution system through REG projects, STEI attempts to connect all REG projects as quickly as possible.

3.3 System Capability Assessment for Renewable Energy Generation
(Ch.5.4.3)

STEI has applied for 2.5 MW of solar generation capacity on Edgeware TS B Bus and 5.0 MW on Edgeware TS Y Bus. Hydro One has approved the renewable generation capacity. Refer to Hydro One's Threshold CIA Reports Number 20740 (March 4, 2014) and Number 21350 (March 7, 2014).

M1 & M5 feeders are normally supplied by B Bus and M6 & M10 feeders are normally supplied by Y Bus. As stated above, the amount of load allocated to each 27.6 kV distribution feeder is about 16.5 MW or about 33 MW for two feeders.

2.5 MW of generation is about 7.6% of the load allocated for M1 & M5 feeders (B Bus) and 5.0 MW of generation is about 15.1% of the load allocated for M6 & M10 feeders. Having this amount of the feeder load supplied by solar generation connected downstream of the grid transformer station, will not significantly affect voltage levels along the feeders when solar generation is significantly reduced by cloud cover.

If there is any feeder interruption in the power supply either momentary or sustained, the solar generation protection is designed to take the generation off line. After being taken off line as a result of a feeder power interruption, the solar generation is also designed not to come back on line until it sees 5 minutes of continuous steady power supply. Once again, 7 to 15% of feeder load being switched to solar generation, will not significantly affect voltage levels along the feeders.

Fault current levels at Edgeware TS are approximately 12,500 amps. For more detail fault current levels, please refer to Hydro One's Threshold CIA Reports Number 20740 and Number 21350. The fault levels along the feeders start dropping off the further downstream from the transformer station. At the end of the feeders about 10km from the Transformer Station the fault current drops of to about 3,000 amps

The fault current contribution from solar generation is about 110% of the installed solar generation capacity. For 7.5 MW (2.5 MW + 5.0 MW) of solar generation, the full load current on the 27.6 kV system is about 157 amps which is about 172 amps of fault current contribution. Compared to the thousands of amps of fault current available at the Transformer Station and along the feeders, the fault current contribution from the solar generation can be considered to be negligible and will not have any major impact on feeder operation.

Renewable Generation Status

STEI has successfully connected the following solar generation projects: 36 microFIT, 2 FIT and 2 sites without an OPA contract. The following table outlines the system capacity to accept generation and the projects that have been connected or are pending connection. In addition to the connected and pending projects, there were another 229.5 kW (28 projects) of microFIT and 1,970 kW (7 projects) of FIT projects that were withdrawn or cancelled.

Renewable Generation Type	Edgeware TS B Bus	Edgeware TS Y Bus
Renewable Generation Capacity	2,500 kW	5,000 kW
OPA microFIT Projects Connected projects Pending projects	 25 projects - 230.3 kW 6 projects - 49 kW	 11 projects - 77.9 kW n/a
OPA FIT Projects Connected projects Pending projects	 2 projects - 600 kW 1 project - 38 kW	 n/a 3 projects - 322
Projects with no OPA Contract Connected projects	 2 projects - 48 kW	 n/a
Remaining Capacity	1,534.7 kW	4,600.1 kW

Aside from the information provided by the connected, pending, cancelled or withdrawn projects and despite consultations with our customers, we do not have any other specific information that would help forecast renewable energy generation quantities. Thus, our working assumption is that future levels of installation will be similar to the past projects and it is expected that STEI has ample capacity for renewable generation for the foreseeable future.

Based on STEI's analysis as submitted to the OPA on current and future REG projects, STEI does not expect to make any network investments within the 5-year planning period. However, STEI notes that while all connection costs are the distributor's responsibilities under the DSC, these costs are eligible for recovery through the Provincial cost recovery mechanism per section 79.1 of the OEB Act.

It is also worth noting that the voltage conversion work, while driven mainly by equipment reaching the end of its useful life, will result in more system capacity on the primary and secondary distribution systems. This will allow support more energy intensive applications such as electric vehicles and allow the system to accept more renewable energy generation. The increase of capacity on the primary side is in the range of 40% – 50% while the secondary side will allow about 67% more energy movement.

3.4 Capital Expenditure Summary (Ch.5.4.4)

Appendix 2-AA Capital Projects Table (attached) lists STEI's capital projects in the 10-year period 2010 to 2019 and shows, by year, the actual capital expenditure for projects in the historical period together with the planned capital expenditure for projects in the bridge year and forecast period.

Appendix 2-AB, i.e. Table 2 – Capital Expenditure Summary (attached), consolidates the information in Appendix 2-AA by investment category for each year and, in addition to the actual and planned capital expenditures already noted, includes the plan amount and variance amount for each project in the historical period.

Table 2 together with the following discussion, provides a high-level snapshot of STEI's expenditures over the 10-year DS Plan period.

Appendix 2-AA
Distribution Capital Projects

NO.	PROJECT NAME	2010	2011	2012	2013	2014 Bridge Year	2015 Test Year	2016	2017	2018	2019
1	New Subdivision - Lake Margaret, Phase 9	81,487									
2	New Subdivision - Orchard Park, Phase 3	71,980									
3	Voltage Conversion - Chestnut East of Fifth	84,700									
4	Build New OH Powerline - Sutherland Line	45,076									
5	Relocate Poles - Wellington - Princess to Elgin	60,326									
6	New Subdivision - Shaw Valley, Phase 2A	31,896	256,725								
7	New Subdivision - Dalewood Meadows, Phase 4A	151,558	47								
8	New Subdivision - Dalewood Meadows, Phase 4B	92,432	13,335								
9	New Subdivision - Misc	-592		8,087	44,791	200,000	200,000	200,000	200,000	200,000	200,000
10	Voltage Conversion - Misc.	82,120	102,961	33,414	28,188						
11	New Services Residential - Misc	97,510	66,929	40,098	71,033						
12	New Services Commercial - Misc	66,155	66,671	68,969	97,133						
13	Municipal Road Rebuilds - Misc	41,114	23,547	11,755	29,401						
14	Pole Replacement Program	201,630	36,140	19,585	25,202						
15	Voltage Conversion - Locust, Fifth to Third	94,209	-3,638								
16	Voltage Conversion - Fourth, Myrtle, Forest, Erie	170,126	8,347								
17	Voltage Conversion - Forest, Third, Erie, Second	145,687	79,028								
18	New Subdivision - Orchard Park, Phase 4		130,940								
19	Voltage Conversion - Elmina/Churchill Area		271,108								
20	Voltage Conversion - Dieppe, Dunkirk, Churchill		254,658								
21	Upgrade Service - 84 Edward - School		57,405								
22	Upgrade Service - 22 S. Edgeware - School		82,373								
23	New Subdivision - Dalewood Meadows, Phase 5		37,246	110,145							
24	Voltage Conversion - Meehan, Montgomery, Coyne		185,207	113,169	838						
25	Voltage Conversion - Parkview, Pinafore, etc.		212,723	305,096	13,262						
26	Smart Meter Transfer			3,082,487							
27	New Subdivision - Shaw Valley, Phase 2B			161,796	23,591						
28	New Subdivision - Lake Margaret Estates, Phase 11			95,969	763						
29	New Subdivision - Dalewood Meadows, Phase 6			12,115	190,237						
30	New Subdivision - Orchard Park, Phase 5			1,352	119,556						
31	New Subdivision - Orchard Park South			351,017	3,912						
32	Voltage Conversion - Churchill & Chestnut Area			140,125	58						
33	Voltage Conversion - Alma Kains North			46,473	145,134						
34	Voltage Conversion - Stokes & Manor			325,185	330						
35	Voltage Conversion - McLachlin Place			7,827	135,344						
36	Voltage Conversion - Massey & Michener			85,829	3,919						
37	Voltage Conversion - Luton, McLarty, Dyer Area			478	226,098	211,972					
38	Voltage Conversion - Erie, Talequah to Park				50,860	34,140					
39	Voltage Conversion - Highview, Vanbuskirk & McCully Area				379,044	40,956					
40	Voltage Conversion - Steele St.				68	114,932					
41	Voltage Conversion - Locke, Rosemount area				471	700,000					
42	System Upgrade - Bush Line					320,000					
43	Voltage Conversion - Mary St. East					115,000					
44	Voltage Conversion - Warehouse, Park to Fairview					35,000					
45	Voltage Conversion - Mandeville West of First					28,000					
46	Voltage Conversion - Fairview, Sinclair & Talbot Area						298,750				
47	Voltage Conversion - Paulson, Gustin & Paddon Area						358,750				
48	Voltage Conversion - Confederation, Lakeview, Stirling Area						683,750				
49	Build New Powerline - Elmwood Ave						208,750				
50	Voltage Conversion - Hammond, Patricia, Inkerman, Daniel Area							790,000			
51	Voltage Conversion - Highview, Aspen, Chestnut, Croatia, Pol Area							800,000			
52	Voltage Conversion - Tecumseh, Montcalm, Brock, Alma Area								763,335		
53	Voltage Conversion - Park, Mary Bucke, Forest & First Area								463,335		
54	Voltage Conversion - Balaclava & S. Edgeware Area								303,330		
55	Build New Powerline - Centennial, Talbot to Wellington									305,000	
56	Voltage Conversion - Applewood, Lawrence, Butler, Dyer Area									700,000	
57	Voltage Conversion - Major Line West of Sunset Area									285,000	
58	System Upgrade - Edward, Gaylord, East side of Elgin Mall									230,000	
59	Voltage Conversion - First, Thompson, Glanworth, Ashton Area										511,660
60	Voltage Conversion - Aldborough, Airey, Vanier Area										561,670
61	Voltage Conversion - Aldborough, Pullen, Sparta, Parish Area										486,670
62	Asset Transfer - Restructuring			1,407,734	69,795						
63	GIS			397,908		150,000	50,000				
64	New Financial software			353,134							
65	Smart Meter Transfer			185,288							
66	Other			37,621	22,888	28,000	20,000	20,000	20,000	20,000	20,000
67	Computer hardward & software				180,898	116,000	98,000	131,000	98,000	120,000	97,000
68	Fleet				247,083	264,000	125,000	60,000	265,000	20,000	
69	Building, furniture & equipment				17,973	170,000	170,000	175,000	15,000	5,000	5,000
70	SCADA						50,000	50,000	50,000	100,000	100,000
71											
72											
73											
74											
75											
	TOTAL	**1,517,416**	**1,881,754**	**7,402,655**	**2,127,870**	**2,528,000**	**2,263,000**	**2,226,000**	**2,178,000**	**1,985,000**	**1,982,000**
	Less Renewable Generation Facility Assests and Other Non Rate-Regulated Utility Assests (input as negative)										
	TOTAL	**1,517,416**	**1,881,754**	**7,402,655**	**2,127,870**	**2,528,000**	**2,263,000**	**2,226,000**	**2,178,000**	**1,985,000**	**1,982,000**

Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

First year of Forecast Period: *2015*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2010			2011			2012			2013			2014			2015	2016	2017	2018	2019
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	953,819	693,867	-27.3%	759,731	735,219	-3.2%	551,200	3,943,790	615.5%	719,000	580,417	-19.3%	200,000		-100.0%	200,000	200,000	200,000	200,000	200,000
System Renewal	872,154	778,473	-10.7%	1,143,467	1,146,535	0.3%	978,700	1,077,181	10.1%	827,423	1,008,816	21.9%	1,600,000		-100.0%	1,341,250	1,590,000	1,530,000	1,215,000	1,560,000
System Service	-	45,076	--	285,510	-	-100.0%	-	-	--	-	-	--	-		--	208,750	-	-	305,000	-
General Plant	-	-	--	-	-	--	743,500	2,381,685	220.3%	888,000	538,637	-39.3%	728,050		-100.0%	513,000	436,000	458,000	265,000	222,000
Contributed Capital	- 302,000	- 384,629	27.4%	- 251,000	- 266,363	6.1%	- 230,500	- 318,521	38.2%	- 311,000	- 596,144	91.7%	- 100,000			- 100,000	- 100,000	- 100,000	- 100,000	- 100,000
TOTAL EXPENDITURE	1,523,973	1,132,787	-25.7%	1,937,708	1,615,391	-16.6%	2,042,900	7,084,134	246.8%	2,123,423	1,531,726	-27.9%	2,428,050	-	-100.0%	2,163,000	2,126,000	2,088,000	1,885,000	1,882,000
System O&M	$ 988,508	$1,085,310	9.8%	$ 916,682	$ 923,291	0.7%	$1,371,654	$1,311,270	-4.4%	$1,305,830	$1,224,643	-6.2%	$1,259,102		-100.0%	$1,318,543	$1,346,233	$ 1,374,503	$1,403,368	$1,432,839

Notes to the Table:	993,089	2,528,050
1. Historical “previous plan” data is not required unless a plan has previously been filed	2,127,870	1,534,961
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):		

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. histrical budgets by category

2012 actual includes smart meter transfer of $3,267,776 and asset purchased per January 1, 2012 restructuring of $1,407,734

Notes on year over year Plan vs. Actual variances for Total Expenditures

Notes on Plan vs. Actual variance trends for individual expenditure categories

Total expenditures and variances

Examination of Table 2 will show that STEI’s capital expenditures in each investment category over the 10 year period have been fairly stable with a slight upward trend of approximately 3% per year in total expenditure after two one-off projects are excluded; also, excluding these two projects, there is otherwise no marked change in the share of total investment represented by any investment category.

Except for 2012 when STEI incurred $3.3 million on the Provincially-mandated Smart Meter Program, the planned capital expenditures (excluding contributed capital) over the historical period trended upwards from $1.5 million in 2010 to $2.1 million in 2013; $2.5 was planned for the 2014 test year. Apart from 2012, actual expenditures were substantially below plan.

The planned capital expenditures (excluding contributed capital) in the forecast period are seen to decrease from $2.2 million in 2015 to $1.9 million in 2019.

Annual O&M expenditures have trended upwards from $1.0 million to $1.4 million over the 10-year period.

The planned and actual expenditures together with variances for each investment category are now summarized.

System Access expenditures and variances

The planned annual capital expenditures during the 2010 to 2013 period for connecting new sub-divisions and providing other *ongoing* power system access have been in the $0.5 million to $1.0 million range. In 2012, STEI spent an additional $3.3 million on the Smart Meter program; of this amount, $3.1 million was allocated to the System Access category and the balance to the General Plant category.

As Table 2 shows, except for the 2012 smart meter investment, the resulting plan vs. actual variances for any one year and the actual expenditures variances between years were moderate in both dollar and percentage terms. When the 2012 actual expenditure is normalized for the Smart Meter Program, the resulting $0.9 million for System Access falls well within the previously-mentioned plan range; nevertheless, because it had been planned to spend just $0.6 million (i.e. much lower than historically) in that year, the resulting variance was $0.3 million over plan.

During the bridge year and throughout the forecast period because of the smaller number of new sub-divisions expected, the plan amount is constant at $0.2 million

System Renewal expenditures and variances

The main thrust of STEI's System Renewal activities throughout the historical and forecast period is replacement of its 50-year old 2,400 V system that is rapidly approaching the end of its life and which, because it is ungrounded, presents a significantly higher safety risk to staff and public when a downed line occurs. (When a single energized conductor contacts the ground or other items like fences/homes, it will not trip the line). The resulting replacement and voltage conversion will provide in an efficient and safer 27.6 kV modern system. Other associated activities in this category relate to associated power line construction and pole replacement.

The planned expenditure each year over the historical period falls in the $0.8 million to $1.1 million range with larger planned expenditures in the $1.2 million to $1.6 million range in the bridge year and forecast years as the renewal/conversion program is accelerated towards completion.

As Table 2 shows, there are no particularly marked plan vs. actual variances in any year.

System Service expenditures and variances

Expenditures in this investment category were planned for only four years in the 10-year DS Plan period; i.e. historical year 2011, bridge year 2014, and forecast years 2015 and 2018; no expenditures were planned in the balance of the years. All four planned expenditures were in the $0.2 million to $0.3 million range.

In the year 2010, $0.05 million was actually spent (against a zero budget) and, in 2011, zero was spent against the $0.3 million plan.

General Plant expenditures and variances

No General Plant expenditures were planned for 2010 or 2011; in the 2012 to 2014 period planned expenditures were in the $0.7 million to $0.9 million range; during the forecast period, planned expenditures decrease from $0.5 million to $0.2 million.

The second expenditure anomaly was, as previously noted, also in 2012 and was in the General Plant category. On January 2, 2012 STEI restructured from a virtual corporation to an operating utility. While the 2012 planned expenditure was $0.7 million, because of the January 1, 2012 restructuring asset purchase of $1.4 million, the actual 2012 expenditure was $2.4 million. This restructuring cost of $1.4 million is a one-time occurrence. When the anomalous expenditure is backed out, the resulting variance is only $0.05 million.

Contributed Capital contributions and variances

STEI's budget estimate in any year for contributed capital is based on quite imperfect input from external parties. During the historical period, this plan amount was approximately $0.3 million in each year.

The actual contributions received were generally a little higher than planned; in 2013 the actual contribution was almost $0.6 million.

With the anticipated reduction in sub-division construction, the plan amount each year in the 2014 to 2019 period is $0.1 million.

System O&M expenditures and variances

During the historical period the System O&M plan expenditures fluctuated within the $1.0 million to $1.4 million range.

Actual expenditures were within 10% of the plan values.

During the 2014 to 2019 period, the O&M plan expenditures are expected to remain at the upper part of the range.

3.5 Justifying Capital Expenditures (Ch.5.4.5)

3.5.1 Overall Plan (Ch.5.4.5.1)

It is STEI's stated objective in section 5.3.1 to meet all regulated requirements in a manner that minimizes the overall cost to STEI customers.

It is with this objective in mind that some 5 years ago, STEI carefully examined its distribution system to determine the direction the utility should take over the following 10 years in the renewal/replacement of its physical assets. The most evident characteristic of STEI's distribution system was that it was then almost 50 years old and designed to engineering standards of that vintage. With significant effort focused on preventive and corrective maintenance, the rapidly aging system was still essentially achieving the high level of reliability that STEI's customers were demanding but it was quite apparent that as the equipment continued to age and deteriorate that the then-current situation would not remain viable for long. Maintenance costs were accelerating and obtaining spares from manufacturers for the old technology was becoming much more difficult. The increasing risk of downed lines and the likelihood of other equipment failures placed the public at elevated danger from live wires since the system was a "floating delta" design whereby a backyard circuit could touch the ground and the circuit not trip. Also, the larger number of maintenance events meant increasing equipment face time for repair crews who had to work with a dangerous ungrounded system.

Only two practical engineering solutions were on offer: continue to operate and maintain the 50-year old system indefinitely or upgrade the system to contemporary standards.

Continuing to operate and maintain the existing system indefinitely would have meant a progressively more expensive maintenance program with increasing difficulty in sourcing spare parts from manufacturers as fewer North American utilities continued using the old technology; a greater number of outages as the aging equipment failed and the customers' – especially industrial customers' – much-cherished high reliability standards suffered; progressively more incidents whereby the public and STEI crews were exposed to the dangers of an ungrounded aging system; and STEI's inability to meet customers' increased capacity requirements due to the limitations of the older technology. Deciding to pursue this alternative would have been for the very long term since no silver bullet negating the need for electricity distribution was present on the horizon.

The alternative that would see the total replacement of the existing system presented a severe financial challenge. The cost for this alternative was expected to be in the $10 million to $15 million range which, for a company the size of STEI, was a decade-long commitment. Nevertheless, pursuing this alternative was believed to meet the lowest lifecycle cost through reduced outage and preventive maintenance costs; the opportunity to obtain reduced operating costs by moving from the existing 2400 V system to a modern 27.6 kV system with the resultant equipment efficiencies including reduced line losses due to the high voltage, removal of a number of sub-stations and elimination of multiple kilometers of cable; the ability to continue to achieve the customer-demanded reliability standards for the foreseeable future; enhanced public safety by replacing the bulk of the pole-mounted delivery system located in backyards to underground delivery in city street rights of way; ability to meet customers' needs for adequate capacity delivery; and staff's enhanced ability to maintain the system in a safer manner with readily available spare parts.

STEI management carefully considered the two apparently-viable alternatives and firmly concluded that in fact only one alternative was truly viable and practical: it decided to make a decade long commitment to replace the existing overhead 2400 V rear-lot delta system with a modern 27.6 kV front-lot grounded system.

STEI began progressively implementing the new distribution system in 2010, balancing in each year the need to fully implement the system as soon as possible to obtain the identified cost, efficiency and safety improvements with the conflicting requirement to minimize customer bill increases and the need to implement other smaller renewals/replacements. (Capital projects undertaken in the 2010 to 2014 period are discussed in section 3.5.2.)

In preparation for the development of this current DS Plan, management reviewed its previous plan to ensure the decision made some 5 years ago continued to be the optimal solution. A careful analysis of all the factors led to the firm conclusion that completing the replacement of the 2,400 V system with the modern 27.6 kV system was indeed the correct approach. In allocating funds each year in the 2015 to 2019 forecast period, STEI has continued to balance the desire to fund the Voltage Conversion program to the maximum extent possible with the need to perform other smaller refurbishment/replacement work together with the desire to keep the bill impacts as level as possible and within a reasonable range.

