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Vice President, Regulatory Affairs & Chief Risk Officer

BY COURIER

December 7, 2018

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli,

EB-2018-0218 - Hydro One Sault Ste. Marie's Application for 2019 Rates and Other Related Matters – Interrogatory Responses

On July 26, 2018, Hydro One Sault Ste. Marie ("HOSSM") filed an Application pursuant to Section 78 of the Ontario Energy Board Act for an Order or Orders for 2019 transmission rates and related matters.

On October 5, 2018, the OEB issued Procedural Order No. 1, outlining steps for written interrogatories and directing HOSSM to file written responses by December 7, 2018. With this letter, HOSSM is now filing its written responses.

Below are the Tab numbers for each intervenor

Tab	Intervenor
1	Ontario Energy Board Staff
2	Power Workers' Union
3	Energy Probe
4	Association of Major Power Consumers in Ontario
5	School Energy Coalition
6	Vulnerable Energy Consumers Coalition

Please note that abbreviations have been used in certain places. For clarity, "HOSSM" and "Hydro One SSM" are used interchangeably to both refer synonymously to Hydro One Sault Ste Marie. "HONI" and "Hydro One" both refer to Hydro One Networks Inc.

Hydro One wishes to advise the panel of the following:

- the load forecast provided with OEB Staff Interrogatory #4 contains the specific names of HOSSM's customers in conjunction with certain details regarding their historical load. This information may be considered commercially sensitive for the identified customers so their names have been redacted.
- The KPI Summary provided with OEB Staff Interrogatory #43 contains the names of several private individuals and their names have been redacted to protect their privacy.

An electronic copy of the Interrogatory responses has been filed using the Board's Regulatory Electronic Submission System (RESS).

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea

OEB Staff Interrogatory # 1

Reference:

Letters of Comment
Filing Requirements, pages 11 & 13, sections 2.3.2 & 2.3.4

Interrogatory:

Preamble:

OEB staff notes that Hydro One SSM has not received any letters of comment to date regarding this proceeding. However, sections 2.3.2 and 2.3.4 of the Filing Requirements[1] indicate that transmitters are expected to file with the OEB their response to the matters raised in any letters of comment sent to the OEB related to the transmitter's application.

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

Response:

Noted. HOSSM warrants that all responses to comment letters received on a timely basis will be filed before the argument phase of the proceeding.

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[1] Filing Requirements For Electricity Transmission Applications Chapter 2 Revenue Requirement Applications, February 11, 2016

OEB Staff Interrogatory # 2

Reference:

Exhibit A, Tab 2, Schedule 1, Page 3

Interrogatory:

Preamble:

In the above-noted first reference, Hydro One SSM stated the following:

HOSSM also requests an accounting order to establish a sub-account within deferral account 1574 to record revenue deficiencies incurred from January 1, 2019 until HOSSM's proposed 2019 rates are implemented, if necessary.

a) Please provide a draft accounting order reflecting Hydro One SSM's above-noted request.

Response:

See following page:

Transmission Accounting Order – Revenue Deficiencies Variance Account

HOSSM proposes the establishment of a new "Revenue Deficiencies Variance Account" to record revenue deficiencies incurred from January 1, 2019 until HOSSM's proposed 2019 revenue requirement and rates are implemented.

The account will be established as Account 1574, Deferred Rate Impact Amounts – Sub-Account "Revenue Deficiencies Variance Account" effective January 1, 2019. HOSSM will record interest on the balance in the sub-account using the prescribed interest rates set by the Board. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this variance account.

	USofA #	Account Description
DR/CR	1574	Deferred Rate Impact Amounts – Sub-Account "Revenue Deficiencies Variance Account"
DR/CR	4110	Transmission Services Revenue

Initial entry to record revenue deficiencies incurred from January 1, 2019 until HOSSM's proposed 2019 revenue requirement and rates are implemented.

DR/CR	6035	Other Interest Expense
DR/CR	1574	Deferred Rate Impact Amounts – Sub-Account "Revenue Deficiencies Variance Account"

To record interest improvement on principal balance of the Revenue Deficiencies Variance Account.

OEB Staff Interrogatory # 3

Reference:

Exhibit A, Tab 2, Schedule 1, page 4

Preamble:

In paragraph 14 of the above-noted reference Hydro One SSM stated:

> As outlined in the OEB Handbook to Electricity Distributor and Transmitter Consolidations, dated January 19, 2016, HOSSM will apply for an Incremental Capital Module ("ICM") funding in the event HOSSM encounters unplanned capital expenditures prior to any rebasing application to be filed for 2026 rates.

Any application for an ICM is dependent on calculation of a materiality threshold which determines that amount of capital expenditure which is presumed to be funded or fundable through existing rates, accounting for the formulaic adjustment to rates for inflation less expected productivity, and also growth in demand. These are explicitly shown in the materiality threshold for the ICM formula as documented in the Report of the Board on New Policy Options for the Funding of Capital Investments: Supplemental Report (EB-2014-0219), January 22, 2016:

$$Threshold\ Value\ (\%) = \left(1 + \left[\left(\frac{RB}{d}\right) \times \left(g + PCI \times (1+g)\right)\right]\right) \times \left((1+g) \times (1+PCI)\right)^{n-1} + X\%$$

Where:

- RB is the rate base from the last CoS rebasing application
- d is depreciation expense from the last CoS rebasing application
- n is the number of years since the cost of service rebasing
- the growth factor g is annualized. g represents the change is demand (customers, kWh and kW). It is not the change in revenues – rates are held constant.
- PCI (Price Cap Index) is the current $I – X$ price cap adjustment for electricity distributors
- the stretch factor used in the PCI will be the factor assigned to the middle cohort (currently 0.3%) for all distributors
- the dead band X is 10%

Hydro One SSM has proposed a revenue cap, and its revenue requirement is aggregated with revenue requirements of other electricity transmitters, including Hydro One Networks, to determine Uniform Transmission Rates (UTRs) to be paid by all Ontario electricity ratepayers. Each transmitter's revenue requirement is recovered through UTR revenues as allocated to each transmitter.

Interrogatory:

a) Given the differences of Hydro One SSM's proposed revenue cap (as opposed to price cap) plan, and the recovery of the revenue requirement through the UTR approach, what, if any, changes to the ICM materiality threshold may be necessary should Hydro One SSM apply for an ICM?

b) In Hydro One SSM's view, are there any other changes needed to be able to apply the ICM policy and mechanism if Hydro One SSM's revenue cap proposal is approved? Please explain your response.

Response:

a) Should Hydro One SSM apply for an ICM, the formula should be modified to remove the growth parameter which would revise the formula to:

$$Threshold\ Value\ (\%) = \left(1 + \left[\left(\frac{RB}{d}\right) \times \ (PCI)\right] \times (1 + PCI)^{n-1}\right) + X\%$$

Hydro One SSM believes the growth parameter is inappropriate due to the structure of the UTRs. UTRs in Ontario are set by aggregating both the revenue requirement and the billing determinants of all transmitters in the province. All transmission customers are charged uniform rates and revenues are apportioned between transmitters based on a fixed allocation factor established by the Board for a given year. For smaller transmitters, such as Hydro One SSM, that means that revenue from rates is largely driven by the actual load of Hydro One. If Hydro One SSM's own utility growth was used in the formula, it would not be reflective of the amount of capital expenditures that could be presumed to be funded through rates because Hydro One SSM's rates revenue would largely be driven by the load of another larger utility. Therefore, Hydro One SSM's growth is not an appropriate parameter for the existing ICM formula. Conversely, if the overall UTR billing determinant growth was used in the formula it would result in an unreasonable outcome as the eligibility for funding of necessary capital expenditures would become dependent on the behaviours of the costs and load of other utilities and their customers.

Additionally, the growth parameter for distributors is driven by 3 revenue-weighted factors: kWh, kW and the number of customers. This is appropriate for distributors given that all three factors directly contribute to the rates revenue they collect. In the transmission sector, only monthly peak demand (kW) contributes to the rates revenue collected. Actual monthly peak demand is far more susceptible to variations due to weather and conservation programs (e.g. demand response programs and ICI) than the number of customers or the kWh, which would lead to greater variability in revenue year over year.

Hydro One SSM believes these factors suggest that growth is not appropriate parameter for an ICM formula when applied to electricity transmitters.

b) Transmission projects differ from distribution projects in that they tend to have capital expenditures that span multiple years before the full cost of the project is placed in service for rate recovery. As a result, Hydro One believes that the threshold calculated by the ICM formula should apply to the amount of in-year in-service additions as opposed to amount of in-year capital spend.

OEB Staff Interrogatory # 4

Reference:
Exhibit A, Tab 2, Schedule 2, page 2-3
Exhibit D, Tab 2, Schedule 1, page 3-5
Exhibit D, Tab 1, Schedule 1
Exhibit D, Tab 1, Schedule 1, Attachment 1, page 16-17

Interrogatory:
Preamble:

Hydro One SSM notes that it was directed to produce a detailed updated load forecast by the OEB in the Decision EB-2016-0356. Hydro One SSM states that it engaged an external consultant to produce a load forecast in 2016. However, it has not filed the load forecast before, and also states that it has not filed the load forecast in this application.

Hydro One SSM states that the reason for not doing this is that its application is for a revenue cap to formulaically adjust the annual revenue requirement through an (inflation less productivity), and that it is not rebasing its revenue requirement from a bottom-up cost of-service based methodology, in accordance with the deferred rebased approved in the Decision and Order EB-2016-0050 approving the acquisition of Great Lakes Power Limited's transmission assets and operations.

Further, Hydro One SSM's revenue requirement is not translated into rates directly, but is aggregated with the revenue requirements of other Ontario electricity transmitters to calculate UTRs.

Hydro One SSM has proposed a revenue cap approach for annually updating the revenue requirement. However, a traditional revenue cap includes a growth factor g to account for growth in capital and operating costs due to added investments and associated operating expenses to serve additional customers and demand:

$$RR_t = RR_{t-1} \times (1 + (I - X + g \pm Z))$$

Where:
- RR_t is the revenue requirement for year t
- I is the inflation (IPI) for that year

- *X* is the X-factor, incorporating both base X and any approved stretch factor (formally, consumer productivity dividend)
- *g* is growth in demand
- *Z* is for an adjustments for approved exogenous factors.

Hydro One SSM has not included a growth factor in its revenue cap proposal, and PSE documents that a growth factor in the revenue cap formulation for Hydro One Networks Transmission is not proposed on the basis that, due to natural conservation, CDM, and economic patterns in its service territory, there is not appreciable growth in demand from a transmission system perspective.

While Hydro One SSM's revenue requirement is not directly calculated into Hydro One SSM-specific transmission rates, OEB staff believes that knowledge of a transmitter's forecasted demand would be informative for assessing the reasonableness of its revenue requirement on a stand-alone basis and as part of the aggregated revenue requirement for purposes of calculating the UTRs.

a) Please provide Hydro One SSM's updated load forecast, along with sufficient explanation and supporting data and evidence, in accordance with the OEB's direction in EB-2016-0356.

b) As noted in A2-OEB Staff-3, the materiality threshold for the ICM includes growth ("*g*"), as a parameter. In the event that Hydro One SSM applies for an ICM or a Z-factor, please provide Hydro One SSM's views, with reasons, on whether its load forecast, or actual growth should be taken into account in determining the ICM or Z-factor materiality threshold.

c) For electricity distributors, growth is measured as a weighted average of changes in number of customers, kWh and kW, based on the revenue proportions for each and holding rates constant at current levels. Please provide Hydro One SSM's proposal for how growth should be measured for the ICM materiality threshold, in the context of the demand for a transmitter's products and services.

Response:

a) Attached please find a redacted copy of the transmission system load forecast completed by Elenchus Research Associates Inc ("the Elenchus report"). The Elenchus report has been redacted to protect commercially sensitive customer information.

b) For the reasons outlined in Hydro One SSM's response to OEB Staff #3, Hydro One does not believe its load forecast or actual growth should be included when determining the ICM or Z-factor materiality threshold.

c) As discussed in its response to OEB Staff #3, Hydro One SSM does not believe that growth should be used in setting the ICM materiality threshold. Hydro One SSM notes that transmission rates are demand-based per kW charges. Therefore, the number of customers and the throughput in kWh of the system are not relevant parameters for assessing revenue growth under the current rate design for the Uniform Transmission Rates.

elenchus

Weather Normalized Transmission System Load Forecast: 2017-2018

A Report Prepared by
Elenchus Research Associates Inc.

On Behalf of
Great Lakes Power Transmission

01/06/2016

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1 INTRODUCTION

This report outlines the results and methodology used to derive the weather normal load forecast prepared for use in the Cost of Service application for 2017-2018 rates for Great Lakes Power Transmission ("GLP Transmission").

GLP Transmission has two connected LDC customers, as well as four large and a few smaller directly connected end use customers. The LDC customers are weather sensitive while the other customers load is the result of situations specific to those customers. As a result, a weather normalized regression approach is used to forecast the two LDC customers, while other customers are forecasted based on historical average consumption. The 4 large are forecasted individually, and the remaining customers are forecasted as a group.

The regression equations used to normalize and forecast GLP Transmission's weather sensitive load use monthly heating degree days and cooling degree days as measured at Environment Canada's Sault Ste Marie A station to take into account temperature sensitivity. This location is relatively central to the PUC distribution customer, is at one end of the Algoma Power Inc. (API) service territory, and is the only nearby weather station for API. 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).

Overall economic activity also impacts energy consumption. In order to measure the impact of change in economic activity on energy consumption, a data series must be chosen which represents, as much as possible, that of the service territory. There is no known agency that publishes monthly economic accounts on a regional basis for Ontario. Regional employment levels are available, but the nearest region for which data is available is Sudbury. Given that income from employment and labour sources accounts for the largest portion of GDP on an income basis, and a study by Statistics Canada that has indicated that "turning points in the growth of output and employment appear to have been virtually the same over the past three decades"[1], employment has been chosen as the economic variable to consider for the analysis. Specifically, the monthly full-time employment level for Ontario, as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM series Table 282-0135) is used.

In addition to the weather and economic variables, a time trend variable, number of days and number of working days in each month, and month of year variables, have been examined for all rate classes. More details on the individual LDC specifications are provided in the next section.

In order to select explanatory variables which more accurately forecast each LDC customer, the two LDC customers were forecasted separately. GLP Transmission does not have access to energy consumption data. In order to capture the relationship between degree days, other explanatory variables, and electric use, a proxy for Energy was used. GLP Transmission has data on hourly peak MW per delivery

[1] Philip Cross, "Cyclical changes in output and employment," *Canadian Economic Observer*, May 2009.

point, which responds to explanatory variables on the same way that MWh would, and is used as MWh would be.

Finally, transmission connected customers are billed on charge determinants for Network (NW), Connection (CN), and Transformation (TRN). An annual ratio of MWh as described above to charge determinants, is calculated using actual observations for each historical year and applied to the normalized MWh to derive weather normalized charge determinants. For forecast values, the average of the ratios from 2011-2015 applied.

1.1 SUMMARIZED RESULTS

The following table summarizes the charge determinant forecasts for 2017-2018. The calculations can be found as follows:

Normal Forecast

NW Charge Determinant	2014 Actual	2015 Actual	2015 Normalized	2016 Forecast	2017 Forecast	2018 Forecast
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	3,371,301	3,181,059	3,196,432	3,162,855	3,120,843	3,083,048

Table 1 NW Forecast

CN Charge Determinant	2014 Actual	2015 Actual	2015 Normalized	2016 Forecast	2017 Forecast	2018 Forecast
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	2,574,147	2,553,111	2,618,518	2,619,062	2,618,518	2,618,518

Table 2 CN Forecast

TRN Charge Determinant	2014 Actual	2015 Actual	2015 Normalized	2016 Forecast	2017 Forecast	2018 Forecast
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	448,556	469,939	484,506	485,603	484,506	484,506

Table 1 TRN Forecast

The following table summarizes 2017-2018 CDM Load Forecast kW adjustment. Details for this calculation can be found at the end of Schedule 6 of this report.

CDM Adjusted 2017

NW Charge Determinant	2017 Weather Normal Forecast	CDM Adjustment	2017 CDM Adjusted Forecast
[redacted]	[redacted]	[redacted]	[redacted]
Total	3,120,843	24,490	3,096,353

Table 4 2017 CDM Adjusted NW Forecast

CN Charge Determinant	2017 Weather Normal Forecast	CDM Adjustment	2017 CDM Adjusted Forecast
[redacted]	[redacted]	[redacted]	[redacted]
Total	2,618,518	2,922	2,615,596

Table 5 2017 CDM Adjusted CN Forecast

TRN Charge Determinant	2017 Weather Normal Forecast	CDM Adjustment	2017 CDM Adjusted Forecast
[redacted]	[redacted]	[redacted]	[redacted]
Total	484,506	5,895	478,611

Table 6 2017 CDM Adjusted TRN Forecast

CDM Adjusted 2018

NW Charge Determinant	2018 Weather Normal Forecast	CDM Adjustment	2018 CDM Adjusted Forecast
[redacted]	[redacted]	[redacted]	[redacted]
Total	3,	35,68	3,0

Table 7 2018 CDM Adjusted NW Forecast

CN Charge Determinant	2018 Weather Normal Forecast	CDM Adjustment	2018 CDM Adjusted Forecast
[redacted]	[redacted]	[redacted]	[redacted]
Total	2,618,518	4,383	2,614,135

Table 8 2018 CDM Adjusted CN Forecast

TRN Charge Determinant	2018 Weather Normal Forecast	CDM Adjustment	2018 CDM Adjusted Forecast
[redacted]	[redacted]	[redacted]	[redacted]
Total	484,506	8,842	475,663

Table 9 2018 CDM Adjusted TRN Forecast

Summarized CDM Adjusted Load Forecast

Charge Determinant	2017 CDM Adjusted Forecast	2018 CDM Adjusted Forecast
NW	3,096,353	3,047,365
CN	2,615,596	2,614,135
TRN	478,611	475,663

Table 10 2017-2018 CDM Adjusted Charge Determinant Forecast

2 LDC Specific MWh Regression

2.1 Algoma Power Inc.

For API consumption the equation was estimated using 60 observations from 2011:01-2015:12.

Heating and Cooling Degree days were used, as measured at the Sault Ste. Marie A weather station as described in the introduction. An indicator of the number of calendar days in the month, MonthDays was used.

Binary variables representing spring months' and fall months' consumption have also been included. In recent LDC cost-of-service filings in which Elenchus has participated, both Board Staff and intervenors have requested that separate variables for spring and fall be included for testing. The spring variable designates the months of March, April, May, and June as spring months while the fall variable designates the months of September, October and November as fall months. Therefore, the variables take a value of 1 in the indicated months and a value of 0 in all other months.

Several other variables were examined, and found to not show a statistically significant relationship to energy usage. Those included an economic indicator of full time employment, the number of working days in the month, and a trend variable.

The following table outlines the resulting regression model:

Model 4: OLS, using observations 2011:01-2015:12 (T = 60)
Dependent variable: ALGOMAPI_TN_MWh

	Coefficient	*Std. Error*	*t-ratio*	*p-value*	
const	−2822.28	3269.28	−0.8633	0.3918	
HDD	10.71	0.439532	24.3668	<0.0001	***
CDD	15.3822	8.66549	1.7751	0.0815	*
Spring	−1203.56	233.987	−5.1437	<0.0001	***
Fall	−866.618	261.186	−3.3180	0.0016	***
MonthDays	559.115	106.189	5.2653	<0.0001	***

Mean dependent var	17935.81	S.D. dependent var	3205.987
Sum squared resid	22969747	S.E. of regression	652.2006
R-squared	0.962123	Adjusted R-squared	0.958615
F(5, 54)	274.3302	P-value(F)	4.41e-37
Log-likelihood	−470.7966	Akaike criterion	953.5933
Schwarz criterion	966.1593	Hannan-Quinn	958.5085
rho	0.414128	Durbin-Watson	1.168430
Theil's U	0.31701		

Table 11 API Regression Model

Using the above model coefficients we derive the following:

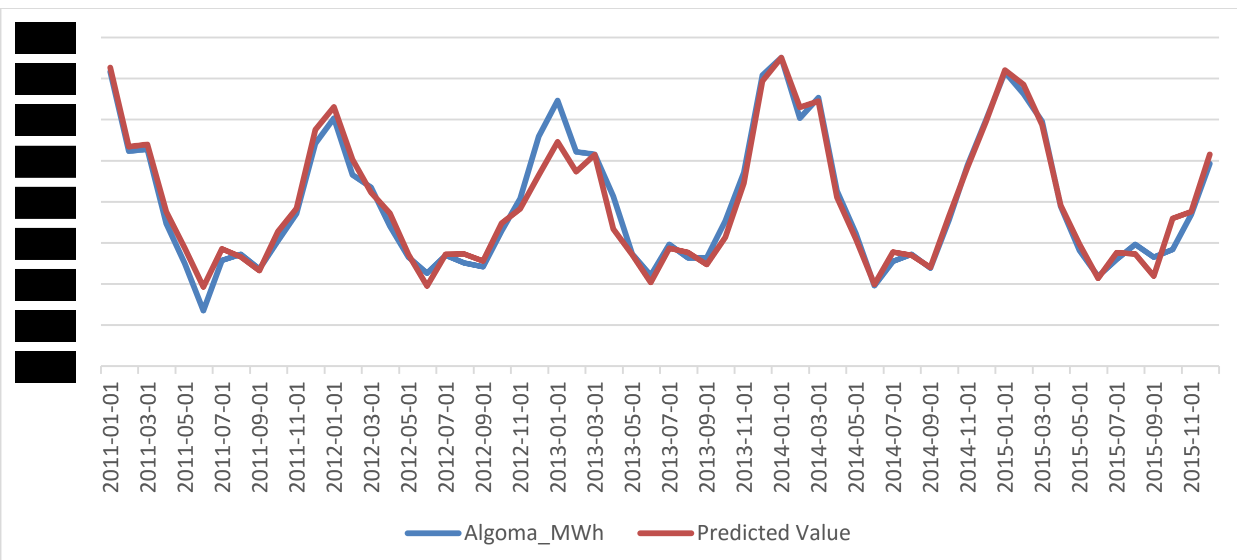


Figure 1 API Predicted vs Actual observations

Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 1.3%. Annual errors are calculated as the model is used to derive annual forecasts. However, in proceedings Elenchus has been involved in, intervenors and Board Staff have requested MAPE calculated on a monthly basis and this has been provided as well. The MAPE calculated monthly over the period is 2.5%.

Year	API_MWh Actual	API_MWh Predicted	Absolute Error (%)
2011	[redacted]	[redacted]	2.3%
2012			0.0%
2013			3.1%
2014			0.2%
2015			0.8%
Mean Absolute Percentage of Error (Annual)			1.3%
Mean Absolute Percentage of Error (Monthly)			2.5%

Table 12 API model error

2.2 PUC

For PUC, the regression equation was also estimated using 60 observations from 2011:01-2015:12.

Heating degree days was used, as measured at the Sault Ste. Marie A weather station as described in the introduction. An indicator of the number of calendar days in the month, MonthDays was used. A Trend variable was also used, indicating 1 in January 2011, and incrementing once each month, reaching 60 in the last month of the regression, December 2015.

Binary variables representing spring months' consumption was also included. The spring variable designates the months of March, April, May, and June as spring months. Specific dummy variables for September, October, and December were used in lieu of a Fall variable as these exhibited a more statistically significant relationship to energy use. The variables take a value of 1 in the indicated months and a value of 0 in all other months.

Several other variables were examined, and found to not show a statistically significant relationship to energy usage. Those included an economic indicator of full time employment, the number of working days in the month, and the number of cooling degree days.

The following table outlines the resulting regression model:

Model 21: OLS, using observations 2011:01-2015:12 (T = 60)
Dependent variable: PUC_TN_MWh

	Coefficient	*Std. Error*	*t-ratio*	*p-value*	
const	−8802.59	17456.3	−0.5043	0.6162	
HDD	40.8551	1.59573	25.6027	<0.0001	***
Trend	−143.494	24.0395	−5.9691	<0.0001	***
Sept	−4545.5	1655.33	−2.7460	0.0083	***
Oct	−4129.94	1621.48	−2.5470	0.0139	**
Dec	3845.56	1689.19	2.2766	0.0270	**
MonthDays	1779.79	568.626	3.1300	0.0029	***
Spring	−6826.29	970.724	−7.0322	<0.0001	***

Mean dependent var	54464.47	S.D. dependent var	13785.80
Sum squared resid	5.30e+08	S.E. of regression	3193.964
R-squared	0.952691	Adjusted R-squared	0.946322
F(7, 52)	149.5924	P-value(F)	3.84e-32
Log-likelihood	−564.9844	Akaike criterion	1145.969
Schwarz criterion	1162.723	Hannan-Quinn	1152.522
rho	0.340290	Durbin-Watson	1.315827
Theil's U	0.37995		

Table 13 PUC Regression Model

Using the above model coefficients we derive the following:

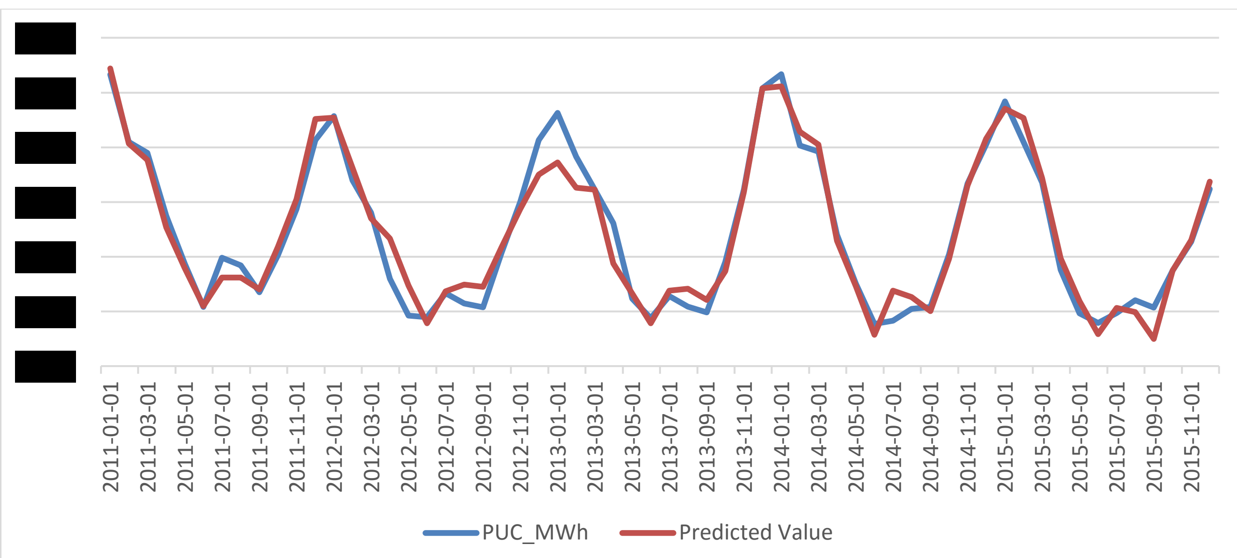


Figure 2 PUC Predicted vs Actual observations

Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 1.2%. Annual errors are calculated as the model is used to derive annual forecasts. However, in recent proceedings Elenchus has been involved in, intervenors and Board Staff have requested MAPE calculated on a monthly basis and this has been provided as well. The MAPE calculated monthly over the period is 4.2%.

Year	PUC_MWh Actual	PUC_MWh Predicted	Absolute Error (%)
2011	[redacted]	[redacted]	0.2%
2012			2.2%
2013			2.7%
2014			0.7%
2015			0.1%
Mean Absolute Percentage of Error (Annual)			1.2%
Mean Absolute Percentage of Error (Monthly)			4.2%

Table 14 PUC model error

3 WEATHER NORMALIZATION

It is not possible to accurately forecast weather for months or years in advance. Therefore, one can only base future weather expectations on what has happened in the past. Individual years may experience unusual spells of weather (unusually cold winter, unusually warm summer, etc.). However, over time, these unusual spells “average” out. While there may be trends over several years (e.g., warmer winters for example), using several years of data rather than one particular year filters out the extremes of any particular year. While there are several different approaches to determining an appropriate weather normal, GLP Transmission has adopted the most recent 10 year monthly degree day average as the definition of weather normal, which to our knowledge, is consistent with many LDCs load forecast filings for cost-of-service rebasing applications.

The table below displays the most recent 10 year average of heating degree days and cooling degree days as reported by Environment Canada for Sault Ste. Marie A, which is used as the weather station for GLP Transmission.

10 Year Average

		HDD	CDD
Sault Ste Marie A	January	820.37	0
Sault Ste Marie A	February	774.93	0
Sault Ste Marie A	March	678.89	0
Sault Ste Marie A	April	419.9	0.02
Sault Ste Marie A	May	228.805	5.64
Sault Ste Marie A	June	96.81	13.745
Sault Ste Marie A	July	38.17	41.67
Sault Ste Marie A	August	41.65	33.97
Sault Ste Marie A	September	139.21	9.19
Sault Ste Marie A	October	313.64	0.36
Sault Ste Marie A	November	482.63	0
Sault Ste Marie A	December	688.15	0

Table 15 10 Year Average HDD and CDD

As part of the minimum distribution filing requirements the OEB has requested monthly degree days calculated using a trend based on 20 years. This is shown in the table below.

20 Year Trend		2017		2018	
		HDD	CDD	HDD	CDD
Sault Ste Marie A	January	817.44	0.00	814.38	0.00
Sault Ste Marie A	February	802.84	0.00	807.05	0.00
Sault Ste Marie A	March	686.19	0.00	685.82	0.00
Sault Ste Marie A	April	417.33	0.03	416.24	0.03
Sault Ste Marie A	May	217.98	5.96	215.85	6.19
Sault Ste Marie A	June	103.53	10.91	104.21	10.43
Sault Ste Marie A	July	35.88	43.23	35.42	43.35
Sault Ste Marie A	August	39.86	36.15	39.50	36.42
Sault Ste Marie A	September	137.63	9.75	138.29	9.48
Sault Ste Marie A	October	299.47	0.63	297.41	0.62
Sault Ste Marie A	November	472.43	0.00	470.92	0.00
Sault Ste Marie A	December	671.37	0.00	668.88	0.00

Table 16 20 Year Trend HDD and CDD

4 LDC SPECIFIC NORMALIZED FORECASTS

4.1 ALGOMA POWER INC.

Incorporating the forecast economic variables, 10-yr weather normal heating and cooling degree days, and calendar variables, the following weather corrected consumption and forecast values are calculated:

Year	API_MWh Actual	Annual Change	Normalized	Annual Change
2011	[redacted]		[redacted]	
2012	[redacted]	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]
2016			[redacted]	[redacted]
2017			[redacted]	[redacted]
2018			[redacted]	[redacted]

Table 21 Actual vs Normalized API MWh

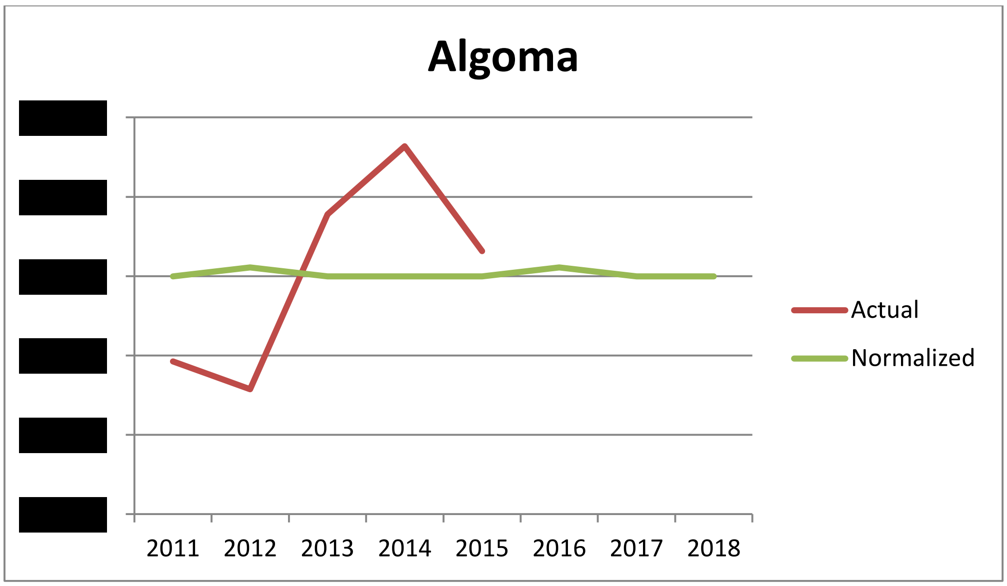


Figure 3 Actual vs Normalized API MWh

API is charged 3 billing determinants, all of which exhibit a relatively stable relationship with the summed hourly MW. A trend or step change in the relationship between the hourly MW and the billing determinants, could indicate a structural change over time. Since none was observed, a 5-year average of the ratio of billing determinant to hourly MW was used in each case.

			API				
Year	MWh Actual	NW Ratio	NW	CN Ratio	CN	TRN Ratio	TRN
	A	C = B / A	B	E = D / A	D	G = F / A	F
2011	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MWh Normalized						
	H	I = Avg (C)	J = H * I	K = Avg (E)	L = H * K	M = Avg (G)	N = H * M
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 22 API billing determinants

4.2 PUC

Year	PUC_MWh Actual	Annual Change	Normalized	Annual Change
2011	[redacted]		[redacted]	
2012	[redacted]	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]
2016			[redacted]	[redacted]
2017			[redacted]	[redacted]
2018			[redacted]	[redacted]

Table 23 Actual vs Normalized PUC MWh

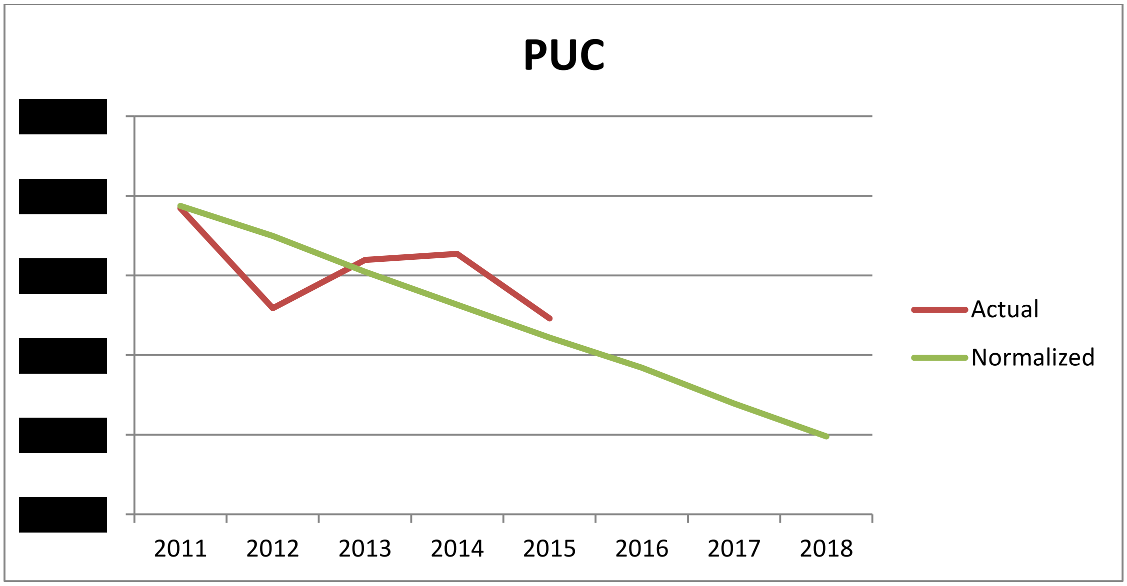


Figure 4 Actual vs Normalized PUC MWh

PUC is only charged the NW billing determinants which exhibits a relatively stable relationship with the summed hourly MW. A trend or step change in the relationship between the hourly MW and the NW billing determinant, could indicate a structural change over time. Since none was observed, a 5-year average of the ratio of NW billing determinant to hourly MW was used.

PUC

Year	MWh Actual	NW Ratio	NW
	A	**C = B / A**	**B**
2011	[redacted]	[redacted]	[redacted]
2012			
2013			
2014			
2015			
	MWh Normalized		
	H	**I = Avg (C)**	**J = H * I**
2015	[redacted]	[redacted]	[redacted]
2016			
2017			
2018			

Table 24 PUC NW billing determinant

5 CDM ADJUSTMENT TO LOAD FORECAST

The current Chapter 2 OEB Minimum Distribution Filing requirements, consistent with the Board's CDM Guideline EB-2012-0003, expects the distributors to integrate an adjustment into its load forecast that takes into account the six-year (2015-2020) targets for MWh and kW reductions.

The filing requirements note that the distributors license condition targets and the LRAMVA balances are based on the IESO targets, which are annualized. It is recognized that the CDM programs in a year are not in effect for the full year, although persistence of previous year's programs will be. Therefore, the actual impact on the load forecast for the first year of the program should not be the full annualized amount. GLP Transmission assumes that the distributors in its service territory will choose to achieve their targets with equal reductions in each year over the 6 years.

API's target for 2015-2020 is [redacted] GWh, which Elenchus assumes will occur as a reduction of [redacted] GWh in each of the 5 years. The impact of this reduction is calculated as follows:

API

	2015-2020 CDM Target	Application Factor 1.0 Full Year 0.5 Half Year	2017 Net MWh Load Forecast CDM Adjustment	Application Factor 1.0 Full Year 0.5 Half Year	2018 Net MWh Load Forecast CDM Adjustment
Year	A	B	C = A * B		
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]			[redacted]	[redacted]
	[redacted]		[redacted]		[redacted]

Table 30 API CDM Impact Forecast

PUC's target is [redacted] GWh, which Elenchus assumes will occur in equal reductions of [redacted] GWh per year. The impact of this reduction is calculated as follows:

PUC

	2015-2020 CDM Target	Application Factor 1.0 Full Year 0.5 Half Year	2017 Net MWh Load Forecast CDM Adjustment	Application Factor 1.0 Full Year 0.5 Half Year	2018 Net MWh Load Forecast CDM Adjustment
Year	A	B	C = A * B		
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]			[redacted]	[redacted]
	[redacted]		[redacted]		[redacted]

Table 31 PUC CDM Impact Forecast

The following is the proposed adjustment to the MWh forecast for GLP Transmission's LDC customers

MWh	Weather Normalized 2017 (Elenchus) A	2017 CDM Load Forecast Adjustment B	2017 CDM Adjusted Load Forecast C=A-B	2018 CDM Load Forecast Adjustment D	2018 CDM Adjusted Load Forecast E=A-B
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Customer (MWh)	784,641	13,568	771,073	20,352	764,289

Table 32 LDC CDM Adjusted Forecasts

In order to calculate the charge determinant impacts Elenchus proposes using a proportional ratio utilizing the base load forecast charge determinants and MWh

NW	Weather Normalized 2017 (Elenchus) F	CDM Load Forecast Adjustment G = F / A * B	2017 CDM Adjusted Load Forecast H = F - G
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
	1,411,747	24,490	1,387,258

Table 33 LDC CDM Adjusted 2017 NW Forecast

NW	Weather Normalized 2018 (Elenchus) I	CDM Load Forecast Adjustment J = I / A * D	2018 CDM Adjusted Load Forecast K = I - J
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
	1,373,953	35,683	1,338,270

Table 34 LDC CDM Adjusted 2018 NW Forecast

CN	Weather Normalized 2017 (Elenchus) L	CDM Load Forecast Adjustment M = L / A * B	2017 CDM Adjusted Load Forecast N = L - M
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
	209,140	2,922	206,217

Table 35 LDC CDM Adjusted 2017 CN Forecast

CN	Weather Normalized 2018 (Elenchus) N	CDM Load Forecast Adjustment O = N / A * D	2018 CDM Adjusted Load Forecast P = N - O
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
	209,140	4,383	204,756

Table 36 LDC CDM Adjusted 2018 CN Forecast

TRN	Weather Normalized 2017 (Elenchus) Q	CDM Load Forecast Adjustment R = Q / A * B	2017 CDM Adjusted Load Forecast S = Q - R
[redacted]	[redacted]	[redacted]	[redacted]
	421,882	5,895	415,987

Table 37 LDC CDM Adjusted 2017 TRN Forecast

TRN	Weather Normalized 2018 (Elenchus) T	CDM Load Forecast Adjustment U = T / A * D	2018 CDM Adjusted Load Forecast V = T - U
API	[redacted]	[redacted]	[redacted]
PUC			
	421,882	8,842	413,039

Table 38 LDC CDM Adjusted 2018 TRN Forecast

6 Direct Connected Customers

The Direct Connected Customers are industrial or natural resource in nature, and therefore, are not weather sensitive loads. GLP Transmission has been in contact with the major directly connected customers about plans for future use, and believes that recent historical load is the best predictor of load for the test year.

[redacted] has expanded their operations, and load stabilized early in 2015. This new level is projected to persist into 2017 and 2018.

RenTech
[redacted]

Table 25 RenTech billing determinants

[redacted] have all exhibited stable load since 2011. 2017 and 2018 are forecasted based on the average consumption from 2011-2015.

	[redacted]		
Year	NW	CN	TRN
2011	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]

Table 26 Flakeboard billing determinants

	[redacted]		
Year	NW	CN	TRN
2011	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]

Table 27 River Gold billing determinants

	[redacted]		
Year	NW	CN	TRN
2011	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]

Table 28 Essar Steel billing determinants

GLP Transmission added a few customers in 2014-2015. 2014 was a comparatively heavy utilization year for the existing customer base – both compared to 2011-2013, and compared to 2015. The year 2015, reflecting all customers has been selected as most representative of the load anticipated in 2017 and 2018.

	Others		
Year	NW	CN	TRN
2011	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]

Table 29 Other customers billing determinants

OEB Staff Interrogatory # 5

Reference:

Exhibit B1, Tab 1, Schedule 1, Page 10
Exhibit B1, Tab 1, Schedule 1, Page 109

Interrogatory:

Preamble:

In the above-noted first reference, Hydro One SSM stated the following:

For the 2018-2026 Plan period, HOSSM plans to manage capital expenditures within the funding envelope provided by the depreciation funding embedded in the last (2016) rebasing proceeding, adjusted through application of the annual Revenue Cap Index.

In the above-noted second reference, Hydro One SSM stated the following:

…HOSSM expects to manage its total annual OM&A expenditures within the envelope commensurate to historical levels.

a) Please explain in more detail how Hydro One SSM has managed and plans to manage both its capital expenditures and OM&A expenses historically and going forward within the funding envelopes approved in its last (2016) rebasing proceeding.

b) Please provide an explanation if Hydro One SSM has not managed certain costs within the funding envelopes approved in its last (2016) rebasing proceeding.

Response:

a) Hydro One SSM continues to manage both its capital expenditures and OM&A expenses within approved funding levels by:
    - Prioritization expenditures by utilizing a risk assessment framework (ARA) and following a rigorous investment planning process; and
    - Following defined maintenance programs cycled for stations/circuits/ROW's to ensure assets are maintained on a regular basis to prevent or reduce the potential for failure.

b) All costs have been managed within approved envelopes with one exception. Non-budgeted costs to negotiate a new Host Agreement with Batchewana First Nation have been excluded and HOSSM will seek recovery of these costs in a future rate application once the matter has been settled in full.

OEB Staff Interrogatory # 6

Reference:

Exhibit B1, Tab 1, Schedule 1, Page 96

Interrogatory:

Preamble:

At the above-noted reference, Hydro One SSM stated the following:

Accordingly, the table provides an indicative breakdown only, and should not be interpreted as a detailed forecast of capital additions across asset classes.

At the above-noted reference, the table that Hydro One SSM is referring to is titled “Table 4-1: Planned HOSSM Capital Expenditures by Major Asset Category ($M).”

a) Please confirm that Hydro One SSM uses the term “capital addition” interchangeably with the term “capital expenditure” throughout the evidence. If this is not the case, please explain.

b) Please confirm that when the term “capital expenditures” is used, Hydro One SSM has presented all information on the basis of capital additions and has not included work in process in its numbers. If this is not the case, please explain and indicate areas of the evidence that are impacted.

Response:

a) HOSSM confirms that, in this context, the term “capital additions” is used synonymously with “capital expenditures” in the references on pages 18, 96 and 110 of the TSP.

b) HOSSM can confirm that, to the best of its ability, it has provided all relevant financial estimates pertaining to the listed projects. Capital expenditures, for accounting purposes, are classified as work-in-progress until the project is complete and the asset is placed into service. When a project extends over multiple years, the capital expenditure estimates for the years prior to completion are, by definition, treated as work-in-progress. This is the case for all forecasts where multi-year projects exist.

OEB Staff Interrogatory # 7

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 2

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

HOSSM submits that this TSP is distinct from most Transmission and Distribution System Plans submitted to the OEB in that it is not being filed to support any additional capital funding requests.

a) Please confirm whether Hydro One SSM's TSP was filed to support the base projects and programs comprising the filed capital forecast.

Response:

a) Starting on Line 4 of Page 3 of Exhibit A, Schedule 3, Tab 1, is a description of the purpose of the submission. Included in that description is the outline of the TSP that describes HOSSM's asset plan over the period.

   For clarity, the distinctive part of this TSP alluded to in the reference noted in this Interrogatory is that it is not submitted to support a funding request related to a capital plan. Rather the submission of the TSP in this instance is to support the capital plan insofar as to demonstrate the feasibility, the outcomes, and the value for customers offered by the intended capital expenditure plan.

OEB Staff Interrogatory # 8

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 2-3

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

Since it is not designed to support requests for additional capital funding, this Plan focuses to a greater extent on the dynamics underlying the operational integration of HOSSM's system planning, operation, and capital work execution activities with those of Hydro One. Operational integration is set to formally commence on October 1, 2018.

a) Did the operational integration formally commence on October 1, 2018?
   i. If yes, please provide an update of the operational integration completed to date.
   ii. If no, what caused the delay and when does Hydro One SSM anticipate the formal operational integration to commence?

b) When does Hydro One SSM anticipate that operational integration with Hydro One will be complete?

Response:

a) Yes, as of October 1st, the assets of HOSSM have been operationally integrated into Hydro One Networks Inc. Hydro One Networks Inc. has taken over duties for capital and maintenance planning and execution on behalf of HOSSM via service level agreements. Hydro One's grid control centre is now responsible for monitoring, control and compliance of HOSSM's power system.

b) The integration process follows a multi-phase approach as described in Section 3.1.1 of Exhibit B1 Tab 1 Schedule 1 (TSP). As of October 1st, Hydro One considers Phase 1 of the integration to be complete. Phases 2 and 3 of the integration require Phase 1 as a foundation, and will gradually take place as Hydro One staff continues to gain operating experience with HOSSM's system. Hydro One anticipates that Phases 2 and 3 will be iterative, and will ultimately take years to completely merge all aspects of HOSSM operations into Hydro One's.

OEB Staff Interrogatory # 9

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 10

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

For the 2018-2026 Plan period, HOSSM plans to manage capital expenditures within the funding envelope provided by the depreciation funding embedded in the last (2016) rebasing proceeding, adjusted through application of the annual Revenue Cap Index. For further discussion on the Revenue Cap Index see Exhibit D, Tab 1, Tab 1. The following Table 1-3 provides the breakdown of Historical and Plan period capital expenditures for the period covered in this TSP.

Table 1-3: Historical and Plan Period Capital Expenditures Summary

	Historical					Plan									Total Plan
Category ($M)	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	
System Access	$0	$0	$0	$0	$0	$0.0	$0.0	$0.0	$0.0	$0.0	$1.4	$3.4	$0.0	$0.0	**$4.8**
System Renewal	$2.3	$3.3	$7.1	$6.5	$10.2	$5.1	$3.0	$8.0	$7.9	$5.9	$7.6	$7.1	$8.7	$7.8	**$61.0**
System Service	$0.6	$0.2	$0.1	$0.5	$0.7	$1.3	$1.3	$2.6	$2.8	$5.5	$0.3	$0.3	$1.6	$0.6	**$16.0**
General Plant	$0.5	$0.5	$1.3	$1.9	$4.1	$0.1	$2.9	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	**$3.9**
Total	**$3.3**	**$4.0**	**$8.5**	**$8.9**	**$15.0**	**$6.5**	**$7.1**	**$10.7**	**$10.7**	**$11.5**	**$9.4**	**$10.8**	**$10.4**	**$8.5**	**$85.7**

a) Given that the depreciation funding is relatively linear and the capital spending varies significantly from year to year, there is not a 1:1 correspondence between these parameters. Please provide a table showing the annual delta between depreciation funding and capital spending for each forecast year over the plan period (2018-2026).

Response:

a) Per the RRWF, $9,771,327 of depreciation/amortization is built into the approved revenue requirement for 2016. The requested table is provided below.

	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**Total**
Capex	6.5	7.1	10.7	10.7	11.5	9.4	10.8	10.4	8.5	85.6
Annual Dep	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	88.2
Difference	-3.3	-2.7	0.9	0.9	1.7	-0.4	1	0.6	-1.3	-2.6

OEB Staff Interrogatory # 10

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 11

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

Notwithstanding potential updates, and subject to unforeseen circumstances beyond HOSSM's control, the company plans to manage the funding for the Plan period capital projects within the funding envelope displayed in Table 1-3.

a) Please provide an example of an unforeseen circumstance beyond Hydro One SSM's control.
   i. How does Hydro One SSM plan to deal with unforeseen circumstance beyond Hydro One SSM's control?

b) Please provide an example of an unforeseen circumstance within Hydro One SSM's control.
   i. How does Hydro One SSM plan to deal with unforeseen circumstances within Hydro One SSM's control

Response:

a) Examples of an unforeseen circumstance beyond Hydro One SSM's control are:
   - changes to IESO market rules;
   - changes to government policy, legislation, regulation, such as environmental laws; or
   - changes to OEB codes, policies or other directions.

In the event that such circumstances occurred and had a material impact on Hydro One SSM's operations, Hydro One SSM may consider filing for a Z-factor or ICM, as appropriate.

b) An example of an unforeseen circumstance within Hydro One SSM's control might be a delay to a planned project as result of a storm. Assuming the impact of the storm was not significant, such a change could be accommodated by reprioritizing work and managing within the existing funding envelope.

OEB Staff Interrogatory # 11

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 14

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM states the following:

By virtue of acquisition of HOSSM's predecessor GLPT by Hydro One Inc. and through the ongoing integration with Hydro One's Asset Management function, the investments comprising this plan underwent assessment using a similar asset management and investment planning processes employed by the acquiring utility, modified to reflect the current state of integration of the two entities' information technology systems and the availability of pertinent data.

a) Please provide an evaluation of the current state of integration of the two entities' information technology systems.

b) What are the most significant outstanding gaps, and what are the likely results of those gaps?

c) What still needs to be done to fully integrate the systems and what will it cost to do so?

d) Will fully integrating the information technology systems create operations and maintenance cost savings? Please quantify and elaborate

Response:

a) At present time, these is minimal integration between the systems of HOSSM and HONI. Relevant data required to support HOSSM's operations has been migrated to HONI's IT systems. HOSSM's systems are in the process of being decommissioned.

b) HOSSM's power systems are now monitored and controlled by HONI's grid control centre via a remote computer link to HOSSMs Grid control centre. Full power system control integration is underway and expected to be complete by Q2 2019.

c) HOSSM's power system control integration is estimated to cost approximately \$900,000. The effort associated with decommissioning HOSSMs remaining IT systems has an estimated cost <\$100,000.

d) The operational integration of HOSSM allowed for the reduction of duplicate hardware and software licenses. The total OM&A savings annually is approx. \$150k. Upon completion of the SCADA integration in 2019 this will remove the need for the planned Capital expenditures of \$2.5Million in 2022 and \$2.5Million in 2023.

OEB Staff Interrogatory # 12

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 18

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

System Renewal:

Over the 2018-2026 Plan period, System Renewal represents the largest investment driver, amounting to approximately $61.0 million or 71% of the forecasted expenditures. Among the work program activities comprising the System Renewal budget are replacements of wooden support structures, conductor segments, transformers, and other types of station equipment found to be in deteriorating condition, exhibiting known operational or reliability performance issues, or otherwise determined to warrant replacement over the nine-year Plan period. Average annual planned System Renewal expenditures amount to approximately $6.8 million.

a) What are the other possible drivers for replacement besides deteriorating condition or known operational or reliability performance issues?

b) What is the proportion of total replacements driven by each of the following:
   i. Deteriorating condition
   ii. Operational issues
   iii. Reliability performance issues and
   iv. Other drivers, as determined in part a)

Response:

a) Other drivers for asset replacement are safety requirements, customer requests, and system interoperability.

b) The proportion of the total forecasted expenditure on asset replacement projects attributable to each driver is as follows:
   i. Deteriorating Condition – 76.4%
   ii. Operational Issues – 23.9%

iii. Reliability Performance – 89.1%
iv. Safety Requirement – 14.4%
v. Customer Requests – 6.2%
vi. System Interoperability – 2.7%

Note: single projects can have multiple drivers, resulting in the total adding to more than 100%.

OEB Staff Interrogatory # 13

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 19

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

The forecasted 15% increase in the average annual Renewal expenditures is primarily attributable to the fact that the Plan Period investments target replacement of larger (and more expensive) station assets such as transformers and breakers, whereas the station assets targeted in the last five years prioritized upgrades of ancillary electrical equipment, as shown in Table 2-3.

a) What were the primary drivers of the discontinuity in focus towards larger and more expensive station asset replacements?

b) Are the assessed conditions of these asset classes significantly different?

Response:

a) The primary drivers for the current focus towards replacing larger assets is to achieve greater system reliability by replacing the most aged and deteriorated critical assets in the system. In addition, major investment is required for the new station assets that will be integrated into the Greenfield Transmission Station project.

b) Please refer to METSCO's Asset Condition Assessment report filed as Appendix B to Exhibit B1-1-1 for the evaluation of condition of all HOSSM's asset classes. Figure 7.1 of the Asset Condition Assessment provides a high-level overview of the assessed condition distribution for each asset class. It is noticeable that a large proportion of the Power Transformer and Circuit Breaker classes are in "Fair" condition. Further analysis shows that these assets are also, on the whole, of older vintage and forecasted to transition to "Poor" condition over the following evaluation period. In comparison, other asset class populations are primarily comprised of assets in "Very Good" or "Good Condition", with much smaller proportions of assets in "Fair", "Poor", and "Very Poor" condition. Asset classes with "Poor" and "Very Poor" assets are also accounted for in other projected or ongoing programs.

OEB Staff Interrogatory # 14

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 20

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

Moreover, the Plan period line upgrade work includes replacement of conductor on the Sault Number 3 line, found to be in "Poor" condition based on the outcomes of a 2015 Kinectrics testing report (See Appendix C).

a) Did Hydro One SSM evaluate the risk of failure of the conductor on the Sault Number 3 line?
   i. If yes, what was the outcome of the risk assessment? Please provide details.
   ii. If no, why not?

Response:

The Hydro One IPP framework (Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 69, Figure 3-8) was applied to the Sault # 3 project. It was determined that there would be an approximately 97% decrease in risk by executing the Sault # 3 replacement project. The decrease in risk is attributable to the lower likelihood of failures along the Sault # 3 line, which carry large reliability and safety impacts.

OEB Staff Interrogatory # 15

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 30

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

Weather / Climate-Related Challenges
The majority of System Service and System Renewal work underlying the planned capital work program require planning and coordination of outages on the relevant portions of the HOSSM system. Given the increasingly volatile weather patterns observed in recent years, HOSSM's ability to plan for and execute the requisite outages may be affected by the local, regional and inter-area transfer capability constraints that may emerge as a result of unpredictable weather patterns such as abnormal temperatures, major storms, or water levels affecting the operations of hydroelectric generators directly connected to the HOSSM system.

a) Please describe which two periods are being compared in order to justify the following statement: *"Given the increasingly volatile weather patterns observed in recent years"*

b) Is Hydro One SSM able to quantify and show a trend of increasingly volatile weather patterns observed between the two periods described in part a)?
   i. If yes, please provide this quantification and trend.
   ii. If no, please explain how Hydro One SSM can use this reasoning to justify an inability to plan capital work.

c) Please describe how Hydro One SSM plans to address this risk if it materializes.

Response:

a) This was a general statement based upon recent global observations.

b) One example is a capital work project involving the Watson TS protection was scheduled to be completed in Nov/Dec 2018. Given the early arrival of very cold and snowy conditions in the SSM-region, the generator in the area recently provided HOSSM with minimal notice that they were cancelling two outages previously granted, thus preventing the project from being completed in 2018. HOSSM will now look for the next earliest opportunity (hopefully in 2019) to coordinate this outage and complete this work.

c) HOSSM will, where necessary, re-schedule work to a future period when an outage can be taken and re-prioritize future work to the present (where planning/risk allows). As mentioned in Exhibit B1-1-1-pg 10, "HOSSM may amend the scope, timing, or sequencing of the projects contained in the work program due to……other events that may occur in the normal course of system operation". "…subject to unforeseen circumstances beyond HOSSM's control, the company plans to manage the funding for the Plan period capital projects within the funding envelope displayed in Table 1-3."

OEB Staff Interrogatory # 16

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 36

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

In preparing this Plan, HOSSM obtained a letter from the IESO (Appendix A), confirming that the 2014 process identified no need for regional planning, requiring no further actions such as the preparation of Scoping Assessments or the Integrated Regional Resource Plan. Consistent with the findings of the last Regional Planning Process, HOSSM's current TSP does not include any investments identified through this process. The next cycle of the Regional Planning work for the East Lake Superior region is scheduled to commence in 2019. HOSSM will participate in the process as the lead transmitter and incorporate any relevant findings into the subsequent iterations of this TSP as necessary.

a) Does Hydro One SSM anticipate that the commencement / completion of the East-West Tie line or any other projects presently under development will have a material impact upon Hydro One SSM capital plans?
   i. If yes, will those impacts likely be identified within the next Regional Planning cycle, or were they already addressed in the prior planning cycle?
   ii. If the impacts were already addressed if the prior planning cycle, please describe the outcomes reached.

Response:

a) HOSSM does not believe the commencement / completion of the East-West Tie line or any other projects presently under development will have a material impact upon Hydro One SSM capital plans. Any changes to capital plans resulting from the next round of regional planning for the East Lake Superior Region, starting in 2019, will be reflected in a future application.

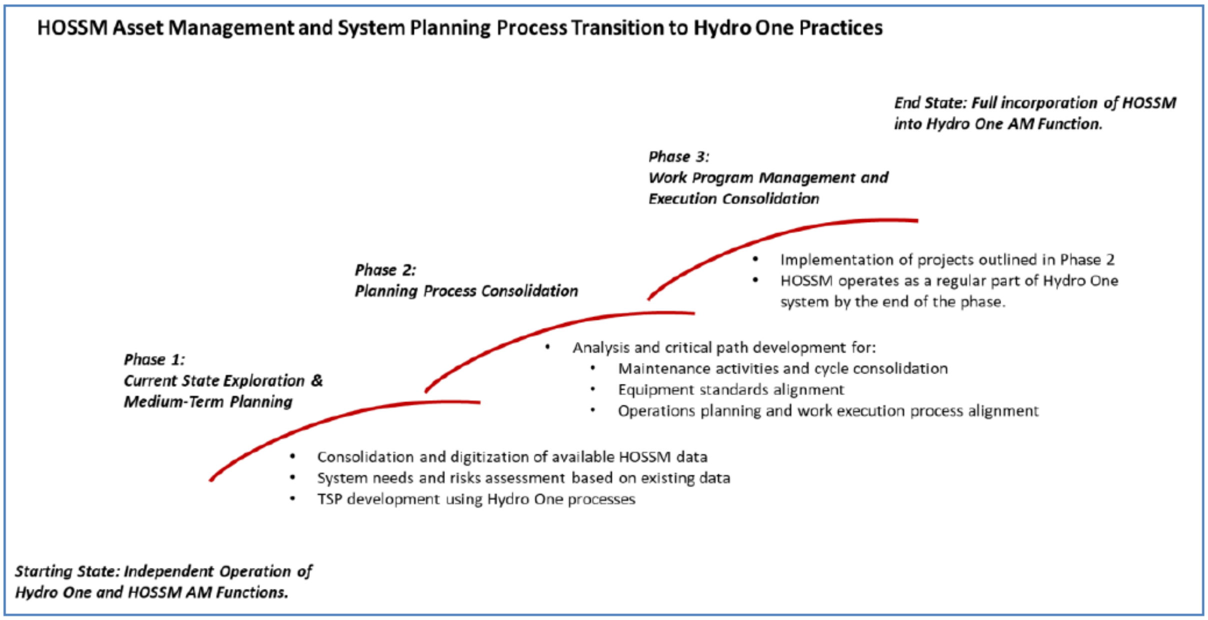
OEB Staff Interrogatory # 17

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 44

Interrogatory:

Preamble:



3-1: HOSSM Asset Management Function Integration Process

a) Does Hydro One SSM anticipate that significant capital investments will be triggered in Phase 3 as a result of aligning its equipment standards with Hydro One's in Phase 2? Please elaborate.

Response:

a) No. It is not Hydro One SSM's intent to align standards of existing infrastructure with that of HONI. Only new capital projects as defined in the capital plan (Table 1-3) will be constructed under the HONI standard. Table 1-3 reflects the costs of applying the HONI standard to new capital investments.

OEB Staff Interrogatory # 18

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 50

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

HOSSM employs a systematic approach for conducting inspections, testing, and executing preventative maintenance tasks (vegetation management, insulator washing, etc.) on a six-year cyclical basis, with some deviations for specific asset classes where more or less frequent maintenance is deemed necessary, or dictated by applicable statutory and regulatory requirements, such as the TSC or the North American Electric Reliability Corporation ("NERC").

a) Please confirm whether conducting vegetation management on a six-year cyclical basis is consistent with Hydro One's current vegetation management process.
   i. If not consistent, what steps is Hydro One SSM taking to integrate its current vegetation management program with Hydro One's, what is the associated timeline and are there any anticipated changes in program cost?

Response:

Hydro One Transmission performs vegetation maintenance on an eight-year cycle in Northern Ontario. This maintenance cycle is forecast to be implemented onto HOSSM's rights-of-way by 2024. There are no anticipated changes in program costs.

OEB Staff Interrogatory # 19

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 52

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

When examining Hydro One's assets, the ARA process includes an assessment using an integrated quantitative multi-factor Asset Analytics platform, which evaluates information drawn in real time from multiple Hydro One databases to identify the areas warranting further attention from planners. Given that the integration of HOSSM's asset management data with Hydro One's system is ongoing, planners relied on a modified version of the ARA process, reflective of its key assessment dimensions and available HOSSM system data

a) Hydro One SSM relied on a modified version of the ARA process in this TSP as a result of the ongoing integration with Hydro One's system.
    i. What are the key difference between Hydro One SSM's modified ARA process and Hydro One's ARA process?
    ii. What is the current status of the ARA integration?
    iii. What further steps are required to fully integrate Hydro One SSM's modified ARA process with Hydro One's ARA process?
    iv. What is the anticipated timeline and what are the costs associated with completing this integration?

Response:

a)
    i. The key difference is the scope and nature of asset data that HOSSM has historically collected, relative to the data inputs that Hydro One routinely collects and uses in its ARA analysis. Absent all the requisite data inputs, HOSSM and Hydro One opted to modify the ARA process for this transitional plan. Moreover, in light of the differences in size between Hydro One's and HOSSM systems, the risk assessment framework required modification, to use the risk consequence financial values more appropriate for a smaller utility.

ii. Since the filing of the application, the integration team has concluded the data transfer and consolidation activities.

iii. At this stage of the integration initiative, HOSSM is still determining the nature and sequencing of the specific steps required to achieve full consolidation of both processes.

iv. HOSSM expects to consolidate the ARA processes with those of HONI over the next 1-2 planning cycles (years).

OEB Staff Interrogatory # 20

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 52-53

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

The ARA process evaluated system needs on the basis of the following five risk factors:
Condition - Risk related to the increased probability of failure that assets experience when their condition degrades over time. While methods to evaluate condition vary from asset type to asset type, the condition of all assets of a given type is evaluated consistently. Assets determined to have a comparatively high condition risk become candidates for intervention.
Demographics - Risk related to the increased probability of failure exhibited by assets of a particular make, manufacturer, or vintage. Typically, the probability of asset failure increases with age. In certain cases, assets of a particular make or year of manufacturing exhibit known performance issues, making them candidates for replacement, refurbishment or other form of intervention

Criticality - Represents the impact that the failure of 1 a specific asset would have on the transmission system, based on that asset's electrical location, the amount of load it supports, and the extent of available system redundancies. Criticality is a criterion that the analysis employs to further prioritize among assets identified as potential investment candidates on the basis of other assessment factors.

Performance - Risk that reflects the historical performance of an asset, as represented by the frequency and duration of past outages. Assets with a known history of material outages represent viable candidates for replacement, refurbishment or additional follow-up.
Utilization - Risk associated with accelerated rate of deterioration experienced by assets that are consistently utilized at levels approaching or exceeding their normal operating capacity. The asset utilization risk for assets like transformers and circuit breakers attempts to consider their relative deterioration based on available loading and operational history, respectively.

a) By what percentage (or amount) do the Condition and Demographics risk factors overlap one another?

b) Is Condition correlated with Demographics?
   i. If not, please explain how they are different and provide concrete examples to justify this difference.

c) By what percentage (or amount) do the Condition and Performance risk factors overlap one another?

d) Is Condition correlated with Performance?
   i. If not, please explain how they are different and provide concrete examples to justify this difference.

e) By what percentage (or amount) do the Utilization and Criticality risk factors overlap one another?

f) Is Utilization correlated with Criticality?
   i. If not, please explain how they are different and provide concrete examples to justify this difference.

g) Does Hydro One SSM adjust the scoring of Criticality or Utilization risk in the event of redundancy for the asset (or the system)?

h) Under Utilization risk, is it Hydro One SSM's experience that assets utilized in a manner that "approaches their normal operating capacity" presents an operational risk?
   i. If yes, please explain why.

Response:

a) There is no overlap between the application of the Condition and Demographic risk factors as applied in the ARA process.

b) Older assets often tend to be in a state of reduced capability. However, Condition itself is not always correlated with Demographics. For a relevant practical example, see the response to Interrogatory PWU #5 (a).

c) HOSSM is unable to provide a single, specific answer to this question. Numerous individual characteristics and circumstances across asset classes, materials and other factors influence the nature of the Condition and Performance risks.

d) Please refer to HOSSM's response to Staff IR #20 (c)

e) There is no overlap between the application in the Utilization and Criticality risk factors as applied in the ARA process.

f) Utilization is not directly correlated with Criticality. For example, a power transformer may be consistently overloaded, which would inflate its utilization risk. That same transformer may be connected only to a single, small (from a system perspective) radial connection/load, and therefore exhibit very little criticality risk.

The converse example is also true, where an asset that is highly inter-connected asset within a system that is being run well below its normal operating capacity. This case would pose high criticality risk but low utilization risk.

g) Criticality takes into direct consideration available redundancies. From Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 53: "Criticality – Represents the impact that the failure of a specific asset would have on the transmission system, based on the asset's electrical location, amount of load it supports, and the extent of available system redundancies."

Utilization risk scores are not impacted by asset or system redundancy.

h) Assets that are "approaching their normal operating capacity", when compared to assets that are not, present additional utilization risk. The more heavily utilized an asset is within the system the more accelerated the utilization risk of said asset will become. As with any increasing equipment performance / availability risk, it is reasonable to expect an impact on utility operations.

OEB Staff Interrogatory # 21

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 67

Interrogatory:

Preamble:

Taxonomy to evaluate the probability of a failure event

Score	Frequency OR	Expected time to event OR	Prob. of event occurring in the next yr. OR	Prob. of event occurring in the next 5 yr.	Example phrases you might hear during scoring
7	4+ per year	<3 months	100%	100%	This has happened 10 times every year for the last 5 years
6	1-4 times per year	3-12 months	100%	100%	Based on run time, the equipment life is over for 2 years, it will fail in the next year
5	1 every 1-3 years	1-3 years	33-100%	85-100%	We have to trench every 2 years, disturbing the habitat
4	1 every 3-10 years	3-10 years	10-33%	40-85%	We see this event about once a year on the whole system, which has 8 of these assets
3	1 every 10-25 years	10-25 years	4-10%	20-40%	This event happens on the system sometimes, and it's much more likely to happen here
2	1 every 25-100 years	25-100 years	1-4%	5-20%	This would happen on an APD (abnormal peak day), a 1/90 year event
1	Less than 1 every 100 years	>100 years	0-1%	0-5%	This has never happened, and I don't want to think about how we'd let it happen

Figure 3-7 – Probability Framework

a) Are the probability parameters normalized to evaluate probability that a specific individual asset might fail, rather than the probability that one asset out of a portfolio will fail? For example, the probability that one of the poles in a long transmission line might fail over a given period is significantly higher than the probability that a specific pole will fail over the same period.

b) Could this probability table be applied in a manner that inadvertently overstates the risk attributable to failure of a specific asset in a large portfolio? Please discuss.

Response:

a) The probability framework is assessed based on the occurrence of a single specific event. This event is named the "Worst Reasonable Direct Impact" ("WRDI"). This will be based on the failure of a specified functional group, which can contain a single, or many, assets. In a portfolio considering many assets, probability of failure of individual assets is only considered if their failure will lead directly to the WRDI.

b) The probability table is unlikely to be applied in a manner that inadvertently overstates the risk attributable to failure of a specific asset in a large portfolio, since events are always framed on a relative basis from the perspective of the WRDI.

OEB Staff Interrogatory # 22

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 69

Interrogatory:

Preamble:

Risk score (risk unit)

Consequence								
	7	900	4,200	12,000	36,000	100,000	400,000	1,000,000
	6	430	1,900	5,000	17,000	50,000	200,000	500,000
	5	170	800	2,100	7,000	20,000	80,000	200,000
	4	60	280	800	2,400	7,000	28,000	70,000
	3	20	80	230	700	2,200	8,000	20,000
	2	4	20	50	150	460	1,700	4,200
	1	1	3	10	30	90	350	800
		1	2	3	4	5	6	7
		Probability						

Figure 3-8: Hydro One Risk Matrix Applied to HOSSM Projects

a) Based on the above noted risk scores, please confirm that the higher probability of failure projects are addressed before the higher consequence projects.

   i. If not confirmed, please explain the reason for the following discrepancy:

      - Consequence of 6 * Probability of 7 = 500,000 Risk Score
      - Consequence of 7 * Probability of 6 = 400,000 Risk Score

b) How does Hydro One SSM determine the cut off risk score for projects moving forward versus those that are deferred?

c) What is the typical delta in risk score from one evaluation period to the next (i.e. how does asset deterioration impact overall risk score)?

Response:

a) Projects with higher probability of failure are not always addressed before the higher consequence projects, specifically in the case where the products of two projects' consequence and probability scores are the same. If the total risk score for the two projects is low (i.e. within the lower left half of Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 69, Figure 3-8), the project with higher consequences of failure will be seen as more critical of the two.

   If the total risk score for the projects is high (i.e. within the upper right half of Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 69, Figure 3-8), the project with higher probabilities of failure will be preferred.

b) For each evaluation period, projects are ranked via risk points mitigated per dollar. After mandatory projects (driven by 3rd party request, compliance, contracts, load growth, or those projects already in-flight) are included into the project portfolio, the remaining capital is typically allotted to those projects with the highest risk points mitigated per dollar.

c) Overall risk score scales exponentially with increasing probability and consequence scores as shown in the referenced table. A deteriorating asset will exhibit an increasing probability of failure, but the consequence of its failure will remain relatively constant. As the asset continues to deteriorate, the overall risk score will follow an exponential trend until it is replaced or fails. The typical delta in risk score for an asset between evaluation periods therefore depends on its condition. If an asset is heavily deteriorated it will experience a steep increase in overall risk between evaluation periods.

OEB Staff Interrogatory # 23

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 76

Interrogatory:

Preamble:

Asset Class	Population	Sample Size	Health Index Distribution					Average Health Index
			Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (85 - 100%)	
Power Transformers	20	20	0	0	9	3	8	74.00%
Oil Circuit Breakers	19	19	0	0	0	0	19	90.87%
Vacuum Circuit Breakers	16	16	0	0	0	0	16	93.19%
SF6 Circuit Breakers	70	60	0	0	0	9	51	94.21%
Relays	361	361	13	8	20	118	158	81.84%
Batteries	22	22	0	0	3	6	9	76.14%
Capacitor Banks	2	2	0	0	0	0	2	100%
Reactors	3	3	0	0	2	0	1	78.21%
Circuit Switchers	5	5	0	0	0	0	5	94.77%
Instrument Transformers	59	59	0	0	0	0	59	98.28%
Switches	163	147	2	12	20	43	70	73.92%

Table 3-9 Station Assets Average Health Index

a) What is the average age of power transformers assessed as being in Fair condition?

b) What is the typical expected service life for Hydro One SSM power transformers?

c) Is Hydro One SSM a winter peaking or summer peaking system?

d) What is the typical ambient temperature when these power transformers experience peak loads?

e) Would the cold climate in Hydro One SSM's service area be expected to extend or reduce the expected service life for power transformers relative to the service life expectation for similar transformers located in warmer climatic zones? Please explain.

Response:

a) The average age of power transformers assessed as being in Fair condition is 39.11 years.

b) The assumed typical useful life for HOSSM power transformers is 50 years.

c) Hydro One SSM is a winter peaking system.

d) The transformers experience peak loading from November through February. The average ambient temperature for the Sault Ste. Marie area can range from 1 to -11 degrees Celsius, with average lows down to -15 degrees Celsius, and average highs up to 4 degrees Celsius. *Source: The Weather Network Statistics for Sault Ste Marie, Ontario.*

e) The service life of power transformers depends heavily on their design and utilization during these cold periods, making it hard to determine the precise effect on their expected service life. Operating higher loads at lower ambient temperatures will effectively provide additional cooling to the transformer, meaning less thermal and mechanical stress, which effectively extends the service life of the asset. On the other hand, operation of lower internal temperature and mechanical structures (such as an on-load tap changer) within the transformer at extremely low ambient temperatures materially increases the risk of that critical component of the asset failing. In events of peak loading at extremely low ambient temperatures, the aforementioned effects both contribute to the operational degradation of the transformer, making the impact on expected service life impractical to describe in a definitive manner.

OEB Staff Interrogatory # 24

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 79

Interrogatory:

Preamble:

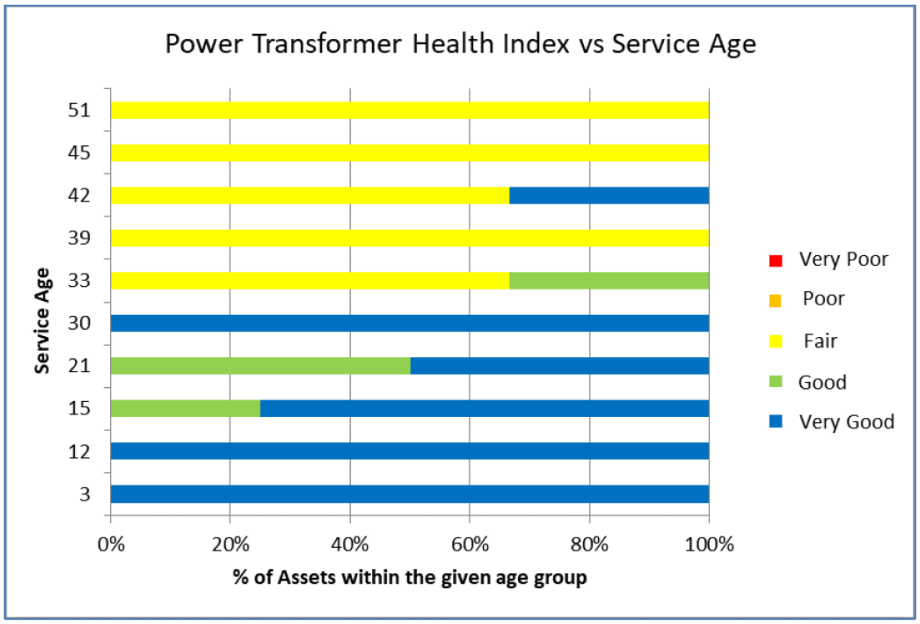


Figure 3-12: Power Transformer Health Index Scores vs. Unit Age

a) Please explain what is driving the following apparent discontinuities:

   i. The change from Very Good to Fair for older vintage transformers (42 years).

   ii. The abrupt change in typical condition between transformers aged 30 years or younger, versus the array of conditions for transformers aged 33 years and older.

   iii. Older vintage transformers being in better condition than younger vintage transformers (i.e. some 42 year old transformers are in Very Good condition while some 15 and 21 year old transformers are only in Good condition).

Response:

a)

i. The change from Very Good to Fair for older vintage transformers is due to a combination of a variety weighted factors such as dissolved gas analysis (DGA), main tank corrosion, moisture content, and oil quality/levels.

ii. In a much larger asset population, it would be reasonable expect to see a health index versus service age trend similar to the one laid out in Figure 5.4 of Appendix B of Exhibit B1-1-1 (METSCO ACA). Additionally, the rate of installation across the years is not constant, meaning some “year groupings” contain only a single transformer whilst others contain up to four separate assets.

iii. These discrepancies are seen due to a combinatory effect of condition parameters (apart from age) varying between separate transformers. The responsible condition parameters include oil leaks, DGA, insulation PF, degree of polymerization, IR Scans, bushing condition, main tank corrosion, cooling equipment, grounding, and load history.

OEB Staff Interrogatory # 25

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 81

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

Of all station assets examined in the METSCO ACA study, the population of Protection Relays is the only asset class with units in Very Poor and Poor condition, with approximately 6% of the total Relay Population falling into these categories as shown in figure 3-14.

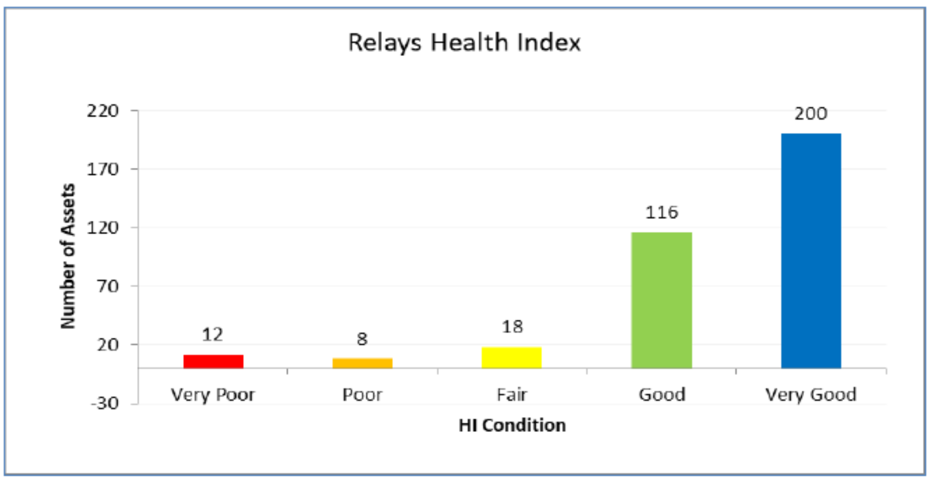


Figure 3-14: HOSSM Relay Population Health Index

According to the METSCO study, a significant portion of the protection relay Health Index scoring is tied to their degree of obsolescence, as determined by ongoing vendor support, parts availability, and ability to support the utility's interoperability needs across the communication devices on their system.

a) Please quantify the portion of protection relay Health Index scoring which is tied to their degree of obsolescence.

b) Please confirm whether there have been any outages or operational malfunctions associated with the 6% of relays in Very Poor and Poor condition.

i. If yes, please quantify.

Response:

a) Obsolescence is tied to 6/17, or approximately 35% of the Health Index score for relays.

b) There have been no documented outages or operational malfunctions associated with the 6% of in-service relays that are rated in a Very Poor or Poor condition.

OEB Staff Interrogatory # 26

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 83

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

A notable exception is the conductor on the Sault #3 Line, which is discussed in Section 3.2.3. This line has historically been the worst-performing circuit on the HOSSM system; responsible for 39% of all outage minutes attributable to line equipment failures between 2012 and 2017. For comparison – the second worst-performing line accounts for 12% of total outage minutes over the same timeframe.

a) Is the conductor condition the direct cause or primary cause of the poor performance on this circuit?
   i. If yes, what is the typical failure mechanism?
   ii. If no, what is the primary cause and the failure mechanism?

b) What percentage of the line reconductoring project (SR-02) will directly address the primary cause and failure mechanism?

Response:

a) Conductor condition is the primary cause of the poor performance on the Sault #3 circuit. Kinetrics produced a cable testing report which is available in Appendix C of Exhibit B1-1-1. Failure of aluminum splice assembly, driven largely by moisture ingress and resultant corrosion, is seen across the failed cable samples as the typical failure mechanism.

b) Project SR-02 reconductoring will be executed with brand new cable and should address the primary cause and failure mechanism for conductor failure within the Sault #3 115 kV circuit.

OEB Staff Interrogatory # 27

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 86

Interrogatory:

Preamble:

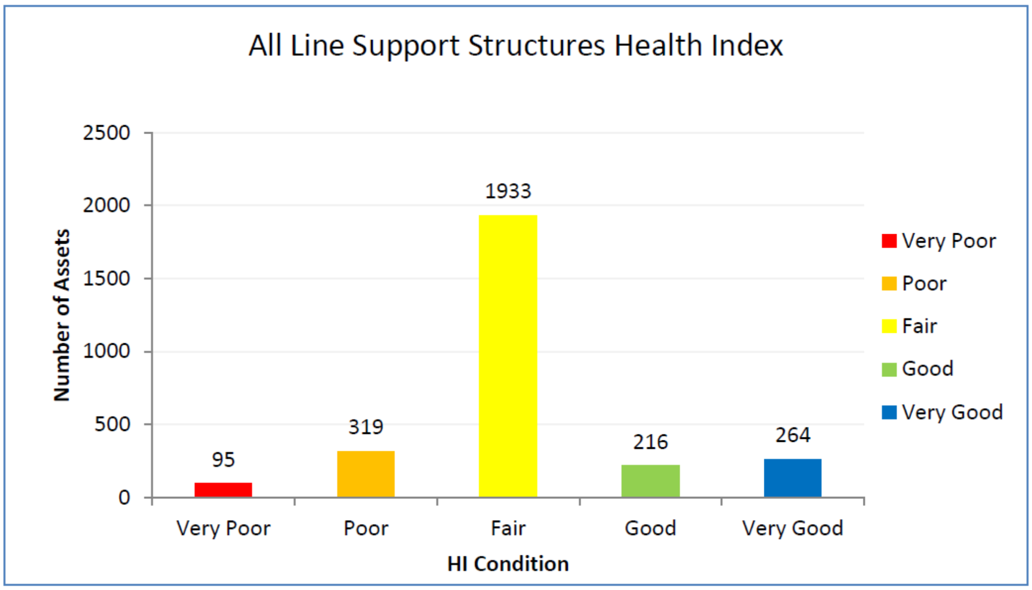


Figure 3-17: HOSSM Structures Health Index

a) Please explain the reasons for the atypical structure condition distribution shown in the above figure, which indicates that almost 70% of structures are in Fair condition.

Response:

a) As discussed further in the METSCO ACA Report (Appendix B), HOSSM currently collects only a limited amount of information on the health condition of structures. This affected the number of criteria included in the derivation of their respective Health Indices in the METSO ACA Report. The result is Health Indices for line structures with shallow stratification which land mostly within the "Fair" condition.

OEB Staff Interrogatory # 28

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 88

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

Line Equipment

Over the historical 2012-2017 period, HOSSM experienced defective equipment-related outages across 24 of its circuits. Five of these circuits, depicted on the figure 3-18, are responsible for 84% of total outage minutes over that timeframe.

a) What percentage of outages relate to tree contact versus defective equipment?

b) Has the brushing program changed over the last 10 years?
   i. If yes, please describe the changes that were implemented, the associated costs, and the anticipated resulting impacts to reliability performance.

Response:

a) 100% of the outages at the reference noted above relate to defective equipment.

b)
   i. The brushing program has largely remained the same with a few minor changes. The program consists of a pre-work gps based survey, herbicide application wherever it is permitted, and manual or mechanical cutting where herbicide is not permitted. The work has always been completed on a 6 year cycle. For the Hydro One SSM system (formerly Great Lakes Power Transmission), the only change over the last 10 years is how we manage vegetation in herbicide exclusion zones adjacent to riparian habitat (water course). In these areas we have implemented a more targeted approach to address vegetation of more immediate concern to ensure we are leaving adequate vegetation cover for the purpose of erosion mitigation and habitat management. This has had no impact to reliability. There has been minimal impact to cost (slight cost

reduction) as the crews don’t spend as much time in these areas when compared to our former approach.

OEB Staff Interrogatory # 29

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 90-91

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

A notable example of HOSSM's attempt to prolong the lifecycle of installed assets is the utility's strategy for wood support structures. The factors associated with its service territory, such as large woodpecker populations, harsh weather conditions, among others, cause a comparably faster deterioration of wood structure populations that at times require replacement as early as 15-20 years after installation, based on historical data. Given these circumstances, the utility's management made a strategic decision approximately 15 years ago to replace deteriorated wood structures with composite fibreglass installations, which are expected to withstand the challenges offered by HOSSM's operating environment better than wooden structures, offering a more optimal economic outcome for the utility and its ratepayers.

a) Does Hydro One SSM have data from peers in comparable climatic zones that indicates a similarly accelerated deterioration of wood structures?
   i. If yes, please provide this data.
   ii. If no, is it possible that the faster deterioration of wood structure populations in the Hydro One SSM service area is due to poor quality initial pole treatment, pole species that are not compatible with the region, or some other reason? Please elaborate.

b) Please provide the business case that supports the economics of transitioning from wood structures to composite counterparts.

c) Please provide the average unit installation cost for wood structures and the average unit installation costs for composite structures.

d) How old are the oldest composite structures in Hydro One SSM's fleet?

e) Does Hydro One SSM have data from peers in comparable climatic zones that indicates how long composite poles can be expected to last in this zone?

f) How do those average life expectancies compare with the typical survival curve for wood poles in Hydro One SSM's service area?

Response:

a)

i. Hydro One SSM does not have this data

ii. Hydro One SSM does not believe there are issues with the company's pole species choice or the corresponding pole treatment. These are prescribed based on engineering review after consideration of localized environmental factors.

b) Please refer to Attachment 1 of Exhibit I-1-29 (Staff IR#29) the attached Pole Care report (2009) provided to Metsco for their Condition Assessment review. This was a third party report that assessed the condition of HOSSM structures in 2009 which largely drove the structure replacement project (replacing wood poles with composite) since 2012/2013. This report was previously filed as part of interrogatory responses to our 2013/2014 cost of service rate application (EB-2012-0300).

c) This information is not readily available.

d) The oldest group of composite structures were installed in 2006 (12 years of age).

e) Hydro One SSM does not have this data.

f) Wood poles in Hydro One SSM's service area have at times required replacement as early as 15-20 years after installation due to harsh weather exposure and woodpecker damage. The expected useful life of a typical wood transmission pole is between 40 and 50 years. The average life expectancy of a composite pole within the Hydro One SSM service should more closely resemble that of a typical wood pole. The effect on the survival curve for structures in the Hydro One SSM service area is to eliminate the subset of poles that experience early failure due to extreme weather conditions and woodpecker damage.

PoleCare International Inc.

NON-DESTRUCTIVE TESTING OF WOOD TRANSMISSION POLES

Third Line TS to St. Patrick St. TS

Great Lakes Power

November 2009

Table 5A: Poles with Extensive Mechanical Damage and Feathering

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 3 Algoma	17	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Joint Use	RG Tested Ok	117
# 3 Algoma	20	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use, Pole in water	Replace in 2010	120
# 3 Algoma	21	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use	Replace in 2010	121
# 3 Algoma	32	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	123

Table 5A: Poles with Extensive Mechanical Damage and Feathering

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 1 Algoma	1 Centre	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight	Dip	RG Tested Ok	2
# 1 Algoma	4	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	21
# 1 Algoma	6	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	29
# 1 Algoma	7	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Dip	RG Tested Ok	33
# 1 Algoma	8	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Bend in Pole	RG Tested Ok	37
# 1 Algoma	13	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	57
# 2 Algoma	6	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	30
# 2 Algoma	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate	Bend in Pole	RG Tested Ok	34
# 2 Algoma	9	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	42
# 2 Algoma	10	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	46

Table 5A: Page 1 of 5

Table 5A: Poles with Extensive Mechanical Damage and Feathering

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 2 Algoma	11	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Bend in Pole	RG Tested Ok	50
# 2 Algoma	12	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	54
# 2 Algoma	13	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight, Guying (slack, broken, buried) - extensive	Bend in Pole	RG Tested Ok	58
# 3 Algoma	2	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	15
# 3 Algoma	3	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Guy guard required	RG Tested Ok	19
# 3 Algoma	5	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	27
# 3 Algoma	6	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	31
# 3 Algoma	7	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	35
# 3 Algoma	8	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	39

Table 5A: Page 2 of 5

Table 5A: Poles with Extensive Mechanical Damage and Feathering

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 3 Algoma	9	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	43
# 3 Algoma	10	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	47
# 3 Algoma	11	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	51
# 3 Algoma	13	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	59
# 3 Algoma	14	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	61
# 3 Algoma	15	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	RG Tested, Replace in 2010	63
3 1 Algoma	12	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	53
Northern Ave	1 Right	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight		RG Tested Ok	10
Northern Ave	1 Centre	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	11
Northern Ave	1 Left	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	12
Northern Ave	3	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Internal Decay - Slight	Guy guard required	RG Tested Ok	20

Table 5A: Page 3 of 5

Table 5A: Poles with Extensive Mechanical Damage and Feathering

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
Northern Ave	4	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Internal Decay - Slight	Guy guard required, Slack Guy Wire	RG Tested Ok	24
Northern Ave	5	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Internal Decay - Slight		RG Tested Ok	28
Northern Ave	6	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	32
Northern Ave	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	36
Northern Ave	8	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	40
Northern Ave	9	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	44
Northern Ave	10	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate, Guying (slack, broken, buried) - extensive		RG Tested Ok	48
Northern Ave	11	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	52
Northern Ave	12	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	56

Table 5A: Page 4 of 5

Table 5A: Poles with Extensive Mechanical Damage and Feathering

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
Northern Ave	14	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	62
Northern Ave	15	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	RG Tested, Replace in 2010	64
Northern Avenue	13	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	60

NOTICE

It is recommended that wood poles are inspected and tested every 5 years. The final recommendations made in this report are based on the assumption that the 5-year inspection cycle will be adhered to by the utility. In other words, the conclusions and recommendations contained in the report are valid only for a five-year period form the year in which the poles were tested.

In analyzing the poles the effects of external load such as wind and ice are not considered; only the pole strength and mechanical condition of the poles are used. In other words the client requested no engineering analysis and none was done.

All the measurements and observations are done from the ground level and no climbing of the poles was involved.

Neither PoleCare International Inc., nor Great Lakes Power, nor any other person acting on their behalf makes any warranty, express or implied, or assumes any legal responsibility for the information presented in this report or accepts liability resulting from its use.

EXECUTIVE SUMMARY

A total of 124 in-service transmission poles were inspected to assess their structural integrity. The inspection and the analysis were done in two Parts.

Part A: Sixty four poles between 3rd Line TS and 2nd Line were tested and treated with boron rods, copper napthenate or insecticide, as required by the condition of the poles, to prevent further damage from carpenter ants.

Part B: Sixty poles between 2nd Line and Patrick St. TS were tested and treated, as required, with boron rods, copper napthenate or insecticide. No poles were treated with pole wrap because none was found with below ground-line decay.

The residual strengths of these poles were measured by using non-destructive testing equipment called Poletest.

Based on the preliminary assessment of the information gathered for each pole, a number of poles were reassessed using a Resistograph that is capable of determining the extent of degradation in wood poles.

Based on a systematic analysis of the field data, the following conclusions are made:

Part A (3rd Line TS – 2nd Line):

Number of poles recommended for replacement	7
Number of poles with carpenter ants damage	25
Number of poles with internal decay	58
Number of poles with excessive top feathering and/or excessive mechanical damage	42
Number of poles treated	58
Number of poles with limited remaining life	19

Part B (2nd Line – St. Patrick St TS):

Number of poles recommended for replacement	4
Number of poles with carpenter ants damage	12
Number of poles with internal decay	16
Number of poles with excessive top feathering and/or excessive mechanical damage	4
Number of poles treated	60
Number of poles with limited remaining life	5

The detailed analysis procedure and the results are discussed in detail in the report.

To:

Great Lakes Power, Sault Ste. Marie

NON-DESTRUCTIVE TESTING OF WOOD TRANSMISSION POLES FOR GREAT LAKES POWER

INTRODUCTION

In the summer 2009, as part of its pole management program, Great Lakes Power tested a total of about 124 in-service wood transmission poles. The inspection/testing were done in two parts.

Part A: Sixty four poles between 3rd Line TS and 2nd Line were tested and treated with boron rods, copper napthenate or insecticide, as required by the condition of the poles, to prevent further damage from carpenter ants.

Part B: Sixty poles between 2nd Line and Patrick St. TS were tested and treated, as required, with boron rods, copper napthenate or insecticide. No poles were treated with pole wrap because none was found with below ground-line decay.

TESTING TECHNIQUES

A non-destructive testing (NDT) technique was utilized as a key component of the program. The NDT equipment, POLETEST ™, originally developed by Electric Power Research Institute (EPRI) and marketed by Engineering Data Management (EDM), was used. A Resistograph, capable of measuring the relative density of wood, was used to determine the extent of degradation in selected poles.

The following is a list of major data gathered on each pole:

- Pole strength at or closer to ground line
- Physical condition at ground line area
  - Ground line rot
  - Below ground line rot
  - Carpenter ants damage
  - Surface rot etc.
  - Wood pecker damage
- Overall physical condition of pole (poor, fair or good)
- Equipment mounted on to poles
- Other related information

The information gathered was analyzed to identify the condition of each pole and sort out the poles that need replacement and treatment.

The **EDM non-destructive testing technique** applies the principles of sonic spectral wave analysis. The sonic test signal, obtained from applying the NDT technique to a wood pole, is analyzed and compared to a machine-stored database relating the sonic signal and pole strength. The sonic signal varies depending on the type of pole species, the degree of mechanical degradation as well as other parameters that affect the material properties. By comparing the received signal to that of the stored database for the pole species, a measure of the pole strength is determined. The equipment that incorporates this technique is marketed under the name POLETEST™. The equipment is data dependent and uses a database established by EDM

The **Resistograph** is a special type of drill with a drill bit of approximately 2 mm in diameter and about 400 mm in length. The instrument is battery operated and self-powered to eliminate any external influence on the measurements. The instrument provides a measure of relative density of wood by measuring its resistance. The results are presented in a graphic form showing the relative density of wood across the pole cross section. The graph could be used to assess qualitatively the amount of degradation in the pole.

FIELD MEASUREMENTS AND OBSERVATIONS

STEP 1: The EDM Poletest was used in assessing pole strength:

- Sound the pole for weak points at various pole heights.
- Take strength reading at GL (Ground Line), perpendicular to line direction.
- If strength reading at GL is good then take readings at suspected weak points.
- If no strength reading or a very low reading is obtained then take readings at various orientations at GL.
- If a reading can't be obtained at GL then take more readings at locations above GL.
- Take as many readings as necessary for a good assessment.
- Check pole for decay, rot, mechanical damage etc.
- Using a shovel check for any decay below GL

STEP 2: After completion of testing with EDM Poletest, poles that showed marginal mechanical strength and poles for which the results were not conclusive were tested with the Resistograph

PRESENTATION OF FIELD DATA

The strength and other information gathered in the field along with some typical results are summarized below:

- The line in which the pole is located
- Pole ID Number
- Pole species (from information stamped on poles)
- Pole diameter (from measurements)
- Pole strength (from measurements)
- Pole mechanical condition (from observations)
- Comments
- Recommendations
- Probable remaining life

DATA ANALYSIS

Based on a systematic analysis procedure the following conclusions are arrived at:

<u>Part A (3rd Line TS – 2nd Line):</u>

- **<u>Summary of analysis of poles inspected (Table 1A.):</u>**

Information on the 64 poles tested/inspected along with analysis done is summarized in Table 1A.

- **<u>Poles recommended for replacement (Table 2A)</u>**

A total of 7 poles need replacement. These poles have varying degree of extensive degradation, both visible and hidden, at or below ground line.

- **<u>Poles with carpenter ants infestation (Table 3A)</u>**

A total of 25 poles were identified as having various stages of carpenter ants infestation.

- **<u>Poles to which remedial treatment applied (Table 4A)</u>**

Since the section of the line between the 3rd Line TS and the 2nd Line is scheduled to be replaced in a couple of years, it was decided to treat the poles to protect them from insects such as carpenter ants. Therefore the treatment applied, as required by the condition of a pole, was limited to boron rods, copper napthenate and insecticide. A total of 58 poles were treated and no pole wrap was applied to any of them.

- **<u>Poles with extensive feathering and mechanical damage (Table 5A)</u>**

Extensive pole top feathering and or mechanical damage were noticed in about 42 poles. These poles need a closer inspection by line crew.

- **<u>Poles with internal decay (Table 6A)</u>**

A total of 58 poles were identified with varying degree of internal decay.

- **<u>Poles with limited remaining life (Table 7A)</u>**

There are 19 poles for which the calculated probable remaining life is about 2 years. These poles are not in any immediate danger. However, in case of severe storms these 19 poles may not be safe.

Therefore it is advisable to take some measures to strengthen these structures.

- **<u>Individual pole records (Table 8A)</u>**

An electronic record for each of the 64 poles tested is given.

Part B (2nd Line – St. Patrick St TS):

- **Summary of analysis of poles inspected (Table 1B.):**

Information on the 60 poles tested/inspected along with analysis done is summarized in Table 1B.

- **Poles recommended for replacement (Table 2B)**

A total of 4 poles need replacement. These poles have varying degree of extensive degradation, both visible and hidden, at or below ground line.

- **Poles with carpenter ants infestation (Table 3B)**

A total of 12 poles were identified as having various stages of carpenter ants infestation.

- **Poles to which remedial treatment applied (Table 4B)**

Since the section of the line between the 2nd Line and St. Patrick St. TS is relatively new it was decided to treat the poles as required by the condition of each pole. However, each pole was treated with boron rods to provide them added protection. Therefore the treatment applied, as required by the condition of a pole, was limited to boron rods, copper napthenate and insecticide. No pole wrap was applied to any of the 60 poles treated.

- **Poles with extensive feathering and mechanical damage (Table 5B)**

Extensive pole top feathering and or mechanical damage were noticed in about 4 poles. These poles need a closer inspection by line crew.

- **Poles with internal decay (Table 6B)**

A total of 16 poles were identified with varying degree of internal decay.

- **Poles with limited remaining life (Table 7B)**

There are 5 poles for which the calculated probable remaining life is about 2 years. These poles are not in any immediate danger. However, in case of severe storms these 5 poles may not be safe.

Therefore it is advisable to take some measures to strengthen these structures.

- **Individual pole records (Table 8B)**

An electronic record for each of the 60 poles tested is given.

<u>Part C (3rd line TS – St. Patrick St. TS)</u>

A combined database for the two sections tested is given in Part C.

Note 1: The individual pole record provides all the information collected for each pole and the results of the analysis done.

Note 2: It should be noted that a number of poles appear under different categories because these poles have multiple mechanical defects

Because of the unpredictable nature of the external influences that would affect the remaining life of a pole it is recommended that any life prediction beyond 5 years be used with caution. It is also recommended that the poles be tested on a 5-year cycle to maintain the necessary reliability and safety.

In analyzing the poles the effects of external load such as wind and ice are not considered; only the pole strength and mechanical condition of the poles are used. In other words the client requested no engineering analysis and none was done.

COMPREHENSIVE DATABASE

- **Separate databases for Part A (3rd Line TS – 2nd Line) and Part B (2nd Line – St. Patrick St TS), containing all the information discussed in this report, are provided in MS Access format.**
- **Also attached to this report are the first pages of all the tables (except Tables 2DB and 2WA, which are given in full). All the tables in their entirety are included in the MS Database.**
- **A combined database for the two sections of the line tested is also given in MS Access format.**

NOTATIONS USED IN THE REPORT

Part A: **3rd Line TS – 2nd Line**

Part B: **2nd Line – St. Patrick St TS**

Part C: **3rd line TS – St. Patrick St. TS**

Part A: 3rd Line TS – 2nd Line

Table 1A: Summary of Pole Data

Line Number	Pole ID	Pole Strength GL (psi)	Mechanical Condition	Comments	Recommendations	Probable Remaining Life (Yrs)	Record Number
# 1 Algoma	1 Right	4210	Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Internal Decay - Moderate	Guy guard required, Slack Guy Wire	RG Tested Ok	8	1
# 1 Algoma	1 Centre	4450	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight	Dip	RG Tested Ok	12	2
# 1 Algoma	1 Left	5260	Cracks - Slight, Decay pockets at GL - Slight, Internal Decay - Slight, Guying (slack, broken, buried) - slight		RG Tested Ok	12	3
# 1 Algoma	2		Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010		13
# 1 Algoma	3	4900	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight, Guying (slack, broken, buried) - moderate	Bend in Pole, Guy guard required	RG Tested Ok	5	17
# 1 Algoma	4	4800	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	2	21
# 1 Algoma	5	5120	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Moderate, Guying (slack, broken, buried) - slight		RG Tested Ok	2	25
# 1 Algoma	6	4880	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	8	29
# 1 Algoma	7	4770	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Dip	RG Tested Ok	8	33

Table 1A: Page 1 of 8

Table 2A: Poles for Replacement

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 1 Algoma	2	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	13
# 2 Algoma	2	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	14
# 3 Algoma	2	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	15
# 3 Algoma	7	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	35
# 3 Algoma	15	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	RG Tested, Replace in 2010	63
Northern Ave	12	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	56
Northern Ave	15	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	RG Tested, Replace in 2010	64

Table 3A: Poles Affected by Carpenter Ants

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 1 Algoma	2	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	13
# 1 Algoma	4	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	21
# 1 Algoma	5	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Moderate, Guying (slack, broken, buried) - slight		RG Tested Ok	25
# 2 Algoma	2	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	14
# 2 Algoma	5	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	26
# 2 Algoma	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate	Bend in Pole	RG Tested Ok	34
# 2 Algoma	10	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	46
# 3 Algoma	2	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	15
# 3 Algoma	3	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Guy guard required	RG Tested Ok	19

Table 3A: Page 1 of 3

Table 4A: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 1 Algoma	1 Right	Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Internal Decay - Moderate	Guy guard required, Slack Guy Wire	Yes	Yes	Yes	No	1
# 1 Algoma	1 Centre	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight	Dip	Yes	Yes	Yes	No	2
# 1 Algoma	1 Left	Cracks - Slight, Decay pockets at GL - Slight, Internal Decay - Slight, Guying (slack, broken, buried) - slight		Yes	Yes	Yes	No	3
# 1 Algoma	2	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Yes	No	Yes	Yes	13
# 1 Algoma	3	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight, Guying (slack, broken, buried) - moderate	Bend in Pole, Guy guard required	Yes	Yes	Yes	No	17

Table 4A: Page 1 of 13

Table 5A: Poles with Extensive Mechanical Damage and Feathering

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 1 Algoma	1 Centre	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight	Dip	RG Tested Ok	2
# 1 Algoma	4	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	21
# 1 Algoma	6	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	29
# 1 Algoma	7	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Dip	RG Tested Ok	33
# 1 Algoma	8	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Bend in Pole	RG Tested Ok	37
# 1 Algoma	13	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	57
# 2 Algoma	6	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	30
# 2 Algoma	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate	Bend in Pole	RG Tested Ok	34
# 2 Algoma	9	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	42
# 2 Algoma	10	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	46

Table 5A: Page 1 of 5

Table 6A: Poles with Internal Decay

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 1 Algoma	1 Right	Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Internal Decay - Moderate	Guy guard required, Slack Guy Wire	RG Tested Ok	1
# 1 Algoma	1 Centre	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight	Dip	RG Tested Ok	2
# 1 Algoma	1 Left	Cracks - Slight, Decay pockets at GL - Slight, Internal Decay - Slight, Guying (slack, broken, buried) - slight		RG Tested Ok	3
Northern Ave	1 Right	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight		RG Tested Ok	10
Northern Ave	1 Centre	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	11
Northern Ave	1 Left	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	12
# 1 Algoma	2	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	13
# 2 Algoma	2	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	14
# 3 Algoma	2	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	15
Northern Ave	2	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	16
# 1 Algoma	3	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight, Guying (slack, broken, buried) - moderate	Bend in Pole, Guy guard required	RG Tested Ok	17
# 2 Algoma	3	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Slight		RG Tested Ok	18

Table 6A: Page 1 of 5

Table 7A: Poles with Limited Remaining Life

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Remaining life (yrs)	Record Number
# 1 Algoma	4	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	21
# 1 Algoma	5	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Moderate, Guying (slack, broken, buried) - slight		RG Tested Ok	Remaining life 2 years	25
# 1 Algoma	11	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Extensive, Surface Rot below GL - Moderate, Internal Decay - Slight	Climbing Inspection Required	RG Tested Ok	Remaining life 2 years	49
# 2 Algoma	5	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	26
# 2 Algoma	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate	Bend in Pole	RG Tested Ok	Remaining life 2 years	34

Table 7A: Page 1 of 4

Table 8A: Individual Pole Records

Line #:	# 1 Algoma	Test Date:	10-Nov-09	Record No.:	1	Pole ID:	1 Right
Private Property:	No	Pole Class:	2	Pole Ht (ft):	60		
Install Date	1964	Pole species:	WC	Treatment Length:	Full	Treatment Type:	Penta
Overall Pole Condition:	Good	Pole Diameter (in):	17	Pole Strength at GL (psi):	4210		
Mechanical Condition:	Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Internal Decay - Moderat						
# of broken/chipped insulators:	0	# of small wood pecker holes:	5	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:	Guy guard required, Slack Guy Wire						
Probable Remaining Life (yrs):	6						
Other Comments:							
Recommendations:	[illegible]						

Table 8A: Page 1 of 65

Part B: 2nd Line – St. Patrick St TS

Table 1B: Summary of Pole Data

Line Number	Pole ID	Pole Strength GL (psi)	Mechanical Condition	Comments	Recommendations	Probable Remaining Life (Yrs)	Record Number
# 1 Algoma	27R	5130	Cracks - Slight		No RG Required, Pole OK	38	65
# 1 Algoma	27L	4850	Carpenter ants damage - Slight, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	6	66
# 1 Algoma	28R	5220	Cracks - Slight		No RG Required, Pole OK	35	67
# 1 Algoma	28L	5090	Cracks - Slight		No RG Required, Pole OK	38	68
# 1 Algoma	29	4710	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Bend In Pole	RG Tested Ok	4	69
# 1 Algoma	29L	5100	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	4	70
# 1 Algoma	30	5370	Cracks - Slight		No RG Required, Pole OK	37	71
# 1 Algoma	31	5120	Cracks - Slight	Bend In Pole, Dip, Joint Use, Lights on Pole	RG Tested Ok	32	72
# 1 Algoma	32	5280		Dip, Joint Use	No RG Required, Pole OK	38	73
# 1 Algoma	33	5140	Cracks - Slight	Bend In Pole, Dip, Joint Use	No RG Required, Pole OK	38	74
# 1 Algoma	34	5330		Joint Use	No RG Required, Pole OK	38	75

Table 2B: Poles for Replacement

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 3 Algoma	18	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Ground Guard Required, Joint Use, Pole in water	Replace in 2010	118
# 3 Algoma	19	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Joint Use, Pole in water	Replace in 2010	119
# 3 Algoma	20	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use, Pole in water	Replace in 2010	120
# 3 Algoma	21	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use	Replace in 2010	121

Table 2B: Page 1 of 1

Table 3B: Poles Affected by Carpenter Ants

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 1 Algoma	27L	Carpenter ants damage - Slight, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	66
# 1 Algoma	29	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Bend in Pole	RG Tested Ok	69
# 1 Algoma	29L	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	70
# 1 Algoma	45	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Joint Use, Lights on Pole	RG Tested Ok	84
# 2 & 3 Algoma	57	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	94
# 2 Algoma	29	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	114
# 3 Algoma	18	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Ground Guard Required, Joint Use, Pole in water	Replace in 2010	118
# 3 Algoma	19	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Joint Use, Pole in water	Replace in 2010	119
# 3 Algoma	20	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use, Pole in water	Replace in 2010	120
# 3 Algoma	21	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use	Replace in 2010	121
# 3 Algoma	22	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Moderate	Joint Use	RG Tested Ok	122

Table 3B: Page 1 of 2

Table 4B: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 1 Algoma	27R	Cracks - Slight		Yes	Yes	No	No	65
# 1 Algoma	27L	Carpenter ants damage - Slight, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	66
# 1 Algoma	28R	Cracks - Slight		Yes	Yes	No	No	67
# 1 Algoma	28L	Cracks - Slight		Yes	Yes	No	No	68
# 1 Algoma	29	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Bend in Pole	Yes	Yes	Yes	Yes	69
# 1 Algoma	29L	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	70
# 1 Algoma	30	Cracks - Slight		Yes	Yes	No	No	71
# 1 Algoma	31	Cracks - Slight	Bend in Pole, Dip, Joint Use, Lights on Pole	Yes	Yes	No	No	72
# 1 Algoma	32		Dip, Joint Use	Yes	Yes	No	No	73
# 1 Algoma	33	Cracks - Slight	Bend in Pole, Dip, Joint Use	Yes	Yes	No	No	74
# 1 Algoma	34		Joint Use	Yes	Yes	No	No	75

Table 4B: Page 1 of 6

Table 5B: Poles with Extensive Mechanical Damage and Feathering

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 3 Algoma	17	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Joint Use	RG Tested Ok	117
# 3 Algoma	20	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use, Pole in water	Replace in 2010	120
# 3 Algoma	21	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use	Replace in 2010	121
# 3 Algoma	32	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	123

Table 6B: Poles with Internal Decay

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 1 Algoma	27L	Carpenter ants damage - Slight, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	66
# 1 Algoma	29	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Bend in Pole	RG Tested Ok	69
# 1 Algoma	29L	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	70
# 1 Algoma	45	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Joint Use, Lights on Pole	RG Tested Ok	84
# 2 & 3 Algoma	57	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	94
# 2 & 3 Algoma	46	Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Guy guard required	RG Tested Ok	98
# 2 Algoma	35	Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	108
# 2 Algoma	29	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	114
# 3 Algoma	17	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Joint Use	RG Tested Ok	117
# 3 Algoma	18	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Ground Guard Required, Joint Use, Pole in water	Replace in 2010	118
# 3 Algoma	19	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Joint Use, Pole in water	Replace in 2010	119
# 3 Algoma	20	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use, Pole in water	Replace in 2010	120

Table 6B: Page 1 of 2

Table 7B: Poles with Limited Remaining Life

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Remaining life (yrs)	Record Number
# 1 Algoma	45	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Joint Use, Lights on Pole	RG Tested Ok	Remaining life 2 years	84
# 2 & 3 Algoma	57	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	94
# 2 Algoma	29	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	114
# 3 Algoma	22	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Moderate	Joint Use	RG Tested Ok	Remaining life 2 years	122
# 3 Algoma	32	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	123

Table 7B: Page 1 of 1

Table 8B: Individual Pole Records

Line #:	# 1 Algoma	Test Date:	11-Nov-09	Record No.:	68	Pole ID:	27R
Private Property:	No	Pole Class:	2	Pole Ht (ft):	75		
Install Date	1994	Pole species:	WC	Treatment Length:	Full	Treatment Type:	CCA
Overall Pole Condition:	Fair	Pole Diameter (in):	19	Pole Strength at GL (psi):	5130		
Mechanical Condition:	Cracks - Slight						
# of broken/chipped insulators:	0	# of small wood pecker holes:	1	# of large wood pecker holes:	4		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	[illegible]						

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Part C: 3rd line TS – St. Patrick St TS

A combined database for the two sections (Part A and Part B) is given in MS Access format

Table 1C: Summary of Pole Data

Line Number	Pole ID	Pole Strength GL (psi)	Mechanical Condition	Comments	Recommendations	Probable Remaining Life (Yrs)	Record Number
# 1 Algoma	1 Right	4210	Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Internal Decay - Moderate	Guy guard required, Slack Guy Wire	RG Tested Ok	8	1
# 1 Algoma	1 Centre	4450	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight	Dip	RG Tested Ok	12	2
# 1 Algoma	1 Left	5260	Cracks - Slight, Decay pockets at GL - Slight, Internal Decay - Slight, Guying (slack, broken, buried) - slight		RG Tested Ok	12	3
# 1 Algoma	2		Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010		13
# 1 Algoma	3	4900	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight, Guying (slack, broken, buried) - moderate	Bend in Pole, Guy guard required	RG Tested Ok	5	17
# 1 Algoma	4	4800	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	2	21
# 1 Algoma	5	5120	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Moderate, Guying (slack, broken, buried) - slight		RG Tested Ok	2	25
# 1 Algoma	6	4880	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	8	29
# 1 Algoma	7	4770	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Dip	RG Tested Ok	8	33

Table 1C: Summary of Pole Data

Line Number	Pole ID	Pole Strength GL (psi)	Mechanical Condition	Comments	Recommendations	Probable Remaining Life (Yrs)	Record Number
# 1 Algoma	8	5090	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Bend in Pole	RG Tested Ok	7	37
# 1 Algoma	9	5000	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight	Bend in Pole	RG Tested Ok	5	41
# 1 Algoma	10	5090	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Slight, Internal Decay - Slight		RG Tested Ok	7	45
# 1 Algoma	11	4820	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Extensive, Surface Rot below GL - Moderate, Internal Decay - Slight	Climbing Inspection Required	RG Tested Ok	2	49
# 1 Algoma	13	5060	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	7	57
# 1 Algoma	27R	5130	Cracks - Slight		No RG Required, Pole OK	38	65
# 1 Algoma	27L	4650	Carpenter ants damage - Slight, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	6	66
# 1 Algoma	28R	5220	Cracks - Slight		No RG Required, Pole OK	35	67
# 1 Algoma	28L	5090	Cracks - Slight		No RG Required, Pole OK	36	68
# 1 Algoma	29	4710	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Bend in Pole	RG Tested Ok	4	69
# 1 Algoma	29L	5100	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	4	70

Table 1C: Summary of Pole Data

Line Number	Pole ID	Pole Strength GL (psi)	Mechanical Condition	Comments	Recommendations	Probable Remaining Life (Yrs)	Record Number
# 1 Algoma	30	5370	Cracks - Slight		No RG Required, Pole OK	37	71
# 1 Algoma	31	5120	Cracks - Slight	Bend in Pole, Dip, Joint Use, Lights on Pole	RG Tested Ok	32	72
# 1 Algoma	32	5290		Dip, Joint Use	No RG Required, Pole OK	38	73
# 1 Algoma	33	5140	Cracks - Slight	Bend in Pole, Dip, Joint Use	No RG Required, Pole OK	38	74
# 1 Algoma	34	5330		Joint Use	No RG Required, Pole OK	38	75
# 1 Algoma	35	4980	Cracks - Slight	Dip, Joint Use	No RG Required, Pole OK	38	76
# 1 Algoma	36	5200	Cracks - Slight	Joint Use	No RG Required, Pole OK	38	77
# 1 Algoma	37	5420	Cracks - Slight	Dip, Joint Use	No RG Required, Pole OK	38	78
# 1 Algoma	38	5110	Cracks - Slight	Joint Use	No RG Required, Pole OK	38	79
# 1 Algoma	39	4820	Cracks - Slight	Dip, Joint Use	No RG Required, Pole OK	38	80
# 1 Algoma	40	5060	Cracks - Slight	Dip, Joint Use	No RG Required, Pole OK	38	81

Table 1C: Summary of Pole Data

Line Number	Pole ID	Pole Strength GL (psi)	Mechanical Condition	Comments	Recommendations	Probable Remaining Life (Yrs)	Record Number
# 1 Algoma	43	5240	Cracks - Slight		No RG Required, Pole OK	35	82
# 1 Algoma	44	5360	Cracks - Slight	Joint Use, Lights on Pole	No RG Required, Pole OK	37	83
# 1 Algoma	45	4770	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Joint Use, Lights on Pole	RG Tested Ok	2	84
# 1 Algoma	46	5380	Cracks - Slight	Joint Use, Lights on Pole	No RG Required, Pole OK	38	85
# 1 Algoma	47	5100	Cracks - Slight	Joint Use, Lights on Pole	No RG Required, Pole OK	38	86
# 1 Algoma	48	4860	Cracks - Slight	Joint Use, Lights on Pole	No RG Required, Pole OK	38	87
# 1 Algoma	49	5420	Cracks - Slight	Joint Use, Lights on Pole	No RG Required, Pole OK	38	88
# 1 Algoma	50	5050	Cracks - Slight	Joint Use, Lights on Pole	No RG Required, Pole OK	38	89
# 1 Algoma	51	5260	Cracks - Slight	Dip, Joint Use, Lights on Pole	No RG Required, Pole OK	38	90
# 1 Algoma	52	5400	Cracks - Slight	Joint Use, Lights on Pole	No RG Required, Pole OK	38	91
# 1 Algoma	53	5240	Cracks - Slight	Joint Use, Lights on Pole	No RG Required, Pole OK	36	92
# 2 & 3 Algoma	58	4910	Cracks - Slight		RG Tested Ok	34	93

Table 1C: Summary of Pole Data

Line Number	Pole ID	Pole Strength GL (psi)	Mechanical Condition	Comments	Recommendations	Probable Remaining Life (Yrs)	Record Number
# 2 & 3 Algoma	57	4820	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	2	94
# 2 & 3 Algoma	51	5070	Cracks - Slight		RG Tested Ok	34	95
# 2 & 3 Algoma	49	5010	Cracks - Slight		RG Tested Ok	34	96
# 2 & 3 Algoma	48	4790	Cracks - Slight		RG Tested Ok	34	97
# 2 & 3 Algoma	46	4920	Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Guy guard required	RG Tested Ok	11	98
# 2 & 3 Algoma	45	5120			RG Tested Ok	34	99
# 2 & 3 Algoma	44	5040	Cracks - Slight, Ground wire (slack, broken, buried) - extensive	Slack Guy Wire	RG Tested Ok	34	100
# 2 & 3 Algoma	43	4930	Cracks - Slight		RG Tested Ok	34	101
# 2 & 3 Algoma	42	4990	Cracks - Slight	Bend in Pole	RG Tested Ok	34	102
# 2 & 3 Algoma	41	5240	Cracks - Slight	Guy guard required, Slack Guy Wire	RG Tested Ok	33	103
# 2 & 3 Algoma	40	5370	Cracks - Slight		RG Tested Ok	33	104
# 2 & 3 Algoma	39	5150	Cracks - Slight	Guy guard required	RG Tested Ok	34	105
# 2 & 3 Algoma	38	5300	Cracks - Slight		RG Tested Ok	33	106

Table 1C: Summary of Pole Data

Line Number	Pole ID	Pole Strength GL (psi)	Mechanical Condition	Comments	Recommendations	Probable Remaining Life (Yrs)	Record Number
# 2 Algoma	1 Right	5340			No RG Required, Pole OK	40	4
# 2 Algoma	1 Centre	4920			No RG Required, Pole OK	41	5
# 2 Algoma	2		Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010		14
# 2 Algoma	3	5180	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Slight		RG Tested Ok	7	18
# 2 Algoma	4	5110	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Slight		RG Tested Ok	7	22
# 2 Algoma	5	4340	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	2	26
# 2 Algoma	6	4970	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	8	30
# 2 Algoma	7	4990	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate	Bend in Pole	RG Tested Ok	2	34

Table 1C: Summary of Pole Data

Line Number	Pole ID	Pole Strength GL (psi)	Mechanical Condition	Comments	Recommendations	Probable Remaining Life (Yrs)	Record Number
# 2 Algoma	8	5220	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	7	38
# 2 Algoma	9	5190	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	7	42
# 2 Algoma	10	4860	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	2	46
# 2 Algoma	11	4880	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Bend in Pole	RG Tested Ok	8	50
# 2 Algoma	12	4600	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	9	54
# 2 Algoma	13	5170	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight, Guying (slack, broken, buried) - extensive	Bend in Pole	RG Tested Ok	7	58
# 2 Algoma	36	4900	Cracks - Slight		RG Tested Ok	34	107
# 2 Algoma	35	4780	Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	11	108
# 2 Algoma	34	5080	Cracks - Slight		RG Tested Ok	34	109
# 2 Algoma	33	5270	Cracks - Slight		RG Tested Ok	33	110

Table 1C: Summary of Pole Data

Line Number	Pole ID	Pole Strength GL (psi)	Mechanical Condition	Comments	Recommendations	Probable Remaining Life (Yrs)	Record Number
# 2 Algoma	32	5160	Cracks - Slight		RG Tested Ok	34	111
# 2 Algoma	31	4940	Cracks - Moderate, Pole top feathering/split/rot - Slight	Dip	RG Tested Ok	33	112
# 2 Algoma	30	5200	Cracks - Slight		RG Tested Ok	33	113
# 2 Algoma	29	4520	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	2	114
# 2 Algoma	28	5330	Cracks - Slight		No RG Required, Pole OK	37	115
# 2 Algoma	27	5030	Cracks - Moderate	Pole in water	RG Tested Ok	34	116
# 2Algoma	1 Left	5120			No RG Required, Pole OK	40	6
# 3 Algoma	1 Right	5100			No RG Required, Pole OK	40	7
# 3 Algoma	1 Centre	4870			No RG Required, Pole OK	41	8
# 3 Algoma	1 Left	5090			No RG Required, Pole OK	40	9
# 3 Algoma	2		Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010		15

Table 1C: Summary of Pole Data

Line Number	Pole ID	Pole Strength GL (psi)	Mechanical Condition	Comments	Recommendations	Probable Remaining Life (Yrs)	Record Number
# 3 Algoma	3	4790	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Guy guard required	RG Tested Ok	2	19
# 3 Algoma	4	4770	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate, Guying (slack, broken, buri		RG Tested Ok	2	23
# 3 Algoma	5	4000	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	2	27
# 3 Algoma	6	4160	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	2	31
# 3 Algoma	7		Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010		35
# 3 Algoma	8	4870	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	2	39
# 3 Algoma	9	4130	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	2	43

Table 1C: Summary of Pole Data

Line Number	Pole ID	Pole Strength GL (psi)	Mechanical Condition	Comments	Recommendations	Probable Remaining Life (Yrs)	Record Number
# 3 Algoma	10	4910	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	8	47
# 3 Algoma	11	4550	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	9	51
# 3 Algoma	12	4120	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	2	55
# 3 Algoma	13	4990	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	2	59
# 3 Algoma	14	4800	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	8	61
# 3 Algoma	15		Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	RG Tested, Replace in 2010		63
# 3 Algoma	17	4410	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Joint Use	RG Tested Ok	4	117

Table 1C: Summary of Pole Data

Line Number	Pole ID	Pole Strength GL (psi)	Mechanical Condition	Comments	Recommendations	Probable Remaining Life (Yrs)	Record Number
# 3 Algoma	18		Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Ground Guard Required, Joint Use, Pole in water	Replace in 2010		118
# 3 Algoma	19		Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Joint Use, Pole in water	Replace in 2010		119
# 3 Algoma	20		Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use, Pole in water	Replace in 2010		120
# 3 Algoma	21		Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use	Replace in 2010		121
# 3 Algoma	22	4840	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Moderate	Joint Use	RG Tested Ok	2	122
# 3 Algoma	32	4370	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	2	123
# 3 Algoma	33	5020	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Internal Decay - Slight		RG Tested Ok	14	124
3 1 Algoma	12	4980	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	8	53

Table 1C: Summary of Pole Data

Line Number	Pole ID	Pole Strength GL (psi)	Mechanical Condition	Comments	Recommendations	Probable Remaining Life (Yrs)	Record Number
Northern Ave	1 Right	4780	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight		RG Tested Ok	12	10
Northern Ave	1 Centre	4640	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	9	11
Northern Ave	1 Left	4810	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	8	12
Northern Ave	2	5060	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	5	16
Northern Ave	3	5010	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Internal Decay - Slight	Guy guard required	RG Tested Ok	7	20
Northern Ave	4	5130	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Internal Decay - Slight	Guy guard required, Slack Guy Wire	RG Tested Ok	7	24
Northern Ave	5	4730	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Internal Decay - Slight		RG Tested Ok	8	28
Northern Ave	6	4010	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	2	32
Northern Ave	7	4560	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	2	36

Table 1C: Summary of Pole Data

Line Number	Pole ID	Pole Strength GL (psi)	Mechanical Condition	Comments	Recommendations	Probable Remaining Life (Yrs)	Record Number
Northern Ave	8	4400	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	2	40
Northern Ave	9	4680	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	8	44
Northern Ave	10	4770	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate, Guying (slack, broken, buried) - extensive		RG Tested Ok	2	48
Northern Ave	11	4670	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	8	52
Northern Ave	12		Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010		56
Northern Ave	14	4670	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	2	62
Northern Ave	15		Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	RG Tested, Replace in 2010		64

Table 1C: Summary of Pole Data

Line Number	Pole ID	Pole Strength GL (psi)	Mechanical Condition	Comments	Recommendations	Probable Remaining Life (Yrs)	Record Number
Northern Avenue	13	5010	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	7	60

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	*Test Date*	11-Nov-09	*Record No.:*	65	*Pole ID:*	27R
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	75		
Install Date	1994	*Pole species:*	WC	*Treatment Length:*	Full	*Treatment Type*	CCA
Overall Pole Condition	Fair	*Pole Diameter (in)*	19	*Pole Strength at GL (psi)*	5130		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	1	*# of large wood pecker holes:*	4		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	No	*Insecticide used?*	No
Comments:							
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	**Test Date**	11-Nov-09	**Record No.:**	66	**Pole ID:**	27L
Private Property:	No	**Pole Class:**	2	**Pole Ht (ft):**	75		
Install Date	1994	**Pole species:**	WC	**Treatment Length:**	Full	**Treatment Type**	CCA
Overall Pole Condition	Fair	**Pole Diameter (in)**	17	**Pole Strength at GL (psi)**	4650		
Mechanical Condition	Carpenter ants damage - Slight, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate						
# of broken/chipped insulators	0	**# of small wood pecker holes:**	0	**# of large wood pecker holes:**	9		
Treatment required ?	Yes	**Rods used ?**	Yes	**Copper used?**	Yes	**Insecticide used?**	Yes
Comments:							
Probable Remaining Life (yrs):	6						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	67	Pole ID:	28R
Private Property:	No	Pole Class:	2	Pole Ht (ft):	75		
Install Date	1986	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	18	Pole Strength at GL (psi)	5220		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	2		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	35						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	*Test Date*	11-Nov-09	*Record No.:*	68	*Pole ID:*	28L
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	75		
Install Date	1986	*Pole species:*	WC	*Treatment Length:*	Full	*Treatment Type*	Penta
Overall Pole Condition	Fair	*Pole Diameter (in)*	17	*Pole Strength at GL (psi)*	5090		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	6		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	No	*Insecticide used?*	No
Comments:							
Probable Remaining Life (yrs):	36						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	69	Pole ID:	29
Private Property:		Pole Class:	4	Pole Ht (ft):	65		
Install Date	1993	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	ir to Po	Pole Diameter (in)	17	Pole Strength at GL (psi)	4710		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate

# of broken/chipped insulators	0	# of small wood pecker holes:	1	# of large wood pecker holes:	1		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments: Bend in Pole

Probable Remaining Life (yrs): 4

Other Comments:

Recommendations: RG Tested Ok

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	**Test Date**	11-Nov-09	**Record No.:**	70	**Pole ID:**	29L
Private Property:	No	**Pole Class:**	4	**Pole Ht (ft):**	65		
Install Date	1993	**Pole species:**	WC	**Treatment Length:**	Full	**Treatment Type**	CCA
Overall Pole Condition	ir to Po	**Pole Diameter (in)**	15	**Pole Strength at GL (psi)**	5100		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate

# of broken/chipped insulators	0	**# of small wood pecker holes:**	0	**# of large wood pecker holes:**	0

Treatment required ?	Yes	**Rods used ?**	Yes	**Copper used?**	Yes	**Insecticide used?**	Yes

Comments:

Probable Remaining Life (yrs): 4

Other Comments:

Recommendations: RG Tested Ok

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	71	Pole ID:	30
Private Property:	No	Pole Class:	2	Pole Ht (ft):	75		
Install Date	1994	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	19	Pole Strength at GL (psi)	5370		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	2	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	37						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	72	Pole ID:	31
Private Property:	No	Pole Class:	3	Pole Ht (ft):	90		
Install Date	1973	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	17	Pole Strength at GL (psi)	5120		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Bend in Pole, Dip, Joint Use, Lights on Pole						
Probable Remaining Life (yrs):	32						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	*Test Date*	11-Nov-09	*Record No.:*	73	*Pole ID:*	32
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	80		
Install Date	1995	*Pole species:*	WC	*Treatment Length:*	Full	*Treatment Type*	CCA
Overall Pole Condition	Good	*Pole Diameter (in)*	17	*Pole Strength at GL (psi)*	5290		
Mechanical Condition							
# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	No	*Insecticide used?*	No
Comments:	Dip, Joint Use						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	*Test Date*	11-Nov-09	*Record No.:*	74	*Pole ID:*	33
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	80		
Install Date	1995	*Pole species:*	WC	*Treatment Length:*	Full	*Treatment Type*	CCA
Overall Pole Condition	Good	*Pole Diameter (in)*	18	*Pole Strength at GL (psi)*	5140		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	No	*Insecticide used?*	No
Comments:	Bend in Pole, Dip, Joint Use						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	75	Pole ID:	34
Private Property:	No	Pole Class:	2	Pole Ht (ft):	80		
Install Date	1995	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	18	Pole Strength at GL (psi)	5330		
Mechanical Condition							
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Joint Use						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	76	Pole ID:	35
Private Property:	No	Pole Class:	2	Pole Ht (ft):	80		
Install Date	1995	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	16	Pole Strength at GL (psi)	4980		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Dip, Joint Use						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	77	Pole ID:	36
Private Property:	No	Pole Class:	2	Pole Ht (ft):	80		
Install Date	1995	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	17	Pole Strength at GL (psi)	5200		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Joint Use						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	78	Pole ID:	37
Private Property:	No	Pole Class:	2	Pole Ht (ft):	80		
Install Date	1995	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	18	Pole Strength at GL (psi)	5420		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Dip, Joint Use						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	*Test Date*	11-Nov-09	*Record No.:*	79	*Pole ID:*	38
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	80		
Install Date	1995	*Pole species:*	WC	*Treatment Length:*	Full	*Treatment Type*	CCA
Overall Pole Condition	Good	*Pole Diameter (in)*	17	*Pole Strength at GL (psi)*	5110		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	No	*Insecticide used?*	No
Comments:	Joint Use						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	80	Pole ID:	39
Private Property:	No	Pole Class:	2	Pole Ht (ft):	80		
Install Date	1995	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	16	Pole Strength at GL (psi)	4820		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Dip, Joint Use						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	81	Pole ID:	40
Private Property:	No	Pole Class:	2	Pole Ht (ft):	80		
Install Date	1995	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	17	Pole Strength at GL (psi)	5060		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Dip, Joint Use						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	82	Pole ID:	43
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1985	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	22	Pole Strength at GL (psi)	5240		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	35						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	83	Pole ID:	44
Private Property:	No	Pole Class:	2	Pole Ht (ft):	90		
Install Date	1994	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	20	Pole Strength at GL (psi)	5360		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Joint Use, Lights on Pole						
Probable Remaining Life (yrs):	37						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	*Test Date*	11-Nov-09	*Record No.:*	84	*Pole ID:*	45
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	85		
Install Date	1972	*Pole species:*	WC	*Treatment Length:*	Full	*Treatment Type*	Penta
Overall Pole Condition	ir to Po	*Pole Diameter (in)*	17	*Pole Strength at GL (psi)*	4770		
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	Yes	*Insecticide used?*	Yes
Comments:	Joint Use, Lights on Pole						
Probable Remaining Life (yrs):	2						
Other Comments:	Remaining life 2 years						
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	85	Pole ID:	46
Private Property:	No	Pole Class:	2	Pole Ht (ft):	80		
Install Date	1995	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	17	Pole Strength at GL (psi)	5380		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Joint Use, Lights on Pole						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	*Test Date*	11-Nov-09	*Record No.:*	86	*Pole ID:*	47
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	80		
Install Date	1995	*Pole species:*	WC	*Treatment Length:*	Full	*Treatment Type*	CCA
Overall Pole Condition	Good	*Pole Diameter (in)*	18	*Pole Strength at GL (psi)*	5100		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	No	*Insecticide used?*	No
Comments:	Joint Use, Lights on Pole						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	**Test Date**	11-Nov-09	**Record No.:**	87	**Pole ID:**	48
Private Property:	No	**Pole Class:**	2	**Pole Ht (ft):**	80		
Install Date	1995	**Pole species:**	WC	**Treatment Length:**	Full	**Treatment Type**	CCA
Overall Pole Condition	Good	**Pole Diameter (in)**	16	**Pole Strength at GL (psi)**	4860		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	**# of small wood pecker holes:**	0	**# of large wood pecker holes:**	0		
Treatment required ?	Yes	**Rods used ?**	Yes	**Copper used?**	No	**Insecticide used?**	No
Comments:	Joint Use, Lights on Pole						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	*Test Date*	11-Nov-09	*Record No.:*	88	*Pole ID:*	49
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	80		
Install Date	1995	*Pole species:*	WC	*Treatment Length:*	Full	*Treatment Type*	CCA
Overall Pole Condition	Good	*Pole Diameter (in)*	18	*Pole Strength at GL (psi)*	5420		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	No	*Insecticide used?*	No
Comments:	Joint Use, Lights on Pole						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	89	Pole ID:	50
Private Property:	No	Pole Class:	2	Pole Ht (ft):	80		
Install Date	1995	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	19	Pole Strength at GL (psi)	5050		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Joint Use, Lights on Pole						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	*Test Date*	11-Nov-09	*Record No.:*	90	*Pole ID:*	51
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	80		
Install Date	1995	*Pole species:*	WC	*Treatment Length:*	Full	*Treatment Type*	CCA
Overall Pole Condition	Good	*Pole Diameter (in)*	18	*Pole Strength at GL (psi)*	5260		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	No	*Insecticide used?*	No
Comments:	Dip, Joint Use, Lights on Pole						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	91	Pole ID:	52
Private Property:	No	Pole Class:	2	Pole Ht (ft):	80		
Install Date	1995	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	18	Pole Strength at GL (psi)	5400		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Joint Use, Lights on Pole						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 1 Algoma	*Test Date*	11-Nov-09	*Record No.:*	92	*Pole ID:*	53
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	85		
Install Date	1992	*Pole species:*	WC	*Treatment Length:*	Full	*Treatment Type*	CCA
Overall Pole Condition	Good	*Pole Diameter (in)*	22	*Pole Strength at GL (psi)*	5240		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	No	*Insecticide used?*	No
Comments:	Joint Use, Lights on Pole						
Probable Remaining Life (yrs):	36						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	93	Pole ID:	58
Private Property:	Yes	Pole Class:	1	Pole Ht (ft):	80		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	23	Pole Strength at GL (psi)	4910		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	94	Pole ID:	57
Private Property:	Yes	Pole Class:	1	Pole Ht (ft):	80		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	ir to Po	Pole Diameter (in)	23	Pole Strength at GL (psi)	4820		
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Modera						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes
Comments:							
Probable Remaining Life (yrs):	2						
Other Comments:	Remaining life 2 years						
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	95	Pole ID:	51
Private Property:	Yes	Pole Class:	1	Pole Ht (ft):	80		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	19	Pole Strength at GL (psi)	5070		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	96	Pole ID:	49
Private Property:	No	Pole Class:	1	Pole Ht (ft):	80		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	22	Pole Strength at GL (psi)	5010		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	97	Pole ID:	48
Private Property:	No	Pole Class:	1	Pole Ht (ft):	80		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	22	Pole Strength at GL (psi)	4790		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	98	Pole ID:	46
Private Property:	No	Pole Class:	1	Pole Ht (ft):	80		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Fair	Pole Diameter (in)	22	Pole Strength at GL (psi)	4920		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes
Comments:	Guy guard required						
Probable Remaining Life (yrs):	11						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	99	Pole ID:	45
Private Property:	No	Pole Class:	1	Pole Ht (ft):	90		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	24	Pole Strength at GL (psi)	5120		
Mechanical Condition							
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 2 & 3 Algoma	*Test Date*	11-Nov-09	*Record No.:*	100	*Pole ID:*	44
Private Property:	No	*Pole Class:*	1	*Pole Ht (ft):*	80		
Install Date	1977	*Pole species:*	WC	*Treatment Length:*	Full	*Treatment Type*	Penta
Overall Pole Condition	Good	*Pole Diameter (in)*	18	*Pole Strength at GL (psi)*	5040		
Mechanical Condition	Cracks - Slight, Ground wire (slack, broken, buried) - extensive						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	No	*Insecticide used?*	No
Comments:	Slack Guy Wire						
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	101	Pole ID:	43
Private Property:	No	Pole Class:	1	Pole Ht (ft):	75		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	23	Pole Strength at GL (psi)	4930		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	102	Pole ID:	42
Private Property:	No	Pole Class:	1	Pole Ht (ft):	75		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	22	Pole Strength at GL (psi)	4990		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Bend in Pole						
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	103	Pole ID:	41
Private Property:	No	Pole Class:	1	Pole Ht (ft):	75		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	19	Pole Strength at GL (psi)	5240		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Guy guard required, Slack Guy Wire						
Probable Remaining Life (yrs):	33						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	104	Pole ID:	40
Private Property:	No	Pole Class:	1	Pole Ht (ft):	75		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	18	Pole Strength at GL (psi)	5370		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	33						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	105	Pole ID:	39
Private Property:	No	Pole Class:	1	Pole Ht (ft):	75		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	18	Pole Strength at GL (psi)	5150		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Guy guard required						
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	106	Pole ID:	38
Private Property:	No	Pole Class:	1	Pole Ht (ft):	75		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	19	Pole Strength at GL (psi)	5300		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	33						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 2 Algoma	Test Date	11-Nov-09	Record No.:	107	Pole ID:	36
Private Property:	No	Pole Class:	1	Pole Ht (ft):	75		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	18	Pole Strength at GL (psi)	4900		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 2 Algoma	***Test Date***	11-Nov-09	***Record No.:***	108	***Pole ID:***	35
Private Property:	No	***Pole Class:***	1	***Pole Ht (ft):***	80		
Install Date	1977	***Pole species:***	WC	***Treatment Length:***	Full	***Treatment Type***	Penta
Overall Pole Condition	Fair	***Pole Diameter (in)***	20	***Pole Strength at GL (psi)***	4780		
Mechanical Condition	Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate						
# of broken/chipped insulators	0	***# of small wood pecker holes:***	0	***# of large wood pecker holes:***	0		
Treatment required ?	Yes	***Rods used ?***	Yes	***Copper used?***	Yes	***Insecticide used?***	No
Comments:							
Probable Remaining Life (yrs):	11						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 2 Algoma	Test Date	11-Nov-09	Record No.:	109	Pole ID:	34
Private Property:	No	Pole Class:	1	Pole Ht (ft):	90		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	22	Pole Strength at GL (psi)	5080		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 2 Algoma	Test Date	11-Nov-09	Record No.:	110	Pole ID:	33
Private Property:	No	Pole Class:	1	Pole Ht (ft):	90		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	22	Pole Strength at GL (psi)	5270		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	33						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 2 Algoma	Test Date	11-Nov-09	Record No.:	111	Pole ID:	32
Private Property:	No	Pole Class:	1	Pole Ht (ft):	90		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	23	Pole Strength at GL (psi)	5160		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 2 Algoma	Test Date	11-Nov-09	Record No.:	112	Pole ID:	31
Private Property:	No	Pole Class:	1	Pole Ht (ft):	80		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Fair	Pole Diameter (in)	23	Pole Strength at GL (psi)	4940		
Mechanical Condition	Cracks - Moderate, Pole top feathering/split/rot - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Dip						
Probable Remaining Life (yrs):	33						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 2 Algoma	Test Date	11-Nov-09	Record No.:	113	Pole ID:	30
Private Property:	No	Pole Class:	1	Pole Ht (ft):	70		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	18	Pole Strength at GL (psi)	5200		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	33						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 2 Algoma	Test Date	11-Nov-09	Record No.:	114	Pole ID:	29
Private Property:	No	Pole Class:	1	Pole Ht (ft):	70		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	ir to Po	Pole Diameter (in)	22	Pole Strength at GL (psi)	4520		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Modera

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Remaining life 2 years

Recommendations: RG Tested Ok

Table 7A: Individual Pole Records

Line #:	# 2 Algoma	*Test Date*	11-Nov-09	*Record No.:*	115	*Pole ID:*	28
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	75		
Install Date	1994	*Pole species:*	WC	*Treatment Length:*	Full	*Treatment Type*	CCA
Overall Pole Condition	Good	*Pole Diameter (in)*	17	*Pole Strength at GL (psi)*	5330		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	1		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	No	*Insecticide used?*	No
Comments:							
Probable Remaining Life (yrs):	37						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 7A: Individual Pole Records

Line #:	# 2 Algoma	Test Date	11-Nov-09	Record No.:	116	Pole ID:	27
Private Property:	No	Pole Class:	1	Pole Ht (ft):	85		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Fair	Pole Diameter (in)	22	Pole Strength at GL (psi)	5030		
Mechanical Condition	Cracks - Moderate						
# of broken/chipped insulators	0	# of small wood pecker holes:	3	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Pole in water						
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 3 Algoma	Test Date	11-Nov-09	Record No.:	117	Pole ID:	17
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1960	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	20	Pole Strength at GL (psi)	4410		
Mechanical Condition	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL -						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:	Joint Use						
Probable Remaining Life (yrs):	4						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 3 Algoma	Test Date	11-Nov-09	Record No.:	118	Pole ID:	18
Private Property:	Yes	Pole Class:	1	Pole Ht (ft):	75		
Install Date	1955	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Poor	Pole Diameter (in)	20	Pole Strength at GL (psi)			
Mechanical Condition	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot -						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	No	Copper used?	Yes	Insecticide used?	Yes
Comments:	Ground Guard Required, Joint Use, Pole in water						
Probable Remaining Life (yrs):							
Other Comments:	Transformer on pole						
Recommendations:	Replace in 2010						

Table 7A: Individual Pole Records

Line #:	# 3 Algoma	**Test Date**	11-Nov-09	**Record No.:**	119	**Pole ID:**	19
Private Property:	Yes	**Pole Class:**	1	**Pole Ht (ft):**	75		
Install Date	1955	**Pole species:**	WC	**Treatment Length:**	Butt	**Treatment Type**	Creo
Overall Pole Condition	Poor	**Pole Diameter (in)**	20	**Pole Strength at GL (psi)**			
Mechanical Condition	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot -						
# of broken/chipped insulators	0	**# of small wood pecker holes:**	7	**# of large wood pecker holes:**	0		
Treatment required ?	Yes	**Rods used ?**	No	**Copper used?**	Yes	**Insecticide used?**	Yes
Comments:	Joint Use, Pole in water						
Probable Remaining Life (yrs):							
Other Comments:	Transformer on pole						
Recommendations:	Replace in 2010						

Table 7A: Individual Pole Records

Line #:	# 3 Algoma	Test Date	11-Nov-09	Record No.:	120	Pole ID:	20
Private Property:	Yes	Pole Class:	1	Pole Ht (ft):	75		
Install Date	1955	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Poor	Pole Diameter (in)	20	Pole Strength at GL (psi)			
Mechanical Condition	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot -						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	No	Copper used?	Yes	Insecticide used?	Yes
Comments:	Dip, Joint Use, Pole in water						
Probable Remaining Life (yrs):							
Other Comments:							
Recommendations:	Replace in 2010						

Table 7A: Individual Pole Records

Line #:	# 3 Algoma	***Test Date***	11-Nov-09	***Record No.:***	121	***Pole ID:***	21
Private Property:	No	***Pole Class:***	1	***Pole Ht (ft):***	75		
Install Date	1955	***Pole species:***	WC	***Treatment Length:***	Butt	***Treatment Type***	Creo
Overall Pole Condition	Poor	***Pole Diameter (in)***	20	***Pole Strength at GL (psi)***			
Mechanical Condition	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot -						
# of broken/chipped insulators	0	***# of small wood pecker holes:***	0	***# of large wood pecker holes:***	1		
Treatment required ?	Yes	***Rods used ?***	No	***Copper used?***	Yes	***Insecticide used?***	Yes
Comments:	Dip, Joint Use						
Probable Remaining Life (yrs):							
Other Comments:	Transformer on pole						
Recommendations:	Replace in 2010						

Table 7A: Individual Pole Records

Line #:	# 3 Algoma	Test Date	11-Nov-09	Record No.:	122	Pole ID:	22
Private Property:	No	Pole Class:	1	Pole Ht (ft):	75		
Install Date	1955	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	20	Pole Strength at GL (psi)	4840		
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes
Comments:	Joint Use						
Probable Remaining Life (yrs):	2						
Other Comments:	Remaining life 2 years						
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Line #:	# 3 Algoma	*Test Date*	11-Nov-09	*Record No.:*	123	*Pole ID:*	32
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	75		
Install Date	1955	*Pole species:*	WC	*Treatment Length:*	Butt	*Treatment Type*	Creo
Overall Pole Condition	ir to Po	*Pole Diameter (in)*	16	*Pole Strength at GL (psi)*	4370		

Mechanical Condition: **Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot**

# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	0

Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	No	*Insecticide used?*	No

Comments:

Probable Remaining Life (yrs): 2

Other Comments: **Remaining life 2 years**

Recommendations: **RG Tested Ok**

Table 7A: Individual Pole Records

Line #:	# 3 Algoma	Test Date	11-Nov-09	Record No.:	124	Pole ID:	33
Private Property:	Yes	Pole Class:	3	Pole Ht (ft):	75		
Install Date	1972	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Fair	Pole Diameter (in)	16	Pole Strength at GL (psi)	5020		
Mechanical Condition	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Internal Decay - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	14						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 7A: Individual Pole Records

Table 8A: Individual Pole Records

Line #:	# 1 Algoma	*Test Date*	10-Nov-09	*Record No.:*	1	*Pole ID:*	1 Right
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	60		
Install Date	1964	*Pole species:*	WC	*Treatment Length:*	Full	*Treatment Type*	Penta
Overall Pole Condition	Good	*Pole Diameter (in)*	17	*Pole Strength at GL (psi)*	4210		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Internal Decay - Moderate						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	5	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	Yes	*Insecticide used?*	No
Comments:	Guy guard required, Slack Guy Wire						
Probable Remaining Life (yrs):	8						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	10-Nov-09	Record No.:	2	Pole ID:	1 Centre
Private Property:	No	Pole Class:	2	Pole Ht (ft):	60		
Install Date	1964	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Fair	Pole Diameter (in)	14	Pole Strength at GL (psi)	4450		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:	Dip						
Probable Remaining Life (yrs):	12						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	10-Nov-09	Record No.:	3	Pole ID:	1 Left
Private Property:	No	Pole Class:	2	Pole Ht (ft):	60		
Install Date	1964	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Fair	Pole Diameter (in)	14	Pole Strength at GL (psi)	5260		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Internal Decay - Slight, Guying (slack, broken, buried) - slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	12						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	4	Pole ID:	1 Right
Private Property:	No	Pole Class:	2	Pole Ht (ft):	60		
Install Date	2005	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	16	Pole Strength at GL (psi)	5340		
Mechanical Condition							
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	No	Rods used ?		Copper used?		Insecticide used?	
Comments:							
Probable Remaining Life (yrs):	40						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8A: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	5	Pole ID:	1 Centre
Private Property:	No	Pole Class:	2	Pole Ht (ft):	60		
Install Date	2005	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	16	Pole Strength at GL (psi)	4920		
Mechanical Condition							
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	No	Rods used ?		Copper used?		Insecticide used?	
Comments:							
Probable Remaining Life (yrs):	41						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8A: Individual Pole Records

Line #:	# 2Algoma	Test Date	10-Nov-09	Record No.:	6	Pole ID:	1 Left
Private Property:	No	Pole Class:	2	Pole Ht (ft):	60		
Install Date	2005	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	17	Pole Strength at GL (psi)	5120		
Mechanical Condition							
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	No	Rods used ?		Copper used?		Insecticide used?	
Comments:							
Probable Remaining Life (yrs):	40						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8A: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	7	Pole ID:	1 Right
Private Property:	No	Pole Class:	2	Pole Ht (ft):	60		
Install Date	2005	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	16	Pole Strength at GL (psi)	5100		
Mechanical Condition							
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	No	Rods used ?		Copper used?		Insecticide used?	
Comments:							
Probable Remaining Life (yrs):	40						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8A: Individual Pole Records

Line #:	# 3 Algoma	*Test Date*	10-Nov-09	*Record No.:*	8	*Pole ID:*	1 Centre
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	60		
Install Date	2005	*Pole species:*	WC	*Treatment Length:*	Full	*Treatment Type*	CCA
Overall Pole Condition	Good	*Pole Diameter (in)*	15	*Pole Strength at GL (psi)*	4870		
Mechanical Condition							
# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	0		
Treatment required ?	No	*Rods used ?*		*Copper used?*		*Insecticide used?*	
Comments:							
Probable Remaining Life (yrs):	41						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8A: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	9	Pole ID:	1 Left
Private Property:	No	Pole Class:	2	Pole Ht (ft):	60		
Install Date	2005	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition		Pole Diameter (in)	16	Pole Strength at GL (psi)	5090		
Mechanical Condition							
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	No	Rods used ?		Copper used?		Insecticide used?	
Comments:							
Probable Remaining Life (yrs):	40						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8A: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	10	Pole ID:	1 Right
Private Property:	No	Pole Class:	2	Pole Ht (ft):	60		
Install Date	1964	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition		Pole Diameter (in)	14	Pole Strength at GL (psi)	4780		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	12						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	11	Pole ID:	1 Centre
Private Property:	No	Pole Class:	2	Pole Ht (ft):	60		
Install Date	1960	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	15	Pole Strength at GL (psi)	4640		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Mo						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	9						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	12	Pole ID:	1 Left
Private Property:	No	Pole Class:	2	Pole Ht (ft):	60		
Install Date	1960	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	16	Pole Strength at GL (psi)	4810		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Mo						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	8						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	10-Nov-09	Record No.:	13	Pole ID:	2
Private Property:	No	Pole Class:	2	Pole Ht (ft):	65		
Install Date	1964	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Poor	Pole Diameter (in)	16	Pole Strength at GL (psi)			
Mechanical Condition	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot -						
# of broken/chipped insulators	0	# of small wood pecker holes:	3	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	No	Copper used?	Yes	Insecticide used?	Yes
Comments:							
Probable Remaining Life (yrs):							
Other Comments:							
Recommendations:	Replace in 2010						