Specific information points:

- Comparative expenditures by category over the historical and forecast periods have been reported in section 3.4 and in Table 2 specifically.
- The forecast impact of system investments on system O&M costs is shown in Table 2. Despite escalating costs in general, Table 2 shows a modest 2% p.a. improvement in the plan cost for O&M in the forecast period compared to the plan cost of O&M in the historical period.
- As just discussed, the primary driver for investments in both the historical period and the forecast period has been in the System Renewal category and relates to the need to replace the aging 2,400 V ungrounded distribution system. Other drivers are discussed below in section 3.5.2.
- STEI's system capability assessment has been presented in section 3.3.

3.5.2 Material Investments (Ch.5.4.5.2)

2010 to 2014 Investments

In the 2010 – 2014 time period the capital spending on St. Thomas Energy's distribution system can be broken down into the following main categories; new services, Voltage Conversion project, Geographic Information System, upgrading/modifying/maintaining existing services and building/office/fixtures. These categories do not include the smart meter cost or the asset transfers into STEI associated with the company restructuring, which were one-time events occurring in 2012.

New Services (mandatory work items)

This category includes both planned and unplanned work that has taken place in this time period. New services include supplying electrical equipment and materials to residential, commercial and industrial accounts where no electrical supply currently exists.

The supply to new services can be to a single lot, a residential subdivision or a multi-site commercial/industrial complex. The electrical supply includes: wires or cable, transformers, hydro poles and associated hardware, switches, metering and labour.

Voltage Conversion Project

The Voltage Conversion project has been underway in St. Thomas Energy's service territory throughout this historical time period. On average approximately $1M was spent each year to convert sections of the city.

The voltage conversion effort was driven primarily by the need to replace assets that were aging, in poor condition and pose a reliability and safety risk to the customers in each area. Once the conversion is completed the security of supply to customers increase because of; newer equipment being used, introducing looped circuits that can supply power from two directions and moving conductors underground where practical. Moving conductors underground protects them from events such as vehicle accidents and ice storms.

There is an increase in safety for customers and the public because this work will remove an old 2,400 V 'floating delta' system that runs through backyards and moves most of the primary 27.6 kV voltage conductors underground. The safety risk of a 'floating delta' electrical system is that one of the phases can make contact with the ground or other conducting material without causing the feeder to trip.

There are also economic benefits to customers from the Voltage Conversion project. Increasing the voltage of the prime conductors will reduce line losses in St. Thomas. Reducing the line losses means lower electricity bills for customers.

Geographic Information System (GIS)

The purpose of this project is to update the software used to generate and maintain St. Thomas Energy Inc.'s electrical grid maps to current industry standard tools. This is required to ensure data accuracy and integrity in order to address health and safety concerns and take advantage of the potential productivity gains.

This project includes the transition of engineering drawings from a traditional paper based/CAD (computer aided drawing) to a GIS/AM (geographic information system/Asset Management) environment that will improve information accuracy and accommodate new and more efficient information management solutions. This migrates linear asset and connectivity data such as conductors and cables to a geographic representation environment where they are best managed (currently in various excel spreadsheets, access databases or not in existence at all).

The purpose of STEI's GIS is to help ensure that the accurate, timely display of assets and their relationships with one another is conveyed to users. In turn, those responsible for maintaining or monitoring these assets in the field will be provided with the most reliable information on which to base decisions influencing system operation. Front line staff will also be provided with important, quality information, to be conveyed to customers more effectively.

Service Upgrades, Modifications and Maintenance

This category includes both planned and unplanned work that has taken place in this time period. There are a variety of scenarios that drive this activity, some of which are:

- A customer wants to add an addition on to their home or business and need to increase the supply of electricity, example – changing a 100 A service to 200 A.
- The municipality requires an electrical line to be moved because they are widening a road.
- A customer requires the existing feed to be rerouted to accommodate an expansion.
- Revenue meter and hydro pole replacements.
- Maintenance of revenue meters, protection and control equipment and transformers.

The work in this category can include some, or all, of the requirements listed in New Services. The costs in this category are driven by the demands of customers or by regulatory requirements, and is not controlled by a distributor.

Building, Office and Fixtures

St. Thomas Energy's building at 135 Edward Street in St. Thomas is 20 years old and is need of upgrading, no renovations have been carried out since the building was built. There have been a number of problems identified such as water issues in the ceiling, windows and walls and basement flooding. The building and office furniture/fixture changes are planned to take place over a three year period, starting in 2014 continuing through 2016. The expenditures shown in Appendix A to Section 3.5 are costs per year.

The building issues affect customers as the flooring in the customer entrance and main lobby is very slippery when wet which is a safety issue. Also, the design of the ceiling in the main lobby causes echoes which makes it difficult for customers and the customer service staff to hear and understand each other.

The office furniture is 20 years old and the furniture needs to be improved from an ergonomic perspective, which is a health and wellness item. The building costs also include other items such as elevator upgrades, which are at times mandated by regulatory changes.

Changes to the lobby will enhance the display of CDM programs, use of electric vehicles and application of solar panels to educate our customers. Changes to the lighting fixtures throughout the building will reduce energy use and save money.

2015 to 2019 Investments

"Appendix A to Section 3.5" provides a description of all STEI material and minor projects in the forecast period; per Chapter 2 filing requirements, the materiality threshold for STEI projects is $50,000. In the Appendix, all material projects (i.e. those individual projects costing or exceeding $50,000) are described in detail using the three-part template discussed below. Individual minor projects costing less than $50,000 and, in some cases, groups of minor projects collectively costing less than $50,000 are described in less detail using the first part only of the three-part template used for the material projects.

The material projects described in "Appendix A to Section 3.5" following provide the information required by Section 5.4.5.2 of the Chapter 5 filing requirements:

Part A of the template provides General Information on each project including:

- Total capital and, where applicable, O&M costs
- Customer attachments and loads
- Applicable dates and expenditure timing
- Risks to completion of the project and mitigation
- Comparative information on historical projects
- Details on REG investments
- Leave to Construct information (as appropriate)

Part B of the template provides Evaluation Criteria and information requirements for each material project

Part C of the template provides Category-Specific Requirements for each material project as appropriate for its type; i.e.:

a. System Access projects,
b. System Renewal projects,
c. System Service projects or
d. General Plant projects

During the 5-year future period, the majority of the material projects (13) are part of the Voltage Conversion program; these material projects total $7.0 million. In addition, there are 2 related New Powerline projects and 1 System Upgrade project summing to $0.7 million. In total, these 16 material projects, directly or indirectly enabling the voltage conversion, claim 73% of all capital expenditures during the 2015 to 2019 period.

The balance of the $10.6 million capital expenditure in the 5-year period is made up of a few miscellaneous material projects (New Subdivision, I.T. and Fleet) and a number of minor capital projects.

"Appendix A to Section 3.5" providing the project details is attached.

APPENDIX A to Section 3.5

2015 – 2019 CAPITAL PROJECTS

INSERT 2015 – 2019 CAPITAL PROJECTS HERE

Attachment 2 of 4

STEI Capital Plans 2015-2019

Capital Expenditure Plan Projects

2015 - 2019

Part 1: 2015 Projects

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

1. Project Identification	Name: Fairview, Sinclair & Talbot Area Conversion Project Number: 2015-1
2. Purpose/Overview	Replace overhead assets due to the reliability risk to customers associated with aging. To replace the existing 2,400 V distribution system in this area which is 49 years old and is near end of life. In addition to customers benefiting from reduced maintenance costs due to the elimination of the transformer and the several kilometers of overhead line, this will save in transformer and wire losses and permit reasonable reliability levels to be achieved in the area.
3. Category	100% System Renewal
4. Cost	$298,750 Timing; Q1 & Q2 2015
5. Attachments/Loads	The Area is supplying approximately 100 residential customers
6. Dates	Start date: January 2015 In-Service date: May 2015
7. Risks	• Labour o Low risk: The project will be carried out mainly by internal staff with access to additional resources from the hiring hall to manage work fluctuation • Monetary o Low risk: Staff has extensive experience estimating and completing similar projects on budget • Expertise o Low risk: Experienced internal staff available with relevant work experience • Weather o Mitigated by planning weather appropriate projects. An example is by planning back-yard work in good weather conditions to reduce the amount property restoration than from spring weather. • External o Moderate risk: Higher priority developer and City

	projects can impact timing of internal plans for this and other projects • Customer o Low Risk: The company has an excellent history of cooperating with customers to obtain access in backyards to minimize customer intrusion and enhance project efficiency
8. Comparative Information	The experience gained on the 2014 projects will benefit the on-schedule and on-cost completion of this 2015 project.
9. REG Investment data	No
10. Leave to Construct	Not applicable

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

<u>Part B</u> (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

Project Identification	Name: Fairview, Sinclair & Talbot Area Conversion Project Number: 2015-1
Category	100% System Renewal
1. Efficiency, Customer Value, Reliability	This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system and a customer safety risk to pedestrians. Voltage upgrade will reduce line loss and decrease customer bills. Maintain service quality standards. The risk of not doing this work is the need for spot replacement on an unplanned for basis which would increase O&M costs. An increased risk of customer outages and interruptions would also occur. As the electrical system ages there is an increased public safety risk due to infrastructure failure in front of customers' properties, sidewalks and roadways. This includes a potential electrical shock risk because of the hazardous existing delta system.

	This is high priority project since it will bring about cost efficiencies and will improve customer and staff safety.
2. Safety	This project will provide a significant improvement in staff safety and public safety by replacing the current hazardous conditions of the existing delta 2,400 V system. Safety is improved by going from an ungrounded system to a grounded system which provides increased safety in a downed power line situation.
3. Cyber-security, Privacy	Not applicable
4. Co-ordination, Interoperability	The system enhancement allows for future smart grid integration.
5. Economic Development	The workforce required for this project will be both local contractors and also STEI staff. Materials are sourced from Provincial suppliers. Maintaining our system reliability is a key driver for attracting commercial and industrial businesses.
6. Environmental Benefits	Reduced line loss resulting in decreased power consumption and reduced associated environmental impacts. Existing poles that were treated with creosote are being removed, creosote is no longer allowed for poles. Any new poles installed will meet the current environmental standards

Part C2 (To be fully completed for each Test Year System Renewal material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

Project Identification	Name: Fairview, Sinclair & Talbot Area Conversion Project Number: 2015-1
1. Relationship between cause and effect on performance	The poles, overhead wires, pole-mounted transformers and underground cables are 49 years in age and are one of the oldest assets in the system. The original system installed is based upon a 49 year old engineering standard that results in equipment that is more costly to maintain, less efficient and presents higher customer and staff safety risks than equipment built to today's standard. This existing system is not built to handle increased customer load thereby increasing the potential of system outages and potential customer hazards, customer owned equipment failure. Existing poles in this area are at end of useful life resulting in increased pole failures Impacting approximately 100 residential customers
2. Other factors affecting project timing	The project is best completed in the winter months because the resources in summer months are deployed for other backyard projects. This front yard project can be done in the winter. The timing of this project is based on the relative priorities of a number of similar projects. Conversion projects have been systematically reviewed and assigned based upon various criteria including age and potential failure of system and compliance with ESA Regulation 22/04. Any delays in preceding projects will impact the timing of subsequent projects and increasing the failure risk. The City may have additional requirements that could impact the project timing.
3. Consequences for system O&M costs	Refurbishment of equipment and cables rather than replacement is not a practical engineering option primarily due to higher present day

	design and safety standards. This is due to higher voltage and conductor size requirements. Replacement of wood poles in this area will decrease the required testing and treatment costs for the next 20 years. Possible failures would require expensive unplanned repairs and lengthy power outages. The elimination of a transformer and several kilometers of overhead line will also reduce O&M costs and line losses which reduce customer bills.
4. Reliability and safety influences	This area will be rebuilt to new standards for increased safety and reliability by removing the overhead 2,400 V circuits and installing new overhead 27.6 kV lines and pole mounted transformers on a city road allowance. Reduced risk of pole failure and related electrical contact due to end of life assets and increased pole clearance reduces potential public contact
5. Analysis of project benefits and costs	Not applicable
6. Like for Like analysis	It is not feasible to maintain the current 49 year old system as replacement parts are not readily available; requiring STEI to maintain used spare parts for the system. These older spare parts are becoming more and more difficult to obtain. Additionally, when doing system spot replacements, ESA Regulation 22/04 requires a utility to maintain the existing line on a like for like basis, however, when building new power lines STEI is required to upgrade the replacement to existing standards.

<u>Part A</u> (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

1. Project Identification	Name: Paulson, Gustin & Paddon Street Area Conversion Project Number: 2015-2
2. Purpose/Overview	Replace underground & overhead assets due to the reliability risk to customers associated with aging. To replace the existing 2,400 V backyard distribution system in this area which is 47 years old. The 2,400 V underground cables are at the end of their life and are not in conduit and consequently not cost effective to replace. Many cables in this area have been previously replaced due to system issues. The completion of this work will provide for better system reliability by having a looped primary system across the area thus eliminating a single point-of-failure type outage for customers in the area served. This project will lead to the elimination of a 3 MVA Substation and also eliminate several kilometres of overhead 2,400 V circuitry with a resultant saving in customer bills through reduced O&M cost. This will save in transformer and wire losses.
3. Category	100% System Renewal
4. Cost	$358,750 Timing; Q2 & Q3 2015
5. Attachments/Loads	The Area is supplying approximately 100 residential customers
6. Dates	Start date: May 2015 In-Service date: September 2015
7. Risks	• Labour o Low risk: The project will be carried out mainly by internal staff with access to additional resources from the hiring hall to manage work fluctuation • Monetary o Low risk: Staff has extensive experience estimating and completing similar projects on budget • Expertise o Low risk: Experienced internal staff available with relevant work experience

	• Weather
	  o Mitigated by planning weather appropriate projects. An example is by planning back-yard work in good weather conditions to reduce the amount property restoration than from spring weather.
	• External
	  o Moderate risk: Higher priority developer and City projects can impact timing of internal plans for this and other projects
	• Customer
	  o Low Risk: The company has an excellent history of cooperating with customers to obtain access in backyards to minimize customer intrusion and enhance project efficiency

8. Comparative Information	The experience gained from the 2014 projects will benefit the on-schedule and on-cost completion of this 2015 project. Project scope and costs are similar to previously completed projects. Previous projects were completed on schedule and on budget.
9. REG Investment data	No
10. Leave to Construct	Not applicable

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

<u>Part B (To be fully completed for each Test Year material project; and all material projects in other years.)</u>

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

Project Identification	Name: Paulson, Gustin & Paddon Street Area Conversion Project Number: 2015-2
Category	100% System Renewal
1. Efficiency, Customer Value, Reliability	This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system serving the customers in that area. Once completed there will be better overall system security by providing a looped distribution system to a larger customer area that will eliminate the risk of outage caused by a loss of electrical supply from

	just one direction. This will eventually eliminate 2 radial feeds to areas where there are significant high-density housing complexes and through reduced O&M costs contribute to lowering customers' bills. The voltage upgrade will reduce line loss and decrease customer bills. Replacing old equipment will help maintain the service quality measures for the customers. Decreased intrusion onto customer property and increased operational service will result by moving the primary supply out of customers' backyards to the front of the houses. The risk of not doing this work is the need for spot replacement on an unplanned for basis, which increases the number and duration of customer outages and interruptions. As the system continues to age there is an increased public safety risk from infrastructure failure in customers' backyards. These can damage customer property and presents a potential electrical shock hazard due to the delta system. This project was prioritized for the 2015 capital expenditure program based on assessment of cost, efficiency, public and worker safety, etc. when compared to alternative projects.
2. Safety	There is a significant improvement in public safety through undertaking this project. This area conversion project will eliminate back-yard overhead 2,400 V circuits and pole-mounted transformers with the installation of new front-yard buried cables and pad-mounted transformers. Removing the risk of potential lines falling in customer back yard. The conductor line type of solid wire has been known to fail in many other jurisdictions and is therefore more hazardous.
3. Cyber-security, Privacy	Privacy Decreased intrusion onto customer property and increased operational service by moving the primary supply to the front of the house
4. Co-ordination, Interoperability	System looping will maintain reliability and reduce outage times. The system enhancement would allow for smart grid integration in the future
5. Economic Development	The workforce required for this project will be both local contractors and STEI staff who have performed this work in the past. Material are sourced from provincial suppliers Maintaining our system reliability is a key driver for attracting commercial and industrial businesses.

6. Environmental Benefits	Reduced line loss resulting in decreased power consumption and reduced associated environmental impacts. Existing poles are treated with creosote which is no longer permissible are being removed. New installed poles meet current environmental standards

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

<u>Part C2</u> (To be fully completed for each Test Year System Renewal material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

Project Identification	Name: Paulson, Gustin & Paddon Street Area Conversion Project Number: 2015-2
1. Relationship between cause and effect on performance	The poles, overhead wires, pole-mounted transformers and underground cables are 47 years in age and are one of the oldest assets in the system. Original system installed based upon an old 47 yr engineering standard that results in equipment that is more costly to maintain, less efficient and presents higher customer and staff safety risks than equipment built to today's standard. Existing system not built to handle increased customer load thereby increasing the potential of system outages and potential customer hazards, customer owned equipment failure. Existing poles in this area are at end of useful life resulting in increased pole failures in customer backyard. The existing poles have the increased potential of dangerous line drops in customer back yard and increased outages. Impacting 100 residential customers.
2. Other factors affecting project timing	This project is best completed in the summer fall period resulting in reduced restoration costs. Because of the lawn damage done by working in back-yards in wet weather there will be less impact on completing project on time. Conversion projects have been systematically reviewed and assigned based upon various criteria including age and potential failure of

	system and compliance with ESA Regulation 22/04. Any delays in preceding projects will impact the timing of subsequent projects and increasing the failure risk. City and developer requirements will impact on project timing
3. Consequences for system O&M costs	Refurbishment of equipment and cables rather than replacement is not a practical engineering option primarily due to higher present day design and safety standards. Primarily due to the higher voltage and conductor size requirements. Replacement of wood poles in this area will decrease the required testing and treatment costs for the next 20 years. Possible failures would require expensive unplanned repairs and lengthy power outages. As noted earlier, the elimination of a transformer and several kilometers of overhead line will also reduce O&M costs and line losses.
4. Reliability and safety influences	This area will be rebuilt to new standards for increased safety and reliability by removing back-yard overhead 2,400 V circuits and installing new underground 27.6 kV cables and pad-mounted transformers in city row-of-way. Reduce risk for electrical contact in customer backyard with potential line drops, children climbing tree, customer trimming trees and animal contact.
5. Analysis of project benefits and costs	Not applicable
6. Like for Like analysis	Not feasible to maintain current 49 year old system, replacement parts are not readily available; requiring STEI to maintain used spare parts to maintain system. Additionally, when doing system spot replacements, ESA Regulation 22/04 requires a utility to maintain the existing line on a like for like basis, however, when building new power lines STEI is required to upgrade the replacement to existing standards.

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

1. Project Identification	Name: Confederation Drive, Lakeview Circle, MacKenzie Place, Warren Crescent, Avon Road & Stirling Crescent Area Conversion Project Number: 2015-3
2. Purpose/Overview	Replace overhead assets due to aging and reliability risk. To replace the existing 2,400 V. Distribution system in the area that is 45 years old and is near end of life. In addition to customers benefiting from reduced maintenance costs due to the elimination of the transformer and the several kilometers of overhead line, this will save in transformer and wire losses and permit mandated reliability levels to be achieved in the area.
3. Category	100% System Renewal
4. Cost	$683,750 Timing; Q2 & Q3 2015
5. Attachments/Loads	The Area is supplying approximately 200 residential customers and 1 City owned sewage pumping station.
6. Dates	Start date: May 2015 In-Service date: September 2015

7. Risks	• Labour
	  o Low risk: The project will be carried out mainly by internal staff with access to additional resources from the hiring hall to manage work fluctuation
	• Monetary
	  o Low risk: Staff has extensive experience estimating and completing similar projects on budget
	• Expertise
	  o Low risk: Experienced internal staff available with relevant work experience
	• Weather
	  o Mitigated by planning weather appropriate projects. An example is by planning back-yard work in good weather conditions to reduce the amount property restoration than from spring weather.