Table 8A: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	14	Pole ID:	2
Private Property:	No	Pole Class:	2	Pole Ht (ft):	65		
Install Date	1964	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Poor	Pole Diameter (in)	16	Pole Strength at GL (psi)			
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/						
# of broken/chipped insulators	0	# of small wood pecker holes:	2	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	No	Copper used?	Yes	Insecticide used?	Yes
Comments:							
Probable Remaining Life (yrs):							
Other Comments:							
Recommendations:	Replace in 2010						

Table 8A: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	15	Pole ID:	2
Private Property:	No	Pole Class:	2	Pole Ht (ft):	65		
Install Date	1964	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Poor	Pole Diameter (in)	15	Pole Strength at GL (psi)			
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	No	Copper used?	Yes	Insecticide used?	Yes
Comments:							
Probable Remaining Life (yrs):							
Other Comments:							
Recommendations:	Replace in 2010						

Table 8A: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	16	Pole ID:	2
Private Property:	No	Pole Class:	2	Pole Ht (ft):	65		
Install Date	1964	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Fair	Pole Diameter (in)	16	Pole Strength at GL (psi)	5060		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Modera						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	5						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	10-Nov-09	Record No.:	17	Pole ID:	3
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1964	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Pc	Pole Diameter (in)	16	Pole Strength at GL (psi)	4900		

Mechanical Condition: Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Mo

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments: Bend in Pole, Guy guard required

Probable Remaining Life (yrs): 5

Other Comments:

Recommendations: RG Tested Ok

Table 8A: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	18	Pole ID:	3
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1964	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Fair	Pole Diameter (in)	15	Pole Strength at GL (psi)	5180		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight,						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	7						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	19	Pole ID:	3
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1964	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	16	Pole Strength at GL (psi)	4790		
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot						
# of broken/chipped insulators	0	# of small wood pecker holes:	6	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes
Comments:	Guy guard required						
Probable Remaining Life (yrs):	2						
Other Comments:	Remaining life 2 years						
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	20	Pole ID:	3
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1964	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Fair	Pole Diameter (in)	16	Pole Strength at GL (psi)	5010		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slig						
# of broken/chipped insulators	0	# of small wood pecker holes:	8	# of large wood pecker holes:	2		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:	Guy guard required						
Probable Remaining Life (yrs):	7						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	10-Nov-09	Record No.:	21	Pole ID:	4
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1964	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	18	Pole Strength at GL (psi)	4800		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Remaining life 2 years

Recommendations: RG Tested Ok

Table 8A: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	22	Pole ID:	4
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1964	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Fair	Pole Diameter (in)	18	Pole Strength at GL (psi)	5110		

Mechanical Condition: Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight,

# of broken/chipped insulators	0	# of small wood pecker holes:	3	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments:

Probable Remaining Life (yrs): 7

Other Comments:

Recommendations: RG Tested Ok

Table 8A: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	23	Pole ID:	4
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1964	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	19	Pole Strength at GL (psi)	4770		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot

# of broken/chipped insulators	0	# of small wood pecker holes:	2	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Remaining life 2 years

Recommendations: RG Tested Ok

Table 8A: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	24	Pole ID:	4
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1964	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Fair	Pole Diameter (in)	18	Pole Strength at GL (psi)	5130		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slig						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:	Guy guard required, Slack Guy Wire						
Probable Remaining Life (yrs):	7						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	# 1 Algoma	*Test Date*	10-Nov-09	*Record No.:*	25	*Pole ID:*	5
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	85		
Install Date	1963	*Pole species:*	WC	*Treatment Length:*	Butt	*Treatment Type*	Creo
Overall Pole Condition	ir to Pc	*Pole Diameter (in)*	18	*Pole Strength at GL (psi)*	5120		
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	Yes	*Insecticide used?*	Yes
Comments:							
Probable Remaining Life (yrs):	2						
Other Comments:	Remaining life 2 years						
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	26	Pole ID:	5
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to P	Pole Diameter (in)	19	Pole Strength at GL (psi)	4340		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/

# of broken/chipped insulators	0	# of small wood pecker holes:	3	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Remaining life 2 years

Recommendations: RG Tested Ok

Table 8A: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	27	Pole ID:	5
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Pc	Pole Diameter (in)	18	Pole Strength at GL (psi)	4000		
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot						
# of broken/chipped insulators	0	# of small wood pecker holes:	10	# of large wood pecker holes:	7		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes
Comments:							
Probable Remaining Life (yrs):	2						
Other Comments:	Remaining life 2 years						
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	Northern Ave	*Test Date*	10-Nov-09	*Record No.:*	28	*Pole ID:*	5
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	85		
Install Date	1963	*Pole species:*	WC	*Treatment Length:*	Butt	*Treatment Type*	Creo
Overall Pole Condition	Poor	*Pole Diameter (in)*	18	*Pole Strength at GL (psi)*	4730		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slig						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	2	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	Yes	*Insecticide used?*	No
Comments:							
Probable Remaining Life (yrs):	8						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	10-Nov-09	Record No.:	29	Pole ID:	6
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	16	Pole Strength at GL (psi)	4880		
Mechanical Condition	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL -						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	8						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	30	Pole ID:	6
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	17	Pole Strength at GL (psi)	4970		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Mo						
# of broken/chipped insulators	0	# of small wood pecker holes:	3	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	8						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	31	Pole ID:	6
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Pc	Pole Diameter (in)	17	Pole Strength at GL (psi)	4160		
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/						
# of broken/chipped insulators	0	# of small wood pecker holes:	4	# of large wood pecker holes:	1		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes
Comments:							
Probable Remaining Life (yrs):	2						
Other Comments:	Remaining life 2 years						
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	32	Pole ID:	6
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to P(	Pole Diameter (in)	18	Pole Strength at GL (psi)	4010		
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot						
# of broken/chipped insulators	0	# of small wood pecker holes:	10	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes
Comments:							
Probable Remaining Life (yrs):	2						
Other Comments:	Remaining life 2 years						
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	# 1 Algoma	*Test Date*	10-Nov-09	*Record No.:*	33	*Pole ID:*	7
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	85		
Install Date	1963	*Pole species:*	WC	*Treatment Length:*	Butt	*Treatment Type*	Creo
Overall Pole Condition	ir to Po	*Pole Diameter (in)*	18	*Pole Strength at GL (psi)*	4770		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Mo						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	4	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	Yes	*Insecticide used?*	No
Comments:	Dip						
Probable Remaining Life (yrs):	8						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	# 2 Algoma	*Test Date*	10-Nov-09	*Record No.:*	34	*Pole ID:*	7
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	85		
Install Date	1963	*Pole species:*	WC	*Treatment Length:*	Butt	*Treatment Type*	Creo
Overall Pole Condition	ir to Po	*Pole Diameter (in)*	18	*Pole Strength at GL (psi)*	4990		
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	3	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	Yes	*Insecticide used?*	Yes
Comments:	Bend in Pole						
Probable Remaining Life (yrs):	2						
Other Comments:	Remaining life 2 years						
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	# 3 Algoma	**Test Date**	10-Nov-09	**Record No.:**	35	**Pole ID:**	7
Private Property:	No	**Pole Class:**	2	**Pole Ht (ft):**	85		
Install Date	1963	**Pole species:**	WC	**Treatment Length:**	Butt	**Treatment Type**	Creo
Overall Pole Condition	Poor	**Pole Diameter (in)**	18	**Pole Strength at GL (psi)**			
Mechanical Condition	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot -						
# of broken/chipped insulators	0	**# of small wood pecker holes:**	7	**# of large wood pecker holes:**	0		
Treatment required ?	Yes	**Rods used ?**	No	**Copper used?**	Yes	**Insecticide used?**	Yes
Comments:							
Probable Remaining Life (yrs):							
Other Comments:	Moderate wood loss/shell rot						
Recommendations:	Replace in 2010						

Table 8A: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	36	Pole ID:	7
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	17	Pole Strength at GL (psi)	4560		

Mechanical Condition Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/

# of broken/chipped insulators	0	# of small wood pecker holes:	2	# of large wood pecker holes:	1

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Remaining life 2 years

Recommendations: RG Tested Ok

Table 8A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	10-Nov-09	Record No.:	37	Pole ID:	8
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	18	Pole Strength at GL (psi)	5090		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Mo						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:	Bend in Pole						
Probable Remaining Life (yrs):	7						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	38	Pole ID:	8
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Fair	Pole Diameter (in)	19	Pole Strength at GL (psi)	5220		

Mechanical Condition: Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Modera

# of broken/chipped insulators	0	# of small wood pecker holes:	2	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments:

Probable Remaining Life (yrs): 7

Other Comments:

Recommendations: RG Tested Ok

Table 8A: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	39	Pole ID:	8
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	19	Pole Strength at GL (psi)	4870		

Mechanical Condition: Carpenter ants damage - Moderate,   Cracks - Moderate,   Decay pockets at GL - Moderate,   Pole top feathering/split/

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Remaining life 2 years

Recommendations: RG Tested Ok

Table 8A: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	40	Pole ID:	8
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	16	Pole Strength at GL (psi)	4400		
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/						
# of broken/chipped insulators	0	# of small wood pecker holes:	4	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes
Comments:							
Probable Remaining Life (yrs):	2						
Other Comments:	Remaining life 2 years						
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	10-Nov-09	Record No.:	41	Pole ID:	9
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	17	Pole Strength at GL (psi)	5000		

Mechanical Condition: Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments: Bend in Pole

Probable Remaining Life (yrs): 5

Other Comments:

Recommendations: RG Tested Ok

Table 8A: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	42	Pole ID:	9
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to P(	Pole Diameter (in)	19	Pole Strength at GL (psi)	5190		

Mechanical Condition: Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Mo

# of broken/chipped insulators	0	# of small wood pecker holes:	2	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments:

Probable Remaining Life (yrs): 7

Other Comments:

Recommendations: RG Tested Ok

Table 8A: Individual Pole Records

Line #:	# 3 Algoma	*Test Date*	10-Nov-09	*Record No.:*	43	*Pole ID:*	9
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	85		
Install Date	1963	*Pole species:*	WC	*Treatment Length:*	Butt	*Treatment Type*	Creo
Overall Pole Condition	ir to P	*Pole Diameter (in)*	18	*Pole Strength at GL (psi)*	4130		
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	4	*# of large wood pecker holes:*	1		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	Yes	*Insecticide used?*	Yes
Comments:							
Probable Remaining Life (yrs):	2						
Other Comments:	Remaining life 2 years						
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	44	Pole ID:	9
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	19	Pole Strength at GL (psi)	4680		

Mechanical Condition: Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL -

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments:

Probable Remaining Life (yrs): 8

Other Comments:

Recommendations: RG Tested Ok

Table 8A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	10-Nov-09	Record No.:	45	Pole ID:	10
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition		Pole Diameter (in)	17	Pole Strength at GL (psi)	5090		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Slight, Internal Decay - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	2	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	7						
Other Comments:	Pole in pavement, Moderate wood loss/shell rot						
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	46	Pole ID:	10
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	19	Pole Strength at GL (psi)	4860		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Moderate wood loss/shell rot, Remaining life 2 years

Recommendations: RG Tested Ok

Table 8A: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	47	Pole ID:	10
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	18	Pole Strength at GL (psi)	4910		

Mechanical Condition Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL -

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments:

Probable Remaining Life (yrs): 8

Other Comments: Pole in pavement

Recommendations: RG Tested Ok

Table 8A: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	48	Pole ID:	10
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	20	Pole Strength at GL (psi)	4770		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Pole in pavement, Moderate wood loss/shell rot, Remaining life 2 years

Recommendations: RG Tested Ok

Table 8A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	10-Nov-09	Record No.:	49	Pole ID:	11
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	19	Pole Strength at GL (psi)	4820		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Extensive, Surface Rot below GL - Moderat						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:	Climbing Inspection Required						
Probable Remaining Life (yrs):	2						
Other Comments:	Remaining life 2 years						
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	50	Pole ID:	11
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	18	Pole Strength at GL (psi)	4880		

Mechanical Condition: Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Mo

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments: Bend in Pole

Probable Remaining Life (yrs): 8

Other Comments:

Recommendations: RG Tested Ok

Table 8A: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	51	Pole ID:	11
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	18	Pole Strength at GL (psi)	4550		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Mo						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	9						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	52	Pole ID:	11
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	18	Pole Strength at GL (psi)	4670		
Mechanical Condition	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL -						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	8						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	3 1 Algoma	Test Date	10-Nov-09	Record No.:	53	Pole ID:	12
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to P(	Pole Diameter (in)	17	Pole Strength at GL (psi)	4980		

Mechanical Condition: Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Mo

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments:

Probable Remaining Life (yrs): 8

Other Comments:

Recommendations: RG Tested Ok

Table 8A: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	54	Pole ID:	12
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	17	Pole Strength at GL (psi)	4600		

Mechanical Condition Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL -

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments:

Probable Remaining Life (yrs): 9

Other Comments:

Recommendations: RG Tested Ok

Table 8A: Individual Pole Records

Line #:	# 3 Algoma	*Test Date*	10-Nov-09	*Record No.:*	55	*Pole ID:*	12
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	85		
Install Date	1963	*Pole species:*	WC	*Treatment Length:*	Butt	*Treatment Type*	Creo
Overall Pole Condition	ir to Po	*Pole Diameter (in)*	21	*Pole Strength at GL (psi)*	4120		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/

# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	Yes	*Insecticide used?*	Yes

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Remaining life 2 years

Recommendations: RG Tested Ok

Table 8A: Individual Pole Records

Line #:	Northern Ave	*Test Date*	10-Nov-09	*Record No.:*	56	*Pole ID:*	12
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	85		
Install Date	1963	*Pole species:*	WC	*Treatment Length:*	Butt	*Treatment Type*	Creo
Overall Pole Condition	Poor	*Pole Diameter (in)*	19	*Pole Strength at GL (psi)*			
Mechanical Condition	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	No	*Copper used?*	Yes	*Insecticide used?*	Yes
Comments:							
Probable Remaining Life (yrs):							
Other Comments:							
Recommendations:	Replace in 2010						

Table 8A: Individual Pole Records

Line #:	# 1 Algoma	Test Date	10-Nov-09	Record No.:	57	Pole ID:	13
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Pc	Pole Diameter (in)	18	Pole Strength at GL (psi)	5060		

Mechanical Condition: Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL -

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments:

Probable Remaining Life (yrs): 7

Other Comments:

Recommendations: RG Tested Ok

Table 8A: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	58	Pole ID:	13
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to P(	Pole Diameter (in)	19	Pole Strength at GL (psi)	5170		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Mo						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:	Bend in Pole						
Probable Remaining Life (yrs):	7						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	# 3 Algoma	*Test Date*	10-Nov-09	*Record No.:*	59	*Pole ID:*	13
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	85		
Install Date	1963	*Pole species:*	WC	*Treatment Length:*	Butt	*Treatment Type*	Creo
Overall Pole Condition	ir to Po	*Pole Diameter (in)*	17	*Pole Strength at GL (psi)*	4990		

Mechanical Condition Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot

# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	0

Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	Yes	*Insecticide used?*	Yes

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Remaining life 2 years

Recommendations: RG Tested Ok

Table 8A: Individual Pole Records

Line #:	Northern Avenue	Test Date	10-Nov-09	Record No.:	60	Pole ID:	13
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	18	Pole Strength at GL (psi)	5010		
Mechanical Condition	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL -						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	7						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	61	Pole ID:	14
Private Property:	No	Pole Class:	2	Pole Ht (ft):	90		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Pc	Pole Diameter (in)	21	Pole Strength at GL (psi)	4800		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Mo						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	8						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	62	Pole ID:	14
Private Property:	No	Pole Class:	2	Pole Ht (ft):	90		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Pc	Pole Diameter (in)	18	Pole Strength at GL (psi)	4670		
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes
Comments:							
Probable Remaining Life (yrs):	2						
Other Comments:	Remaining life 2 years						
Recommendations:	RG Tested Ok						

Table 8A: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	63	Pole ID:	15
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Poor	Pole Diameter (in)	18	Pole Strength at GL (psi)			
Mechanical Condition	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	No	Copper used?	Yes	Insecticide used?	Yes
Comments:	Guy guard required						
Probable Remaining Life (yrs):							
Other Comments:							
Recommendations:	RG Tested, Replace in 2010						

Table 8A: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	64	Pole ID:	15
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Poor	Pole Diameter (in)	19	Pole Strength at GL (psi)			
Mechanical Condition	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot -						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	No	Copper used?	Yes	Insecticide used?	Yes
Comments:	Guy guard required						
Probable Remaining Life (yrs):							
Other Comments:							
Recommendations:	RG Tested, Replace in 2010						

Table 8A: Individual Pole Records

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	10-Nov-09	Record No.:	1	Pole ID:	1 Right
Private Property:	No	Pole Class:	2	Pole Ht (ft):	60		
Install Date	1964	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	17	Pole Strength at GL (psi)	4210		

Mechanical Condition: Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Internal Decay - Moderate

# of broken/chipped insulators	0	# of small wood pecker holes:	5	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments: Guy guard required, Slack Guy Wire

Probable Remaining Life (yrs): 8

Other Comments:

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	**Test Date**	10-Nov-09	**Record No.:**	2	**Pole ID:**	1 Centre
Private Property:	No	**Pole Class:**	2	**Pole Ht (ft):**	60		
Install Date	1964	**Pole species:**	WC	**Treatment Length:**	Full	**Treatment Type**	Penta
Overall Pole Condition	Fair	**Pole Diameter (in)**	14	**Pole Strength at GL (psi)**	4450		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight						
# of broken/chipped insulators	0	**# of small wood pecker holes:**	0	**# of large wood pecker holes:**	0		
Treatment required ?	Yes	**Rods used ?**	Yes	**Copper used?**	Yes	**Insecticide used?**	No
Comments:	Dip						
Probable Remaining Life (yrs):	12						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	***Test Date***	10-Nov-09	***Record No.:***	3	***Pole ID:***	1 Left
Private Property:	No	***Pole Class:***	2	***Pole Ht (ft):***	60		
Install Date	1964	***Pole species:***	WC	***Treatment Length:***	Full	***Treatment Type***	Penta
Overall Pole Condition	Fair	***Pole Diameter (in)***	14	***Pole Strength at GL (psi)***	5260		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Internal Decay - Slight, Guying (slack, broken, buried) - slight						
# of broken/chipped insulators	0	***# of small wood pecker holes:***	0	***# of large wood pecker holes:***	0		
Treatment required ?	Yes	***Rods used ?***	Yes	***Copper used?***	Yes	***Insecticide used?***	No
Comments:							
Probable Remaining Life (yrs):	12						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	4	Pole ID:	1 Right
Private Property:	No	Pole Class:	2	Pole Ht (ft):	60		
Install Date	2005	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	16	Pole Strength at GL (psi)	5340		
Mechanical Condition							
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	No	Rods used ?		Copper used?		Insecticide used?	
Comments:							
Probable Remaining Life (yrs):	40						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	5	Pole ID:	1 Centre
Private Property:	No	Pole Class:	2	Pole Ht (ft):	60		
Install Date	2005	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	16	Pole Strength at GL (psi)	4920		
Mechanical Condition							
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	No	Rods used ?		Copper used?		Insecticide used?	
Comments:							
Probable Remaining Life (yrs):	41						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 2Algoma	Test Date	10-Nov-09	Record No.:	6	Pole ID:	1 Left
Private Property:	No	Pole Class:	2	Pole Ht (ft):	60		
Install Date	2005	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	17	Pole Strength at GL (psi)	5120		
Mechanical Condition							
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	No	Rods used ?		Copper used?		Insecticide used?	
Comments:							
Probable Remaining Life (yrs):	40						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	***Test Date***	10-Nov-09	***Record No.:***	7	***Pole ID:***	1 Right
Private Property:	No	***Pole Class:***	2	***Pole Ht (ft):***	60		
Install Date	2005	***Pole species:***	WC	***Treatment Length:***	Full	***Treatment Type***	CCA
Overall Pole Condition	Good	***Pole Diameter (in)***	16	***Pole Strength at GL (psi)***	5100		
Mechanical Condition							
# of broken/chipped insulators	0	***# of small wood pecker holes:***	0	***# of large wood pecker holes:***	0		
Treatment required ?	No	***Rods used ?***		***Copper used?***		***Insecticide used?***	
Comments:							
Probable Remaining Life (yrs):	40						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	8	Pole ID:	1 Centre
Private Property:	No	Pole Class:	2	Pole Ht (ft):	60		
Install Date	2005	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	15	Pole Strength at GL (psi)	4870		
Mechanical Condition							
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	No	Rods used ?		Copper used?		Insecticide used?	
Comments:							
Probable Remaining Life (yrs):	41						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	9	Pole ID:	1 Left
Private Property:	No	Pole Class:	2	Pole Ht (ft):	60		
Install Date	2005	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition		Pole Diameter (in)	16	Pole Strength at GL (psi)	5090		
Mechanical Condition							
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	No	Rods used ?		Copper used?		Insecticide used?	
Comments:							
Probable Remaining Life (yrs):	40						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	10	Pole ID:	1 Right
Private Property:	No	Pole Class:	2	Pole Ht (ft):	60		
Install Date	1964	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition		Pole Diameter (in)	14	Pole Strength at GL (psi)	4780		

Mechanical Condition: Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments:

Probable Remaining Life (yrs): 12

Other Comments:

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	11	Pole ID:	1 Centre
Private Property:	No	Pole Class:	2	Pole Ht (ft):	60		
Install Date	1960	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	15	Pole Strength at GL (psi)	4640		

Mechanical Condition: Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Mo

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments:

Probable Remaining Life (yrs): 9

Other Comments:

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	12	Pole ID:	1 Left
Private Property:	No	Pole Class:	2	Pole Ht (ft):	60		
Install Date	1960	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	16	Pole Strength at GL (psi)	4810		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Mo						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	8						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	**Test Date**	10-Nov-09	**Record No.:**	13	**Pole ID:**	2
Private Property:	No	**Pole Class:**	2	**Pole Ht (ft):**	65		
Install Date	1964	**Pole species:**	WC	**Treatment Length:**	Butt	**Treatment Type**	Creo
Overall Pole Condition	Poor	**Pole Diameter (in)**	16	**Pole Strength at GL (psi)**			
Mechanical Condition	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot -						
# of broken/chipped insulators	0	**# of small wood pecker holes:**	3	**# of large wood pecker holes:**	0		
Treatment required ?	Yes	**Rods used ?**	No	**Copper used?**	Yes	**Insecticide used?**	Yes
Comments:							
Probable Remaining Life (yrs):							
Other Comments:							
Recommendations:	Replace in 2010						

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	14	Pole ID:	2
Private Property:	No	Pole Class:	2	Pole Ht (ft):	65		
Install Date	1964	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Poor	Pole Diameter (in)	16	Pole Strength at GL (psi)			
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/						
# of broken/chipped insulators	0	# of small wood pecker holes:	2	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	No	Copper used?	Yes	Insecticide used?	Yes
Comments:							
Probable Remaining Life (yrs):							
Other Comments:							
Recommendations:	Replace in 2010						

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	*Test Date*	10-Nov-09	*Record No.:*	15	*Pole ID:*	2
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	65		
Install Date	1964	*Pole species:*	WC	*Treatment Length:*	Butt	*Treatment Type*	Creo
Overall Pole Condition	Poor	*Pole Diameter (in)*	15	*Pole Strength at GL (psi)*			
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	No	*Copper used?*	Yes	*Insecticide used?*	Yes
Comments:							
Probable Remaining Life (yrs):							
Other Comments:							
Recommendations:	Replace in 2010						

Table 8C: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	16	Pole ID:	2
Private Property:	No	Pole Class:	2	Pole Ht (ft):	65		
Install Date	1964	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Fair	Pole Diameter (in)	16	Pole Strength at GL (psi)	5060		

Mechanical Condition: Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Modera

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments:

Probable Remaining Life (yrs): 5

Other Comments:

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	10-Nov-09	Record No.:	17	Pole ID:	3
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1964	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	16	Pole Strength at GL (psi)	4900		

Mechanical Condition: Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Mo

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments: Bend in Pole, Guy guard required

Probable Remaining Life (yrs): 5

Other Comments:

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	18	Pole ID:	3
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1964	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Fair	Pole Diameter (in)	15	Pole Strength at GL (psi)	5180		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight,						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	7						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	19	Pole ID:	3
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1964	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	16	Pole Strength at GL (psi)	4790		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot

# of broken/chipped insulators	0	# of small wood pecker holes:	6	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments: Guy guard required

Probable Remaining Life (yrs): 2

Other Comments: Remaining life 2 years

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	Northern Ave
Test Date	10-Nov-09
Record No.:	20
Pole ID:	3
Private Property:	No
Pole Class:	2
Pole Ht (ft):	85
Install Date	1964
Pole species:	WC
Treatment Length:	Butt
Treatment Type	Creo
Overall Pole Condition	Fair
Pole Diameter (in)	16
Pole Strength at GL (psi)	5010
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slig
# of broken/chipped insulators	0
# of small wood pecker holes:	8
# of large wood pecker holes:	2
Treatment required ?	Yes
Rods used ?	Yes
Copper used?	Yes
Insecticide used?	No
Comments:	Guy guard required
Probable Remaining Life (yrs):	7
Other Comments:	
Recommendations:	RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	10-Nov-09	Record No.:	21	Pole ID:	4
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1964	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	18	Pole Strength at GL (psi)	4800		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Remaining life 2 years

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	22	Pole ID:	4
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1964	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Fair	Pole Diameter (in)	18	Pole Strength at GL (psi)	5110		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight,						
# of broken/chipped insulators	0	# of small wood pecker holes:	3	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	7						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	*Test Date*	10-Nov-09	*Record No.:*	23	*Pole ID:*	4
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	85		
Install Date	1964	*Pole species:*	WC	*Treatment Length:*	Butt	*Treatment Type*	Creo
Overall Pole Condition	ir to Po	*Pole Diameter (in)*	19	*Pole Strength at GL (psi)*	4770		
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	2	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	Yes	*Insecticide used?*	Yes
Comments:							
Probable Remaining Life (yrs):	2						
Other Comments:	Remaining life 2 years						
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	24	Pole ID:	4
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1964	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Fair	Pole Diameter (in)	18	Pole Strength at GL (psi)	5130		

Mechanical Condition: Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slig

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments: Guy guard required, Slack Guy Wire

Probable Remaining Life (yrs): 7

Other Comments:

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	10-Nov-09	Record No.:	25	Pole ID:	5
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	18	Pole Strength at GL (psi)	5120		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Remaining life 2 years

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	26	Pole ID:	5
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	19	Pole Strength at GL (psi)	4340		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/

# of broken/chipped insulators	0	# of small wood pecker holes:	3	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Remaining life 2 years

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	27	Pole ID:	5
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Pc	Pole Diameter (in)	18	Pole Strength at GL (psi)	4000		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot

# of broken/chipped insulators	0	# of small wood pecker holes:	10	# of large wood pecker holes:	7

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Remaining life 2 years

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	28	Pole ID:	5
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Poor	Pole Diameter (in)	18	Pole Strength at GL (psi)	4730		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slig						
# of broken/chipped insulators	0	# of small wood pecker holes:	2	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	8						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	*Test Date*	10-Nov-09	*Record No.:*	29	*Pole ID:*	6
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	85		
Install Date	1963	*Pole species:*	WC	*Treatment Length:*	Butt	*Treatment Type*	Creo
Overall Pole Condition	ir to Po	*Pole Diameter (in)*	16	*Pole Strength at GL (psi)*	4880		
Mechanical Condition	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL -						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	Yes	*Insecticide used?*	No
Comments:							
Probable Remaining Life (yrs):	8						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	*Test Date*	10-Nov-09	*Record No.:*	30	*Pole ID:*	6
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	85		
Install Date	1963	*Pole species:*	WC	*Treatment Length:*	Butt	*Treatment Type*	Creo
Overall Pole Condition	ir to Po	*Pole Diameter (in)*	17	*Pole Strength at GL (psi)*	4970		

Mechanical Condition — Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Mo

# of broken/chipped insulators	0	*# of small wood pecker holes:*	3	*# of large wood pecker holes:*	0

Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	Yes	*Insecticide used?*	No

Comments:

Probable Remaining Life (yrs): 8

Other Comments:

Recommendations: RG Tested Ok

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Table 8C: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	31	Pole ID:	6
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Pc	Pole Diameter (in)	17	Pole Strength at GL (psi)	4160		
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/						
# of broken/chipped insulators	0	# of small wood pecker holes:	4	# of large wood pecker holes:	1		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes
Comments:							
Probable Remaining Life (yrs):	2						
Other Comments:	Remaining life 2 years						
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	32	Pole ID:	6
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	18	Pole Strength at GL (psi)	4010		
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot						
# of broken/chipped insulators	0	# of small wood pecker holes:	10	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes
Comments:							
Probable Remaining Life (yrs):	2						
Other Comments:	Remaining life 2 years						
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	10-Nov-09	Record No.:	33	Pole ID:	7
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	18	Pole Strength at GL (psi)	4770		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Mo						
# of broken/chipped insulators	0	# of small wood pecker holes:	4	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:	Dip						
Probable Remaining Life (yrs):	8						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	34	Pole ID:	7
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ır to Pc	Pole Diameter (in)	18	Pole Strength at GL (psi)	4990		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/

# of broken/chipped insulators	0	# of small wood pecker holes:	3	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments: Bend in Pole

Probable Remaining Life (yrs): 2

Other Comments: Remaining life 2 years

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	35	Pole ID:	7
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Poor	Pole Diameter (in)	18	Pole Strength at GL (psi)			

Mechanical Condition: Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot -

# of broken/chipped insulators	0	# of small wood pecker holes:	7	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	No	Copper used?	Yes	Insecticide used?	Yes

Comments:

Probable Remaining Life (yrs):

Other Comments: Moderate wood loss/shell rot

Recommendations: Replace in 2010

Table 8C: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	36	Pole ID:	7
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to P	Pole Diameter (in)	17	Pole Strength at GL (psi)	4560		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/

# of broken/chipped insulators	0	# of small wood pecker holes:	2	# of large wood pecker holes:	1

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Remaining life 2 years

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	10-Nov-09	Record No.:	37	Pole ID:	8
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	18	Pole Strength at GL (psi)	5090		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Mo						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:	Bend in Pole						
Probable Remaining Life (yrs):	7						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	38	Pole ID:	8
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Fair	Pole Diameter (in)	19	Pole Strength at GL (psi)	5220		

Mechanical Condition: Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Modera

# of broken/chipped insulators	0	# of small wood pecker holes:	2	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments:

Probable Remaining Life (yrs): 7

Other Comments:

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	39	Pole ID:	8
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	19	Pole Strength at GL (psi)	4870		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Remaining life 2 years

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	40	Pole ID:	8
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	16	Pole Strength at GL (psi)	4400		
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/						
# of broken/chipped insulators	0	# of small wood pecker holes:	4	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes
Comments:							
Probable Remaining Life (yrs):	2						
Other Comments:	Remaining life 2 years						
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	10-Nov-09	Record No.:	41	Pole ID:	9
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	17	Pole Strength at GL (psi)	5000		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:	Bend in Pole						
Probable Remaining Life (yrs):	5						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	*Test Date*	10-Nov-09	*Record No.:*	42	*Pole ID:*	9
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	85		
Install Date	1963	*Pole species:*	WC	*Treatment Length:*	Butt	*Treatment Type*	Creo
Overall Pole Condition	ir to Po	*Pole Diameter (in)*	19	*Pole Strength at GL (psi)*	5190		

Mechanical Condition Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Mo

# of broken/chipped insulators	0	*# of small wood pecker holes:*	2	*# of large wood pecker holes:*	0

Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	Yes	*Insecticide used?*	No

Comments:

Probable Remaining Life (yrs): 7

Other Comments:

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	43	Pole ID:	9
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	18	Pole Strength at GL (psi)	4130		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/

# of broken/chipped insulators	0	# of small wood pecker holes:	4	# of large wood pecker holes:	1

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Remaining life 2 years

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	44	Pole ID:	9
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	19	Pole Strength at GL (psi)	4680		

Mechanical Condition: Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL -

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments:

Probable Remaining Life (yrs): 8

Other Comments:

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	10-Nov-09	Record No.:	45	Pole ID:	10
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition		Pole Diameter (in)	17	Pole Strength at GL (psi)	5090		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Slight, Internal Decay - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	2	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	7						
Other Comments:	Pole in pavement, Moderate wood loss/shell rot						
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	46	Pole ID:	10
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	19	Pole Strength at GL (psi)	4860		
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes
Comments:							
Probable Remaining Life (yrs):	2						
Other Comments:	Moderate wood loss/shell rot, Remaining life 2 years						
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	47	Pole ID:	10
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	18	Pole Strength at GL (psi)	4910		

Mechanical Condition: Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL -

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments:

Probable Remaining Life (yrs): 8

Other Comments: Pole in pavement

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	48	Pole ID:	10
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	20	Pole Strength at GL (psi)	4770		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Pole in pavement, Moderate wood loss/shell rot, Remaining life 2 years

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	10-Nov-09	Record No.:	49	Pole ID:	11
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	19	Pole Strength at GL (psi)	4820		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Extensive, Surface Rot below GL - Moderat						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:	Climbing Inspection Required						
Probable Remaining Life (yrs):	2						
Other Comments:	Remaining life 2 years						
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	50	Pole ID:	11
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	18	Pole Strength at GL (psi)	4880		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Mo						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:	Bend in Pole						
Probable Remaining Life (yrs):	8						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	51	Pole ID:	11
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	18	Pole Strength at GL (psi)	4550		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Mo						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	9						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	52	Pole ID:	11
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Pc	Pole Diameter (in)	18	Pole Strength at GL (psi)	4670		

Mechanical Condition	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL -

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments:	
Probable Remaining Life (yrs):	8
Other Comments:	
Recommendations:	RG Tested Ok

Table 8C: Individual Pole Records

Line #:	3 1 Algoma	Test Date	10-Nov-09	Record No.:	53	Pole ID:	12
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	17	Pole Strength at GL (psi)	4980		

Mechanical Condition: Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Mo

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments:

Probable Remaining Life (yrs): 8

Other Comments:

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	54	Pole ID:	12
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	17	Pole Strength at GL (psi)	4600		
Mechanical Condition	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL -						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	9						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	55	Pole ID:	12
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Pc	Pole Diameter (in)	21	Pole Strength at GL (psi)	4120		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Remaining life 2 years

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	56	Pole ID:	12
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Poor	Pole Diameter (in)	19	Pole Strength at GL (psi)			
Mechanical Condition	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	No	Copper used?	Yes	Insecticide used?	Yes
Comments:							
Probable Remaining Life (yrs):							
Other Comments:							
Recommendations:	Replace in 2010						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	10-Nov-09	Record No.:	57	Pole ID:	13
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	18	Pole Strength at GL (psi)	5060		

Mechanical Condition: Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL -

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments:

Probable Remaining Life (yrs): 7

Other Comments:

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	Test Date	10-Nov-09	Record No.:	58	Pole ID:	13
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	19	Pole Strength at GL (psi)	5170		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Mo						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:	Bend in Pole						
Probable Remaining Life (yrs):	7						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	59	Pole ID:	13
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	17	Pole Strength at GL (psi)	4990		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Remaining life 2 years

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	Northern Avenue	Test Date	10-Nov-09	Record No.:	60	Pole ID:	13
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	18	Pole Strength at GL (psi)	5010		

Mechanical Condition: Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL -

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments:

Probable Remaining Life (yrs): 7

Other Comments:

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	61	Pole ID:	14
Private Property:	No	Pole Class:	2	Pole Ht (ft):	90		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	21	Pole Strength at GL (psi)	4800		

Mechanical Condition	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Mo

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments:	
Probable Remaining Life (yrs):	8
Other Comments:	
Recommendations:	RG Tested Ok

Table 8C: Individual Pole Records

Line #:	Northern Ave	*Test Date*	10-Nov-09	*Record No.:*	62	*Pole ID:*	14
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	90		
Install Date	1963	*Pole species:*	WC	*Treatment Length:*	Butt	*Treatment Type*	Creo
Overall Pole Condition	ir to P	*Pole Diameter (in)*	18	*Pole Strength at GL (psi)*	4670		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot

# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	Yes	*Insecticide used?*	Yes

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Remaining life 2 years

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	Test Date	10-Nov-09	Record No.:	63	Pole ID:	15
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Poor	Pole Diameter (in)	18	Pole Strength at GL (psi)			
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	No	Copper used?	Yes	Insecticide used?	Yes

Mechanical Condition: Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/

Comments: Guy guard required

Probable Remaining Life (yrs):

Other Comments:

Recommendations: RG Tested, Replace in 2010

Table 8C: Individual Pole Records

Line #:	Northern Ave	Test Date	10-Nov-09	Record No.:	64	Pole ID:	15
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1963	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Poor	Pole Diameter (in)	19	Pole Strength at GL (psi)			
Mechanical Condition	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot -						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	No	Copper used?	Yes	Insecticide used?	Yes
Comments:	Guy guard required						
Probable Remaining Life (yrs):							
Other Comments:							
Recommendations:	RG Tested, Replace in 2010						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	*Test Date*	11-Nov-09	*Record No.:*	65	*Pole ID:*	27R
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	75		
Install Date	1994	*Pole species:*	WC	*Treatment Length:*	Full	*Treatment Type*	CCA
Overall Pole Condition	Fair	*Pole Diameter (in)*	19	*Pole Strength at GL (psi)*	5130		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	1	*# of large wood pecker holes:*	4		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	No	*Insecticide used?*	No
Comments:							
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	66	Pole ID:	27L
Private Property:	No	Pole Class:	2	Pole Ht (ft):	75		
Install Date	1994	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Fair	Pole Diameter (in)	17	Pole Strength at GL (psi)	4650		

Mechanical Condition: Carpenter ants damage - Slight, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	9		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments:

Probable Remaining Life (yrs): 6

Other Comments:

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	67	Pole ID:	28R
Private Property:	No	Pole Class:	2	Pole Ht (ft):	75		
Install Date	1986	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	18	Pole Strength at GL (psi)	5220		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	2		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	35						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	**Test Date**	11-Nov-09	**Record No.:**	68	**Pole ID:**	28L
Private Property:	No	**Pole Class:**	2	**Pole Ht (ft):**	75		
Install Date	1986	**Pole species:**	WC	**Treatment Length:**	Full	**Treatment Type**	Penta
Overall Pole Condition	Fair	**Pole Diameter (in)**	17	**Pole Strength at GL (psi)**	5090		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	**# of small wood pecker holes:**	0	**# of large wood pecker holes:**	6		
Treatment required ?	Yes	**Rods used ?**	Yes	**Copper used?**	No	**Insecticide used?**	No
Comments:							
Probable Remaining Life (yrs):	36						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	69	Pole ID:	29
Private Property:		Pole Class:	4	Pole Ht (ft):	65		
Install Date	1993	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	ir to Po	Pole Diameter (in)	17	Pole Strength at GL (psi)	4710		
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate						
# of broken/chipped insulators	0	# of small wood pecker holes:	1	# of large wood pecker holes:	1		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes
Comments:	Bend in Pole						
Probable Remaining Life (yrs):	4						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	70	Pole ID:	29L
Private Property:	No	Pole Class:	4	Pole Ht (ft):	65		
Install Date	1993	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	ir to Po	Pole Diameter (in)	15	Pole Strength at GL (psi)	5100		
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes
Comments:							
Probable Remaining Life (yrs):	4						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	71	Pole ID:	30
Private Property:	No	Pole Class:	2	Pole Ht (ft):	75		
Install Date	1994	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	19	Pole Strength at GL (psi)	5370		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	2	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	37						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	72	Pole ID:	31
Private Property:	No	Pole Class:	3	Pole Ht (ft):	90		
Install Date	1973	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	17	Pole Strength at GL (psi)	5120		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Bend in Pole, Dip, Joint Use, Lights on Pole						
Probable Remaining Life (yrs):	32						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	73	Pole ID:	32
Private Property:	No	Pole Class:	2	Pole Ht (ft):	80		
Install Date	1995	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	17	Pole Strength at GL (psi)	5290		
Mechanical Condition							
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Dip, Joint Use						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	74	Pole ID:	33
Private Property:	No	Pole Class:	2	Pole Ht (ft):	80		
Install Date	1995	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	18	Pole Strength at GL (psi)	5140		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Bend in Pole, Dip, Joint Use						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma
Test Date	11-Nov-09
Record No.:	75
Pole ID:	34
Private Property:	No
Pole Class:	2
Pole Ht (ft):	80
Install Date	1995
Pole species:	WC
Treatment Length:	Full
Treatment Type	CCA
Overall Pole Condition	Good
Pole Diameter (in)	18
Pole Strength at GL (psi)	5330
Mechanical Condition	
# of broken/chipped insulators	0
# of small wood pecker holes:	0
# of large wood pecker holes:	0
Treatment required ?	Yes
Rods used ?	Yes
Copper used?	No
Insecticide used?	No
Comments:	Joint Use
Probable Remaining Life (yrs):	38
Other Comments:	
Recommendations:	No RG Required, Pole OK

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	76	Pole ID:	35
Private Property:	No	Pole Class:	2	Pole Ht (ft):	80		
Install Date	1995	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	16	Pole Strength at GL (psi)	4980		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Dip, Joint Use						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	77	Pole ID:	36
Private Property:	No	Pole Class:	2	Pole Ht (ft):	80		
Install Date	1995	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	17	Pole Strength at GL (psi)	5200		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Joint Use						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	78	Pole ID:	37
Private Property:	No	Pole Class:	2	Pole Ht (ft):	80		
Install Date	1995	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	18	Pole Strength at GL (psi)	5420		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Dip, Joint Use						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	79	Pole ID:	38
Private Property:	No	Pole Class:	2	Pole Ht (ft):	80		
Install Date	1995	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	17	Pole Strength at GL (psi)	5110		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Joint Use						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	80	Pole ID:	39
Private Property:	No	Pole Class:	2	Pole Ht (ft):	80		
Install Date	1995	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	16	Pole Strength at GL (psi)	4820		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Dip, Joint Use						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	81	Pole ID:	40
Private Property:	No	Pole Class:	2	Pole Ht (ft):	80		
Install Date	1995	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	17	Pole Strength at GL (psi)	5060		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Dip, Joint Use						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	82	Pole ID:	43
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1985	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	22	Pole Strength at GL (psi)	5240		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	35						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	83	Pole ID:	44
Private Property:	No	Pole Class:	2	Pole Ht (ft):	90		
Install Date	1994	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	20	Pole Strength at GL (psi)	5360		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Joint Use, Lights on Pole						
Probable Remaining Life (yrs):	37						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	84	Pole ID:	45
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1972	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	ir to Po	Pole Diameter (in)	17	Pole Strength at GL (psi)	4770		
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes
Comments:	Joint Use, Lights on Pole						
Probable Remaining Life (yrs):	2						
Other Comments:	Remaining life 2 years						
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	85	Pole ID:	46
Private Property:	No	Pole Class:	2	Pole Ht (ft):	80		
Install Date	1995	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	17	Pole Strength at GL (psi)	5380		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Joint Use, Lights on Pole						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	*Test Date*	11-Nov-09	*Record No.:*	86	*Pole ID:*	47
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	80		
Install Date	1995	*Pole species:*	WC	*Treatment Length:*	Full	*Treatment Type*	CCA
Overall Pole Condition	Good	*Pole Diameter (in)*	18	*Pole Strength at GL (psi)*	5100		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	No	*Insecticide used?*	No
Comments:	Joint Use, Lights on Pole						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	87	Pole ID:	48
Private Property:	No	Pole Class:	2	Pole Ht (ft):	80		
Install Date	1995	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	16	Pole Strength at GL (psi)	4860		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Joint Use, Lights on Pole						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	88	Pole ID:	49
Private Property:	No	Pole Class:	2	Pole Ht (ft):	80		
Install Date	1995	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	18	Pole Strength at GL (psi)	5420		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Joint Use, Lights on Pole						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	**Test Date**	11-Nov-09	**Record No.:**	89	**Pole ID:**	50
Private Property:	No	**Pole Class:**	2	**Pole Ht (ft):**	80		
Install Date	1995	**Pole species:**	WC	**Treatment Length:**	Full	**Treatment Type**	CCA
Overall Pole Condition	Good	**Pole Diameter (in)**	19	**Pole Strength at GL (psi)**	5050		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	**# of small wood pecker holes:**	0	**# of large wood pecker holes:**	0		
Treatment required ?	Yes	**Rods used ?**	Yes	**Copper used?**	No	**Insecticide used?**	No
Comments:	Joint Use, Lights on Pole						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	90	Pole ID:	51
Private Property:	No	Pole Class:	2	Pole Ht (ft):	80		
Install Date	1995	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	18	Pole Strength at GL (psi)	5260		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Dip, Joint Use, Lights on Pole						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	91	Pole ID:	52
Private Property:	No	Pole Class:	2	Pole Ht (ft):	80		
Install Date	1995	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	18	Pole Strength at GL (psi)	5400		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Joint Use, Lights on Pole						
Probable Remaining Life (yrs):	38						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 1 Algoma	Test Date	11-Nov-09	Record No.:	92	Pole ID:	53
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1992	Pole species:	WC	Treatment Length:	Full	Treatment Type	CCA
Overall Pole Condition	Good	Pole Diameter (in)	22	Pole Strength at GL (psi)	5240		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Joint Use, Lights on Pole						
Probable Remaining Life (yrs):	36						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	93	Pole ID:	58
Private Property:	Yes	Pole Class:	1	Pole Ht (ft):	80		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	23	Pole Strength at GL (psi)	4910		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 & 3 Algoma	*Test Date*	11-Nov-09	*Record No.:*	94	*Pole ID:*	57
Private Property:	Yes	*Pole Class:*	1	*Pole Ht (ft):*	80		
Install Date	1977	*Pole species:*	WC	*Treatment Length:*	Full	*Treatment Type*	Penta
Overall Pole Condition	ir to Po	*Pole Diameter (in)*	23	*Pole Strength at GL (psi)*	4820		
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Modera						
# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	Yes	*Insecticide used?*	Yes
Comments:							
Probable Remaining Life (yrs):	2						
Other Comments:	Remaining life 2 years						
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	95	Pole ID:	51
Private Property:	Yes	Pole Class:	1	Pole Ht (ft):	80		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	19	Pole Strength at GL (psi)	5070		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	96	Pole ID:	49
Private Property:	No	Pole Class:	1	Pole Ht (ft):	80		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	22	Pole Strength at GL (psi)	5010		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	97	Pole ID:	48
Private Property:	No	Pole Class:	1	Pole Ht (ft):	80		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	22	Pole Strength at GL (psi)	4790		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	98	Pole ID:	46
Private Property:	No	Pole Class:	1	Pole Ht (ft):	80		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Fair	Pole Diameter (in)	22	Pole Strength at GL (psi)	4920		
Mechanical Condition	Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes
Comments:	Guy guard required						
Probable Remaining Life (yrs):	11						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	99	Pole ID:	45
Private Property:	No	Pole Class:	1	Pole Ht (ft):	90		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	24	Pole Strength at GL (psi)	5120		
Mechanical Condition							
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	100	Pole ID:	44
Private Property:	No	Pole Class:	1	Pole Ht (ft):	80		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	18	Pole Strength at GL (psi)	5040		
Mechanical Condition	Cracks - Slight, Ground wire (slack, broken, buried) - extensive						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Slack Guy Wire						
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	101	Pole ID:	43
Private Property:	No	Pole Class:	1	Pole Ht (ft):	75		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	23	Pole Strength at GL (psi)	4930		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	102	Pole ID:	42
Private Property:	No	Pole Class:	1	Pole Ht (ft):	75		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	22	Pole Strength at GL (psi)	4990		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Bend in Pole						
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	103	Pole ID:	41
Private Property:	No	Pole Class:	1	Pole Ht (ft):	75		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	19	Pole Strength at GL (psi)	5240		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Guy guard required, Slack Guy Wire						
Probable Remaining Life (yrs):	33						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	104	Pole ID:	40
Private Property:	No	Pole Class:	1	Pole Ht (ft):	75		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	18	Pole Strength at GL (psi)	5370		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	33						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 & 3 Algoma	***Test Date***	11-Nov-09	***Record No.:***	105	***Pole ID:***	39
Private Property:	No	***Pole Class:***	1	***Pole Ht (ft):***	75		
Install Date	1977	***Pole species:***	WC	***Treatment Length:***	Full	***Treatment Type***	Penta
Overall Pole Condition	Good	***Pole Diameter (in)***	18	***Pole Strength at GL (psi)***	5150		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	***# of small wood pecker holes:***	0	***# of large wood pecker holes:***	0		
Treatment required ?	Yes	***Rods used ?***	Yes	***Copper used?***	No	***Insecticide used?***	No
Comments:	Guy guard required						
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 & 3 Algoma	Test Date	11-Nov-09	Record No.:	106	Pole ID:	38
Private Property:	No	Pole Class:	1	Pole Ht (ft):	75		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	19	Pole Strength at GL (psi)	5300		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	33						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	Test Date	11-Nov-09	Record No.:	107	Pole ID:	36
Private Property:	No	Pole Class:	1	Pole Ht (ft):	75		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	18	Pole Strength at GL (psi)	4900		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	Test Date	11-Nov-09	Record No.:	108	Pole ID:	35
Private Property:	No	Pole Class:	1	Pole Ht (ft):	80		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Fair	Pole Diameter (in)	20	Pole Strength at GL (psi)	4780		
Mechanical Condition	Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	11						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #: # 2 Algoma | Test Date 11-Nov-09 | Record No.: 109 | Pole ID: 34

Private Property: No | Pole Class: 1 | Pole Ht (ft): 90

Install Date 1977 | Pole species: WC | Treatment Length: Full | Treatment Type Penta

Overall Pole Condition Good | Pole Diameter (in) 22 | Pole Strength at GL (psi) 5080

Mechanical Condition: Cracks - Slight

# of broken/chipped insulators 0 | # of small wood pecker holes: 0 | # of large wood pecker holes: 0

Treatment required ? Yes | Rods used ? Yes | Copper used? No | Insecticide used? No

Comments:

Probable Remaining Life (yrs): 34

Other Comments:

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	Test Date	11-Nov-09	Record No.:	110	Pole ID:	33
Private Property:	No	Pole Class:	1	Pole Ht (ft):	90		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	22	Pole Strength at GL (psi)	5270		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	33						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	Test Date	11-Nov-09	Record No.:	111	Pole ID:	32
Private Property:	No	Pole Class:	1	Pole Ht (ft):	90		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	23	Pole Strength at GL (psi)	5160		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	Test Date	11-Nov-09	Record No.:	112	Pole ID:	31
Private Property:	No	Pole Class:	1	Pole Ht (ft):	80		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Fair	Pole Diameter (in)	23	Pole Strength at GL (psi)	4940		
Mechanical Condition	Cracks - Moderate, Pole top feathering/split/rot - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Dip						
Probable Remaining Life (yrs):	33						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	Test Date	11-Nov-09	Record No.:	113	Pole ID:	30
Private Property:	No	Pole Class:	1	Pole Ht (ft):	70		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Good	Pole Diameter (in)	18	Pole Strength at GL (psi)	5200		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:							
Probable Remaining Life (yrs):	33						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	Test Date	11-Nov-09	Record No.:	114	Pole ID:	29
Private Property:	No	Pole Class:	1	Pole Ht (ft):	70		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	ir to Po	Pole Diameter (in)	22	Pole Strength at GL (psi)	4520		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Modera

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Remaining life 2 years

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	**Test Date**	11-Nov-09	**Record No.:**	115	**Pole ID:**	28
Private Property:	No	**Pole Class:**	2	**Pole Ht (ft):**	75		
Install Date	1994	**Pole species:**	WC	**Treatment Length:**	Full	**Treatment Type**	CCA
Overall Pole Condition	Good	**Pole Diameter (in)**	17	**Pole Strength at GL (psi)**	5330		
Mechanical Condition	Cracks - Slight						
# of broken/chipped insulators	0	**# of small wood pecker holes:**	0	**# of large wood pecker holes:**	1		
Treatment required ?	Yes	**Rods used ?**	Yes	**Copper used?**	No	**Insecticide used?**	No
Comments:							
Probable Remaining Life (yrs):	37						
Other Comments:							
Recommendations:	No RG Required, Pole OK						

Table 8C: Individual Pole Records

Line #:	# 2 Algoma	Test Date	11-Nov-09	Record No.:	116	Pole ID:	27
Private Property:	No	Pole Class:	1	Pole Ht (ft):	85		
Install Date	1977	Pole species:	WC	Treatment Length:	Full	Treatment Type	Penta
Overall Pole Condition	Fair	Pole Diameter (in)	22	Pole Strength at GL (psi)	5030		
Mechanical Condition	Cracks - Moderate						
# of broken/chipped insulators	0	# of small wood pecker holes:	3	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	No	Insecticide used?	No
Comments:	Pole in water						
Probable Remaining Life (yrs):	34						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	Test Date	11-Nov-09	Record No.:	117	Pole ID:	17
Private Property:	No	Pole Class:	2	Pole Ht (ft):	85		
Install Date	1960	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	20	Pole Strength at GL (psi)	4410		

Mechanical Condition: Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL -

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	No

Comments: Joint Use

Probable Remaining Life (yrs): 4

Other Comments:

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	Test Date	11-Nov-09	Record No.:	118	Pole ID:	18
Private Property:	Yes	Pole Class:	1	Pole Ht (ft):	75		
Install Date	1955	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Poor	Pole Diameter (in)	20	Pole Strength at GL (psi)			
Mechanical Condition	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot -						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	No	Copper used?	Yes	Insecticide used?	Yes
Comments:	Ground Guard Required, Joint Use, Pole in water						
Probable Remaining Life (yrs):							
Other Comments:	Transformer on pole						
Recommendations:	Replace in 2010						

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	Test Date	11-Nov-09	Record No.:	119	Pole ID:	19
Private Property:	Yes	Pole Class:	1	Pole Ht (ft):	75		
Install Date	1955	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Poor	Pole Diameter (in)	20	Pole Strength at GL (psi)			
Mechanical Condition	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot -						
# of broken/chipped insulators	0	# of small wood pecker holes:	7	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	No	Copper used?	Yes	Insecticide used?	Yes
Comments:	Joint Use, Pole in water						
Probable Remaining Life (yrs):							
Other Comments:	Transformer on pole						
Recommendations:	Replace in 2010						

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	Test Date	11-Nov-09	Record No.:	120	Pole ID:	20
Private Property:	Yes	Pole Class:	1	Pole Ht (ft):	75		
Install Date	1955	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Poor	Pole Diameter (in)	20	Pole Strength at GL (psi)			

Mechanical Condition: Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot -

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0

Treatment required ?	Yes	Rods used ?	No	Copper used?	Yes	Insecticide used?	Yes

Comments: Dip, Joint Use, Pole in water

Probable Remaining Life (yrs):

Other Comments:

Recommendations: Replace in 2010

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	Test Date	11-Nov-09	Record No.:	121	Pole ID:	21
Private Property:	No	Pole Class:	1	Pole Ht (ft):	75		
Install Date	1955	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	Poor	Pole Diameter (in)	20	Pole Strength at GL (psi)			

Mechanical Condition: Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot -

# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	1

Treatment required ?	Yes	Rods used ?	No	Copper used?	Yes	Insecticide used?	Yes

Comments: Dip, Joint Use

Probable Remaining Life (yrs):

Other Comments: Transformer on pole

Recommendations: Replace in 2010

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	Test Date	11-Nov-09	Record No.:	122	Pole ID:	22
Private Property:	No	Pole Class:	1	Pole Ht (ft):	75		
Install Date	1955	Pole species:	WC	Treatment Length:	Butt	Treatment Type	Creo
Overall Pole Condition	ir to Po	Pole Diameter (in)	20	Pole Strength at GL (psi)	4840		
Mechanical Condition	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot						
# of broken/chipped insulators	0	# of small wood pecker holes:	0	# of large wood pecker holes:	0		
Treatment required ?	Yes	Rods used ?	Yes	Copper used?	Yes	Insecticide used?	Yes
Comments:	Joint Use						
Probable Remaining Life (yrs):	2						
Other Comments:	Remaining life 2 years						
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	*Test Date*	11-Nov-09	*Record No.:*	123	*Pole ID:*	32
Private Property:	No	*Pole Class:*	2	*Pole Ht (ft):*	75		
Install Date	1955	*Pole species:*	WC	*Treatment Length:*	Butt	*Treatment Type*	Creo
Overall Pole Condition	ir to Po	*Pole Diameter (in)*	16	*Pole Strength at GL (psi)*	4370		

Mechanical Condition: Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot

# of broken/chipped insulators	0	*# of small wood pecker holes:*	0	*# of large wood pecker holes:*	0		
Treatment required ?	Yes	*Rods used ?*	Yes	*Copper used?*	No	*Insecticide used?*	No

Comments:

Probable Remaining Life (yrs): 2

Other Comments: Remaining life 2 years

Recommendations: RG Tested Ok

Table 8C: Individual Pole Records

Line #:	# 3 Algoma	***Test Date***	11-Nov-09	***Record No.:***	124	***Pole ID:***	33
Private Property:	Yes	***Pole Class:***	3	***Pole Ht (ft):***	75		
Install Date	1972	***Pole species:***	WC	***Treatment Length:***	Full	***Treatment Type***	Penta
Overall Pole Condition	Fair	***Pole Diameter (in)***	16	***Pole Strength at GL (psi)***	5020		
Mechanical Condition	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Internal Decay - Slight						
# of broken/chipped insulators	0	***# of small wood pecker holes:***	0	***# of large wood pecker holes:***	0		
Treatment required ?	Yes	***Rods used ?***	Yes	***Copper used?***	No	***Insecticide used?***	No
Comments:							
Probable Remaining Life (yrs):	14						
Other Comments:							
Recommendations:	RG Tested Ok						

Table 8C: Individual Pole Records

Table 2A: Poles for Replacement

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 1 Algoma	2	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	13
# 2 Algoma	2	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	14
# 3 Algoma	2	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	15
# 3 Algoma	7	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	35
# 3 Algoma	15	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	RG Tested, Replace in 2010	63
Northern Ave	12	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	56
Northern Ave	15	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	RG Tested, Replace in 2010	64

Table 2A: Page 1 of 1

Table 2A: Poles for Replacement

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 3 Algoma	18	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Ground Guard Required, Joint Use, Pole in water	Replace in 2010	118
# 3 Algoma	19	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Joint Use, Pole in water	Replace in 2010	119
# 3 Algoma	20	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use, Pole in water	Replace in 2010	120
# 3 Algoma	21	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use	Replace in 2010	121

Table 2C: Poles for Replacement

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 1 Algoma	2	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	13
# 2 Algoma	2	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	14
# 3 Algoma	2	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	15
# 3 Algoma	7	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	35
# 3 Algoma	15	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	RG Tested, Replace in 2010	63
# 3 Algoma	18	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Ground Guard Required, Joint Use, Pole in water	Replace in 2010	118
# 3 Algoma	19	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Joint Use, Pole in water	Replace in 2010	119

Table 2C: Page 1 of 2

Table 2C: Poles for Replacement

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 3 Algoma	20	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use, Pole in water	Replace in 2010	120
# 3 Algoma	21	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use	Replace in 2010	121
Northern Ave	12	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	56
Northern Ave	15	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	RG Tested, Replace in 2010	64

Table 3A: Poles Affected by Carpenter Ants

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 1 Algoma	2	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	13
# 1 Algoma	4	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	21
# 1 Algoma	5	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Moderate, Guying (slack, broken, buried) - slight		RG Tested Ok	25
# 2 Algoma	2	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	14
# 2 Algoma	5	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	26
# 2 Algoma	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate	Bend in Pole	RG Tested Ok	34
# 2 Algoma	10	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	46
# 3 Algoma	2	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	15
# 3 Algoma	3	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Guy guard required	RG Tested Ok	19

Table 3A: Poles Affected by Carpenter Ants

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 3 Algoma	4	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate, Guying (slack, broken, buri		RG Tested Ok	23
# 3 Algoma	5	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	27
# 3 Algoma	6	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	31
# 3 Algoma	7	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	35
# 3 Algoma	8	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	39
# 3 Algoma	9	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	43
# 3 Algoma	12	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	55
# 3 Algoma	13	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	59
# 3 Algoma	15	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	RG Tested, Replace in 2010	63
Northern Ave	6	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	32

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Table 3A: Poles Affected by Carpenter Ants

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
Northern Ave	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	36
Northern Ave	8	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	40
Northern Ave	10	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate, Guying (slack, broken, buried) - extensive		RG Tested Ok	48
Northern Ave	12	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	56
Northern Ave	14	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	62
Northern Ave	15	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	RG Tested, Replace in 2010	64

Table 3A: Poles Affected by Carpenter Ants

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 1 Algoma	27L	Carpenter ants damage - Slight, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	66
# 1 Algoma	29	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Bend in Pole	RG Tested Ok	69
# 1 Algoma	29L	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	70
# 1 Algoma	45	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Joint Use, Lights on Pole	RG Tested Ok	84
# 2 & 3 Algoma	57	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	94
# 2 Algoma	29	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	114
# 3 Algoma	18	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Ground Guard Required, Joint Use, Pole in water	Replace in 2010	118
# 3 Algoma	19	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Joint Use, Pole in water	Replace in 2010	119
# 3 Algoma	20	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use, Pole in water	Replace in 2010	120
# 3 Algoma	21	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use	Replace in 2010	121
# 3 Algoma	22	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Moderate	Joint Use	RG Tested Ok	122

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Table 3A: Poles Affected by Carpenter Ants

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 3 Algoma	32	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	123

Table 3C: Poles Affected by Carpenter Ants

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 1 Algoma	2	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	13
# 1 Algoma	4	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	21
# 1 Algoma	5	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Moderate, Guying (slack, broken, buried) - slight		RG Tested Ok	25
# 1 Algoma	27L	Carpenter ants damage - Slight, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	66
# 1 Algoma	29	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Bend in Pole	RG Tested Ok	69
# 1 Algoma	29L	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	70
# 1 Algoma	45	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Joint Use, Lights on Pole	RG Tested Ok	84
# 2 & 3 Algoma	57	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	94
# 2 Algoma	2	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	14
# 2 Algoma	5	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	26
# 2 Algoma	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate	Bend in Pole	RG Tested Ok	34

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Table 3C: Poles Affected by Carpenter Ants

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 2 Algoma	10	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	46
# 2 Algoma	29	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	114
# 3 Algoma	2	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	15
# 3 Algoma	3	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Guy guard required	RG Tested Ok	19
# 3 Algoma	4	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate, Guying (slack, broken, buri		RG Tested Ok	23
# 3 Algoma	5	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	27
# 3 Algoma	6	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	31
# 3 Algoma	7	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	35
# 3 Algoma	8	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	39
# 3 Algoma	9	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	43

Table 3C: Poles Affected by Carpenter Ants

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 3 Algoma	12	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	55
# 3 Algoma	13	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	59
# 3 Algoma	15	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	RG Tested, Replace in 2010	63
# 3 Algoma	18	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Ground Guard Required, Joint Use, Pole in water	Replace in 2010	118
# 3 Algoma	19	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Joint Use, Pole in water	Replace in 2010	119
# 3 Algoma	20	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use, Pole in water	Replace in 2010	120
# 3 Algoma	21	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use	Replace in 2010	121
# 3 Algoma	22	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Moderate	Joint Use	RG Tested Ok	122
# 3 Algoma	32	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	123
Northern Ave	6	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	32

Table 3C: Poles Affected by Carpenter Ants

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
Northern Ave	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	36
Northern Ave	8	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	40
Northern Ave	10	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate, Guying (slack, broken, buried) - extensive		RG Tested Ok	48
Northern Ave	12	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	56
Northern Ave	14	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	62
Northern Ave	15	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	RG Tested, Replace in 2010	64

Table 4A: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 1 Algoma	1 Right	Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Internal Decay - Moderate	Guy guard required, Slack Guy Wire	Yes	Yes	Yes	No	1
# 1 Algoma	1 Centre	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight	Dip	Yes	Yes	Yes	No	2
# 1 Algoma	1 Left	Cracks - Slight, Decay pockets at GL - Slight, Internal Decay - Slight, Guying (slack, broken, buried) - slight		Yes	Yes	Yes	No	3
# 1 Algoma	2	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Yes	No	Yes	Yes	13
# 1 Algoma	3	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight, Guying (slack, broken, buried) - moderate	Bend in Pole, Guy guard required	Yes	Yes	Yes	No	17

Table 4A: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 1 Algoma	4	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	21
# 1 Algoma	5	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Moderate, Guying (slack, broken, buried) - slight		Yes	Yes	Yes	Yes	25
# 1 Algoma	6	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	29
# 1 Algoma	7	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Dip	Yes	Yes	Yes	No	33
# 1 Algoma	8	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Bend in Pole	Yes	Yes	Yes	No	37

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Table 4A: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 1 Algoma	9	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight	Bend in Pole	Yes	Yes	Yes	No	41
# 1 Algoma	10	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Slight, Internal Decay - Slight		Yes	Yes	Yes	No	45
# 1 Algoma	11	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Extensive, Surface Rot below GL - Moderate, Internal Decay - Slight	Climbing Inspection Required	Yes	Yes	Yes	No	49
# 1 Algoma	13	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	57
# 2 Algoma	2	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Yes	No	Yes	Yes	14

Table 4A: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 2 Algoma	3	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Slight		Yes	Yes	Yes	No	18
# 2 Algoma	4	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Slight		Yes	Yes	Yes	No	22
# 2 Algoma	5	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	26
# 2 Algoma	6	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	30
# 2 Algoma	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate	Bend in Pole	Yes	Yes	Yes	Yes	34

Table 4A: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 2 Algoma	8	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	38
# 2 Algoma	9	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	42
# 2 Algoma	10	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	46
# 2 Algoma	11	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Bend in Pole	Yes	Yes	Yes	No	50
# 2 Algoma	12	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	54

Table 4A: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 2 Algoma	13	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight, Guying (slack, broken, buried) - extensive	Bend in Pole	Yes	Yes	Yes	No	58
# 3 Algoma	2	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Yes	No	Yes	Yes	15
# 3 Algoma	3	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Guy guard required	Yes	Yes	Yes	Yes	19
# 3 Algoma	4	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate, Guying (slack, broken, buri		Yes	Yes	Yes	Yes	23

Table 4A: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 3 Algoma	5	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	27
# 3 Algoma	6	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	31
# 3 Algoma	7	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Yes	No	Yes	Yes	35
# 3 Algoma	8	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	39

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Table 4A: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 3 Algoma	9	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	43
# 3 Algoma	10	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	47
# 3 Algoma	11	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	51
# 3 Algoma	12	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	55

Table 4A: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 3 Algoma	13	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	59
# 3 Algoma	14	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	61
# 3 Algoma	15	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	Yes	No	Yes	Yes	63
3 1 Algoma	12	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	53
Northern Ave	1 Right	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	10

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Table 4A: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
Northern Ave	1 Centre	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	11
Northern Ave	1 Left	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	12
Northern Ave	2	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	16
Northern Ave	3	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Internal Decay - Slight	Guy guard required	Yes	Yes	Yes	No	20
Northern Ave	4	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Internal Decay - Slight	Guy guard required, Slack Guy Wire	Yes	Yes	Yes	No	24
Northern Ave	5	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Internal Decay - Slight		Yes	Yes	Yes	No	28

Table 4A: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
Northern Ave	6	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	32
Northern Ave	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	36
Northern Ave	8	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	40
Northern Ave	9	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	44

Table 4A: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
Northern Ave	10	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate, Guying (slack, broken, buried) - extensive		Yes	Yes	Yes	Yes	48
Northern Ave	11	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	52
Northern Ave	12	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Yes	No	Yes	Yes	56
Northern Ave	14	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	62

Table 4A: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
Northern Ave	15	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	Yes	No	Yes	Yes	64
Northern Avenue	13	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	60

Table 4A: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 1 Algoma	27R	Cracks - Slight		Yes	Yes	No	No	65
# 1 Algoma	27L	Carpenter ants damage - Slight, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	66
# 1 Algoma	28R	Cracks - Slight		Yes	Yes	No	No	67
# 1 Algoma	28L	Cracks - Slight		Yes	Yes	No	No	68
# 1 Algoma	29	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Bend in Pole	Yes	Yes	Yes	Yes	69
# 1 Algoma	29L	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	70
# 1 Algoma	30	Cracks - Slight		Yes	Yes	No	No	71
# 1 Algoma	31	Cracks - Slight	Bend in Pole, Dip, Joint Use, Lights on Pole	Yes	Yes	No	No	72
# 1 Algoma	32		Dip, Joint Use	Yes	Yes	No	No	73
# 1 Algoma	33	Cracks - Slight	Bend in Pole, Dip, Joint Use	Yes	Yes	No	No	74
# 1 Algoma	34		Joint Use	Yes	Yes	No	No	75

Table 4A: Page 1 of 6

Table 4A: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 1 Algoma	35	Cracks - Slight	Dip, Joint Use	Yes	Yes	No	No	76
# 1 Algoma	36	Cracks - Slight	Joint Use	Yes	Yes	No	No	77
# 1 Algoma	37	Cracks - Slight	Dip, Joint Use	Yes	Yes	No	No	78
# 1 Algoma	38	Cracks - Slight	Joint Use	Yes	Yes	No	No	79
# 1 Algoma	39	Cracks - Slight	Dip, Joint Use	Yes	Yes	No	No	80
# 1 Algoma	40	Cracks - Slight	Dip, Joint Use	Yes	Yes	No	No	81
# 1 Algoma	43	Cracks - Slight		Yes	Yes	No	No	82
# 1 Algoma	44	Cracks - Slight	Joint Use, Lights on Pole	Yes	Yes	No	No	83
# 1 Algoma	45	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Joint Use, Lights on Pole	Yes	Yes	Yes	Yes	84
# 1 Algoma	46	Cracks - Slight	Joint Use, Lights on Pole	Yes	Yes	No	No	85
# 1 Algoma	47	Cracks - Slight	Joint Use, Lights on Pole	Yes	Yes	No	No	86
# 1 Algoma	48	Cracks - Slight	Joint Use, Lights on Pole	Yes	Yes	No	No	87
# 1 Algoma	49	Cracks - Slight	Joint Use, Lights on Pole	Yes	Yes	No	No	88
# 1 Algoma	50	Cracks - Slight	Joint Use, Lights on Pole	Yes	Yes	No	No	89

Table 4A: Page 2 of 6

Table 4A: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 1 Algoma	51	Cracks - Slight	Dip, Joint Use, Lights on Pole	Yes	Yes	No	No	90
# 1 Algoma	52	Cracks - Slight	Joint Use, Lights on Pole	Yes	Yes	No	No	91
# 1 Algoma	53	Cracks - Slight	Joint Use, Lights on Pole	Yes	Yes	No	No	92
# 2 & 3 Algoma	58	Cracks - Slight		Yes	Yes	No	No	93
# 2 & 3 Algoma	57	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	94
# 2 & 3 Algoma	51	Cracks - Slight		Yes	Yes	No	No	95
# 2 & 3 Algoma	49	Cracks - Slight		Yes	Yes	No	No	96
# 2 & 3 Algoma	48	Cracks - Slight		Yes	Yes	No	No	97
# 2 & 3 Algoma	46	Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Guy guard required	Yes	Yes	Yes	Yes	98
# 2 & 3 Algoma	45			Yes	Yes	No	No	99
# 2 & 3 Algoma	44	Cracks - Slight, Ground wire (slack, broken, buried) - extensive	Slack Guy Wire	Yes	Yes	No	No	100
# 2 & 3 Algoma	43	Cracks - Slight		Yes	Yes	No	No	101
# 2 & 3 Algoma	42	Cracks - Slight	Bend in Pole	Yes	Yes	No	No	102

Table 4A: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 2 & 3 Algoma	41	Cracks - Slight	Guy guard required, Slack Guy Wire	Yes	Yes	No	No	103
# 2 & 3 Algoma	40	Cracks - Slight		Yes	Yes	No	No	104
# 2 & 3 Algoma	39	Cracks - Slight	Guy guard required	Yes	Yes	No	No	105
# 2 & 3 Algoma	38	Cracks - Slight		Yes	Yes	No	No	106
# 2 Algoma	36	Cracks - Slight		Yes	Yes	No	No	107
# 2 Algoma	35	Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	No	108
# 2 Algoma	34	Cracks - Slight		Yes	Yes	No	No	109
# 2 Algoma	33	Cracks - Slight		Yes	Yes	No	No	110
# 2 Algoma	32	Cracks - Slight		Yes	Yes	No	No	111
# 2 Algoma	31	Cracks - Moderate, Pole top feathering/split/rot - Slight	Dip	Yes	Yes	No	No	112
# 2 Algoma	30	Cracks - Slight		Yes	Yes	No	No	113
# 2 Algoma	29	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	114
# 2 Algoma	28	Cracks - Slight		Yes	Yes	No	No	115
# 2 Algoma	27	Cracks - Moderate	Pole in water	Yes	Yes	No	No	116

Table 4A: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 3 Algoma	17	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Joint Use	Yes	Yes	Yes	No	117
# 3 Algoma	18	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Ground Guard Required, Joint Use, Pole in water	Yes	No	Yes	Yes	118
# 3 Algoma	19	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Joint Use, Pole in water	Yes	No	Yes	Yes	119
# 3 Algoma	20	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use, Pole in water	Yes	No	Yes	Yes	120

Table 4A: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 3 Algoma	21	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use	Yes	No	Yes	Yes	121
# 3 Algoma	22	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Moderate	Joint Use	Yes	Yes	Yes	Yes	122
# 3 Algoma	32	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		Yes	Yes	No	No	123
# 3 Algoma	33	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Internal Decay - Slight		Yes	Yes	No	No	124

Table 4C: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 1 Algoma	1 Right	Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Internal Decay - Moderate	Guy guard required, Slack Guy Wire	Yes	Yes	Yes	No	1
# 1 Algoma	1 Centre	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight	Dip	Yes	Yes	Yes	No	2
# 1 Algoma	1 Left	Cracks - Slight, Decay pockets at GL - Slight, Internal Decay - Slight, Guying (slack, broken, buried) - slight		Yes	Yes	Yes	No	3
# 1 Algoma	2	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Yes	No	Yes	Yes	13
# 1 Algoma	3	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight, Guying (slack, broken, buried) - moderate	Bend in Pole, Guy guard required	Yes	Yes	Yes	No	17

Table 4C: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 1 Algoma	4	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	21
# 1 Algoma	5	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Moderate, Guying (slack, broken, buried) - slight		Yes	Yes	Yes	Yes	25
# 1 Algoma	6	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	29
# 1 Algoma	7	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Dip	Yes	Yes	Yes	No	33
# 1 Algoma	8	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Bend in Pole	Yes	Yes	Yes	No	37