	• External
	  o Moderate risk: Higher priority developer and City projects can impact timing of internal plans for this and other projects
	• Customer
	  o Low Risk: The company has an excellent history of cooperating with customers to obtain access in backyards to minimize customer intrusion and enhance project efficiency

8. Comparative Information	The experience gained on the 2014 projects will benefit the on-schedule and on-cost completion of this 2015 project. Project scope and cost are similar to previously completed projects.
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

Project Identification	Name: Confederation Drive, Lakeview Circle, MacKenzie Place, Warren Crescent, Avon Road & Stirling Crescent Area Conversion Project Number: 2015-3
Category	100% System Renewal
1. Efficiency, Customer Value, Reliability	This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system and a customer safety risk to pedestrians. Once completed there will be better overall system security by providing a looped distribution system to a larger customer area. This will eliminate 2 radial feeds to areas where there are significant high-density housing complexes. Voltage upgrade will reduce line loss and decrease customer bill

	impact Maintain service quality standards. Decreased intrusion onto customer property and increased operational service by moving the primary supply to the front of the house The risk of not doing this work is the need for spot replacement on an unplanned for basis which would increase O&M costs. Potential risk for increased outage and customer interruption. Increased public safety risk as infrastructure failure in customer back yard and property damage, potential electrical shock and hazardous delta system.
2. Safety	There is a significant increase in staff safety and public safety since this results in replacing the current hazardous conditions of the existing delta 2,400 V system. That is, going from an ungrounded system to a grounded system which provides increased safety in a downed power line situation. This area conversion project will eliminate back-yard overhead 2,400 V circuits and pole-mounted transformers with the installation of new front-yard buried cables and pad-mounted transformers. One particular area is the perimeter around a local Park and baseball diamond. Removing the risk of potential lines falling in customer back yard. The conductor line type of solid wire has been known to fail in many other jurisdictions and is therefore more hazardous.
3. Cyber-security, Privacy	Privacy: Decreased intrusion onto customer property and increased operational service by moving the primary supply to the front of the house.
4. Co-ordination, Interoperability	System looping will maintain reliability and reduce outage times. The system enhancement would allow for smart grid integration in the future.
5. Economic Development	The workforce required for this project will be both local contractors and STEI staff who have performed this work in the past. Material are sourced from provincial suppliers Maintaining our system reliability is a key driver for attracting commercial and industrial businesses.
6. Environmental Benefits	Reduced line loss resulting in decreased power consumption and reduced associated environmental impacts

	Existing poles are treated with creosote which is no longer permissible are being removed. New installed poles meet current environmental standards.

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

Part C2 (To be fully completed for each Test Year System Renewal material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

Project Identification	Name: Confederation Drive, Lakeview Circle, MacKenzie Place, Warren Crescent, Avon Road & Stirling Crescent Area Conversion Project Number: 2015-3
1. Relationship between cause and effect on performance	The poles, overhead wires, pole-mounted transformers and underground cables are 45 years in age and are one of the oldest assets in the system. Original system installed based upon an old 45 yr engineering standard that results in equipment that is more costly to maintain, less efficient and presents higher customer and staff safety risks than equipment built to today's standard. Existing system not built to handle increased customer load thereby increasing the potential of system outages and potential customer hazards, customer owned equipment failure. Existing poles in this area are at end of useful life resulting in increased pole failures in customer backyard. The existing poles have the increased potential of dangerous line drops in customer back yard and increased outages Impacting 200 residential customers and 1 City sewage pumping station
2. Other factors affecting project timing	This project is best completed in the summer fall period resulting in reduced restoration costs. Less impact of weather on completing project on time. Conversion projects have been systematically reviewed and assigned based upon various criteria including age and potential failure of system and compliance with ESA Regulation 22/04. Any delays in

	preceding projects will impact the timing of subsequent projects and increasing the failure risk. City and developer requirements will impact on project timing
3. Consequences for system O&M costs	Refurbishment of equipment and cables rather than replacement is not a practical engineering option primarily due to higher present day design and safety standards. Primarily due to the higher voltage and conductor size requirements. Replacement of wood poles in this area will decrease the required testing and treatment costs for the next 20 years. Possible failures would require expensive unplanned repairs and lengthy power outages. As noted earlier, the elimination of a transformer and several kilometers of overhead line will also reduce O&M costs and line losses.
4. Reliability and safety influences	This area will be rebuilt to new standards for increased safety and reliability by removing back-yard overhead 2,400 V circuits and installing new underground 27.6 kV cables and pad-mounted transformers in city row-of-way. Reduce risk for electrical contact in customer backyard with potential line drops, children climbing tree, customer trimming trees and animal contact. Potential for greater community access of park, kite flying etc.
5. Analysis of project benefits and costs	Not applicable
6. Like for Like analysis	Not feasible to maintain current 49 year old system, replacement parts are not readily available; requiring STEI to maintain used spare parts to maintain system. Additionally, when doing system spot replacements, ESA Regulation 22/04 requires a utility to maintain the existing line on a like for like basis, however, when building new power lines STEI is required to upgrade the replacement to existing standards.

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

1. Project Identification	Name: Elmwood Avenue New Power Line Construction Project Number: 2015-4
2. Purpose/Overview	The completion of this work will provide for better system reliability by having a looped primary system on this main feeder to the south-east section of the City. The work will involve upgrading the size of the conductors to allow for increased system capacity. This system upgrade will save in wire losses. This work is not part of the voltage conversion project.
3. Category	100% System Service
4. Cost	$209,000 Timing; Q3 & Q4 2015
5. Attachments/Loads	The Area is supplying approximately 1200 residential customers.
6. Dates	Start date: September 2015 In-Service date: December 2015
7. Risks	• Labour o Low risk: The project will be carried out mainly by internal staff with access to additional resources from the hiring hall to manage work fluctuation • Monetary o Low risk: Staff has extensive experience estimating and completing similar projects on budget • Expertise o Low risk: Experienced internal staff available with relevant work experience • Weather o Mitigated by planning weather appropriate projects • External o Moderate risk: Higher priority developer and City projects can impact timing of internal plans for this and other projects

	• Customer o Low Risk: The company has an excellent history of cooperating with customers to obtain access in backyards to minimize customer intrusion and enhance project efficiency
8. Comparative Information	The experience gained on the 2014 projects will benefit the on-schedule and on-cost completion of this 2015 project.
9. REG Investment data	No
10. Leave to Construct	Not applicable

St.**Thomas***energy*inc.

Capital Expenditure Plan Projects

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

Project Identification	Name: Elmwood Avenue New Power Line Construction Project Number: 2015-4
Category	System Service
1. Efficiency, Customer Value, Reliability	This project is driven primarily by the need to provide increased system reliability that poses a risk to the distribution system. Once completed there will be better overall system security by providing a looped distribution system to a larger customer area. Maintain service quality standards. The work involves upgrading the conductor size and capacity on a main system feeder.
2. Safety	This area conversion project will eliminate back-yard overhead 27.6 kV circuit with the installation of new front-yard overhead 27.6 kV circuit power line in the city right-of-way. Eliminates potential customer electrical contact by tree climbing and customer tree trimming. Also eliminates an overhead high-voltage line from close vicinity to customer's houses in many locations. Removes the risks of high voltage downed lines in customer back yard as these lines will be in front yard.

3. Cyber-security, Privacy	Decreased intrusion onto customer property and increased operational service by moving the primary supply to the front of the house
4. Co-ordination, Interoperability	System looping will maintain reliability, reduce outage times. The system enhancement would allow for smart grid integration in the future
5. Economic Development	The workforce required for this project will be both local contractors and also STEI staff. Materials are sourced from Provincial suppliers. Maintaining our system reliability is a key driver for attracting commercial and industrial businesses
6. Environmental Benefits	Reduced line loss resulting in decreased power consumption and reduced associated environmental impacts. Existing poles are treated with creosote which is no longer permissible are being removed. New installed poles meet current environmental standards

Part C3 (To be fully completed for each Test Year System Service material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

1. Project Identification	Name: Elmwood Avenue New Power Line Construction Project Number: 2015-4
2. Customers' benefits	The completion of this work will provide for better system reliability by having a looped primary system on this main feeder to the south-east section of the City. The work will include upgrading the size of the conductors to allow for increased system capacity, saving in wire losses. Customers will see a high level of reliability as the looped line can be fed from two different sources of electricity. Increasing the conductors will reduce line losses which reduces customers' bills, and provides more capacity to supply new electrical loads like electric vehicles and the system can accept more renewable generation.

3. Regional electricity infrastructure requirements	This project was identified in an internal Block 3 Area Study for the need of an underground feeder through the area which would replace the rear-yard feeder.
4. Incorporation of advanced technology etc.	The system enhancement would allow for smart grid integration in the future by installing smart switches to control the dual supply.
5. Additional project benefits	System looping will maintain reliability, reduce outage times.
6. Factors affecting project timing	Conversion projects have been systematically reviewed and assigned based upon various criteria including age and potential failure of system and compliance with ESA Regulation 22/04. Any delays in preceding projects will impact the timing of subsequent projects and increasing the failure risk. The City could add requirements that may impact the project timing
7. Comparison of alternatives	The other options are to replace the existing system with; 1. A new underground system throughout established city streets taking a longer route, excavating across driveways and landscaped lawns. 2. A new underground system on the established city street (Elmwood Ave) which also requires excavating across driveways and landscaped lawns. Both options are more expensive considering material and restoration costs. The most cost effective solution is to rebuild the overhead power line on the city street, Elmwood Ave, in co-operation with the joint use agreement with Hydro One.

<u>Part A</u> (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

1. Project Identification	Name: Building and Equipment Expenditure Project Number: 2015-5
2. Purpose/Overview	The building is 20 years old and is need of upgrading, no renovations have been carried out since it was built. There have been a number of problems identified such as water issues in the ceiling, walls and basement flooding, the flooring in the customer entrance and main lobby is very slippery when wet which is a safety issue, office furniture is 20 years old and needs to be improved from an ergonomic perspective and other items such as elevator upgrades.
3. Category	100% General Plant
4. Cost	$170,000 Timing; distributed across the 2015 year
5. Attachments/Loads	
6. Dates	This project is scheduled to start in Q3 2014 and will continue through 2015 into 2016 ($170,000 will be used and useful in the 2015TY). The implementation is staged to help manage costs.
7. Risks	• Labour o Low risk: The project will be carried out by external resources • Monetary o Low risk: The external resources will have extensive experience estimating and completing similar projects on budget • Expertise o Low risk: Experienced external resources available with relevant work experience • Weather o Low risk: Only basement leak repairs will be subject to external weather, and this can be planned accordingly • External o Moderate risk: This work may compete with other projects being managed by an external contractor. This can be

	mitigated by good project planning and regular communication • Customer o Low Risk: Only the front entrance and lobby work will impact customers coming into the office. This can be mitigated by planning for customers to be in these areas during the work, i.e. put barriers directing customers away from work areas and when necessary work after office hours
8. Comparative Information	There is no comparative information for this building as similar work has not been done in the past. Competitive purchasing practices will ensure market value for the work
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

Project Identification	Name: Building and Equipment Expenditure Project Number: 2015-5
Category	100% General Plant
1. Efficiency, Customer Value, Reliability	The building is 20 years old and is need of upgrading, no renovations have been carried out since it was built. There is a problem for customers and our customer service staff being able to hear and understand each other in the lobby area because of a ceiling design that causes echoes. This will be addressed in the renovations. There have been a number of building problems identified such as: • Water issues in the ceiling and walls • Basement flooding • Office furniture is 20 years old and needs to be improved from

	an ergonomic perspective • Other items such as elevator upgrades (some are regulatory driven)
2. Safety	The flooring in the customer entrance and main lobby is very slippery when wet. This will be addressed as part of the office expenditures.
3. Cyber-security, Privacy	Because of the lobby echoing problem, customers and customer service staff often have to speak more loudly which makes it easy for other people to overhear their conversation. Fixing the sound problem will provide more privacy in conversations. More sound suppression barriers will be included in the customer service work stations design which also improve privacy when dealing with customers.
4. Co-ordination, Interoperability	The new furniture will improve the coordination for staff at their work location. This will result in less bending and easier access to information, both electronic and hardcopy. Example: adjustable work surfaces and portable storage.
5. Economic Development	The changes to the building, office and fixtures will benefit Ontario workers and businesses such as furniture suppliers. The plan is to use local designers and contractors for this project.
6. Environmental Benefits	Improvements to the lobby will benefit the customers in several ways. Controlling noise will provide more privacy for the customer when they are discussing their bill with the customer service staff. Changing the flooring in this area will eliminate a slipping hazard when the floor is wet. In the lobby area there will be displays highlighting CDM programs and information on electric vehicle charging and solar panels to educate customers. Repairs to control water leaking into the building will provide a drier and more comfortable work environment. This will also avoid mold growth in areas affected by leaks. New lighting for the offices will use less energy and this will improve energy efficiency. Renewing insulation in walls that are being repaired will also improve energy efficiency. The new furniture will improve ergonomics for the staff which improves the work environment from a health and safety and wellness perspective.

Part C4 (To be fully completed for each Test Year General Plant material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

Project Identification	Name: Building and equipment expenditure Project Number: 2015-5
1. Comparison of alternatives	Alternative 1: Do nothing. This alternative is not practical because the changes address health and safety and wellness issues, provide better customer privacy and improve energy efficiency. The water infiltration is a safety issue as it creates a slipping hazard on the smooth floors of the customer entrance, and will create a mold problem in these areas if this is not addressed. Upgrading the office furniture improves health and safety (e.g. avoids bending) and improves wellness by providing a work environment that is comfortable and reduces noise. The service to customers is improved by removing slipping hazards in the main lobby and entrance and improving the noise issue at the customer service desks. This will also improve privacy. Alternative 2: Carry out the necessary repairs to manage water issues, improve office equipment and layouts and carry out required maintenance for equipment such as the elevator. The alternatives for improving the workplace were explored by surveying staff to understand their issues and needs for the work being done. Competitive tendering will be used to select the contractors for this project.
2. Very large projects	Not applicable

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

1. Project Identification	Name: Smart meter WAN replacement Number: 2015-6
2. Purpose/Overview	The smart meter network currently uses Bell's CDMA network to collect the meter reads. This system is being decommissioned by Bell, and as a result the WAN needs to be replaced.
3. Category	100% General Plant
4. Cost	$50,000
5. Attachments/Loads	Smart meter data collection
6. Dates	May through September 2015

7. Risks	• Labour
	  o Low risk: The project will be carried out by internal resources
	• Monetary
	  o Low risk: Relatively small project and solution is known
	• Expertise
	  o Low risk: Experienced internal resources available with relevant work experience
	• Weather
	  o Low risk: Not a factor that will affect this work
	• External
	  o Low risk: Need to source new equipment, not expected to be a problem
	• Customer
	  o High Risk: This work must be done to ensure the smart meter network, and subsequent billing processes, continue to function

8. Comparative Information	Comparing alternate equipment to replace this system
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

Project Identification	Name: Smart meter WAN replacement Project number: 2015-6
Category	100% General Plant
1. Efficiency, Customer Value, Reliability	Bell is going to decommission the existing CDMA network. This replacement project is needed to ensure the smart meter data continues to be collected. Smart meter data must be collected for use in the billing system, and for display purposes for customers to understand their usage profile
2. Safety	No safety implications
3. Cyber-security, Privacy	The new system will continue to protect customers' data while being collected
4. Co-ordination, Interoperability	Smart meter data collection is necessary to coordinate and operate with the billing system and data display systems
5. Economic Development	Will result in the sourcing and installation of new equipment
6. Environmental Benefits	Not applicable

Part C4 (To be fully completed for each Test Year General Plant material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

Project Identification	Name: Smart meter WAN replacement Number: 2015-6
1. Comparison of alternatives	The existing Bell CDMA system must be replaced. Currently evaluating different product options: • Rogers • Bell • Telus
2. Very large projects	Not applicable

<u>Part A</u> (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

1. Project Identification	Name: Geographical Information System (GIS) Implementation Project Number: 2015-7
2. Purpose/Overview	STEI has been implementing a GIS system since 2011. A GIS is a system where the system mapping and the distribution system equipment data are linked or tied together such that the data can be accessed directly from the map. In 2014 the GIS is will be operating with the core functions of mapping and equipment location/inventory. The next step in the evolution of this system is to add engineering modules to allow for outage management capabilities. By integrating smart meter data with the GIS, outages can be quickly and clearly identified showing location and customers affected. This is planned for 2015.
3. Category	100% General Plant
4. Cost	$50,000
5. Attachments/Loads	Not applicable
6. Dates	Q2 – Q3 2015
7. Risks	• Labour o Low risk: The project will be carried out by experienced external resources • Monetary o Low risk: Relatively small project and solution is known • Expertise o Low risk: Experienced external resources available with relevant work experience • Weather o Low risk: Not a factor that will affect this work • External o Low risk: Need to source new software, not expected to be a problem • Customer o Low Risk: This system functionality is largely invisible to the customers. They will benefit from it though, through

	better outage assessments and communications which can restore power faster and keep customers informed
8. Comparative Information	Options for this module will be assessed before selecting the final product
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

Project Identification	Name: Geographical Information System Implementation Project Number: 2015-7
Category	100% General Plant
1. Efficiency, Customer Value, Reliability	Using smart meter data together with the GIS system will quickly and accurately show the location and extent of outages. It will also show which customers are affected. Customers will benefit through faster outage response times to return power and improve communications with them. Better outage identification will save time spend searching for the cause of outages, saving costs. Faster outage responses will help support the reliability of the electric system.
2. Safety	Faster response to outages will result in faster cleanup of downed lines which can be a safety hazard to the public. Shorter outages will return the function of safety equipment like traffic and streetlights more quickly.
3. Cyber-security, Privacy	Not applicable
4. Co-ordination, Interoperability	This project will coordinate the smart meter functions with the GIS system to improve outage responses.
5. Economic Development	Will provide some economic benefits for software suppliers and installation contractors.
6. Environmental Benefits	Not applicable

Part C4 (To be fully completed for each Test Year General Plant material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

Project Identification	Name: Geographical Information System Implementation Number: 2015-7
1. Comparison of alternatives	Integrating GIS and outage management modules is the current standard in most utilities today. Will evaluate the different options available to provide this function.
2. Very large projects	Not applicable

St.Thomas*energy*inc. **Capital Expenditure Plan Projects**

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

1. Project Identification	Name: System Control and Data Acquisition (SCADA) Implementation Project Number: **2015-8**
2. Purpose/Overview	The current SCADA program has been largely "orphaned" with the planned system conversion and smart grid plans, STEI did not think it would be financially prudent to invest in what could be an obsolete system. Much of the current SCADA elements reside in the substations that are being phased out. As the conversion program has progressed there is a need for system control infrastructure to enable future smart grid and reduce the length of customer outages and to provide trouble shooting information. STEI has planned a conservative implementation over a five year period from 2015 to 2019 to enable STEI to spread out the investment that's needed and to react to potential government initiatives that may impact this type of system.
3. Category	100% General Plant
4. Cost	$50,000
5. Attachments/Loads	Not applicable
6. Dates	Q2 – Q4 2015
7. Risks	• Labour o Low risk: The project will be carried out by experienced external and internal resources • Monetary o Low risk: Relatively small project for 2015 • Expertise o Low risk: Experienced external and internal resources available with relevant work experience • Weather o Low risk: Not a factor that will affect this work • External o Low risk: Need to source new software and system data elements, this not expected to be a problem

	• Customer o Low Risk: This system functionality is largely invisible to the customers. They will benefit from it though, through better outage assessments and communications which can restore power faster and keep customers informed
8. Comparative Information	Options for this module will be assessed before selecting the final product
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

Project Identification	Name: System Control and Data Acquisition (SCADA) Implementation Project Number: 2015-8
Category	100% General Plant
1. Efficiency, Customer Value, Reliability	Improving the data collected from various parts of the distribution system and brining this together with the smart meter data and the GIS system will quickly and accurately show the location and extent of outages. More SCADA data collection will provide an even better picture of problems in the distribution system. Customers will benefit through faster outage response times to return power and improve communications with them. Better outage identification will save time spend searching for the cause of outages, saving costs. Faster outage responses will help support the reliability of the electric system.
2. Safety	Faster response to outages will result in faster cleanup of downed lines which can be a safety hazard to the public. Shorter outages will return the function of safety equipment like traffic and streetlights more quickly.
3. Cyber-security, Privacy	Not applicable
4. Co-ordination, Interoperability	This project will coordinate data from the SCADA system with smart meter functions with the GIS system to improve outage responses and

	system control.
5. Economic Development	Will provide some economic benefits for software suppliers and installation contractors.
6. Environmental Benefits	Not applicable

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

<u>Part C4</u> (To be fully completed for each Test Year General Plant material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

Project Identification	Name: System Control and Data Acquisition (SCADA) Implementation Number: 2015-8
1. Comparison of alternatives	Will evaluate different systems and modules to rebuild the SCADA system. Will need to integrate this with the GIS and our smart meter data collection system. The use of SCADA systems is common in the utility business, and is needed to be able to quickly and effectively understand what is happening within a distribution system. Third party outsourcing not an option, monitoring and safely controlling the distribution system is part of our core business and requires special skills, knowledge and experience. For example, outage management and response is very specialized activity involving live line work, switching elements of the electric system, work protection (holdoffs), etc.
2. Very large projects	Not applicable

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

1. Project Identification	Name: Miscellaneous IT hardware costs Number: 2015-9
2. Purpose/Overview	This item includes a number of smaller IT hardware costs including; regular maintenance to the data centre cabling/HVAC system, desktop/laptop/tablet repairs and replacement and providing a hot backup server at the disaster recovery site.
3. Category	100% General Plant
4. Cost	$35,000
5. Attachments/Loads	IT system maintenance
6. Dates	Throughout 2015
7. Risks	• Labour o Low risk: The project will be carried out by internal resources • Monetary o Low risk: Relatively small project and solution is known • Expertise o Low risk: Experienced internal resources available with relevant work experience • Weather o Low risk: Not a factor that will affect this work • External o Low risk: Need to source new equipment, not expected to be a problem • Customer o Low Risk: Regular maintenance and backup work
8. Comparative Information	Routine maintenance that involves comparative pricing
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

1. Project Identification	Name: Miscellaneous IT software costs Number: 2015-10
2. Purpose/Overview	This item includes two smaller IT software costs including; regular add-ons to the company SharePoint site and regular addition of storage capacity.
3. Category	100% General Plant
4. Cost	$13,000
5. Attachments/Loads	IT system maintenance
6. Dates	Throughout 2015
7. Risks	• Labour o Low risk: The project will be carried out by internal resources • Monetary o Low risk: Relatively small project and solution is known • Expertise o Low risk: Experienced internal resources available with relevant work experience • Weather o Low risk: Not a factor that will affect this work • External o Low risk: Need to source new equipment, not expected to be a problem • Customer o Low Risk: Regular maintenance and storage capacity
8. Comparative Information	Routine maintenance that involves comparative pricing
9. REG Investment data	No
10. Leave to Construct	Not applicable

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

<u>Part A</u> (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

1. Project Identification	Name: Mini-derrick (backyard machine) Project Number: 2015-11
2. Purpose/Overview	About 35% of our distribution lines are routed through customer backyards using overhead conductors. The mini-derrick is needed to install poles, transformers and conduct emergency tree trimming in the backyards. A regular line truck/RBD cannot access these areas because of their size. Currently STEI is renting a mini-derrick in excess of $5,000 per month. Purchasing a unit will be cost effective with a two year payback.
3. Category	100% General Plant
4. Cost	$125,000
5. Attachments/Loads	Not applicable
6. Dates	Q1 2015
7. Risks	• Labour o Low risk: Minimal resources required to purchase unit • Monetary o Low risk: Equipment is known and available • Expertise o Low risk: Equipment is known and available • Weather o Low risk: Not a factor • External o Low risk: Need to source new equipment, not expected to be a problem • Customer o Low Risk: Have a rental unit to complete work in backyards until a replacement unit can be purchased
8. Comparative Information	Will review competitive pricing options when selecting the new equipment
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

Project Identification	Name: Mini-derrick (backyard machine) Project Number: 2015-11
Category	100% General Plant
1. Efficiency, Customer Value, Reliability	Using a mini-derrick is the most efficient way of carrying out work in backyards. The alternative would be to do this manually which introduces safety hazards (lifting, climbing, working live-line off a pole). This also saves physical fatigue for workers as poles and transformers are very heavy. The mini-derrick completes the work in a timely manner which reduces the time we are inconveniencing customers in their private backyards. Faster time to work on lines in backyards will also return power faster in outage situations.
2. Safety	Use of a mini-derrick is a much safer way to work in backyards, it avoids heavy lifting of poles and transformers, avoids live line work from a pole (instead of an insulated bucket), and prevents physical fatigue.
3. Cyber-security, Privacy	Not applicable
4. Co-ordination, Interoperability	
5. Economic Development	Will provide some economic benefits for equipment supplier.
6. Environmental Benefits	This unit can remove pole butts from the ground in the backyards which otherwise would have to be left in place.

Part C4 (To be fully completed for each Test Year General Plant material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
					X				

Project Identification	Name: Mini-derrick (backyard machine) Number: 2015-11
1. Comparison of alternatives	Manual effort to carry out this work is not effective and is hazardous to staff (safety, physical exhaustion). Can either continue to rent a mini-derrick or purchase one. It is economic to purchase a unit as this has a two year payback.
2. Very large projects	Not applicable

Part 2: 2016 Projects

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
						X			

1. Project Identification	Name: Hammond, Patricia, Inkerman, Woodworth, Joyce, Daniel & Frisch Streets Area Conversion Project Number: **2016-1**
2. Purpose/Overview	Replace overhead assets due to the reliability risk to customers associated with aging. To replace the existing 2,400 V distribution system in the area that is 46 years old and is near end of life. In addition to customers benefiting from reduced maintenance costs due to the elimination of the transformer and the several kilometers of overhead line, this will save in transformer and wire losses and permit mandated reliability levels to be achieved in the area
3. Category	100% System Renewal
4. Cost	$790,000 Timing; Q1 & Q2 2016
5. Attachments/Loads	The Area is supplying approximately 250 residential customers
6. Dates	Start date: January 2016 In-Service date: June 2016
7. Risks	• Labour o Low risk: The project will be carried out mainly by internal staff with access to additional resources from the hiring hall to manage work fluctuation • Monetary o Low risk: Staff has extensive experience estimating and completing similar projects on budget • Expertise o Low risk: Experienced internal staff available with relevant work experience • Weather o Mitigated by planning weather appropriate projects. An example is by planning back-yard work in good weather conditions to reduce the amount property restoration than from spring weather.

	• External o Moderate risk: Higher priority developer and City projects can impact timing of internal plans for this and other projects • Customer o Low Risk: The company has an excellent history of cooperating with customers to obtain access in backyards to minimize customer intrusion and enhance project efficiency o
8. Comparative Information	The experience gained on the 2014 projects will benefit the on-schedule and on-cost completion of this 2016 project.
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
						X			

Project Identification	Name: Hammond, Patricia, Inkerman, Woodworth, Joyce, Daniel & Frisch Streets Area Conversion Project Number: 2016-1
Category	100% System Renewal
1. Efficiency, Customer Value, Reliability	This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system and a customer safety risk to pedestrians Voltage upgrade will reduce line loss and decrease customer bill impact. Maintain service quality standards. The risk of not doing this work is the need for spot replacement on an unplanned for basis which would increase O&M costs. Increased risk of customer outage and interruption would also likely occur. Increased public safety risk of infrastructure failure in front of

	customer property, sidewalks and roadway, potential electrical shock and hazardous delta system. This is fairly high priority project since it will bring about cost efficiencies and, as noted, will improve customer and staff safety.
2. Safety	There is a significant increase in staff safety and public safety since this results in replacing the current hazardous conditions of the existing delta 2,400 V system. That is, going from an ungrounded system to a grounded system which provides increased safety in a downed power line situation.
3. Cyber-security, Privacy	Not applicable
4. Co-ordination, Interoperability	The system enhancement allows for future smart grid integration.
5. Economic Development	The workforce required for this project will be both local contractors and also STEI staff. Materials are sourced from Provincial suppliers. Maintaining our system reliability is a key driver for attracting commercial and industrial businesses.
6. Environmental Benefits	Reduced line loss resulting in decreased power consumption and reduced associated environmental impacts Existing poles are treated with creosote which is no longer permissible are being removed. New installed poles meet current environmental standards

Part C2 **(To be fully completed for each Test Year System Renewal material project; populate as appropriate for all material projects in other years.)**

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
						X			

Project Identification	Name: Hammond, Patricia, Inkerman, Woodworth, Joyce, Daniel & Frisch Streets Area Conversion Project Number: 2016-1
1. Relationship between cause and effect on performance	The poles, overhead wires, pole-mounted transformers and underground cables are 46 years in age and are one of the oldest assets in the system. Original system installed based upon an old 46 yr engineering standard that results in equipment that is more costly to maintain, less efficient and presents higher customer and staff safety risks than equipment built to today's standard. Existing system not built to handle increased customer load thereby increasing the potential of system outages and potential customer hazards, customer owned equipment failure. Existing poles in this area are at end of useful life resulting in increased pole failures Impacting approximately 250 residential customers.
2. Other factors affecting project timing	The project is best completed in the winter months. Because resources are more readily available. The timing of this project is based on the relative priorities of a number of similar projects. Conversion projects have been systematically reviewed and assigned based upon various criteria including age and potential failure of system and compliance with ESA Regulation 22/04. Any delays in preceding projects will impact the timing of subsequent projects and increasing the failure risk. City and developer requirements will impact on project timing
3. Consequences for system O&M costs	Refurbishment of equipment and cables rather than replacement is not a practical engineering option primarily due to higher present day design and safety standards. Primarily due to the higher voltage and conductor size requirements. Replacement of wood poles in this area will decrease the required

	testing and treatment costs for the next 20 years. Possible failures would require expensive unplanned repairs and lengthy power outages. As noted earlier, the elimination of a transformer and several kilometers of overhead line will also reduce O&M costs and line losses.
4. Reliability and safety influences	This area will be rebuilt to new standards for increased safety and reliability by removing overhead 2,400 V circuits and installing new overhead 27.6 kV lines and pole mounted transformers on City road allowance. Reduced risk of pole failure and related electrical contact due to end of life assets and increased pole clearance reduces potential public contact
5. Analysis of project benefits and costs	Not applicable
6. Like for Like analysis	Not feasible to maintain current 46 year old system, replacement parts are not readily available; requiring STEI to maintain used spare parts to maintain system. Additionally, ESA Regulation 22/04 requires a utility to maintain the existing line on a like for like basis, however, when parts are no longer available STEI is required to upgrade the replacement to existing standards.

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
						X			

1. Project Identification	Name: Highview, Aspen, Chestnut, Croatia & Pol Area Conversion Project Number: 2016-2
2. Purpose/Overview	Replace overhead assets due to the reliability risk to customers associated with aging. To replace the existing 2,400 V distribution system in the area that is 45 years old and is near end of life. In addition to customers benefiting from reduced maintenance costs due to the elimination of the transformer and the several kilometers of overhead line, this will save in transformer and wire losses and permit mandated reliability levels to be achieved in the area
3. Category	100% System Renewal
4. Cost	$800,000 Timing; Q3 & Q4 2016
5. Attachments/Loads	The Area is supplying approximately 350 residential customers
6. Dates	Start date: June 2016 In-Service date: December 2016
7. Risks	• Labour o Low risk: The project will be carried out mainly by internal staff with access to additional resources from the hiring hall to manage work fluctuation • Monetary o Low risk: Staff has extensive experience estimating and completing similar projects on budget • Expertise o Low risk: Experienced internal staff available with relevant work experience • Weather o Mitigated by planning weather appropriate projects. An example is by planning back-yard work in good weather conditions to reduce the amount property restoration than from spring weather. • External

	o Moderate risk: Higher priority developer and City projects can impact timing of internal plans for this and other projects • Customer o Low Risk: The company has an excellent history of cooperating with customers to obtain access in backyards to minimize customer intrusion and enhance project efficiency o
8. Comparative Information	The experience gained on the 2014 projects will benefit the on-schedule and on-cost completion of this 2016 project.
9. REG Investment data	No
10. Leave to Construct	Not applicable

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
						X			

Project Identification	Name: Highview, Aspen, Chestnut, Croatia & Pol Area Conversion Project Number: 2016-2
Category	100% System Renewal
1. Efficiency, Customer Value, Reliability	This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system and a customer safety risk to pedestrians Voltage upgrade will reduce line loss and decrease customer bill impact. Maintain service quality standards. The risk of not doing this work is the need for spot replacement on an unplanned for basis which would increase O&M costs. Increased risk of customer outage and interruption would also likely occur. As this infrastructure ages there is increased public safety risk associated with infrastructure failure in front of customers' property,

	sidewalks and roadways. The potential for electrical shock is greater because of the hazardous delta system. This is high priority project since it will bring about cost efficiencies and will improve customer and staff safety.
2. Safety	There will be a significant improvement in staff and public safety since this project replaces the current hazardous conditions of the existing delta 2,400 V system. That is, going from an ungrounded system to a grounded system which provides increased safety in a downed power line situation.
3. Cyber-security, Privacy	Not applicable
4. Co-ordination, Interoperability	The system enhancement allows for future smart grid integration.
5. Economic Development	The workforce required for this project will be both local contractors and also STEI staff. Materials are sourced from Provincial suppliers. Maintaining our system reliability is a key driver for attracting commercial and industrial businesses.
6. Environmental Benefits	Reduced line loss resulting in decreased power consumption and reduced associated environmental impacts Existing poles are treated with creosote which is no longer permissible are being removed. New installed poles meet current environmental standards

Part C2 (To be fully completed for each Test Year System Renewal material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
						X			

Project Identification	Name: Highview, Aspen, Chestnut, Croatia & Pol Area Conversion Project Number: 2016-2
1. Relationship between cause and effect on performance	The poles, overhead wires, pole-mounted transformers and underground cables are 45 years in age and are among the oldest assets in the system. Original system installed based upon an old 45 year engineering standard that results in equipment that is more costly to maintain, less efficient and presents higher customer and staff safety risks than equipment built to today's standard. The existing system was not built to handle the increased customer loads we experience today. This increases the potential of system outages and potential customer hazards due to a floating delta system. With the older system customer owned equipment failures could result because of today's higher load demands. Existing poles in this area are at end of useful life resulting in increased pole failures Impacting approximately 350 residential customers.
2. Other factors affecting project timing	The timing of this project is based on the relative priorities of a number of similar projects. Conversion projects have been systematically reviewed and assigned based upon various criteria including age and potential failure of system and compliance with ESA Regulation 22/04. Any delays in preceding projects will impact the timing of subsequent projects and increasing the failure risk. The City could add requirements that may impact the project timing
3. Consequences for system O&M costs	Refurbishment of equipment and cables rather than replacement is not a practical engineering option primarily due to higher present day design and safety standards. This is primarily due to the higher voltage level and different conductor size requirements.

	Replacement of wood poles in this area will decrease the required testing and treatment costs for the next 20 years. Possible failures would require expensive unplanned repairs and lengthy power outages. As noted earlier, the elimination of a transformer and several kilometers of overhead line will also reduce O&M costs and line losses.
4. Reliability and safety influences	This area will be rebuilt to new standards that improve safety and reliability by removing overhead 2,400 V circuits and installing new overhead 27.6 kV lines and pole mounted transformers on the city road allowance. Renewing these lines will reduced risk of pole failure and related electrical contact from downed lines. The increased pole clearance included in these changes also reduces the potential for public contact (e.g. from ladders, hoists).
5. Analysis of project benefits and costs	Not applicable
6. Like for Like analysis	Not feasible to maintain current 45 year old system, replacement parts are not readily available; requiring STEI to maintain used spare parts to maintain system. Additionally, ESA Regulation 22/04 requires a utility to maintain the existing line on a like for like basis, however, as parts are not available STEI is required to upgrade the replacement to existing standards.

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
						X			

1. Project Identification	Name: Building and Equipment Expenditure Project Number: 2016-3
2. Purpose/Overview	The building is 20 years old and is need of upgrading, no renovations have been carried out since it was built. There have been a number of problems identified such as water issues in the ceiling, walls and basement flooding, the flooring in the customer entrance and main lobby is very slippery when wet which is a safety issue, office furniture is 20 years old and needs to be improved from an ergonomic perspective and other items such as elevator upgrades.
3. Category	100% General Plant
4. Cost	$175,000 Timing; distributed through 2016.
5. Attachments/Loads	
6. Dates	This project is scheduled to start in Q3 2014 and will continue through 2015 into 2016. The implementation is staged to help manage costs.
7. Risks	• Labour o Low risk: The project will be carried out by external resources • Monetary o Low risk: The external resources will have extensive experience estimating and completing similar projects on budget • Expertise o Low risk: Experienced external resources available with relevant work experience • Weather o Low risk: Only basement leak repairs will be subject to external weather, and this can be planned accordingly • External o Moderate risk: This work may compete with other projects being managed by an external contractor. This can be mitigated by good project planning and regular

	communication • Customer o Low Risk: Only the front entrance and lobby work will impact customers coming into the office. This can be mitigated by planning for customers to be in these areas during the work, i.e. put barriers directing customers away from work areas and when necessary work after office hours
8. Comparative Information	There is no comparative information for this building as similar work has not been done in the past. Competitive purchasing practices will ensure market value for the work
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
						X			

Project Identification	Name: Building and Equipment Expenditure Project Number: 2016-3
Category	100% General Plant
1. Efficiency, Customer Value, Reliability	The building is 20 years old and is need of upgrading, no renovations have been carried out since it was built. There is a problem for customers and our customer service staff being able to hear and understand each other in the lobby area because of a ceiling design that causes echoes. This will be addressed in the renovations. There have been a number of building problems identified such as: • Water issues in the ceiling and walls • Basement flooding • Office furniture is 20 years old and needs to be improved from an ergonomic perspective

	• Other items such as elevator upgrades (some are regulatory driven)
2. Safety	The flooring in the customer entrance and main lobby is very slippery when wet. This will be addressed as part of the office expenditures.
3. Cyber-security, Privacy	Because of the lobby echoing problem, customers and customer service staff often have to speak more loudly which makes it easy for other people to overhear their conversation. Fixing the sound problem will provide more privacy in conversations. More sound suppression barriers will be included in the customer service work stations design which also improve privacy when dealing with customers.
4. Co-ordination, Interoperability	The new furniture will improve the coordination for staff at their work location. This will result in less bending and easier access to information, both electronic and hardcopy. Example: adjustable work surfaces and portable storage.
5. Economic Development	The changes to the building, office and fixtures will benefit Ontario workers and businesses such as furniture suppliers. The plan is to use local designers and contractors for this project.
6. Environmental Benefits	Improvements to the lobby will benefit the customers in several ways. Controlling noise will provide more privacy for the customer when they are discussing their bill with the customer service staff. Changing the flooring in this area will eliminate a slipping hazard when the floor is wet. In the lobby area there will be displays highlighting CDM programs and information on electric vehicle charging and solar panels to educate customers. Repairs to control water leaking into the building will provide a drier and more comfortable work environment. This will also avoid mold growth in areas affected by leaks. New lighting for the offices will use less energy and this will improve energy efficiency. Renewing insulation in walls that are being repaired will also improve energy efficiency. The new furniture will improve ergonomics for the staff which improves the work environment from a health and safety and wellness perspective.

<u>Part C4</u> (To be fully completed for each Test Year General Plant material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
						X			

Project Identification	Name: Building and equipment expenditure Number: 2016-3
1. Comparison of alternatives	Alternative 1: Do nothing. This alternative is not practical because the changes address health and safety and wellness issues, provide better customer privacy and improve energy efficiency. The water infiltration is a safety issue as it creates a slipping hazard on the smooth floors of the customer entrance, and will create a mold problem in these areas if this is not addressed. Upgrading the office furniture improves health and safety (e.g. avoids bending) and improves wellness by providing a work environment that is comfortable and reduces noise. The service to customers is improved by removing slipping hazards in the main lobby and entrance and improving the noise issue at the customer service desks. This will also improve privacy. Alternative 2: Carry out the necessary repairs to manage water issues, improve office equipment and layouts and carry out required maintenance for equipment such as the elevator. The alternatives for improving the workplace were explored by surveying staff to understand their issues and needs for the work being done. Competitive tendering will be used to select the contractors for this project.
2. Very large projects	Not applicable

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
						X			

1. Project Identification	Name: System Control and Data Acquisition (SCADA) Implementation Project Number: 2016-4
2. Purpose/Overview	The current SCADA program has been largely "orphaned" with the planned system conversion and smart grid plans, STEI did not think it would be financially prudent to invest in what could be an obsolete system. Much of the current SCADA elements reside in the substations that are being phased out. As the conversion program has progressed there is a need for system control infrastructure to enable future smart grid and reduce the length of customer outages and to provide trouble shooting information. STEI has planned a conservative implementation over a five year period from 2015 to 2019 to enable STEI to spread out the investment that's needed and to react to potential government initiatives that may impact this type of system.
3. Category	100% General Plant
4. Cost	$50,000
5. Attachments/Loads	Not applicable
6. Dates	To be scheduled for 2016
7. Risks	• Labour o Low risk: The project will be carried out by experienced external and internal resources • Monetary o Low risk: Relatively small project for 2016 • Expertise o Low risk: Experienced external and internal resources available with relevant work experience • Weather o Low risk: Not a factor that will affect this work • External o Low risk: Need to source new software and system data elements, this not expected to be a problem

	• Customer o Low Risk: This system functionality is largely invisible to the customers. They will benefit from it though, through better outage assessments and communications which can restore power faster and keep customers informed
8. Comparative Information	Options for this module will be assessed before selecting the final product
9. REG Investment data	No
10. Leave to Construct	Not applicable

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
						X			

Project Identification	Name: System Control and Data Acquisition (SCADA) Implementation Project Number: 2016-4
Category	100% General Plant
1. Efficiency, Customer Value, Reliability	Improving the data collected from various parts of the distribution system and brining this together with the smart meter data and the GIS system will quickly and accurately show the location and extent of outages. More SCADA data collection will provide an even better picture of problems in the distribution system. Customers will benefit through faster outage response times to return power and improve communications with them. Better outage identification will save time spend searching for the cause of outages, saving costs. Faster outage responses will help support the reliability of the electric system.
2. Safety	Faster response to outages will result in faster cleanup of downed lines which can be a safety hazard to the public. Shorter outages will return the function of safety equipment like traffic and streetlights more quickly.
3. Cyber-security, Privacy	Not applicable
4. Co-ordination, Interoperability	This project will coordinate data from the SCADA system with smart meter functions with the GIS system to improve outage responses and

	system control.
5. Economic Development	Will provide some economic benefits for software suppliers and installation contractors.
6. Environmental Benefits	Not applicable