Table 4C: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 1 Algoma	9	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight	Bend in Pole	Yes	Yes	Yes	No	41
# 1 Algoma	10	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Slight, Internal Decay - Slight		Yes	Yes	Yes	No	45
# 1 Algoma	11	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Extensive, Surface Rot below GL - Moderate, Internal Decay - Slight	Climbing Inspection Required	Yes	Yes	Yes	No	49
# 1 Algoma	13	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	57
# 1 Algoma	27R	Cracks - Slight		Yes	Yes	No	No	65
# 1 Algoma	27L	Carpenter ants damage - Slight, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	66
# 1 Algoma	28R	Cracks - Slight		Yes	Yes	No	No	67
# 1 Algoma	28L	Cracks - Slight		Yes	Yes	No	No	68

Table 4C: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 1 Algoma	29	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Bend in Pole	Yes	Yes	Yes	Yes	69
# 1 Algoma	29L	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	70
# 1 Algoma	30	Cracks - Slight		Yes	Yes	No	No	71
# 1 Algoma	31	Cracks - Slight	Bend in Pole, Dip, Joint Use, Lights on Pole	Yes	Yes	No	No	72
# 1 Algoma	32		Dip, Joint Use	Yes	Yes	No	No	73
# 1 Algoma	33	Cracks - Slight	Bend in Pole, Dip, Joint Use	Yes	Yes	No	No	74
# 1 Algoma	34		Joint Use	Yes	Yes	No	No	75
# 1 Algoma	35	Cracks - Slight	Dip, Joint Use	Yes	Yes	No	No	76
# 1 Algoma	36	Cracks - Slight	Joint Use	Yes	Yes	No	No	77
# 1 Algoma	37	Cracks - Slight	Dip, Joint Use	Yes	Yes	No	No	78
# 1 Algoma	38	Cracks - Slight	Joint Use	Yes	Yes	No	No	79
# 1 Algoma	39	Cracks - Slight	Dip, Joint Use	Yes	Yes	No	No	80
# 1 Algoma	40	Cracks - Slight	Dip, Joint Use	Yes	Yes	No	No	81

Table 4C: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 1 Algoma	43	Cracks - Slight		Yes	Yes	No	No	82
# 1 Algoma	44	Cracks - Slight	Joint Use, Lights on Pole	Yes	Yes	No	No	83
# 1 Algoma	45	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Joint Use, Lights on Pole	Yes	Yes	Yes	Yes	84
# 1 Algoma	46	Cracks - Slight	Joint Use, Lights on Pole	Yes	Yes	No	No	85
# 1 Algoma	47	Cracks - Slight	Joint Use, Lights on Pole	Yes	Yes	No	No	86
# 1 Algoma	48	Cracks - Slight	Joint Use, Lights on Pole	Yes	Yes	No	No	87
# 1 Algoma	49	Cracks - Slight	Joint Use, Lights on Pole	Yes	Yes	No	No	88
# 1 Algoma	50	Cracks - Slight	Joint Use, Lights on Pole	Yes	Yes	No	No	89
# 1 Algoma	51	Cracks - Slight	Dip, Joint Use, Lights on Pole	Yes	Yes	No	No	90
# 1 Algoma	52	Cracks - Slight	Joint Use, Lights on Pole	Yes	Yes	No	No	91
# 1 Algoma	53	Cracks - Slight	Joint Use, Lights on Pole	Yes	Yes	No	No	92
# 2 & 3 Algoma	58	Cracks - Slight		Yes	Yes	No	No	93

Table 4C: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 2 & 3 Algoma	57	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	94
# 2 & 3 Algoma	51	Cracks - Slight		Yes	Yes	No	No	95
# 2 & 3 Algoma	49	Cracks - Slight		Yes	Yes	No	No	96
# 2 & 3 Algoma	48	Cracks - Slight		Yes	Yes	No	No	97
# 2 & 3 Algoma	46	Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Guy guard required	Yes	Yes	Yes	Yes	98
# 2 & 3 Algoma	45			Yes	Yes	No	No	99
# 2 & 3 Algoma	44	Cracks - Slight, Ground wire (slack, broken, buried) - extensive	Slack Guy Wire	Yes	Yes	No	No	100
# 2 & 3 Algoma	43	Cracks - Slight		Yes	Yes	No	No	101
# 2 & 3 Algoma	42	Cracks - Slight	Bend in Pole	Yes	Yes	No	No	102
# 2 & 3 Algoma	41	Cracks - Slight	Guy guard required, Slack Guy Wire	Yes	Yes	No	No	103
# 2 & 3 Algoma	40	Cracks - Slight		Yes	Yes	No	No	104
# 2 & 3 Algoma	39	Cracks - Slight	Guy guard required	Yes	Yes	No	No	105
# 2 & 3 Algoma	38	Cracks - Slight		Yes	Yes	No	No	106

Table 4C: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 2 Algoma	2	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Yes	No	Yes	Yes	14
# 2 Algoma	3	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Slight		Yes	Yes	Yes	No	18
# 2 Algoma	4	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Slight		Yes	Yes	Yes	No	22
# 2 Algoma	5	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	26
# 2 Algoma	6	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	30

Table 4C: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 2 Algoma	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate	Bend in Pole	Yes	Yes	Yes	Yes	34
# 2 Algoma	8	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	38
# 2 Algoma	9	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	42
# 2 Algoma	10	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	46
# 2 Algoma	11	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Bend in Pole	Yes	Yes	Yes	No	50

Table 4C: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 2 Algoma	12	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	54
# 2 Algoma	13	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight, Guying (slack, broken, buried) - extensive	Bend in Pole	Yes	Yes	Yes	No	58
# 2 Algoma	36	Cracks - Slight		Yes	Yes	No	No	107
# 2 Algoma	35	Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	No	108
# 2 Algoma	34	Cracks - Slight		Yes	Yes	No	No	109
# 2 Algoma	33	Cracks - Slight		Yes	Yes	No	No	110
# 2 Algoma	32	Cracks - Slight		Yes	Yes	No	No	111
# 2 Algoma	31	Cracks - Moderate, Pole top feathering/split/rot - Slight	Dip	Yes	Yes	No	No	112
# 2 Algoma	30	Cracks - Slight		Yes	Yes	No	No	113
# 2 Algoma	29	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	114

Table 4C: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 2 Algoma	28	Cracks - Slight		Yes	Yes	No	No	115
# 2 Algoma	27	Cracks - Moderate	Pole in water	Yes	Yes	No	No	116
# 3 Algoma	2	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Yes	No	Yes	Yes	15
# 3 Algoma	3	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Guy guard required	Yes	Yes	Yes	Yes	19
# 3 Algoma	4	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate, Guying (slack, broken, buri		Yes	Yes	Yes	Yes	23

Table 4C: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 3 Algoma	5	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	27
# 3 Algoma	6	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	31
# 3 Algoma	7	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Yes	No	Yes	Yes	35
# 3 Algoma	8	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	39

Table 4C: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 3 Algoma	9	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	43
# 3 Algoma	10	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	47
# 3 Algoma	11	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	51
# 3 Algoma	12	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	55

Table 4C: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 3 Algoma	13	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	59
# 3 Algoma	14	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	61
# 3 Algoma	15	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	Yes	No	Yes	Yes	63
# 3 Algoma	17	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Joint Use	Yes	Yes	Yes	No	117

Table 4C: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 3 Algoma	18	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Ground Guard Required, Joint Use, Pole in water	Yes	No	Yes	Yes	118
# 3 Algoma	19	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Joint Use, Pole in water	Yes	No	Yes	Yes	119
# 3 Algoma	20	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use, Pole in water	Yes	No	Yes	Yes	120
# 3 Algoma	21	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use	Yes	No	Yes	Yes	121

Table 4C: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
# 3 Algoma	22	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Moderate	Joint Use	Yes	Yes	Yes	Yes	122
# 3 Algoma	32	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		Yes	Yes	No	No	123
# 3 Algoma	33	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Internal Decay - Slight		Yes	Yes	No	No	124
3 1 Algoma	12	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	53
Northern Ave	1 Right	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	10

Table 4C: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
Northern Ave	1 Centre	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	11
Northern Ave	1 Left	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	12
Northern Ave	2	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	16
Northern Ave	3	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Internal Decay - Slight	Guy guard required	Yes	Yes	Yes	No	20
Northern Ave	4	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Internal Decay - Slight	Guy guard required, Slack Guy Wire	Yes	Yes	Yes	No	24
Northern Ave	5	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Internal Decay - Slight		Yes	Yes	Yes	No	28

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Table 4C: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
Northern Ave	6	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	32
Northern Ave	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	36
Northern Ave	8	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	40
Northern Ave	9	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	44

Table 4C: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
Northern Ave	10	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate, Guying (slack, broken, buried) - extensive		Yes	Yes	Yes	Yes	48
Northern Ave	11	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	52
Northern Ave	12	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Yes	No	Yes	Yes	56
Northern Ave	14	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		Yes	Yes	Yes	Yes	62

Table 4C: Poles for Remedial Treatment

line #	Pole ID	Mech Condition	Comments	Treatment required ?	Rodes used ?	Copper used ?	Insecticide used ?	Record Number
Northern Ave	15	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	Yes	No	Yes	Yes	64
Northern Avenue	13	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		Yes	Yes	Yes	No	60

Table 5A: Poles with Extensive Mechanical Damage and Feathering

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 3 Algoma	17	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Joint Use	RG Tested Ok	117
# 3 Algoma	20	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use, Pole in water	Replace in 2010	120
# 3 Algoma	21	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use	Replace in 2010	121
# 3 Algoma	32	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	123

Table 5C: Poles with Extensive Mechanical Damage and Feathering

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 1 Algoma	1 Centre	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight	Dip	RG Tested Ok	2
# 1 Algoma	4	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	21
# 1 Algoma	6	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	29
# 1 Algoma	7	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Dip	RG Tested Ok	33
# 1 Algoma	8	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Bend in Pole	RG Tested Ok	37
# 1 Algoma	13	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	57
# 2 Algoma	6	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	30
# 2 Algoma	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate	Bend in Pole	RG Tested Ok	34
# 2 Algoma	9	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	42
# 2 Algoma	10	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	46

Table 5C: Poles with Extensive Mechanical Damage and Feathering

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 2 Algoma	11	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Bend in Pole	RG Tested Ok	50
# 2 Algoma	12	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	54
# 2 Algoma	13	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight, Guying (slack, broken, buried) - extensive	Bend in Pole	RG Tested Ok	58
# 3 Algoma	2	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	15
# 3 Algoma	3	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Guy guard required	RG Tested Ok	19
# 3 Algoma	5	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	27
# 3 Algoma	6	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	31
# 3 Algoma	7	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	35
# 3 Algoma	8	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	39

Table 5C: Poles with Extensive Mechanical Damage and Feathering

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 3 Algoma	9	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	43
# 3 Algoma	10	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	47
# 3 Algoma	11	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	51
# 3 Algoma	13	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	59
# 3 Algoma	14	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	61
# 3 Algoma	15	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	RG Tested, Replace in 2010	63
# 3 Algoma	17	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Joint Use	RG Tested Ok	117
# 3 Algoma	20	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use, Pole in water	Replace in 2010	120
# 3 Algoma	21	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use	Replace in 2010	121

Table 5C: Poles with Extensive Mechanical Damage and Feathering

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 3 Algoma	32	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	123
3 1 Algoma	12	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	53
Northern Ave	1 Right	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight		RG Tested Ok	10
Northern Ave	1 Centre	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	11
Northern Ave	1 Left	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	12
Northern Ave	3	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Internal Decay - Slight	Guy guard required	RG Tested Ok	20
Northern Ave	4	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Internal Decay - Slight	Guy guard required, Slack Guy Wire	RG Tested Ok	24
Northern Ave	5	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Internal Decay - Slight		RG Tested Ok	28
Northern Ave	6	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	32
Northern Ave	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	36

Table 5C: Poles with Extensive Mechanical Damage and Feathering

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
Northern Ave	8	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	40
Northern Ave	9	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	44
Northern Ave	10	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate, Guying (slack, broken, buried) - extensive		RG Tested Ok	48
Northern Ave	11	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	52
Northern Ave	12	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	56
Northern Ave	14	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	62
Northern Ave	15	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	RG Tested, Replace in 2010	64
Northern Avenue	13	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	60

Table 6A: Poles with Internal Decay

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 1 Algoma	1 Right	Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Internal Decay - Moderate	Guy guard required, Slack Guy Wire	RG Tested Ok	1
# 1 Algoma	1 Centre	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight	Dip	RG Tested Ok	2
# 1 Algoma	1 Left	Cracks - Slight, Decay pockets at GL - Slight, Internal Decay - Slight, Guying (slack, broken, buried) - slight		RG Tested Ok	3
Northern Ave	1 Right	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight		RG Tested Ok	10
Northern Ave	1 Centre	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	11
Northern Ave	1 Left	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	12
# 1 Algoma	2	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	13
# 2 Algoma	2	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	14
# 3 Algoma	2	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	15
Northern Ave	2	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	16
# 1 Algoma	3	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight, Guying (slack, broken, buried) - moderate	Bend in Pole, Guy guard required	RG Tested Ok	17
# 2 Algoma	3	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Slight		RG Tested Ok	18

Table 6A: Page 1 of 5

Table 6A: Poles with Internal Decay

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 3 Algoma	3	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Guy guard required	RG Tested Ok	19
Northern Ave	3	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Internal Decay - Slight	Guy guard required	RG Tested Ok	20
# 1 Algoma	4	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	21
# 2 Algoma	4	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Slight		RG Tested Ok	22
# 3 Algoma	4	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate, Guying (slack, broken, buri		RG Tested Ok	23
Northern Ave	4	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Internal Decay - Slight	Guy guard required, Slack Guy Wire	RG Tested Ok	24
# 1 Algoma	5	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Moderate, Guying (slack, broken, buried) - slight		RG Tested Ok	25
# 2 Algoma	5	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	26
# 3 Algoma	5	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	27
Northern Ave	5	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Internal Decay - Slight		RG Tested Ok	28
# 1 Algoma	6	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	29

Table 6A: Page 2 of 5

Table 6A: Poles with Internal Decay

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 2 Algoma	6	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	30
# 3 Algoma	6	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	31
Northern Ave	6	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	32
# 1 Algoma	7	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Dip	RG Tested Ok	33
# 2 Algoma	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate	Bend in Pole	RG Tested Ok	34
# 3 Algoma	7	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	35
Northern Ave	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	36
# 1 Algoma	8	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Bend in Pole	RG Tested Ok	37
# 2 Algoma	8	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	38
# 3 Algoma	8	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	39
Northern Ave	8	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	40

Table 6A: Poles with Internal Decay

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 1 Algoma	9	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight	Bend in Pole	RG Tested Ok	41
# 2 Algoma	9	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	42
# 3 Algoma	9	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	43
Northern Ave	9	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	44
# 1 Algoma	10	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Slight, Internal Decay - Slight		RG Tested Ok	45
# 2 Algoma	10	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	46
# 3 Algoma	10	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	47
Northern Ave	10	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate, Guying (slack, broken, buried) - extensive		RG Tested Ok	48
# 1 Algoma	11	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Extensive, Surface Rot below GL - Moderate, Internal Decay - Slight	Climbing Inspection Required	RG Tested Ok	49
# 2 Algoma	11	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Bend in Pole	RG Tested Ok	50
# 3 Algoma	11	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	51
Northern Ave	11	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	52
3 1 Algoma	12	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	53

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Table 6A: Poles with Internal Decay

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 2 Algoma	12	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	54
# 3 Algoma	12	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	55
Northern Ave	12	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	56
# 1 Algoma	13	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	57
# 2 Algoma	13	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight, Guying (slack, broken, buried) - extensive	Bend in Pole	RG Tested Ok	58
# 3 Algoma	13	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	59
Northern Avenue	13	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	60
# 3 Algoma	14	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	61
Northern Ave	14	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	62
# 3 Algoma	15	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	RG Tested, Replace in 2010	63
Northern Ave	15	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	RG Tested, Replace in 2010	64

Table 6A: Poles with Internal Decay

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 1 Algoma	27L	Carpenter ants damage - Slight, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	66
# 1 Algoma	29	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Bend in Pole	RG Tested Ok	69
# 1 Algoma	29L	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	70
# 1 Algoma	45	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Joint Use, Lights on Pole	RG Tested Ok	84
# 2 & 3 Algoma	57	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	94
# 2 & 3 Algoma	46	Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Guy guard required	RG Tested Ok	98
# 2 Algoma	35	Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	108
# 2 Algoma	29	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	114
# 3 Algoma	17	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Joint Use	RG Tested Ok	117
# 3 Algoma	18	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Ground Guard Required, Joint Use, Pole in water	Replace in 2010	118
# 3 Algoma	19	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Joint Use, Pole in water	Replace in 2010	119
# 3 Algoma	20	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use, Pole in water	Replace in 2010	120

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Table 6A: Poles with Internal Decay

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 3 Algoma	21	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use	Replace in 2010	121
# 3 Algoma	22	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Moderate	Joint Use	RG Tested Ok	122
# 3 Algoma	32	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	123
# 3 Algoma	33	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Internal Decay - Slight		RG Tested Ok	124

Table 6C: Poles with Internal Decay

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 1 Algoma	1 Right	Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Internal Decay - Moderate	Guy guard required, Slack Guy Wire	RG Tested Ok	1
# 1 Algoma	1 Centre	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight	Dip	RG Tested Ok	2
# 1 Algoma	1 Left	Cracks - Slight, Decay pockets at GL - Slight, Internal Decay - Slight, Guying (slack, broken, buried) - slight		RG Tested Ok	3
Northern Ave	1 Right	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Internal Decay - Slight		RG Tested Ok	10
Northern Ave	1 Centre	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	11
Northern Ave	1 Left	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	12
# 1 Algoma	2	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	13
# 2 Algoma	2	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	14
# 3 Algoma	2	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	15
Northern Ave	2	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	16
# 1 Algoma	3	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight, Guying (slack, broken, buried) - moderate	Bend in Pole, Guy guard required	RG Tested Ok	17
# 2 Algoma	3	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Slight		RG Tested Ok	18

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Table 6C: Poles with Internal Decay

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 3 Algoma	3	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Guy guard required	RG Tested Ok	19
Northern Ave	3	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Internal Decay - Slight	Guy guard required	RG Tested Ok	20
# 1 Algoma	4	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	21
# 2 Algoma	4	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Slight		RG Tested Ok	22
# 3 Algoma	4	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate, Guying (slack, broken, buri		RG Tested Ok	23
Northern Ave	4	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Internal Decay - Slight	Guy guard required, Slack Guy Wire	RG Tested Ok	24
# 1 Algoma	5	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Moderate, Guying (slack, broken, buried) - slight		RG Tested Ok	25
# 2 Algoma	5	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	26
# 3 Algoma	5	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	27
Northern Ave	5	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Internal Decay - Slight		RG Tested Ok	28
# 1 Algoma	6	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	29

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Table 6C: Poles with Internal Decay

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 2 Algoma	6	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	30
# 3 Algoma	6	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	31
Northern Ave	6	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	32
# 1 Algoma	7	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Dip	RG Tested Ok	33
# 2 Algoma	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate	Bend in Pole	RG Tested Ok	34
# 3 Algoma	7	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	35
Northern Ave	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	36
# 1 Algoma	8	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Bend in Pole	RG Tested Ok	37
# 2 Algoma	8	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	38
# 3 Algoma	8	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	39
Northern Ave	8	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	40

Table 6C: Poles with Internal Decay

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 1 Algoma	9	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Moderate, Internal Decay - Slight	Bend in Pole	RG Tested Ok	41
# 2 Algoma	9	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	42
# 3 Algoma	9	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	43
Northern Ave	9	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	44
# 1 Algoma	10	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Slight, Internal Decay - Slight		RG Tested Ok	45
# 2 Algoma	10	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	46
# 3 Algoma	10	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	47
Northern Ave	10	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate, Guying (slack, broken, buried) - extensive		RG Tested Ok	48
# 1 Algoma	11	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Extensive, Surface Rot below GL - Moderate, Internal Decay - Slight	Climbing Inspection Required	RG Tested Ok	49
# 2 Algoma	11	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Bend in Pole	RG Tested Ok	50
# 3 Algoma	11	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	51
Northern Ave	11	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	52
3 1 Algoma	12	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	53

Table 6C: Poles with Internal Decay

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 2 Algoma	12	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	54
# 3 Algoma	12	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	55
Northern Ave	12	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Extensive		Replace in 2010	56
# 1 Algoma	13	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	57
# 2 Algoma	13	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight, Guying (slack, broken, buried) - extensive	Bend in Pole	RG Tested Ok	58
# 3 Algoma	13	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	59
Northern Avenue	13	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	60
# 3 Algoma	14	Cracks - Slight, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight		RG Tested Ok	61
Northern Ave	14	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	62
# 3 Algoma	15	Carpenter ants damage - Extensive, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	RG Tested, Replace in 2010	63
Northern Ave	15	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Extensive, Internal Decay - Extensive	Guy guard required	RG Tested, Replace in 2010	64

Table 6C: Poles with Internal Decay

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 1 Algoma	27L	Carpenter ants damage - Slight, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	66
# 1 Algoma	29	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Bend in Pole	RG Tested Ok	69
# 1 Algoma	29L	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	70
# 1 Algoma	45	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Joint Use, Lights on Pole	RG Tested Ok	84
# 2 & 3 Algoma	57	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	94
# 2 & 3 Algoma	46	Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Guy guard required	RG Tested Ok	98
# 2 Algoma	35	Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	108
# 2 Algoma	29	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	114
# 3 Algoma	17	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Joint Use	RG Tested Ok	117
# 3 Algoma	18	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Ground Guard Required, Joint Use, Pole in water	Replace in 2010	118
# 3 Algoma	19	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Extensive	Joint Use, Pole in water	Replace in 2010	119
# 3 Algoma	20	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use, Pole in water	Replace in 2010	120
# 3 Algoma	21	Carpenter ants damage - Extensive, Cracks - Slight, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Extensive	Dip, Joint Use	Replace in 2010	121

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Table 6C: Poles with Internal Decay

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Record Number
# 3 Algoma	22	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Moderate	Joint Use	RG Tested Ok	122
# 3 Algoma	32	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	123
# 3 Algoma	33	Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Slight, Internal Decay - Slight		RG Tested Ok	124

Table 6A: Poles with Limited Remaining Life

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Remaining life (yrs)	Record Number
# 1 Algoma	45	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Joint Use, Lights on Pole	RG Tested Ok	Remaining life 2 years	84
# 2 & 3 Algoma	57	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	94
# 2 Algoma	29	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	114
# 3 Algoma	22	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Moderate	Joint Use	RG Tested Ok	Remaining life 2 years	122
# 3 Algoma	32	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	123

Table 6A: Page 1 of 1

Table 6A: Poles with Limited Remaining Life

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Remaining life (yrs)	Record Number
# 1 Algoma	4	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	21
# 1 Algoma	5	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Moderate, Guying (slack, broken, buried) - slight		RG Tested Ok	Remaining life 2 years	25
# 1 Algoma	11	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Extensive, Surface Rot below GL - Moderate, Internal Decay - Slight	Climbing Inspection Required	RG Tested Ok	Remaining life 2 years	49
# 2 Algoma	5	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	26
# 2 Algoma	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate	Bend in Pole	RG Tested Ok	Remaining life 2 years	34

Table 6A: Page 1 of 4

Table 6A: Poles with Limited Remaining Life

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Remaining life (yrs)	Record Number
# 2 Algoma	10	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Moderate wood loss/shell rot, Remaining life 2 years	46
# 3 Algoma	3	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Guy guard required	RG Tested Ok	Remaining life 2 years	19
# 3 Algoma	4	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate, Guying (slack, broken, buri		RG Tested Ok	Remaining life 2 years	23
# 3 Algoma	5	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	27
# 3 Algoma	6	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	31

Table 6A: Poles with Limited Remaining Life

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Remaining life (yrs)	Record Number
# 3 Algoma	8	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	39
# 3 Algoma	9	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	43
# 3 Algoma	12	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	55
# 3 Algoma	13	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	59
Northern Ave	6	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	32

Table 6A: Page 3 of 4

Table 6A: Poles with Limited Remaining Life

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Remaining life (yrs)	Record Number
Northern Ave	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	36
Northern Ave	8	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	40
Northern Ave	10	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate, Guying (slack, broken, buried) - extensive		RG Tested Ok	Pole in pavement, Moderate wood loss/shell rot.	48
Northern Ave	14	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	62

Table 7C: Poles with Limited Remaining Life

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Remaining life (yrs)	Record Number
# 1 Algoma	4	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	21
# 1 Algoma	5	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Internal Decay - Moderate, Guying (slack, broken, buried) - slight		RG Tested Ok	Remaining life 2 years	25
# 1 Algoma	11	Cracks - Slight, Decay pockets at GL - Slight, Surface Rot above GL - Extensive, Surface Rot below GL - Moderate, Internal Decay - Slight	Climbing Inspection Required	RG Tested Ok	Remaining life 2 years	49
# 1 Algoma	45	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Internal Decay - Moderate	Joint Use, Lights on Pole	RG Tested Ok	Remaining life 2 years	84
# 2 & 3 Algoma	57	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	94
# 2 Algoma	5	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	26

Table 7C: Page 1 of 5

Table 7C: Poles with Limited Remaining Life

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Remaining life (yrs)	Record Number
# 2 Algoma	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate	Bend in Pole	RG Tested Ok	Remaining life 2 years	34
# 2 Algoma	10	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Extensive, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Moderate wood loss/shell rot, Remaining life 2 years	46
# 2 Algoma	29	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	114
# 3 Algoma	3	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Slight, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Slight	Guy guard required	RG Tested Ok	Remaining life 2 years	19
# 3 Algoma	4	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate, Guying (slack, broken, buri		RG Tested Ok	Remaining life 2 years	23

Table 7C: Poles with Limited Remaining Life

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Remaining life (yrs)	Record Number
# 3 Algoma	5	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	27
# 3 Algoma	6	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	31
# 3 Algoma	8	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	39
# 3 Algoma	9	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	43
# 3 Algoma	12	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	55

Table 7C: Poles with Limited Remaining Life

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Remaining life (yrs)	Record Number
# 3 Algoma	13	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	59
# 3 Algoma	22	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Slight, Surface Rot above GL - Moderate, Internal Decay - Moderate	Joint Use	RG Tested Ok	Remaining life 2 years	122
# 3 Algoma	32	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Slight, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	123
Northern Ave	6	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	32
Northern Ave	7	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	36

Table 7C: Poles with Limited Remaining Life

Line #	Pole ID	Mechanical Conditions	Comments	Recommendations	Remaining life (yrs)	Record Number
Northern Ave	8	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	40
Northern Ave	10	Carpenter ants damage - Moderate, Cracks - Moderate, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Internal Decay - Moderate, Guying (slack, broken, buried) - extensive		RG Tested Ok	Pole in pavement, Moderate wood loss/shell rot.	48
Northern Ave	14	Carpenter ants damage - Moderate, Cracks - Slight, Decay pockets at GL - Moderate, Pole top feathering/split/rot - Moderate, Surface Rot above GL - Moderate, Surface Rot below GL - Moderate, Internal Decay - Moderate		RG Tested Ok	Remaining life 2 years	62

OEB Staff Interrogatory # 30

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 91

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

Another example concerning station assets, are the power transformers at Clergue TS. While METSCO's ACA study determined these units to be in the lower part of the Fair condition band (51% and 64% Health Indices), subsequent analysis determined that the low scores were related to a significant degree of oil leakage observed on transformer assets. HOSSM considered replacing both units over the course of this TSP, but as a part of the Needs Assessment process, opted for the replacement of transformer bushing gaskets – a significantly less costly solution expected to prolong the useful lives of the two transformers.

a) Please confirm the anticipated condition rating of these transformers after the bushing gaskets have been replaced.

b) Could the Health Indices resulting from METSCO's ACA study be applied in a manner that leads to a premature replacement of an asset? Please discuss.

c) Are transformers the only asset class for which replacement of a component (such as bushings) can significantly improve the assessed condition or health index score? Please explain

Response:

a) After bushing replacement, the anticipated condition for MT1 will be 68% (Fair) and MT2 will be 72% (Good).

b) METSCO ACA Health Index results are a snapshot of the asset base and should be used to point the owner to assets that require further investigation by operators and subject matter experts. METSCO ACA Health Index results are a single input into a multivariable process to determine asset replacement. Proper utilization of the Health index data should not singlehandedly lead to the premature replacement of an asset. As discussed throughout HOSSM's TSP (Exhibit B1-1-1)

c) Transformers are not the only asset class for which replacement of a component can significantly improve the health index score. This is especially true for assets which are in otherwise good condition but are significantly degraded in a single degradation factor that is related to a specific subcomponent of the asset that is modular and replaceable. Examples include SF6 refills (circuit breakers), drive train repairs (circuit switchers), primary connector and bolting replacements (instrument transformers), fuse replacements (capacitor banks), etc.

OEB Staff Interrogatory # 31

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 92

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

By adopting Hydro One's risk-based IPP approach for pacing and prioritization of its planned capital work program, HOSSM has significantly enhanced the rigour applied in the area of risk based asset intervention planning in respect to its assets, as in the past, equipment-related risk assessments were conducted in a more informal manner only. As detailed in Section 3.1.3.3 of this plan, the current approach adopted from Hydro One is grounded in evidence-based assessment of each project's risk mitigation potential on the basis of three core risk dimensions – reliability, safety and environment.

a) The above statements says that significant enhancements have materialized by adopting Hydro One's evidence-based approach. Are Hydro One's historic reliability numbers materially better than Hydro One SSM's historic reliability numbers? Please quantify.

Response:

a) Please refer to Table 6 located in Exhibit A Tab 2, Schedule 1, from EB-2016-0050. This table compares Hydro One's regional reliability indices against those of GLPT. For convenience, a copy is included below.

Please see **Table 6** below for a comparison of Hydro One's regional reliability indices against those of GLPT.

TABLE 6 – RELIABILITY INDICES REGIONALLY OF HYDRO ONE AND GLPT

	2010	2011	2012	2013	2014	2015
HONI - SAIDI[3]	28.1	39.6	75.9	184.3	40.7	66.1
GLPT - SAIDI	150.7	296.7	176.8	861.1	25.4	79.8
HONI - SAIFI	0.76	0.50	0.86	0.97	2.23	0.81
GLPT - SAIFI	1.33	2.14	2.24	1.37	0.47	0.89

[3] Hydro One's SAIDI and SAIFI results in Table 7 are premised on the results of the Mississagi TS to Martindale TS subsystem. This segment of Hydro One's transmission system is similarly situated, sized (in terms of asset types, line length, and delivery points) and carries a comparable load to that of GLPT.

OEB Staff Interrogatory # 32

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 105

Interrogatory:

Preamble:

Table 4-5: General Plant Investments

Project	Description	Driver(s)	Execution Timeline	Capital Cost
GP-01. Greenfield TS Land Purchase	Purchase a suitable land purchase in the area north of Sault Ste. Marie to enable the planned construction of the Greenfield TS (ISD #S1).	General Plant	2023	$2.0M
GP-02. Third Line TS Storage Building	Construct a permanent indoor climate-controlled storage facility on the Third Line TS grounds for spares and equipment.	General Plant, Operating Efficiency	2019	$0.8M
GP-03. General Plant Renewal Program	Enable regular upkeep and replacement of HOSSM's IT hardware and software, vehicle fleet, tools, and office equipment.	Genera Plant, Safety	2018-2026	$1.1M
Total General Plant				**$3.9M**

a) Has Hydro One SSM considered implementing ISD #S1 on one of the existing lots rather than spending $2.0M to purchase land for the construction of the Greenfield TS?
   i. If yes, why was this option discarded?
   ii. If no, why not?

Response:

a) A preliminary feasibility study completed in 2016 examined some possible options for the location of the new TS. The $2M allocated in the capital plan provides for further evaluation of location options. Hydro One SSM has not fully discounted the possibility of leveraging an existing lot if feasible and permissible.

OEB Staff Interrogatory # 33

Reference:

Ref: Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 107

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

All types of customers also express the preference for paced and gradual investments to help manage their electricity bills.

a) Customers expressed the preference for paced and gradual investments relative to what other types of investment options? Did Hydro One SSM present the different investment options to customers and outline the pros and cons associated with each option?

b) If customers requested paced and gradual investments, please explain why Hydro One SSM is proposing significant inter-annual variability of System Renewal and System Service spending over the forecast period.

Response:

a) During customer/stakeholder meetings held in May 2018, Hydro One SSM presented two generic options to customers for approaching capital investments: (1) paced and gradual investments which would involve a larger number of short-duration outages spread over a longer period of time, versus (2) a smaller number of long-duration outages over a shorter period of time. From these discussions, it was concluded in all instances that customers preferred more short-duration outages as this presented a lesser impact on their operations. Meetings were held with generation, distribution and direct-industrial transmission customers.

b) HOSSM does not believe the plan displays “significant inter-annual variability”. In all cases, outages would be coordinated to align with the customer preferences.

OEB Staff Interrogatory # 34

Reference:

Ref: Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, p. 109

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

While the ongoing integration with Hydro One creates opportunities to realize a number of potential operating and capital synergies discussed in Section 2.2.3, HOSSM expects that the gradual adoption of Hydro One's asset management policies and practices may result in the need for incremental increases to its current Maintenance expenditures in particular, as Hydro One asset management processes include a number of equipment maintenance and inspection procedures that HOSSM does not currently undertake on a regular basis.

a) Is there evidence justifying that the additional procedures that Hydro One SSM does not currently undertake on a regular basis are necessarily required?
   i. If so, please provide this evidence.
   ii. If not, is it possible to achieve satisfactory performance without having to increase maintenance expenditures?

b) Please provide the business cases demonstrating that there will be a net benefit to customers prior to undertaking these investments.

c) Does Hydro One SSM anticipate that the increase in maintenance expenditures will be offset by a related decrease in capital expenditures or lower spending in other OM&A areas?
   i. If yes, please describe and quantify the anticipated trade-offs.

d) Does Hydro One SSM expect any other trade-offs between OM&A and Capital expenditures to materialize over the 9-year planning period? Please elaborate.

e) Please identify any initiatives considered and/or undertaken by Hydro One SSM, including any analysis conducted, to optimize plans and activities from a cost perspective, including balancing cost levels of OM&A versus capital.

f) To date, which asset management functions have been consolidated with Hydro One and have any additional maintenance expenditures emerged as a result?

Response:

a) During integration, Hydro One SSM was made aware of the following maintenance practice gaps that Hydro One SSM felt needed additional procedures/maintenance:
- HOSSM did not use a federally accredited laboratory that would meet PCB regulation. In addition, it was discovered that HOSSM's previous practice did not include sampling oil-filled bushings. As a result, HOSSM needs to initiate oil testing and a retrofit program for HOSSM's oil filled equipment.
- The verification of entire DC trip path from protection equipment to actual trip coil of the breaker was not part of HOSSM's maintenance practice.

b) No business case exists.

c) In the long run increased maintenance costs may decrease capital costs but HOSSM has not quantified this.

d) Other trade-offs between OM&A and Capital expenditures may materialize over the 9-year planning period but they cannot be quantified at this time.

e) No initiatives have been considered to-date.

f) Operational integration only started in Oct 1st, 2018. As part of the integration strategy, recognizing that there are only 3 months left in 2018, the adoption of Hydro One's maintenance practices have a delayed start of January 2019. This approach allows the wrap up of HOSSM practices as a whole in 2018, as well as avoiding potential unforeseen effects due to abrupt changes in practice. This will also minimize any financial impact to HOSSM OM&A budget for the remaining of 2018.

OEB Staff Interrogatory # 35

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, ISD SS-01: New Greenfield TS, p. 160-168

Interrogatory:

Preamble:

Investment Results and RRF Outcomes:

Customer Focus	• Improves local area reliability by addressing two locations with extensive equipment condition deterioration issues.
Operational Effectiveness	• Provides opportunities maintenance savings through, reducing travel requirements for proactive and reactive maintenance combining maintenance activities and simplifying outage coordination for maintenance work.
	• Enhances Employee Safety by addressing historical issues with equipment clearances that could not be addressed at the legacy sites.
Financial Performance	• Introduces opportunities for capital asset consolidation by leveraging ability to deploy common station infrastructure at a single location instead of having two sets of similar equipment at two discrete locations.

a) Does Hydro One SSM perform any actual cost-benefit analysis when evaluating the RRF outcomes?
   i. If no, why not?
   ii. If yes, please provide the actual financial cost-benefit analysis of the four alternatives considered:
      - Alternative #1: “Do Nothing”
      - Alternative #2: Replace aging transformers and other equipment at the individual locations
      - Alternative #3: Build a consolidated new station served by a single transformer
      - Alternative #4: Build new station with two transformers

Response:

a) While HOSSM does not run a specific cost-benefit analysis in relation to RRF outcomes, many of the steps comprising the ARA and the SPP processes explore the project's relative value propositions across the dimensions that the RRF outcomes cover. For detailed information of how HOSSM has incorporated the RRF outcomes into its planning process, please see pp. 46-47 of its Transmission System Plan.

OEB Staff Interrogatory # 36

Reference:

Exhibit B1, Tab 1, Schedule 1 – Transmission System Plan, ISD GP-01 Greenfield TS Land Purchase, p. 183 -184

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

Alternative #2: Lease a Land Parcel

Leasing land parcels for the expected lifetime of a new station (40-60 years, with potential subsequent extensions through equipment replacement) introduces substantial risks to HOSSM's lifetime cost of ownership and continued site access, should the land owner choose to modify the terms of the arrangement during its time. This alternative is not recommended

a) Was the lifetime cost of ownership for leasing land parcels mentioned above quantified?
    i. If yes, please provide the financial analysis.

Response:

a) The lifetime cost of ownership for leasing land parcels has not been quantified. However a thorough analysis will be performed prior to moving forward with any land acquisition.

OEB Staff Interrogatory # 37

Reference:

Ref: Exhibit B2, Tab 1, Schedule 1, Attachment 1, Page 1

Interrogatory:

Preamble:

At the above-noted reference, Hydro One SSM showed that Appendix 2-AA, Capital Projects Table, reflects a reporting reference of MIFRS for the years 2013 through 2018.

a) Please provide a summary of changes to Hydro One SSM's accounting policies made since Hydro One SSM's last revenue requirement application, and the associated revenue requirement impacts.

b) Please confirm that Hydro One SSM has used MIFRS for the numbers underlying the proposed revenue requirement requested in the application. Please explain.

c) If Hydro One SSM has not used MIFRS for the numbers underlying the proposed revenue requirement requested in the application, please explain.

d) It is OEB staff's understanding that Hydro One Networks uses US GAAP as its financial reporting standard and regulatory reporting standard. Please describe the impact on Hydro One SSM's proposed revenue requirement requested in the application, if Hydro One SSM proposes to change from MIFRS to US GAAP at any point in time in the future, including the use of Account 1575 or Account 1576, where appropriate.

Response:

a) No changes have been made to Hydro One SSM's accounting policies since the last revenue requirement application.

b) Confirmed.

c) N/A.

d) Hydro One SSM intends to remain a stand-alone licensed transmitter reporting under MIFRS until the financial integration with Hydro One Networks Inc.

OEB Staff Interrogatory # 38

Reference:

Exhibit B2, Tab 3, Schedule 1, Page 1
Exhibit C, Tab 1, Schedule 1, Page 19

Interrogatory:

Preamble:

At the first above-noted reference, Hydro One SSM stated the following:

Hydro One Sault Ste. Marie ("HOSSM") undertakes to determine its customers' needs and preferences, which help to inform its Transmission System Plan ("TSP"), investment plan and business objectives.

At the second above-noted reference, Hydro One SSM stated the following:

As HOSSM integrates with Hydro One, HOSSM customers will be included in Hydro One's customer satisfaction surveys online, followed by computer-assisted telephone interviews based on customer preference or availability.

a) Please describe any specific customer engagement, if any, that was performed that might have affected the preparation of this application.

b) Please describe whether Hydro One SSM has undertaken any customer satisfaction surveys in the past and any planned future customer engagement activities that are not described in the application.

Response:

a) Annual Customer stakeholder meetings were held in May 2018 with 4 largest directly impacted customers.

b) Hydro One SSM has not performed any customer satisfaction surveys in the past.

OEB Staff Interrogatory # 39

Reference:
Exhibit B2, Tab 2, Schedule 1, Page 1

Interrogatory:
Preamble:

At the above-noted reference Hydro One SSM stated the following:

Throughout the integration process, Hydro One and Hydro One Sault Ste. Marie ("HOSSM") have committed to investigating areas of opportunity to realize savings through productivity, efficiency and synergies. HOSSM will operationally integrate on October 1, 2018 and will financially integrate at a later time. One of the areas targeted for full review was the Capital Investment Plan.

a) Please describe when financial integration is expected to occur.

Response:
a) HOSSM has outstanding external debt that is not set to be retired until 2023. It is expected that financial integration will be completed after this debt has been retired.

OEB Staff Interrogatory # 40

Reference:

Exhibit B2, Tab 1, Schedule 1, Attachment 2 – Capital Expenditure Summary from Chapter 5 Consolidated, p. 1

Interrogatory:

Preamble:

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

First year of Forecast Period: *2018*

CATEGORY	Historical Period (previous plan[1] & actual)														
	2013			2014			2015			2016			2017		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	-	-	--	-	-	--	-	-	--	-	-	--	-	-	--
System Renewal	1,860,387	2,378,253	27.8%	3,183,457	3,274,680	2.9%	5,780,000	6,081,360	5.2%	4,486,188	4,316,484	-3.8%	5,613,700	5,949,171	6.0%
System Service	1,284,996	1,266,948	-1.4%	249,000	249,776	0.3%	1,152,800	1,149,674	-0.3%	3,298,913	2,622,523	-20.5%	3,702,000	4,643,508	25.4%
General Plant	1,341,275	811,870	-39.5%	912,317	787,213	-13.7%	2,527,197	1,512,544	-40.1%	1,983,583	2,618,930	32.0%	975,402	3,895,498	299.4%
TOTAL EXPENDITURE	4,486,658	4,457,071	-0.7%	4,344,774	4,311,669	-0.8%	9,459,997	8,743,578	-7.6%	9,768,684	9,557,937	-2.2%	10,291,102	14,488,177	40.8%
System O&M	$ 10,100,000	$ 10,210,900	1.1%	$ 10,305,535	$ 10,304,457	0.0%	$ 10,821,095	$ 10,424,380	-3.7%	$ 11,121,876	$ 10,941,448	-1.6%	$ 11,121,876	$ 9,492,621	-14.6%

CATEGORY	Forecast Period (planned)				
	2018	2019	2020	2021	2022
	$ '000				
System Access	-	-	-	-	-
System Renewal	5,100,000	3,000,000	8,000,000	7,900,000	5,900,000
System Service	1,300,000	1,300,000	2,600,000	2,800,000	5,500,000
General Plant	100,000	2,900,000	100,000	1,000,000	1,000,000
TOTAL EXPENDITURE	6,500,000	7,200,000	10,700,000	11,700,000	12,400,000
System O&M	$ 9,449,000	$ 10,700,000	$ 11,000,000	$ 11,200,000	$ 11,400,000

a) Please explain the reason for the drop in System O&M in 2017, and the subsequent increase in 2019.

b) Please provide an updated table with the anticipated System O&M expenditures for the complete 9-year forecast period (2018 – 2026).

Response:

a) The drop in System O&M in 2017 is primarily due to employee attrition (refer to statement in Exh C,Tab 1, Sch 1, pg 9) and some minor efficiencies leveraging HONI resources. The subsequent increase in 2019 is due to improvements to the maintenance program to align with HONI standards plus inflation.

b) From 2020 onwards, O&M spend increases by 200,000 annually, largely due to inflation. The forecast for 2023 to 2026 is:

- 2023: $11,600,000
- 2024: $11,800,000
- 2025: $12,000,000
- 2026: $12,200,000

OEB Staff Interrogatory # 41

Reference:

Exhibit B2, Tab 2, Schedule 1 – Capital Plan Evolution, p. 1-20

Interrogatory:

a) Hydro One SSM has provided evidence within the Capital Plan Evolution of projected savings of over $76 million over the 2017-2025 period relative to GLPT's draft capital plans:

Table Reference in Application	**Projected Savings 2017 – 2025 (in C$ in thousands)**
Table 3 – Capital Investment Removed from Plan Due to Redundancy with Hydro One	24,994.5
Table 4 - Projects Removed from the Plan Due to Investment Prioritization	2,373.2
Table 5 – Adjustments to Align with Current Capital Investment Plan	35,128.8
Table 6 – Other Adjustments	14,072.1
Total Projected Savings (2016 – 2025):	**76,568.6**

Please confirm that the projected savings are based on comparing Hydro One SSM current capital plans with a draft capital plan that has never been presented to or approved by the OEB. If Hydro One SSM asserts that the draft capital plan has been presented to or approved by the OEB, please provide particulars.

b) Does Hydro One SSM agree that the above noted savings may not be a fair representation of the realistic savings accruing to ratepayers?
   i. If no, please explain why not.
   ii. If yes, what would be a fair representation of the realistic savings?

Response:

a) Please refer to Exhibit B2-2-S1 Page 1 for the draft capital plan for Great Lakes Power Transmission. Table 1 was included in the MAAD application presented to the OEB for reference purposes, but was never presented for Board approval.

b) HOSSM still believes the savings are a realistic representation of what will ultimately accrue to ratepayers as a result of the integration with HONI.

OEB Staff Interrogatory # 42

Reference:

EB-2016-0356, Decision and Order September 28, 2017, page 9
Exhibit C, Tab 1, Schedule 1, Page 12
Exhibit C, Tab 1, Schedule 1, Figure 5
Exhibit C, Tab 1, Schedule 1, Page 35
Exhibit C, Tab 1, Schedule 1, Page 15

Preamble:

In its Decision and Order in Hydro One SSM's previous revenue requirement proceeding,[1] the OEB determined that the proposed scorecard for 2017 was incomplete. Specifically the OEB stated that Hydro One SSM falls short of the OEB expectations for performance measure metrics, each with specific performance outcomes and implementation timelines. The OEB also noted that while a scorecard submitted after 2019 may reflect future operational changes, the current application must comply with the scorecard requirements in 2017, the year in which rate increase is proposed.

In the second above-noted reference, Hydro One SSM stated the following:

Figure 5, HOSSM's proposed scorecard, shows the performance metrics HOSSM expects to be measured against and the associated annual results, targets and trending of each metric. The descriptions of the various metrics can be found in section 1.6 of this exhibit.

In the third above-noted reference, Hydro One SSM has included its proposed scorecard in "Figure 5 - Proposed Hydro One Sault Ste. Marie Scorecard."

In the last above-noted reference, Hydro One SSM stated the following:

The following sections include a description of each metric on the proposed scorecard. For each metric, there is a current description and a description of how the metric will evolve as HOSSM adopts Hydro One's methodologies and continues to migrate its records and data into Hydro One's systems through the integration process. Annual targets for 2023 have been proposed for

[1] EB-2016-0356, September 28, 2017, page 9

each metric that coincides with the five years included in the Transmission System Plan ("TSP") and is aligned with Hydro One's 2023 transmission scorecard targets.

Interrogatory:

a) OEB staff notes that Hydro One SSM's proposed scorecard in Figure 5 does not specify improvement initiatives, as well as business drivers. Please explain.

b) Hydro One SSM stated that annual targets for 2023 have been proposed to align with the five years included in the TSP and Hydro One's 2023 transmission scorecard. OEB staff notes that Hydro One SSM's proposed scorecard in Figure 5 includes targets of 2023 for some metrics, and does not include a target for other metrics. Please provide a description of the targets, an explanation as to how the targets were derived, and also address the metrics that do not have any targets.

c) Please explain whether Hydro One SSM expects to have the necessary systems and processes in place to report on all of the measures in the proposed scorecard by the end of 2018.

d) If this is not the case, please explain which measures and associated systems and processes will not be in place by the end of 2018, as well as when Hydro One SSM expects to be able to report on these measures.

e) Please explain if Hydro One SSM consulted with any external stakeholders and/or customers in the development of its proposed scorecard. Please outline the nature of the consultation.

f) Please explain whether Hydro One SSM has benchmarked its performance with respect to any of the scorecard measures against the performance of its peers. If so, please provide the results.

g) Please explain whether or not Hydro One SSM has any plans to further benchmark its performance with respect to its proposed scorecard measures against that of its peers. If this is the case, please outline such plans. If this not the case, please explain.

h) Please list and explain any additional data that would be beneficial to customers and submitted going forward under the OEB's *Reporting and Record-Keeping Requirements* (RRR).

i) Please indicate how Hydro One SSM has complied with the current OEB scorecard requirements.

j) Please explain whether Hydro One SSM has considered any of the following items in its scorecard, as well as other items typically addressed in OEB distributor scorecards:

   i. No Management Discussion and Analysis (MD&A) was included
   ii. Some metrics still show N/A instead of actual values
   iii. Some additional measures found in the typical OEB electricity distributor scorecards such as:

      i. Scheduled Appointments Met On Time
      ii. Telephone Calls Answered On Time
      iii. First Contact Resolution
      iv. Billing Accuracy
      v. Level of Public Awareness
      vi. Transmission System Plan Implementation Progress
      vii. Any other items that Hydro One SSM is of the view would be beneficial

k) Please explain if Hydro One SSM believes that the changes it has made to its scorecard have addressed the deficiencies noted by the OEB in its decision.[2] Please also explain how these deficiencies were addressed.

Response:

a) While not identical, the scorecard presented and proposed as Figure 5 (referenced above) is largely similar to that submitted by Hydro One Networks (HONI) as part of its TSP that was approved by the Board in September 2017.[3] This scorecard itself did not specifically include improvement initiatives as these were included in a different area of their TSP[4]. For HOSSM's TSP the Anticipated Sources of Efficiencies are included in Section 2.2.3 of the TSP.

b) The targets were set and approved by senior management. The derivation of the targets depends on the individual measures. In some cases, targets were set on a discretionary,

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[2] EB-2016-0356, September 28, 2017, page 9
[3] EB-2016-0160, Exhibit B2-1-1, Attachment 1
[4] EB-2016-0160, Exhibit B1-1-3

stretch basis where prior information was not readily available (e.g. "Satisfaction with Outage Planning Procedures"). In other cases, an algorithm was derived using past data along with management judgement (e.g. T-SAIFI). In some cases, targets are not available or meaningful as the outcome of the measure itself is not something that lends itself to active management to a specific target (e.g. Current Ratio – this is observed for information as the financial health of the utility but is not managed to a discrete number).

c) Yes, the expectation is that sufficient systems will be in place in order to report on the intended measures by end of 2018.

d) Please see the response to question (c) above.

e) Hydro One SSM did not consult with any external stakeholders and/or customers in the development of its proposed scorecard.

f) Hydro One SSM has not benchmarked its performance with respect to any of the scorecard measures against the performance of its peers.

g) Given its operational integration, Hydro SSM will primarily rely upon and seek to implement improvements based on the benchmarking activities and artifacts of HONI going forward rather than having a separate set of benchmarking activities. Such a duplicative program would involve additional costs with little if any incremental benefit to customers.

h) Hydro One SSM complies with the RRR submission requirements mandated by the OEB for licenced transmitters. If requested, HOSSM would be happy to participate in any activity that reviews those requirements.

i) Hydro One SSM is of the view that the proposed scorecard complies with the requirements including those outlined in the Report of the Board from EB-2010-0379, "*Performance Measurement for Electricity Distributors: A Scorecard Approach*".

j) i) Hydro One SSM has included explanations as to the performance of the measures as part of its scorecard submission. Creating and including a Management Discussion and Analysis piece beyond that would likely cover much of the same information.

ii) Please see Part a) of Exhibit I, Tab 4, Schedule 29 (AMPCO IR #29)

iii) Most of the measures listed in the question are associated with Distributors who have meaningful numbers of directly served customers. HOSSM is a transmitter and while many customers from other LDCs are impacted by their performance, HOSSM has a relatively small number of directly served customers and thus does not seek to track many of the measures denoted here. .*Level of Public Awareness* and *Transmission System Plan Implementation Progress* could be included separately if the Board feels that would be helpful. But, in any event, these two items will be monitored as part of HONI's performance measurement program.

k) The OEB indicated in the previous proceeding that HOSSM fell short of the OEB expectations for performance measure metrics, each with specific performance outcomes and implementation timelines. Now, the Hydro One SSM scorecard includes the expected outcomes and implementation timelines and is substantially aligned with the HONI Tx scorecard. Hydro One SSM believes that its scorecard should now be acceptable as well.

OEB Staff Interrogatory # 43

Reference:

Exhibit C, Tab 1, Schedule 1, Page 2 & 3

Interrogatory:

Preamble:

At the above-noted reference, Hydro One SSM stated the following:

HOSSM's KPIs have traditionally been separated into four corporate drivers:

- Excellence in Health, Safety, Security and Environment ("HSSE")…
- Continued Value Creation…
- Risk Management…
- Investment in our People…

Certain KPIs have been adopted as metrics on the newly proposed corporate scorecard, described in Section 1.2 of this exhibit. Examples of corporate KPIs are described in Section 1.4 of this exhibit.

a) Please provide a complete list of Hydro One SSM's historical KPIs.

b) Please provide Hydro One SSM's historical targets and actuals for each KPI for the years 2013 to 2017, if not already provided in Hydro One SSM's application.

c) Based on the results in part (b), please explain any significant trends in the data.

d) Please provide targets for each KPI for 2018 and 2019.

e) Please explain any significant differences between the KPIs and the scorecard metrics, including any timelines for alignment of these two groups of measurement.

Response:

a) Prior to being acquired by Hydro One, GLPT (now HOSSM) had annual KPI's that were typically developed during the budgeting process (Q4 of the year prior), spanning financial, Health, Safety & Environmental, reliability and other one-off items. Included as Attachment

1 to this Exhibit are detailed KPI summaries from past years covering 2014-2017.

Once the Hydro One acquisition was finalized in October 2016, HOSSM (GLPT) began to produce monthly scorecards, leveraging a variation of the existing HONI format, and tracked performance of their KPI's on a monthly basis. Reporting was done to the VP in charge. For 2017, annual KPI's were essentially built into the scorecard. Beginning in 2018 with the operational integration ongoing, HOSSM solely focused on the scorecard and had similar metrics as in 2017 with minor adjustments to further align with Hydro One. Now with operational integration in place, metrics relating to health & safety and reliability, rely on certain assumptions in order to be tracked separately. Financial measures/tracking is still done separately for HOSSM.

b) Please see the KPI summary include in Attachment 1 to this Exhibit.

c) Please see the KPI summary include in Attachment 1 to this Exhibit.

d) Attached on the following page is a copy of HOSSM's recent Dashboard for August 2018. This is the most recent, complete version available at time of writing. This Dashboard represents the measurements used by management on a monthly basis to measure the performance of the business. Many of the measures incorporated, align with the Scorecard but other metrics are included to round out performance monitoring. Targets ("Plan") and most recent historical comparisons ("Prior") are included on the Dashboard.

e) Please see the response to part a).

Business Unit Dashboard - August
Hydro One Sault Ste. Marie LP

Meets/Exceeds plan
At-Risk
Below plan

		MONTHLY 2018			YEAR TO DATE 2018			FULL YEAR 2018		
Objective	**Metric**	**Actual**	**Plan**	**Prior**	**Actual**	**Plan**	**Prior**	**Forecast**	**Plan**	**Prior**
Safety	High MRPH Incidents	0	0	0	0	0	0	0	0	0
	Safe Work Observations	18	16	10	58	76	44	88	98	86
	HS&E Initiatives	8%	8%	0%	94%	58%	60%	100%	100%	100%
	Recordable Injuries	0	0	0	1	1	1	1	1	1
	Preventable Motor Vehicle Collisions	0	0	1	2	1	1	2	2	1
Reliability	Outliers	0	0	0	0	0	0	0	0	0
	Tx SAIDI (min) - radial	0.0	4.0	N/A	10.0	33.0	N/A	20.0	50.0	N/A
	Tx SAIFI – radial	0.0	0.1	N/A	0.2	0.7	N/A	0.4	1.0	N/A
	Tx SAIDI (min) – multi-circuit	0.0	0.2	0.0	0.0	1.4	23.16	0.6	2.0	0.0
	Tx SAIFI – multi-circuit	0.0	0.0	0.0	0.0	0.0	0.22	0.0	0.2	0.0
Work Program	Work Program (PMs)	11%	12%	10%	62%	68%	50%	94%	100%	84%
	In-Service Capital	$0.0M	$0.0M	$0.0M	$0.5M	$0.3M	$0.3M	$7.0M	$9.3M	$11.1M
	OM&A	$0.9M	$0.8M	$0.9M	$6.3M	$6.4M	$6.4M	$9.4M	$9.4M	$9.5M
Other	Compliance	0	0	1	4	0	1	4	0	1
Financial	Funds from Operations (FFO)	$2.2M	$2.1M	$1.9M	$15.5M	$14.7M	$13.0M	$22.2M	$21.6M	$19.8M

Safety: For recordable injuries, based on number of incidents
SAIDI\SAIFI: Based on 5yr average removing large one time items (2013)
FFO: Revenue less operating expenses (OM&A) less cash interest payments on long-term debt
SWO: Original plan 108 adjusted to 98 based on current staff complement

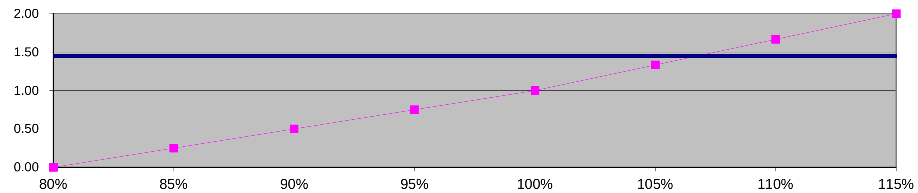
2014

KPI Summary

GREAT LAKES POWER TRANSMISSION
KPI SUMMARY - 2014

	2014 KPI SCORE	MULTIPLIER	WEIGHT	VP IMPACT
GREAT LAKES POWER NOI	1.067	1.445	40%	57.80%

	Actual NOI	Plan NOI	Variance	% vs. Plan
Transmission	$ 29,263.4	$ 27,434.0	$ 1,829.4	106.7%
Great Lakes Power Total	$ 29,263.4	$ 27,434.0	$ 1,829.4	106.7%



	2014 KPI SCORE	MULTIPLIER	WEIGHT	VP IMPACT
COMMON OBJECTIVES	4.0	1.500	40%	60%

5.0 ***DELIVER ZERO HIGH RISK HSS&E INCIDENTS***

Weighting: 10%

Operations	HIGH RISK INCIDENTS Fatality	Serious	Contact	No Contact
Health & Safety	0	0	0	0
Security	0	0	0	0
Environment	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**

Key Performance Indicator (K.P.I.) score scale				5
Disability or Fatality	**Serious**	**Contact**	**No Contact**	**Score**
0	0	0	2	5
0	0	0	3	4
0	0	1	3	3
0	1	2	4	2
1	2	3	5	1

3.0 ***MEET LEADING INDICATOR TARGETS RELATED TO HEALTH & SAFETY***

Weighting: 5%

GLPT has a number of initiatives and processes in place to provide leading indicators that ensure shortfalls or deficiencies in the health and safety program are identified early and corrected proactively. GLPT's 2014 focus will be on establishing a program for job plan quality assurance (QA) checks, and continuing its work observation program.

Job Plan QAs - 81.0% - Score of 2

Work Observations - 92.1% completed - Score of 3

Key Performance Indicator (K.P.I.) score scale - Quality Job Plans	2
	Score
Achieve >95% of targeted QA checks for entire mgmt team & 100% of overall target	5
Achieve >95% of targeted QA checks for entire mgmt team	4
Achieve 90-95% of targeted QA checks for entire mgmt team	3
Achieve 80-90% of targeted QA checks for entire mgmt team	2
Achieve <80% of targeted QA checks for entire mgmt team	1

Key Performance Indicator (K.P.I.) score scale - Work Oberservations	3
	Score
Achieve >95% of targeted work observations for entire mgmt team & 100% of overall target	5
Achieve >95% of targeted work observations for entire mgmt team	4
Achieve 90-95% of targeted work observations for entire mgmt team	3
Achieve 80-90% of targeted work observations for entire mgmt team	2
Achieve <80% of targeted work observations for entire mgmt team	1

GREAT LAKES POWER TRANSMISSION

KPI SUMMARY - 2014

5.0	***FILE 2015-16 RATE APPLICATION RECEIVING OEB APPROVAL FOR ALL OM&A AND CAPITAL SPENDING FOR THE TEST YEARS 2015-16***	Weighting: **7%**

KPI measured based on achievement of strategic objectives in application, timing of filing and interrogatory responses, and effective and implementation dates.

Objectives - All objectives achieved as filed (rate base, corporate structure, deferral account recovery).
Timing - No procedural delays on the part of GLPT.
Effective and Implementation Dates - Rates effective and implemented January 1, 2015.

Board File EB-2014-0238

Key Performance Indicator (K.P.I.) score scale - Strategic Objectives - 4%	Score: 5
	Scoring
Objectives achieved as filed	5
Minor changes, no negative consequences	4
Minor changes, some negative consequences	3
One strategic objective not approved or changes with significant negative consequences	2
More than one strategic objective not approved	1

Key Performance Indicator (K.P.I.) score scale - Timing - 1.5%	Score: 5
	Scoring
Filed July 15 and no controllable delays in interrogatory responses	5
Filed July 31 and no controllable delays in interrogatory responses	4
Filed August 15, or Controllable delay in interrogatory responses 0-5 working days	3
Filed August 31, or Controllable delay in interrogatory responses 5-10 working days	2
Filed after August 31 or Controllable delays in interrogatory responses > 10 working days	1

Key Performance Indicator (K.P.I.) score scale - Effective and Implementation Dates - 1.5%	Score: 5
	Scoring
Effective January 1 and Implemented January 1	5
Effective January 1 and Implemented February 1	4
Effective January 1 and Implemented March 1	3
Effective January 1 and implemented after March 1	2
Effective after January 1	1

4.0	***EXECUTE 2014 CAPITAL PLAN ON SCOPE AND BUDGET***	Weighting: **4%**

Capital	**Budget**	**Actual**	**%**	**Rating**
OEB Capital Spend	$4,393	$4,312	98.1%	**5.0**
Project Scope/Schedule	Weighted	3.80		**3.8**
KPI Score				**4.4**

- 98.1% of OEB-approved budget added to rate base, all spent prudently - Score of 5.

- Each project was measured individually on scope, schedule and budget - weighted score of 3.80.

- For individual project ratings, total score was weighted based on total approved budget.

Key Performance Indicator (K.P.I.) score scale - OEB - 2%	5
	Score
Spend 98% to 100% of OEB-approved Budget	5
Spend 95% to 98% or 100% to 101% of envelope	4
Spend 92% to 95% or 101% to 102% of envelope	3
Spend 90% to 92% of envelope	2
Spend less than 90% or greater than 102%of envelope	1

Key Performance Indicator (K.P.I.) score scale - Scope/Schedule - 2%	4
	Score
Spend 98% to 102% of approved IRF/FWO	5
Spend 96% to 104% of approved IRF/FWO	4
Spend 94% to 106% of approved IRF/FWO	3
Spend 90% to 110% of approved IRF/FWO	2
Spend <90% or >110% of approved IRF/FWO, or not compelted within defined scope or schedule	1

Weighting

5.0 ***DELIVER OM&A AT OR BELOW OEB APPROVED LEVELS*** **3%**

Controllable OM&A	**Transmission**
	2014
OM&A Budget	$10,552
OM&A Actual	$10,542
% of Budget	99.9%
KPI Score	

$400k in corporate costs were included in OM&A

Key Performance Indicator (K.P.I.) score scale	**5**
	Score
Costs are at or below the OM&A approved by the OEB with $400k for CCA	5
Costs do not exceed OEB approved by more than $50k with $400k for CCA	4
Costs do not exceed OEB approved by more than $100k with $400k for CCA	3
Costs do not exceed OEB approved by more than $200k with $400k for CCA	2
Costs exceed OEB approved by more than $200k or less than $400k in CCA	1

Weighting

5.0 ***DELIVER ZERO HIGH RISK COMPLIANCE AND OPERATIONAL INCIDENTS*** **3%**

	HIGH RISK INCIDENTS			
	Major	**Serious**	**Minor**	**None**
Regulatory Compliance	0	0	0	0
Operational	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**

Key Performance Indicator (K.P.I.) score scale				**5**
Major	**Serious**	**Minor**	**No Consequence**	**Score**
0	0	0	1	5
0	0	0	2	4
0	0	1	3	3
0	1	2	4	2
1	2	3	5	1

Weighting

4.0 ***MAINTAIN RELIABILITY STANDARDS*** **3%**

Three year rolling averages indicate a score of 4 for Frequency: All load blocks are better than the minimum standard with two better than the average standard. The >80MW load block is better than minimum but slightly behind average standard as a result of a 2012 outage. The 40-80MW block is better than minimum but slightly behind average standard as a result of a 2013 outage.

Three year rolling averages indicate a score of 3 for Duration: One load block below 40MW exceeds the minimum standard. The <15MW load block does not meet minimum standard primarily due to 2013 outage at Northern Ave TS.

Key Performance Indicator (K.P.I.) score scale - Outage Frequency - 1.5%	**4**
	Score
All load blocks better than average standard	5
All load blocks better than minimum standard, with 2 better than average standard	4
All load blocks better than minimum standard, or 1 below 40MW exceeding minimum	3
Two load blocks below 40MW or one above 40MW exceed minimum standard	2
Two load blocks above 40MW or three total load blocks exceed minimum standard	1

Key Performance Indicator (K.P.I.) score scale - Outage Duration - 1.5%	**3**
	Score
All load blocks better than average standard	5
All load blocks better than minimum standard, with 2 better than average standard	4
All load blocks better than minimum standard, or 1 below 40MW exceeding minimum	3
Two load blocks below 40MW or one above 40MW exceed minimum standard	2
Two load blocks above 40MW or three total load blocks exceed minimum standard	1

GREAT LAKES POWER TRANSMISSION

KPI SUMMARY - 2014

		Weighting
5.0	***MANAGEMENT TRAINING DELIVERY***	3%

Leadership development is an important part of building a strong team. Most of current leadership team has had limited leadership training with Brookfield. Training program to focus on individual development plans and employee engagement.

Individual development plans were complete before April 30th and training was booked in April. Half of training completed in 2014, remainder to be completed in 2015 - Score of 5.

Key Performance Indicator (K.P.I.) score scale - Leadership Training	5
	Score
Training initiated by Q2-2014	5
Training initiated by Q3-2014	4
Training initiated by Q4-2014	3
Training scheduled to start in 2015	2
Training not scheduled	1

		Weighting
3.0	***NEW MANAGEMENT / SUPERVISORY ORIENTATION***	2%

GLPT's orientation programs are relatively broad and apply to all new hires. Newly hired and promoted managers and supervisors have increased responsibilities that are not communicated through an orientation program. GLPT will create an orientation for new managers and supervisors to describe responsibilities and promote leadership development.

Orientation manual was created in September 2014 - Score of 3.