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

<u>Part C4</u> (To be fully completed for each Test Year General Plant material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
						X			

Project Identification	Name: System Control and Data Acquisition (SCADA) Implementation Number: 2016-4
1. Comparison of alternatives	Will evaluate different systems and modules to rebuild the SCADA system. Will need to integrate this with the GIS and our smart meter data collection system. The use of SCADA systems is common in the utility business, and is needed to be able to quickly and effectively understand what is happening within a distribution system. Third party outsourcing not an option, monitoring and safely controlling the distribution system is part of our core business and requires special skills, knowledge and experience. For example, outage management and response is very specialized activity involving live line work, switching elements of the electric system, work protection (holdoffs), etc.
2. Very large projects	Not applicable

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
						X			

1. Project Identification	Name: Miscellaneous IT hardware costs Number: 2016-5
2. Purpose/Overview	This item includes a number of smaller IT hardware costs including; regular maintenance to the data centre cabling/HVAC system, desktop/laptop/tablet repairs and replacement, replacing the smart meter server at end of useful life and a PureFlex management node.
3. Category	100% General Plant
4. Cost	$47,000
5. Attachments/Loads	IT system maintenance
6. Dates	Throughout 2016
7. Risks	• Labour o Low risk: The project will be carried out by internal resources • Monetary o Low risk: Relatively small project and solution is known • Expertise o Low risk: Experienced internal resources available with relevant work experience • Weather o Low risk: Not a factor that will affect this work • External o Low risk: Need to source new equipment, not expected to be a problem • Customer o Low Risk: Regular maintenance and backup work
8. Comparative Information	Routine maintenance that involves comparative pricing
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
						X			

1. Project Identification	Name: Miscellaneous IT software costs Number: 2016-6
2. Purpose/Overview	This item includes a number of smaller IT software costs including; PureFlex computer node central server license, PureFlex network module license and SharePoint add-ons.
3. Category	100% General Plant
4. Cost	$34,000
5. Attachments/Loads	IT system maintenance
6. Dates	Throughout 2016
7. Risks	• Labour o Low risk: The project will be carried out by internal resources • Monetary o Low risk: Relatively small project and solution is known • Expertise o Low risk: Experienced internal resources available with relevant work experience • Weather o Low risk: Not a factor that will affect this work • External o Low risk: Need to source components, not expected to be a problem • Customer o Low Risk: Regular maintenance and backup work
8. Comparative Information	Routine maintenance that involves comparative pricing
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
						X			

1. Project Identification	Name: Replace a 2003 pickup truck, Ford Ranger Number: 2016-7
2. Purpose/Overview	To replace a pickup truck that has reached the end of its useful life. This vehicle will be 16 years old in 2016 when it is planned to replace it. The previous replacement cycle was 10 years, however the life of the vehicle was extended through good maintenance and indoor storage when parked.
3. Category	100% General Plant
4. Cost	$30,000
5. Attachments/Loads	N/A
6. Dates	To be replaced in Q2 or Q3 2016
7. Risks	• Labour o Low risk: External purchase, minor changes required to standard vehicle • Monetary o Low risk: Relatively small project and solution is known • Expertise o Low risk: Routine purchase of vehicle • Weather o Low risk: Not a factor that will affect this item • External o Low risk: Need to source vehicle, not expected to be a problem • Customer o Low Risk: Replacement to maintain service to customers
8. Comparative Information	Regular replacement of rolling stock. Will look at competitive offers for a standard specification for this vehicle.
9. REG Investment data	No
10. Leave to Construct	Not applicable

St.Thomas*energy*inc. **Capital Expenditure Plan Projects**

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
						X			

1. Project Identification	Name: Replace 2004 dump truck Number: 2016-8
2. Purpose/Overview	To replace a dump truck that has reached the end of its useful life. This unit has been showing a deteriorating maintenance record and its reliability is poor.
3. Category	100% General Plant
4. Cost	$30,000
5. Attachments/Loads	N/A
6. Dates	Replace in Q3 or Q4 2016
7. Risks	• Labour o Low risk: External purchase, minor changes required from standard unit • Monetary o Low risk: Relatively small project and solution is known • Expertise o Low risk: Routine purchase of vehicle • Weather o Low risk: Not a factor that will affect this item • External o Low risk: Need to source vehicle, not expected to be a problem • Customer o Low Risk: Replacement to maintain service to customers
8. Comparative Information	Regular replacement of rolling stock
9. REG Investment data	No
10. Leave to Construct	Not applicable

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
						X			

1. Project Identification	Name: Regular upgrades to the NorthStar CIS billing system Number: 2016-9
2. Purpose/Overview	Regular upgrades are necessary for the CIS billing system to keep it current. These upgrades will make changes/enhancements to the CIS for: bill print changes, RRR new and amended reporting requirements and OEB new and amended code requirements.
3. Category	100% General Plant
4. Cost	$25,000
5. Attachments/Loads	N/A
6. Dates	To be scheduled in 2016
7. Risks	• Labour o Low risk: Changes will be made by external resources with expertise with this CIS system • Monetary o Low risk: Relatively small project and solution is known • Expertise o Low risk: Using external resources with expertise in this area • Weather o Low risk: Not a factor that will affect this item • External o Low risk: There are dedicate professionals servicing this system. Changes will affect a number of utilities at the same time, which will require their focus • Customer o Low Risk: Regular upgrades to the CIS system, changes will be tested before moving to production
8. Comparative Information	Regular maintenance for the NorthStar CIS system. Will need to use the supplier of the system for these changes as they have the expertise to make any changes.
9. REG Investment data	No
10. Leave to Construct	Not applicable

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

<u>Part A</u> (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
						X			

1. Project Identification	Name: IT system management and monitoring function Number: **2016-10**
2. Purpose/Overview	Regular upgrades are necessary for the IT system to keep it current. This upgrade is to automate the monitoring of the health of the computer systems, this change will anticipate problems and helps keep the system reliable.
3. Category	100% General Plant
4. Cost	$25,000
5. Attachments/Loads	N/A
6. Dates	To be scheduled in 2016
7. Risks	• Labour o Low risk: Changes will be made by internal resources with expertise with the IT system • Monetary o Low risk: Relatively small project and solution is known • Expertise o Low risk: Using internal resources with expertise in this area • Weather o Low risk: Not a factor that will affect this item • External o Low risk: Will control using internal resources • Customer o Low Risk: Regular upgrade to the IT system, changes will be tested before moving to production
8. Comparative Information	Regular maintenance for the IT system.
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part 3: 2017 Projects

St.Thomas*energy*inc. **Capital Expenditure Plan Projects**

<u>Part A</u> (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
							X		

1. Project Identification	Name: Tecumseh, Montcalm, Brock, Hughes & Alma Area Conversion Project Number: 2017-1
2. Purpose/Overview	Replace overhead assets due to the reliability risk to customers associated with aging. To replace the existing 2,400 V distribution system in the area that is 52 years old and is near end of life. In addition to customers will benefit from reduced maintenance costs due to the elimination of transformers and the several kilometers of overhead line. This will save in transformer and wire losses and support good reliability levels in the area.
3. Category	100% System Renewal
4. Cost	$763,335 Timing; Q1, Q2 & Q3 2017
5. Attachments/Loads	The Area is supplying approximately 175 residential customers
6. Dates	Start date: January 2017 In-Service date: June 2017
7. Risks	• Labour o Low risk: The project will be carried out mainly by internal staff with access to additional resources from the hiring hall to manage work fluctuation • Monetary o Low risk: Staff has extensive experience estimating and completing similar projects on budget • Expertise o Low risk: Experienced internal staff available with relevant work experience • Weather o Mitigated by planning weather appropriate projects. An example is by planning back-yard work in good weather conditions to reduce the amount property restoration than from spring weather.

	• External
	  o Moderate risk: Higher priority developer and City projects can impact timing of internal plans for this and other projects
	• Customer
	  o Low Risk: The company has an excellent history of cooperating with customers to obtain access in backyards to minimize customer intrusion and enhance project efficiency
	  o

8. Comparative Information	The experience gained on the 2014 projects will benefit the on-schedule and on-cost completion of this 2017 project.
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
							X		

Project Identification	Name: Tecumseh, Montcalm, Brock, Hughes & Alma Area Conversion Project Number: 2017-1
Category	100% System Renewal
1. Efficiency, Customer Value, Reliability	This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system and a customer safety risk from downed lines. The voltage upgrade will reduce line losses and lower customer bills as a result. Maintaining the electrical system will support meeting the service quality standards. The risk of not doing this work is the need for spot replacement on an unplanned for basis which would increase O&M costs. As this equipment continues to age there is an increasing risk of customer outages and interruptions. Aging equipment also Increases the public safety risk due to infrastructure failure in front of customers' property, sidewalks and roadways from downed lines. This presents an electrical

	shock hazard especially due to the delta system. This is high priority project since it will bring about cost efficiencies and will improve customer and staff safety.
2. Safety	There is a significant increase in staff safety and public safety since this results in replacing the current hazardous conditions of the existing delta 2,400 V system. That is, going from an ungrounded system to a grounded system which provides increased safety in a downed power line situation.
3. Cyber-security, Privacy	Not applicable
4. Co-ordination, Interoperability	The system enhancement allows for future smart grid integration.
5. Economic Development	The workforce required for this project will be both local contractors and also STEI staff. Materials are sourced from Provincial suppliers. Maintaining our system reliability is a key driver for attracting commercial and industrial businesses.
6. Environmental Benefits	Reduced line loss resulting in decreased power consumption and reduced associated environmental impacts. Existing poles are treated with creosote which is no longer permissible are being removed. New installed poles meet current environmental standards

Part C2 (To be fully completed for each Test Year System Renewal material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
							X		

Project Identification	Name: Tecumseh, Montcalm, Brock, Hughes & Alma Area Conversion Project Number: 2017-1
1. Relationship between cause and effect on performance	The poles, overhead wires, pole-mounted transformers and underground cables are 52 years in age and are one of the oldest assets in the system. Original system installed based upon an old 52 yr engineering standard that results in equipment that is more costly to maintain, less efficient and presents higher customer and staff safety risks than equipment built to today's standard. Existing system not built to handle increased customer load thereby increasing the potential of system outages and potential customer hazards, customer owned equipment failure. Existing poles in this area are at end of useful life resulting in increased pole failures Impacting approximately 175 residential customers.
2. Other factors affecting project timing	The project is best completed in the winter months. Because resources are more readily available. The timing of this project is based on the relative priorities of a number of similar projects. Conversion projects have been systematically reviewed and assigned based upon various criteria including age and potential failure of system and compliance with ESA Regulation 22/04. Any delays in preceding projects will impact the timing of subsequent projects and increasing the failure risk. City and developer requirements will impact on project timing
3. Consequences for system O&M costs	Refurbishment of equipment and cables rather than replacement is not a practical engineering option primarily due to higher present day design and safety standards. Primarily due to the higher voltage and conductor size requirements.

	Replacement of wood poles in this area will decrease the required testing and treatment costs for the next 20 years. Possible failures would require expensive unplanned repairs and lengthy power outages. As noted earlier, the elimination of a transformer and several kilometers of overhead line will also reduce O&M costs and line losses.
4. Reliability and safety influences	This area will be rebuilt to new standards for increased safety and reliability by removing overhead 2,400 V circuits and installing new overhead 27.6 kV lines and pole mounted transformers on City road allowance. Reduced risk of pole failure and related electrical contact due to end of life assets and increased pole clearance reduces potential public contact
5. Analysis of project benefits and costs	Not applicable
6. Like for Like analysis	Not feasible to maintain current 52 year old system, replacement parts are not readily available; requiring STEI to maintain used spare parts to maintain system. Additionally, ESA Regulation 22/04 requires a utility to maintain the existing line on a like for like basis, however, as parts are not available STEI is required to upgrade the replacement to existing standards.

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
							X		

1. Project Identification	Name: Park, Mary Bucke, Forest & First Area Conversion Project Number: 2017-2
2. Purpose/Overview	Replace overhead assets due to the reliability risk to customers associated with aging. To replace the existing 2,400 V. Distribution system in the area that is 46 years old and is near end of life. In addition to customers benefiting from reduced maintenance costs due to the elimination of transformers and the several kilometers of overhead line, this will save in transformer and wire losses and permit mandated reliability levels to be achieved in the area
3. Category	100% System Renewal
4. Cost	$463,335 Timing; Q3 & Q4 2017
5. Attachments/Loads	The Area is supplying approximately 150 residential customers
6. Dates	Start date: June 2017 In-Service date: December 2017

7. Risks	• Labour
	  o Low risk: The project will be carried out mainly by internal staff with access to additional resources from the hiring hall to manage work fluctuation
	• Monetary
	  o Low risk: Staff has extensive experience estimating and completing similar projects on budget
	• Expertise
	  o Low risk: Experienced internal staff available with relevant work experience
	• Weather
	  o Mitigated by planning weather appropriate projects. An example is by planning back-yard work in good weather conditions to reduce the amount property restoration than from spring weather.

	• External
	  o Moderate risk: Higher priority developer and City projects can impact timing of internal plans for this and other projects
	• Customer
	  o Low Risk: The company has an excellent history of cooperating with customers to obtain access in backyards to minimize customer intrusion and enhance project efficiency
	  o

8. Comparative Information	The experience gained on the 2014 projects will benefit the on-schedule and on-cost completion of this 2017 project.
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
							X		

Project Identification	Name: Park, Mary Bucke, Forest & First Area Conversion Project Number: 2017-2
Category	100% System Renewal
1. Efficiency, Customer Value, Reliability	This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system and a customer safety risk to pedestrians Voltage upgrade will reduce line loss and decrease customer bill impact. Maintain service quality standards. The risk of not doing this work is the need for spot replacement on an unplanned for basis which would increase O&M costs. Increased risk of customer outage and interruption would also likely occur. Increased public safety risk of infrastructure failure in front of customer property, sidewalks and roadway, potential electrical shock and hazardous delta system.

	This is fairly high priority project since it will bring about cost efficiencies and, as noted, will improve customer and staff safety.
2. Safety	There is a significant increase in staff safety and public safety since this results in replacing the current hazardous conditions of the existing delta 2,400 V system. That is, going from an ungrounded system to a grounded system which provides increased safety in a downed power line situation.
3. Cyber-security, Privacy	Not applicable
4. Co-ordination, Interoperability	The system enhancement allows for future smart grid integration.
5. Economic Development	The workforce required for this project will be both local contractors and also STEI staff. Materials are sourced from Provincial suppliers. Maintaining our system reliability is a key driver for attracting commercial and industrial businesses.
6. Environmental Benefits	Reduced line loss resulting in decreased power consumption and reduced associated environmental impacts. Existing poles are treated with creosote which is no longer permissible are being removed. New installed poles meet current environmental standards

Part C2 (To be fully completed for each Test Year System Renewal material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
							X		

Project Identification	Name: Park, Mary Bucke, Forest & First Area Conversion Project Number: 2017-2
1. Relationship between cause and effect on performance	The poles, overhead wires, pole-mounted transformers and underground cables are 46 years in age and are one of the oldest assets in the system. Original system installed based upon an old 46 yr engineering standard that results in equipment that is more costly to maintain, less efficient and presents higher customer and staff safety risks than equipment built to today's standard. Existing system not built to handle increased customer load thereby increasing the potential of system outages and potential customer hazards, customer owned equipment failure. Existing poles in this area are at end of useful life resulting in increased pole failures Impacting approximately 150 residential customers.
2. Other factors affecting project timing	The timing of this project is based on the relative priorities of a number of similar projects. Conversion projects have been systematically reviewed and assigned based upon various criteria including age and potential failure of system and compliance with ESA Regulation 22/04. Any delays in preceding projects will impact the timing of subsequent projects and increasing the failure risk. City and developer requirements will impact on project timing
3. Consequences for system O&M costs	Refurbishment of equipment and cables rather than replacement is not a practical engineering option primarily due to higher present day design and safety standards. Primarily due to the higher voltage and conductor size requirements. Replacement of wood poles in this area will decrease the required testing and treatment costs for the next 20 years. Possible failures would require expensive unplanned repairs and lengthy power outages. As

	noted earlier, the elimination of a transformer and several kilometers of overhead line will also reduce O&M costs and line losses.
4. Reliability and safety influences	This area will be rebuilt to new standards for increased safety and reliability by removing overhead 2,400 V circuits and installing new overhead 27.6 kV lines and pole mounted transformers on City road allowance. Reduced risk of pole failure and related electrical contact due to end of life assets and increased pole clearance reduces potential public contact
5. Analysis of project benefits and costs	Not applicable
6. Like for Like analysis	Not feasible to maintain current 46 year old system, replacement parts are not readily available; requiring STEI to maintain used spare parts to maintain system. Additionally, ESA Regulation 22/04 requires a utility to maintain the existing line on a like for like basis, however, as parts are not available STEI is required to upgrade the replacement to existing standards.

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
							X		

1. Project Identification	Name: Balaclava St and South Edgeware Road Area Reconstruction Project Number: 2017-3
2. Purpose/Overview	Replace overhead assets due to the reliability risk to customers associated with aging. To replace the existing 2,400 V. Distribution system in the area that is 37 years old and is near end of life. In addition to customers benefiting from reduced maintenance costs due to the elimination of 2 Substation transformers and the several kilometers of overhead line, this will save in transformer and wire losses and permit mandated reliability levels to be achieved in the area.
3. Category	100% System Renewal
4. Cost	$303,330 Timing; Q1 & Q2 2017
5. Attachments/Loads	The Area is supplying approximately 100 residential customers
6. Dates	Start date: January 2017 In-Service date: June 2017
7. Risks	• Labour o Low risk: The project will be carried out mainly by internal staff with access to additional resources from the hiring hall to manage work fluctuation • Monetary o Low risk: Staff has extensive experience estimating and completing similar projects on budget • Expertise o Low risk: Experienced internal staff available with relevant work experience • Weather o Mitigated by planning weather appropriate projects. An example is by planning back-yard work in good weather conditions to reduce the amount property restoration than from spring weather.

	• External
	  o Moderate risk: Higher priority developer and City projects can impact timing of internal plans for this and other projects
	• Customer
	  o Low Risk: The company has an excellent history of cooperating with customers when rebuilding powerlines to minimize customer intrusion and enhance project efficiency

8. Comparative Information	The experience gained on the 2014 projects will benefit the on-schedule and on-cost completion of this 2017 project.
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
							X		

Project Identification	Name: Balaclava St and South Edgeware Road Area Reconstruction Project Number: 2017-3
Category	100% System Renewal
1. Efficiency, Customer Value, Reliability	This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system. Voltage upgrade will reduce line loss and decrease customer bill impact. Maintain service quality standards. The risk of not doing this work is the need for spot replacement on an unplanned for basis which would increase O&M costs. Increased risk of customer outage and interruption would also likely occur. This is fairly high priority project since it will bring about cost

	efficiencies and, as noted, will improve customer and staff safety.
2. Safety	There is a significant increase in staff safety and public safety since this results in replacing the current hazardous conditions of the existing delta 2,400 V system. That is, going from an ungrounded system to a grounded system which provides increased safety in a downed power line situation.
3. Cyber-security, Privacy	Not applicable
4. Co-ordination, Interoperability	The system enhancement allows for future smart grid integration.
5. Economic Development	The workforce required for this project will be both local contractors and also STEI staff. Materials are sourced from Provincial suppliers. Maintaining our system reliability is a key driver for attracting commercial and industrial businesses.
6. Environmental Benefits	Reduced line loss resulting in decreased power consumption and reduced associated environmental impacts Existing poles are treated with creosote which is no longer permissible are being removed. New installed poles meet current environmental standards

Part C2 (To be fully completed for each Test Year System Renewal material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
							X		

Project Identification	Name: Balaclava St and South Edgeware Road Area Reconstruction Project Number: 2017-3
1. Relationship between cause and effect on performance	The poles, overhead wires, pole-mounted transformers and underground cables are 47 years in age and are one of the oldest assets in the system. Original system installed based upon an old 47 yr engineering standard that results in equipment that is more costly to maintain, less efficient and presents higher customer and staff safety risks than equipment built to today's standard. Existing system not built to handle increased customer load thereby increasing the potential of system outages and potential customer hazards, customer owned equipment failure. Existing poles in this area are at end of useful life resulting in increased pole failures. Impacting approximately 100 residential customers.
2. Other factors affecting project timing	The project is best completed in the winter months. Because resources are more readily available. The timing of this project is based on the relative priorities of a number of similar projects. Conversion projects have been systematically reviewed and assigned based upon various criteria including age and potential failure of system and compliance with ESA Regulation 22/04. Any delays in preceding projects will impact the timing of subsequent projects and increasing the failure risk. City and developer requirements will impact on project timing
3. Consequences for system O&M costs	Refurbishment of equipment rather than replacement is not a practical engineering option primarily due to higher present day design and safety standards. Primarily due to the higher voltage and conductor size requirements. Replacement of wood poles in this area will decrease the required testing

	and treatment costs for the next 20 years. Possible failures would require expensive unplanned repairs and lengthy power outages due to its inaccessible location.
4. Reliability and safety influences	This area will be rebuilt to new standards for increased safety and reliability by removing overhead 2,400 V circuits and installing new overhead 27.6 kV lines on the City road allowance. Reduced risk of pole failure and related electrical contact due to end of life assets.
5. Analysis of project benefits and costs	Not applicable
6. Like for Like analysis	Not feasible to maintain current 47 year old system, replacement parts are not readily available; requiring STEI to maintain used spare parts to maintain system. Additionally, when doing system spot replacements, ESA Regulation 22/04 requires a utility to maintain the existing line on a like for like basis, however, when building new power lines STEI is required to upgrade the replacement to existing standards.

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
							X		

1. Project Identification	Name: Disaster Recovery Site hardware upgrade Project Number: 2017-4
2. Purpose/Overview	Having a disaster recovery site is critical to any IT system and is necessary to maintain. This project is to replace disaster recovery hardware that is at the end of its useful life. This equipment will need additional processing and storage resources, and further extended warranty to continue to be used for this purpose. As well, licenses and hardware are required to ensure communications systems continue to operate in the event of a disaster.
3. Category	100% General Plant
4. Cost	$60,000
5. Attachments/Loads	Not applicable
6. Dates	To be scheduled in 2017
7. Risks	• Labour o Low risk: The project will be carried out by experienced external and internal resources • Monetary o Low risk: Relatively small project for 2017 • Expertise o Low risk: Experienced external and internal resources available with relevant work experience • Weather o Low risk: Not a factor that will affect this work • External o Low risk: Need to source new hardware components, this not expected to be a problem • Customer o Low Risk: This system functionality is largely invisible to the customers. They will benefit from it though, through reliable IT systems that are used to manage customer accounts

8. Comparative Information	Options for this hardware will be assessed before selecting the final product
9. REG Investment data	No
10. Leave to Construct	Not applicable

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
							X		

Project Identification	Name: Disaster Recovery Site hardware upgrade Project Number: 2017-4
Category	100% General Plant
1. Efficiency, Customer Value, Reliability	It is critical for the operation of an IT system to have a reliable disaster recovery site. These systems are essential when dealing with customers about their bills and accounts. The replacement of hardware at the end of its useful life will ensure we have a reliable IT system.
2. Safety	Not applicable
3. Cyber-security, Privacy	Not applicable
4. Co-ordination, Interoperability	The IT system is the backbone of the various systems used to deal with customers. These systems coordinate and present various types of data to customers and to customer service staff. These must be available to see usage, bills and account histories.
5. Economic Development	Will provide some economic benefits for hardware suppliers and installation contractors.
6. Environmental Benefits	Not applicable

Part C4 (To be fully completed for each Test Year General Plant material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
							X		

Project Identification	Name: Disaster Recovery Site hardware upgrade Number: 2017-4
1. Comparison of alternatives	Will evaluate hardware from different suppliers to determine the most reliable and economic products. The key criteria that will be considered are: • Cost • Demonstrated reliability • Availability (for replacement parts / components) • Service, ability to respond to high priority equipment requests • Timeliness to provide equipment • Compatibility with other system components and software
2. Very large projects	Not applicable

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
							X		

1. Project Identification	Name: Replacement for a 1997 single-bucket truck Project Number: 2017-5
2. Purpose/Overview	This capital purchase is to replace a single-bucket truck that will be at the end of its useful life. This unit will be 20 years old in 2017 and will need to be replaced. This truck is essential to maintain the electric system in St. Thomas.
3. Category	100% General Plant
4. Cost	$230,000
5. Attachments/Loads	Not applicable
6. Dates	Q2-Q3 2017
7. Risks	• Labour o Low risk: Will require resources to specify the replacement unit and manage a tender • Monetary o Medium risk: Equipment is known and available, however this is a significant investment • Expertise o Low risk: Equipment is known and available • Weather o Low risk: Not a factor • External o Low risk: Need to source new equipment, not expected to be a problem • Customer o Medium Risk: Bucket trucks are an essential element to install, maintain and repair an electric distribution system. These must be available and in good repair
8. Comparative Information	Will review competitive pricing options when selecting the new equipment
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
							X		

Project Identification	Name: Replacement for a 1997 single-bucket truck Project Number: 2017-5
Category	100% General Plant
1. Efficiency, Customer Value, Reliability	To properly install, repair and maintain the infrastructure for electrical distribution there must be enough bucket trucks. These units are used to work at heights on live line equipment. They are also used to manage heavy pieces of equipment that must be lifted into place such as distribution poles and pole-mounted transformers.
2. Safety	The bucket truck forms part of the safety equipment used by lines personnel when working on live lines. These units have insulated buckets, bucket-liners and booms for safety reasons. Use of a bucket truck is much safer than staff climbing poles, and doing live line work from a pole.
3. Cyber-security, Privacy	Not applicable
4. Co-ordination, Interoperability	These vehicles are used in combination with other pieces of equipment to complete much of the work. For example when running sections of overhead conductor there will be a truck at both ends of the run to hold and tension the line. In outage situations the various trucks work in tandem with other vehicles to search for causes of outages and carry out the necessary switching of lines to restore power.
5. Economic Development	Will provide some economic benefits for equipment suppliers.
6. Environmental Benefits	The newer trucks tend to have better emission profiles than those units they are replacing. This will result in less pollutants being released as part of the line work. Will consider a hybrid vehicle in the replacement specifications.

Part C4 (To be fully completed for each Test Year General Plant material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
							X		

Project Identification	Name: Replacement for a 1997 single-bucket truck Number: 2017-5
1. Comparison of alternatives	A single-bucket truck specification is well defined at this time. Will look at the different equipment suppliers/manufacturers that can provide this vehicle. Will use competitive pricing approach to select final supplier. A high level of reliability is critical for this vehicle as it is used to respond to emergency situations and routine line work to provide power to customers. A used vehicle cannot be depended on for this level of reliability. Renting vehicles is not a good option as rentals are usually used vehicles and the safety aspects may be compromised without our knowledge. The economics are that a new vehicle will pay for itself in a 2 to 3 year timeframe.
2. Very large projects	Not applicable

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

<u>Part A</u> (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
							X		

1. Project Identification	Name: System Control and Data Acquisition (SCADA) Implementation Project Number: 2017-6
2. Purpose/Overview	The current SCADA program has been largely "orphaned" with the planned system conversion and smart grid plans, STEI did not think it would be financially prudent to invest in what could be an obsolete system. Much of the current SCADA elements reside in the substations that are being phased out. As the conversion program has progressed there is a need for system control infrastructure to enable future smart grid and reduce the length of customer outages and to provide trouble shooting information. STEI has planned a conservative implementation over a five year period from 2015 to 2019 to enable STEI to spread out the investment that's needed and to react to potential government initiatives that may impact this type of system.
3. Category	100% General Plant
4. Cost	$50,000
5. Attachments/Loads	Not applicable
6. Dates	To be scheduled for 2017
7. Risks	• Labour o Low risk: The project will be carried out by experienced external and internal resources • Monetary o Low risk: Relatively small project for 2017 • Expertise o Low risk: Experienced external and internal resources available with relevant work experience • Weather o Low risk: Not a factor that will affect this work • External o Low risk: Need to source new software and system data elements, this not expected to be a problem

	• Customer o Low Risk: This system functionality is largely invisible to the customers. They will benefit from it though, through better outage assessments and communications which can restore power faster and keep customers informed
8. Comparative Information	Options for this module will be assessed before selecting the final product
9. REG Investment data	No
10. Leave to Construct	Not applicable

<u>Part B (To be fully completed for each Test Year material project; and all material projects in other years.)</u>

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
							X		

Project Identification	Name: System Control and Data Acquisition (SCADA) Implementation Project Number: 2017-6
Category	100% General Plant
1. Efficiency, Customer Value, Reliability	Improving the data collected from various parts of the distribution system and brining this together with the smart meter data and the GIS system will quickly and accurately show the location and extent of outages. More SCADA data collection will provide an even better picture of problems in the distribution system. Customers will benefit through faster outage response times to return power and improve communications with them. Better outage identification will save time spend searching for the cause of outages, saving costs. Faster outage responses will help support the reliability of the electric system.
2. Safety	Faster response to outages will result in faster cleanup of downed lines which can be a safety hazard to the public. Shorter outages will return the function of safety equipment like traffic and streetlights more quickly.
3. Cyber-security, Privacy	Not applicable
4. Co-ordination, Interoperability	This project will coordinate data from the SCADA system with smart meter functions with the GIS system to improve outage responses and

	system control.
5. Economic Development	Will provide some economic benefits for software suppliers and installation contractors.
6. Environmental Benefits	Not applicable

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

Part C4 (To be fully completed for each Test Year General Plant material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
							X		

Project Identification	Name: System Control and Data Acquisition (SCADA) Implementation Number: 2017-6
1. Comparison of alternatives	Will evaluate different systems and modules to rebuild the SCADA system. Will need to integrate this with the GIS and our smart meter data collection system. The use of SCADA systems is common in the utility business, and is needed to be able to quickly and effectively understand what is happening within a distribution system. Third party outsourcing not an option, monitoring and safely controlling the distribution system is part of our core business and requires special skills, knowledge and experience. For example, outage management and response is very specialized activity involving live line work, switching elements of the electric system, work protection (holdoffs), etc.
2. Very large projects	Not applicable

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
							X		

1. Project Identification	Name: Various computer hardware and software Number: 2017-7
2. Purpose/Overview	This item includes a number of smaller IT hardware and software costs including; regular maintenance to the data centre cabling/HVAC system, desktop/laptop/tablet repairs and replacement, replace network switches and SharePoint add-ons.
3. Category	100% General Plant
4. Cost	$38,000
5. Attachments/Loads	N/A
6. Dates	To be replaced throughout 2017
7. Risks	• Labour o Low risk: The project will be carried out by internal resources • Monetary o Low risk: Relatively small project and solution is known • Expertise o Low risk: Experienced internal resources available with relevant work experience • Weather o Low risk: Not a factor that will affect this work • External o Low risk: Need to source new equipment, not expected to be a problem • Customer o Low Risk: Regular maintenance and backup work
8. Comparative Information	Routine maintenance that involves comparative pricing
9. REG Investment data	No
10. Leave to Construct	Not applicable

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

<u>Part A</u> **(To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)**

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
							X		

1. Project Identification	Name: Replace a 2007 pickup truck, Ford F-150 4x4 Number: 2017-8
2. Purpose/Overview	To replace a pickup truck that has reached the end of its useful life. This vehicle will be 10 years old in 2017 when it is planned to replace it. This vehicle is used for emergency response and it is important to keep this unit in reliable condition. The current vehicle has been in a collision.
3. Category	100% General Plant
4. Cost	$35,000
5. Attachments/Loads	N/A
6. Dates	To be replaced in Q2 or Q3 2017
7. Risks	• Labour o Low risk: External purchase, minor changes required to standard vehicle • Monetary o Low risk: Relatively small project and solution is known • Expertise o Low risk: Routine purchase of vehicle • Weather o Low risk: Not a factor that will affect this item • External o Low risk: Need to source vehicle, not expected to be a problem • Customer o Low Risk: Replacement to maintain service to customers
8. Comparative Information	Regular replacement of rolling stock. Will look at competitive offers for a standard specification for this vehicle.
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
							X		

1. Project Identification	Name: Building changes for data centre Number: 2017-9
2. Purpose/Overview	The changes planned for this time period is to improve the security of the data centre and to install a protective wall within the room. The security improvements are a better door into the data centre and to extend the ceiling space to the roof to prevent access over the walls. The wall within the centre is to protect the servers from other activities that are carried out in the room.
3. Category	100% General Plant
4. Cost	$10,000
5. Attachments/Loads	N/A
6. Dates	To be completed in 2017
7. Risks	• Labour o Low risk: The project will be carried out by local resources • Monetary o Low risk: Relatively small project and solution is known • Expertise o Low risk: Experienced external resources available with relevant work experience • Weather o Low risk: Not a factor that will affect this work • External o Low risk: Using local contractors, not expected to be a problem • Customer o Low Risk: Improvements to the data centre will help protect customer information and will also safeguard system components which will maintain the availability of customer data
8. Comparative Information	Will look at comparative pricing from contractors
9. REG Investment data	No

Part 4: 2018 Projects

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
								X	

1. Project Identification	Name: Applewood, Lawrence, Butler, Porter, Raven & Dyer Area Conversion Project Number: **2018-1**
2. Purpose/Overview	Replace overhead assets due to the reliability risk to customers associated with aging. To replace the existing 2,400 V. Distribution system in the area that is 45 years old and is near end of life. In addition to customers benefiting from reduced maintenance costs due to the elimination of 2 Substation transformers and several kilometers of overhead line, this will save in transformer and wire losses and permit mandated reliability levels to be achieved in the area
3. Category	100% System Renewal
4. Cost	$700,000 Timing; Q2, Q3 & Q4 2018
5. Attachments/Loads	The Area is supplying approximately 250 residential customers
6. Dates	Start date: April 2018 In-Service date: December 2018
7. Risks	• Labour o Low risk: The project will be carried out mainly by internal staff with access to additional resources from the hiring hall to manage work fluctuation • Monetary o Low risk: Staff has extensive experience estimating and completing similar projects on budget • Expertise o Low risk: Experienced internal staff available with relevant work experience • Weather o Mitigated by planning weather appropriate projects. An example is by planning back-yard work in good weather conditions to reduce the amount property restoration than from spring weather.

	• External
	  o Moderate risk: Higher priority developer and City projects can impact timing of internal plans for this and other projects
	• Customer
	  o Low Risk: The company has an excellent history of cooperating with customers to obtain access in backyards to minimize customer intrusion and enhance project efficiency

8. Comparative Information	The experience gained on the 2014 projects will benefit the on-schedule and on-cost completion of this 2018 project.
9. REG Investment data	No
10. Leave to Construct	Not applicable

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
								X	

Project Identification	Name: Applewood, Lawrence, Butler, Porter, Raven & Dyer Area Conversion Project Number: 2018-1
Category	100% System Renewal
1. Efficiency, Customer Value, Reliability	This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system and a customer safety risk to pedestrians Voltage upgrade will reduce line loss and decrease customer bill impact. Maintain service quality standards. The risk of not doing this work is the need for spot replacement on an unplanned for basis which would increase O&M costs. Increased risk of customer outage and interruption would also likely occur. Increased public safety risk of infrastructure failure in front of customer property, sidewalks and roadway, potential electrical shock and

	hazardous delta system. This is fairly high priority project since it will bring about cost efficiencies and, as noted, will improve customer and staff safety.
2. Safety	There is a significant increase in staff safety and public safety since this results in replacing the current hazardous conditions of the existing delta 2,400 V system. That is, going from an ungrounded system to a grounded system which provides increased safety in a downed power line situation.
3. Cyber-security, Privacy	Not applicable
4. Co-ordination, Interoperability	The system enhancement allows for future smart grid integration.
5. Economic Development	The workforce required for this project will be both local contractors and also STEI staff. Materials are sourced from Provincial suppliers. Maintaining our system reliability is a key driver for attracting commercial and industrial businesses.
6. Environmental Benefits	Reduced line loss resulting in decreased power consumption and reduced associated environmental impacts Existing poles are treated with creosote which is no longer permissible are being removed. New installed poles meet current environmental standards

Part C2 (To be fully completed for each Test Year System Renewal material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
								X	

Project Identification	Name: Applewood, Lawrence, Butler, Porter, Raven & Dyer Area Conversion Project Number: 2018-1
1. Relationship between cause and effect on performance	The poles, overhead wires, pole-mounted transformers and underground cables are 45 years in age and are one of the oldest assets in the system. Original system installed based upon an old 45 yr engineering standard that results in equipment that is more costly to maintain, less efficient and presents higher customer and staff safety risks than equipment built to today's standard. Existing system not built to handle increased customer load thereby increasing the potential of system outages and potential customer hazards, customer owned equipment failure. Existing poles in this area are at end of useful life resulting in increased pole failures Impacting approximately 250 residential customers
2. Other factors affecting project timing	The project is best completed in the winter months. Because resources are more readily available. The timing of this project is based on the relative priorities of a number of similar projects. Conversion projects have been systematically reviewed and assigned based upon various criteria including age and potential failure of system and compliance with ESA Regulation 22/04. Any delays in preceding projects will impact the timing of subsequent projects and increasing the failure risk. City and developer requirements will impact on project timing
3. Consequences for system O&M costs	Refurbishment of equipment and cables rather than replacement is not a practical engineering option primarily due to higher present day design and safety standards. Primarily due to the higher voltage and conductor size requirements.

	Replacement of wood poles in this area will decrease the required testing and treatment costs for the next 20 years. Possible failures would require expensive unplanned repairs and lengthy power outages. As noted earlier, the elimination of a transformer and several kilometers of overhead line will also reduce O&M costs and line losses.
4. Reliability and safety influences	This area will be rebuilt to new standards for increased safety and reliability by removing overhead 2,400 V circuits and installing new overhead 27.6 kV lines and pole mounted transformers on City road allowance. Reduced risk of pole failure and related electrical contact due to end of life assets and increased pole clearance reduces potential public contact
5. Analysis of project benefits and costs	Not applicable
6. Like for Like analysis	Not feasible to maintain current 45 year old system, replacement parts are not readily available; requiring STEI to maintain used spare parts to maintain system. Additionally, when doing system spot replacements, ESA Regulation 22/04 requires a utility to maintain the existing line on a like for like basis, however, when building new powerlines STEI is required to upgrade the replacement to existing standards.

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
								X	

1. Project Identification	Name: Major Line West of Sunset Drive Area Conversion Project Number: 2018-2
2. Purpose/Overview	Replace overhead assets due to the reliability risk to customers associated with aging. To replace the existing 8,320 V distribution system in the area that is 40 years old and is near end of life. This power line was originally built by Hydro One and is located through a hilly, uneven and terrain accessible only by off-road vehicles. Many of the poles are in poor condition and are in need of proper support by storm guying. This section of line is very difficult to patrol and tree trim.
3. Category	100% System Renewal
4. Cost	$285,000 Timing; Q2 & Q3 2018
5. Attachments/Loads	The area is supplying 2 residential and 1 rural farm customers
6. Dates	Start date: April 2018 In-Service date: September 2018
7. Risks	• Labour o Low risk: The project will be carried out mainly by internal staff with access to additional resources from the hiring hall to manage work fluctuation • Monetary o Low risk: Staff has extensive experience estimating and completing similar projects on budget • Expertise o Low risk: Experienced internal staff available with relevant work experience • Weather o Mitigated by planning weather appropriate projects. An example is by planning back-yard work in good weather conditions to reduce the amount property restoration than from spring weather.

	• External
	  o Moderate risk: Higher priority developer and City projects can impact timing of internal plans for this and other projects
	• Customer
	  o Low Risk: The company has an excellent history of cooperating with customers to obtain access in backyards to minimize customer intrusion and enhance project efficiency

8. Comparative Information	The experience gained on the 2014 projects will benefit the on-schedule and on-cost completion of this 2018 project.
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
								X	

Project Identification	Name: Major Line West of Sunset Drive Area Conversion Project Number: 2018-2
Category	100% System Renewal
1. Efficiency, Customer Value, Reliability	This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system. Voltage upgrade will reduce line loss and decrease customer bill impact. Maintain service quality standards. The risk of not doing this work is the need for spot replacement on an unplanned for basis which would increase O&M costs. Increased risk of customer outage and interruption would also likely occur. This is fairly high priority project since it will bring about cost

	efficiencies and, as noted, will improve customer and staff safety.
2. Safety	There is a significant increase in staff safety due to old porcelain insulators, poor pole conditions and un-guyed poles.
3. Cyber-security, Privacy	Not applicable
4. Co-ordination, Interoperability	The system enhancement allows for future smart grid integration.
5. Economic Development	The workforce required for this project will be both local contractors and also STEI staff. Materials are sourced from Provincial suppliers. Maintaining our system reliability is a key driver for attracting commercial and industrial businesses.
6. Environmental Benefits	Reduced line loss resulting in decreased power consumption and reduced associated environmental impacts Existing poles are treated with creosote which is no longer permissible are being removed. New installed poles meet current environmental standards

Part C2 (To be fully completed for each Test Year System Renewal material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
								X	

Project Identification	Name: Major Line West of Sunset Drive Area Conversion Project Number: 2018-2
1. Relationship between cause and effect on performance	The poles, overhead wires, pole-mounted transformers and underground cables are 40 years in age and are one of the oldest assets in the system. Original system installed based upon an old 40 yr engineering standard that results in equipment that is more costly to maintain, less efficient and presents higher customer and staff safety risks than equipment built to today's standard. Existing system not built to current guying standards thereby increasing the potential of system outages and potential customer hazards due to downed power lines. Existing poles in this area are at end of useful life resulting in increased pole failures. Impacting 2 residential customers and 1 rural farm customer.
2. Other factors affecting project timing	The project is best completed in the winter months. Because resources are more readily available. The timing of this project is based on the relative priorities of a number of similar projects. Conversion projects have been systematically reviewed and assigned based upon various criteria including age and potential failure of system and compliance with ESA Regulation 22/04. Any delays in preceding projects will impact the timing of subsequent projects and increasing the failure risk. City and developer requirements will impact on project timing
3. Consequences for system O&M costs	Refurbishment of equipment rather than replacement is not a practical engineering option primarily due to higher present day design and safety standards. Primarily due to the higher voltage and conductor size requirements. Replacement of wood poles in this area will decrease the required testing

	and treatment costs for the next 20 years. Possible failures would require expensive unplanned repairs and lengthy power outages due to its inaccessible location.
4. Reliability and safety influences	This area will be rebuilt to new standards for increased safety and reliability by removing overhead 8,320 V circuits and installing new overhead 27.6 kV lines in improved locations. Reduced risk of pole failure and related electrical contact due to end of life assets.
5. Analysis of project benefits and costs	Not applicable
6. Like for Like analysis	Not feasible to maintain current 40 year old system, replacement parts are not readily available; requiring STEI to maintain used spare parts to maintain system. Additionally, when doing system spot replacements, ESA Regulation 22/04 requires a utility to maintain the existing line on a like for like basis, however, when building new power lines STEI is required to upgrade the replacement to existing standards.