Key Performance Indicator (K.P.I.) score scale - Supervisor Orientation Manual	3
	Score
Orientation program developed by June 30, 2014	5
Orientation program developed by August 31, 2014	4
Orientation program developed by September 30, 2014	3
Orientation program developed by November 30, 2014	2
Orientation program not developed by Dec 31, 2014	1

	2014 KPI SCORE	MULTIPLIER	WEIGHT	VP IMPACT
PERSONAL OBJECTIVES	3	1.000	20%	20%

	WEIGHT	VP IMPACT
TOTAL VARIABLE PAY SCORE	100%	138%

Great Lakes Power Transmission LP
Reconciliation of NOI for 2014

OEB Approved NOI	**27,434,485**	
NOI Budget	**27,434,000**	**Revised from Ontario T Budget v10 to move $50k in HoldCo costs, $100k in Comstock, $100k in BES and $340k in EWT Variance budgets below the line.
NOI per Financial Statements & Metrics	**28,962,389**	**Moved from $26,844 + $100 + $100 + $340 + $50 = $27,434
Add Back:	262,267	Regulatory Expenses
	38,706	HoldCo Operating Expenses
NOI per KPI Measurement	**29,263,362**	
Core OM&A Variances	10,215	
Revenue Variances	1,818,898	
NOI per Budget	**27,434,249**	**27,434,000** Check vs budget
		(249) Variance

OM&A Calculations:

Actual OM&A	10,541,885
Less:	-
Less:	-
Measured OM&A	**10,541,885**
OM&A Budget	10,552,100
Core OM&A Variance	**10,215**

Report for Month of: December 2014
Health, Safety and Environment

<u>Contractor - Summary of Statistics – Year to Date</u>

	Current Month	YTD		Current Month	YTD
High Risk	**0**	**0**	**Contractor Incident**	**0**	**6**

<u>GLPT - Summary of Statistics – Year to Date</u>

	Current Month	YTD		Current Month	YTD
High Risk	**0**	**0**	**Personal Injury**	**1**	**2**
			Equipment Damage	**0**	**1**
Vehicle Accidents	**0**	**0**	**Environmental Incident**	**0**	**0**
Reported Incident/Near Miss	**0**	**0**	**Public Incident**	**0**	**1**
<u>Lost Time</u> resulting from a personal injury.	**0**	**0**	**<u>Medical Aid</u> resulting from a personal injury.**	**0**	**2**
High Risk Incidents (near miss) YTD	**0**	**0**	**Calendar Days without Lost Time (cumulative)**	**2,008**	
Total Incidents YTD = 10					

Great Lakes Power Transmission LP
2014 Work Observation Counts for KPI Scoring

	Total Target	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Actual	Total for Count	Individual %
[redacted]	18		2	1	2	2	3		3	4				17	17	94%
	6			1			2	1	1	1				6	6	100%
	2											1		1	1	50%
	12		1	2	1		2	3	1	2		1	1	14	12	117%
	12			1				1	2	2		1	1	8	8	67%
	12		1		1	2	1	2	3	2		1		13	12	108%
	12	1	2	2		1	1	4	1	1	1	1	1	16	12	133%
	2								1			1		2	2	100%
	76	**1**	**6**	**7**	**4**	**5**	**9**	**11**	**12**	**12**	**1**	**6**	**3**	**77**	**70**	

Q1: 14 Q2: 18 Q3: 35 Q4: 10

92.1% Completed

Final KPI Score:

92.1% % for KPI Scoring

101.3% Needs to be >100% for a 5

Additional Info:

The scores of 1-4 are based on all managers getting out into the field a sufficient number of times. To achieve a 5, the criteria for scoring a 4 must be met, with additional management presence in the field to push the total work observations over 100%

KPI Scoring:

1	2	3	4	5
Achieve <80% of targeted work observations for entire supervisory / management team, with maximums applied to each super/mgr	Achieve 80 – 90% of targeted work observations for entire supervisory / management team, with maximums applied to each super/mgr	Achieve 90 – 95% of targeted work observations for entire supervisory / management team, with maximums applied to each super/mgr	Achieve >95% of targeted work observations for entire supervisory / management team, with maximums applied to each super/mgr	Achieve >95% of targeted work observations for entire supervisory / management team, with maximums applied to each super/mgr, **and** >100% of overall target

Great Lakes Power Transmission LP
2014 Job Plan QA Counts for KPI Scoring

	Total Target	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Actual	Total for Count	Individual %
[redacted]	9	1	1	1	1	1	1	1	1	1				9	9	100%
	12	1	3	3							3	2		12	12	100%
	9												2	2	2	22%
	9	1	1	2	1	1	1	1	1	1				10	9	111%
	24	1	2	2	2			2	3	1	3		3	19	19	79%
	63	**4**	**7**	**8**	**4**	**2**	**2**	**4**	**5**	**3**	**6**	**2**	**5**	**52**	**51**	
			Q1:	19		Q2:	8		Q3:	12		Q4:	13		81.0%	Completed

Final KPI Score: **81.0%** **% for KPI Scoring**

82.5% **Needs to be >100% for a 5**

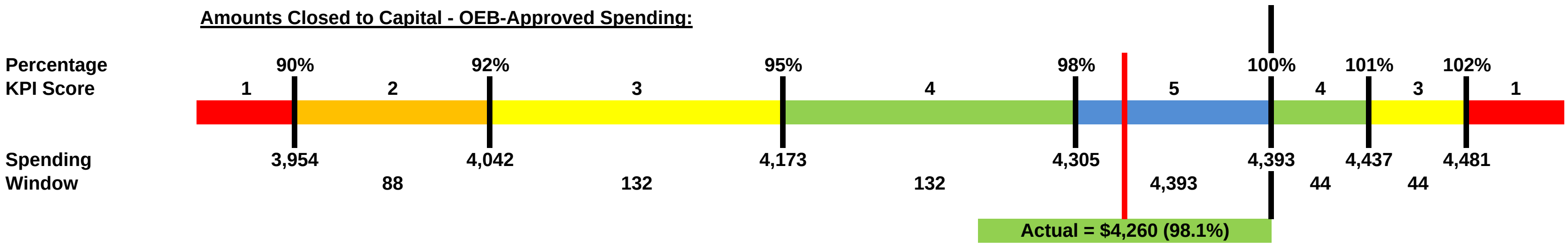
Additional Info:

The scores of 1-4 are based on all managers getting out into the field a sufficient number of times. To achieve a 5, the criteria for scoring a 4 must be met, and additional management presence in the field to push the total work observations over 100%

KPI Scoring:

1	2	3	4	5
Achieve <80% of targeted work observations for entire supervisory / management team, with maximums applied to each super/mgr	Achieve 80 – 90% of targeted work observations for entire supervisory / management team, with maximums applied to each super/mgr	Achieve 90 – 95% of targeted work observations for entire supervisory / management team, with maximums applied to each super/mgr	Achieve >95% of targeted work observations for entire supervisory / management team, with maximums applied to each super/mgr	Achieve >95% of targeted work observations for entire supervisory / management team, with maximums applied to each super/mgr, **and** >100% of overall target

GLPT KPI on Capital Spending



GREAT LAKES POWER TRANSMISSION LP
CAPITAL WORK IN PROGRESS
December 31, 2014

PROJECT NUMBER	PROJECT DESCRIPTION	OPENING 2014	CAPITAL EXPENDITURES	Adjustments	Capitalized Int Adjustment	CLOSED TO CAPITAL	Closed Less Int. Adj.	CLOSING Dec-14
I06015	WATSON BUS PROTECTION	22,761.33	-		-	0.00	0.00	22,761.33
I06045	WATSON B.F. PROTECTIONS	13,243.28	-		-	0.00	0.00	13,243.28
I06077	ANJIGAMI BRAKER FAIL PROT	30,008.44	-		-	0.00	0.00	30,008.44
I07006	ALGOMA LINES UPGRADE	673,694.12	45,314.47	(390,704.20)	26,201.98	0.00	0.00	354,506.37
I07128	TS GROUNDING - GOULAIS	67,851.50	-		-	0.00	0.00	67,851.50
IT9086	CLERGUE TS UPGRADE -ENGIN	80,224.70	-		-	0.00	0.00	80,224.70
I10011	REMOTE TERMINAL UNIT STUD	121,810.55	-		3,428.02	0.00	0.00	125,238.57
I10012	NETWK SYSTEM CONFIG STUDY	219,563.54	-		6,179.02	0.00	0.00	225,742.56
I10047	RELAY PROT REPLACE STUDY	236,989.39	-		6,669.43	0.00	0.00	243,658.82
I11028	BATTERY CHARGER ADEQUACY	9,597.87	-	(9,597.87)	-	0.00	0.00	0.00
I11031	DIESEL GENERAT- 3RD LINE	44,971.33	-		-	0.00	0.00	44,971.33
I11032	DIESEL GENERAT- MACKAY TS	47,471.33	-		-	0.00	0.00	47,471.33
I11033	ERP SOFTWARE UPGRDE STUDY	81,413.80	89,873.09		2,283.47	0.00	0.00	173,570.36
I11063	AMS FRAMEWORK DEVELOPMENT	107,470.42	-		2,822.51	0.00	0.00	110,292.93
I11085	DOC MGEMENT STRATEGIC PLN	49,265.01	-		-	0.00	0.00	49,265.01
I11107	COMMUNICATIONS STUDY	139,870.14	9,781.71		4,274.27	0.00	0.00	153,926.12
I12005	MYPASSWORDS SOFTWARE	25,572.07	-		-	0.00	0.00	25,572.07
I13022	SPARE CURRENT TRANSFORMER	-	13,630.27		-	13,630.27	13,630.27	0.00
I13026	WATSON BATTERY BANK	88,945.85	28,228.85		-	117,174.70	117,174.70	0.00
I13032	STOKELY STRUCTURE EROSION	69,049.99	17,381.81	(86,431.80)	-	0.00	0.00	0.00
I13043	TANK HEATERS	29,311.73	-		-	29,311.73	29,311.73	0.00
I13044	PHYSICAL SECURITY SERVER	-	11,654.06		-	11,654.06	11,654.06	0.00
I14001	SERVER ROOM AIR CONDITION	-	17,326.00		-	17,326.00	17,326.00	0.00
I14002	SMALL COMPUTER PURCHASES	-	14,250.66		-	14,250.66	14,250.66	0.00
I14003	VACUUM ANCHOR SYSTEM	-	11,807.00		-	11,807.00	11,807.00	0.00
I14004	Algoma Lines Structure Replacement	-	1,593,792.69	390,704.20	-	1,984,496.89	1,984,496.89	0.00
I14005	Stokely Structure Replacement	-	1,018,184.39	86,431.80	-	1,104,616.19	1,104,616.19	0.00
I14006	2014 SMALL TOOLS	-	6,419.76		-	6,419.76	6,419.76	0.00
I14007	2014 SIGNAGE & GUY GUARDS	-	54,762.07		0.00	54,762.07	54,762.07	0.00
I14008	FINANCE PRINTER	-	8,090.57		0.00	8,090.57	8,090.57	0.00
I14009	THIRD LINE OIL CONTAINMNT	-	249,776.11		0.00	249,776.11	249,776.11	0.00
I14010	ACTIVE DIRECTORY SERVER	-	7,887.54		0.00	7,887.54	7,887.54	0.00
I14011	LAPTOPS	-	23,803.50		0.00	23,803.50	23,803.50	0.00
I14012	DESKTOPS	-	3,203.88		0.00	3,203.88	3,203.88	0.00
I14013	CHECKPOINT FIREWALL APPLC	-	19,210.10		0.00	19,210.10	19,210.10	0.00
I14014	INTELEX ADMIN LICENSE	-	1,750.00		0.00	1,750.00	1,750.00	0.00
I14015	2015 CHEVROLET 2500 14 02	-	50,102.15		0.00	50,102.15	50,102.15	0.00
I14016	2014 DODGE RAM 1500 14 01	-	43,310.55		0.00	43,310.55	43,310.55	0.00
I14017	2015 CHEVROLET 2500 1403	-	51,157.39		0.00	51,157.39	51,157.39	0.00
I14018	HUMIDIFIER SUITE A	-	3,351.50		0.00	3,351.50	3,351.50	0.00

GREAT LAKES POWER TRANSMISSION LP
CAPITAL WORK IN PROGRESS
December 31, 2014

PROJECT NUMBER	PROJECT DESCRIPTION	OPENING 2014	CAPITAL EXPENDITURES	Adjustments	Capitalized Int Adjustment	CLOSED TO CAPITAL	Closed Less Int. Adj.	CLOSING Dec-14
I14019	MACKAY BUILDING ROOF	-	77,714.48		0.00	77,714.48	77,714.48	0.00
I14020	LAPTOP PROJECT MANAGER	-	2,360.34		0.00	2,360.34	2,360.34	0.00
I14021	ERGONOMIC ASSESSMENTS	-	3,469.57		0.00	3,469.57	3,469.57	0.00
I14022	ANDREWS UPS BATTERIES	-	30,944.96		0.00	30,944.96	30,944.96	0.00
I14023	P&C MAINTENANCE PROGRAM	-	33,484.10		0.00	0.00	0.00	33,484.10
I14024	SACKVILLE LINK ROOF	-	26,356.42		0.00	26,356.42	26,356.42	0.00
I14025	PM PROGRAM STEELTON TS	-	46,207.15		0.00	46,207.15	46,207.15	0.00
I14026	PM PROGRAM NORTHERN AVE	-	36,981.70		0.00	36,981.70	36,981.70	0.00
I14027	PM PROGRAM CLERGUE TS	-	40,745.90		0.00	40,745.90	40,745.90	0.00
I14028	QRADAR APPLIANCES	-	99,645.33		0.00	99,645.33	99,645.33	0.00
I14029	MICRO DD ADVISOR SERVER	-	8,779.74		0.00	8,779.74	8,779.74	0.00
I14030	2014 LAWN TRACTOR	-	7,340.00		0.00	7,340.00	7,340.00	0.00
I14031	PLOTTER WORKSTATION	-	1,879.36		0.00	1,879.36	1,879.36	0.00
I14032	SACKVILLE SPRINKLER SYSTM	-	19,424.25		0.00	19,424.25	19,424.25	0.00
I14033	GLPT SIGNAGE	-	1,470.00		0.00	1,470.00	1,470.00	0.00
I14034	ELFIQ LINK BALANCER	-	5,270.00		0.00	5,270.00	5,270.00	0.00
I14035	AUTOCAD UPGRADES	-	10,796.65		0.00	10,796.65	10,796.65	0.00
I14036	HOGG STRUCTURE REPLACMENT	-	42,398.36		0.00	0.00	0.00	42,398.36
I14037	GARTSHORE STRUCTURES	-	42,149.05		0.00	0.00	0.00	42,149.05
I14038	HIGHWAY 101 UPGRADES	-	116,695.19		0.00	0.00	0.00	116,695.19
I14039	SCADA WORKSTATIONS	-	6,628.59		0.00	6,628.59	6,628.59	0.00
I14040	NTHRN AV TRANSFORMER TB	-	28,205.15		0.00	0.00	0.00	28,205.15
I14041	GOULAIS BATTERY & CHARGER	-	13,443.57		0.00	0.00	0.00	13,443.57
I14042	ICCP CONNECTION	-	5,763.58		0.00	0.00	0.00	5,763.58
I14043	FLASH CARD RTU UPDATE	-	-		0.00	0.00	0.00	0.00
I14044	ANJIGAMI TS REFURBISHMENT	-	13,008.92		0.00	0.00	0.00	13,008.92
I14045	WATSON T2 HV BREAKER	-	8,514.10		0.00	0.00	0.00	8,514.10
I14046	TS DOOR PANIC BARS	-	29,432.41		0.00	29,432.41	29,432.41	0.00
I14047	CABLE TRENCH SIGNAGE	-	18,136.36		0.00	18,136.36	18,136.36	0.00
I14048	MAGPIE VIDEO CAMERA	-	3,405.69		0.00	3,405.69	3,405.69	0.00
I14049	SNOWBLOWER	-	2,519.00		0.00	2,519.00	2,519.00	0.00
I14050	HOOD VENTS	-	2,312.77		0.00	2,312.77	2,312.77	0.00
I14051	STAIR ENCLOSURE MESH/PLTE	-	2,755.27		0.00	2,755.27	2,755.27	0.00
I10074	ANJIGAMI OIL CONTAINMENT	-	-		1,455.50	1,455.50	0.00	0.00
I10100	TL-GROUND GRID	-	-		17,277.66	17,277.66	0.00	0.00
I10101	TL-BUILDING	-	-		17,260.01	17,260.01	0.00	0.00
I10103	TL-ELECTRICAL STRUCTURES	-	-		349,702.94	349,702.94	0.00	0.00
I10104	TL-115KV CIRCUIT RELOCATE	-	-		57,008.88	57,008.88	0.00	0.00
I10105	TL-FIBRE OPTICS	-	-		8,784.44	8,784.44	0.00	0.00
I11002	2011 GIS UPGRADES	-	-		0.00	0.00	0.00	0.00

GREAT LAKES POWER TRANSMISSION LP
CAPITAL WORK IN PROGRESS
December 31, 2014

PROJECT NUMBER	PROJECT DESCRIPTION	OPENING 2014	CAPITAL EXPENDITURES	Adjustments	Capitalized Int Adjustment	CLOSED TO CAPITAL	Closed Less Int. Adj.	CLOSING Dec-14
I11003	2011 CIRS UPGRADES	-	-		52.06	52.06	0.00	0.00
I11027	ASSET REGISTRY	-	-		2,537.58	2,537.58	0.00	0.00
I11048	ROW ACQUISITION K24G	-	-		2,268.28	2,268.28	0.00	0.00
I11072	ROW ACQUISITION W23K	-	-		1,594.13	1,594.13	0.00	0.00
I11093	SCADA EMS - ANDREWS BUILD	-	-		8,185.90	8,185.90	0.00	0.00
I12001	2012 GIS UPGRADES	-	-		384.89	384.89	0.00	0.00
I12006	ANJIGAMI OIL CONTAINMENT	-	-		2,425.97	2,425.97	0.00	0.00
I12007	2012 SIGNAGE & GUY GUARDS	-	-		828.81	828.81	0.00	0.00
I12031	115KV STRUCTURE REPLACMNT	-	-		3,118.07	3,118.07	0.00	0.00
I12036	3RD LINE WATERLINE INSTAL	-	-		850.98	850.98	0.00	0.00
I12037	STEELTON TS PROT UPGRADE	-	-		1,024.77	1,024.77	0.00	0.00
I12044	SF6 GAS RECLAIM UNIT	-	-		334.75	334.75	0.00	0.00
I12045	SACKVILLE B ROOF REPLACE	-	-		1,778.18	1,778.18	0.00	0.00
IT9095	SCADA EMS-MAIN CNTRL CNTR	-	-		67,281.57	67,281.57	0.00	0.00
		2,159,086.39	**4,182,288.08**	**(9,597.87)**	**596,014.07**	**4,855,823.93**	**4,311,668.56**	**2,071,966.74**

Project Information			Project to Date					
	Project Description	Proj Status	FWO/ IRF Approval	Project to Date Actual	$ Variance	% Variance	Rating	Weighted Rating
OVER $250k Total								
I13022	SPARE CURRENT TRANSFORMER	I	11,087.00	13,630.27	2,543.27	22.9%	1	0.00316
I13026	WATSON BATTERY BANK	I	135,000.00	117,174.70	(17,825.30)	13.2%	1	0.02718
I13043	TANK HEATERS	I	28,830.00	29,311.73	481.73	1.7%	5	0.03399
I13044	PHYSICAL SECURITY SERVER	I	12,870.00	11,654.06	(1,215.94)	9.4%	2	0.00541
I14001	SERVER ROOM AIR CONDITION	I	21,000.00	17,326.00	(3,674.00)	17.5%	1	0.00402
I14002	SMALL COMPUTER PURCHASES	I	15,000.00	14,250.66	(749.34)	5.0%	3	0.00992
I14003	VACUUM ANCHOR SYSTEM	I	14,487.00	11,807.00	(2,680.00)	18.5%	1	0.00274
I14004-05	Wood Structure Replacements	I	3,183,456.97	3,089,113.08	(94,343.89)	3.0%	4	2.86582
I14006	2014 SMALL TOOLS	I	5,000.00	6,419.76	1,419.76	28.4%	1	0.00149
I14007	2014 SIGNAGE & GUY GUARDS	I	55,000.00	54,762.07	(237.93)	0.4%	5	0.06350
I14008	FINANCE PRINTER	I	8,495.00	8,090.57	(404.43)	4.8%	3	0.00563
I14009	THIRD LINE OIL CONTAINMNT	I	249,000.00	249,776.11	776.11	0.3%	5	0.28965
I14010	ACTIVE DIRECTORY SERVER	I	8,282.00	7,887.54	(394.46)	4.8%	3	0.00549
I14011	LAPTOPS	I	23,533.00	23,803.50	270.50	1.1%	5	0.02760
I14012	DESKTOPS	I	3,166.00	3,203.88	37.88	1.2%	5	0.00372
I14013	CHECKPOINT FIREWALL APPLC	I	19,836.00	19,210.10	(625.90)	3.2%	4	0.01782
I14014	INTELEX ADMIN LICENSE	I	1,750.00	1,750.00	-	0.0%	5	0.00203
I14015	2015 CHEVROLET 2500 14 02	I	51,300.00	50,102.15	(1,197.85)	2.3%	4	0.04648
I14016	2014 DODGE RAM 1500 14 01	I	43,308.00	43,310.55	2.55	0.0%	5	0.05022
I14017	2015 CHEVROLET 2500 1403	I	51,840.00	51,157.39	(682.61)	1.3%	5	0.05932
I14018	HUMIDIFIER SUITE A	I	4,400.00	3,351.50	(1,048.50)	23.8%	1	0.00078
I14019	MACKAY BUILDING ROOF	I	14,300.00	77,714.48	63,414.48	443.5%	1	0.01802
I14020	LAPTOP PROJECT MANAGER	I	2,478.00	2,360.34	(117.66)	4.7%	3	0.00164
I14021	ERGONOMIC ASSESSMENTS	I	2,834.00	3,469.57	635.57	22.4%	1	0.00080
I14022	ANDREWS UPS BATTERIES	I	33,716.00	30,944.96	(2,771.04)	8.2%	2	0.01435
I14024	SACKVILLE LINK ROOF	I	20,900.00	26,356.42	5,456.42	26.1%	1	0.00611
I14025	PM PROGRAM STEELTON TS	I	38,000.00	46,207.15	8,207.15	21.6%	1	0.01072
I14026	PM PROGRAM NORTHERN AVE	I	38,000.00	36,981.70	(1,018.30)	2.7%	4	0.03431
I14027	PM PROGRAM CLERGUE TS	I	48,000.00	40,745.90	(7,254.10)	15.1%	1	0.00945
I14028	QRADAR APPLIANCES	I	101,307.00	99,645.33	(1,661.67)	1.6%	5	0.11555
I14029	MICRO DD ADVISOR SERVER	I	11,760.00	8,779.74	(2,980.26)	25.3%	1	0.00204
I14030	2014 LAWN TRACTOR	I	7,100.00	7,340.00	240.00	3.4%	4	0.00681
I14031	PLOTTER WORKSTAION	I	2,274.00	1,879.36	(394.64)	17.4%	1	0.00044
I14032	SACKVILLE SPRINKLER SYSTM	I	19,491.00	19,424.25	(66.75)	0.3%	5	0.02253
I14033	GLPT SIGNAGE	I	1,350.00	1,470.00	120.00	8.9%	2	0.00068

Project Information			Project to Date					
	Project Description	Proj Status	FWO/ IRF Approval	Project to Date Actual	$ Variance	% Variance	Rating	Weighted Rating
OVER $250k Total								
I14034	ELFIQ LINK BALANCER	I	5,586.00	5,270.00	(316.00)	5.7%	3	0.00367
I14035	AUTOCAD UPGRADES	I	11,183.00	10,796.65	(386.35)	3.5%	4	0.01002
I14039	SCADA WORKSTATIONS	I	7,035.00	6,628.59	(406.41)	5.8%	3	0.00461
I14046	TS DOOR PANIC BARS	I	22,641.00	29,432.41	6,791.41	30.0%	1	0.00683
I14047	CABLE TRENCH SIGNAGE	I	15,600.00	18,136.36	2,536.36	16.3%	1	0.00421
I14048	MAGPIE VIDEO CAMERA	I	3,901.00	3,405.69	(495.31)	12.7%	1	0.00079
I14049	SNOWBLOWER	I	2,519.00	2,519.00	-	0.0%	5	0.00292
I14050	HOOD VENTS	I	1,920.00	2,312.77	392.77	20.5%	1	0.00054
I14051	STAIR ENCLOSURE MESH/PLTE	I	2,475.00	2,755.27	280.27	11.3%	1	0.00064
	Totals		**4,361,010.97**	**4,311,668.56**			**Score:**	**3.80363**

No High Risk Regulatory or Operational Incidents

Re: Compliance & Operational Incidents

[redacted]

[redacted]

No High Risk Operational events or Regulatory non-compliance issues in 2014.

Regards,

[redacted]

Director of Operations
Great Lakes Power Transmission
Phone: 705.941.5652
Mobile: 705.542.8316
Fax: 705.759.6110

Customer DP - Frequency of Interruptions (Outages/yr)									
	Number of Outages			3 Year Average (2012-14)	Minimum Standard Of Performance	Standard Average Performance	Load Category	Exceed Min?	Exceed Avg?
Customer Delivery Point	**2014**	**2013**	**2012**						
EASI (301T1, 301T2, 301T3) (DP1)	-	-	1.00	0.33					
(>80 MW)	**-**	**-**	**1.00**	**0.33**					
Average for Load Block	**-**	**-**	**1.00**	**0.33**	1	0.3	(>80 MW)	Yes	No
PUC GL1TA / GL2TA (DP2)	-	2.00	-	0.67					
(40-80 MW)	**-**	**2.00**	**-**	**0.67**					
Average for Load Block	**-**	**2.00**	**-**	**0.67**	1.5	0.5	(40-80 MW)	Yes	No
St Marys Paper Corp. (Breakers 150&155) Removed 2012	-	-	1.00	0.33					
St Marys Paper Corp. (Breakers 154&151) Removed 2012	-	-	1.00	0.33					
EASI (10T1) (DP3)	-	-	1.00	0.33					
PUC GL1SM / GL2SM (DP4)	-	-	-	-					
(15-40MW)	**-**	**-**	**3.00**	**1.00**					
Average for Load Block	**-**	**-**	**0.75**	**0.25**	3.5	1.1	(15-40MW)	Yes	Yes
Flakeboard Company (DP5)	-	-	1.00	0.33					
EASI (T6 and T7) (DP6)	-	-	1.00	0.33					
EASI (LMF - Wallace Terrace Sub) (DP7)	-	-	1.00	0.33					
API DIST (NA 34.5 kV) (DP8)	-	-	-	-					
API DIST (NA 12kV) (DP9)	-	2.00	2.00	1.33					
API DIST (ER) (DP10)	3.00	3.00	2.00	2.67					
API DIST (BATCH) (DP11)	1.00	3.00	-	1.33					
API DIST (GOULAIS) (DP12)	2.00	3.00	-	1.67					
API DIST (MACKAY) (DP13)	-	-	-	-					
API DIST (ANDREWS) (DP14)	-	8.00	-	2.67					
API DIST (WATSON - Wawa No.1 & No.2) (DP15)	1.00	-	4.00	1.67					
API DIST (No. 4 Circuit) (DP16)	-	1.00	2.00	1.00					
API DIST (Hwy 101 DS) (Removed 2013- all load on No.4 cct)	-	-	12.00	4.00					
Weyerhaeuser Company Ltd. (DP17)	1.00	2.00	13.00	5.33					
Wesdome Gold Mines (DP18)	1.00	2.00	5.00	2.67					
(0-15 MW)	**9.00**	**24.00**	**43.00**	**8.44**					
Average for Load Block	**0.64**	**1.71**	**2.87**	**1.74**	9	4.1	(0-15 MW)	Yes	Yes

All four load blocks better than minimum standard, two load blocks better than average standard. Score of 4.

Customer DP Interruption Duration (min/yr)									
	Interruption Duration (minutes)			3 Year Average (2012-14)	Minimum Standard Of Performance	Standard Average Performance	Load Category	Exceed Min?	Exceed Avg?
Customer Delivery Point	**2014**	**2013**	**2012**						
EASI (301T1, 301T2, 301T3)	-	-	16	5					
(>80 MW)	**-**	**-**	**16**	**5**					
Average for Load Block	**-**	**-**	**16**	**5**	25	5	(>80 MW)	Yes	No
PUC GL1TA / GL2TA	-	23	-	8					
(40-80 MW)	**-**	**23**	**-**	**8**					
Average for Load Block	**-**	**23**	**-**	**8**	55	11	(40-80 MW)	Yes	Yes
St Marys Paper Corp. (Breakers 150&155) Removed 2012	-	-	5	2					
St Marys Paper Corp. (Breakers 154&151) Removed 2012	-	-	5	2					
ASI (10T1)	-	-	34	11					
PUC GL1SM / GL2SM	-	-	-	-					
(15-40MW)	**-**	**-**	**44**	**15**					
Average for Load Block	**-**	**-**	**11**	**4**	140	22	(15-40MW)	Yes	Yes
Flakeboard Company	-	-	17	6					
EASI (T6 and T7)	-	-	34	11					
EASI (Wallace Terrace Sub)	-	-	17	6					
API DIST (NA 34.5 kV)	-	-	-	-					
API DIST (NA 12kV)	-	11,248	118	3,789					
API DIST (ER)	86	98	7	64					
API DIST (BATCH)	14	566	-	193					
API DIST (GOULAIS)	299	601	-	300					
API DIST (MACKAY)	-	-	-	-					
API DIST (ANDREWS)	-	3,248	-	1,083					
API DIST (WATSON - No.1 & No.2 Wawa)	7	-	79	29					
API DIST (No. 4 Circuit)	-	11	35	15					
API DIST (Hwy 101 DS) (Removed 2013- all load on No.4 cct)	-	-	1,507	502					
Weyerhaeuser	14	402	1,549	655					
Wesdome Gold Mines	62	164	289	172					
(0-15 MW)	**482**	**16,338**	**3,652**	**6,824**					
Average for Load Block	**34**	**1,167**	**243**	**482**	360	89	(0-15 MW)	No	No

One load block <40MW worse than minimum standard, all other load blocks better than minimum standard. Score of 3.

Training initiated in Q2, first training sessions held May 1-2, 2014

Leadership Development with [redacted]

Thu 05/01/2014 8:00 AM - 5:00 PM (Repeats)

Attendance is **required** for [redacted]

Show Details

Chair: [redacted]

Location: Water-Tower - Library

Required: [redacted]

Repeats: This entry repeats

⊞ View Dates

Description | **Personal Notes**

This will be the first 2 day leadership development training - Role of a Supervisor/Leader.
We need everyone committed to this training. If you have any major conflicts, please see me asap, so we can move forward with the scheduling.

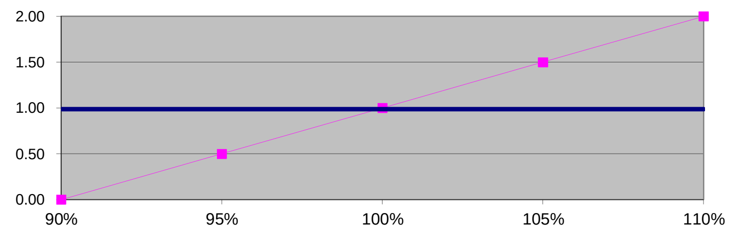
2015
KPI Summary

GREAT LAKES POWER TRANSMISSION

KPI SUMMARY - 2015

	2015 KPI SCORE	MULTIPLIER	WEIGHT	VP IMPACT
GREAT LAKES POWER FFO	0.999	0.987	40%	39.48%

	Actual FFO	Plan FFO	Variance	% vs. Plan
Transmission	$ 19,795.6	$ 19,822.2	$ (26.6)	99.9%
Great Lakes Power Total	$ 19,795.6	$ 19,822.2	$ (26.6)	99.9%



	2015 KPI SCORE	MULTIPLIER	WEIGHT	VP IMPACT
COMMON OBJECTIVES	4.0	1.500	40%	60%

5.0 ***DELIVER ZERO HIGH RISK HSS&E INCIDENTS***

Weighting: **10%**

	HIGH RISK INCIDENTS			
Operations	**Fatality**	**Serious**	**Contact**	**No Contact**
Health & Safety	0	0	0	0
Security	0	0	0	0
Environment	0	0	0	1
TOTAL	**0**	**0**	**0**	**1**

Key Performance Indicator (K.P.I.) score scale

Disab or Fat	Serious	Contact	No Contact	Score
0	0	0	2	5
0	0	0	3	4
0	0	1	3	3
0	1	2	4	2
1	2	3	5	1

5.0 ***Completion of HSS&E Strategic Plans***

Weighting: **2%**

GLPT prepares and executes against a strategic plan for Health & Safety, Public Safety and Environment each year. This objective is to measure GLPT's success in completing the objectives of each plan for the year.

H&S - 100%
Public Safety - 95%
Environment - 98%

Average - 98%

Key Performance Indicator (K.P.I.) score scale

	Score
Complete >95% of plan objectives in the year	5
Complete 90-95% of plan objectives in the year	4
Complete 85-90% of plan objectives in the year	3
Complete 80-85% of plan objectives in the year	2
Complete <80% of plan objectives in the year	1

GREAT LAKES POWER TRANSMISSION

KPI SUMMARY - 2015

2.0	***MEET LEADING INDICATOR TARGETS RELATED TO HEALTH & SAFETY***	Weighting: **2%**

GLPT has a number of initiatives and processes in place to provide leading indicators that ensure shortfalls or deficiencies in the health and safety program are identified early and corrected proactively. GLPT's 2015 focus remained on establishing a program for job plan quality assurance (QA) checks, and continuing its work observation program.

Job Plan QAs - 69%

Work Observations - 83%

Key Performance Indicator (K.P.I.) score scale - QA - 1%	Score
Achieve >95% of targeted QA checks for entire mgmt team & :	5
Achieve >95% of targeted QA checks for entire mgmt team	4
Achieve 90-95% of targeted QA checks for entire mgmt team	3
Achieve 80-90% of targeted QA checks for entire mgmt team	2
Achieve <80% of targeted QA checks for entire mgmt team	1

Key Performance Indicator (K.P.I.) score scale - Work Obs - 1%	Score
Achieve >95% of targeted work observations for entire mgmt t	5
Achieve >95% of targeted work observations for entire mgmt t	4
Achieve 90-95% of targeted work observations for entire mgm	3
Achieve 80-90% of targeted work observations for entire mgm	2
Achieve <80% of targeted work observations for entire mgmt t	1

4.0	***EXECUTE 2015 CAPITAL PLAN ON SCOPE AND BUDGET***	Weighting: **4%**

Capital	Budget	Actual	%	Rating
Total Spending	$9,220	$9,211	99.9%	**5.0**
Individual Projects	Weighted	3.0		**3.0**
KPI Score				**4.0**

Key Performance Indicator (K.P.I.) score scale - Budget - 2%	Score
Spend 98% to 100% of OEB-approved Budget	5
Spend 95% to 98% or 100% to 101% of envelope	4
Spend 92% to 95% or 101% to 102% of envelope	3
Spend 90% to 92% of envelope	2
Spend less than 90% or greater than 102%of envelope	1

- Maximum capital expenditure equal to OEB-approved capital spending, all of which is spent prudently

- Each project is managed on scope, schedule and budget

- For individual project ratings (for scope, schedule and budget), total score to be weighted based on total approved budget

Key Performance Indicator (K.P.I.) score scale - Projects - 2%	Score
Spend 98% to 102% of approved IRF/FWO	5
Spend 96% to 104% of approved IRF/FWO	4
Spend 94% to 106% of approved IRF/FWO	3
Spend 90% to 110% of approved IRF/FWO	2
Spend <90% or >110% of approved IRF/FWO, or not compelte	1

1.0 ***COMPLETE ASSET MANAGEMENT PLAN***

Weighting
3%

A third party consultant has been engaged and the plan will be completed prior to filing with the OEB, however the plan is still in progress at Dec 31, 2015.

Key Performance Indicator (K.P.I.) score scale - AM Plan	Score
Asset Management Plan completed by Sept 30, 2015	5
Asset Management Plan completed by Oct 31, 2015	4
Asset Management Plan completed by Nov 30, 2015	3
Asset Management Plan completed by Dec 31, 2015	2
Asset Management Plan not completed at Dec 31, 2015	1

5.0 ***DEVELOP LAND MANAGEMENT STRATEGY***

Weighting
3%

Land Management Strategy was in place by Sept 30, 2015.

Key Performance Indicator (K.P.I.) score scale - Land Mgmt	Score
Land Management Strategy completed by Sept 30, 2015	5
Land Management Strategy completed by Oct 31, 2015	4
Land Management Strategy completed by Nov 30, 2015	3
Land Management Strategy completed by Dec 31, 2015	2
Land Management Strategy not completed at Dec 31, 2015	1

5.0 ***DELIVER OM&A AT OR BELOW OEB APPROVED LEVELS***

Weighting
3%

Controllable OM&A	Transmission 2015
OM&A Budget	$11,109
OM&A Actual	$10,746
% of Budget	96.7%
KPI Score	

$412k in corporate costs were included in OM&A

Key Performance Indicator (K.P.I.) score scale	Score
Costs are at or below the OM&A approved by the OEB with $4	5
Costs do not exceed OEB approved by more than $50k with $	4
Costs do not exceed OEB approved by more than $100k with	3
Costs do not exceed OEB approved by more than $200k with	2
Costs exceed OEB approved by more than $200k or less than	1

GREAT LAKES POWER TRANSMISSION

KPI SUMMARY - 2015

		Weighting
4.0	***MAINTAIN RELIABILITY STANDARDS***	3%

Three year rolling averages indicate a score of 4 for Frequency:

Three year rolling averages indicate a score of 3 for Duration:

Key Performance Indicator (K.P.I.) score scale - Outage Frequency - 1.5%	Score
All load blocks better than average standard	5
All load blocks better than minimum standard, with 2 better thar	4
All load blocks better than minimum standard, or 1 below 40MW	3
Two load blocks below 40MW or one above 40MW exceed min	2
Two load blocks above 40MW or three total load blocks exceed	1

Key Performance Indicator (K.P.I.) score scale - Outage Duration - 1.5%	Score
All load blocks better than average standard	5
All load blocks better than minimum standard, with 2 better thar	4
All load blocks better than minimum standard, or 1 below 40MW	3
Two load blocks below 40MW or one above 40MW exceed min	2
Two load blocks above 40MW or three total load blocks exceed	1

		Weighting
1.0	***COMPLETE COMPLIANCE PROGRAM***	3%

GLPT on-boarded a Compliance Analyst, completed a gap analysis, and is in the process of documenting its NERC training program and NERC compliance program (including CIP v5 compliance), however the program is not complete as at Dec 31, 2015.

Key Performance Indicator (K.P.I.) score scale - AM Plan	Score
Compliance Program completed by Sept 30, 2015	5
Compliance Program completed by Oct 31, 2015	4
Compliance Program completed by Nov 30, 2015	3
Compliance Program completed by Dec 31, 2015	2
Compliance Program not completed at Dec 31, 2015	1

		Weighting
5.0	***DELIVER ZERO HIGH RISK COMPLIANCE AND OPERATIONAL INCIDENTS***	2%

	HIGH RISK INCIDENTS			
	Major	**Serious**	**Minor**	**None**
Regulatory Compliance	0	0	0	0
Operational	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**

Key Performance Indicator (K.P.I.) score scale				
Major	**Serious**	**Minor**	**lo Consequenc**	**Score**
0	0	0	1	5
0	0	0	2	4
0	0	1	3	3
0	1	2	4	2
1	2	3	5	1

GREAT LAKES POWER TRANSMISSION

KPI SUMMARY - 2015

5.0 ***SECURE MANDATE AND COMPLETE C/A NEGOTIATION***

Weighting: **3%**

Completed in October 2015, with costs in line with negotiating mandate. Three year agreement in place effective Jan 1, 2016.

Key Performance Indicator (K.P.I.) score scale - Regional Planning	Score
Agreement signed by Dec 31, 2015 with costs in line	5
Agreement in principle by Dec 31, 2015 with costs in line	4
Agreement in principle by Dec 31, 2015, and 0-3% above costs	3
Agreement in principle by Jan 15, 2016, or 3-5% above costs	2
No agreement in principle at Jan 15, 2016 or costs +5%	1

1.0 ***ESTABLISH DEVELOPMENT PLAN FOR KEY STAFF***

Weighting: **2%**

Individual development plans serve to equip GLPT for succession planning in the future. While some development plans were completed, not all were completed for various reasons, including:

- New hires were not in place in time to allow for a full assessment of development needs, and
- Certification of administrative salary employees into a union occurred in Summer 2015

Key Performance Indicator (K.P.I.) score scale - IDP's	Score
Individual Development Plans in place by March 31, 2015	5
Individual Development Plans in place by May 31, 2015	4
Individual Development Plans in place by July 31, 2015	3
Individual Development Plans in place by Sept 30, 2015	2
Individual Development Plans not in place by Sept 30, 2015	1

	2015 KPI SCORE	MULTIPLIER	WEIGHT	VP IMPACT
PERSONAL OBJECTIVES	3	1.000	20%	20%

	WEIGHT	VP IMPACT
TOTAL VARIABLE PAY SCORE	100%	119%

Great Lakes Power Transmission LP
Reconciliation of FFO for 2015

FFO Budget		**19,822,200**	Budget FFO of $19,572 plus $250 in development cost budget.	
NOI per Financial Statements & Metrics		**19,620,400**		
Add Back:	Development Expenses	160,100		
	Regulatory Expenses	15,100		
NOI per KPI Measurement		**19,795,600**		
	Core OM&A Variances	362,500		
	Other Income Variance	15,500		
	Interest Expense Variance	10,600		
	Revenue Variances	(415,200)		
NOI per Budget		**19,822,200**	**19,822,200**	Check vs budget
			-	Variance

OM&A Calculations:

Actual OM&A	10,746,400	
Less:	-	
Less:	-	
Measured OM&A	**10,746,400**	
OM&A Budget	11,108,900	**Includes $50k in Holdco expenses, and is therefore $50k higher than OEB-Approved OM&A plus property taxes
Core OM&A Variance	**362,500**	

Health, Safety & Environment Monthly Incident Reporting

Report for Month of: December 2015

Summary of Statistics - Year to Date									
	Contractor			GLPT			Third Party (No GLPT / Contractor Involvement)		
Incident Type	Current Month	YTD		Current Month	YTD		Current Month	YTD	
Public Incident	0	0		0	2		0	1	
Environmental Incident	0	0		0	3		0	0	
Personal Injury	0	0		1	6		0	0	
Property Damage	0	2		1	4		0	0	
Vehicle Accidents	0	0		0	0		0	2	
Contractor	0	1		0	0		0	1	
Totals	0	3		2	15		0	4	
Risk Rating for all Incidents	High	Medium	Low	High	Medium	Low	High	Medium	Low
	0	0	3	1	0	14	3	0	1

Total Summary of Statistics – Year to Date			
Total Incidents YTD	22	(Includes Third Party Reporting Incidents)	
Lost Time resulting from a personal injury.	0	Medical Aid resulting from a personal injury.	0
High Risk Incidents (near miss) YTD	1	Calendar Days without Lost Time (cumulative)	2372

Incident Details:

1. **2015-1 GLPT Feb. 20/15-Public Incident Potential for Harm: High**
Sleeve failure on Sault#3: A sleeve failure in the Sault#3 Conductor caused the conductor to fall onto Hwy 17 North at Post Office Road. The Hwy was closed in its entirety by emergency services shortly after the failure was reported. There were no and no injuries reported. The local distribution was effected by the trip of Sault#3 resulting in an extended outage for some of the local distribution customers. The local distribution was effected as the broken Sault #3 conductor was lying across the single phase distribution circuit. The Sault#3 downed phase was initially cleared from the highway by an Algoma Power Line crew to allow limited traffic to pass. Later in the day the downed phase was fully cleared to allow the resumption of normal traffic flow to both lanes of traffic. The line was fully restored on Saturday February 21-2015 in order to minimize additional disruption to local distribution on Friday.
Corrective Actions:
    a. CCT15033
    b. ERP15037
    c. SYS15038
    d. GLPT15039

Great Lakes Power
Transmission

2015 Strategic Safety Plan Objectives, Targets and Programs

Objective	Target(s)	Program(s)	Actions	Responsibility	Q4 Updates	% Complete	Target Achievement Status
2015 Strategic Initiatives							
1. The #1 focus for GLPT in 2015 will be "0" High Risk Safety Incidents	Complete 2015 with zero High Risk Safety Incidents.	All GLPT Health & Safety Programs, BREG-SP2	Meet or exceed GLPT, BREG and Legislative requirements - continue focus on Job Planning, Project Planning & Change Analysis - Work Observations & Quality Assurance	[redacted]	ZERO High Risk Safety Incidents in Q4 ZERO Lost time Incidents through Q4	100%	
2. Job Planning	Job Planning Authorization Form (2.5.1Fa)	Work Observation Program	Determine the criteria as it relates to competency to complete Job Plans. Complete by Q4 1) Initial Authorization 2) Annual Job plan Quality reviews 3) Ongoing coaching through Crew Visits	[redacted]	**As per GLPT Procedure 2.5.1 - Job Planning:** a) Responsible Authority will approve those people deemed qualified to approve Job Plans. Form 2.5.1Fa to be signed by the Responsible Authority Annually b) Management must conduct formal Quarterly Quality & Assessment reviews of Project S&E Plans and Daily Job S&E Plans. Agenda item added to Managers meetings c) Job Planning shall be formally monitored during safety meetings and work observations. Job Plan Quality reviews and crew visits to continue * Management to continue mentorship in completion of job plans through the quarterly quality reviews	100%	
3. Contractor Orientation	Contractor Safety Orientation Improvements	Contractor Safety Management (4.5.1)	Ensure orientation adequately covers: 1) Security Element 2) Job Planning Procedure 3) Work protection expectations. 4) Low Risk - separate orientation 5) Add an example of a completed DJSEP c/w environmental aspects / impacts	[redacted]	Two (2) Contractor Orientation have been developed. a) Orientation for Low Risk Work b) Orientation for Medium/High Risk Work.	100%	
Audit Findings (2015)							
4. Job Planning	Job Planning Procedure (2.5.1)	Job Planning	1. Review the requirements of the Job Planning Procedure with Management to ensure that all requirements are being met. Complete by Q4	[redacted]	Management review of PSEP's: Quarterly Managers meetings in 2016 will have an agenda item pertaining to review of PSEP's Supervisor Handbook: Supervisor Handbook will have a section outlining the Job Planning Procedure Requirements	100%	
	Job Planning	Job Planning	1. Reinforce the requirements of the Daily Job Safety & Environmental Plans process and provide awareness (or refresher) training to staff. Complete by Q4	[redacted]	Job Planning/Change Analysis Training: - Tom Headrick provided high level training to two managers October 15. - Tom provided training to most of GLPT November 30 - Tom provided work group specific training December 7/8	100%	
5. Contractor Management	Conformance to Procedure	Contractor Safety Management (4.5.1)	Ensure the contractor safety management procedure (4.5.1) is applied to all contracts or revise procedure to reflect smaller contracts	[redacted]	GLPT Contractor Safety Management Procedure 4.5.1 has been revised to identify requirements for Low, Medium and High Risk work activities This will be reviewed by JHSC in 2016	100%	
Audit Findings (2013)							
6. GLPT 2013 Safety Management Audit	Item #1 - Develop Procedure re biological hazards. (priority 1)	Occupational Health - Biological & Physical Agents	Develop a procedure and provide training on preventative and protective measures re bee stings, ticks, poisonous plants and wild animals. As part of the development process research industry and BREG companies to identify best practices. This procedure to be completed, signed and implemented into SWMS by end Q2.	[redacted]	A new "Biological Hazards" Procedure has reviewed by JH&S, approved and placed in the SWMS as #2.3.11.	100%	
	Item #3 - Job Safety Analysis. GLPT should include critical tasks performed by Contractors. (priority 2)	GLPT SWMS 2.1.2 Critical Task List	* Safety Specialist with assistance from operations, review contractors work procedures to identify if additional work procedures should be added to GLPT critical tasks (Q3). * New critical task procedures developed and rolled out by Q4.	[redacted]	Two work procedures were identified to be added to the GLPT critical task list. 1) Use and Operation of a wood chipper. This has been finalized. Needs to be approved 2) Use and Operation of cranes. This is has been approved. 3) Both procedures will be reviewed by JHSC in 2016	100%	
	Item #4 - GLPT should include Job Safety Analysis as part of critical task development. (priority 2)	GLPT SWMS 2.1.1 Hazard Analysis	GLPT to ensure Job Safety Analysis is utilized in the development of Critical Task Procedure on a go forward basis. For existing Critical Tasks we will develop 6 JSA's by end of Q4. Remaining Critical Task JSA's to be completed in 2016 The 6 JSA's selected for 2015 are: #2 Chainsaw Use, #4 Driving, #9 Tree Felling, #5 Management of SOD, #8 Switching, #13 Working Under Work Protection Code. July 8/15: Review draft version of #5, #8, #13.Set date for review of draft for #2, #4, #9	[redacted]	GLPT to ensure GLPT 2.1.1 Hazard Analysis, "Job Safety Analysis" (JSA) is utilized in the development of Critical Task Procedures on a go forward basis. In 2015, "Use and Operation of a Wood Chipper" and "Use and Operation of Cranes" were identified as two new Critical tasks. In 2016, JHSC will review the Procedures and assit in the completion and review of the JSA related to both new Critical Tasks.	100%	
7. GLPT 2012 Safety Management Audit	Item #10 - GLPT should document how the administration of the Heat & Cold Stress should proceed. (priority 3)	Occupational Health - Biological & Physical Agents	Develop a Heat & Cold Stress Procedure using BREG and industry best practices Q2, trained and rolled out by Q3. This procedure to be completed, signed and implemented into SWMS by end Q2 2015	[redacted]	A new "Work in Adverse Environments" Procedure has been approved and placed in the SWMS as #2.3.12.	100%	
2013 / 2014 Carry forward Items							
8. Review Work Observation process to identify and implement continuous improvement.	1) Look for opportunities to improve Work Observation process. 2) Review of existing process completed by Q2 3) Proposed new process developed and approved by Q3 4)Implementation and training initiated in Q4	Safe Work Observations - Crew Visits - SWMS 5.1.1	Review Work Observation process focusing on: 1) Site visits 2) Forms 3) Work observation training for observers 4) Summary reporting. The focus for 2015 will be to: 1) Develop Work Observation Training by Q3. Roll out training in Q4. 2) Develop a report to summarize trends during Job Plan Quality Reviews and Safe Work Observations	[redacted]	Work Observation Training: - Tom Headrick provided high level training to two managers October 15. - Tom provided training to most of GLPT November 30 -Tom provided work group specific training December 9/10	100%	

Great Lakes Power Transmission		2015 Public Safety Plan Objectives, Targets and Programs				
Objective	**Target(s)**	**Program(s)**	**Actions**	**Q4 Updates**	**% Complete**	**Target Acheivement Status**
2015 Strategic Initiatives						
The #1 focus for GLPT in 2015 will be "0" High Risk Public Safety Incidents	Complete 2015 with ZERO High Risk Public Safety Incidents. Ongoing	GLPT Public Safety Program	Meet or exceed BREG EP08 (R2), GLPT and Legislative requirements (via committee and management team meetings)	a) No High Risk Incidents in Q4 b) One (1) High Risk Incident in Q1 (Sault#3, Equipment Related, No Injuries)	100%	
Develop & Communicate Public Safety Education Plan	Promote Public Safety Awareness around TS's and on ROW's Ongoing	Public Safety Communication & Education	Promote Public Safety awareness using various methods i.e. Trade Shows, Intranet & Internet sites and awareness sessions with stakeholders. Complete by Q4	a)Attended the Chamber of Commerce Spring Expo in March b) Stake Holder meetings will be completed in Q1 of 2016 c) Electrical Awarness was completed with Lyons staff October 13-2015 d) Flying J site was visited on a number of occasions during construction	100%	
Clergue Safety Review	Review physical security at Clergue TS with focus on public safety due to increased public traffic	Public Safety	Focus on Signage, Fence, Bollards, Snow removal practices, Cameras. Complete by Q4	a) Public Safety Committee visited the Clergue site. b) Identified items for Corrective Actions that have been provided to Civil and Forestry. c) Recommendations were provided to Engineering for future station refurbishment.	100%	
Tower Sites	Tower Lighting and Tower Security	Public Safety	Complete Physical review at Tower sites. Complete by Q4	a) Helen Mine and Gartshore completed week of October 19-23 b) St. Joe's and Northland completed September 29 c) Hubbert completed October 28	100%	
Transmission Stations Equipment	Station Equipment locks	GLPT Public Safety Program - BREG-EP08	Company locks must be installed on all switch handles and outdoor equipment access doors (e.g. at circuit breakers and switchgear enclosures, pad mounted transformers, or control cabinets) Complete by Q4	a) System review was completed. b) There are approx. 200 pieces of equipment have been identified as potentially needing locks. c) Darrel to discuss Brookfield procedure with Duane to determine next steps	75%	
Review and Comply with AODA	Accessibility Standards (2 Sackville Road)	Legal Compliance	Review Accessibility for Ontarians with Disabilities Act (AODA) Complete by Q4	a) GLPT has gathered required information to become compliant. (Policy, Procedure, employee training program) b) There is no requirement to file compliance reports at this time. c) Implementation of documents to the Portal and GLPT website to be completed in 2016 d) Training to GLPT staff to be provided in 2016	100%	
2014 Carry Forward Items						
2. Develop & Communicate Public Safety Education Plan (Audit Finding)	Item #2 - continue to incorporate information from the G. Gazankas Report into Public Safety Program	GLPT Public Safety Program - BREG-EP08	Thorough review of document to ensure all appropriate components incorporated i.e. facilities description. Complete by Q4	a) Implementation of recommendations complete b) This is now at the review level and awaiting final approval.	95%	

Great Lakes Power
Transmission

2015 Environmental Plan, Objectives, Targets and Programs

Objective	Target(s)	Actions	Q4 Updates	% Complete	Target Achievement Status
2015 Strategic Initiatives					
1. The #1 focus for GLPT in 2015 will be "0" High Risk Environmental Incidents	Complete 2015 with zero High Risk Environmental Incidents as it relates to the Public, Third-Party Property, Environment and GLPT Reputation	Meet or exceed GLPT, BREG and Legislative requirements - continue focus on Job Planning, Project Planning & Change Analysis - Work Observations & Quality Assurance	ZERO High Risk Environmental Incidents in Q4	100%	
2. Develop and maintain strategic partnerships with third parties to expand environmental knowledge, assess our environmental impacts, increase our effectiveness, and promote our work.	Continue supporting CFL program (financial commitment, goal setting and monitoring). 2015 goals set with CFL strategic action plan. Monthly meetings throughout 2015 to set objectives and monitor progress.	Continued participation with CFL (Corridors For Life) program. 2015 key objectives include: 1) Develop BMP for management of Riparian Zones 2)Implement APP (Avian Protection Plan) including field staff training 3) Execute all pre and post vegetation management field surveys to support impact assessment initiative 4) Final year for Chippewa and Goulais River Wood turtle populations study	1) Develop BMP (Best Management Plan/Practice) for management of Riparian Zones. This will not be completed in 2015. Investigating resources to continue in 2016. 2) APP implemented and staff trained. 3) All surveys for 2015 completed. 4) Final report for Wood Turtle study should be received early 2016.	90%	
2013 / 2014 Carry Forward Items					
3. EMS Documentation	Integration of RIM and EMS Documentation Procedures. Q3 & Q4.	Work with RIM committee for completion of e-filing as per determined direction. Integrate with EMS Document Management procedure. Q3 Filing, Q4 Procedure	An electronic filing structure was completed for all Environmental documents	100%	
4. Review GLPT's Environmental Management System (EMS) requirements to identify and implement continuous improvements	a) Look for opportunities to improve GLPT's existing aspect scoring and management process. Review of existing process completed by Q2 Proposed new process developed and approved by Q3 Implementation and training initiated in Q4.	1) Review existing aspect scoring and management process focusing on: * Matrix Structure, * Aspect Wording, * Aspect Categories, * Environmental Impact, * Legislation, * Scoring Methodology, * Reference to Procedures., * Update aspect matrix to reflect findings. 2) See Audit 2013 targets 5 for specific deliverables arising from audit. 3) Review Brookfield current Scoring methodology. Complete by Q4	Inclusion of the following will be considered for scoring methodology in 2016: a) Public health and safety impact to business criteria b) Degree and control of influence to environmental criteria	100%	
	b) Review and update all GLPT environmental procedures within the EMS to reflect operations. 1/3 by Q2, 2/3 by Q3, completed by Q4	Create an environmental procedure review team to review all environmental procedures. Complete by Q4. Scheduled to be developed for 2016.	ELT will create a schedule to review GLPT Environmental Prorceudures in 2016. Some procedures may need to be reviewed in 2017.	100%	
5. Develop and maintain a program that continues to support and improve stakeholder relations	Engage in open and transparent dialogue with First Nation stakeholders when opportunity arises.	Open and transparent dialogue is offered to First Nation Bands, Townships, other interest groups) as required for projects, etc.. Ongoing	a) Longterm land use permit has been reached with Garden River. b) Batchawana First Nation negotiation is ongoing.	100%	

Great Lakes Power
Transmission

Health, Safety & Environment Monthly Incident Reporting

Great Lakes Power
Transmission

Job Plan Quality Reviews & Safe Work Observations

GLPT Job Plan Quality Reviews - 2015															
Employee	Targets per Year	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total	% Complete
Supervision															
[redacted]	0													0	0%
	6													0	0%
	12			2	1	2		1	4	1			1	12	100%
	6							3		1	2			6	100%
	2													0	0%
Expected	26												Summary YTD	18	69%
GLPT Safe Work Observations - 2015															
Employee	Targets per Year	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total	% Complete
Management															
[redacted]	6								2					2	33%
	2												2	2	100%
	0													0	0%
	12						1						3	4	33%
	2											1		1	50%
	12			2	1	1	3	2	1	1	1	1	1	14	117%
	12			1		2	3	7	2					15	125%
	12				1		2	2		3				8	67%
Group Leaders															
[redacted]	12							3	3	3	1	1	2	13	108%
JH&SC															
Committee Members	2				1									1	50%
[redacted]															
Expected	72												Summary YTD	60	83%

GLPT KPI on Capital Spending

Total CapEx - Brookfield Budget:

Percentage		**90%**		**92%**		**95%**		**98%**		**100%**		**101%**		**102%**	
KPI Score	**1**		**2**		**3**		**4**		**5**		**4**		**3**		**1**
Spending		**8,298**		**8,482**		**8,759**		**9,036**		**9,220**		**9,312**		**9,404**	
Window			**184**		**277**		**277**		**184**		**92**		**92**		

GREAT LAKES POWER TRANSMISSION LP
CAPITAL WORK IN PROGRESS
December 31, 2015

PROJECT NUMBER	PROJECT DESCRIPTION	OPENING 2015	CAPITAL EXPENDITURES	Adjustments	CLOSED TO CAPITAL	CLOSING Dec-15	IRF/FWO Amount	Variance	% Variance	KPI Score	Weighted
I06015	WATSON BUS PROTECTION	22,761.33	0.00		0.00	22,761.33					
I06045	WATSON B.F. PROTECTIONS	13,243.28	0.00		0.00	13,243.28					
I06077	ANJIGAMI BRAKER FAIL PROT	30,008.44	0.00		0.00	30,008.44					
I07006	ALGOMA LINES UPGRADE	354,506.37	1,949.79	(356,456.16)	0.00	(0.00)					
I07128	TS GROUNDING - GOULAIS	67,851.50	0.00		0.00	67,851.50					
IT9086	CLERGUE TS UPGRADE -ENGIN	80,224.70	0.00		0.00	80,224.70					
I10011	REMOTE TERMINAL UNIT STUD	125,238.57	0.00	0.00	0.00	125,238.57					
I10012	NETWK SYSTEM CONFIG STUDY	225,742.56	0.00		0.00	225,742.56					
I10047	RELAY PROT REPLACE STUDY	243,658.82	0.00	0.00	0.00	243,658.82					
I11033	ERP SOFTWARE UPGRDE STUDY	173,570.36	336,331.62		367,129.43	142,772.55					
I11085	DOC MGEMENT STRATEGIC PLN	49,265.01	0.00	(49,265.01)	0.00	0.00					
I11107	COMMUNICATIONS STUDY	153,926.12	0.00		0.00	153,926.12					
I12005	MYPASSWORDS SOFTWARE	25,572.07	0.00	(25,572.07)	0.00	0.00					
I14023	P&C MAINTENANCE PROGRAM	33,484.10	33,202.87		66,686.97	0.00					
I14036	HOGG STRUCTURE REPLACMENT	42,398.36	152,144.24	(194,542.60)	0.00	0.00					
I14037	GARTSHORE STRUCTURES	42,149.05	5,273,747.29	550,998.76	5,866,895.10	0.00	5,630,000.00	236,895.10	104.21%	3	2.349665759
I14038	HIGHWAY 101 UPGRADES	116,695.19	1,032,978.55	0.00	1,149,673.74	0.00	1,029,600.00	120,073.74	111.66%	1	0.143233621
I14040	NTHRN AV TRANSFORMER TB	28,205.15	183,842.36		212,047.51	0.00	218,100.00	(6,052.49)	97.22%	4	0.121364619
I14041	GOULAIS BATTERY & CHARGER	13,443.57	114,085.32		127,528.89	0.00	156,556.43	(29,027.54)	81.46%	1	0.021779472
I14042	ICCP CONNECTION	5,763.58	10,952.54		16,716.12	0.00					
I14043	FLASH CARD RTU UPDATE	0.00	28,475.65		28,475.65	0.00					
I14044	ANJIGAMI TS REFURBISHMENT	13,008.92	290,593.96		0.00	303,602.88					
I14045	WATSON T2 HV BREAKER	8,514.10	79,057.25		0.00	87,571.35					
I15001	GIS UPGRADES	0.00	35,320.33		35,320.33	0.00					
I15002	15 01 SKI DOO SKANDIC	0.00	12,370.93		12,370.93	0.00					
I15003	15 02 SKI DOO SKANDIC	0.00	12,370.92		12,370.92	0.00					
I15004	15 03 SNOWMOBILE TRAILER	0.00	5,611.95		5,611.95	0.00					
I15005	BUTLER BUILDING UPGRADES	0.00	0.00		0.00	0.00					
I15006	LAPTOP FOR ENGIN TECH	0.00	3,038.78		3,038.78	0.00					
I15007	SMALL COMPUTER PURCHASES	0.00	11,213.15		11,213.15	0.00					
I15008	STORAGE UPGRADE	0.00	4,972.00		4,972.00	0.00					
I15009	API GARAGE PANEL	0.00	11,018.64		11,018.64	0.00					
I15010	SIGNAGE & GUY GUARDS	0.00	86,935.54		86,935.54	0.00					
I15011	15 04 2015 CHEV TRAVERSE	0.00	38,251.34		38,251.34	0.00					
I15012	15 05 2015 CHEV SILVER	0.00	42,037.05		42,037.05	0.00					
I15013	15 06 2015 CHEV SILVERADO	0.00	42,037.05		42,037.05	0.00					
I15014	MACKAY GROUND GRID UPGRDE	0.00	53,475.86		0.00	53,475.86					
I15015	CT REPLACEMENTS	0.00	75,914.32		0.00	75,914.32					
I15016	GARAGE STAIRS ROOF ACCESS	0.00	10,405.33		10,405.33	0.00					
I15017	T450 LAPTOPS (8)	0.00	21,459.81		21,459.81	0.00					
I15018	T450 LAPTOPS (2)	0.00	5,322.74		5,322.74	0.00					
I15019	T450 LAPTOPS (3)	0.00	10,204.85		10,204.85	0.00					
I15020	AUTOCAD LT-LINE ENG	0.00	1,571.00		1,571.00	0.00					
I15021	Suite A HVAC Upgrade	0.00	140,815.67		140,815.67	0.00	154,000.00	(13,184.33)	91.44%	2	0.042847665
I15022	RADIO SYSTEM STUDY	0.00	15,146.70		0.00	15,146.70					
I15023	ANDREWS OIL CONTAINMENT	0.00	53,834.47		53,834.47	0.00					
I15024	HOLLINGSWORTH STRUCTURES	0.00	268,690.36		0.00	268,690.36					
I15025	VAULT SUMP PUMP	0.00	7,975.00		7,975.00	0.00					
I15026	WINMAGIC LICENSES	0.00	2,481.78		2,481.78	0.00					
I15027	SEA CANS- THIRD LINE	0.00	14,217.50		14,217.50	0.00					
I15028	15 07 HONDA ORV	0.00	19,161.68		19,161.68	0.00					
I15029	15 08 POLARIS RANGER	0.00	18,344.59		18,344.59	0.00					

GREAT LAKES POWER TRANSMISSION LP
CAPITAL WORK IN PROGRESS
December 31, 2015

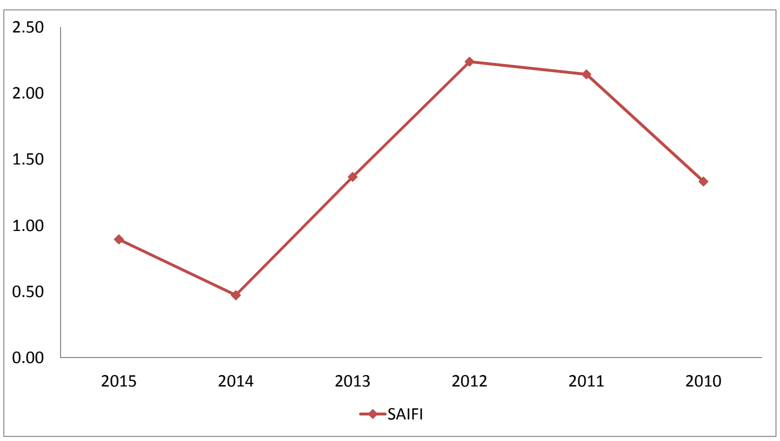
PROJECT NUMBER	PROJECT DESCRIPTION	OPENING 2015	CAPITAL EXPENDITURES	Adjustments	CLOSED TO CAPITAL	CLOSING Dec-15	IRF/FWO Amount	Variance	% Variance	KPI Score	Weighted
I15030	15 09 POLARIS RANGER	0.00	18,144.61		18,144.61	0.00					
I15031	OFFICE UPGRADE	0.00	54,958.43		54,958.43	0.00					
I15032	STORES BUILDING SIDING	0.00	9,025.00		9,025.00	0.00					
I15033	PLS CADD	0.00	20,107.67		20,107.67	0.00					
I15034	DESK & CHAIR	0.00	5,168.67		5,168.67	0.00					
I15035	GENERLINK SURGE W/30 AMP	0.00	1,049.75		1,049.75	0.00					
I15036	CISCO SWITCH UPGRADE	0.00	98,700.19			98,700.19					
I15037	HOLLINGSWORTH T2 PROTECT.	0.00	63,554.99			63,554.99					
I15038	OC 48	0.00	122,185.73			122,185.73					
I15039	FRONT STAIRS SACKVILLE	0.00	6,631.26		6,631.26	0.00					
I15040	SUMP PUMP ALARM	0.00	2,087.00		2,087.00	0.00					
I15041	4 LENOVO M93P DESKTOPS	0.00	5,142.15		5,142.15	0.00					
I15042	CANNON PLOTTER	0.00	11,250.00		11,250.00	0.00					
I15043	AUTOCAD SOFTWARE	0.00	15,712.00		15,712.00	0.00					
I15044	LAND ACQUISITION	0.00	68,000.00			68,000.00					
I15045	SNOWMOBILE TRAILER 15.10	0.00	6,632.66		6,632.66	0.00					
I15046	SNOWMOBILE TRAILER 15.11	0.00	6,632.66		6,632.66	0.00					
I15047	CT ANALYZER/TEST SET	0.00	10,716.61		10,716.61	0.00					
I15048	GARDEN RIVER PERMIT	0.00	124,194.25		124,194.25	0.00					
		1,869,231.15	**9,211,454.41**	**(74,837.08)**	**8,743,578.23**	**2,262,270.25**	**7,188,256.43**				**2.68**

	Customer DP Interruption Duration (min/yr)								
		Interruption Duration (minutes)			3Year Average (2013-15)	Minimum Standard Of Performance	Standard Average Performance	Load Category	
	Customer Delivery Point	2015	2014	2013					
1	EASI (301T1, 301T2, 301T3)	0	0	0	0.00	25	5	(>80 MW)	
	(>80 MW)	**0**	**0**	**0**	**0.00**				Better than average
2	PUC GL1TA / GL2TA	0	0	23	7.67	55	11	(40-80 MW)	
	(40-80 MW)	**0**	0	23	**7.67**				Better than average
	St Marys Paper Corp. (Breakers 150&155) Removed 2012	0	0	0	0.00	140	22	(15-40MW)	
	St Marys Paper Corp. (Breakers 154&151) Removed 2012	0	0	0	0.00	140	22	(15-40MW)	
3	ASI (10T1)	0	0	0	0.00	140	22	(15-40MW)	
4	PUC GL1SM / GL2SM	0	0	0	0.00	140	22	(15-40MW)	
	(15-40MW)	**0**	**0**	**0**	**0.00**				Better than average
5	Flakeboard Company	0	0	0	0.00	360	89	(0-15 MW)	
6	EASI (T6 and T7)	0	0	0	0.00	360	89	(0-15 MW)	
7	EASI (Wallace Terrace Sub)	0	0	0	0.00	360	89	(0-15 MW)	
8	API DIST (NA 34.5 kV)	0	0	0	0.00	360	89	(0-15 MW)	
9	API DIST (NA 12kV)	0	0	11248	3749.33	360	89	(0-15 MW)	
10	API DIST (ER)	0	86	98	61.33	360	89	(0-15 MW)	
11	API DIST (BATCH)	482	14	566	354.00	360	89	(0-15 MW)	
12	API DIST (GOULAIS)	276	299	601	392.00	360	89	(0-15 MW)	
13	API DIST (MACKAY)	0	0	0	0.00	360	89	(0-15 MW)	
14	API DIST (ANDREWS)	20	0	3248	1089.33	360	89	(0-15 MW)	
15	API DIST (WATSON - No.1 & No.2 Wawa)	0	7	0	2.33	360	89	(0-15 MW)	
	API DIST (WATSON Local Dist) Removed 2007	0	0	0	0.00	360	89	(0-15 MW)	
16	API DIST (No. 4 Circuit)	357	0	11	122.67	360	89	(0-15 MW)	
	API DIST (Hwy 101 DS) (Removed 2013- all load on No.4 cct)	0	0	0	0.00	360	89	(0-15 MW)	
17	Weyerhaueser	368	14	402	261.33	360	89	(0-15 MW)	
18	Wesdome Gold Mines	13	62	164	79.67	360	89	(0-15 MW)	
	(0-15 MW)	**94.75**	**30.13**	**1021.13**	**382.00**	360	89		Better than minimum
	A -Total Interruption Duration (minutes)	**94.75**	**30.125**	**1044.125**					
	B - Customers Served	**19**	**19**	**19**					
	SAIDI (A/B)	**5.0**	**1.6**	**55.0**					

Delivery Points		Load Category	10 year Average (2004-2013)
ESAI (301T1, 301T2, 301T3)		**(>80 MW)**	#REF!
PUC GL1TA / GL2TA		**(40-80 MW)**	#REF!
St Marys Paper Corp. (Breakers 150&155) Removed		**(15-40MW)**	#REF!
St Marys Paper Corp. (Breakers 154&151) Removed		**(15-40MW)**	#REF!
EASI (10T1)		**(15-40MW)**	#REF!
PUC GL1SM / GL2SM		**(15-40MW)**	#REF!
Flakeboard Company		**(0-15 MW)**	#REF!
ESAI (T6 and T7)		**(0-15 MW)**	#REF!
ESAI (Wallace Terrace Sub)		**(0-15 MW)**	#REF!
API DIST (NA 34.5 kV)		**(0-15 MW)**	#REF!
API DIST (NA 12kV)		**(0-15 MW)**	#REF!
API DIST (ER)		**(0-15 MW)**	#REF!
API DIST (BATCH)		**(0-15 MW)**	#REF!
API DIST (GOULAIS)		**(0-15 MW)**	#REF!
API DIST (MACKAY)		**(0-15 MW)**	#REF!
API DIST (ANDREWS)		**(0-15 MW)**	#REF!
API DIST (WATSON - No.1 & No.2 Wawa)		**(0-15 MW)**	#REF!
API DIST (No. 4 Circuit)		**(0-15 MW)**	#REF!
API DIST (Hwy 101 DS) (Removed 2013)		**(0-15 MW)**	#REF!
Weyerhauser		**(0-15 MW)**	#REF!
Wesdome Gold Mines		**(0-15 MW)**	#REF!

Customer DP - Frequency of Interruptions (Outages/yr)

Customer Delivery Point	Number of Outages 2015	2014	2013	3Year Average (2013-15)	Minimum Standard Of Performance	Standard Average Performance	Load Category	
EASI (301T1, 301T2, 301T3) (DP1)	0	0	0	0.00	1	0.3	(>80 MW)	
(>80 MW)	**0**	**0**	**0**	**0.00**				Better than average
PUC GL1TA / GL2TA (DP2)	0	0	2	0.67	1.5	0.5	(40-80 MW)	
(40-80 MW)	0	0	2	**0.67**				Better than minimum
St Marys Paper Corp. (Breakers 150&155) Removed 2012	0	0	0	0.00	3.5	1.1	(15-40MW)	
St Marys Paper Corp. (Breakers 154&151) Removed 2012	0	0	0	0.00	3.5	1.1	(15-40MW)	
EASI (10T1) (DP3)	0	0	0	0.00	3.5	1.1	(15-40MW)	
PUC GL1SM / GL2SM (DP4)	0	0	0	0.00	3.5	1.1	(15-40MW)	
(15-40MW)	**0**	**0**	**0**	**0.00**				Better than average
Flakeboard Company (DP5)	0	0	0	0.00	9	4.1	(0-15 MW)	
EASI (T6 and T7) (DP6)	0	0	0	0.00	9	4.1	(0-15 MW)	
EASI (LMF - Wallace Terrace Sub) (DP7)	0	0	0	0.00	9	4.1	(0-15 MW)	
API DIST (NA 34.5 kV) (DP8)	0	0	0	0.00	9	4.1	(0-15 MW)	
API DIST (NA 12kV) (DP9)	0	0	2	0.67	9	4.1	(0-15 MW)	
API DIST (ER) (DP10)	0	3	3	2.00	9	4.1	(0-15 MW)	
API DIST (BATCH) (DP11)	4	1	3	2.67	9	4.1	(0-15 MW)	
API DIST (GOULAIS) (DP12)	4	2	3	3.00	9	4.1	(0-15 MW)	
API DIST (MACKAY) (DP13)	0	0	0	0.00	9	4.1	(0-15 MW)	
API DIST (ANDREWS) (DP14)	1	0	8	3.00	9	4.1	(0-15 MW)	
API DIST (WATSON - Wawa No.1 & No.2) (DP15)	0	1	0	0.33	9	4.1	(0-15 MW)	
API DIST (WATSON Local Dist) Removed 2007	0	0	0	0.00	9	4.1	(0-15 MW)	
API DIST (No. 4 Circuit) (DP16)	3	0	1	1.33	9	4.1	(0-15 MW)	
API DIST (Hwy 101 DS) (Removed 2013- all load on No.4 cct)	0	0	0	0.00	9	4.1	(0-15 MW)	
Weyerhaueser Company Ltd. (DP17)	4	1	2	2.33	9	4.1	(0-15 MW)	
Wesdome Gold Mines (DP18)	1	1	2	1.33	9	4.1	(0-15 MW)	
(0-15 MW)	**17**	**9**	**24**	**5.56**				Better than minimum
A - Total Outages	**17**	**9**	**26**					
B - Customers Served	19	19	19					
SAIFI (A/B)	**0.9**	**0.5**	**1.4**					



Delivery Points		Load Category	10 year Average (2004-2013)
ESAI (301T1, 301T2, 301T3)		**(>80 MW)**	#REF!
PUC GL1TA / GL2TA		**(40-80 MW)**	#REF!
St Marys Paper Corp. (Breakers 150&155) Removed		**(15-40MW)**	#REF!
St Marys Paper Corp. (Breakers 154&151) Removed		**(15-40MW)**	#REF!
EASI (10T1)		**(15-40MW)**	#REF!
PUC GL1SM / GL2SM		**(15-40MW)**	#REF!
Flakeboard Company		**(0-15 MW)**	#REF!
ESAI (T6 and T7)		**(0-15 MW)**	#REF!
ESAI (Wallace Terrace Sub)		**(0-15 MW)**	#REF!
API DIST (NA 34.5 kV)		**(0-15 MW)**	#REF!
API DIST (NA 12kV)		**(0-15 MW)**	#REF!
API DIST (ER)		**(0-15 MW)**	#REF!
API DIST (BATCH)		**(0-15 MW)**	#REF!
API DIST (GOULAIS)		**(0-15 MW)**	#REF!
API DIST (MACKAY)		**(0-15 MW)**	#REF!
API DIST (ANDREWS)		**(0-15 MW)**	#REF!
API DIST (WATSON - No.1 & No.2 Wawa)		**(0-15 MW)**	#REF!
API DIST (No. 4 Circuit)		**(0-15 MW)**	#REF!
API DIST (Hwy 101 DS) (Removed 2013)		**(0-15 MW)**	#REF!
Weyerhauser		**(0-15 MW)**	#REF!
Wesdome Gold Mines		**(0-15 MW)**	#REF!

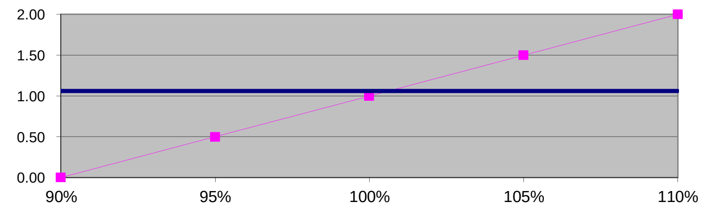
2016

KPI Summary

HYDRO ONE SAULT STE MARIE
KPI SUMMARY - 2016

	2016 KPI SCORE	MULTIPLIER	WEIGHT	VP IMPACT
HYDRO ONE SAULT STE MARIE FFO	1.006	1.060	40%	42.40%

	Actual FFO	Plan FFO	Variance	% vs. Plan
Transmission	$ 20,124.4	$ 20,005.2	$ 119.2	100.6%
Hydro One SSM Total	$ 20,124.4	$ 20,005.2	$ 119.2	100.6%



	2016 KPI SCORE	MULTIPLIER	WEIGHT	VP IMPACT
COMMON OBJECTIVES	4.0	1.500	40%	60%

5.0 ***DELIVER ZERO HIGH RISK HSS&E INCIDENTS*** — Weighting: 10%

	HIGH RISK INCIDENTS			
Operations	**Fatality**	**Serious**	**Contact**	**No Contact**
Health & Safety	0	0	0	0
Security	0	0	0	0
Environment	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**

KPI score scale

Disab or Fat	Serious	Contact	No Contact	Score
0	0	0	2	5
0	0	0	3	4
0	0	1	3	3
0	1	2	4	2
1	2	3	5	1

4.0 ***Completion of HSS&E Strategic Plans*** — Weighting: 3%

See attached, achieved a 99% completion for H&S and 93% for both Environment and Public Safety for an average of 95%

KPI score scale

	Score
Complete >95% of plan objectives in the year	5
Complete 90-95% of plan objectives in the year	4
Complete 85-90% of plan objectives in the year	3
Complete 80-85% of plan objectives in the year	2
Complete <80% of plan objectives in the year	1

3.0 MEET LEADING INDICATOR TARGETS RELATED TO HEALTH & SAFETY

Weighting: 2%

See Attached, achieved a 5 for work observations and a 1 for quality reviews for an average of 3

KPI score scale - QA - 1%	
	Score
Achieve >95% of targeted QA checks for entire mgmt team & 1	5
Achieve >95% of targeted QA checks for entire mgmt team	4
Achieve 90-95% of targeted QA checks for entire mgmt team	3
Achieve 80-90% of targeted QA checks for entire mgmt team	2
Achieve <80% of targeted QA checks for entire mgmt team	1

KPI score scale - Work Obs - 1%	
	Score
Achieve >95% of targeted work observations for entire mgmt te	5
Achieve >95% of targeted work observations for entire mgmt te	4
Achieve 90-95% of targeted work observations for entire mgmt	3
Achieve 80-90% of targeted work observations for entire mgmt	2
Achieve <80% of targeted work observations for entire mgmt te	1

4.0 FILE 2017-18 RATE APPLICATION RECEIVING OEB APPROVAL FOR ALL OM&A AND CAPITAL SPENDING FOR THE TEST YEARS

Weighting: 7%

Hydro One SSM filed a 2017/18 COS rate application as planned, the COS rate application was withdrawn as per the Hydro One Inc. MAAD decision. In response to the Hydro One Inc. MAAD decision Hydro One SSM filed a 2017 IRM rate application prior to year end. The IRM application is still in front of the OEB. I have assessed the rate application KPI as a 4 given the need to file 2 applications in 1 year.

KPI score scale - Strategic Objectives - 4%	5
	Score
Objectives achieved as filed	5
Minor changes, no negative consequences	4
Minor changes, some negative consequences	3
One strategic objective not approved or changes with significar	2
More than one strategic objective not approved	1

KPI score scale - Timing - 1.5%	5
	Score
Filed July 15 and no controllable delays in IR responses	5
Filed July 31 and no controllable delays in IR responses	4
Filed August 15, or Controllable delay in IR responses 0-5 work	3
Filed August 31, or Controllable delay in IR responses 5-10 wo	2
Filed after August 31 or Controllable delays in IR responses > 1	1

KPI score scale - Dates - 1.5%	5
	Score
Effective January 1 and Implemented January 1	5
Effective January 1 and Implemented February 1	4
Effective January 1 and Implemented March 1	3
Effective January 1 and implemented after March 1	2
Effective after January 1	1

HYDRO ONE SAULT STE MARIE

KPI SUMMARY - 2016

		Weighting
3.0	***EXECUTE 2016 CAPITAL PLAN ON SCOPE AND BUDGET***	4%

Capital	Budget	Actual	%	Rating
Total Spending	$9,380	$9,325	99.4%	5.0
Individual Projects	Weighted	1.0		1.0
KPI Score				3.0

- Maximum capital expenditure equal to OEB-approved capital spending, all of which is spent prudently

- Each project is managed on scope, schedule and budget

- For individual project ratings (for scope, schedule and budget), total score to be weighted based on total approved budget

KPI score scale - Budget - 2%	Score
Spend 98% to 100% of OEB-approved Budget	5
Spend 95% to 98% or 100% to 101% of envelope	4
Spend 92% to 95% or 101% to 102% of envelope	3
Spend 90% to 92% of envelope	2
Spend less than 90% or greater than 102%of envelope	1

KPI score scale - Projects - 2%	Score
Spend 98% to 102% of approved IRF/FWO	5
Spend 96% to 104% of approved IRF/FWO	4
Spend 94% to 106% of approved IRF/FWO	3
Spend 90% to 110% of approved IRF/FWO	2
Spend <90% or >110% of approved IRF/FWO, or not complete	1

5.0	***DELIVER OM&A AT OR BELOW OEB APPROVED LEVELS***	4%

Controllable OM&A	Transmission
	2016
OM&A Budget	$11,322
OM&A Actual	$10,842
% of Budget	95.8%
KPI Score	

$420k in corporate costs were included in OM&A

KPI score scale	Score
Costs are at or below the OM&A approved by the OEB with $4:	5
Costs do not exceed OEB approved by more than $50k with $4	4
Costs do not exceed OEB approved by more than $100k with $	3
Costs do not exceed OEB approved by more than $200k with $	2
Costs exceed OEB approved by more than $200k or less than !	1

		Weighting
5.0	***MAINTAIN RELIABILITY STANDARDS***	3%

Hydro One SSM achieved all load blocks better than average for both frequency and duration

KPI score scale - Outage Frequency - 1.5%	Score
All load blocks better than average standard	5
All load blocks better than minimum standard, with 2 better thar	4
All load blocks better than minimum standard, or 1 below 40MV	3
Two load blocks below 40MW or one above 40MW exceed mir	2
Two load blocks above 40MW or three total load blocks exceec	1

KPI score scale - Outage Duration - 1.5%	Score
All load blocks better than average standard	5
All load blocks better than minimum standard, with 2 better thar	4
All load blocks better than minimum standard, or 1 below 40MV	3
Two load blocks below 40MW or one above 40MW exceed mir	2
Two load blocks above 40MW or three total load blocks exceec	1

HYDRO ONE SAULT STE MARIE

KPI SUMMARY - 2016

3.0	***Complete and Execute Compliance Program***	Weighting: **3%**

Hydro One SSM was compliant with NERC standards by July 1, 2016 and had a TFE in place for patch management.