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
								X	

1. Project Identification	Name: Centennial Avenue Talbot to Wellington New Power line and System Upgrade Project Number: **2018-3**
2. Purpose/Overview	The completion of this work will provide for better system reliability by having a looped primary system on this main feeder to the south-east section of the City. The work will involve upgrading the size of the conductors to allow for increased system capacity. This system upgrade will save in wire losses. This work is not part of the voltage conversion project.
3. Category	100% System Service
4. Cost	$305,000 Timing; Q2 & Q3 2018
5. Attachments/Loads	The Area is supplying approximately 1200 residential customers
6. Dates	Start date: April 2018 In-Service date: September 2018
7. Risks	• Labour o Low risk: The project will be carried out mainly by internal staff with access to additional resources from the hiring hall to manage work fluctuation • Monetary o Low risk: Staff has extensive experience estimating and completing similar projects on budget • Expertise o Low risk: Experienced internal staff available with relevant work experience • Weather o Mitigated by planning weather appropriate projects. An example is by planning back-yard work in good weather conditions to reduce the amount property restoration than from spring weather.

	• External
	  o Moderate risk: Higher priority developer and City projects can impact timing of internal plans for this and other projects
	• Customer
	  o Low Risk: The company has an excellent history of cooperating with customers to obtain access in backyards to minimize customer intrusion and enhance project efficiency

8. Comparative Information	The experience gained on the 2014 projects will benefit the on-schedule and on-cost completion of this 2018 project.
9. REG Investment data	No
10. Leave to Construct	Not applicable

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

<u>Part B (To be fully completed for each Test Year material project; and all material projects in other years.)</u>

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
								X	

Project Identification	Name: Centennial Avenue Talbot to Wellington System Upgrade Project Number: 2018-3
Category	100% System Service
1. Efficiency, Customer Value, Reliability	This project is driven primarily by the need to provide increased system reliability that poses a risk to the distribution system. Once completed there will be better overall system security by providing a looped distribution system to a larger customer area. Maintain service quality standards. The work involves upgrading the conductor size and capacity on a main system feeder.
2. Safety	This new overhead 27.6 kV circuit overhead power line will be constructed in the city right-of-way and be built to current safety standards.

3. Cyber-security, Privacy	Not applicable
4. Co-ordination, Interoperability	System looping will maintain reliability, reduce outage times. The system enhancement would allow for smart grid integration in the future
5. Economic Development	The workforce required for this project will be both local contractors and also STEI staff. Materials are sourced from Provincial suppliers. Maintaining our system reliability is a key driver for attracting commercial and industrial businesses.
6. Environmental Benefits	Reduced line loss resulting in decreased power consumption and reduced associated environmental impacts Existing poles are treated with creosote which is no longer permissible are being removed. New installed poles meet current environmental standards

Part C3 (To be fully completed for each Test Year System Service material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
								X	

Project Identification	Name: Centennial Avenue Talbot to Wellington System Upgrade Project Number: 2018-3
1. Customers' benefits	The completion of this work will provide for better system reliability by having a looped primary system on this main feeder to the south-east section of the City. The work will involve upgrading the size of the conductors to allow for increased system capacity, saving in wire losses.
2. Regional electricity infrastructure	This project was identified in an internal Block 3 Area Study for the

requirements	need of an underground feeder through the area which would replace the rear-yard feeder.
3. Incorporation of advanced technology etc.	The system enhancement would allow for smart grid integration in the future.
4. Additional project benefits	System looping will maintain reliability, reduce outage times.
5. Factors affecting project timing	Conversion projects have been systematically reviewed and assigned based upon various criteria including age and potential failure of system and compliance with ESA Regulation 22/04. Any delays in preceding projects will impact the timing of subsequent projects and increasing the failure risk. The City can add requirements that may impact project timing.
6. Comparison of alternatives	The alternative option is to replace the existing overhead and underground system with a new distribution, along a route 5 times longer and excavating across existing driveways and landscaped lawns. This option is more expensive by material costs and restoration costs. The most cost effective solution is to rebuild the overhead powerline on the city street, Centennial Ave, in co-operation with the joint use agreement with Hydro One.

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
								X	

1. Project Identification	Name: Edward, Gaylord, E. side of Elgin Mall System Upgrade Project Number: 2018-4
2. Purpose/Overview	Replace overhead assets due to the reliability risk to customers associated with aging and substandard performance. To replace the existing 27.6 kV distribution system in the area that is 30 years old and needs to be upgraded. The completion of this work will provide for better system efficiency and performance by replacing the poles and upgrading the conductors. This is a main feeder and also the back-up for a parallel feeder when necessary. Replacing several kilometers of overhead line will provide an increased system capacity across the area and save in distribution system wire losses.
3. Category	100% System Renewal
4. Cost	$230,000 Timing; Q4 2018
5. Attachments/Loads	The Area is supplying approximately 1000 residential customers
6. Dates	Start date: October 2018 In-Service date: December 2018
7. Risks	• Labour o Low risk: The project will be carried out mainly by internal staff with access to additional resources from the hiring hall to manage work fluctuation • Monetary o Low risk: Staff has extensive experience estimating and completing similar projects on budget • Expertise o Low risk: Experienced internal staff available with relevant work experience • Weather o Mitigated by planning weather appropriate projects. An example is by planning back-yard work in good weather conditions to reduce the amount property restoration than from spring weather.

	• External
	  o Moderate risk: Higher priority developer and City projects can impact timing of internal plans for this and other projects
	• Customer
	  o Low Risk: The company has an excellent history of cooperating with customers to obtain access in backyards to minimize customer intrusion and enhance project efficiency

8. Comparative Information	The experience gained on the 2014 projects will benefit the on-schedule and on-cost completion of this 2018 project.
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
								X	

Project Identification	Name: Edward, Gaylord, Farmington System Upgrade Project Number: 2018-4
Category	100% System Renewal
1. Efficiency, Customer Value, Reliability	This project is driven primarily by the need to replace assets that are in need of replacement due to aging and substandard performance. Pole replacement and increasing the conductor size will reduce line loss and decrease customer bill impact. Maintain service quality standards. The risk of not doing this work is the need for spot replacement on an unplanned for basis which would increase O&M costs. Increased risk of customer outage and interruption would also likely occur. This is fairly high priority project since it will bring about cost

	efficiencies and, as noted, will improve customer and staff safety.
2. Safety	The newer assets are more reliable and will minimize the risk to failure and/or flashover. The existing poles are class 3, where the new poles will be a higher class 2. The area will be rebuilt to new standards for materials and clearances which will increase the safety and reliability.
3. Cyber-security, Privacy	Not applicable
4. Co-ordination, Interoperability	The system enhancement allows for future smart grid integration.
5. Economic Development	The workforce required for this project will be both local contractors and also STEI staff. Materials are sourced from Provincial suppliers. Maintaining our system reliability is a key driver for attracting commercial and industrial businesses.
6. Environmental Benefits	Reduced line loss resulting in decreased power consumption and reduced associated environmental impacts Existing poles are treated with creosote which is no longer permissible are being removed. New installed poles meet current environmental standards.

Part C2 (To be fully completed for each Test Year System Renewal material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
								X	

Project Identification	Name: Edward, Gaylord, Farmington System Upgrade Project Number: 2018-4
1. Relationship between cause and effect on performance	The poles, overhead wires and the pole-mounted transformers are aging and pose a reliability risk to the distribution system. Original system installed based upon an old 30 yr engineering standard that results in equipment that is more costly to maintain, less efficient and presents higher customer and staff safety risks than equipment built to today's standard. Existing system not built to handle increased customer load thereby increasing the potential of system outages and potential customer hazards, customer owned equipment failure. Existing poles in this area are at end of useful life resulting in increased pole failures. Impacting approximately 1000 residential customers.
2. Other factors affecting project timing	The project is best completed in the winter months. Because resources are more readily available. The timing of this project is based on the relative priorities of a number of similar projects. Conversion projects have been systematically reviewed and assigned based upon various criteria including age and potential failure of system and compliance with ESA Regulation 22/04. Any delays in preceding projects will impact the timing of subsequent projects and increasing the failure risk. City and developer requirements will impact on project timing
3. Consequences for system O&M costs	Refurbishment of equipment rather than replacement is not a practical engineering option primarily due to higher present day design and safety standards. Primarily due to the higher voltage and conductor size requirements. Replacement of wood poles in this area will decrease the required testing

	and treatment costs for the next 20 years. Possible failures would require expensive unplanned repairs and lengthy power outages due to its inaccessible location.
4. Reliability and safety influences	This area will be rebuilt to new standards for increased safety and reliability which exceeded the original construction for materials and clearances. Reduced risk of pole failure and related electrical contact due to end of life assets.
5. Analysis of project benefits and costs	Not applicable
6. Like for Like analysis	From a system configuration perspective the project is like-for-like, however new equipment will be used which is expected to increase reliability in the area.

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
								X	

1. Project Identification	Name: System Control and Data Acquisition (SCADA) Implementation Project Number: 2018-5
2. Purpose/Overview	The current SCADA program has been largely “orphaned” with the planned system conversion and smart grid plans, STEI did not think it would be financially prudent to invest in what could be an obsolete system. Much of the current SCADA elements reside in the substations that are being phased out. As the conversion program has progressed there is a need for system control infrastructure to enable future smart grid and reduce the length of customer outages and to provide trouble shooting information. STEI has planned a conservative implementation over a five year period from 2015 to 2019 to enable STEI to spread out the investment that’s needed and to react to potential government initiatives that may impact this type of system.
3. Category	100% General Plant
4. Cost	$100,000
5. Attachments/Loads	Not applicable
6. Dates	To be scheduled for 2018
7. Risks	• Labour o Low risk: The project will be carried out by experienced external and internal resources • Monetary o Low risk: Relatively small project for 2018 • Expertise o Low risk: Experienced external and internal resources available with relevant work experience • Weather o Low risk: Not a factor that will affect this work • External o Low risk: Need to source new software and system data elements, this not expected to be a problem

	• Customer o Low Risk: This system functionality is largely invisible to the customers. They will benefit from it though, through better outage assessments and communications which can restore power faster and keep customers informed
8. Comparative Information	Options for this module will be assessed before selecting the final product
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
								X	

Project Identification	Name: System Control and Data Acquisition (SCADA) Implementation Project Number: 2018-5
Category	100% General Plant
1. Efficiency, Customer Value, Reliability	Improving the data collected from various parts of the distribution system and brining this together with the smart meter data and the GIS system will quickly and accurately show the location and extent of outages. More SCADA data collection will provide an even better picture of problems in the distribution system. Customers will benefit through faster outage response times to return power and improve communications with them. Better outage identification will save time spend searching for the cause of outages, saving costs. Faster outage responses will help support the reliability of the electric system.
2. Safety	Faster response to outages will result in faster cleanup of downed lines which can be a safety hazard to the public. Shorter outages will return the function of safety equipment like traffic and streetlights more quickly.
3. Cyber-security, Privacy	Not applicable
4. Co-ordination, Interoperability	This project will coordinate data from the SCADA system with smart meter functions with the GIS system to improve outage responses and

	system control.
5. Economic Development	Will provide some economic benefits for software suppliers and installation contractors.
6. Environmental Benefits	Not applicable

<u>Part C4</u> (To be fully completed for each Test Year General Plant material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
								X	

Project Identification	Name: System Control and Data Acquisition (SCADA) Implementation Number: 2018-5
1. Comparison of alternatives	Will evaluate different systems and modules to rebuild the SCADA system. Will need to integrate this with the GIS and our smart meter data collection system. The use of SCADA systems is common in the utility business, and is needed to be able to quickly and effectively understand what is happening within a distribution system. Third party outsourcing not an option, monitoring and safely controlling the distribution system is part of our core business and requires special skills, knowledge and experience. For example, outage management and response is very specialized activity involving live line work, switching elements of the electric system, work protection (holdoffs), etc.
2. Very large projects	Not applicable

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
								X	

1. Project Identification	Name: Various computer hardware and software Number: 2018-6
2. Purpose/Overview	This item is to replace the PureFlex server which will be at the end of its useful life.
3. Category	100% General Plant
4. Cost	$40,000
5. Attachments/Loads	N/A
6. Dates	To be replaced in 2018
7. Risks	• Labour o Low risk: The project will be carried out by internal resources • Monetary o Low risk: Relatively small project and solution is known • Expertise o Low risk: Experienced internal resources available with relevant work experience • Weather o Low risk: Not a factor that will affect this work • External o Low risk: Need to source new equipment, not expected to be a problem • Customer o Low Risk: Regular equipment replacement project
8. Comparative Information	Routine replacement that involves comparative pricing
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
								X	

1. Project Identification	Name: Regular upgrades to the NorthStar CIS billing system Number: 2018-7
2. Purpose/Overview	Regular upgrades are necessary for the CIS billing system to keep it current. These upgrades will make changes/enhancements to the CIS for: bill print changes, RRR new and amended reporting requirements and OEB new and amended code requirements.
3. Category	100% General Plant
4. Cost	$25,000
5. Attachments/Loads	N/A
6. Dates	To be scheduled in 2018
7. Risks	• Labour o Low risk: Changes will be made by external resources with expertise with this CIS system • Monetary o Low risk: Relatively small project and solution is known • Expertise o Low risk: Using external resources with expertise in this area • Weather o Low risk: Not a factor that will affect this item • External o Low risk: There are dedicate professionals servicing this system. Changes will affect a number of utilities at the same time, which will require their focus • Customer o Low Risk: Regular upgrades to the CIS system, changes will be tested before moving to production
8. Comparative Information	Regular maintenance for the NorthStar CIS system. Will need to use the supplier of the system for these changes as they have the expertise to make any changes.
9. REG Investment data	No
10. Leave to Construct	Not applicable

St.**Thomas***energy***inc.** **Capital Expenditure Plan Projects**

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
								X	

1. Project Identification	Name: Replace a pole-trailer Number: 2018-8
2. Purpose/Overview	To replace a pole-trailer that has reached the end of its useful life. The existing pole-trailer will be 30 years old in 2018 when it is planned to replace it. This unit is used for emergency response and it is important to keep this equipment in reliable condition.
3. Category	100% General Plant
4. Cost	$20,000
5. Attachments/Loads	N/A
6. Dates	To be replaced in Q2 or Q3 2018
7. Risks	• Labour o Low risk: External purchase, minor changes required to standard product • Monetary o Low risk: Relatively small project and solution is known • Expertise o Low risk: Routine purchase of pole-trailer • Weather o Low risk: Not a factor that will affect this item • External o Low risk: Need to source pole-trailer, not expected to be a problem • Customer o Low Risk: Replacement to maintain service to customers
8. Comparative Information	Regular replacement of rolling stock. Will look at competitive offers for a standard specification for this unit.
9. REG Investment data	No
10. Leave to Construct	Not applicable

<u>Part A</u> (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
								X	

1. Project Identification	Name: Various computer hardware and software Number: 2018-9
2. Purpose/Overview	This item includes a number of smaller IT hardware costs including; regular maintenance to the data centre cabling/HVAC system, desktop/laptop/tablet repairs and replacement and to replace the Fortinet appliance.
3. Category	100% General Plant
4. Cost	$27,000
5. Attachments/Loads	N/A
6. Dates	To be replaced in 2018

7. Risks	• Labour
	  o Low risk: The project will be carried out by internal resources
	• Monetary
	  o Low risk: Relatively small project and solution is known
	• Expertise
	  o Low risk: Experienced internal resources available with relevant work experience
	• Weather
	  o Low risk: Not a factor that will affect this work
	• External
	  o Low risk: Need to source new equipment, not expected to be a problem
	• Customer
	  o Low Risk: Regular equipment replacement project

8. Comparative Information	Routine replacement that involves comparative pricing
9. REG Investment data	No
10. Leave to Construct	Not applicable

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

<u>Part A</u> (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
								X	

1. Project Identification	Name: Miscellaneous IT software costs Number: **2018-10**
2. Purpose/Overview	This item includes a number of smaller IT software costs including; new firewalls and SharePoint add-ons.
3. Category	100% General Plant
4. Cost	$28,000
5. Attachments/Loads	IT system maintenance
6. Dates	To be scheduled in 2018
7. Risks	• Labour o Low risk: The project will be carried out by internal resources • Monetary o Low risk: Relatively small project and solution is known • Expertise o Low risk: Experienced internal resources available with relevant work experience • Weather o Low risk: Not a factor that will affect this work • External o Low risk: Need to source components, not expected to be a problem • Customer o Low Risk: Regular maintenance of IT systems
8. Comparative Information	Routine maintenance that involves comparative pricing
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
								X	

1. Project Identification	Name: Office furniture replacement Number: 2018-11
2. Purpose/Overview	This cost is for routine replacement of office furniture to cover equipment that has worn out.
3. Category	100% General Plant
4. Cost	$5,000
5. Attachments/Loads	N/A
6. Dates	To be completed in 2018
7. Risks	• Labour o Low risk: The project will be carried out by local suppliers • Monetary o Low risk: Relatively small project and solution is known • Expertise o Low risk: Experienced external suppliers available, routine replacement of furniture • Weather o Low risk: Not a factor that will affect this work • External o Low risk: Using local suppliers, not expected to be a problem • Customer o Low Risk: No direct customer impact, affects staff who service the customers
8. Comparative Information	Will look at comparative pricing from suppliers
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part 5: 2019 Projects

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
									X

1. Project Identification	Name: First, Thompson, Glanworth, Ashton Area Conversion Project Number: 2019-1
2. Purpose/Overview	Replace overhead assets due to the reliability risk to customers associated with aging. To replace the existing 2,400 V. Distribution system in the area that is 40 years old and is near end of life. In addition to customers benefiting from reduced maintenance costs due to the elimination of transformers and the several kilometers of overhead line, this will save in transformer and wire losses and permit mandated reliability levels to be achieved in the area.
3. Category	100% System Renewal
4. Cost	$511,660 Timing; Q2 & Q3 2019
5. Attachments/Loads	The Area is supplying approximately 150 residential customers
6. Dates	Start date: April 2019 In-Service date: September 2019
7. Risks	• Labour o Low risk: The project will be carried out mainly by internal staff with access to additional resources from the hiring hall to manage work fluctuation • Monetary o Low risk: Staff has extensive experience estimating and completing similar projects on budget • Expertise o Low risk: Experienced internal staff available with relevant work experience • Weather o Mitigated by planning weather appropriate projects. An example is by planning back-yard work in good weather conditions to reduce the amount property restoration than from spring weather.

	• External
	  o Moderate risk: Higher priority developer and City projects can impact timing of internal plans for this and other projects
	• Customer
	  o Low Risk: The company has an excellent history of cooperating with customers when rebuilding powerlines to minimize customer intrusion and enhance project efficiency

8. Comparative Information	The experience gained on the 2014 projects will benefit the on-schedule and on-cost completion of this 2019 project.
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
									X

Project Identification	Name: First, Thompson, Glanworth, Ashton Area Conversion Project Number: 2019-1
Category	100% System Renewal
1. Efficiency, Customer Value, Reliability	This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system. Voltage upgrade will reduce line loss and decrease customer bill impact. Maintain service quality standards. The risk of not doing this work is the need for spot replacement on an unplanned for basis which would increase O&M costs. Increased risk of customer outage and interruption would also likely occur. This is fairly high priority project since it will bring about cost

	efficiencies and, as noted, will improve customer and staff safety.
2. Safety	There is a significant increase in staff safety and public safety since this results in replacing the current hazardous conditions of the existing delta 2,400 V system. That is, going from an ungrounded system to a grounded system which provides increased safety in a downed power line situation.
3. Cyber-security, Privacy	Not applicable
4. Co-ordination, Interoperability	The system enhancement allows for future smart grid integration.
5. Economic Development	The workforce required for this project will be both local contractors and also STEI staff. Materials are sourced from Provincial suppliers. Maintaining our system reliability is a key driver for attracting commercial and industrial businesses.
6. Environmental Benefits	Reduced line loss resulting in decreased power consumption and reduced associated environmental impacts Existing poles are treated with creosote which is no longer permissible are being removed. New installed poles meet current environmental standards

Part C2 (To be fully completed for each Test Year System Renewal material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
									X

Project Identification	Name: First, Thompson, Glanworth, Ashton Area Conversion Project Number: 2019-1
1. Relationship between cause and effect on performance	The poles, overhead wires, pole-mounted transformers and underground cables are 40 years in age and are one of the oldest assets in the system. Original system installed based upon an old 40 yr engineering standard that results in equipment that is more costly to maintain, less efficient and presents higher customer and staff safety risks than equipment built to today's standard. Existing system not built to handle increased customer load thereby increasing the potential of system outages and potential customer hazards, customer owned equipment failure. Existing poles in this area are at end of useful life resulting in increased pole failures. Impacting approximately 150 residential customers.
2. Other factors affecting project timing	The project is best completed in the late summer and fall and months. Because resources are more readily available. The timing of this project is based on the relative priorities of a number of similar projects. Conversion projects have been systematically reviewed and assigned based upon various criteria including age and potential failure of system and compliance with ESA Regulation 22/04. Any delays in preceding projects will impact the timing of subsequent projects and increasing the failure risk. City and developer requirements will impact on project timing
3. Consequences for system O&M costs	Refurbishment of equipment rather than replacement is not a practical engineering option primarily due to higher present day design and safety standards. Primarily due to the higher voltage and conductor size requirements. Replacement of wood poles in this area will decrease the required testing

	and treatment costs for the next 20 years. Possible failures would require expensive unplanned repairs and lengthy power outages due to its inaccessible location.
4. Reliability and safety influences	This area will be rebuilt to new standards for increased safety and reliability by removing overhead 2,400 V circuits and installing new overhead 27.6 kV lines and pad-mounted transformers on City road allowance. Reduced risk of pole failure and related electrical contact due to end of life assets.
5. Analysis of project benefits and costs	Not applicable
6. Like for Like analysis	Not feasible to maintain current 40 year old system, replacement parts are not readily available; requiring STEI to maintain used spare parts to maintain system. Additionally, when doing system spot replacements, ESA Regulation 22/04 requires a utility to maintain the existing line on a like for like basis, however, when building new powerlines STEI is required to upgrade the replacement to existing standards.

<u>Part A</u> **(To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)**

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
									X

1. Project Identification	Name: Aldborough, Airey & Vanier Area Conversion Project Number: 2019-2
2. Purpose/Overview	Replace overhead assets due to the reliability risk to customers associated with aging. To replace the existing 2,400 V. Distribution system in the area that is 46 years old and is near end of life. In addition to customers benefiting from reduced maintenance costs due to the elimination of transformers and the several kilometers of overhead line, this will save in transformer and wire losses and permit mandated reliability levels to be achieved in the area.
3. Category	100% System Renewal
4. Cost	$561,670 Timing; Q2 & Q3 2019
5. Attachments/Loads	The Area is supplying approximately 200 residential customers
6. Dates	Start date: May 2019 In-Service date: September 2019
7. Risks	• Labour o Low risk: The project will be carried out mainly by internal staff with access to additional resources from the hiring hall to manage work fluctuation • Monetary o Low risk: Staff has extensive experience estimating and completing similar projects on budget • Expertise o Low risk: Experienced internal staff available with relevant work experience • Weather o Mitigated by planning weather appropriate projects. An example is by planning back-yard work in good weather conditions to reduce the amount property restoration than from spring weather.

	• External o Moderate risk: Higher priority developer and City projects can impact timing of internal plans for this and other projects • Customer o Low Risk: The company has an excellent history of cooperating with customers when rebuilding powerlines to minimize customer intrusion and enhance project efficiency
8. Comparative Information	The experience gained on the 2014 projects will benefit the on-schedule and on-cost completion of this 2019 project.
9. REG Investment data	No
10. Leave to Construct	Not applicable

<u>Part B (To be fully completed for each Test Year material project; and all material projects in other years.)</u>

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
									X

Project Identification	Name: Aldborough, Airey & Vanier Area Conversion Project Number: 2019-2
Category	100% System Renewal
1. Efficiency, Customer Value, Reliability	This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system. Voltage upgrade will reduce line loss and decrease customer bill impact. Maintain service quality standards. The risk of not doing this work is the need for spot replacement on an unplanned for basis which would increase O&M costs. Increased risk of customer outage and interruption would also likely occur. This is fairly high priority project since it will bring about cost

	efficiencies and, as noted, will improve customer and staff safety.
2. Safety	There is a significant increase in staff safety and public safety since this results in replacing the current hazardous conditions of the existing delta 2,400 V system. That is, going from an ungrounded system to a grounded system which provides increased safety in a downed power line situation.
3. Cyber-security, Privacy	Not applicable
4. Co-ordination, Interoperability	The system enhancement allows for future smart grid integration.
5. Economic Development	The workforce required for this project will be both local contractors and also STEI staff. Materials are sourced from Provincial suppliers. Maintaining our system reliability is a key driver for attracting commercial and industrial businesses.
6. Environmental Benefits	Reduced line loss resulting in decreased power consumption and reduced associated environmental impacts Existing poles are treated with creosote which is no longer permissible are being removed. New installed poles meet current environmental standards

Part C2 (To be fully completed for each Test Year System Renewal material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
									X

Project Identification	Name: Aldborough, Airey & Vanier Area Conversion Project Number: 2019-2
1. Relationship between cause and effect on performance	The poles, overhead wires, pole-mounted transformers and underground cables are 46 years in age and are one of the oldest assets in the system. Original system installed based upon an old 46 yr engineering standard that results in equipment that is more costly to maintain, less efficient and presents higher customer and staff safety risks than equipment built to today's standard. Existing system not built to handle increased customer load thereby increasing the potential of system outages and potential customer hazards, customer owned equipment failure. Existing poles in this area are at end of useful life resulting in increased pole failures. Impacting approximately 200 residential customers.
2. Other factors affecting project timing	The project is best completed in the late summer and fall and months. Because resources are more readily available. The timing of this project is based on the relative priorities of a number of similar projects. Conversion projects have been systematically reviewed and assigned based upon various criteria including age and potential failure of system and compliance with ESA Regulation 22/04. Any delays in preceding projects will impact the timing of subsequent projects and increasing the failure risk. City and developer requirements will impact on project timing
3. Consequences for system O&M costs	Refurbishment of equipment rather than replacement is not a practical engineering option primarily due to higher present day design and safety standards. Primarily due to the higher voltage and conductor size requirements. Replacement of wood poles in this area will decrease the required testing

	and treatment costs for the next 20 years. Possible failures would require expensive unplanned repairs and lengthy power outages due to its inaccessible location.
4. Reliability and safety influences	This area will be rebuilt to new standards for increased safety and reliability by removing overhead 2,400 V circuits and installing new overhead 27.6 kV lines and pad-mounted transformers on City road allowance. Reduced risk of pole failure and related electrical contact due to end of life assets.
5. Analysis of project benefits and costs	Not applicable
6. Like for Like analysis	Not feasible to maintain current 46 year old system, replacement parts are not readily available; requiring STEI to maintain used spare parts to maintain system. Additionally, when doing system spot replacements, ESA Regulation 22/04 requires a utility to maintain the existing line on a like for like basis, however, when building new powerlines STEI is required to upgrade the replacement to existing standards.

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
									X

1. Project Identification	Name: Aldborough, Pullen, Sparta & Parish Area Conversion Project Number: 2019-3
2. Purpose/Overview	Replace overhead assets due to the reliability risk to customers associated with aging. To replace the existing 2,400 V. Distribution system in the area that is 46 years old and is near end of life. In addition to customers benefiting from reduced maintenance costs due to the elimination of transformers and the several kilometers of overhead line, this will save in transformer and wire losses and permit mandated reliability levels to be achieved in the area.
3. Category	100% System Renewal
4. Cost	$486,670 Timing; Q3 & Q4 2019
5. Attachments/Loads	The Area is supplying approximately 200 residential customers
6. Dates	Start date: July 2019 In-Service date: December 2019
7. Risks	• Labour o Low risk: The project will be carried out mainly by internal staff with access to additional resources from the hiring hall to manage work fluctuation • Monetary o Low risk: Staff has extensive experience estimating and completing similar projects on budget • Expertise o Low risk: Experienced internal staff available with relevant work experience • Weather o Mitigated by planning weather appropriate projects. An example is by planning back-yard work in good weather conditions to reduce the amount property restoration than from spring weather.

	• External o Moderate risk: Higher priority developer and City projects can impact timing of internal plans for this and other projects • Customer o Low Risk: The company has an excellent history of cooperating with customers when rebuilding power lines to minimize customer intrusion and enhance project efficiency
8. Comparative Information	The experience gained on the 2014 projects will benefit the on-schedule and on-cost completion of this 2019 project.
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
									X

Project Identification	Name: Aldborough, Pullen, Sparta & Parish Area Conversion Project Number: 2019-3
Category	100% System Renewal
1. Efficiency, Customer Value, Reliability	This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system. Voltage upgrade will reduce line loss and decrease customer bill impact. Maintain service quality standards. The risk of not doing this work is the need for spot replacement on an unplanned for basis which would increase O&M costs. Increased risk of customer outage and interruption would also likely occur. This is fairly high priority project since it will bring about cost

	efficiencies and, as noted, will improve customer and staff safety.
2. Safety	There is a significant increase in staff safety and public safety since this results in replacing the current hazardous conditions of the existing delta 2,400 V system. That is, going from an ungrounded system to a grounded system which provides increased safety in a downed power line situation.
3. Cyber-security, Privacy	Not applicable
4. Co-ordination, Interoperability	The system enhancement allows for future smart grid integration.
5. Economic Development	The workforce required for this project will be both local contractors and also STEI staff. Materials are sourced from Provincial suppliers. Maintaining our system reliability is a key driver for attracting commercial and industrial businesses.
6. Environmental Benefits	Reduced line loss resulting in decreased power consumption and reduced associated environmental impacts Existing poles are treated with creosote which is no longer permissible are being removed. New installed poles meet current environmental standards

Part C2 (To be fully completed for each Test Year System Renewal material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
									X

Project Identification	Name: Aldborough, Pullen, Sparta & Parish Area Conversion Project Number: 2019-3
1. Relationship between cause and effect on performance	The poles, overhead wires, pole-mounted transformers and underground cables are 46 years in age and are one of the oldest assets in the system. Original system installed based upon an old 46 yr engineering standard that results in equipment that is more costly to maintain, less efficient and presents higher customer and staff safety risks than equipment built to today's standard. Existing system not built to handle increased customer load thereby increasing the potential of system outages and potential customer hazards, customer owned equipment failure. Existing poles in this area are at end of useful life resulting in increased pole failures. Impacting approximately 200 residential customers.
2. Other factors affecting project timing	The project is best completed in the late summer and fall months. Because resources are more readily available. The timing of this project is based on the relative priorities of a number of similar projects. Conversion projects have been systematically reviewed and assigned based upon various criteria including age and potential failure of system and compliance with ESA Regulation 22/04. Any delays in preceding projects will impact the timing of subsequent projects and increasing the failure risk. City and developer requirements will impact on project timing
3. Consequences for system O&M costs	Refurbishment of equipment rather than replacement is not a practical engineering option primarily due to higher present day design and safety standards. Primarily due to the higher voltage and conductor size requirements. Replacement of wood poles in this area will decrease the required testing

	and treatment costs for the next 20 years. Possible failures would require expensive unplanned repairs and lengthy power outages due to its inaccessible location.
4. Reliability and safety influences	This area will be rebuilt to new standards for increased safety and reliability by removing overhead 2,400 V circuits and installing new overhead 27.6 kV lines and pad-mounted transformers on City road allowance. Reduced risk of pole failure and related electrical contact due to end of life assets.
5. Analysis of project benefits and costs	Not applicable
6. Like for Like analysis	Not feasible to maintain current 46 year old system, replacement parts are not readily available; requiring STEI to maintain used spare parts to maintain system. Additionally, when doing system spot replacements, ESA Regulation 22/04 requires a utility to maintain the existing line on a like for like basis, however, when building new power lines STEI is required to upgrade the replacement to existing standards.

<u>Part A</u> (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
									X

1. Project Identification	Name: System Control and Data Acquisition (SCADA) Implementation Project Number: 2019-4
2. Purpose/Overview	The current SCADA program has been largely "orphaned" with the planned system conversion and smart grid plans, STEI did not think it would be financially prudent to invest in what could be an obsolete system. Much of the current SCADA elements reside in the substations that are being phased out. As the conversion program has progressed there is a need for system control infrastructure to enable future smart grid and reduce the length of customer outages and to provide trouble shooting information. STEI has planned a conservative implementation over a five year period from 2015 to 2019 to enable STEI to spread out the investment that's needed and to react to potential government initiatives that may impact this type of system.
3. Category	100% General Plant
4. Cost	$100,000
5. Attachments/Loads	Not applicable
6. Dates	To be scheduled for 2019
7. Risks	• Labour o Low risk: The project will be carried out by experienced external and internal resources • Monetary o Low risk: Relatively small project for 2019 • Expertise o Low risk: Experienced external and internal resources available with relevant work experience • Weather o Low risk: Not a factor that will affect this work • External o Low risk: Need to source new software and system data elements, this not expected to be a problem

	• Customer o Low Risk: This system functionality is largely invisible to the customers. They will benefit from it though, through better outage assessments and communications which can restore power faster and keep customers informed
8. Comparative Information	Options for this module will be assessed before selecting the final product
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part B (To be fully completed for each Test Year material project; and all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
									X

Project Identification	Name: System Control and Data Acquisition (SCADA) Implementation Project Number: 2019-4
Category	100% General Plant
1. Efficiency, Customer Value, Reliability	Improving the data collected from various parts of the distribution system and brining this together with the smart meter data and the GIS system will quickly and accurately show the location and extent of outages. More SCADA data collection will provide an even better picture of problems in the distribution system. Customers will benefit through faster outage response times to return power and improve communications with them. Better outage identification will save time spend searching for the cause of outages, saving costs. Faster outage responses will help support the reliability of the electric system.
2. Safety	Faster response to outages will result in faster cleanup of downed lines which can be a safety hazard to the public. Shorter outages will return the function of safety equipment like traffic and streetlights more quickly.
3. Cyber-security, Privacy	Not applicable
4. Co-ordination, Interoperability	This project will coordinate data from the SCADA system with smart meter functions with the GIS system to improve outage responses and

	system control.
5. Economic Development	Will provide some economic benefits for software suppliers and installation contractors.
6. Environmental Benefits	Not applicable

<u>Part C4</u> (To be fully completed for each Test Year General Plant material project; populate as appropriate for all material projects in other years.)

Is this a material project? Yes

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
									X

Project Identification	Name: System Control and Data Acquisition (SCADA) Implementation Number: 2019-4
1. Comparison of alternatives	Will evaluate different systems and modules to rebuild the SCADA system. Will need to integrate this with the GIS and our smart meter data collection system. The use of SCADA systems is common in the utility business, and is needed to be able to quickly and effectively understand what is happening within a distribution system. Third party outsourcing not an option, monitoring and safely controlling the distribution system is part of our core business and requires special skills, knowledge and experience. For example, outage management and response is very specialized activity involving live line work, switching elements of the electric system, work protection (holdoffs), etc.
2. Very large projects	Not applicable

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
									X

1. Project Identification	Name: Disaster Recovery Site hardware upgrade Project Number: 2019-5
2. Purpose/Overview	Having a disaster recovery site is critical to any IT system and is necessary to maintain. This project is to add disaster recovery hardware that is projected to be needed at this time. This equipment will provide additional processing and storage resources.
3. Category	100% General Plant
4. Cost	$25,000
5. Attachments/Loads	Not applicable
6. Dates	To be scheduled in 2019
7. Risks	• Labour o Low risk: The project will be carried out by experienced external and internal resources • Monetary o Low risk: Relatively small project for 2019 • Expertise o Low risk: Experienced external and internal resources available with relevant work experience • Weather o Low risk: Not a factor that will affect this work • External o Low risk: Need to source new hardware components, this not expected to be a problem • Customer o Low Risk: This system functionality is largely invisible to the customers. They will benefit from it though, through reliable IT systems that are used to manage customer accounts
8. Comparative Information	Options for this hardware will be assessed before selecting the final product
9. REG Investment data	No
10. Leave to Construct	Not applicable

<u>Part A</u> (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
									X

1. Project Identification	Name: Various computer hardware and software Number: 2019-6
2. Purpose/Overview	This item includes a number of smaller IT hardware costs including; regular maintenance to the data centre cabling/HVAC system, desktop/laptop/tablet repairs, iSCSI storage and additional system storage capacity.
3. Category	100% General Plant
4. Cost	$40,000
5. Attachments/Loads	N/A
6. Dates	To be replaced in 2019
7. Risks	• Labour o Low risk: The project will be carried out by internal resources • Monetary o Low risk: Relatively small project and solution is known • Expertise o Low risk: Experienced internal resources available with relevant work experience • Weather o Low risk: Not a factor that will affect this work • External o Low risk: Need to source new equipment, not expected to be a problem • Customer o Low Risk: Regular equipment replacement project
8. Comparative Information	Routine replacement that involves comparative pricing
9. REG Investment data	No
10. Leave to Construct	Not applicable

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

<u>Part A</u> (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
									X

1. Project Identification	Name: Miscellaneous IT software costs Number: **2019-7**
2. Purpose/Overview	This item includes a number of smaller IT software costs including; Fortinet Web Publishing security and SharePoint add-ons.
3. Category	100% General Plant
4. Cost	$7,000
5. Attachments/Loads	IT system maintenance
6. Dates	To be scheduled in 2019
7. Risks	• Labour o Low risk: The project will be carried out by internal resources • Monetary o Low risk: Relatively small project and solution is known • Expertise o Low risk: Experienced internal resources available with relevant work experience • Weather o Low risk: Not a factor that will affect this work • External o Low risk: Need to source components, not expected to be a problem • Customer o Low Risk: Regular maintenance of IT systems
8. Comparative Information	Routine maintenance that involves comparative pricing
9. REG Investment data	No
10. Leave to Construct	Not applicable

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
									X

1. Project Identification	Name: Building changes for Board Room Number: 2019-8
2. Purpose/Overview	The changes planned for this time period is to replace the touch screen display in the Board Room which will be reaching the end of its useful life.
3. Category	100% General Plant
4. Cost	$8,000
5. Attachments/Loads	N/A
6. Dates	To be completed in 2019
7. Risks	• Labour o Low risk: The project will be carried out by external resources • Monetary o Low risk: Relatively small project and solution is known • Expertise o Low risk: Experienced external resources available with relevant work experience • Weather o Low risk: Not a factor that will affect this work • External o Low risk: Using local contractors, not expected to be a problem • Customer o Low Risk: used to present information about the utility operations and capital plans.
8. Comparative Information	Will look at comparative pricing for this purchase
9. REG Investment data	No
10. Leave to Construct	Not applicable

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

<u>Part A</u> (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
									X

1. Project Identification	Name: IT system management and monitoring function Number: 2019-9
2. Purpose/Overview	Regular upgrades are necessary for the IT system to keep it current. This upgrade is to automate the monitoring of the health of the computer systems, this change will anticipate problems and helps keep the system reliable.
3. Category	100% General Plant
4. Cost	$25,000
5. Attachments/Loads	N/A
6. Dates	To be scheduled in 2019
7. Risks	• Labour o Low risk: Changes will be made by internal resources with expertise with the IT system • Monetary o Low risk: Relatively small project and solution is known • Expertise o Low risk: Using internal resources with expertise in this area • Weather o Low risk: Not a factor that will affect this item • External o Low risk: Will control using internal resources • Customer o Low Risk: Regular upgrade to the IT system, changes will be tested before moving to production
8. Comparative Information	Regular maintenance for the IT system.
9. REG Investment data	No
10. Leave to Construct	Not applicable

St.**Thomas***energy*inc. **Capital Expenditure Plan Projects**

Part A (To be fully completed for each Test Year material project; populate as appropriate for Test Year non-material projects and all projects in other years.)

Is this a material project? No

State the applicable year(s) for this project:

2010	2011	2012	2013	2014 Bridge	2015 Test	2016	2017	2018	2019
									X

1. Project Identification	Name: Office furniture replacement Number: 2019-10
2. Purpose/Overview	This cost is for routine replacement of office furniture to cover equipment that has worn out.
3. Category	100% General Plant
4. Cost	$5,000
5. Attachments/Loads	N/A
6. Dates	To be completed in 2019
7. Risks	• Labour o Low risk: The project will be carried out by local suppliers • Monetary o Low risk: Relatively small project and solution is known • Expertise o Low risk: Experienced external suppliers available, routine replacement of furniture • Weather o Low risk: Not a factor that will affect this work • External o Low risk: Using local suppliers, not expected to be a problem • Customer o Low Risk: No direct customer impact, affects staff who service the customers
8. Comparative Information	Will look at comparative pricing from suppliers
9. REG Investment data	No
10. Leave to Construct	Not applicable