KPI score scale - AM Plan	Score
Compliant with all NERC standards by July 1, 2016	5
N/A	4
Compliant with all NERC standards by July 1, 2016 with TFE	3
N/A	2
Compliance not achieved by July 1, 2016	1

5.0	***DELIVER ZERO HIGH RISK COMPLIANCE AND OPERATIONAL INCIDENTS***	Weighting: **2%**

	HIGH RISK INCIDENTS			
	Major	**Serious**	**Minor**	**None**
Regulatory Compliance	0	0	0	0
Operational	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**

KPI score scale				
Major	Serious	Minor	No Consequence	**Score**
0	0	0	1	5
0	0	0	2	4
0	0	1	3	3
0	1	2	4	2
1	2	3	5	1

1.0	***INVESTMENT IN OUR PEOPLE - OBJECTIVE #1***	Weighting: **2%**

Completion of the individual development plans (IDP) were dropped in 2016 to focus on integration activities

KPI score scale	Score
IDPs created by Sept 30, 2016	5
IDPs created by Oct 31, 2016	4
IDPs created by Nov 30, 2016	3
IDPs created by Dec 31, 2016	2
IDPs not created by Dec 31, 2016	1

	2016 KPI SCORE	MULTIPLIER	WEIGHT	VP IMPACT
PERSONAL OBJECTIVES	3	1.000	20%	20%

	WEIGHT	VP IMPACT
TOTAL VARIABLE PAY SCORE	100%	122%

Metrics Report

Great Lakes Power Transmission Holdings LP (Consolidated)

Analysis of December 2016 Results - CDN $

$ 000's, except for Volume

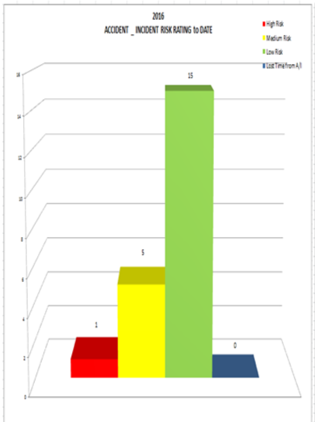
December 2016 Actual	December 2016 Budget	Variance		YTD Actual	YTD Budget	Variance
$ 720.0	**$ 495.0**	**$ (225.0)**	**Total CapEx**	**$ 9,325.0**	**$ 9,379.7**	**$ 54.7**
			In-Service	**$ 9,541.0**	**$ 9,768.0**	**$ 227.0**
20,688	21,537	(849)	VOLUME (Σ MW)	248,101	251,178	(3,077)
$ 3,227.6	**$ 3,417.8**	**$ (190.2)**	**Revenue**	**$ 40,204.2**	**$ 40,565.9**	**$ (361.7)**
964.4	851.7	(112.7)	OM&A	11,005.5	11,300.7	295.2
11.9	9.3	(2.6)	Taxes, other than income	117.2	111.6	(5.6)
-	-	-	Development Expenses	91.4	-	(91.4)
(2.2)	-	2.2	Regulatory Expenses	(15.4)	-	15.4
(20.5)	(7.5)	13.0	Other Expense/(Income)	(110.8)	(89.9)	20.9
953.6	853.5	(100.1)		11,087.9	11,322.4	234.5
$ 2,274.0	**$ 2,564.3**	**$ (290.3)**	**EBITDA**	**$ 29,116.3**	**$ 29,243.5**	**$ (127.2)**
763.1	763.1	-	Cash Interest expense	9,238.3	9,238.3	-
$ 1,510.9	**$ 1,801.2**	**$ (290.3)**	**FFO - CDN$**	**$ 19,878.0**	**$ 20,005.2**	**$ (127.2)**
800.9	819.7	18.8	Depreciation	9,293.5	9,836.3	542.8
(4.2)	(17.7)	(13.5)	Non Cash Interest expense	35.4	66.3	30.9
605.8	550.0	(55.8)	Loss/(Gain) on disposal PPE	599.5	550.0	(49.5)
$ 108.4	**$ 449.2**	**$ (340.8)**	**Net Income - CDN$**	**$ 9,949.6**	**$ 9,552.6**	**$ 397.0**

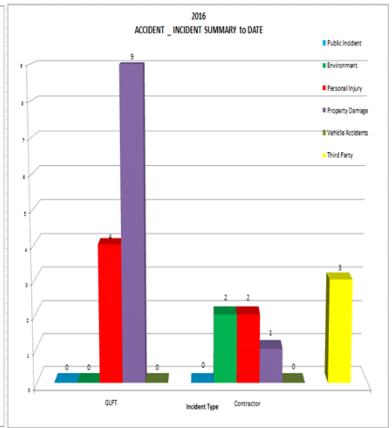
Notes

Add back to FFO & OM&A development expenses as a non regulatory Brookfield cost ($91.4k)

Health, Safety & Environment Monthly Incident Reporting

Report for Month of: December 2016 – Calendar Days without a Lost Time (Cumulative: 2738)





Incident Details:

1. 2016-1 GLPT Jan. 19/16-Personal Injury – Slip / Trip Risk Rating: L
Location: K24G / Soo 3
Description: After loading snowmobile trailer, a staff member walked down middle black track on snowmobile loading door and slipped striking entire body flat on their back, injuring left elbow.
Action Description: Paint slippery part of ramps to draw workers attention
Completion Results: After review of options the existing glides were removed and replaced with a non-slip glide from trailer supplier. All three trailers converted - COMPLETE

2. 2016-2 GLPT Feb 10/16-Personal Injury – Finger Injury, Tree Cutting Risk Rating: L
Location: K24G ROW – Using Aerial Device
Description: While cutting a tree from an aerial device, cutters left index finger was caught by a falling piece of wood that the cutter had just finishes cutting.
Action Description: N/A
Completion Results: N/A

3. 2016-3 GLPT Feb 18/16-Environmental – Hydraulic Oil Leak, Tracked Unit Risk Rating: L
Location: 38th Rd – K24G / Soo 3 ROW Access
Description: Small Hydraulic oil leak on a contractor's tracked unit.
Action Description 1: Review with Field Services at HS&E / Discuss incident with employee supervisor
Completion Results 1: Good discussion took place- COMPLETE
Action Description 2: Discuss incident with employee supervisor
Completion Results 2: Incident was discussed with the Supervisor of the Company. - COMPLETE

4. 2016-4 GLPT Feb 25/16-Environmental – Diesel Spill Potential for Harm: Low
Location: Building 56 – Montreal River
Description: Small diesel fuel leak inside building 56 while contractor was filling the generator fuel tanks located in the basement. Fuel escaped through the breather cap. Issue to be investigated.
Action Description: Understand filling system clearly to determine if adequate controls are in place
Completion Results: May 5-16 update: McDougall energy attending Building 56 on May 25 to install independent venting pipes for the two fill valves at Building 56. They have indicated that this is what is required to be able to rely on the audible warning to ensure the filling is stopped at 95% capacity. - COMPLETE

1. 2016-5 GLPT March 4/16-Property Damage – Trailer Dropped From Truck Risk Rating: M
Location: Mile 38 Rd KM 7
Description: Tongue of a snow mobile trailer was not properly fastened to the hitch of the truck causing the trailer to become un-attached when sudden braking occurred. Minor damage to the trailer occurred.
Action Description: Have Trailer inspected for damage
Completion Results: Trailer was inspected by a local dealer and approved for use. (Minor repairs completed) - COMPLETE

2. 2016-6 GLPT April 20/16-Property Damage – ORV Windshield Damage Risk Rating: L
Location: P-Lines – Wing Rd area on ROW access trail
Description: ORV windshield broken when the windshield wiper got caught by a spruce causing pressure and cracking the windshield.
Action Description 1: Review incident at Department HS&E
Completion Results 1: Reviewed at Department HS&E- COMPLETE
Action Description 2: Replace windshield with new
Completion Results 2: Completed by Speedy Glass April 21/2016- COMPLETE

3. 2016-7 GLPT May 3l 20/16-Property Damage – Cu Downground theft on P21/P22G Risk Rating:H
Location: P-Lines – Cooper Lake Road, Shaw Flats
Description: Cu down ground was stolen from the structures on both P21/22G.
Action Description 1: Review site conditions, order material and Off Road Unit required for repairs
Completion Results 1: - COMPLETE
Action Description 2: Replace Cu down ground on all structures
Completion Results 2: Completed May 13.
P21G Structure #218 (Composite) outstanding as an outage is required for repairs

4. 2016-8 GLPT May 26/16-Personal Injury – Right Knee Injury Risk Rating: L
<u>Location</u>: Batchewana TS – Obtaining Oil Sample
<u>Description</u>: While collecting a water sample from the Imbiber discharge the individual kneeled down and experienced pain in right knee.
<u>Action Description</u>: N/A
<u>Completion Results</u>: N/A

5. 2016-9 GLPT May 31/16-Contractor – Slip, Trip and Fall Potential for Harm: Low
<u>Location</u>: 2 Sackville Road
<u>Description</u>: Tripped on uneven pavement in front of cement staircase, hitting left lower leg on cement stair scrapping left hand and both knees.
<u>Action Description</u>: N/A
<u>Completion Results</u>: N/A

1. 2016-10-TP GLPT June 29/16-Personal Injury – Broken Tooth Risk Rating: L
<u>Location</u>: Montreal River GLPT Transmission ROW
<u>Description</u>: A supervisor from Wilderness Environmental after filling the oil for the ORV and was putting the seat back on that was being held in place by a bungee cord. As he was bending over the seat the bungee cord (which was stretched to its maximum) slipped and snapped back on his face. The "S" ring struck his tooth and broke it leaving him with tooth bits and a fat lip.
<u>Action Description 1</u>: Create an alternate system to secure the seat to control possible hazards (Wilderness)
<u>Completion Results 1</u>: The seat was securely fastened and a new seat was on order- COMPLETE
<u>Action Description 2</u>: Focus topic on bungee cord best practices at following monthly safety meeting. (Wilderness)
<u>Completion Results 2</u>: Discussed at safety meeting. – COMPLETE

2. 2016-11 GLPT July 21/16-Property Damage – Wire theft Risk Rating: L
<u>Location</u>: 2 Sackville Road – Work Compound
<u>Description</u>: Access was gained into compound by cutting the fence. Approximately 100' of insulated wire belonging to API was stolen. The exact date is unknown, but it was sometime on July 19 or 20.
<u>Action Description 1</u>: N/A
<u>Completion Results 1</u>: N/A

3. 2016-12 GLPT September 22/16-Contractor – Fibre Optic – Underground Contact Potential for Harm: Medium
<u>Location</u>: Anjigami TS
<u>Description</u>: In the process of removing stone layer in the yard the equipment made contact w/buried conduit and damaged the fibre optic jacket of the cable within.
<u>Action Description 1</u>: Stopped onsite operations – reviewed incident w/all crew members
<u>Completion Results</u>: Improved awareness of the repercussions. - COMPLETE
<u>Action Description 2</u>: Crew workshop – crew self-directed evaluation of root-cause analysis
<u>Completion Results 2</u>: Change in procedure w/o reviewing all possible hazards before executing. - COMPLETE

4. 2016-13 GLPT October 13/16-Property Damage – Vehicle Damage Risk Rating: M
<u>Location</u>: Tremblay Road by Magpie TS
<u>Description</u>: On the way to Magpie TS a moose walked out from bush/tree line adjacent to side of road and hit front right fender and passenger door.
<u>Action Description 1</u>: Have 10-56 repaired right away by body shop
<u>Completion Results</u>: Vehicle sent to Body Shop October 18-2016- COMPLETE

5. 2016-14 GLPT October 18/16-Property Damage – Trailer Jack Damage Risk Rating: L
<u>Location</u>: Frater Road – Km 10
<u>Description</u>: While trailering along Frater Rd. at approx. 10 km/hr, the hitch pin fell out causing the hitch to slide from the receiver. The safety chains caught the trailer and the hitch remained clasped within the trailer tongue causing minor damage to trailer jack.
<u>Action Description</u>: Review past incidents in attempt to identify pattern. Ultimately recommend option for pin.
<u>Completion Results:</u>

1. 2016-15 GLPT November 23/16-Property Damage – Trailer Damage Risk Rating: L
<u>Location</u>: Tree Tops Adventures
<u>Description</u>: While loading pole butts into the trailer (10' long and apx. 500 lbs) the pole butt spun around on its chain and swung into the trailer causing minor cosmetic damage to the fender and top rail of the trailer. (apx. $1000) In total 2 pole butts were loaded, the first one was the cause of the incident. The second one was slung in the same manor but was lifted higher than the first.
<u>Action Description</u>: Review at Quarterly meeting December 8/16
<u>Completion Results:</u> Reviewed.

2. 2016-16 GLPT December 7/16-Personal Injury – Station Battery Cell Explosion Risk Rating: M
<u>Location</u>: Hollingsworth TS
<u>Description</u>: Station Battery Cell #8 failed during annual load test. Battery load test was calculated at 11 AMPS. Injuries were a result of inhalation of gaseous fumes and noise made from explosion. Battery test procedure was followed. Impedance/voltage tests prior to load test did not indicate issues.
<u>Action Description 1</u>: Install additional labeling on DC system. (Breaker/Charger/Panel)
<u>Completion Results</u>:
<u>Action Description 2</u>: Confirm / provide drawing showing complete charger / battery bank CCT
<u>Completion Results</u>:
<u>Action Description 3</u>: Identify similar battery banks in GLPT system. Review testing requirements / restrictions on those types of banks
<u>Completion Results</u>:

3. 2016-17 GLPT Date Dec 7 – (Unknown date of damage)-Property Damage – Copper Downground Theft – Soo #3 Risk Rating: L
<u>Location</u>: Soo #3 Str. 68-72
<u>Description</u>: Copper downgrounds were stolen from Soo #3 Str 68-72. Downgrounds were cut at grade level and at approx. 7-8 ft. from the ground, and removed. Str 68-72 are in a remote area accessible by gravel road for pick-up trucks
<u>Action Description</u>:
<u>Completion Results</u>:

4. 2016-18 GLPT Date Dec 26/16-Property Damage – No. 3 Sault - Str #170 Conductor Break Risk Rating: M
<u>Location</u>: No 3 Sault – Str # 170 Conductor Break
<u>Description</u>: High winds blew two (2) large spruce trees onto No. 3 Sault 115KV conductor the morning of December 26-2016. After restoring the circuit to service, the "B" Phase conductor (outside phase) at Str. #170 broke. The line was then sectionalized to feed customers and GLPT forestry was dispatched to perform a patrol. The downed conductor was identified at Str. #170 and another tree on the line at Str. #172. A line crew from PowerTel was dispatched and the line was repaired the evening of December 27, 2016. Public Safety was a concern as the incident occurred in Stokely Creek area.
<u>Action Description</u>: Conductor may have been damaged at Str#172. Engineering to review to determine a need for Corrective Action.
<u>Target Date:</u> 03/31/2017 (Passed to planning to create CAF /WO#)
<u>Completion Results</u>:
<u>Completion Date:</u>

<u>Action Description</u>: Review the No. 3 Sault 115kV protection settings due the current de-rating status
<u>Target Date:</u> 03/31/2017 (Passed to planning to create CAF /WO#)
<u>Completion Results</u>:
<u>Completion Date:</u>

Third Part Incidents:

1. **2016-1-TP GLPT April 1/16-Property Damage – Damage to (ADSS) Fibre Optic Potential for Harm: Low**
   Location: Hwy 17 North, Batchewana TS
   Description: Private logging owner caught ADSS with equipment causing the ADSS to break and fall across API underbuild/Strung.
   Action Description: Because of shock to our assets – poles were inspected and assessed by GLPT Lines department.
   Completion Description: All structures were deemed to be in good condition. ADSS was repaired and attached to poles. No further action required.

2. **2016-2-TP GLPT August 10/16-Contractor – Brookfield Supporting Guarantee Potential for Harm: Low**
   Location: Hollingsworth TS
   Description: Visual verified Supporting Guarantee. Findings: SW1000 gang operated switch was open/locked with key in lock no tag was applied.
   Action Description:
   Completion Results:

3. **2016-3-TP GLPT October 11/16-Contractor –Supporting Guarantee Issue Potential for Harm: Low**
   Location: Harris GS and Mission GS
   Description: When verifying Supporting Guarantee at Mission GS & Harris GS for outage at Magpie TS, both locations had no PC3 tag on the metering box for CT/PT-M1 at. GLPT staff would not accept the work permit. New Supporting Guarantee issued and corrected problem
   Action Description: Obtain all supporting documents from NASCC.
   Completion Results: Obtained all related documents.

Great Lakes Power
Transmission

2016 Health and Safety Plan Objectives, Targets and Programs

Item	Objective	Target(s)	Program(s)	Actions	Responsibility	Q1 Updates	Q2 Updates	Q3 Updates	Q4 Updates	% Complete	Target Achievement Status
2016 Strategic Initiatives										99%	8
1	The #1 focus for GLPT in 2016 will be "0" High Risk Safety Incidents	Complete 2016 with zero High Risk Safety Incidents.	GLPT Safe Work Management System (SWMS)	Meet or exceed GLPT, and Legislative requirements - continue to focus on: - Job Planning - Project Planning & Change Analysis - Work Observations - Quality Assurance	[redacted]	ZERO High Risk Safety Incidents in Q1 ZERO Lost time Incidents through Q1	ZERO High Risk Safety Incidents in Q2 ZERO Lost time Incidents through Q2	ZERO High Risk Safety Incidents in Q3 ZERO Lost time Incidents through Q3	ZERO High Risk Safety Incidents in Q4 ZERO Lost time Incidents through Q4	100%	
2	Update the GLPT SWMS	Standardize all GLPT Procedures and forms located in the SWMS	GLPT Safe Work Management System (SWMS)	a) Transfer all current GLPT procedures and forms into a standard template and electronic file structure. b) Remove all references to Brookfield procedures. To be completed by Q2	[redacted]	a) Suzanne Salituri has completed converting the existing SWMS procedures into the new template and electronic filing structure b) Standardization of "forms" to be completed c) There are a number of procedures that are awaiting final review. d) Once final approval has been completed all procedures and forms will be placed on the portal and rolled out to staff.	a) Suzanne Salituri is continuing to update the procedures with current markups. b) Review of all SWMS Proceudres is about 85% c) Standardization of "forms" complete d) There are a number of procedures that are awaiting final review. e) Discussion ongoing with IT as to how to implement procedures into the new SWMS on the Portal.	a) Binder 1, 2, 3, reviewd by Duane. Minor changes completed (75%) b) Waiting on approval of binder 4 by Duane c) Discussions ongoing with IT as to implementation d) There are some procedures currently under review by JHSC	All procedures and related forms in the existing SWMS have been updated. Updates to the SWMS will continue as required. Rollout of this new system took place on December 8-2016	100%	
Carry Forwards 2015											
3	Contractor Management	Conformance to Procedure	Contractor Safety Management (4.5.1)	Ensure the contractor safety management procedure (4.5.1) is applied to all contracts or revise procedure to reflect smaller contracts **Contractor Safety Management Procedure 4.5.1** This to be revised to identify Contractor requirements for: Low, Medium and High Risk work activities. This will be implemented into the new SWMS Procedure in 2016 To be completed by Q4	[redacted]	The existing "Contractor Safety Management" procedure has been revised to suit GLPT practices.. This document is awaiting approval. The Procedure was updated as follows: *If the Operation's Responsible Authority or designate deem the work to be repetitive,(i.e. Janitorial, Snow Removal etc.) there will only be:* *o An annual review of the current contract and related documentation* *o An annual review of the work specific job plan, work site hazards and all required documentation related to the task being completed.* *o Regular interaction and communication will be completed during the contract period to ensure the work is being carried out as per the intent of the original contract.*	Waiting for final approval	Waiting for final approval	Contactor Safety Management Procedure 4.5.1 has been revised and approved. This procedure is located in the new SWMS	100%	
4	Hazard Analysis	Item #4 - GLPT should include Job Safety Analysis as part of critical task development. (priority 2)	GLPT SWMS 2.1.1 Hazard Analysis	**Job Safety Analysis** GLPT to ensure JSA is utilized in the development of "NEW" Critical Task Procedure on a go forward basis. Existing Critical Task Procedures to remain as implemented. * GLPT's practice is to complete the Hazard Assessment Form (HAF) rather than a Job Safety Analysis Form (JSA). * In 2015, "Wood Chipper Operation" and "Use and Operation of Cranes" were identified as two new Critical tasks. * In 2016, JHSC will review the Procedures and HAF related to both new Critical Tasks. * The current procedure 2.1.1 will be reviewed and revised to reflect this practice. To be completed by Q4	[redacted]	Review of both procedures will be set as an agenda item for the August 2016 JHSC meeting	Ongoing	Ongoing	Wood Chipper Operation" and "Use and Operation of Cranes" were reviewed by the JHSC in November 2016.	100%	
5											
5	Job Planning Requirements	Conformance to Procedure	Job Planning	**Quality and Assessment Review** Completion of the Q&A's to be reinforced to the Management Group (Priority 2) To be completed by Q1	[redacted]	Expectations reviewed with all managers during the February 2016 Managers meeting	Complete	Complete	Expectations reviewed with all managers during the October 2016 Managers meeting	100%	
6	Contractor Management	Conformance to Procedure	Contractor Safety Management (4.5.1)	**Contractor Orientation** This is to be reviewed and revised to make it easier for contractors to understand by including an example of a completed Daily Job Safety & Environment Plan to illustrate the proper way of completing all information related to the significant environmental aspects / impacts the contractors may encounter while working at GLPT and including information related to what to do in the event of a spill. (Priority 2) To be completed by Q4	[redacted]	Completed examples of a CTP, PSEP, DJP and HAF will be included in the Contractor Orientations. These are underway.	Ongoing	Ongoing	Nov 7-2016: Gene has started this and will work to complete. The new Contractor Orientations have been updated and circulated to the Project managers, Matt Baker and also saved in Z:\HealthSafety\GLPT Contractor Orientations	100%	
		Conformance to Procedure	Contractor Safety Management (4.5.1)	**Hazard Assessment Form** Ensure the most current version of the form is being used by staff. (Priority 2) To be completed by Q2	[redacted]	All Forms located in the current SMS and EMS are being reviewed, revised if required and included in the new Safety / Environmental Systems.	Ongoing	Ongoing	All procedures and related forms in the existing SWMS have been updated Anyone with copies of forms from the old SWMS should replace them with the new version.	100%	
		Conformance to Procedure	Contractor Safety Management (4.5.1)	**Contractor Qualification Database** to be reviewed and revised to include fields to record information related to environmental licences and approvals. (Priority 3) To be completed by Q4	[redacted]	No Update	Ongoing	Ongoing	Meeting with IT completed December 21-2016. Database to be updated by end of January 2017	90%	

Great Lakes Power
Transmission

2016 Public Safety Plan Objectives, Targets and Programs

Item	Objective	Actions	Responsibility	Q1 Updates	Q2 Updates	Q3 Updates	Q4 Updates	% Complete	Target Achievement Status
				2016 Strategic Initiatives				93%	8
1	The #1 focus for GLPT in 2016 will be "0" High Risk Public Safety Incidents	Meet or exceed GLPT and Legislative requirements	[redacted]	ZERO High Risk Safety Incidents in Q1 ZERO Lost time Incidents through Q1	ZERO High Risk Safety Incidents in Q2 ZERO Lost time Incidents through Q2	ZERO High Risk Safety Incidents in Q3 ZERO Lost time Incidents through Q3	ZERO High Risk Safety Incidents in Q4 ZERO Lost time Incidents through Q4	100%	
2	Develop & Communicate Public Safety Education Plan	Promote Public Safety awareness using various methods: i.e. - Forestry company consultation - Trade Shows - Intranet & Internet sites - awareness sessions with stakeholders. To be completed by Q4	[redacted] / Public Safety Group	Plan for public awareness session to be held for local forestry companies working within our geographic area. We plan to target snowmachine clubs regarding ROW access.	Tiana A and Matt C completed a public awareness session on April 15th & 19th with local forestry logging companies.	No Update	Bon Soo Committee: Matt Corbett met with the committee Nov 10-2016 reguarding proximaty to Clergue TS. They will be hosting Bon Soo at the Machine Shop. This will include the bum slides and fireworks. These activities will not have any public safety related issues. They will have additional security on the evening of the fireworks and will keep an eye on Clergue TS. Local Snowmobile Clubs: Matt Cobett sent an email out to all relevant clubs that are affiliated with snowmobile travel and have received a response from John Breckenridge and the Wawa club. No new developments just maintaining what is in place.	100%	
3	Review landowner lock system and determine appropriate course of action	a) Identify all landowners and/or stakeholders with T/TL keys and have them returned. b) Establish private lock to GLPT lock at locations requiring security. c) Archive all lock locations with landowner information. To be completed by Q4	[redacted]	Started to contact key holders and have started to receive some of the keys.	Ongoing	We will need to dedicate time to this. Preferably Sept or Oct.	In progress. Nov 29-2016: This process has been started. New locks have been ordered through greenwoods. GLPT has started to switch locks from TL to TPA. This task is taking time as GLPT needs to speak with all effected landowners. Forecast completion is Q4. All planned TPA locks have been installed.	100%	
4	Tower Sites	Review tower site inspections from 2015 and develop an action plan To be completed by Q4	Public Safety Group	We have included tower sites into the vegetation management system. Next step is to summarize inspections into a action/recommendation plan.	Inspections have been reviewed by the Public Saftey Committee. Recommondations have been submitted to AME for information.	Complete	Inspections have been reviewed by the Public Saftey Committee. Recommondations have been submitted to AME for information.	100%	
5	Update the GLPT Public Safety Work Management System (PSWMS)	a) Transfer all current GLPT procedures and forms into a standard template and electronic file structure. b) Remove all references to Brookfield procedures. To be completed by Q4	[redacted]	To date we reviewed: 0.0-Public Safety Management System Terms of Reference. 1.0 Facilities and Public Safety Features Description to be reviewed next meeting. The current Public Safety Procedures will not be transferd to the new template until late 2016 early 2017.	0.0 and 1.0 reviewed to date.	No Update	The Public Safety Committee reviewed and updated all Public Safety Procedures. These procedures will be transferred to the new template and implemented into the SWMS in 2017	100%	
6	Transmission Stations Equipment	BREG EP08 states: *Company locks must be installed on all switch handles and outdoor equipment access doors (e.g. at circuit breakers and switchgear enclosures, pad mounted transformers, or control cabinets)* a) A high level system review was partialy completed in 2015. b) There are approx. 200 pieces of equipment have been identified as potentially needing locks. c) A more detailed station by station review to be completed to identify "Lockable" and "Unlockable" equipment. d) An action plan to be created to identify equipment to be locked and a standard developed for the type of lock to be used. To be completed by Q4	[redacted]	Darrel discussed requirements with Duane. Action plan to be as follows: a) perform a detailed station by station review b) create a spreadsheet to track findings c) what equipment has locking capabilities d) what equipment should be locked e) develop a standard for locks and keys	The Electricians have completed the list for the Wawa Area. Remaining areas to be completed.	Electricians have taken an inventory from a portion of the stations. Remaing to be completed. Traking as per spreadsheet. Review and standardization to take place once inventory is complete. Completed Stations: Mackay 115/230, Gartshore, Andrews, Watson, Magpie, Hollingsworth, Hwy 101, Anjigami Remaining stations: Batchewana, Goulais, Clergue, Northern, Steelton, Echo, Third Line	In progress. a) The electrical group performed a detailed station by station inventory review. Complete b) A spreadsheet was created to track findings. Complete c) Equipment locking capabilities has been identified on the spreadsheet. Complete d) what equipment should be locked. *Tiana is currently reviewing what equipment should be locked and will discuss with the electrical group once comlete.Ongoing* e) The new standard for locks and keys will be developed by the appropriate group. Ongoing **2016.12.07 Tiana will work with Electricians to finalize the spreadsheet and arrange for a meeting to discuss how to implement plan. This plan will be confirmed in Q1 of 2017**	90%	
7	Accessibility for Ontarians with Disabilities Act (AODA)	A review of the Accessibility for Ontarians with Disabilities Act (AODA) was completed in 2015. a) GLPT has gathered required information to become compliant. (Policy, Procedure, employee training program) b) Accessibility Policy to be created and placed on the GLPT website c) A Multi-Year Accessibility Plan to be created and placed on the GLPT website d) Training for GLPT staff to be completed e) A GLPT Compliance Report to be filed To be completed by Q4	[redacted]	a) Requirements have been received from Dawna Kinnunen from Accessibilty North. b) Information currently under review and modification.	Ongoing	Ongoing	Ongoing Nov 28: Alison and Darrel are working with Accessibility North and GLPT Management to complete all required documentation. Formal training for GLPT will take place in Q2 of 2017. 2016.12.07 Hard copy of GLPT expectations circulating to management team for review. Official training and role out to take place in 2017.	50%	
8	2. Develop & Communicate Public Safety Education Plan (Audit Finding)	Thorough review of document to ensure all appropriate components incorporated i.e. facilities description. To be completed by Q4 a) Implementation of recommendations complete b) This is now at the review level and awaiting final approval. To be completed by Q4	[redacted]	We have decided as a committee to review procedures as stated above in Item 5	Ongoing	No Update	Refer to action item #5	100%	

Great Lakes Power Transmission

2016 Environmental Plan Objectives, Targets and Programs

Item	Objective	Actions	Responsibility	Q1 Updates	Q2 Updates	Q3 Updates	Q4 Updates	% Complete	Target Achievement Status
2016 Strategic Initiatives								93%	11
1	The #1 focus for GLPT in 2016 will be "0" High Risk Environmental Incidents	Meet or exceed GLPT and Legislative requirements - continue focus on Job Planning, Project Planning & Change Analysis - Work Observations & Quality Assurance	[redacted]	ZERO High Risk Environmental Incidents in Q1	ZERO High Risk Environmental Incidents in Q2	ZERO High Risk Environmental Incidents in Q3	ZERO High Risk Environmental Incidents in Q4	100%	
2	Update the GLPT Environmental Management System (EMS)	a) Transfer all current GLPT procedures and forms into a standard template and electronic file structure. b) Remove all references to Brookfield procedures. To be completed by Q4	[redacted]	Suzanne Salituri will be working on transfering content of the procedures to the new templates later in 2016	ELT currently reviewing procedures	ELT currently reviewing procedures and forms	Environmental Procedures are being reviewd by the ELT group and will be placed in the new EMS. This procedure review and implementation will extend into 2017	50%	
3	Develop and maintain strategic partnerships with third parties to expand environmental knowledge, assess our environmental impacts, increase our effectiveness, and promote our work.	Continued participation with CFL (Corridors For Life) program. 2016 key objectives include: 1) Develop BMP (Best Management Plan/Practice) for management of Riparian Zones. AHC resources confirmed to complete in 2016. 2) Implement first year of pollinator insect studies. To be completed by Q4	[redacted]	Field season to begin in May	1) Pollenator Project is now in operations status. Ongoing.	1) BMP on target for completion 2) Pollenator project in progress.	Nov 29-2016: BMP for Riparian zones BMP on target for completion by end of Q4. Draft report was received and reviewed by the field services group and returned for the next revision. This document will then be provided to the ELT. Once finalized, existing EMS procedures will be revised to reflect findings. Nov 29-2016: Pollenator project: Overall project is in progress. The scope of work for 2016 is complete. (waiting on interm progress report)	100%	
4	Water Crossings within GLPT system	a) Identify and engage with Environmental Consultant and develop classification system for water crossings. To be completed by Q4 b) Assess existing and potential water crossings To be completed in 2017 c) Implementation of recommendations at identified crossing locations. To be completed in 2018/2019	[redacted]	No Update	No Update	No Update	Nov 29-2016: RFP has been developed. Classification system is still being developed. Still in process of choosing Environmental Consultant and determining water crossing classification systems. Project will continue through 2017/18/19. Program modified. No longer pursueing external resource.	80%	
5	Review GLPT's Environmental Management System (EMS) requirements to identify and implement continuous improvements	Create an environmental procedure review team to review all environmental procedures. To be completed by Q4	[redacted]	EMS Procedure Priority list created to be reviewed by ELT group as an Agenda item during meetings	Procedure review ongoing.	Procedure review ongoing during ELT meetings.	**Refer to Item #2 above**		
6	Management of historical Soil Contamination within GLPT	Discovery of contamination at all GLPT sites that could be causing degradation of soil and or water quality. To be completed by Q4	[redacted]	No Update	Clarification of intent of this item; historic records review of soil contaimination and soil remediation. Identify where recommendations provided by Ministry or consultant have not been implemented in order to ensure that programs are developed.	Historical record and gap analyses has been completed. Next step to determine how to implement and manage.	Nov 29-2016: Matt Baker to sit with Engineering to: a) create a process for Engineering to review degradation of soil and or water quality when developing project need/scope. b) Pass to Engineering the final inventory of site water testing wells so Engineering can develop a testing frequency.	90%	
Carry Forwards 2015									
7	Maintain strategic partnerships with third parties to: a) expand environmental knowledge, b) assess our environmental impacts, c) increase our effectiveness d) and promote our work.	2015 was the final year for Chippewa and Goulais River Wood turtle populations study. Final report for Wood Turtle study should be received early 2016. Report to be reviewed once received.	[redacted]	No Update	Report reviewed. We will circulate the report to the ELT team. The end result being populations stronger than previously believed. Complete.	Report circulated to the ELT Group	Report reviewed. The end result being populations stronger than previously believed.	100%	
Audit Findings (2015)									
8	2015 Environmental Compliance Audit (Audit Completed by IMS)	**Operations Manual for the 500 kw generator.** a) revise to include a reference to the Spill Response Plan EMSERP-01 b) provide direction on where the weekly inspection is documented c) manual to be officially approved. To be completed by Q4	[redacted]	No Update	No Update	No Update	Nov 8: Marked up binder. Passed to Alison / Kari to update Dec 6: Binder updated and officially approved	100%	
		PCB Storage Site The monthly inspection form will be revised to align with the PCB Regulation requirements (e.g. look for weatherproofing of the roofs and barriers). To be completed by Q4	[redacted]	No Update	Forms have been revised. Currently being reviewed by ELT	No Update	Nov 8: Darrel and Kari reviewed the existing binder and forms and proposed modifications. Nov 29-2016: Forms and binder have been revised and are now being utilized.	100%	
		Waste Accumulation Log Binder (Currently located in the Oil Shed) a) This binder to be removed as there is no waste oil stored in this location. b) A new binder to be created and installed to monitor the inventory of "New Oil" for each month. To be completed by Q4	[redacted]	No Update	Forms have been revised. Currently being reviewed by ELT	No Update	Nov 8: Darrel and Kari reviewed the existing binder and forms and proposed modifications. Nov 29-2016: Forms and binder have been revised and are now being utilized.	100%	
		PCB Storage Building. a) A contingency plan shall be prepared identifing procedures to be followed in the event of a fire or spill. b) Develop a list of authorized persons knowledgable in the contingency plan and who are authorized to access the site. To be completed by Q4	[redacted]	No Update	No Update	No Update	Matt Baker to initiate contengency plan for fire and spill response as it relates to the PCB building. This will also include a list of authorized personnel. GLPT has a very detailed Emergency Preparedness Response Plan Manual with a section referencing "Reportable Spills of PCB Contaminated Materials Requirements" and "Emergency Preparedness and Procedures" (Fire and Spills). This documents was revised to reflect the requirements for the PCB storage building and includes a list of authorized persons knowledgable in the contingency plan and who are authorized to access the site.	100%	
		Oil Containment monthly inspection forms The forms located in the site log book to be modified to ease in completion for all months (winter and summer) and provide identification areas for signoff. To be completed by Q4	[redacted]	No Update	Forms have been revised. Currently being reviewed by ELT	Complete. New forms have been reviewed and issued and are being utilized in the field by the Civil staff.	Complete. New forms have been reviewed and issued and are being utilized in the field by the Civil staff.	100%	

GLPT Job Plan Quality Reviews - 2016 - FINAL

Employee	Targets per Year	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total	% Complete
Supervision															
[redacted]	0													0	
[redacted]	**0**													0	
[redacted]	**12**		1	1		1		2	1	2		2		10	83%
[redacted]	**6**									1	1			2	33%
[redacted]	**6**													0	0%
[redacted]	**2**									1	1			2	100%
Team	**26**													**14**	**54%**

GLPT Safe Work Observations - 2016 - FINAL

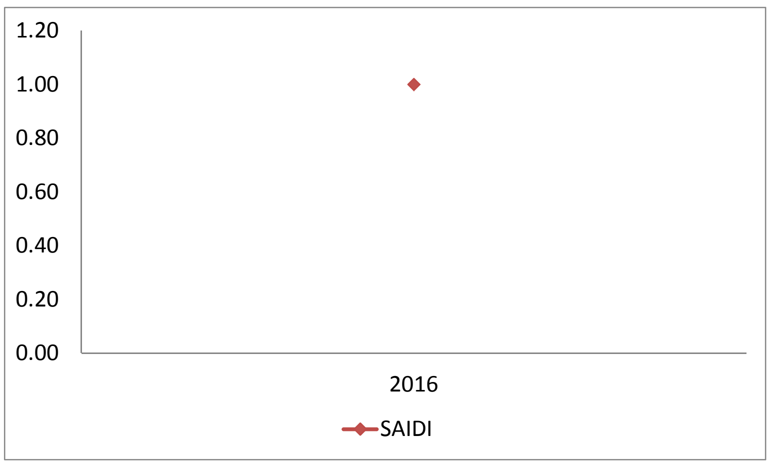
Employee	Targets per Year	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total	% Complete
Management															
[redacted]	**6**							1	3	3				7	117%
[redacted]	**2**										2			2	100%
[redacted]	**12**	1	1		1	1	2	2	3	4	1			16	133%
[redacted]	**12**						4	3	2	4	4			17	142%
[redacted]	**12**				1		3		2					6	50%
[redacted]	**12**								2	6				8	67%
Team	**56**													**56**	**100%**
Group Leaders															
[redacted]	**12**	1		1	6	2		1	1					12	100%
JH&SC															
Committee Members	**2**				1							1		2	100%
[redacted]															
Expected	**70**												**Summary YTD**	**70**	**100%**

GREAT LAKES POWER TRANSMISSION LP
CAPITAL WORK IN PROGRESS
December 31, 2016

PROJECT NUMBER	PROJECT DESCRIPTION	OPENING BALANCE	YEAR TO DATE	Write Off to OM&A	Transfer	CLOSED TO CAPITAL	IRF/FWO	Variance	KPI	Wighting
I11033	ERP SOFTWARE UPGRDE STUDY	$142,757.71	$95,831.30		$0.00	$238,589.01	$153,812.86	155%	1	0.02
I14044	ANJIGAMI TS REFURBISHMENT	$303,602.88	$1,014,291.69		($328,308.97)	$660,000.00	$752,694.03	88%	1	0.10
I14045	WATSON T2 HV BREAKER	$87,571.35	$1,322,615.43		($102,600.00)	$1,056,270.00	$1,239,971.00	85%	1	0.17
I15014	MACKAY GROUND GRID UPGRDE	$53,475.86	$57,425.15		$0.00	$110,901.01	$55,000.00	202%	1	0.01
I15015	MAGPIE CT REPLACEMENTS	$75,914.32	$636,579.55		$0.00	$712,493.87	$620,986.00	115%	1	0.08
I15024	HOLLINGSWORTH STRUCTURES	$268,690.36	$2,884,322.86		$0.00	$3,153,013.22	$2,788,510.00	113%	1	0.38
I15036	CISCO SWITCH UPGRADE	$98,700.19	$55,462.84		$0.00	$154,163.03	$55,462.84	278%	1	0.01
I15038	OC 48	$122,185.73	$17,763.43		$0.00	$139,949.16	$26,385.77	530%	1	0.00
I16001	RS POLE PURCHASE	$0.00	$84,701.05		$0.00	$84,701.05	$97,407.00	87%	1	0.01
I16002	2016 TRAILER 16 01	$0.00	$4,786.35		$0.00	$4,786.35	$4,927.00	97%	4	0.00
I16003	2016 TRAILER 16 02	$0.00	$4,786.35		$0.00	$4,786.35	$4,927.00	97%	4	0.00
I16004	2016 TRAILER 16 03	$0.00	$4,786.35		$0.00	$4,786.35	$4,927.00	97%	4	0.00
I16005	2016 TRAILER 16 04	$0.00	$4,786.35		$0.00	$4,786.35	$4,927.00	97%	4	0.00
I16006	2016 SUITE A ROOF REPLACE	$0.00	$207,047.00		$0.00	$207,047.00	$199,250.00	104%	4	0.11
I16007	2016 WORK CAP FLEET 10 56	$0.00	$3,234.95		$0.00	$3,234.95	$3,235.00	100%	5	0.00
I16009	HOLLINGSWORTH OIL CONTAIN	$0.00	$164,706.83		$0.00	$164,706.83	$163,346.00	101%	5	0.11
I16011	2016 SIGNAGE & GUY GUARDS	$0.00	$47,859.23		$0.00	$47,859.23	$80,000.00	60%	1	0.01
I16012	WATER PRESSURE SYSTEM	$0.00	$8,880.85		$0.00	$8,880.85	$8,880.85	100%	5	0.01
I16013	MEGGER DET4TC2	$0.00	$3,915.00		$0.00	$3,915.00	$3,915.00	100%	5	0.00
I16014	ANDREWS BATTERY REPLACE	$0.00	$6,110.19		$0.00	$6,110.19	$7,500.00	81%	1	0.00
I16015	NORTHLAND RADIO BUILDING	$0.00	$225,321.89		$0.00	$225,321.89	$225,000.00	100%	5	0.15
I16020	QUALITY TRAINING DATABASE	$0.00	$38,620.96		$0.00	$38,620.96	$64,097.00	60%	1	0.01
I16021	ENG OPS TECH LAPTOP	$0.00	$4,579.33		$0.00	$4,579.33	$5,481.00	84%	1	0.00
I16022	2 SACKVILLE ROAD AC UPGRD	$0.00	$116,015.18		$0.00	$116,015.18	$132,000.00	88%	1	0.02
I16023	MEGGER BATTERY GF TRACER	$0.00	$8,180.90		$0.00	$8,180.90	$8,181.00	100%	5	0.01
I16025	IBM QRADAR	$0.00	$23,053.59		$0.00	$23,053.59	$23,054.00	100%	5	0.02
I16026	CIPv5 COMPLIANCE	$0.00	$50,860.29		$0.00	$50,860.29	$36,850.00	138%	1	0.00
I16027	NETWORK VIDEO RECORDER	$0.00	$12,630.58		$0.00	$12,630.58	$14,638.00	86%	1	0.00
I16029	SSL INSPECTION APPLIANCE	$0.00	$25,064.32		$0.00	$25,064.32	$26,354.00	95%	4	0.01
I16030	SERVER AND STORAGE UPDATE	$0.00	$157,607.15		$0.00	$157,607.15	$178,185.00	88%	1	0.02
I16033	LAPTOP REPLACEMENTS 2016	$0.00	$18,409.41		$0.00	$18,409.41	$19,614.00	94%	3	0.01
I16034	ENGINEERING RUGGED LAPTOP	$0.00	$5,692.13		$0.00	$5,692.13	$5,875.00	97%	4	0.00
I16035	2016 CHEVY SILVERADO 1605	$0.00	$52,952.24		$0.00	$52,952.24	$52,093.00	102%	5	0.04
I16036	2016 CHEVY SILVERADO 1606	$0.00	$51,695.02		$0.00	$51,695.02	$51,255.00	101%	5	0.03
I16038	2016 ANDREWS STRUCTURES	$0.00	$145,378.97		$0.00	$145,378.97	$145,378.97	100%	5	0.10
I16039	CLERGUE OIL REPLACEMENT	$0.00	$173,037.75		$0.00	$173,037.75	$160,000.00	108%	2	0.04
Overall - Total		**$1,152,898.40**	**$7,738,992.46**	**$0.00**	**($430,908.97)**	**$7,880,079.51**	**$7,424,120.32**			1.50

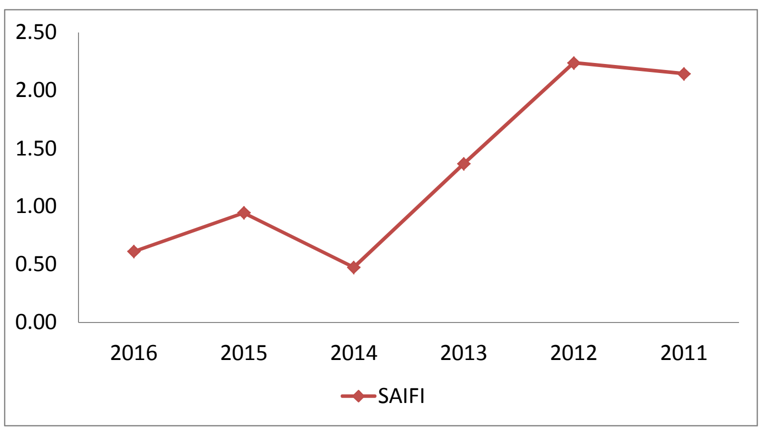
Customer DP Interruption Duration (min/yr)

	Customer Delivery Point	2016	2015	2014	2013	2012	2011	3Year Average (2014-16)	Minimum Standard Of Performance	Standard Average Performance	Load Category	
		Interruption Duration (minutes)										
1	EASI (301T1, 301T2, 301T3)	0	0	0	0	16	356	0.00	25	5	(>80 MW)	Below Average
	(>80 MW)	**0**	**0**	0	0	16	356	**0.00**				Overall Load Blk is performning better than average
2	PUC GL1TA / GL2TA	0	0	0	23	0	345	0.00	55	11	(40-80 MW)	Below Average
	(40-80 MW)	**0**	**0**	0	23	0	345	**0.00**				Overall Load Blk is performning better than average
	St Marys Paper Corp. (Breakers 150&155) Removed 2012	0	0	0	0	5	372	0.00	140	22	(15-40MW)	Below Average
	St Marys Paper Corp. (Breakers 154&151) Removed 2012	0	0	0	0	5	368	0.00	140	22	(15-40MW)	Below Average
3	ASI (10T1)	0	0	0	0	34	355	0.00	140	22	(15-40MW)	Below Average
4	PUC GL1SM / GL2SM	47	0	0	0	0	347	15.67	140	22	(15-40MW)	Below Average
	(15-40MW)	**47**	**0**	0	0	44	1442	**15.67**				Overall Load Blk is performning better than average
5	Flakeboard Company	0	0	0	0	17	358	0.00	360	89	(0-15 MW)	Below Average
6	EASI (T6 and T7)	0	0	0	0	34	356	0.00	360	89	(0-15 MW)	Below Average
7	EASI (Wallace Terrace Sub)	0	0	0	0	17	358	0.00	360	89	(0-15 MW)	Below Average
8	API DIST (NA 34.5 kV)	0	0	0	0	0	118	0.00	360	89	(0-15 MW)	Below Average
9	API DIST (NA 12kV)	0	0	0	11248	118	119	0.00	360	89	(0-15 MW)	Below Average
10	API DIST (ER)	7	0	86	98	7	357	31.00	360	89	(0-15 MW)	Below Average
11	API DIST (BATCH)	75	482	14	566	0	16	190.33	360	89	(0-15 MW)	Below Minimum
12	API DIST (GOULAIS)	43	276	299	601	0	13	206.00	360	89	(0-15 MW)	Below Minimum
13	API DIST (MACKAY)	0	0	0	0	0	0	0.00	360	89	(0-15 MW)	Below Average
14	API DIST (ANDREWS)	0	20	0	3248	0	67	6.67	360	89	(0-15 MW)	Below Average
15	API DIST (WATSON - No.1 & No.2 Wawa)	0	0	7	0	79	39	2.33	360	89	(0-15 MW)	Below Average
	API DIST (WATSON Local Dist) Removed 2007	0	0	0	0	0	0	0.00	360	89	(0-15 MW)	Below Average
16	API DIST (No. 4 Circuit)	148	357	0	11	35	103	168.33	360	89	(0-15 MW)	Below Minimum
	API DIST (Hwy 101 DS) (Removed 2013- all load on No.4 cct)	0	0	0	0	1507	233	0.00	360	89	(0-15 MW)	Below Minimum
17	Weyerhaueser	137	368	14	402	1549	233	173.00	360	89	(0-15 MW)	Below Minimum
18	Wesdome Gold Mines	0	13	62	164	289	1718	25.00	360	89	(0-15 MW)	Below Average
	(0-15 MW)	**410.00**	**1516.00**	**482.00**	**16338.00**	**3652.00**	**4088.00**	**50.17**	360	89		Overall Load Blk is performning better than average
	A -Total Interruption Duration (minutes)	**457.00**	**1516**	**482**	**16361**	**3712**	**6231**					
	B - Customers Served	**18**	**18**	**19**	**19**	**21**	**21**					



Customer DP - Frequency of Interruptions (Outages/yr)

Customer Delivery Point	Number of Outages						3Year Average (2014-16)	Minimum Standard Of Performance	Standard Average Performance	Load Category	
	2016	2015	2014	2013	2012	2011					
EASI (301T1, 301T2, 301T3) (DP1)	0	0	0	0	1	1	0.00	1	0.3	(>80 MW)	Below Average
(>80 MW)	**0**	**0**	**0**	**0**	**1**	**1**	**0.00**				Overall Load Blk is performning better than average
PUC GL1TA / GL2TA (DP2)	0	0	0	2	0	1	0.00	1.5	0.5	(40-80 MW)	Below Average
(40-80 MW)	0	0	0	2	0	1	**0.00**				Overall Load Blk is performning better than average
St Marys Paper Corp. (Breakers 150&155) Removed 2012	0	0	0	0	1	1	0.00	3.5	1.1	(15-40MW)	Below Average
St Marys Paper Corp. (Breakers 154&151) Removed 2012	0	0	0	0	1	1	0.00	3.5	1.1	(15-40MW)	Below Average
EASI (10T1) (DP3)	0	0	0	0	1	1	0.00	3.5	1.1	(15-40MW)	Below Average
PUC GL1SM / GL2SM (DP4)	1	0	0	0	0	1	0.33	3.5	1.1	(15-40MW)	Below Average
(15-40MW)	**1**	**0**	**0**	**0**	**3**	**4**	**0.33**				Overall Load Blk is performning better than average
Flakeboard Company (DP5)	0	0	0	0	1	1	0.00	9	4.1	(0-15 MW)	Below Average
EASI (T6 and T7) (DP6)	0	0	0	0	1	1	0.00	9	4.1	(0-15 MW)	Below Average
EASI (LMF - Wallace Terrace Sub) (DP7)	0	0	0	0	1	1	0.00	9	4.1	(0-15 MW)	Below Average
API DIST (NA 34.5 kV) (DP8)	1	0	0	0	0	1	0.33	9	4.1	(0-15 MW)	Below Average
API DIST (NA 12kV) (DP9)	0	0	0	2	2	1	0.00	9	4.1	(0-15 MW)	Below Average
API DIST (ER) (DP10)	1	0	3	3	2	6	1.33	9	4.1	(0-15 MW)	Below Average
API DIST (BATCH) (DP11)	2	4	1	3	0	2	2.33	9	4.1	(0-15 MW)	Below Average
API DIST (GOULAIS) (DP12)	2	4	2	3	0	2	2.67	9	4.1	(0-15 MW)	Below Average
API DIST (MACKAY) (DP13)	0	0	0	0	0	0	0.00	9	4.1	(0-15 MW)	Below Average
API DIST (ANDREWS) (DP14)	0	1	0	8	0	1	0.33	9	4.1	(0-15 MW)	Below Average
API DIST (WATSON - Wawa No.1 & No.2) (DP15)	0	0	1	0	4	3	0.33	9	4.1	(0-15 MW)	Below Average
API DIST (WATSON Local Dist) Removed 2007	0	0	0	0	0	0	0.00	9	4.1	(0-15 MW)	Below Average
API DIST (No. 4 Circuit) (DP16)	2	3	0	1	2	5	1.67	9	4.1	(0-15 MW)	Below Average
API DIST (Hwy 101 DS) (Removed 2013- all load on No.4 cct)	0	0	0	0	12	5	0.00	9	4.1	(0-15 MW)	Below Average
Weyerhaeuser Company Ltd. (DP17)	2	4	1	2	13	5	2.33	9	4.1	(0-15 MW)	Below Average
Wesdome Gold Mines (DP18)	0	1	1	2	5	5	0.67	9	4.1	(0-15 MW)	Below Average
(0-15 MW)	**10**	**17**	**9**	**24**	**43**	**39**	**4.00**				Overall Load Blk is performning better than average
A - Total Outages	**10**	**17**	**9**	**26**	**47**	**45**					
B - Customers Served	18	18	19	19	21	21					
SAIFI (A/B)	**0.6**	**0.9**	**0.5**	**1.4**	**2.2**	**2.1**					



2017

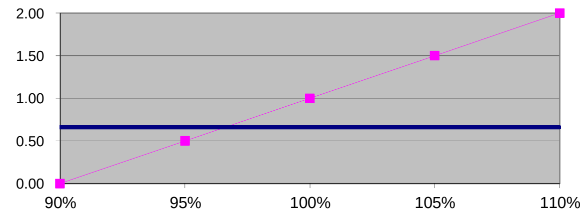
KPI Summary

HYDRO ONE SAULT STE. MARIE LP

KPI SUMMARY - 2017

	2017 KPI SCORE	MULTIPLIER	WEIGHT	VP IMPACT
HYDRO ONE SAULT STE MARIE FFO	0.966	0.660	40%	26.40%

	Actual FFO	Plan FFO	Variance	% vs. Plan
Transmission	$ 19,901.3	$ 20,602.0	$ (700.7)	96.6%
Great Lakes Power Total	$ 19,901.3	$ 20,602.0	$ (700.7)	96.6%



	2017 KPI SCORE	MULTIPLIER	WEIGHT	VP IMPACT
COMMON OBJECTIVES	4.0	1.500	40%	60%

5.0 ***DELIVER ZERO HIGH RISK HSS&E INCIDENTS***

Weighting: **10%**

	HIGH RISK INCIDENTS			
Operations	**Fatality**	**Serious**	**Contact**	**No Contact**
Health & Safety	0	0	0	0
Security	0	0	0	0
Environment	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**

KPI score scale

Disab or Fa	Serious	Contact	No Contact	Score
0	0	0	2	5
0	0	0	3	4
0	0	1	3	3
0	1	2	4	2
1	2	3	5	1

5.0 ***Completion of HSS&E Strategic Plans***

Weighting: **3%**

KPI score scale

	Score
Complete >95% of plan objectives in the year	5
Complete 90-95% of plan objectives in the year	4
Complete 85-90% of plan objectives in the year	3
Complete 80-85% of plan objectives in the year	2
Complete <80% of plan objectives in the year	1

HYDRO ONE SAULT STE. MARIE LP

KPI SUMMARY - 2017

3.5 ***MEET LEADING INDICATOR TARGETS RELATED TO HEALTH & SAFETY***

Weighting

2%

KPI score scale - QA - 1%	Score
Achieve >95% of targeted QA checks for entire mg	5
Achieve >95% of targeted QA checks for entire mg	4
Achieve 90-95% of targeted QA checks for entire r	3
Achieve 80-90% of targeted QA checks for entire r	2
Achieve <80% of targeted QA checks for entire mg	1

KPI score scale - Work Obs - 1%	Score
Achieve >95% of targeted work observations for er	5
Achieve >95% of targeted work observations for er	4
Achieve 90-95% of targeted work observations for	3
Achieve 80-90% of targeted work observations for	2
Achieve <80% of targeted work observations for er	1

3.0 ***DEVELOP, IMPLEMENT AND INITIATE THE EXECUTION OF THE TRANSITION PLAN***

Weighting

11%

KPI measured based on timing of executive sign-off of the transition plan and achieving OM&A savings through productivity measures

KPI score scale - Executive Sign-off Timing - 9%	Score
Receive sign-off in Q1	5
Receive sign-off in Q2	4
Receive sign-off in Q3	3
Receive sign-off in Q4	2
Do not receive sign-off in 2017	1

KPI score scale - Productivity OM&A savings - 2%	Score
More than $500k in cost savings	5
More than $250k in cost savings	4
Less than $250k in cost savings	3
No cost savings	2
Negative cost implications	1

HYDRO ONE SAULT STE. MARIE LP
KPI SUMMARY - 2017

Weighting

3.0	***EXECUTE 2017 CAPITAL PLAN ON SCOPE AND BUDGET***	3%

Capital	**Budget**	**Actual**	**%**	**Rating**
Total Spending	$10,272	$9,748	94.9%	**3.0**
Individual Projects	Weighted	4.0		**4.0**
KPI Score				**3.5**

KPI score scale - Budget - 1.5%	
	Score
Spend 98% to 100% of OEB-approved Budget	5
Spend 95% to 98% or 100% to 101% of envelope	4
Spend 92% to 95% or 101% to 102% of envelope	3
Spend 90% to 92% of envelope	2
Spend less than 90% or greater than 102%of enve	1

- Maximum capital expenditure equal to OEB-approved capital spending, all of which is spent prudently

- Each project is managed on scope, schedule and budget

- For individual project ratings (for scope, schedule and budget), total score to be weighted based on total approved budget

KPI score scale - Projects - 1.5%	
	Score
Spend 98% to 102% of approved IRF/FWO	5
Spend 96% to 104% of approved IRF/FWO	4
Spend 94% to 106% of approved IRF/FWO	3
Spend 90% to 110% of approved IRF/FWO	2
Spend <90% or >110% of approved IRF/FWO, or r	1

Weighting

5.0	***DELIVER OM&A AT OR BELOW OEB APPROVED LEVELS***	3%

Controllable OM&A	**Transmission**
	2017
OM&A Budget	$11,251
OM&A Actual	$9,481
% of Budget	84.3%
KPI Score	**5**

$423k in corporate costs were included in OM&A

KPI score scale	
	Score
Costs are at or below the OM&A approved by the (	5
Costs do not exceed OEB approved by more than	4
Costs do not exceed OEB approved by more than	3
Costs do not exceed OEB approved by more than	2
Costs exceed OEB approved by more than $200k	1

HYDRO ONE SAULT STE. MARIE LP

KPI SUMMARY - 2017

5.0 *MAINTAIN RELIABILITY STANDARDS*

Weighting: **3%**

KPI score scale - Outage Frequency - 1.5%	Score
All load blocks better than average standard	5
All load blocks better than minimum standard, with	4
All load blocks better than minimum standard, or 1	3
Two load blocks below 40MW or one above 40MW	2
Two load blocks above 40MW or three total load bl	1

KPI score scale - Outage Duration - 1.5%	Score
All load blocks better than average standard	5
All load blocks better than minimum standard, with	4
All load blocks better than minimum standard, or 1	3
Two load blocks below 40MW or one above 40MW	2
Two load blocks above 40MW or three total load bl	1

3.0 *EXECUTION OF VEGETATION, LINES AND STATIONS PREVENTATIVE MTCE*

Weighting: **3%**

Forestry - 100%, Lines - 77%, Electrical - 90% - all under budget

KPI score scale - Completion % & % budget	Score
100% complete at 90% of budgeted 3rd party costs	5
100% complete at 95% of budgeted 3rd party costs	4
100% complete at 100% of 3rd party costs	3
>95% complete on budget	2
<95% complete on budget	1

HYDRO ONE SAULT STE. MARIE LP

KPI SUMMARY - 2017

	Weighting
5.0 ***DELIVER ZERO HIGH RISK COMPLIANCE AND OPERATIONAL INCIDENTS***	2%

	HIGH RISK INCIDENTS			
	Major	**Serious**	**Minor**	**None**
Regulatory Compliance	0	0	0	0
Operational	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**

KPI score scale				
Major	Serious	Minor	No Consequence	**Score**
0	0	0	1	5
0	0	0	2	4
0	0	1	3	3
0	1	2	4	2
1	2	3	5	1

	2017 KPI SCORE	MULTIPLIER	WEIGHT	VP IMPACT
PERSONAL OBJECTIVES	3	1.000	20%	20%

	WEIGHT	VP IMPACT
TOTAL VARIABLE PAY SCORE	100%	106%

OEB Staff Interrogatory # 44

Reference:
Exhibit C, Tab 1, Schedule 1, Page 1

Interrogatory:
Preamble:

At the above-noted reference, Hydro One SSM stated the following:

Hydro One Sault Ste. Marie ("HOSSM") is committed to demonstrating continuous improvement in the transmission of electricity that is at a level expected by our customers. To measure the performance to this commitment, HOSSM has developed a balanced scorecard that is aligned with the OEB's Renewed Regulatory Framework ("RRF") and is substantially aligned with Hydro One's transmission scorecard. The scorecard combined with HOSSM's Key Performance Indicators ("KPIs") program will aid in identifying areas of opportunity to enhance the effectiveness of HOSSM's performance management program and will help to ensure that the objectives and goals of the company are being managed to create additional value for the rate payer. HOSSM maintains and tracks measures across the company to align work execution in each line of business with the corporate drivers.

a) Please explain how Hydro One SSM's proposed scorecard is substantially aligned with Hydro One's transmission scorecard.

b) Please explain in more detail how Hydro One SSM's proposed scorecard is aligned with the OEB's RRF.

c) Please explain how the scorecard combined with Hydro One SSM's KPIs program will aid in identifying areas of opportunity to enhance the effectiveness of its performance management program.

d) Please provide Hydro One SSM's goals and objectives for 2018 and 2019, in particular those relating to Hydro One SSM's scorecard metrics.

e) Please explain how the scorecard combined with Hydro One SSM's KPIs program will help to ensure that the objectives and goals of the company are being managed to create additional value for the rate payer.

Response:

a) The HOSSM proposed scored has more than 70% of the metrics that are aligned with the current Hydro One's Transmission scorecard.

b) Please refer to part (i) of Exhibit I, Tab 1, Schedule 42 (Staff IR#42).
The measures were informed by the OEB's guidance in the Handbook for Utility Rate Applications[1] ("Handbook") by reflecting the following key considerations:
- A focus on strategy and results, not activities;
- The need to demonstrate continuous improvement;
- Outcomes that are demonstrated to be of value to customers; and
- Performance metrics that accurately measure whether outcomes are being achieved, and that include stretch goals to demonstrate enhanced effectiveness and continuous improvement.

c) The framework is intended to enhance management visibility to key metrics that highlight success during the current period and allow for proactive changes to the underlying drivers of success in those metrics. Application of this framework is evident in the Dashboard provided in the response to part (d) of I-1-43 (Staff IR#43).

d) Please see response to part (d) of I-1-43 (Staff IR#43).

e) Please see response to part (d) of I-1-43 (Staff IR#43).

[1] Ontario Energy Board, Handbook for Utility Rate Applications, October 13, 2016, p.16

OEB Staff Interrogatory # 45

Reference:

Exhibit C, Tab 1, Schedule 1, Page 3
Filing Requirements, page 25, section 2.8.1
Exhibit B1, Tab 1, Schedule 1, Page 15
Exhibit B1, Tab 1, Schedule 1, Page 25-30
Exhibit B2, Tab 2, Schedule 1

Interrogatory:

Preamble:

At the first above-noted reference, Hydro One SSM stated the following:

HOSSM is committed to continuous improvement in productivity and efficiency to demonstrate value to customers…

Section 2.8.1 of the Filing Requirements state that a description of the continuous improvement or efficiency gains that will be achieved over the term is to be provided, together with the means by which those gains and savings will be achieved and the benefits assured for customers.

At the third above-noted reference, Hydro One SSM stated the following:

Among the operating areas where HOSSM expects to leverage opportunities for efficiencies are the areas captured in Table 1-5.

The anticipated sources of efficiencies are explained in more detail at the fourth above-noted reference.

Although Table 1-5 Summary of Anticipated Sources of Efficiencies, provides a summary of efficiencies, and some amounts have been quantified in fifth above-noted reference (Capital Plan Evolution), not all of these amounts have been mapped from Table 1-5 to the Capital Plan Evolution evidence.

a) Please provide an explanation of the means by which continuous improvement, gains and savings will be achieved and the benefits assured for customers.

b) Please map the above-noted Table 1-5 to the Capital Plan Evolution evidence.

c) Please confirm that the above-noted areas in Table 1-5 are capable of producing productivity gains and synergistic lowering of OM&A.

d) Given the above anticipated sources of efficiencies, please explain why Hydro One SSM's expected productivity factor is not greater than 0%.

Response:

a) For convenience, a copy of Table 1-5 (referenced above) has been provided. For each of the headings in the left column, HOSSM has included details as to the expectations for improvement on pages 26-28 in Section 2.2.3 of its TSP.

b) HOSSM has not performed a direct mapping exercise to align each of the prospective savings initiatives to the Capital Plan.

c) HOSSM confirms that it believes the areas listed in Table 1-5 will produce productivity gains and lower OM&A over time.

d) Please see the response to Exhibit I, Tab 1, Sections 58 a) and 62 a).

OEB Staff Interrogatory # 46

Reference:

Exhibit C, Tab 1, Schedule 1, Page 9-10
EB-2016-0050, October 13, 2016, Decision and Order, Application for the acquisition of Great Lakes Power Transmission Inc. by Hydro One Inc. (MAADs Decision), page 11

Interrogatory:

Preamble:

In the above-noted first reference, Hydro One SSM stated the following:

HOSSM strives to maintain compliance with reliability standards mandated by the North American Electric Reliability Corporation ("NERC") for an Electricity Transmitter. The tracking of this measure will also ensure the appropriate compliance program is in place. In 2016, HOSSM started tracking any incidents that required HOSSM to file a self-report of non-compliance. The target has been set a zero high-risk regulatory compliance and operational incidents.

At the above-noted second reference, page 11 of the MAADs decision stated the following:

The OEB expects that both Hydro One and GLPT will continue to comply with rules set out for all transmitters and meet the reliability standards established by NERC and the OEB approved customer delivery point standards…

a) Please provide more detail as to how Hydro One SSM will meet the expectations articulated in the MAADs decision. In particular, please explain how Hydro One SSM is compliant with rules set out for all transmitters and meets the reliability standards established by NERC and the OEB approved customer delivery point standards.

Response:

a) As a transmitter market participant, Hydro One SSM must comply with the IESO market rules and reliability standards established by North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council (NPCC).

   As of October 1, 2018, Hydro One SSM is operationally integrated with HONI. This integration resulted in the application of HONI's operational procedures and processes to

Hydro One SSM. These operational procedures and processes are designed to achieve the desired business objectives based on good utility practice principles, maintain reliability of the IESO-controlled grid, and continue to fulfill compliance obligations with reliability standards and the IESO market rules.

In addition, Hydro One's internal compliance program (ICP) applicable to reliability standards is now expanded to apply to the operational activities of Hydro One SSM. The ICP is designed to provide a reasonable level of assurance that compliance is achieved, sustained and demonstrated.

OEB Staff Interrogatory # 47

Reference:

Exhibit C, Tab 1, Schedule 1, Page 32-33
EB-2016-0050, October 13, 2016, Decision and Order, Application for the acquisition of Great Lakes Power Transmission Inc. by Hydro One Inc. (MAADs Decision), page 3-4

Interrogatory:

Preamble:

In the above-noted first reference, Hydro One SSM stated the following:

Leverage: Total Debt to Equity Ratio

Description

The debt-to-equity ratio is a measure of the company's financial leverage and serves to identify the ability to finance assets and fulfill obligations to creditors, while remaining within the OEB-mandated 60 per cent to 40 per cent debt-to-equity structure (a ratio of 1.5). This metric includes short-term and long-term debt.

Performance

HOSSM's annual Leverage: Total Debt to Equity Ratio is shown in Figure 13. HOSSM's average debt to equity ratio over the past five years was 1.05, and is trending downwards below the OEB-deemed ratio of 1.50. The ratio is trending downward primarily due to principal payments on long term debt trending from approximately $2 M to $2.5 M in annual principal repayments over the last 4 years.

At the second above-noted reference, page 3-4 of the MAADs decision stated the following:

Following the completion of the share purchase transaction, GLPT and Hydro One will continue to operate as stand-alone licensed transmitters. Hydro One states that the existing GLPTLP debt covenants prevent GLPT from being amalgamated absent consent of the debt holders. This may involve renegotiation of the terms of the GLPTLP debt instruments which could result in substantial additional costs. Therefore, Hydro One intends to allow GLPT's outstanding debt obligations to continue until they reach maturity in mid-2023. Amalgamation steps will be considered after this time.

a) Please provide the current status of the existing GLPTLP debt covenants and debt instruments.

b) Please describe if there has been any renegotiation of the terms of the GLPTLP debt instruments and whether substantial additional costs have been incurred or will result in the future.

c) Please explain whether GLPT's outstanding debt obligations are still planned to continue until they reach maturity in mid-2023, as well as any future amalgamation steps, and the timing of these steps.

Response:

a) HOSSM is currently in compliance with debt covenants.

b) There has been no renegotiation of the terms of the debt issues.

c) Yes, the obligations are still currently planned to continue until they reach maturity.

OEB Staff Interrogatory # 48

Reference:
Exhibit C, Tab 1, Schedule 1 – Performance Measurement and Continuous Improvement, p.4

Interrogatory:
Preamble:

At the above noted reference, Hydro One SSM stated the following:

As stated in EB-2016-0050, "commencing in 2017 and 2018, HOSSM and Hydro One will begin to identify areas where longer-term operational synergies and savings may be achieved" as a result of consolidation. The outcome of this work is reflected in the proposed scorecard.

a) It is also stated in the EB-2016-0356 Decision and Order that *"The requirement for continuous improvement should not be delayed until the company's operational integration process is complete."*[1] Please demonstrate how both the shorter-term and longer-term operational synergies and savings are reflected in HOSSM's scorecard and other evidence within the application.

Response:
a) Please see the response to I-1-43 d).

[1] EB-2016-0356 Decision and Order. Hydro One Sault Ste. Marie LLP Application for electricity transmission revenue requirement effective January 1, 2017. September 28, 2017. Page 8.

OEB Staff Interrogatory # 49

Reference:

Exhibit C, Tab 1, Schedule 1 – Performance Measurement and Continuous Improvement, p.5

Interrogatory:

Preamble:

Table 1 - HOSSM KPIs

Corporate Driver	Measurement
HSSE	High Risk Incidents (determined per HOSSM's Managed System)
	Preventable Motor Vehicle Accidents
	Safe Work Observations (% of total planned)
Continued Value Creation	OM&A at approved levels (actual as % of budget)
Risk Management	Self-Reports of Non-Compliance with NERC Standards
	Job Plan Quality Reviews (% of total planned)
Investment in our People	No measurement at this time

a) Do the KPIs identified in Table 1 above directly align with Hydro One's KPIs?
   i. If no, please identify what is different and explain why.

b) With regards to HSSE, please explain why there is no metric associated with HSSE training or stats for non-high risk incidents.

c) Please describe the link (if any) between Continued Value Creation and productivity or efficiency gains.

d) Does Hydro One SSM link the Risk Management KPI to the actual Risk Management program?
   i. If no, why doesn't Hydro One SSM attempt to validate the projected risks of projects versus the reality that emerges in retrospect?

e) Has Hydro One SSM considered including training programs in safety, productivity gains and risk management under the "Investment in our People" KPI?
   i. If yes, why did Hydro One SSM decide to exclude this measurement?
   ii. If no, why not?

Response:

a) The current KPIs for HOSSM outlined in the table above align with certain measures included in Hydro One's KPIs. However, the point of alignment rests in the Proposed Scorecard for HOSSM on Pages 13 and 14 of Exhibit C-1-1 versus that included for HONI in Attachment 1 of EB-2016-0160. The only difference between these scorecards is the inclusion on HONI's scorecards of two measurements related to NERC/NPCC compliance. Discussions are on-going on the whether they will be included in HOSSM's scorecard going forward.

b) The scorecard includes a measure for Recordable incidents that includes incidents of all risk levels

c) Finding productivity/efficiency gains is tied to OM&A management (Continued Value Creation)

d) The current risk program at HOSSM does not track the actual risk metrics post completion. With integration, projects will be completed within HONI's risk program.

e) To the extent where a gap exists, HOSSM will gradually adhere up to HONI standards.

OEB Staff Interrogatory # 50

Reference:
Exhibit C, Tab 1, Schedule 1 – Performance Measurement and Continuous Improvement, p. 10

Interrogatory:
Preamble:

At the above noted reference, Hydro One SSM stated the following:

Job Plan Quality Assurance Reviews
The completion and maintenance of documented Job Plans is required by the Electrical Utility Safety Rule 107. The Job Plan process is "to establish a safe work area, by identifying the job steps, hazards and appropriate barriers."

Job Plans therefore are to mitigate safety risks by hazard identification for workers in the field. To ensure the Job Plan is completed accurately and demonstrates a comprehensive knowledge of the work environment, HOSSM implemented a Quality Assurance ("QA") program. HOSSM started tracking the completion of QA reviews against the number of those targeted at the end of 2013 to ensure the right program is in place

a) Based on the above provided description, please explain why the "Job Plan Quality Assurance Reviews" are included as a KPI under the Risk Management driver as opposed to the HSSE driver.

Response:
a) When asked as part of this process, Management acknowledged that there is a significant safety component to the measure and it could reasonably be included in the HSSE driver. However, there also exists a large component to job planning that deals with risk mitigation.

   In short, the measure could be included in either section for classification purposes.

OEB Staff Interrogatory # 51

Reference:

Exhibit C, Tab 1, Schedule 1 – Performance Measurement and Continuous Improvement, p. 13-14

Interrogatory:

Preamble:

Performance Outcomes	Performance Categories	Measures		Historical Years 2011	2012	2013	2014	2015	2016	2017	Trend	2023 Targets
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	Satisfaction with Outage Planning Procedures (% Satisfied)		N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	90%
		Customer Delivery Point Performance Standard Outliers as % of Total Delivery Points		33%	24%	25%	20%	16%	0%	0%	▲	11.80%
	Customer Satisfaction	Overall % Customer Satisfaction in Corporate Survey		N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	85%
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Recordable Incidents (# of injuries/illnesses per 200,000 hours worked)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	-	<1.0
	System Reliability	T-SAIFI (Average # Power Interruptions per Delivery Point)		2.14	2.24	1.16	0.32	1.11	0.37	0.42	▲	0.53
		T-SAIDI (Average # Minutes of Power Interruptions per Delivery Point)		296.71	176.76	233.7	9.3	85.8	10.0	30.9	▲	42.1
		System Unavailability (%) - Lines		N/A	N/A	0.25	0.02	0.09	0.39	0.10	▲	0.38
		System Unavailability (%) - Stations		N/A	N/A	0.03	0.00	0.13	0.00	0.00	-	0.38
		Unsupplied Energy (minutes)		N/A	N/A	12.63	2.98	16.42	2.88	9.19	▲	11.4
	Asset Management	In-Service Additions (% of HOSSM's Capital Plan)		120%	111%	99%	99%	92%	98%	108.5 %	-	100%
		CapEx as % of Budget		97%	113%	95%	95%	100%	101%	129%	▲	100%
	Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)		10.69 %	6.87%	4.38%	4.33%	5.76 %	5.81 %	6.23%	▲	7.80%
		Sustainment Capital per Gross Fixed Asset Value (%)		7.55%	4.03%	1.29%	1.25%	2.70 %	2.70 %	3.69%	▲	4.40%
		OM&A per Gross Fixed Asset Value (%)		3.15%	2.84%	3.09%	3.08%	3.06 %	3.10 %	2.54%	▲	1.80%
Public Policy Responsiveness Transmitters deliver on obligations mandated by government (e.g. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Connection of Renewable Generation	% on time completion of renewables connection impact assessments		100%	100%	100%	100%	100%	100%	100%	-	100%
	Regional Infrastructure	Regional Infrastructure Planning progress - % Deliverables met		N/A	N/A	N/A	100%	100%	100%	100%	-	100%
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.21	1.34	1.69	1.67	1.62	1.33	1.38	N/A	N/A
		Leverage: Total Debt (includes short-term & long-term debt) to Equity Ratio		1.13	1.10	1.09	1.12	1.04	1.03	0.97	N/A	N/A
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.66%	9.42%	8.93%	9.36%	9.30 %	9.19 %	N/A	N/A	N/A
			Achieved	10.94 %	11.86 %	11.51 %	11.42 %	9.66 %	9.93 %	N/A	N/A	N/A

Figure 5 - Proposed Hydro One Sault Ste. Marie Scorecard

a) Please provide a table of reliability figures that excludes the reliability impacts of major weather events and exogenous variables.

b) Please confirm whether the OM&A per Gross Fixed Asset Value is primarily a function of low OM&A or high Gross Fixed Asset Values.

c) Please describe why a target of 7.80% was selected for the Total OM&A and Capital per Gross Fixed Asset Value.

d) Will Hydro One SSM provide the OEB with an updated scorecard following the 2023 target year?

Response:

a) There is not a criterion defining major weather events and exogenous variables.

Below are reliability figures excluding all weather events:

	2011	2012	2013	2014	2015	2016	2017
T-SAIFI	1.52	1.24	0.53	0.26	0.66	0.37	0.37
T-SAIDI	279.71	97.57	131.68	8.74	43.34	10.00	30.73
System Unavailability (%) - Lines	N/A	N/A	0.18	0.01	0.08	0.39	0.10
System Unavailability (%) - Station	N/A	N/A	0.00	0.00	0.11	0.00	0.00
Unsupplied Energy (minutes)	N/A	N/A	8.13	2.79	10.23	2.88	9.15

b) The variability in OM&A per Gross Fixed Asset Value is primarily a function of changing OM&A given that Gross Fixed Asset Value tends to remain relatively constant over time.

c) HOSSM has reviewed this target for correctness as this appears to have been inserted in error. The corrected 2023 target value for this measure should be 4.93%. HOSSM apologizes for any confusion.

For an updated scorecard including all targets please refer to the response to I-5-14 (SEC IR# 14).

d) HOSSM is prepared to submit an updated Scorecard in 2023 if that would be helpful to the Board.

OEB Staff Interrogatory # 52

Reference:

Exhibit C, Tab 2, Schedule 1

Interrogatory:

Preamble:

At the first above-noted reference, Hydro One SSM has provided an overview of its reliability performance.

In the first above-noted reference, Hydro One SSM has also included the Canadian Electricity Association (CEA) composite for some measures from 2013 to 2016 but did not include the 2017 CEA measure. Hydro One SSM stated that "CEA statistics were not available for 2017 at the time of the development of this exhibit."

a) Please provide additional evidence which highlights how Hydro One SSM has addressed the OEB's performance standards for transmitters, specifically as set out in Chapter 4 of the Transmission System Code.

b) Please provide additional evidence which shows how Hydro One SSM has compared it system performance to those of other systems, both nationally and internationally, where available. OEB staff notes that Hydro One SSM has provided some CEA data, but requests that Hydro One SSM also provide CEA data related to 2017.

Response:

a) Section 4.5 of the Transmission System Code generally seeks to ensure that a Transmitter observes appropriate standards with respect to reliability performance at delivery points. The Performance data related for delivery points is provided in Exhibit C-2-1. HOSSM is operationally integrated with Hydro One and as such Hydro One is under contract to ensure that the HOSSM portion of its system complies with the TSC going forward.

b) Aside from the CEA data provided, Hydro One SSM has not previously benchmarked its performance against the performance of its peers.

OEB Staff Interrogatory #53

Reference:

Exhibit C, Tab 2, Schedule 1 – Reliability Performance, p. 3
Exhibit C, Tab 2, Schedule 1 – Reliability Performance, p. 4

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

The Standard Average and Minimum Standard of performance relates to the reliability of supply to the size of load being served at the delivery point measures for both frequency (total interruptions / load block) and duration (total minutes / load block) of interruption. The standard was established utilizing Hydro One Networks Inc.'s historical (1991-2000) statistics, shown in Table 1.

Table 1 - Delivery Point Performance Standards[2]

Performance Measures	Delivery Point Performance Standards (Based on a Delivery Point's Total Average Station Load)							
	0 to 15MW		>15 to 40MW		>40 to 80MW		>80MW	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/yr)	**4.1**	**9.0**	**1.1**	**3.5**	**0.5**	**1.5**	**0.3**	**1.0**
DP Interruption Duration (min/yr)	**89**	**360**	**22**	**140**	**11**	**55**	**5**	**25**

At the above noted reference, Hydro One SSM stated the following:

Table 2 shows HOSSM's CDPP[1] Minimum Standards and Standard Averages for each load category. This is calculated as the number of DP[2]s in each of HOSSM's respective load category multiplied by each of the CDPP Standards for DP Frequency of Interruptions (Outages) and DP Interruption Duration (Minutes) found in table 1.

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[1] Customer Delivery Point Performance ("CDPP")
[2] Delivery Point ("DP")

Table 2 - HOSSM CDPP Standards

Customer Deliver Point Load Categories	Number of Delivery Points	Standards	Interruption Frequency (Outages)	Interruption Duration (Minutes)
>80 MW	1	Minimum Standard	1.0	25
		Standard Average	0.3	5
40-80 MW	1	Minimum Standard	1.5	55
		Standard Average	0.5	11
15-40 MW	2	Minimum Standard	2	280
		Standard Average	2.2	44
0-15 MW	14	Minimum Standard	126	5,040
		Standard Average	57.4	1,246

a) Please explain why Hydro One SSM is utilizing Hydro One Networks Inc.'s historical (1991-2000) performance statistics to establish current standards.

b) Can Hydro One SSM establish updated standards based on more modern statistics?
   i. If no, why not?
   ii. If yes, please provide an updated Table 1 and Table 2 reflecting the more modern statistics, and describe the resulting impacts on the filed evidence.

Response:

a) As referenced in EB-2018-0218 Exhibit C-2-1 & Attachment 1, the HOSSM delivery point standard was based on the Hydro One's Customer Delivery Point Performance Standard as approved in RP-1999-0057/EB-2002-0424. The approved standard is based on historical 1991-2000 performance.

b) No. HOSSM has a limited number of delivery points within larger average load groupings to be able to come to a statistically meaningful computation.

OEB Staff Interrogatory #54

Reference:

Exhibit C, Tab 3, Schedule 1, Page 2
Exhibit B1, Tab 1, Schedule 1, Page 113
Filing Requirements, page 5, section 2.1

Interrogatory:

Preamble:

At the above-noted first reference, Hydro One SSM stated the following:

As the definition of benchmarking is a standard against which something can be measured or assessed, HOSSM has also provided a proposed scorecard that includes metrics, annual results and proposed targets in Exhibit C, Tab 1, Schedule 1. The annual results of the scorecard metrics have also been provided on graphs to illustrate the year over year trending. Key Performance Indicators ("KPIs") that are currently tracked by HOSSM are also included in the same exhibit.

It is expected that the next application submitted to the OEB will be after HOSSM's integration with Hydro One. At that time, HOSSM will be included as part of Hydro One for any benchmarking studies.

HOSSM will also participate in any benchmarking studies undertaken by Hydro One in which it is requested to do so.

At the above-noted second reference, Hydro One SSM stated the following:

Since the current Plan does not propose any capital or OM&A expenditures in excess of the levels already embedded into HOSSM's last approved Revenue Requirement, a benchmarking study confirming the reasonableness of HOSSM's expenditures would not be instructive. However, in preparing this Plan, HOSSM staff referred to the Total Factor Productivity study prepared by Power System Engineering Inc. ("PSE") for Hydro One Transmission. Moreover, as the integration between HOSSM and Hydro One continues, HOSSM plans to utilize a range of studies prepared by the Electric Power Research Institute ("EPRI") on a number of topics concerning asset management best practices. HOSSM will leverage these insights to continually improve the efficiency and cost effectiveness of its operations.

Section 2.1 of the Filing Requirements also state that internal benchmarking[1] and external benchmarking[2] may be addressed.

a) Please discuss which costs Hydro One SSM tracks/measures to benchmark its own internal cost performance over time. Please provide the data for the years 2013 to 2017.

b) Please discuss which costs Hydro One SSM tracks/measures to benchmark its cost performance versus external comparators over time (i.e. against other transmitters), if any. Please provide the data for the years 2013 to 2017.

c) Please confirm that Hydro One SSM has not participated in any benchmarking studies undertaken by Hydro One or another external comparator. If this is not the case, please explain.

d) Please provide more detail regarding why a benchmarking study would not be instructive, even given that Hydro One SSM does not propose any capital or OM&A expenditures in excess of the levels already embedded into its last approved revenue requirement.

Response:

a) HOSSM did not actively benchmark internal cost performance from 2013-2017.

b) See the response to a).

c) HOSSM confirms that it has not participated in any benchmarking studies.

d) The referenced statement attempts to convey HOSSM's position that benchmarking would not be instructive to the process of determining the reasonableness of forecasted expenditures for this TSP in particular. This is because the forecasted expenditures in this TSP do not exceed the depreciation funding available to HOSSM as a result of prior proceedings.

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[1] Internal benchmarking: Against own cost performance over time to demonstrate continuous improvement
[2] External benchmarking: Against other transmitters, including rationale for selected comparators

OEB Staff Interrogatory #55

Reference:

Exhibit D, Tab 1, Schedule 1, Page 1

Interrogatory:

Preamble:

At the above noted reference, Hydro One SSM stated the following:

The Hydro One Sault Ste. Marie ("HOSSM") application is a Revenue Cap Incentive Rate-setting application ("RCIR"). As detailed in Chapter 2 of the Filing Requirements for Electricity Transmitter Applications, a transmitter can propose an incentive mechanism for adjusting the revenue requirement on an annual basis. A revenue cap refers to the mathematical formula used to set how much a utility's revenue can increase in a year when the utility is not having a full review of its rates through an OEB process. *The formula ensures that a utility's rates will increase at a rate which is less than inflation. [Emphasis added]*

As documented, the revenue cap adjusts the allowed revenues to be recovered to rates to inflation less expected productivity (with possibly some other adjustments such as Z-factors). Rates to recover the adjusted revenue cap are derived by allocating the revenue to customer classes and dividing the allocated revenues by billing determinants, such as number of accounts, kW or kWh, in each class. Depending on the growth in demand relative to the inflation less productivity adjustment to revenues, the rate of change of rates may be higher, lower, or equal to the rate of inflation.

a) Please explain how Hydro One SSM believes generally that the revenue cap formula "ensures that a utility's rates will increase at a rate which is less than inflation".

b) Hydro One SSM's proposed revenue cap is for a transmission-specific 2-factor inflation measure (input price index or IPI) offset by an X-factor of 0%, composed of a base X-factor of 0% and a stretch factor of 0%. In this case, Hydro One SSM's revenues would increase annually at a rate **equal to** inflation, not less than it. Please explain how Hydro One SSM's proposed revenue cap plan and parameters "ensure that [Hydro One SSM's] rates will increase at a rate which is less than inflation".

Response:

a) The statement quoted in evidence was misstated. It should have read “The formula ensures that a transmitter’s revenue requirement will increase at a rate no greater than inflation.”

b) As noted in response to part a, the quoted evidence was misstated.

OEB Staff Interrogatory #56

Reference:

Exhibit D, Tab 1, Schedule 1
Exhibit E, Tab 1, Schedule 1
Exhibit A, Tab 2, Schedule 4, page 4
Filing Requirements, page 3, section 2.0
EB-2016-0050, October 13, 2016, Decision and Order, Application for the acquisition Great Lakes Power Transmission Inc. by Hydro One Inc. (MAADs Decision), page 11

Interrogatory:

Preamble:

Hydro One SSM has proposed a revenue cap index of the form:

$$Revenue_t = Revenue_{t-1} \times (1 + RCIR_t)$$

Where:

$$RCIR_t = IPI_t^{Tx} - 0$$

In this formula, IPI^{Tx} refers to the proposed transmission-specific Input Price Index (IPI) measuring inflation in the input prices of labour, capital and materials.

Section 2.0 of the Filing Requirements states:

In recognition of the forecasting uncertainty involved in longer terms, the OEB has included in section 2.8.12 a provision for a “Z-factor” claim, similar to that for electricity distributors operating under multi-year rate plans.

In addition, the OEB will consider requests for a mechanism to fund significant incremental capital during the rate term from applicants proposing a Revenue Cap index. This will enable review during the cost of service application of the need and prudence of any significant, discrete projects coming into service over the plan term that are part of a transmitter’s Transmission System Plan and which transmitters cannot manage through the revenue established through the index. Applicants must propose all criteria and parameters for approval of any capital module.

The OEB will require from transmitters applying for approval of revenue requirements under a Custom IR or Revenue Cap application a proposal to mitigate the potential for any significant earning by the transmitter above the regulatory net income supported by the approved return on equity, such as a capital variance account or an earnings sharing mechanism.

In its Decision and Order EB-2016-0050, with respect to a Z-factor, the OEB stated:[1]

The OEB finds that Hydro One will be granted recourse to file for recovery of Z-factor events, if required, through a separate rate application. The OEB expects in all cases that an applicant will have to demonstrate that failure to recover the sought-after amount would have significant impact on its operations.

In the same decision, the OEB considered the proposed rate-setting plan, including the proposed ESM, in section 4.2.[2] The OEB did not accept the proposed plan, but stated the following:

The OEB accepts that the applicant's proposals for a 10 year deferred rebasing period and ESM are aligned with the Handbook. However, Hydro One's proposal for a resetting of rates at the beginning of the 10 year deferred rebasing period is not contemplated by the Handbook and the OEB does not accept it. Rate-setting policies associated with consolidation are predicated on the notion that the going-in rates are the rates intended to provide the revenues required as the starting point to achieve savings over the deferred rebasing period.

The OEB notes that a cost of service application was filed by GLPT on August 26, 2016. However, the OEB finds that GLPT can continue with its existing revenue requirement. and may bring forward a separate rate application to seek approval for the elements of a specific revenue cap index framework, for the deferral period. Such an application would be expected to encompass the following components as required by the Transmission Filing Requirements: the annual adjustment (expected inflation, productivity, stretch factors) and proposed performance reporting and monitoring (draft scorecard, RRR filings, etc).[3]

a) Hydro One SSM has not addressed the Z-factor explicitly in its revenue cap proposal in the first above noted reference, but stated in the third above noted reference that: "HOSSM will seek to establish a new Z-factor deferral Account 1572 to recover the material costs, associated with any unforeseen event that is outside the control of HOSSM, and which meets

[1] Decision and Order EB-2016-0050, October 13, 2016, p. 20.
[2] *Ibid.*, pp. 12-19
[3] Ibid., pp. 17,19

the defined causation, materiality and prudence criteria in accordance with the OEB's Chapter 2, Filing Requirements for Electricity Transmission Applications dated February 11, 2016."

i. Please confirm that Hydro One SSM's proposal is for a sub-account of the existing Deferral and Variance Account 1572 – Extraordinary Regulatory Events in the event that provide Hydro One SSM experiences such an event that would justify Z-factor treatment.

ii. Please identify what Z-factor materiality threshold, on a revenue requirement basis, would apply, in accordance with the Filing Requirements.

b) The proposed ESM in EB-2016-0050 was as follows: "GLPT's revenue requirement will be adjusted so that prior year excess earnings are shared with ratepayers on a 50:50 basis for all earnings that exceed 300 basis points above the ROE approved by the Board for 2018 in GLPT's 2017-18 rates application."[4] Hydro One SSM notes in its evidence that the 2017-18 rate application (EB2016-0356) was denied by the OEB.[5]

i. What ROE is Hydro One SSM proposing should be used for the proposed ESM?

ii. Please confirm that the proposed ESM is i) unchanged from the EB-2016-0050 proposal except for the ROE; and ii) complies with the requirements of the Handbook for Utility Rate Applications[6] (Rate Handbook) and the Filing Requirements. In the alternative, please explain.

Response:

a) (i) Hydro One SSM confirms that it intends request a sub-account of the existing Account 1572 should it experience an event which meets the existing OEB criteria for a Z-factor claim.

(ii) Hydro One SSM's materiality threshold, consistent with the Filing Requirements, is $200,000 as calculated on pages 1 and 2 of Exhibit A, Tab 2, Schedule 1.

b) (i) Hydro One proposes that the regulatory ROE to be used for the purposes of the proposed ESM should be the OEB-approved ROE underpinning the revenue requirement approved in

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[4] Decision EB-2016-0050, op. cit., p. 12
[5] Exhibit A, Tab 2, Schedule 2, page 3-7
[6] Issued on October 13, 2016

Hydro One SSM's last rebasing application EB-2014-0238 for 2015 and 2016 rates[7]. The 2016 OEB-approved revenue requirement was based on a 9.19% ROE.

(ii) Hydro One SSM confirms that the proposed ESM is consistent with parameters identified on pg. v of Appendix 3 to the OEB's Rate Handbook. Specifically, Hydro One SSM is proposing to share with customers, on a 50:50 basis, all earnings that are more than 300 basis points above its OEB-approved ROE after the initial 5 years of deferred rebasing period (years 6-10).

[7] EB-2014-0238 was a two-year cost of service application. The OEB approved an update of the cost of capital parameters for Hydro One SSM's 2016 revenue requirement which was undertaken in EB-2015-0337.

OEB Staff Interrogatory #57

Reference:

Exhibit D, Tab 1, Schedule 1, page 2-4
Exhibit D, Tab 1, Schedule 1, Attachment 1, page 6(section 1.1.3), page 11 (section 1.4), page 15 (section 2.2.1) and page 49 (section 7)
Exhibit A, Tab 2, Schedule 2, page 5
Exhibit J5.2, EB-2017-0306/0307

Interrogatory:

Preamble:

Hydro One SSM and its consultant, PSE, have proposed a 2-factor IPI as the measure of inflation. Hydro One SSM's proposal is similar to the 2-factor IPI developed for electricity distributors and adopted since 2014, per the Report of the Board (EB-2010-0379). The proposed IPI would use the same two Statistics Canada data series of:

- Average Weekly Earnings, including Overtime, for Ontario, all Business Categories except Unclassified (AWE)

- Implicit Price Index for Gross Domestic Product (Final Domestic Demand) – Canada (GDP-IPI (FDD)),

but would use transmission-specific weights to average the contribution of the two (labour and non-labour) components. Hydro One SSM, based on analysis proposed by PSE, has proposed weights of 14% for labour and 86% for non-labour (capital and materials).

With this proposal, the OEB and the rate-regulated sectors it oversees would have four different IPI measures as follows:

			Component	
			Labour	**Non-labour (capital and materials)**
Data Series			**AWE**	**GDP-IPI (FDD)**
Firm/Sector	**IPI measure**	**Regulatory Filing Reference No.**	**Weight**	
Electricity Distribution	IPI^{Dx}	EB-2010-0379	30%	70%
Ontario Power Generation (prescribed hydroelectric generation)	IPI^{OPG}	EB-2016-0152	12%	88%
Enbridge/Union Gas merger – Natural Gas	IPI^{NG}	EB-2017-0306/-0307		100%
Hydro One SSM – Electricity Transmission (proposed)	IPI^{Tx}	EB-2018-0218	14%	86%

While the inflation measure proposed and approved for natural gas distribution is explicitly defined as GDP-IPI (FDD), it can be mathematically represented as a version of the adopted 2-factor methodology where 0% is assigned to the labour component and 100% is the weighting factor for GDP-IPI (FDD). This is still sound conceptually, as the (rate of change of) GDP-IPI is actually a measure of the inflation of the output GDP, which depends on inflation of all inputs – labour as well and capital and materials.

We thus have a potential to have four inflation measures specific to different energy sectors in Ontario. These measures in turn only rely on two external and publicly collected and reported data series. AWE and GDP-IPI are separate and do show different movements from year-to-year. At the same time, the series are not totally de-linked, as changes in labour prices do factor into GDP-IPI, which is a measure of output price inflation, as described above.

Based on the common data inputs and similarities of weights the four IPI measures will largely coincide, and may show difference of ±0.1% or 0.2%. This was demonstrated by an exhibit that Enbridge Gas Distribution/Union Gas filed in the recent EB-2017-0306/-0307 hearing, showing how GDP-IPI and the two-factor electricity distribution IPI tracked over time.[1]

[1] Exhibit J5.2, EB-2017-0306/0307, May 23, 2018.

a) Please provide Hydro One SSM's, and, if necessary, PSE's, views on the rationale for the proposed 2-factor transmission-specific IPI in light of the existing alternatives.

b) Are there any other measures of inflation that Hydro One SSM and/or PSE considered as alternatives? If so, please identify.

Response:

a) The rationale for Hydro One SSM's flows from the OEB's findings the EB-2016-0356 proceeding. In its decision in EB-2016-0356, the OEB found that "Hydro One SSM's proposed use of 1.9%[2] would have been acceptable if Hydro One SSM's proposed approach to the revenue cap index were being approved in this proceeding, as the inflation factor does not depart from the inflation factor used for distributors." The decision also stated that "evidence regarding the appropriate input weights should be included in any subsequent rate application by Hydro One SSM." Subsequent to the decision in EB-2016-0356, the OEB approved the use of the 2-factor IPI with an 88%/12% split for OEB's prescribed hydroelectric generation facilities in EB-2016-0152. Hydro One SSM's proposal aligns with the OEB's findings in both of those proceedings.

b) Hydro One SSM did not consider other alternative measures of inflation. Hydro One SSM reviewed prior analyses before the OEB regarding the appropriate input price indices in the electricity sector; namely, the work done in the 4th Generation Incentive Regulation proceeding (EB-2010-0379) and the analysis commissioned by OPG in EB-2016-0152 in support of an incentive-rate setting mechanism for its prescribed hydroelectric facilities. Despite the differences between the electricity distribution and hydroelectric generation businesses, the ultimate outcome in both analyses supported the use of the same two input price indexes, albeit with different weightings. Given the significant amount of discovery that has occurred in prior proceedings before the OEB regarding the appropriateness of the two input price indexes underpinning the IPI, Hydro One SSM did not see the need to conduct a further, duplicative analysis. Rather Hydro One SSM focused on the OEB's findings in EB-2016-0356, and only considered what would be an appropriate transmission-specific weighting.

[2] 1.9% was the applicable IPI for setting rates under Price Cap IR at the time of the EB-2016-0356 proceeding.

OEB Staff Interrogatory #58

Reference:

Exhibit D, Tab 1, Schedule 1, Attachment 1, page 11-12, page 50-52 Exhibit A, Tab 2, Schedule 1, page 4
Rate Handbook, page 27

Interrogatory:

Preamble:

In sections 1.4 and 8 of PSE's evidence, PSE provides its conclusions and recommendations with respect to a Custom IR plan based on a revenue cap approach for Hydro One Networks Transmission. There is no discussion of Hydro One SSM or its proposed revenue cap plan.

a) Does PSE believe that the plan parameters that it is recommending for Hydro One Networks Transmission would also hold for Hydro One SSM's proposed plan? Please explain your response.

b) PSE's recommendations are with respect to a Custom IR plan for Hydro One Networks Transmission. Hydro One SSM's proposed plan is for a revenue cap, in accordance with the Filing Requirements. However, Hydro One SSM's proposal is not for a Custom IR plan. For example, Hydro One SSM is proposing that the ICM be available to it on the second above noted reference ; the ICM is not available for a Custom IR plan in accordance with the Rate Handbook. Does PSE recommend any changes to the plan design or parameters for Hydro One SSM since its proposed revenue cap plan is not a Custom IR as PSE has assessed and recommended for Hydro One Networks Transmission? Please explain your response.

Response:

a) The parameter recommendation for the IPI is based on external measurements of the transmission industry labour/non-labour weights. The external measurement would be the same regardless of the transmission company it is being applied to. Thus, the recommendation for the IPI of a 14%/86% weight on AWE and GDP-IPI, respectively, holds for both Hydro One Networks and Hydro One SSM.

Likewise, the productivity factor recommendation is based on an external measurement of the transmission industry's total factor productivity (TFP). This transmission industry TFP result would be the same regardless of the Transmission Company it is being applied to.

Thus, the recommendation for the productivity factor of 0.0% holds for both Hydro One Networks and Hydro One SSM.

The stretch factor is different in that the actual company is being compared and evaluated to an external benchmark. This external benchmark is customized to the operating conditions of the specific company being studied. PSE's benchmark study considered only Hydro One Networks, and not Hydro One SSM. The benchmark finding showed that Hydro One Networks total costs were 27.3% below the expected benchmarks for the 2014-2016 period, and that this strong cost performance is expected to accelerate into the projected periods. Hydro One SSM was not added in our analysis. However, if Hydro One SSM were combined with Hydro One Networks, there is a high probability that the benchmark results would not change significantly, since Hydro One SSM is a small fraction of HON. The recommendation of a 0.0% stretch factor based on the benchmarking results for the combined company would very likely hold.

PSE did not perform a separate benchmarking analysis for Hydro One SSM. However, there were two reasons we put forth a recommendation of a 0.0% stretch factor for Hydro One Networks. The first was the benchmarking result for Hydro One Networks that showed the company was nearly 32% below benchmark costs in the CIR period of 2019-2022. The second reason was our finding of the industry TFP trend being at -1.71%. This finding, in conjunction with PSE's recommendation of a 0.0% productivity factor, produces an "implicit stretch factor" of 1.71%, which is already an extraordinarily large stretch factor. Given this stretch factor already implicit in PSE's recommendations, a 0.0% stretch factor would remain our recommendation for Hydro One SSM, despite having no benchmarking results specific to Hydro One SSM.

b) PSE's recommendations for the parameters of the Hydro One SSM revenue cap remain unchanged from our recommendations for Hydro One Networks. The inclusion and calculations for the productivity factor, inflation index, and stretch factor are still just as relevant under the revenue cap proposal put forth by Hydro One SSM. We do not see the rationale for differing the approach to the parameters based on the revenue cap proposed.

OEB Staff Interrogatory #59

Reference:

Exhibit D, Tab 1, Schedule 1, Attachment 1, Section 9, Appendix 1

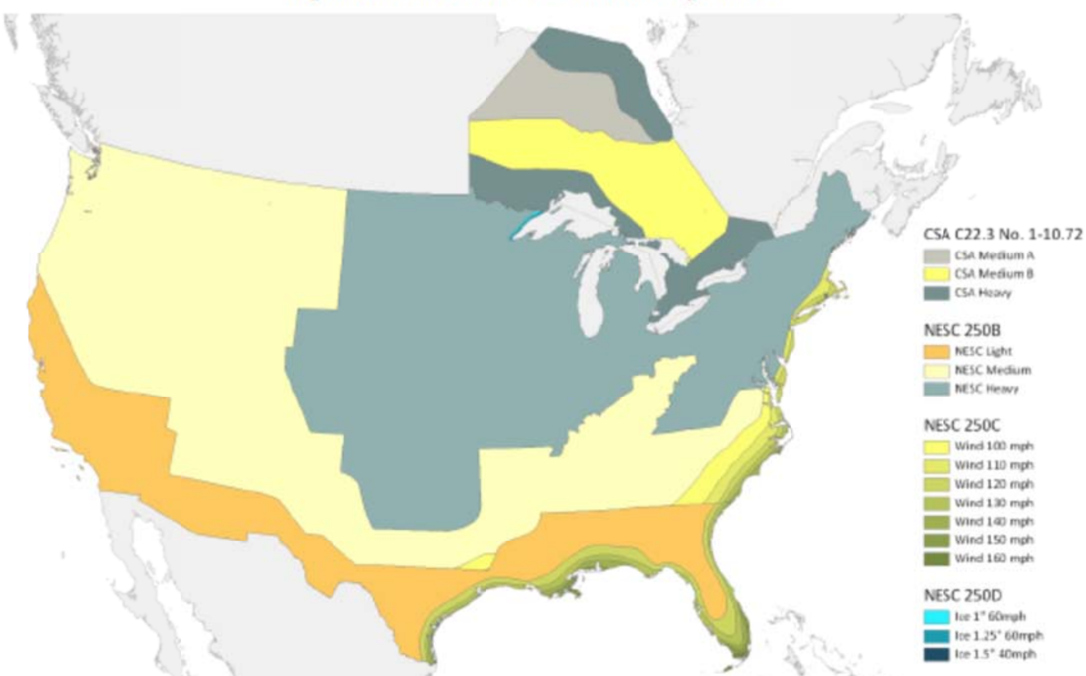
Interrogatory:

Preamble:

In the above noted appendix, PSE describes its methodology for constructing a Transmission Loading Variable, which is intended to proxy the construction standard, and hence the cost, of a transmission line to withstand "a minimum combination of accumulated ice and wind based on local extreme historical weather conditions".

On the bottom of page 53 and most of page 54, PSE describes how CSA and NESC zones were mapped to the continental United States and Ontario, and provides the map replicated below:

Figure 8 CSA and NESC Loading Zones



PSE states the following: "Utility service territories were overlaid with the above loading zone map. GIS analysis revealed the percentage of a given utility's service territory that fell into each loading zone."

With respect to the construction of the variable for Hydro One Networks Transmission:

a) Please confirm that Hydro One Networks Transmission has no transmission lines in service in the CSA Medium A zone shown in medium grey in the western and central portion of Northern Ontario.

b) With respect to the CSA Heavy zone in Northern Ontario running along the south shore of Hudson's Bay and western shore of James Bay, please confirm that Hydro One Networks Transmission has one high voltage line running from Cochrane to Moosonee (at the southern tip of James Bay) and then for about 175 km north from Moosonee until it interconnects with the Five Nations Energy Inc. transmission line to supply the First Nations communities of Kasheschewan, Fort Albany and Attawapiskat, and the DeBeers mine near Attawapiskat.

c) OEB staff acknowledges that Hydro One Networks Transmission has some transmission lines in the yellow shaded area labelled CSA Medium B. These would primarily be in northeastern Ontario roughly corresponding around the northern part of Highway 11. However, it would appear that much of this zone is unserved by electricity, except in certain First Nations communities; these are not served through the IESO-controlled grid. Please identify the km. of lines, capacity and the approximate service area served in the CSA Medium B zone.

d) Please identify what PSE used as Hydro One Networks Transmission's service territory for the purposes of constructing this variable. Did PSE take into account Hydro One's service territory with actual transmission lines in its construction of this variable?

e) Do similar issues of service areas, unserved territory and mapping of zones to service area arise with respect to the U.S. utilities in the samples? If so, how has PSE addressed these?

More generally, with respect to the construction of this variable for Hydro One and U.S. utilities, on page 56 of its study, PSE states:

3. Loading values were calculated for each utility based on the area and loading percentages.
The area percentages derived from the zone map and utility service territory map were multiplied by loading value percentages from PLS-CADD analysis for each loading zone present in a given utility service territory. These values were summed to produce an overall loading value for each

utility. This overall loading value represents (roughly) the minimum design/build structural strength required for the utility's service territory.

f) Was the utility service territory, both for Hydro One Networks and for U.S. utilities based on its distribution network service territory, or where each utility has high voltage transmission lines?

g) The location and capacity of transmission lines will depend on the location of supply (generation, inter-jurisdictional connection) and load (cities). Some forms of generation, particularly hydroelectric, will be located as dictated by nature (i.e., the location of rivers and falls which supply the "power" source for generators. Wind farms will be located where natural conditions (wind patterns, expanse of land) favour siting in certain areas. Other generation, particularly for coal- and natural gas-fired plants, may be located closer to load centers, as these are also often transportation hubs for the cities and communities that can also provide convenient delivery of the fuel (coal and gas) to supply the generators. Thus, transmission lines may be shorter or longer in distance, depending on the operating environment of that jurisdiction or service territory. Utilities, including Hydro One Networks and other Ontario distributors, may also build and operate sub-transmission lines as substitutes for high voltage transmission lines. Please explain how PSE satisfied itself that the "area percentages [, as] derived from the zone map and utility service territory map ... [and] … multiplied by loading value percentages from PLS-CADD analysis for each loading zone present in a given utility service territory … [and] summed to produce an overall loading value for each utility … [appropriately] represents (roughly) the minimum design/build structural strength required for the utility's service territory".

Response:

a) The map referenced above does not align with HONI zones used for operational or asset classification purposes. While it is not possible to provide a conclusive answer without having the exact coordinates of the zones, HONI estimates that it does not have transmission lines in the CSA Medium A zone.

b) HONI has two 115 kilovolt (kV) transmission lines running from Abitibi Canyon to Moosonee (at the southern tip of James Bay). The transmission lines north of Moosonee up to Kasheschewan, Fort Albany and Attawapiskat, and the DeBeers mine near Attawapiskat do not belong to HONI.

c) Based solely on visual inspection of the referenced map, HONI estimates that the only transmission line that may partially lie in the western half of CSA Medium B zone is the 115 kV line E1C. In the eastern half of CSA Medium B zone, HONI owns 500 kV, 230 kV and 115 kV transmission lines. The length and service area of these lines are not readily available as the referenced map does not align with any current operational zones or classifications used by HONI. Additionally, broadly speaking, many of these transmission lines form a network and as such a "Capacity" can't be assigned to each line or to a service area.

d) Complete mapping of transmission lines in Canada and the United States is not publicly available. Therefore, for constructing this variable, PSE used the Hydro One Networks' retail service territory as a proxy for its transmission service territory. The following map illustrates the Hydro One service territory.

e) Similar to the Hydro One Networks' transmission territory, PSE used retail service territories for each U.S. utility as a proxy for their corresponding transmission service territories.

f) The utility service territories in both Canada and the U.S. are based on the geographic extents of retail service areas. It is assumed that the majority of transmission infrastructure is within service territory boundaries. Results are not an exact representation of transmission line locations but should be a strong approximation.

g) The analysis is intended to approximate average loading conditions from a consistent, third-party data set. Locations of supply and load were not factored into the loading analysis. Regional differences in power sources and population distributions could impact the likelihood of a line being built in a particular loading zone within, or adjacent to, a utility's retail service territory. However, it is assumed that the majority of transmission infrastructure is within retail service territory boundaries or within similar loading zone(s) found within the retail service territory.

OEB Staff Interrogatory # 60

Reference:

Exhibit D, Tab 1, Schedule 1, Attachment 1, Section 6

Interrogatory:

Preamble:

In its TFP analysis presented in its evidence, PSE calculated an average annual transmission industry TFP trend of -1.71% based on the sample of Hydro One Networks' and 53 U.S. utilities' transmission assets, operations, outputs, costs and revenues.

In section 6.1 of its evidence, PSE offers potential explanations for the observed negative TFP result, which can be summarized as follows:

1. Increase in the importance of outputs, such as reliability, safety, interconnectivity, power quality, connection of alternative generation sources such as wind and solar, which may be difficult to measure and for which growth and importance may differ from that of the main, traditional measures of kW and kWh.

2. Changes in operating environment characteristics, such as slower growth in developed western economies, aging population, natural conservation due to more energy efficient equipment and appliances by commercial and residential customers.

3. Related to 2 above, the aging of transmission assets which are due or overdue for replacement, and for which replacement costs and ongoing maintenance costs are increasing.

a) With respect to bullet 1, please identify what other output measures PSE investigated for possible inclusion, and why PSE determined that these outputs be omitted from its analysis. For example, PSE incorporated reliability into its TFP and total cost benchmarking study filed in evidence in the current Hydro One Distribution application (EB-2017-0049), but has omitted it here.

b) With respect to bullet 3, PSE comments on increases in replacement costs and maintenance costs. Productivity trend indexes are the difference between the rate of change of outputs to the rate of change of inputs. “Inputs” and “outputs” are expressed in dimensionless indices, and costs and revenues only enter into the weighting of input and output categories.

i. What evidence is PSE relying on in its statements that: “At several utilities throughout North America, a high proportion of capital infrastructure is now past its useful life and needs replacement”?

ii. It is accurate that TFP may show a decline when a firm shows major capital investment for growth and/or replacement of assets. However, in future years, productivity may recover as demand, including new demand, starts to utilize the capacity of the expanded or replaced system, and the firm typically requires less maintenance for newer assets than it did with original assets reaching or at end-of-life. In part for this, as well as to ensure that the TFP sample period covers at least one economic cycle, and other cyclical or random perturbations (e.g., weather), TFP is calculated on an extended period and not just based on short-term or single-year results. PSE’s sample period from 2004 to 2016 would satisfy this, as it covers an economic downturn in the 2008 financial crisis, as well as the recovery starting in 2009 and continuing to date. However, declines in TFP due to major capital investment should be short term, and not persistent over a longer-term cycle of at least 12 years, in many cases. Please explain why PSE believes that reason 3 is persistent to the whole sample period and for the sample of U.S. transmitters and Hydro One Networks Transmission.

iii. In January 1998, Ontario, Québec and neighbouring U.S. states experienced a major ice storm. In southeastern Ontario, parts of Québec, and parts of several northeastern U.S. states, parts of the distribution and even transmission networks were destroyed, and required refurbishment or replacement. In southeastern Ontario, transmission lines north of Cornwall were toppled. The assets were rebuilt in the winter and spring of 1998. This is before PSE’s sample period, but the replacement or rebuilt assets would show up in the capital stock formation for Hydro One Networks Transmission and for any similarly-affected U.S. utilities. With renewed assets, maintenance costs should be lower for these assets as they are in the earlier stages of their economic lives. It is not clear how material these are for any transmitter. For Ontario Hydro/Hydro One, the assets affected in Eastern Ontario were material, but still only a fraction of Ontario Hydro’s/Hydro One’s transmission network. Please confirm that rebuilding of assets following the 1998 Ice Storm should mitigate, over the sample period from 2004 to 2016, declining productivity due to aging of assets (bullet 3) for those transmitters, including Hydro One Networks Transmission, impacted by the 1998 Ice Storm.

c) Please confirm that the -1.71% average annual TFP growth implies that transmission sector productivity has decreased by nearly 20% over the sample period from 2004 to 2016, as shown by the Industry TFP index declining from 1.000 in 2004 to 0.814 in 2016. Please confirm that, if this trend continued, by 2017, the index would have been 0.800, and 0.789 for 2018. Electricity generation and delivery is critical to our modern society for the health and growth of society. Transmission is one component, along with generation and distribution, but is an integral component of the electricity supply and delivery industry. Does PSE consider that a -1.71% TFP on a long-run base for the electricity transmission sector as being reasonable and sustainable? Please explain your answer.

d) In Table 8, PSE shows a -2.40% average annual TFP for the industry from 2010 to 2016. This is only for about half of the study range. However, while there are factors such as natural and targeted CDM and other technological and socioeconomic factors that may have altered and reduced electricity usage on a per capita basis, this was also a period of economic growth recovering from the 2008-9 financial crisis. In particular, economic growth in Canada, including Ontario, and the U.S. has been positive on a sustained basis for this period. Please provide PSE's basis for considering the -2.40% industry TFP reasonable and realistic for this period.

Response:

a) A clarification in the preamble to the question is necessary. There is a statement in this question's preamble that is not contained in the PSE report, and thus the preamble gives an incorrect characterization/summary of PSE's statements.

The incorrect summary statement contained in this preamble is when bullet point 1 summarizes PSE's statements by saying:

"Increase in the importance of outputs, such as reliability, safety, interconnectivity, power quality, connection of alternative generation sources … which may be difficult to measure <u>and for which growth and importance may differ from that of the main, traditional measures of kW and kWh.</u>" [Underlined emphasis added.]

Nowhere in Section 6.1 or throughout the entire PSE report does PSE make this statement, or anything close to it. In fact, the word "kWh" or any variation of it (e.g. "kilowatt-hour") is not found in PSE's report. PSE does not think "kW and kWh" should be the "main" measures of outputs. Our engineering experts do believe that kW and line length are the main drivers of transmission costs, and therefore, should be the main outputs in any proper transmission TFP study.

No other output measures were investigated by PSE other than peak demand and line length. While the outputs listed (e.g., reliability) may have an impact on productivity levels, the data regarding these other outputs is far less uniform and far more challenging, or impossible, to gather for the entire sample. We began the study by starting with the engineering view that line length and peak demands are, by far, the primary drivers of costs for transmission systems. Thus, the study focused on capturing the productivity using the fundamental outputs of line length and peak demand.

b)

i. This statement is based on PSE's experience in working with several transmission utilities throughout North America.

ii. Bullet three was not characterized by PSE as a "reason" but rather a "possibility." PSE does not make the following claim in the report, or anything like it:

"PSE believes that reason 3 is persistent to the whole sample period and for the sample of U.S. transmitters and Hydro One Networks Transmission."

iii. As the question states, "only a fraction of Ontario Hydro's/Hydro One's transmission network" assets were affected. And even this small fraction did not entirely result in a newly replaced system but, it is PSE's understanding after discussing with Hydro One, that the small fraction of the system that was impacted was essentially repaired to its state just prior to the ice storm. The analogy of getting into a small collision with your car is appropriate here. If you then repair a couple of dents resulting the accident, you shouldn't expect your future maintenance costs to go down or expect you'll need to purchase a new car later than you would have otherwise. Further, it is PSE's understanding that the 1998 ice storm did not significantly impact Hydro One SSM's service territory. Given these understandings of the 1998 Ice Storm, PSE does not believe it will have any sort of meaningful impact on Hydro One Network's or Hydro One SSM's expected TFP levels.

c) The calculations are confirmed. PSE cannot predict the future of the industry TFP growth. We use the past calculations to inform the expectation of TFP on the next upcoming CIR period. Given the -1.71% TFP growth and the acceleration of that decline in an even more recent period subsequent to the economic downturn, it is a reasonable expectation that industry TFP will remain negative for the upcoming CIR period.

d) PSE finds the estimate reasonable and realistic for this period based on what the empirical evidence reveals. We discuss a number of possibilities for why the empirical evidence reveals declining TFP, but that is conjecture. However, it is the empirical evidence that provides the foundation for our finding.

OEB Staff Interrogatory # 61

Reference:
Exhibit D, Tab 1, Schedule 1, Attachment 1

Interrogatory:
Preamble:

To date, electricity transmitters in Ontario have had their revenue requirements set through a cost of service approach that resets or rebases the revenue requirement. There is then, typically, a lag of several years before the next rebasing. The lag depends on each transmitter. Hydro One, as the largest transmitter in Ontario, has often rebased every other year, and more frequently than other, smaller transmitters.

a) For each of the U.S. utilities included in the TFP and total cost benchmarking sets (i.e., 57 in total), please identify the form of rate regulation that each is subject to, particularly with respect to transmission revenue requirements and rates to recover that revenue requirement.

Response:
a) It is PSE’s understanding that most, if not all, of the 57 utilities in the sample are rate regulated by the Federal Energy Regulatory Commission (FERC) using the formula rate form of rate regulation. Formula rates are annual and formulaic rate adjustments made on the basis of the reported rate base and expenses of the utility.

OEB Staff Interrogatory # 62

Reference:

Exhibit A, Tab 2, Schedule 2, page 6
Exhibit A, Tab 3, Schedule 1, page 2
Exhibit D, Tab 1, Schedule 1, page 5
Exhibit D, Tab 1, Schedule 1, Attachment 1, page 6 (section 2.2.3) and page 50 (section 8.1)

Interrogatory:

Preamble:

As noted by Hydro One SSM in first above noted reference and the second above noted reference, the OEB denied the 2017 rate adjustment proposal in its Decision and Order EB-2016-0356, in part, on the absence of empirical evidence, such as benchmarking, to support the then proposed stretch factor of 0%. PSE's evidence in the four above noted reference provides the support in this application for the proposed revenue cap stretch factor of 0%, largely through PSE's total cost benchmarking analysis.

The stretch-factor is more formally termed a "consumer productivity dividend" as it represents the dividend of extra earnings that the firm has an opportunity to achieve, through improved performance possible by the lighter-handed regulatory oversight and the opportunity to achieve earnings in excess or what is approved, relative to the situation under traditional cost of service regulation. Thus, the move to incentive forms of regulation (often termed performance-based regulation or PBR outside of Ontario) from cost of service is <u>one</u> of the situations where a non-zero, positive stretch factor is often considered appropriate.

How long the stretch factor should persist is also a matter of analysis and, largely, informed judgement.

The OEB has a fairly lengthy history of forms of incentive regulation and PBR, going back nearly 20 years. Incentive regulation has long been applied to electricity and natural gas distribution, and more recently to OPG's regulated hydroelectric generation assets in EB-2016-0152. Hydro One SSM's application is the first application for an incentive regulation rate adjustment mechanism for electricity transmission in Ontario.

To date, the OEB has approved or adopted a non-zero stretch-factor in all IR plans it has accepted. This has been both in the context of individual plans in utility-specific rate applications (e.g., OPG[1], plans for Enbridge Gas Distribution Inc.[2], Union Gas Limited[3], “Amalco”[4]), and in OEB Reports for generic electricity distribution plans[5].

The OEB stated the following in its EB-2017-0306/-0307 decision on the merger of Enbridge Gas Distribution and Union Gas (collectively, “Amalco”):[6]

The applicants asserted that a stretch factor would not be appropriate as the applicants' productivity growth is in line with the economy as a whole and an economy-wide inflation is appropriate for setting rates during the deferred rebasing period. Further, the applicants expect to experience increasing cost pressures, depreciation increases, and interest rate increases that would put pressure on Amalco's earnings over the deferred rebasing period. The applicants relied on the expert evidence of NERA, which also concluded that a stretch factor of zero was appropriate. *NERA argued that stretch factors may be warranted in a transition period between cost-of-service and IRM regimes*, but not where IRM is firmly in place as it is with both Enbridge Gas and Union Gas.

PEG argued that a stretch factor of 0.3% was appropriate. PEG noted that it was difficult to assess the appropriate stretch factor, as the stretch factor is ordinarily determined using benchmarking analysis, and the applicants had not conducted a thorough benchmarking analysis for this application. Based on the data that it had available, PEG concluded that Union Gas was perhaps slightly more efficient than average, and Enbridge Gas slightly less. Using the OEB's policies for the electricity sector as a guide, PEG therefore placed Amalco in the “middle” cohort, and recommended a corresponding stretch factor of 0.3%.

Most interveners and OEB staff supported a stretch factor of at least 0.3%, and largely relied on the work of PEG. *OEB staff argued that the OEB's longstanding practice and policy was to apply a stretch factor, both in the electricity and gas sectors. OEB staff further noted that the Rate Handbook is also clear that both gas and electric utilities should have a stretch factor under a price cap plan. They also disagreed with NERA that a stretch factor cannot be employed beyond the initial transition to incentive regulation, and referred to the OEB's RRF which provides for a stretch factor in subsequent IRM plans.*

…

[1] EB-2016-0152
[2] Enbridge IRM
[3] Union Gas PBR
[4] EB-2017-0306/-0307
[5] RP-1999-0034, EB-2006-0089, EB-2008-0673, EB-2010-0373
[6] Decision and Order EB-2017-0306/-0307, August 30, 2018, pp. 26-28

OEB Findings

The OEB finds that a stretch factor of 0.3% is appropriate during the deferred rebasing period.

In the absence of benchmarking evidence, the OEB is setting a stretch factor that is the mid-range of the stretch factors established for electricity distributors (0% to 0.6%). This is also the stretch factor approved in the decision for the hydroelectric generation business of Ontario Power Generation (OPG), where the OEB noted that it expects improved benchmarking going forward.[footnote omitted] The mid-range is the stretch factor for an average performer. Without benchmarking, there is no clear evidence on the performance of either Enbridge Gas or Union Gas. As stated by Dr. Lowry: “There is certainly no evidence that they are a bad performer, but no evidence that they're good”.[footnote omitted]

A key objective of the OEB’s incentive regulation is to drive improvements in cost efficiency. This would have been an expectation regardless of the amalgamation. The amalgamation provides additional opportunities to generate cost savings, and the applicants have proposed a number of initiatives for this purpose. The stretch factor provides incentive to find further efficiency improvements beyond those proposed. [Emphasis added]

OEB staff notes that Hydro One SSM has provided total cost benchmarking evidence in its application.

However, Hydro One SSM is essentially transitioning from traditional cost of service regulation.

a) Beyond the reason of negative sector TFP from PSE’s TFP analysis, what other reasons does Hydro One SSM have for asserting that there should not be an expected positive (non-zero) stretch-factor, notwithstanding that the OEB has found positive (non-zero) stretch-factors appropriate for electricity and natural gas distributors and for OPG’s prescribed hydroelectric assets?

Response:

a) The OEB has found zero stretch factors as also being appropriate for electricity distributors. The -1.71% industry TFP, combined with the 0.0% productivity factor recommendation, already serves as an extraordinarily large stretch factor. This serves as PSE’s primary reason for recommending a 0.0% stretch factor in the case of Hydro One SSM. Secondarily, if Hydro One SSM were to be added to Hydro One Networks (which it was not) the benchmarking result for the aggregated company would very likely continue to be better than the -25% stretch factor threshold set for a 0.0% stretch factor in 4GIR.

OEB Staff Interrogatory # 63

Reference:

Exhibit D, Tab 1, Schedule 1, Attachment 1

Interrogatory:

Preamble:

In most econometric studies of TFP and cost benchmarking that have been filed by external experts for applicants in proceeding before the OEB, the evidence often contain a bibliography of research papers that the expert is aware of, read, and may be relying on to inform him or her on the soundness and appropriateness of the methodology and the results. PSE notes various reference papers in footnotes, but these are related generally to technical, methodological aspects.

This is the first study of electricity transmission TFP and total cost benchmarking study that has been filed before the OEB for consideration in a rate application.

a) Please provide a list of other electricity transmission TFP and/or total cost benchmarking studies of electricity transmission that PSE is aware of and has relied on for the methodology used in its evidence, and for assessing the reasonableness of its outcomes, as used in the analyses documented in its evidence. Where practicable, please provide links to each study or a copy of the study.

Response:

There have been far more electric distribution productivity/benchmarking studies than transmission studies throughout the industry. PSE relied on the Ontario Energy Board's precedents concerning the construction of our TFP and total cost benchmarking methodologies. We combined these precedents with PSE's experience in providing engineering work within the transmission industry. We have attempted to be consistent with PSE's research for Hydro One Distribution in EB-2017-0049, but have made the studies specific to the transmission industry, with very minor adjustments based on methodology improvements or data availability concerns. However, the basic methodology is consistent with both: (i) PSE's Hydro One Distribution research, and (ii) what the Board has approved in the 4th Generation IR TFP and benchmarking studies.

As we stated on p. 5 of the PSE report: “PSE has modified the variables and sample to accommodate a transmission total cost econometric study. We have retained the basic benchmarking methodology of the 4GIR proceeding.”

In summary, it is accurate to say that we have examined and relied on prior methodologies put forth in Ontario by both PSE and PEG, but we adjusted those methodologies to accommodate a transmission study rather than a distribution study. However, PSE is aware of other transmission studies. One of the primary ones we reviewed while conducting our research was a recent transmission productivity study for the Australian Energy Regulator (AER).

The report we reviewed was dated November 2016 (link is provided below). It estimated multilateral total factor productivity (MTFP) for five transmission network service providers (TNSPs). The study time period was from 2006-2016. This is two years shorter than PSE’s time period of 2004-2016.

Beyond being close on the time period, the study has some similarities in methodology to PSE’s approach, and some significant differences.

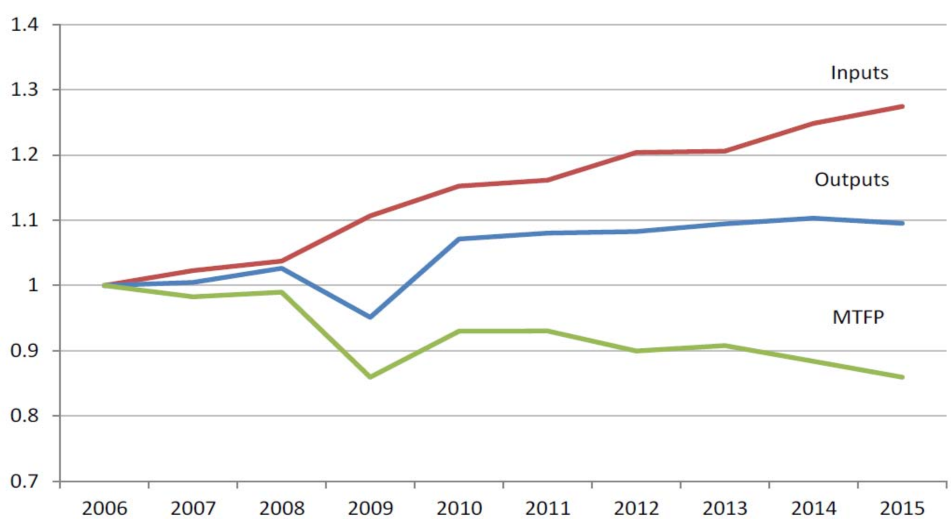
On the input side, the AER methodology uses a physical, rather than monetary, approach to capital. This differs from PSE’s approach as we follow the monetary approach which is also the same approach used in the 4GIR research and PSE’s Hydro One Distribution research.

On the output side, the study uses line length and maximum peak demand as outputs (like PSE), but also adds other outputs such as megawatt hours, reliability, and voltage levels. PSE does use average voltage levels in the total cost benchmarking, but does not use megawatt hours, due to our engineering stance that energy transmitted is not an important cost driver of transmission expenses. The AER report seems to agree with PSE on this point, at least partially. Page 27 of the AER report states: “However, if there is sufficient capacity to meet current energy throughput levels, changes in throughput are unlikely to have a significant impact on a TNSP's costs.” This aligns with PSE’s belief that it is capacity concerns, driven by peak demands, that drive costs, rather than energy transmitted through lines designed to meet those peak demands.

Another output used by AER is reliability. PSE agrees that reliability can be an output in a TFP study. PSE included reliability in our TFP research for Hydro One Distribution. However, that research only calculated Hydro One’s own Distribution TFP, rather than the reliability-adjusted TFP for the entire U.S. industry. We did not include reliability as an output in this study, due to the challenges and general unavailability of uniform reliability data for transmission providers in the U.S.

The AER results showed that the industry MTFP declined during this period. On page 6 under the "Key Messages" heading the report states about the Australian transmission industry: "Overall, productivity across the industry has continued to decline. This can be seen in figure 1, which shows the combined industry inputs have increased at a greater rate than outputs since 2006."

Figure 1 Industry input, output and productivity indices, 2006 to 2015



Click on the AER 2016 transmission network service providers benchmarking report link:

https://www.aer.gov.au/networks-pipelines/network-performance/annual-benchmarking-report-distribution-and-transmission-2016

For an overview of transmission productivity studies around the world which encompass the ones we are aware of, please see the Concentric Energy Advisors report on performance-based regulation parameters applicable to transmission providers. This is research conducted for Hydro Quebec Transenergie. Concentric is recommending a -0.6% X Factor in this ongoing application based on their review of transmission TFP studies. We should also note that Concentric has added the PSE study result to their list of transmission productivity precedents, but had already determined that a -0.6% X Factor was appropriate prior to becoming aware of the PSE study result.

The Concentric study can be found here:

http://publicsde.regie-energie.qc.ca/projets/471/DocPrj/R-4058-2018-B-0013-Demande-Piece-2018_07_27.pdf

OEB Staff Interrogatory # 64

Reference:

Exhibit D, Tab 1, Schedule 1, Attachment 1, page 6 (footnote 3) and page 20 (section 3.1.2)

Interrogatory:

Preamble:

PSE notes that it has included more U.S. utilities in the total cost benchmarking sample, as it requires complete data for all years for each firm used in the TFP analysis, but can include utilities with missing years in the total cost benchmarking.

While PSE notes that it was unable to include suitable data from other Canadian utilities, Canadian utilities would also have data filed, generally on the public record, in rate applications in their respective provincial jurisdictions. In some provinces, the regulated utilities are integrated, with generation, transmission, and distribution operations together, while in others, there may be some separation (e.g., Alberta and Québec), similar to the situation in Ontario.

a) Did PSE attempt to seek out publicly available data for Canadian utilities from which transmission-related data was available or could be proxied, in order to augment its sample for the total cost benchmarking analysis? Please explain your response.

Response:

a) PSE is not aware of all the necessary data being available for other Canadian utilities. We are not aware of any Canadian transmission utilities that publicly file the necessary output and input data and file transmission lines by voltages, number of substations by capacity, and the characteristic of transmission lines (overhead or underground).

OEB Staff Interrogatory # 65

Reference:

Exhibit D, Tab 1, Schedule 1, Attachment 1, Section 3.2 (Variables in the Benchmarking Model)

Interrogatory:

With respect to the variables that PSE has used in its total cost benchmarking analysis comparing Hydro One Networks Transmission to a sample of U.S. electricity transmitters:

a) Please discuss the relative merits of the monthly peak demand variable on p. 401b of the FERC Form 1 vs. the monthly transmission system peak load on p. 400 that PSE used in its research. What criteria did you use for choosing one variable over the other?

b) Please note any known issues with the quality of reporting of the transmission peak load data. For example, why are the transmission peak demand values for Alabama Power and Gulf Power identical on table 6?

c) Is the limitation on the availability of earlier data for the transmission system peak on p. 400 of the Form 1 the sole reason for limiting the study to a 2004 start date? If not, please present other reasons.

d) Please discuss limitations of the available transmission substation data.
   Were these data obtained directly from the FERC or SNL? How were combined T&D stations and unknown/missing data handled? What percentage of substation MVa were either combined T&D or unknown?

e) Please provide any additional information and source data required to calculate the construction standards (loading) variable.

f) Please describe how the km of line variable for Hydro One Networks was calculated. Is it route-km, circuit-km, or another other measure of length?

g) Is the percentage of underground lines variable calculated using plant values or distance?

h) What other business condition variables were considered by PSE in the econometric research, and why were they rejected?

Response:

a) The p. 400 variable that PSE used in its research is the reported transmission system peak, rather than the p. 401b variable, which is the system's own peak (not the transmission system peak). It is PSE's understanding that the differences are that the p. 400 variable includes the impacts of all sales for resale activities and wheeling. PSE believes that in a transmission TFP and benchmarking study, it is the transmission peak that is most relevant to measure and use.

b) PSE used the peak load data as reported by the transmission utilities. This value is found on the FERC Form 1, and we are assuming that the utilities are reporting their transmission peak demands accurately.

Regarding the reference to Alabama Power and Gulf Power, in reading a footnote on the FERC Form 1, it appears the utilities reported the transmission peak demand for the entire Southern Company, rather than the reporting operating company, which PSE had assumed. This reporting of the incorrect data impacts Alabama Power, Gulf Power, and Mississippi Power in both the TFP and benchmarking samples. The incorrectly reported peak data can be adjusted by taking each system's proportion (based on p. 401b mentioned in part a of this interrogatory) of the Southern Company's transmission peak. If this adjustment is undertaken, rather than a 1.71% decline in TFP for the 2004-2016 period, the decline would be 1.29%. For the more recent 2010-2016 time period, the decline in TFP with the exclusion would be -2.50% rather than -2.40%. If these three utilities are excluded due to the incorrect reporting of peak demand data, the TFP decline lessens during the full 2004-2016 period, but the decline does become more pronounced for the more recent time period.

For the total cost benchmarking study, Hydro One Networks total cost score for the 2014-2016 period moves to -22.5%. For the 2019-2022 CIR period the total cost score moves to -25.3%. Making these adjustments would not modify PSE's recommended productivity factor of 0.0% or stretch factor of 0.0%.

c) Yes.

d) The largest hurdle with the transmission substation data is that each utility reports the data in a slightly different manner, which requires a large manual effort to go through and make the data consistent and uniform with the sample. As mentioned in the question, there are also some substations listed as serving both the transmission and distribution operations of the utility. For some substations, the asset's classification was unknown.

The substation data were obtained directly from the FERC Form 1, on pages 426 and 427. The substation classifications that were listed as either (i) "both T&D," or (ii) "unknown" were inserted into the substation MVa variable by adding half of the value in question. For example, if a substation was listed at 100 MVa and the classification was T&D, we'd assume half of the substation capacity was for distribution, and the other half for transmission. In this example, we'd add 50 MVa to the utility's transmission substation MVa total. The same procedure would be used if the asset was classified as unknown.

While this is a data limitation, it is not a significant one. For the entire sample for the years 2013-2016 (which is the time period we gathered and calculated the substation variables), only 3.7% of the substation MVa transmission variable is comprised of substations classified as being either "both T&D" or "unknown." Over 96% of the total MVa value used in the substation variable is classified unambiguously as "transmission".

e) The source data for the construction standards (loading) variable are:
- 2017 National Electrical Safety Code (NESC)
    - Rules 250B / 250C / 250D
- 2011 Canadian Standards Association (CSA) Overhead Systems Standard C22.3 No. 1-10
    - CSA 7.2
- S&P Global Platts Data Set (retrieved 2013)
- Power Line Systems CADD (PLS-CADD) Software

f) The measure of length used for Hydro One Networks is route-km. This measures the length of the lines, assuming there is only one circuit from pole to pole.

g) Distance.

h) Other variables considered were:
- The percentage of service territory forested (found to be statistically insignificant),
- Statistical deviation of the elevation within the service territory (found to be incorrectly signed and statistically insignificant),
- Average circuits (data not available for entire sample and borderline statistical significance),

- Hourly wind readings above 10 knots, where in each hour the wind reading minus 10 is added to the variable (incorrectly signed), and
- Extreme weather temperatures measured by the sum of cooling degree hours above 30 degrees Celsius plus heating degree hours below minus 15 degrees Celsius (incorrectly signed).

OEB Staff Interrogatory # 66

Reference:

Exhibit D. Tab 1, Schedule 1, Attachment 1, Section 3.3 (Perpetual Inventory Capital Cost Model)

Interrogatory:

With respect to Section 3.3 of PSE's evidence on its Perpetual inventory Capital Cost Model:

a) Which cities in the RSMeans *Heavy Construction Cost Data* were assigned to Hydro One? If multiple cities were used, how were the index values averaged?

b) What RSMeans cities were used for each sampled U.S. utility? If multiple cities were used, how were the index values averaged?

c) Which version of the city cost index (e.g. materials, installation, total) was used?

d) When calculating the depreciation rate, does the 1.65 declining balance parameter used refer to just equipment, just structures or both? What would be the appropriate declining balance parameter for each type of plant?

e) Why is a 1989 benchmark year adjustment used for the U.S. utilities?

Response:

a) The city assigned to each utility in the sample for the RSMeans mapping, including Hydro One Networks, was based only on the headquarter city for each utility. In Hydro One Networks' case, this was Toronto.

b) The cities used for the RSMeans mapping was the headquarter city for each utility.

c) Total city cost index was used for the RSMeans variable.

d) The 1.65 declining balance parameter refers to just equipment for electrical transmission, distribution, and industrial apparatus. According to the BEA, the appropriate declining balance parameter for just structures would be 0.91.

e) 1989 is the earliest data available from the data supplied by SNL Energy to begin the capital stock series for the U.S. utilities. In Hydro One's case, the earliest year is 2002.

OEB Staff Interrogatory # 67

Reference:

Exhibit D. Tab 1, Schedule 1, Attachment 1, Section 4.3 (Input Quantity Index)

Interrogatory:

a) Hydro One Networks does not Y-factor expenses for pensions and other benefits in its current rate-setting plans for distribution and transmission, and Hydro One SSM is not proposing any different treatment. Why then were these expenses excluded from the productivity study?

b) Please present productivity results that include pension and other benefit expenses.

c) Please provide evidence supporting the reasonableness of the assumed breakdown of OM&A expenses between labor and other OM&A expenses for the sampled U.S. utilities.

d) Why does PSE not use chain-weighting for the construction of the U.S. OM&A quantity indexing? Would this not produce more accurate results?

Response:

a) The inclusion of pensions and benefits may create a mismatch between Hydro One and the U.S. sample, given the differences between the benefits structures of Canada and the U.S.

b) If the pension and benefit expenses are included, the 2004-2016 industry TFP trend becomes -1.72% rather than -1.71%. For the 2010-2016 period, the industry TFP trend becomes -2.28%, rather than -2.40%.

c) Please see the table of numbers included in the electronic form of the Excel spreadsheet, I-01-67-01 provided as Attachment 1 to this Exhibit.

d) PSE did not use a chain-weighting for the construction of the U.S. OM&A quantity index to provide consistency between the calculations for Hydro One and the rest of the sample. Given that Hydro One does not have the data available to conduct a tornqvist index, the only way to be consistent in the calculations was to fix the weighting rather than use chain-weighting for only the U.S. sample.

If chain-weighting is inserted into the calculations, there is essentially no change in the results. The 2004-2016 TFP trend remains at -1.71%. The TFP trend did get slightly less negative if one goes to the thousandths digit, but with rounding it stays at -1.71%. The 2010-2016 TFP trend goes to -2.39%, rather than -2.40%.

labour	non-labour
38%	62%

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
1	2004	1		623	2518	0.11007	944	#DIV/0!
1	2005	1		626	1833	0.10973	1236	#DIV/0!
1	2006	1		653	1916	0.1125	1368	#DIV/0!
1	2007	1		765	2016	0.11811	1281	#DIV/0!
1	2008	1		985	2146	0.14869	1834	#DIV/0!
1	2009	1		1232	2445	0.16004	1867	#DIV/0!
1	2010	1		1257	3075	0.15264	2201	#DIV/0!
1	2011	1		1256	3071	0.14873	2296	#DIV/0!
1	2012	1		1422	3478	0.15736	2852	#DIV/0!
1	2013	1		1808	3857	0.17111	3302	#DIV/0!
1	2014	1		1828	4205	0.20258	2897	#DIV/0!
1	2015	1		2345	4651	0.19831	3200	#DIV/0!
1	2016	1		2247	4756	0.14358	3255	#DIV/0!
2	2004	1	13687.75098	3121	24436	0.09553	8693	0.459229086
2	2005	1	14001.02539	3192	23644	0.09462	9226	0.450121275
2	2006	1	13091.84863	3357	28325	0.07882	13390	0.507565928
2	2007	1	16803.7832	4442	24572	0.09355	13269	0.4750136
2	2008	1	15962.29004	3676	28095	0.08453	11701	0.44103671
2	2009	1	17735.24023	5291	29392	0.09363	9660	0.504500567
2	2010	1	16652.2793	5008	29194	0.08396	14071	0.518879683
2	2011	1	23383.28906	5148	23702	0.11154	15875	0.40894241
2	2012	1	36599.80859	5191	6320	0.1963	4844	0.201708519
2	2013	1	36446.14844	5822	5909	0.18752	6659	0.224406466
2	2014	1	46880.89844	5714	2280	0.2144	5499	0.157458962
2	2015	1	54892.39453	10600	5318	0.19306	4802	0.228697751
2	2016	1	46956.85547	9533	3811	0.19814	5265	0.241313404
3	2004	0	2922.34424	1130	6226	0.04877	1161	0.509954977
3	2005	0	3757.24121	1286	5851	0.06301	1797	0.470531537
3	2006	0	3321.35059	1348	6461	0.05342	2470	0.549503574
3	2007	0	4338.33154	1487	7012	0.05776	2308	0.466843804
3	2008	0	5367.68652	1738	6914	0.07253	2083	0.445359915
3	2009	0	5374.6582	1736	7675	0.06598	3558	0.460895046
3	2010	0	6358.62256	1878	8921	0.07026	3046	0.427577104
3	2011	0	6257.34521	2079	7335	0.065	1812	0.427266662
3	2012	0	6372.27295	2158	7775	0.06596	3872	0.45921387
3	2013	0	7826.04395	2349	9748	0.07675	3410	0.429192134
3	2014	0	8017.97852	2771	12010	0.07222	3110	0.48178807
3	2015	0	7556.3418	2628	11694	0.06685	3150	0.479110328
3	2016	0	7149.41797	2655	13734	0.06407	2395	0.515900042
4	2004	0	7989.83008	2523	12137	0.03336	2217	0.375708796
4	2005	0	8515.23926	2826	16875	0.03374	1443	0.40445714
4	2006	0	13789.16797	3204	15500	0.04789	2377	0.294443402
4	2007	0	14643.37695	3609	16870	0.05	2055	0.311079201
4	2008	0	15379.81055	3902	14020	0.05071	2433	0.307957736
4	2009	0	17464.04688	3731	15238	0.05191	2503	0.266372127

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
4	2010	0	16618.23047	4146	30712	0.04827	3122	0.347760683
4	2011	0	16163.85742	4452	17329	0.05107	3457	0.341103047
4	2012	0	18165.79492	6116	21053	0.0542	918	0.402230028
4	2013	0	16850.45898	6478	35955	0.04844	1047	0.490810184
4	2014	0	18040.4375	6324	35521	0.0494	1099	0.450822105
4	2015	0	18489.99023	5771	19878	0.04896	5686	0.379806228
4	2016	0	20924.31641	5807	22441	0.05464	7234	0.3550148
5	2004	0	296851.9063	23923	27155	0.32393	122687	0.244099221
5	2005	0	475992.1875	25585	25224	0.4503	139256	0.209352898
5	2006	0	442142.25	26785	23706	0.44447	173990	0.259316863
5	2007	0	320655.25	26901	40523	0.28224	180502	0.278439527
5	2008	0	476982.3438	30390	39047	0.36973	139332	0.201982461
5	2009	0	477652.8438	28463	56042	0.37638	138613	0.212973188
5	2010	0	469749.75	27293	46026	0.37427	117257	0.188195797
5	2011	0	410416.1563	28762	40048	0.30369	131874	0.197294846
5	2012	0	393597.7813	32094	51499	0.27543	169445	0.236151245
5	2013	0	278725.2188	35527	46966	0.2021	153771	0.273014218
5	2014	0	291477.8438	38529	44199	0.19336	160166	0.267756257
5	2015	0	352457.875	40663	43933	0.22382	174961	0.25437325
5	2016	0	456923.6875	42038	50472	0.27133	216359	0.250451571
6	2004	1		2455	16965	0.05803	9958	#DIV/0!
6	2005	1		2566	19549	0.0629	12874	#DIV/0!
6	2006	1		2631	20863	0.08577	11540	#DIV/0!
6	2007	1		2169	20345	0.08521	15671	#DIV/0!
6	2008	1		2005	20440	0.1016	11705	#DIV/0!
6	2009	1		2110	16032	0.06294	2675	#DIV/0!
6	2010	1		2729	15608	0.07855	7182	#DIV/0!
6	2011	1		2542	19888	0.07002	7605	#DIV/0!
6	2012	1		2143	14759	0.08256	8115	#DIV/0!
6	2013	1		2189	15861	0.0487	7337	#DIV/0!
6	2014	1		2031	15379	0.08378	7173	#DIV/0!
6	2015	1		2313	15574	0.06255	6966	#DIV/0!
6	2016	1		2647	16458	0.06362	5944	#DIV/0!
7	2004	0	38214.91406	13174	110960	0.04017	36654	0.499900493
7	2005	0	42354.23828	14415	137355	0.04407	27876	0.512268218
7	2006	0	55553.90234	16406	142944	0.05336	18460	0.450346715
7	2007	0	57970.51563	18602	83302	0.05748	9800	0.413201482
7	2008	0	63657.24609	20977	67201	0.06359	11891	0.408538884
7	2009	0	66300.89063	21702	72875	0.06509	11039	0.409707351
7	2010	0	67812.75	21424	66459	0.06188	9404	0.385154745
7	2011	0	77073.29688	22708	68149	0.06939	10190	0.365158159
7	2012	0	77242.46094	23500	74368	0.06844	13278	0.381894775
7	2013	0	72907.1875	22899	76755	0.06494	16481	0.39713157
7	2014	0	66220.875	24935	75688	0.06258	14157	0.461448148

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
7	2015	0	77099.10938	25137	78097	0.07346	16829	0.416480349
7	2016	0	82563.88281	27292	72807	0.07784	14997	0.413336464
8	2004	1	102031.1953	29863	43539	0.07799	112051	0.411613958
8	2005	1	114663.3984	33103	39842	0.08282	127405	0.409497688
8	2006	1	127025.9922	37657	54184	0.0876	123136	0.418735025
8	2007	1	120911.8828	34517	48466	0.0809	120148	0.398288998
8	2008	1	110043.5078	34730	49093	0.07223	118411	0.425548175
8	2009	1	112914.6094	30225	36918	0.08151	130636	0.388632851
8	2010	1	139751.125	33982	41377	0.08486	144765	0.356190407
8	2011	1	129577.9766	34929	42323	0.07639	149244	0.382494035
8	2012	1	111697.3828	33021	38791	0.07207	147931	0.416106925
8	2013	1	127158.8984	30397	32986	0.0843	136347	0.351306691
8	2014	1	155801.6094	36129	33528	0.08674	144347	0.330920057
8	2015	1	126917.7031	38982	36393	0.06716	148794	0.405137799
8	2016	1	167382.0938	42251	41689	0.09262	140744	0.353370801
9	2004	0	31100.77539	10047	92657	0.04203	40403	0.502865655
9	2005	0	31686.17578	11185	61296	0.05009	31303	0.499374996
9	2006	0	33523.97266	13427	60564	0.04155	41486	0.52700131
9	2007	0	39286.91406	15364	62572	0.0425	38444	0.500349301
9	2008	0	44236.91406	16056	77348	0.05253	40798	0.503249602
9	2009	0	42120.03125	16719	60282	0.03783	34733	0.48227451
9	2010	0	40078.07422	14928	64552	0.03662	45957	0.47344689
9	2011	0	43448.23828	15635	69968	0.04227	36837	0.463762126
9	2012	0	56019.5	16270	82246	0.04462	44051	0.391031197
9	2013	0	72421.80469	16801	114153	0.06022	67850	0.383326828
9	2014	0	65583.5625	14201	74012	0.0526	66250	0.32902728
9	2015	0	46464.05859	13159	100817	0.03098	61478	0.39141865
9	2016	0	56396.23828	16126	116701	0.03914	46129	0.398947995
10	2004	1	136621	53091	157085	0.061	99748	0.503274116
10	2005	1	155626.625	57729	137706	0.07435	128887	0.498309268
10	2006	1	206580.2969	65287	183908	0.08744	156585	0.460158637
10	2007	1	222036.5156	67891	191389	0.09402	174315	0.460620136
10	2008	1	233005.2188	69518	195389	0.08799	159312	0.432299935
10	2009	1	230931.875	70377	324002	0.08419	135568	0.472295989
10	2010	1	233091.5	71743	204021	0.08977	135129	0.438405071
10	2011	1	230844.9219	72311	231108	0.0777	179639	0.451498093
10	2012	1	239729.1094	75036	284242	0.07429	142745	0.445322908
10	2013	1	259360.8438	80098	290818	0.0771	143916	0.438061466
10	2014	1	285856.7813	84282	318572	0.08731	150028	0.437965702
10	2015	1	334922.875	88247	313970	0.09093	200125	0.403058938
10	2016	1	367945.0625	95297	358307	0.09025	205064	0.397182209
11	2004	0	7188.61377	1807	19143	0.06347	7859	0.489776896
11	2005	0	13914.91211	1812	22675	0.09831	11348	0.370595307
11	2006	0	14932.99414	2043	25810	0.10482	12121	0.403062331

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
11	2007	0	15593.40918	2515	31804	0.10358	11478	0.448788939
11	2008	0	21450.76367	3170	19346	0.16701	11265	0.386109476
11	2009	0	12804.70996	3615	18695	0.10456	11768	0.53107109
11	2010	0	10353.93945	3710	14514	0.06798	10598	0.523193494
11	2011	0	14895.01563	4248	14815	0.10214	11548	0.4659758
11	2012	0	14847.66406	4803	15535	0.10038	12937	0.515974724
11	2013	0	15687.68164	5022	17058	0.09658	13035	0.505389013
11	2014	0	15324.32129	4769	20031	0.0885	15848	0.518410659
11	2015	0	17016.46875	5927	25527	0.08043	20624	0.566446839
11	2016	0	18713.87891	6586	27876	0.08746	23013	0.589762924
12	2004	0	56033.23438	15544	112652	0.04744	15049	0.385523621
12	2005	0	54953.76172	17900	133947	0.04099	13783	0.435920162
12	2006	0	50384.82422	15632	168481	0.03687	15192	0.444658166
12	2007	0	51808.95313	16518	176707	0.03709	66175	0.492704288
12	2008	0	66829.54688	16877	151623	0.0449	89569	0.414584897
12	2009	0	59035.56641	19572	136815	0.0411	85535	0.486326917
12	2010	0	69615.47656	19418	246637	0.04166	94312	0.482966389
12	2011	0	68944.10938	19565	141342	0.04028	110633	0.430994805
12	2012	0	77002.54688	20991	182007	0.04295	109495	0.435193539
12	2013	0	69586.85938	19261	124966	0.04158	132551	0.430664024
12	2014	0	65524.51563	20078	118336	0.03717	123464	0.44358521
12	2015	0	69154.72656	22492	205558	0.03658	97907	0.485762165
12	2016	0	64820.94922	22229	178166	0.03442	68015	0.473651657
13	2004	0	31292.16016	14110	17290	0.11842	36823	0.655693354
13	2005	0	29353.43359	13571	13511	0.10095	38976	0.642840048
13	2006	0	30040.16797	11953	12426	0.0914	29195	0.524536328
13	2007	0	31179.625	11927	9967	0.10827	35625	0.540841843
13	2008	0	37024.42578	12636	8196	0.12696	35082	0.489692264
13	2009	0	45307.51172	14872	6981	0.12811	36268	0.450535212
13	2010	0	40940.58203	11477	7223	0.09338	28446	0.361689319
13	2011	0	46116.78516	11250	7939	0.11144	38523	0.356220088
13	2012	0	41051.47656	9500	8364	0.09826	45675	0.360763446
13	2013	0	46900.47656	9839	9410	0.1041	46640	0.334192873
13	2014	0	46080.81641	10784	8379	0.09814	52735	0.364180352
13	2015	0	49713.19922	8519	6052	0.09978	71632	0.327283494
13	2016	0	46520.10938	11650	3983	0.09346	46402	0.35165399
14	2004	0	27914.82617	7110	27040	0.10991	7613	0.391143802
14	2005	0	30658.25391	8079	45280	0.12303	14073	0.501698487
14	2006	1	3087.57495	8572	57567	-0.14975	8163	-0.411671788
14	2007	1	-28369.13086	9099	49829	-0.41905	7797	0.530477136
14	2008	0	33797.88672	10396	42972	0.08672	6761	0.435200162
14	2009	0	38584.53125	12661	59654	0.09201	13870	0.503464539
14	2010	0	40488.72656	14031	52926	0.08844	13936	0.492588357
14	2011	0	47816.13672	15014	60918	0.09766	13943	0.466891029

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
14	2012	0	46898.32031	15426	36704	0.07073	66069	0.483922114
14	2013	0	44200.73047	15894	28294	0.07801	70738	0.534368687
14	2014	0	47890.61719	16311	30619	0.07703	88930	0.532878066
14	2015	0	56298.34766	19788	34369	0.0965	94159	0.571792128
14	2016	0	57429.19922	23062	32834	0.08667	102968	0.606520025
15	2004	1		5262	23647	0.11763	4761	#DIV/0!
15	2005	1		4763	24005	0.07198	6663	#DIV/0!
15	2006	1		5094	28385	0.07362	5864	#DIV/0!
15	2007	1		9720	40736	0.07842	9562	#DIV/0!
15	2008	1		9779	43225	0.07605	9411	#DIV/0!
15	2009	1		10250	41274	0.07798	6999	#DIV/0!
15	2010	1		10483	42870	0.08545	7150	#DIV/0!
15	2011	1		9972	44626	0.08924	7586	#DIV/0!
15	2012	1		10458	43931	0.08175	7944	#DIV/0!
15	2013	1		11533	51006	0.09668	5829	#DIV/0!
15	2014	1		14477	46616	0.08718	15685	#DIV/0!
15	2015	1		13086	71135	0.08805	25105	#DIV/0!
15	2016	1		12747	70075	0.07283	34447	#DIV/0!
16	2004	1	13150.58594	2481	13179	0.04826	5319	0.256544727
16	2005	1	-7912.30029	2469	11660	-0.48023	4806	0.687343374
16	2006	1	14866.33398	2865	16310	0.03828	6345	0.251052708
16	2007	1	22560.93359	3291	15941	0.14384	7210	0.293473664
16	2008	1	33493.24219	2990	13752	0.30462	10113	0.306323175
16	2009	1	22245.63867	2857	13415	0.08159	9605	0.212859782
16	2010	1	34274.66016	2932	14704	0.302	6004	0.268006042
16	2011	1	28138.96289	3311	15278	0.13497	11862	0.247844451
16	2012	1	32091.67188	3316	15788	0.18871	18444	0.30462485
16	2013	1	25453.67773	3137	18528	0.12042	13721	0.275811796
16	2014	1	29687.01172	3253	20997	0.10798	13650	0.23559741
16	2015	1	25802.29297	2583	18895	0.07628	13807	0.196785168
16	2016	1	51880.23438	2136	20115	0.50656	13876	0.373060785
17	2004	1	14.3737	0	31652	0.00007	6379	0.185211184
17	2005	1	-162.09525	0	30521	-0.00091	5136	0.200177797
17	2006	1	3029.26294	0	40667	0.017	5052	0.256571653
17	2007	1	3328.02344	0	31958	0.01802	5351	0.202014256
17	2008	1	3228.82666	0	27097	0.01772	4879	0.175486262
17	2009	1	3015.86279	0	24307	0.0175	5683	0.174021511
17	2010	1	2841.27612	0	29069	0.01614	2944	0.181851322
17	2011	1	3006.83594	0	31287	0.01542	4894	0.185547543
17	2012	1	3526.51807	517	29817	0.01856	3391	0.321376626
17	2013	1	3314.38135	0	36757	0.01665	3653	0.203002138
17	2014	1	3288.19751	0	37945	0.01415	5633	0.187527878
17	2015	1	3274.20483	449	37958	0.01732	5643	0.367774584
17	2016	1	3641.24927	435	36421	0.02181	7251	0.381046783

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
18	2004	1	-7.32843	0	6435	-0.00012	5799	0.200326673
18	2005	1	489.0809	0	6547	0.00843	3445	0.172226231
18	2006	1	359.19876	441	8537	0.00575	3619	1.422323952
18	2007	1	5.80035	510	8693	0.00009	3733	88.11853423
18	2008	1	-701.50702	535	9148	-0.00944	4945	-0.572997944
18	2009	1	-250.0069	536	9702	-0.00349	4156	-1.950488487
18	2010	1	60.77229	547	10930	0.00079	3973	9.194541953
18	2011	1	35.00419	554	11371	0.00045	4677	16.03298348
18	2012	1	4.28662	574	11725	0.00005	4447	134.0936682
18	2013	1	-15.74246	595	12167	-0.00019	4133	-37.5991427
18	2014	1	-31.73348	615	14501	-0.00038	2960	-19.17107169
18	2015	1	16.52116	622	13941	0.0002	3395	37.85855231
18	2016	1	25.68845	647	14870	0.0003	3724	25.40356464
19	2004	0	302143.9063	37623	287912	0.14032	49896	0.281403056
19	2005	0	436708.8125	39773	320001	0.19593	50022	0.257085736
19	2006	0	404570.5	45614	317541	0.17344	53424	0.271779998
19	2007	0	378825.375	52440	331704	0.14921	59810	0.292635634
19	2008	0	384640.4063	65015	379155	0.14324	49216	0.328553267
19	2009	0	321901.0625	62033	434164	0.11749	74949	0.378528376
19	2010	0	331954.0938	70313	518112	0.11048	59637	0.404100181
19	2011	0	320354.25	68830	524914	0.1047	72174	0.409999598
19	2012	0	324846.1563	68083	536918	0.10144	67511	0.398330949
19	2013	0	407868.0313	73141	521548	0.12978	69572	0.367414316
19	2014	0	318363.375	73600	497777	0.11231	65612	0.429930794
19	2015	0	424638.4375	78732	388181	0.15804	97403	0.366131941
19	2016	0	314459.375	79289	370949	0.12509	60668	0.423838439
20	2004	1	8976.22656	2224	8579	0.167	863	0.423431157
20	2005	1	7983.68115	2445	5478	0.15371	620	0.423654642
20	2006	1	8505.54199	2859	5202	0.1526	626	0.44069535
20	2007	1	8387.53223	2673	5671	0.15355	590	0.433307015
20	2008	1	8506.2373	2965	5031	0.15419	423	0.447430765
20	2009	1	8064.93896	2878	4994	0.15024	397	0.45728106
20	2010	1	11262.97949	3335	4977	0.19274	611	0.391728594
20	2011	1	9484.9668	3230	4734	0.15714	330	0.424435535
20	2012	1	8502.52148	3192	4790	0.13398	532	0.459280411
20	2013	1	11204.72266	3459	5194	0.1621	422	0.389956426
20	2014	1	11109.44727	3489	5408	0.15923	428	0.39770352
20	2015	1	10946.56348	3769	5594	0.14759	611	0.427969559
20	2016	1	11319.63184	3875	6917	0.137	659	0.434016942
21	2004	1	19599.82617	6082	9134	0.09413	19294	0.446837006
21	2005	1	22130.5625	5432	8600	0.09508	23342	0.382685499
21	2006	1	22507.43555	7564	8581	0.0938	21772	0.462563199
21	2007	1	20197.20898	9162	10413	0.07494	46312	0.664100248
21	2008	1	22924.19336	9078	12339	0.07647	50901	0.606955393

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
21	2009	1	24419.32813	10998	17013	0.08011	51422	0.674888669
21	2010	1	25306.27539	12140	19089	0.07625	53960	0.699825872
21	2011	1	29715.74609	11634	23969	0.08175	71551	0.654291497
21	2012	1	32211.38086	11537	24073	0.0788	68113	0.583683664
21	2013	1	44002.83984	11796	23948	0.10731	76216	0.512344179
21	2014	1	49880.07813	10918	73579	0.11161	48161	0.491286348
21	2015	1	57411.01953	10500	66147	0.12466	51112	0.437503238
21	2016	1	69014.11719	10259	72837	0.13535	46703	0.383091751
22	2004	1	5952.01172	273	2944	0.01403	56149	0.18516005
22	2005	1	3735.4646	291	1550	0.0086	50511	0.197759765
22	2006	1	8016.41943	331	-920	0.02129	44347	0.156623645
22	2007	1	10559.90918	516	1389	0.02849	44289	0.172100554
22	2008	1	9801.46289	616	1853	0.02712	36325	0.168483764
22	2009	1	6560.97021	270	893	0.01858	36223	0.146261185
22	2010	1	2413.41138	278	1189	0.00816	29986	0.220595628
22	2011	1	2177.74243	455	2327	0.00658	38250	0.33153446
22	2012	1	3034.7627	564	1296	0.00903	35241	0.2945631
22	2013	1	3249.22144	310	5986	0.00993	31619	0.210332741
22	2014	1	2035.34595	363	2796	0.00633	35908	0.298718908
22	2015	1	3226.78809	408	1124	0.00994	35262	0.238527235
22	2016	1	4794.12354	147	2990	0.0156	36257	0.158371638
23	2004	0	63859.1875	11668	36862	0.07045	107206	0.341651553
23	2005	0	68400.3125	11440	37175	0.06659	113656	0.314089739
23	2006	0	76357.78906	12651	43631	0.0731	114903	0.317450724
23	2007	0	81284.17969	13249	44098	0.07181	122637	0.31029704
23	2008	0	96865.4375	14747	38832	0.08051	120257	0.284469426
23	2009	0	90169.46094	14479	44016	0.07704	123101	0.303358736
23	2010	0	119481.8672	17616	51686	0.08596	150297	0.292751189
23	2011	0	89679.14844	15944	50344	0.07377	144494	0.33806297
23	2012	0	79441.42188	15711	52233	0.06585	140705	0.357697114
23	2013	0	76904.21094	15011	47210	0.06378	135634	0.346831337
23	2014	0	91603.75781	17981	56017	0.06532	148904	0.342414334
23	2015	0	90949.95313	17614	50207	0.0655	161809	0.346355846
23	2016	0	104535.125	18119	58826	0.07272	165052	0.329070331
24	2004	1		1520	11241	0.0227	15250	#DIV/0!
24	2005	1		1319	14782	0.02201	11295	#DIV/0!
24	2006	1		1196	19885	0.05339	12113	#DIV/0!
24	2007	1		1396	18621	0.05792	9989	#DIV/0!
24	2008	1		1897	20879	0.04576	7430	#DIV/0!
24	2009	1		1999	13265	0.05474	10931	#DIV/0!
24	2010	1		1773	28896	0.05017	9956	#DIV/0!
24	2011	1		1822	44905	0.04829	9576	#DIV/0!
24	2012	1		654	22805	0.04359	12643	#DIV/0!
24	2013	1		668	23141	0.04251	12298	#DIV/0!

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
24	2014	1		620	11000	0.05026	13451	#DIV/0!
24	2015	1		2173	5990	0.04442	11598	#DIV/0!
24	2016	1		2203	3346	0.03967	12671	#DIV/0!
25	2004	1	923.39758	327	188	0.00685	15854	0.473130653
25	2005	1	510.80594	11	116	0.00489	15773	0.173641696
25	2006	1	1930.42004	7	-296	0.06589	8376	0.279416494
25	2007	1	674.5296	29	98	0.02148	6803	0.262751227
25	2008	1	386.21341	50	103	0.01198	3465	0.240138321
25	2009	1	245.73717	4	32	0.00868	4277	0.168481309
25	2010	1	188.74379	100	126	0.00519	5560	0.686170072
25	2011	1	317.95999	84	248	0.01031	9236	0.571707277
25	2012	1	240.07143	87	76	0.00543	7039	0.523321122
25	2013	1	550.10162	20	854	0.01393	7752	0.254283163
25	2014	1	322.58829	21	472	0.00843	9522	0.32626547
25	2015	1	369.72531	37	56	0.00984	9353	0.350488745
25	2016	1	345.85065	-1	329	0.00834	9588	0.236251631
26	2004	0	7517.18799	2883	17878	0.04006	9234	0.528004185
26	2005	0	6579.45605	2796	20981	0.03126	11173	0.577727704
26	2006	0	7950.62451	3348	21659	0.03422	13566	0.572709665
26	2007	0	8641.78418	3696	23346	0.03969	13251	0.595772218
26	2008	0	10308.68945	3836	25174	0.04107	15541	0.534322532
26	2009	0	9377.59766	4072	23776	0.03868	10795	0.576822175
26	2010	0	10102.90723	4054	24731	0.03791	13451	0.544544208
26	2011	0	10083.11914	4042	25307	0.03709	17587	0.558650392
26	2012	0	10140.34082	4135	25395	0.03883	24004	0.596938829
26	2013	0	12383.42383	4502	28778	0.04182	34830	0.578360771
26	2014	0	11954.00488	3794	32407	0.04033	30546	0.529771784
26	2015	0	9744.04199	3541	29425	0.03097	27416	0.544062287
26	2016	0	28853.31055	4313	18554	0.08433	37903	0.314487961
27	2004	0	18419.96289	671	16465	0.10023	7228	0.165350463
27	2005	0	24159.44336	694	12999	0.0976	7592	0.111909929
27	2006	0	15142.66309	738	14150	0.07248	6958	0.149769418
27	2007	0	18037.58203	683	15682	0.08546	8986	0.154739547
27	2008	0	17605.85742	2658	16142	0.07816	12764	0.279298693
27	2009	0	18865.63477	3009	17890	0.07412	6535	0.255458195
27	2010	0	29094.0332	3427	20343	0.10329	6857	0.214356255
27	2011	0	31788.63086	4339	21604	0.10372	8618	0.235103735
27	2012	0	32812.875	4715	22994	0.09752	7429	0.234110878
27	2013	0	32023.62695	5097	28121	0.09848	15940	0.294661417
27	2014	0	34101.83594	5208	33903	0.09327	17999	0.294673271
27	2015	0	35907.69531	5940	36079	0.09475	19604	0.312355448
27	2016	0	35069.52344	5806	34793	0.09387	17960	0.306759917
28	2004	0	30782.45508	6310	15832	0.13982	40334	0.460103981
28	2005	0	32985.55859	5361	14979	0.14843	52426	0.465837924

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
28	2006	0	30342.5293	5214	16652	0.13838	45454	0.455078354
28	2007	0	32379.5	5067	17715	0.12067	61114	0.450263143
28	2008	0	32881.97266	4207	8768	0.12743	62613	0.404570643
28	2009	0	33965.58984	5480	11895	0.12044	63260	0.427835002
28	2010	0	32179.22852	5886	8911	0.09906	70332	0.426853353
28	2011	0	40858.54297	6876	8396	0.10721	79047	0.397732343
28	2012	0	39966.19141	5680	8713	0.11137	88567	0.413201084
28	2013	0	40190.13672	5937	5619	0.11126	84933	0.398401619
28	2014	0	39581.71094	6785	7517	0.1065	89790	0.433235327
28	2015	0	42402.89063	7263	5456	0.10112	89044	0.396643713
28	2016	0	50864.8125	7468	8835	0.10355	134622	0.438868665
29	2004	1	27759.98633	4843	25883	0.06434	37984	0.32248585
29	2005	1	27904.41797	5054	32083	0.06125	30011	0.317414164
29	2006	1	37691.09766	5231	33150	0.08157	31012	0.277643661
29	2007	1	42766.52344	5282	33265	0.08302	30771	0.247816934
29	2008	1	46679.4375	5392	28518	0.09148	32561	0.23521078
29	2009	1	9839.2334	4946	34049	0.01898	24846	0.616290605
29	2010	1	53347.92188	6375	40432	0.08564	28658	0.230409492
29	2011	1	36045.28906	3737	32268	0.0744	28646	0.22940589
29	2012	1	35561.4375	4649	33037	0.07367	25540	0.252081137
29	2013	1	22395.74219	3857	42145	0.04355	8299	0.270311926
29	2014	1	41896.36328	2438	46446	0.07405	10618	0.159049346
29	2015	1	27964.60742	490	40296	0.0516	10749	0.111709846
29	2016	1	98947.6875	423	39353	0.1596	9584	0.083209071
30	2004	0	19578.34766	10494	38523	0.04157	3056	0.624283481
30	2005	0	22040.84766	10534	39776	0.04311	4827	0.565170429
30	2006	0	22730.16016	11820	53440	0.03914	5352	0.621250303
30	2007	0	24325.11133	12509	58155	0.03898	3287	0.612700553
30	2008	0	27559.08594	14381	66862	0.03985	15608	0.641074582
30	2009	0	29534.85742	14128	66840	0.0396	15036	0.588128439
30	2010	0	32976.64063	15047	79924	0.0419	14484	0.576247151
30	2011	0	77513.1875	16150	82438	0.09346	13319	0.323808761
30	2012	0	56323.97266	17301	96475	0.07117	18840	0.452879429
30	2013	0	59448.01563	19086	96903	0.07317	22932	0.468549314
30	2014	0	61126.48828	18902	96813	0.07432	25038	0.457378906
30	2015	0	66821.89844	20608	92039	0.08083	37024	0.464520809
30	2016	0	64275.10156	20872	91137	0.07889	38976	0.48442731
31	2004	0	8467.66602	1434	2226	0.04351	21751	0.292552784
31	2005	0	8415.85938	1570	3113	0.0311	24172	0.287381643
31	2006	0	9361.47266	1626	4287	0.05103	19767	0.304810549
31	2007	0	10376.99512	1792	3347	0.04837	26721	0.312844819
31	2008	0	12368.03613	1662	3290	0.07823	28678	0.336581863
31	2009	1	-4792.13965	1937	4696	-0.35843	33368	2.44280851
31	2010	0	24557.41992	2204	2251	0.32394	32784	0.551899912

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
31	2011	0	18358.58594	2459	1574	0.12361	36053	0.387288732
31	2012	0	15232.21289	1972	162	0.07111	43417	0.332906501
31	2013	0	15201.49707	1830	853	0.06115	42444	0.294550697
31	2014	0	16408.04102	2240	1343	0.0635	43129	0.308627459
31	2015	0	18730.99219	2546	815	0.06258	45173	0.289569767
31	2016	0	25884.5332	2935	2425	0.08343	73636	0.358544972
32	2004	0	20702.02734	4747	10076	0.1278	14932	0.383683311
32	2005	0	22200.18164	5139	7491	0.13203	16253	0.372696064
32	2006	0	20607.51953	4975	8563	0.11569	16203	0.380452316
32	2007	0	20080.79492	5162	8812	0.11066	16809	0.398252155
32	2008	0	23307.80469	5669	9686	0.12792	17349	0.39159918
32	2009	0	25914.48047	6226	8970	0.12908	16857	0.368896038
32	2010	1	24132.35547	5441	6604	0.13354	16999	0.356075669
32	2011	0	22271.95898	4097	6838	0.12028	22771	0.343857068
32	2012	0	24928.1875	4164	7325	0.12737	25347	0.333976654
32	2013	0	28848.25391	4488	7996	0.15446	31398	0.366496956
32	2014	0	30796.8125	5539	8301	0.16109	34475	0.403606245
32	2015	0	36474.76172	4730	8688	0.15534	34634	0.314179968
32	2016	0	31170.16211	5211	5597	0.14949	23786	0.308098002
33	2004	1		3187	29945	0.07216	26656	#DIV/0!
33	2005	1		3193	29263	0.10881	17894	#DIV/0!
33	2006	1		2907	20387	0.14409	15104	#DIV/0!
33	2007	1		3237	19971	0.13364	18602	#DIV/0!
33	2008	1		3904	16984	0.15169	17564	#DIV/0!
33	2009	1		3864	16796	0.14992	11835	#DIV/0!
33	2010	1		5469	16301	0.13871	13328	#DIV/0!
33	2011	1		3453	14034	0.13882	12063	#DIV/0!
33	2012	1		3775	14811	0.15141	9424	#DIV/0!
33	2013	1		4003	21018	0.15552	3179	#DIV/0!
33	2014	1		4127	21581	0.1781	6101	#DIV/0!
33	2015	1		4348	21728	0.18816	3933	#DIV/0!
33	2016	1		4360	21291	0.20781	3091	#DIV/0!
34	2004	0	12169	2876	26557	0.12863	8678	0.608782813
34	2005	0	15616.41797	3722	36774	0.1499	9039	0.678092039
34	2006	0	8896.38574	2997	32920	0.06005	10763	0.631735664
34	2007	0	9288.61719	2332	37949	0.07111	10680	0.623344473
34	2008	0	9948.83691	2399	35092	0.09051	10250	0.653634639
34	2009	0	8600.2793	2408	36568	0.07306	9483	0.671197511
34	2010	0	9726.18164	2557	44098	0.05785	12737	0.600945465
34	2011	0	10384.64746	2906	49429	0.0645	11038	0.655402268
34	2012	0	9335.57715	2810	45259	0.06937	10838	0.717839806
34	2013	0	9495.74609	2760	45382	0.05715	13938	0.647672962
34	2014	0	13193.94922	2993	48096	0.07396	15272	0.582062061
34	2015	0	11757.06445	3020	49414	0.06145	15917	0.598328773

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
34	2016	0	11969.96582	2940	43369	0.06643	15266	0.571022771
35	2004	1	5323.68164	144	1552	0.01759	59807	0.229785493
35	2005	1	4810.02783	12	281	0.01437	55557	0.169311299
35	2006	1	8232.21191	70	-122	0.05192	35456	0.231352315
35	2007	1	10731.71484	143	1509	0.07066	34778	0.252246678
35	2008	1	9126.07813	167	2181	0.06745	25817	0.225229838
35	2009	1	6840.53076	141	1278	0.05813	27319	0.26362627
35	2010	1	2676.70581	101	1216	0.02497	22759	0.261386869
35	2011	1	2242.14526	172	2121	0.02108	26730	0.347960988
35	2012	1	1545.96265	362	1214	0.01194	25424	0.439892723
35	2013	1	2137.64844	139	5387	0.02127	19879	0.316426129
35	2014	1	1937.89893	126	2668	0.01807	22571	0.300360726
35	2015	1	2959.36133	223	767	0.02874	22711	0.303361982
35	2016	1	4541.38135	128	2703	0.03283	23452	0.217261792
36	2004	0	34751.25	4353	56416	0.09176	17145	0.319498072
36	2005	0	36132.15625	4760	74096	0.08838	14456	0.348338629
36	2006	0	47009.39063	5495	75421	0.09999	15819	0.31096101
36	2007	0	59035.06641	4734	90450	0.10868	19452	0.282512587
36	2008	0	65788.00781	5708	89194	0.10957	22119	0.272155458
36	2009	0	68942.42188	5098	102080	0.11801	20601	0.283941067
36	2010	0	75777.61719	6035	113804	0.13285	21496	0.316842966
36	2011	0	75328.13281	5138	101059	0.12363	20730	0.268090729
36	2012	0	76136.76563	5666	113898	0.12521	15821	0.28774687
36	2013	0	75678.01563	5971	105506	0.13097	14275	0.286195633
36	2014	0	74485.80469	6150	93702	0.11145	23919	0.25855746
36	2015	0	66290.01563	4964	100688	0.10216	39785	0.29136698
36	2016	0	76941.25	3219	89692	0.11533	42444	0.239900507
37	2004	0	4857.91699	1567	13495	0.03003	10356	0.470005053
37	2005	0	8053.97461	3101	19480	0.04612	9767	0.552506291
37	2006	0	11762.38867	4648	23843	0.05776	11613	0.569266902
37	2007	0	12546.4873	4769	22114	0.06075	13078	0.550505798
37	2008	0	12888.26758	5133	19608	0.05622	14938	0.548962541
37	2009	0	13829.99316	5277	24380	0.06023	13543	0.546717717
37	2010	0	14498.85645	6039	21683	0.06228	13273	0.566669496
37	2011	0	15951.74316	5517	23429	0.06491	15699	0.505073232
37	2012	0	16360.45215	6231	25786	0.06621	15111	0.546365729
37	2013	0	17338.67578	6247	26122	0.06984	18875	0.541540231
37	2014	0	18774.80859	6507	28488	0.07157	17251	0.520939544
37	2015	0	19575.12695	6822	32485	0.07326	15326	0.527436368
37	2016	0	21206.92578	7227	32616	0.07871	15741	0.52026303
38	2004	1	22580.92188	5117	23421	0.06271	9353	0.317624656
38	2005	1	28708.38477	4235	21970	0.1821	8815	0.342790045
38	2006	1	23162.29883	5624	27718	0.03921	13815	0.313116974
38	2007	1	35548.35156	6644	29240	0.11944	19964	0.352222402

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
38	2008	1	37835.78906	6336	24622	0.07974	12740	0.246201972
38	2009	1	35348.06641	4856	21918	0.07594	11998	0.210240101
38	2010	1	36996.38281	5807	25684	0.07117	16515	0.238139574
38	2011	1	43795.375	6195	28467	0.13253	23828	0.299704166
38	2012	1	33301.53516	6100	29239	0.05439	29928	0.279809717
38	2013	1	34396.66797	6143	34219	0.06159	21747	0.278804504
38	2014	1	47437.79688	5075	37588	0.10096	26888	0.244203941
38	2015	1	41869.32813	4621	36874	0.0498	24179	0.182984532
38	2016	1	41964.12109	3884	39103	0.06885	31094	0.207726582
39	2004	0	41798.61328	12687	114503	0.03204	15710	0.403339326
39	2005	0	185613.6875	13403	139669	0.35624	19929	0.378518376
39	2006	0	49606.61719	15044	145373	0.02059	21798	0.372652923
39	2007	0	54368.02734	16282	163714	0.03968	27514	0.439043464
39	2008	0	52892.44922	17843	167770	0.04108	21693	0.484495243
39	2009	0	49548.98438	18688	175895	0.03022	19349	0.496241729
39	2010	0	57774.60156	19607	180159	0.04676	21060	0.502227617
39	2011	0	59265.88672	22324	185315	0.03275	31315	0.496383909
39	2012	0	73929.07031	26969	191378	0.04353	32454	0.496589593
39	2013	0	63756.48438	21304	210463	0.04414	43526	0.50998851
39	2014	0	63819.53906	19244	192947	0.04492	29972	0.458441441
39	2015	0	67107.80469	19329	220266	0.03899	34203	0.435876966
39	2016	0	63733.38281	18734	218781	0.04201	35251	0.46138904
40	2004	0	36224.92969	10767	73601	0.06154	28363	0.470445759
40	2005	0	42738.79297	12577	56149	0.0614	30648	0.418971491
40	2006	0	47185.00781	15109	50064	0.07465	35261	0.455197789
40	2007	0	51888.53516	15406	57012	0.06738	34341	0.415532354
40	2008	0	51783.16797	18875	59234	0.06807	35046	0.488433609
40	2009	0	45085.64844	18484	55074	0.06034	34358	0.529665818
40	2010	0	46227.14453	17993	62245	0.05988	51589	0.53668424
40	2011	0	50790.55078	17612	62192	0.0677	34853	0.47611113
40	2012	0	52291.16406	17377	73739	0.06939	38497	0.481248725
40	2013	0	55662.375	20064	83718	0.07852	47062	0.544943431
40	2014	0	46772.64453	13492	63859	0.06026	50197	0.435404386
40	2015	0	49514.63672	12439	72310	0.06514	43611	0.403720905
40	2016	1	48322.05078	12352	93941	0.06201	39440	0.426781469
41	2004	1	4271.34473	378	5936	0.14263	2258	0.362113179
41	2005	1	4191.69385	281	6430	0.1314	2444	0.34521691
41	2006	1	3935.48706	285	6361	0.12154	2628	0.350026068
41	2007	1	3415.15186	297	5388	0.10787	2281	0.329196204
41	2008	1	3476.32471	282	5783	0.09875	2319	0.31126911
41	2009	1	2605.96582	237	6229	0.07779	2196	0.342437626
41	2010	1	2670.77344	275	6826	0.08085	2841	0.395607105
41	2011	1	2382.95776	286	7195	0.07105	2131	0.398081878
41	2012	1	4055.4353	582	9295	0.07536	2459	0.361929443

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
41	2013	1	9382.40234	1011	15325	0.09084	5336	0.307793797
41	2014	1	10399.24707	784	14805	0.09897	5417	0.267843558
41	2015	1	11545.71289	827	12780	0.11597	3695	0.237110153
41	2016	1	12626.04102	673	11790	0.12601	4518	0.216059102
42	2004	0	12236.9707	1733	11008	0.05654	13140	0.253194029
42	2005	0	12605.09766	2137	11256	0.05374	14942	0.281225946
42	2006	0	12638.22852	2260	12000	0.05129	16320	0.293754207
42	2007	0	13038.47656	2248	13142	0.04919	16013	0.282405267
42	2008	0	11769.58496	2101	11799	0.0438	15659	0.280694724
42	2009	0	11755.11328	2233	11383	0.0447	15488	0.292139567
42	2010	0	15098.98438	2890	13738	0.05475	18816	0.30944674
42	2011	0	18526.44336	2691	14225	0.06172	18605	0.254623486
42	2012	0	20406.29102	3022	15102	0.0691	17760	0.25936924
42	2013	0	25535.0625	2903	15353	0.08946	16235	0.224352789
42	2014	0	30874.33008	3341	18405	0.09601	17302	0.219251043
42	2015	0	32236.16406	3353	19188	0.09813	18008	0.217241836
42	2016	0	33800.16016	4279	20949	0.10716	18960	0.253124494
43	2004	1	11434.71484	3429	15185	0.08008	886	0.412425298
43	2005	1	10784.64355	3286	15759	0.07027	1763	0.418861404
43	2006	1	12371.51563	3957	13506	0.07748	1233	0.412154652
43	2007	1	13729.02637	4372	15767	0.07425	1396	0.411271171
43	2008	1	14475.88281	4510	19331	0.06746	1665	0.409397495
43	2009	1	17033.44141	0	18940	0.08203	1849	0.100116097
43	2010	1	22189.34766	0	21668	0.10305	2704	0.1131865
43	2011	1	23603.07813	0	25381	0.10402	2082	0.121030878
43	2012	1	19913.20508	0	26916	0.08663	2893	0.129680464
43	2013	1	23686.99609	0	29397	0.09632	2777	0.130831266
43	2014	1	23789.46484	6145	32631	0.09606	2079	0.398463886
43	2015	1	24592.76367	5894	32215	0.10112	2283	0.381512134
43	2016	1	20836.97852	6221	31825	0.08829	2102	0.442310521
44	2004	0	20146.35938	8327	45232	0.08133	7057	0.624413778
44	2005	0	19949.97461	7888	40438	0.09558	7824	0.626611422
44	2006	0	22678.61914	9434	48936	0.11564	8150	0.707072372
44	2007	0	34541.32422	8867	49784	0.24956	11233	0.697552947
44	2008	0	25608.30469	8759	57537	0.10706	13597	0.639425618
44	2009	0	21429.85547	8987	61678	0.05943	7563	0.611389687
44	2010	0	22577.06055	7265	63661	0.06276	7211	0.518797684
44	2011	0	26298.9082	9764	67143	0.07424	4926	0.574715971
44	2012	0	35880.71875	10136	70377	0.14217	5177	0.581858806
44	2013	0	30376.72266	10149	69144	0.10808	5272	0.598875708
44	2014	0	29301.39258	10215	73164	0.08564	4705	0.576208148
44	2015	0	29111.32617	10633	73063	0.08428	8178	0.600453287
44	2016	0	28007.14844	9613	81423	0.08656	8227	0.620309634
45	2004	1	15909.50684	4105	22873	0.02915	30289	0.355427252

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45	2005	1	20667.89648	4551	27002	0.03573	24438	0.309124405
45	2006	1	22072.89453	4221	24818	0.03892	28262	0.284823252
45	2007	1	29418.51172	4909	25585	0.04912	30243	0.260083563
45	2008	1	28540.54883	4959	21556	0.04832	29506	0.260202279
45	2009	1	27907.81836	4845	23811	0.04707	25645	0.257020948
45	2010	1	33360.51953	7036	27716	0.05236	27568	0.297677326
45	2011	1	31372.00195	4208	26005	0.05164	26538	0.220620939
45	2012	1	31050.70117	4770	26679	0.05232	24930	0.240580167
45	2013	1	30223.41602	3962	34426	0.05085	7381	0.201429446
45	2014	1	37401.03516	4524	35510	0.05839	15586	0.200729616
45	2015	1	40079.82813	4588	33964	0.06505	10650	0.186880559
45	2016	1	35940.36719	4389	34497	0.05967	8647	0.193748785
46	2004	1	-127671.6172	1159	2371	-2.40327	48556	0.949563685
46	2005	1	-8542.40723	2941	1888	-0.42044	45621	1.994014509
46	2006	1	2877.1001	4021	-1216	-0.39326	45695	-4.682079549
46	2007	0	55986.02734	4802	2010	0.44034	49170	0.488311147
46	2008	0	35057.28906	4693	2425	0.22093	38207	0.389928261
46	2009	0	40650.59766	4131	1508	0.3493	38718	0.447273665
46	2010	0	31709.91211	4690	3357	0.16393	45200	0.398927281
46	2011	0	27795.48828	5322	2366	0.10452	42053	0.358499688
46	2012	0	34583.80859	4912	1359	0.08798	38940	0.24455103
46	2013	0	24860.32227	4351	5586	0.08431	38957	0.32607865
46	2014	0	34007.06641	4354	3495	0.10918	46686	0.289138777
46	2015	0	33786.55859	4695	283	0.09785	35972	0.243959494
46	2016	0	23677.38281	5291	3088	0.06443	48677	0.364323161
47	2004	1	6007.90137	1307	6447	0.06909	7242	0.374968374
47	2005	1	7732.19824	1233	7933	0.08619	5778	0.312298135
47	2006	1	11200.66797	1462	7239	0.11913	6176	0.273209505
47	2007	1	10957.55176	1646	6833	0.11334	5790	0.280782686
47	2008	1	9876.87793	1623	5538	0.09173	5885	0.270412554
47	2009	1	8518.03516	1321	6732	0.09138	4484	0.27540601
47	2010	1	9983.25391	1967	7515	0.08078	5211	0.300003016
47	2011	1	8719.77051	988	5810	0.07241	4842	0.201761195
47	2012	1	9114.77539	1153	6723	0.08715	4660	0.235335305
47	2013	1	9084.9541	1004	9408	0.08835	1665	0.218195879
47	2014	1	11285.95996	1156	9261	0.07449	2255	0.178436469
47	2015	1	10197.18457	76	8468	0.07245	2206	0.083290765
47	2016	1	10077.62207	55	9367	0.0735	2144	0.089411817
48	2004	1	1762.03687	322	18095	0.00651	4352	0.265675468
48	2005	1	1724.06238	214	21606	0.00597	4907	0.215933376
48	2006	1	51777.94141	2428	21062	0.13827	4099	0.114083552
48	2007	1	16586.74805	246	20062	0.0466	5512	0.086680547
48	2008	1	18054.33789	243	21904	0.04692	3240	0.078804135
48	2009	1	16375.7832	348	26422	0.03777	6401	0.09695565

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48	2010	1	20390.18945	330	30647	0.04612	4611	0.095933339
48	2011	1	20839.78516	403	29422	0.04654	13211	0.114547237
48	2012	1	21136.83594	456	40848	0.03982	19788	0.135806775
48	2013	1	32269.90625	2650	32324	0.05003	37224	0.189944352
48	2014	1	28616.21289	1714	41398	0.04102	38833	0.174903494
48	2015	1	27555.04688	1923	39467	0.03595	18221	0.145050873
48	2016	1	26217.75977	1770	44998	0.03453	11839	0.142368442
49	2004	1	29121.10156	2551	892	0.77604	23096	0.726849136
49	2005	1	12288.68359	3243	959	0.18007	22907	0.613617444
49	2006	1	18574.67188	3764	-491	0.30703	25108	0.609548184
49	2007	1	21093.64844	4659	1732	0.1624	26708	0.439831735
49	2008	1	15892.56348	4661	1482	0.06964	25328	0.410761197
49	2009	1	11888.22266	4045	427	0.05155	26598	0.457439174
49	2010	1	12180.68555	3821	1396	0.03853	34258	0.426474241
49	2011	1	14963.31348	3226	862	0.14808	44457	0.66408002
49	2012	1	19877.61523	2964	485	0.17348	35726	0.46514052
49	2013	1	15042.24023	2420	2805	0.10359	30310	0.38893029
49	2014	1	12849.15039	1844	1252	0.08132	34691	0.370988323
49	2015	1	13310.48828	1855	310	0.09551	36111	0.400704287
49	2016	1	15639.40918	2282	1261	0.10237	33171	0.371293044
50	2004	0	11415.93945	2547	14844	0.04941	13970	0.347820673
50	2005	0	12328.10547	2636	16371	0.05318	14381	0.346475894
50	2006	0	8246.49121	2702	16186	0.03588	13480	0.456729533
50	2007	0	9154.31738	2798	16056	0.03742	15378	0.434140539
50	2008	0	12373.8877	2897	15809	0.04997	16330	0.363910352
50	2009	0	11303.53711	2089	14461	0.04589	14675	0.303095483
50	2010	0	13607.66895	2346	17144	0.05056	18677	0.305497567
50	2011	0	13834.76172	2626	15030	0.05179	17992	0.313428555
50	2012	0	13298.75293	2627	15713	0.05924	19442	0.35413713
50	2013	0	19075.64258	3097	16062	0.07294	21067	0.304324703
50	2014	0	17347.9375	3481	20730	0.06311	23459	0.361412865
50	2015	0	16332.89648	2896	21548	0.06456	28045	0.373340031
50	2016	0	21896.22461	3612	22185	0.07751	35880	0.370503057
51	2004	0	11720.66016	2746	19048	0.0592	3683	0.34909938
51	2005	0	10348.63965	2994	16382	0.05878	2800	0.398266642
51	2006	0	13771.79688	2891	15936	0.08925	6137	0.352968846
51	2007	0	12123.5459	3194	21431	0.06502	16573	0.467274189
51	2008	0	14747.49707	3311	23594	0.12134	14661	0.539268573
51	2009	0	13663.29883	2975	23269	0.08932	12801	0.453534134
51	2010	0	10307.81152	3136	27593	0.05324	12980	0.513795437
51	2011	0	9766.75098	2149	18047	0.0546	20524	0.435659372
51	2012	0	18936.25977	1795	7620	0.08299	17101	0.203133873
51	2013	0	17071.59375	1734	3556	0.10999	20506	0.256600493
51	2014	0	37058.23047	1688	4006	0.20593	17903	0.167296719

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
51	2015	0	22494.75781	1582	3144	0.10141	19828	0.173888981
51	2016	0	18992.61133	1370	6390	0.07394	19863	0.174338682
52	2004	1	4780.25098	817	7324	0.04791	1509	0.25944015
52	2005	1	5510.10059	799	8557	0.05178	1631	0.240745993
52	2006	1	17764.57031	819	9608	0.13198	2001	0.132350841
52	2007	1	12034.87402	993	8533	0.09291	3030	0.171777314
52	2008	1	12276.9248	941	8768	0.08384	2436	0.153160779
52	2009	1	14070.77539	830	10684	0.08844	2786	0.143651415
52	2010	1	13653.75586	423	11885	0.09145	2724	0.128828512
52	2011	1	15476.51172	544	11938	0.10121	4767	0.144393846
52	2012	1	11998.44922	573	16244	0.07263	6759	0.186999824
52	2013	1	14438.44043	3604	11110	0.06718	12043	0.357339047
52	2014	1	19574.5	5400	13776	0.07923	14738	0.391282752
52	2015	1	19737.26367	5383	12454	0.08344	8781	0.362504576
52	2016	1	22524.09961	5742	19275	0.09373	6314	0.361410983
53	2004	0	66321.50781	18343	47000	0.13278	17552	0.405814274
53	2005	0	60089.39453	14985	47690	0.12108	6758	0.359091051
53	2006	0	78009.96094	17160	44992	0.1457	8016	0.318975491
53	2007	0	88603.52344	16434	44117	0.14483	8599	0.27164674
53	2008	0	96380.9375	17616	49186	0.14114	7573	0.265892467
53	2009	0	108283.2422	18370	62604	0.1428	12711	0.268970354
53	2010	0	135678.7031	18023	68430	0.15422	11414	0.223591035
53	2011	0	111161.8906	18230	60524	0.12874	24944	0.262978168
53	2012	0	142820.2656	18844	46507	0.16852	32266	0.224889835
53	2013	0	176370.125	24351	62783	0.18297	52697	0.257868931
53	2014	0	170843.3594	21637	54027	0.17191	57929	0.239303161
53	2015	1	150199.2031	19412	75269	0.16535	36260	0.252020779
53	2016	1	118868.1719	20527	74823	0.16271	14002	0.294273187
54	2004	1	25817.48047	5616	21022	0.04685	32561	0.314762068
54	2005	1	28871.32813	6345	25526	0.04778	24140	0.301961913
54	2006	1	32916.99609	6142	24867	0.05415	28954	0.275128603
54	2007	1	16901.99805	6016	26773	0.02706	25783	0.440076099
54	2008	1	50979.71484	6875	21528	0.07492	29426	0.20973977
54	2009	1	37158.67578	6006	24974	0.05732	21532	0.233370101
54	2010	1	45141.92188	9756	31166	0.06612	25688	0.299393245
54	2011	1	18099.39648	6876	42022	0.01493	38432	0.446267821
54	2012	1	34192.72266	7208	42517	0.03466	34020	0.288388044
54	2013	1	19655.64063	5967	53146	0.02033	10879	0.369798593
54	2014	1	132562.3281	315	33085	0.18279	7912	0.058906944
54	2015	1	77933.64844	446	32395	0.12278	8100	0.06952037
54	2016	1	33260.98438	502	31679	0.05405	6948	0.077862679
55	2004	0	28007.22266	7056	6627	0.10818	2915	0.288791704
55	2005	0	35076.30078	6736	6569	0.13435	3726	0.231470625
55	2006	0	26717.84766	6636	9470	0.09841	2218	0.291423777

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
55	2007	0	28962.65625	5785	13363	0.08509	3935	0.250560127
55	2008	0	32409.98242	6795	8980	0.08467	4322	0.244408659
55	2009	0	32051.7793	7238	9980	0.08164	4220	0.261991321
55	2010	0	57673.85547	5623	27331	0.12462	8180	0.174227659
55	2011	0	83576.50781	8559	32575	0.1702	13754	0.196756197
55	2012	0	98821.10938	9215	31683	0.1916	6196	0.166691272
55	2013	0	124230.9375	10233	30727	0.23645	8370	0.156784502
55	2014	0	140482.75	10117	33284	0.25644	8764	0.148771213
55	2015	0	155071.7656	10115	38128	0.27657	10492	0.151941479
55	2016	0	193535.4219	11736	41990	0.30603	13580	0.148510732
56	2004	1	61921.79688	1223	480	1.99728	24140	0.813865814
56	2005	1	15542.16797	1698	268	0.28011	24821	0.561419733
56	2006	1	28477.4375	2182	-482	0.79013	25389	0.767687328
56	2007	1	22794.59375	2095	735	0.22522	25821	0.354292005
56	2008	1	17209.37891	2282	823	0.08913	21447	0.247941842
56	2009	1	11922.97559	1710	269	0.06002	22488	0.257978817
56	2010	1	15088.24609	1790	1121	0.06063	26413	0.229276909
56	2011	1	22749.94531	2015	1336	0.31296	39905	0.655904142
56	2012	1	30950.4082	1846	1070	0.48399	33052	0.593229875
56	2013	1	17852.91797	1684	3595	0.12724	29766	0.332094375
56	2014	1	23401.84766	1824	1292	0.16524	36500	0.344791155
56	2015	1	25599.23828	2346	35	0.19195	35466	0.357839435
56	2016	1	26530.12305	2645	1164	0.18648	34926	0.353374283
57	2004	1	12004.74219	2372	32714	0.04895	5459	0.353241101
57	2005	1	13634.11523	3946	33861	0.05232	5751	0.441429439
57	2006	1	15271.05371	4156	35307	0.05706	5219	0.423573493
57	2007	1	16365.53027	4712	46542	0.05533	4870	0.461740367
57	2008	1	17945.69922	5255	42801	0.05537	6547	0.445087074
57	2009	1	17093.51172	5227	35470	0.05506	5268	0.437009925
57	2010	1	19017.54883	5337	41010	0.06012	5998	0.429241488
57	2011	1	19048.51758	5075	43430	0.05228	10913	0.415573128
57	2012	1	17425.20508	4907	52490	0.04817	7760	0.448157853
57	2013	1	18933.64258	4922	52776	0.05034	8499	0.422876024
57	2014	1	18864.97266	4761	58438	0.04553	7081	0.410500466
57	2015	1	22394.12305	4907	60379	0.05096	8456	0.375760711
57	2016	1	24817.17383	5209	61817	0.05265	11902	0.366290917
58	2004	1	6507.26025	2226	13332	0.03423	2168	0.423613763
58	2005	1	5709.97266	2010	12171	0.03116	1436	0.426270714
58	2006	1	9594.43555	2360	11981	0.04831	5221	0.332591595
58	2007	1	9322.78711	3361	12369	0.04038	11221	0.462690411
58	2008	1	9878.14258	3188	12988	0.04246	10343	0.423018217
58	2009	1	8903.65918	2842	12934	0.03778	9005	0.412286156
58	2010	1	7948.01563	2712	14601	0.02917	7420	0.422036484
58	2011	1	6687.40527	1715	8758	0.02301	11896	0.32751844

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
58	2012	1	6094.3877	1385	1928	0.02283	18230	0.302771538
58	2013	1	7801.5332	1175	1368	0.02965	17999	0.224216382
58	2014	1	11309.68945	957	720	0.03567	18628	0.145639999
58	2015	1	9452.2666	1078	187	0.03877	18930	0.192458187
58	2016	1	10763.75977	1029	2302	0.03703	19997	0.17231265
59	2004	0	38291.75391	10569	688	0.11241	2612	0.285699971
59	2005	0	38615.91406	11359	3204	0.11454	139	0.304069126
59	2006	0	50748.99219	8769	8003	0.13952	793	0.196973723
59	2007	0	51726.35547	9807	3266	0.13922	2700	0.205651189
59	2008	0	43993.87109	8494	5849	0.11572	1370	0.212060963
59	2009	0	48080.37109	9082	9537	0.12796	2166	0.220038149
59	2010	0	49452.77734	10277	8946	0.10581	3882	0.235261421
59	2011	0	51188.25781	10404	6391	0.10117	1026	0.217908918
59	2012	0	70418.90625	12019	5862	0.12981	217	0.181884606
59	2013	0	65724.91406	11907	7093	0.13022	209	0.195631544
59	2014	0	55102.79688	8816	3938	0.10592	89	0.167732681
59	2015	0	65219.03125	7925	16246	0.11503	2403	0.154405766
59	2016	0	62467.5625	7240	15123	0.10972	5113	0.151443302
60	2004	0	7345.53369	1283	25289	0.03838	5860	0.337415731
60	2005	0	7912.22217	1425	30364	0.03986	5447	0.360508894
60	2006	0	10791.74414	1667	31905	0.05216	5373	0.3346466
60	2007	0	14345.19824	1827	38292	0.06413	6481	0.327516735
60	2008	0	14766.51465	1977	36114	0.05681	8233	0.304496571
60	2009	0	19317.11523	1026	44950	0.07056	7245	0.243767206
60	2010	0	19828.38867	1251	49652	0.07397	7323	0.27563716
60	2011	0	19185.54883	1171	43929	0.07305	8048	0.258940721
60	2012	0	20057.66992	1312	49313	0.08191	6289	0.292474642
60	2013	0	19204.76367	1221	45330	0.07703	6043	0.269634257
60	2014	0	20576.21875	1838	45988	0.08013	12504	0.317111907
60	2015	0	16434.21289	2068	47629	0.06202	17925	0.373224998
60	2016	0	23193.18945	1936	40913	0.08978	17902	0.311143524
61	2004	1	17137.66016	2142	13943	0.08306	19073	0.285004424
61	2005	1	29420.30273	2380	15505	0.35011	12560	0.414878027
61	2006	1	18432.88281	2696	16818	0.05678	14915	0.244009566
61	2007	1	23125.05859	2856	17491	0.06676	15697	0.219313212
61	2008	1	27776.49414	2894	15746	0.11142	18099	0.239951445
61	2009	1	23197.90039	2679	15456	0.12591	13289	0.271502284
61	2010	1	28965.78125	3476	19336	0.14108	15498	0.289665266
61	2011	1	23405.1543	2506	15482	0.07912	13238	0.204157013
61	2012	1	27374.49414	2862	16816	0.09972	12389	0.210938057
61	2013	1	30155.43164	2734	21601	0.12234	1957	0.186237948
61	2014	1	36541.16016	3483	22125	0.14538	6975	0.211092313
61	2015	1	35075.34375	3781	20877	0.09271	5426	0.177319748
61	2016	1	39260.73047	3779	21097	0.22321	4097	0.23949001

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
62	2004	1	18938.08984	1858	16443	0.09475	18264	0.271753292
62	2005	1	21888.13477	2184	19204	0.0866	15656	0.237703032
62	2006	1	22749.92578	2656	21217	0.08703	19162	0.27121778
62	2007	1	26014.50195	2798	21397	0.09344	19081	0.252946004
62	2008	1	25044.86914	3050	18198	0.08617	20100	0.253550483
62	2009	1	22068.35742	2692	22434	0.08255	16786	0.268692902
62	2010	1	28675.75195	4067	27021	0.09259	17691	0.28619595
62	2011	1	25729.12109	2600	22833	0.08079	18960	0.23228374
62	2012	1	29473.20898	2701	24957	0.09861	17458	0.233552551
62	2013	1	32330	3017	30158	0.0995	3846	0.197970863
62	2014	1	37249.08984	3278	32428	0.10794	10235	0.211630519
62	2015	1	41210.05078	3508	29226	0.11149	8120	0.186161031
62	2016	1	41817.78516	3721	28787	0.11289	6542	0.184354355
63	2004	0	12609.31055	5374	15315	0.08782	5410	0.570536309
63	2005	0	22630.06445	5331	16778	0.25923	6684	0.504331496
63	2006	0	18596.06055	7000	19801	0.07065	4994	0.470624772
63	2007	0	24001.16992	7659	17366	0.11874	6979	0.439550461
63	2008	0	20955.64648	7960	16968	0.08089	7220	0.47321696
63	2009	0	21762.18164	7940	19317	0.09576	4700	0.47053499
63	2010	0	28710.76367	9787	21132	0.13333	4479	0.459817606
63	2011	0	29264.29688	10183	21528	0.11729	3912	0.44992906
63	2012	0	33170.61328	10729	19549	0.13288	4137	0.41833401
63	2013	0	35700.14453	11732	22546	0.13513	5811	0.4359613
63	2014	0	38266.63672	12282	24037	0.13858	6677	0.432187084
63	2015	0	38797.3125	11876	27676	0.13189	8209	0.42809338
63	2016	0	36654.48438	13092	27729	0.13239	9300	0.490915903
64	2004	1		1503	4453	0.10116	2485	#DIV/0!
64	2005	1		1413	4409	0.09369	2505	#DIV/0!
64	2006	1		1297	13491	0.08959	4654	#DIV/0!
64	2007	1		990	9383	0.0765	3373	#DIV/0!
64	2008	1		1275	8592	0.09201	4643	#DIV/0!
64	2009	1		1259	9729	0.08829	5907	#DIV/0!
64	2010	1		1614	9720	0.09108	4131	#DIV/0!
64	2011	1		2099	12317	0.14103	4359	#DIV/0!
64	2012	1		1564	10312	0.09449	6746	#DIV/0!
64	2013	1		1737	11638	0.095	6390	#DIV/0!
64	2014	1		1678	12119	0.08056	6034	#DIV/0!
64	2015	1		1679	11996	0.08411	6764	#DIV/0!
64	2016	1		1834	12696	0.09923	6744	#DIV/0!
65	2004	1	1497.04272	71	785	0.00548	36484	0.183851881
65	2005	1	1284.9165	78	394	0.00457	34925	0.186321703
65	2006	1	3788.87451	29	70	0.02028	21621	0.123755347
65	2007	1	4165.18604	120	733	0.02418	20552	0.152375259
65	2008	1	3995.77759	208	1059	0.0364	16490	0.211919603

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65	2009	1	2431.38232	50	607	0.0223	15361	0.167018735
65	2010	1	1054.41479	64	339	0.01207	12214	0.204392723
65	2011	1	792.43195	76	1065	0.00782	14195	0.24649839
65	2012	1	799.25726	75	726	0.0079	12939	0.228904396
65	2013	1	891.3559	103	2243	0.00942	13638	0.283387388
65	2014	1	683.50537	136	805	0.0069	14283	0.35128795
65	2015	1	888.51129	88	584	0.00858	14221	0.242008067
65	2016	1	1581.2417	10	1436	0.01571	13097	0.150712842
66	2004	0	6841.4834	2942	22977	0.02374	7468	0.535668083
66	2005	0	7106.46143	2784	19697	0.02541	7883	0.490371732
66	2006	0	8675.89648	3336	21770	0.02908	7030	0.48104585
66	2007	0	10081.19043	3620	24725	0.03242	7824	0.463758582
66	2008	0	10432.22266	3448	29877	0.0324	9349	0.452341035
66	2009	0	12115.86914	3950	36097	0.03591	11046	0.465744972
66	2010	0	13428.75977	5250	29747	0.03747	11860	0.507047144
66	2011	0	15731.48047	5825	28023	0.04382	11250	0.479671502
66	2012	0	14159.48926	5479	29225	0.03996	11472	0.501801441
66	2013	0	14747.62207	5800	35830	0.04175	16209	0.540604323
66	2014	0	16465.12891	6485	34983	0.04402	24261	0.552253246
66	2015	0	17705.93945	6775	42494	0.05223	18460	0.562445582
66	2016	0	19058.27734	7101	45493	0.0549	18191	0.556044569
67	2004	1	41290.27344	10182	79488	0.04183	32579	0.360127492
67	2005	1	31246.34961	10370	97198	0.02953	29346	0.451471756
67	2006	1	46366.17188	9498	102477	0.04221	23789	0.319795387
67	2007	1	77534.17188	11216	146269	0.08169	29193	0.329525552
67	2008	1	72378.85938	18595	161459	0.08841	33581	0.495151301
67	2009	1	185478.4219	23256	140707	0.08577	35005	0.206637612
67	2010	1	123330.25	22689	281107	0.09798	29242	0.430526939
67	2011	1	167345.7656	24588	133255	0.12229	27385	0.264319001
67	2012	1	188617.1094	27746	95182	0.11215	21388	0.216413695
67	2013	1	73590.96875	31105	113203	0.05428	22393	0.52268847
67	2014	1	80836.91406	33708	110925	0.0489	29370	0.501855198
67	2015	1	183947.5781	33790	102802	0.11469	34867	0.269529276
67	2016	1	196023.0781	40853	144646	0.10624	32766	0.304562358
68	2004	0	10049.68066	2607	18296	0.07591	2990	0.420194472
68	2005	0	9388.84961	2522	15017	0.076	2138	0.407481231
68	2006	0	15923.44531	3001	15234	0.11996	5469	0.344431232
68	2007	0	18114.64844	3974	14771	0.14037	13531	0.438692021
68	2008	0	14694.69727	3977	16385	0.11382	13247	0.500160984
68	2009	0	16716.92773	3521	15075	0.13517	10089	0.414096298
68	2010	0	15933.82422	3298	19334	0.10551	10407	0.40391891
68	2011	0	11393.27344	2220	10934	0.08316	16626	0.396013457
68	2012	0	13100.41113	1277	3198	0.10882	33395	0.401441619
68	2013	0	16930.95898	1324	1994	0.12523	35839	0.358032088

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
68	2014	0	18961.34766	1436	1237	0.12822	38764	0.346226879
68	2015	0	18768.30469	1621	664	0.11094	38133	0.315699222
68	2016	0	20158.16602	2012	3753	0.10958	38364	0.328759117
69	2004	1		1251	6538	0.13072	10535	#DIV/0!
69	2005	1		1435	7162	0.14876	7437	#DIV/0!
69	2006	1		1630	6273	0.16399	5928	#DIV/0!
69	2007	1		1740	5542	0.18834	5172	#DIV/0!
69	2008	1		1906	4937	0.16834	6518	#DIV/0!
69	2009	1		1771	5434	0.15709	5089	#DIV/0!
69	2010	1		2507	6460	0.23801	4188	#DIV/0!
69	2011	1		2267	5554	0.18708	3841	#DIV/0!
69	2012	1		2288	5863	0.20476	3575	#DIV/0!
69	2013	1		2046	7579	0.19987	974	#DIV/0!
69	2014	1		2246	7642	0.21883	1392	#DIV/0!
69	2015	1		2512	7403	0.22897	1551	#DIV/0!
69	2016	1		2673	7209	0.27112	1125	#DIV/0!
70	2004	1	4617.58252	534	10830	0.06767	3059	0.319186203
70	2005	1	5748.94189	659	14615	0.07908	2607	0.351528298
70	2006	1	7587.9917	964	15003	0.10385	2605	0.368027656
70	2007	1	8471.87207	1063	16833	0.10354	3805	0.377703829
70	2008	1	8377.79492	1052	17488	0.09883	4115	0.380413285
70	2009	1	7793.55664	521	16998	0.09621	3022	0.313993253
70	2010	1	8223.08301	628	22096	0.08349	3354	0.334767446
70	2011	1	8643.22266	520	19197	0.09417	3270	0.30494614
70	2012	1	9220.66406	570	22326	0.08466	3075	0.295038258
70	2013	1	10212.32324	512	20593	0.08419	2331	0.239120081
70	2014	1	10301.38086	806	18270	0.08603	4324	0.266931381
70	2015	1	10560.36621	987	21942	0.08402	7162	0.32501885
70	2016	1	13752.15723	757	18486	0.10091	8987	0.256636131
71	2004	1	23550.50391	5359	22757	0.12364	33440	0.52258742
71	2005	1	19761.48047	5318	20767	0.12957	14428	0.499872272
71	2006	1	21439.03711	6543	17715	0.13345	6078	0.453293485
71	2007	1	23859.09961	6852	26115	0.13602	5513	0.46749629
71	2008	1	25065.61523	7325	25003	0.13902	9382	0.482940578
71	2009	1	30599.34961	8084	25041	0.22096	5667	0.485933194
71	2010	1	29674.77344	8112	23023	0.18476	5857	0.453175113
71	2011	1	27698.23633	8300	25456	0.1663	6324	0.490464947
71	2012	1	37179.48828	8430	25461	0.29763	6555	0.483033062
71	2013	1	30077.58984	8654	27982	0.17078	4637	0.472932602
71	2014	1	29120.2207	8531	30100	0.15024	5864	0.478507066
71	2015	1	27642.97656	9144	32599	0.11698	4928	0.489596641
71	2016	1	22821.66602	8645	34685	0.10603	5470	0.56536778
72	2004	1		22043	-14	0.10614	485	#DIV/0!
72	2005	1		23598	2889	0.11555	556	#DIV/0!

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
72	2006	1		22883	1925	0.11322	685	#DIV/0!
72	2007	1		14896	2606	0.11902	495	#DIV/0!
72	2008	1		11047	2673	0.11301	501	#DIV/0!
72	2009	1		13102	3748	0.11304	682	#DIV/0!
72	2010	1		14415	3418	0.09793	1098	#DIV/0!
72	2011	1		15972	3134	0.12102	821	#DIV/0!
72	2012	1		15944	3470	0.11477	915	#DIV/0!
72	2013	1		17235	3665	0.11335	967	#DIV/0!
72	2014	1		18251	623	0.1157	929	#DIV/0!
72	2015	1		18659	580	0.11378	1025	#DIV/0!
72	2016	1		19659	694	0.1228	926	#DIV/0!
73	2004	0	8306.67285	2984	16050	0.03283	8227	0.455177901
73	2005	0	8582.42676	2386	17784	0.04226	9290	0.411322734
73	2006	0	9774.27246	2669	17413	0.04355	9988	0.395151001
73	2007	0	12360.67969	3122	19387	0.07173	11687	0.432899982
73	2008	0	12572.9248	3325	19182	0.05296	10997	0.391577928
73	2009	0	13750.95898	3287	22474	0.05412	11314	0.372018167
73	2010	0	13604.93262	3448	25317	0.04202	15053	0.378123696
73	2011	0	14495.43945	3567	24938	0.03327	14467	0.336519936
73	2012	0	15960.04883	3642	36662	0.04378	11660	0.360746839
73	2013	0	15300.625	3906	24996	0.04717	10535	0.36482152
73	2014	0	15738.95313	4091	24852	0.05272	11884	0.382981121
73	2015	0	15939.08105	4207	32025	0.05258	9632	0.401360972
73	2016	0	18199.8418	4532	33574	0.06002	7630	0.384896976
74	2004	0	9355.61035	1835	14065	0.10699	2845	0.38952038
74	2005	0	9092.42773	1913	13239	0.10543	3005	0.39874993
74	2006	0	11063.22949	2106	14214	0.11141	2584	0.359521167
74	2007	0	11772.27539	2803	14556	0.11457	2653	0.405583031
74	2008	0	11009.63965	4624	14095	0.09803	2628	0.568897429
74	2009	0	11773.37793	2365	16068	0.09071	2536	0.344214623
74	2010	0	11268.64063	2163	18119	0.07529	2187	0.327620594
74	2011	0	8903.47363	1949	18976	0.05524	2133	0.349870319
74	2012	0	14381.96191	2343	20288	0.08929	1712	0.299498777
74	2013	0	11942.28223	2441	21652	0.07091	3103	0.351388199
74	2014	0	12891.71875	2776	20145	0.07393	3016	0.348153168
74	2015	0	12689.65039	2585	20157	0.07421	1536	0.33057156
74	2016	0	12894.0957	3075	21116	0.07678	1965	0.375920832
75	2004	0	18504.19336	4832	57119	0.04675	24578	0.467533741
75	2005	0	28064.10156	5507	76012	0.06128	27010	0.42118534
75	2006	0	21859.5293	5348	76601	0.0401	25995	0.432859256
75	2007	0	26605.3125	4992	70497	0.04649	26887	0.357800051
75	2008	0	19855.94141	4076	61916	0.03721	39715	0.395734926
75	2009	0	27436.48828	3355	58638	0.05228	37094	0.304698942
75	2010	0	15949.48535	3322	64806	0.02883	27610	0.375332065

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
75	2011	0	39230.85547	3918	39946	0.07749	24339	0.22684809
75	2012	0	21793.2207	3830	51249	0.0506	20444	0.342201178
75	2013	0	33920.23047	3469	32897	0.08308	24935	0.243915871
75	2014	0	42198.5	5848	21738	0.15028	13490	0.264039334
75	2015	0	44997.34766	7185	25330	0.18869	9221	0.3045608
75	2016	0	60003.90625	7939	15319	0.24082	5983	0.217801614
76	2004	0	161860.3438	42217	79377	0.17312	2060	0.3479257
76	2005	0	177921.875	48354	82332	0.16698	2151	0.351058414
76	2006	0	200511.375	51927	99414	0.15926	4174	0.341249592
76	2007	0	219351.4375	46971	95234	0.15925	6081	0.287690906
76	2008	0	228879.8906	50791	100225	0.1608	6006	0.296543941
76	2009	0	241712.7188	52085	110263	0.16118	6156	0.293114135
76	2010	0	272378.2813	51306	117964	0.16082	10859	0.264423854
76	2011	0	268687.6875	55399	137018	0.16187	7485	0.29323897
76	2012	0	247902.75	91015	119648	0.14075	5443	0.438161974
76	2013	0	202870.9375	81532	132346	0.11537	8466	0.481968889
76	2014	0	180047.4063	78464	138795	0.09752	8246	0.515438907
76	2015	0	195860.2188	82952	147012	0.10219	6392	0.503565019
76	2016	0	210213.1719	85138	163642	0.11263	6811	0.496334842
77	2004	1	0	0	27329	0	5368	#DIV/0!
77	2005	1	0	0	26228	0	4389	#DIV/0!
77	2006	1	0	0	30641	0	6178	#DIV/0!
77	2007	1	0	0	32393	0	5959	#DIV/0!
77	2008	1	6934.38525	0	36344	0.01449	15020	0.107329537
77	2009	1	8792.52051	0	37606	0.01697	12396	0.096506336
77	2010	1	13315.55762	0	36182	0.02406	12129	0.087293577
77	2011	1	12315.6875	0	28957	0.01991	15071	0.071177308
77	2012	1	12898.08496	0	29105	0.0213	9927	0.064457755
77	2013	1	12307.6709	0	29270	0.01918	19736	0.076369858
77	2014	1	11765.35938	0	33873	0.01786	26356	0.091428566
77	2015	1	10930.67285	0	38531	0.01755	20306	0.094467135
77	2016	1	13721.38379	549	43277	0.02212	17660	0.138246001
78	2004	0	12833.09082	2404	3684	0.10579	26549	0.43655493
78	2005	0	13086.62109	2239	5367	0.10833	26042	0.431091947
78	2006	0	13079.77441	2246	5545	0.10278	30416	0.454294653
78	2007	0	15165.58301	2524	6646	0.09507	38366	0.448600679
78	2008	0	14608.80762	2247	5518	0.09082	33839	0.398485824
78	2009	0	14671.62793	1830	5443	0.0895	32603	0.356819095
78	2010	0	17655.23438	2315	3795	0.09683	38409	0.362590107
78	2011	0	15351.83887	2719	4128	0.08199	37478	0.399318674
78	2012	0	16707.58789	1884	3132	0.08297	46486	0.359166476
78	2013	0	17451.47852	2043	3231	0.09102	43845	0.362597216
78	2014	0	18219.85156	2236	3769	0.08452	43991	0.344276965
78	2015	0	23617.15039	2768	3035	0.09733	46076	0.319597136

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
78	2016	1	28925.3418	2544	5008	0.10256	71493	0.35919861
79	2004	1	20549.14063	6674	104271	0.01865	15680	0.433647631
79	2005	1	36721.96875	5569	91147	0.03333	51067	0.280730935
79	2006	1	24510.45703	6329	90288	0.02196	43864	0.378409016
79	2007	1	15682.17871	852	103280	0.01317	65098	0.195734172
79	2008	1	12643.8457	12	106160	0.01094	47548	0.133943862
79	2009	1	11940.69629	143	102360	0.01076	24094	0.125926077
79	2010	1	12329.81445	14	103321	0.011	18845	0.11012542
79	2011	1	12977.56055	3	113893	0.01115	17860	0.113430097
79	2012	1	13392.9834	95	125112	0.0113	19716	0.129288326
79	2013	1	12646.79199	12	125236	0.01064	25575	0.127829179
79	2014	1	29924.32227	57	139787	0.02508	25579	0.140500401
79	2015	1	47466.63672	487	110832	0.04115	25744	0.128660946
79	2016	1	44616.95313	36	117370	0.03592	26940	0.116987262
80	2004	1	4247.38086	205	6371	0.06788	3184	0.200969357
80	2005	1	-42201.82422	311	5728	-1.91427	4119	0.439289463
80	2006	1	6743.12646	171	7392	0.07479	15088	0.274691452
80	2007	1	4704.28809	207	7822	0.06217	-10434	0.009483254
80	2008	1	7223.86328	94	5584	0.11093	4523	0.168216017
80	2009	1	5726.51904	13	5113	0.06379	2951	0.092098281
80	2010	1	6409.13818	90	6010	0.0648	3808	0.113307964
80	2011	1	8208.94727	17	6375	0.1146	6676	0.184267793
80	2012	1	7625.85938	27	5024	0.10845	3630	0.12661213
80	2013	1	5760.00928	25	6807	0.06069	4316	0.121537108
80	2014	1	6339.27783	18	7294	0.06729	4782	0.131023448
80	2015	1	6863.08691	21	6726	0.10343	5436	0.186347001
80	2016	1	11476.98242	19	8272	0.21011	7569	0.291657893
81	2004	1		13	825	0.00773	91	#DIV/0!
81	2005	1		30	831	0.02551	152	#DIV/0!
81	2006	1		36	960	0.03679	197	#DIV/0!
81	2007	1		45	1025	0.02553	193	#DIV/0!
81	2008	1		35	946	0.01557	249	#DIV/0!
81	2009	1		50	1736	0.01223	413	#DIV/0!
81	2010	1		80	1159	0.02379	416	#DIV/0!
81	2011	1		46	1551	0.0227	1075	#DIV/0!
81	2012	1		28	1543	0.03534	202	#DIV/0!
81	2013	1		20	1681	0.01444	599	#DIV/0!
81	2014	1		30	1671	0.0211	1942	#DIV/0!
81	2015	1		17	1962	0.01262	744	#DIV/0!
81	2016	1		0	0		0	#DIV/0!
82	2004	1		2155	39621	0.05495	8695	#DIV/0!
82	2005	1		2494	36218	0.06185	7603	#DIV/0!
82	2006	1		2845	43516	0.0744	8258	#DIV/0!
82	2007	1		3701	40636	0.09918	6922	#DIV/0!

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
82	2008	1		315	32669	0.02527	8479	#DIV/0!
82	2009	1		419	24429	0.0204	8072	#DIV/0!
82	2010	1		305	39673	0.01732	5581	#DIV/0!
82	2011	1		340	37892	0.01483	5798	#DIV/0!
82	2012	1		428	36863	0.02214	6228	#DIV/0!
82	2013	1		422	43655	0.01912	5448	#DIV/0!
82	2014	1		431	46558	0.01616	7212	#DIV/0!
82	2015	1		441	46403	0.01467	6132	#DIV/0!
82	2016	1		433	49577	0.01744	9071	#DIV/0!
83	2004	0	49291.34375	1902	18064	0.20318	3084	0.125759417
83	2005	0	49819.03906	2327	17058	0.1934	3012	0.124621794
83	2006	0	56945.22656	2388	19177	0.21759	2994	0.126651316
83	2007	0	63478.65234	2609	20903	0.28264	3568	0.15005806
83	2008	0	60235.90625	2887	22001	0.23471	3766	0.148329678
83	2009	0	77086.00781	3144	22561	0.27493	3972	0.135416504
83	2010	0	84082.69531	3121	27035	0.28083	4640	0.142910384
83	2011	0	92283.66406	3571	25135	0.2614	4290	0.122044298
83	2012	0	112613.5391	3063	23229	0.32098	4296	0.105653144
83	2013	0	114140.4453	3183	23002	0.28312	4371	0.095784134
83	2014	0	143964.5469	3408	28724	0.36311	5148	0.10910507
83	2015	0	146366.8594	3034	27352	0.40558	6245	0.113825434
83	2016	0	148992.7813	3329	25885	0.39248	7676	0.110750475
84	2004	0	11151.35059	679	15244	0.05493	5956	0.165317733
84	2005	0	15560.53027	726	12560	0.07335	5743	0.132934098
84	2006	0	8649.45898	782	12170	0.04458	4777	0.177756466
84	2007	0	10286.44922	760	13300	0.05729	4287	0.171833758
84	2008	0	9808.78516	2185	13398	0.04828	4330	0.310018804
84	2009	0	10613.87598	2104	14424	0.05011	6032	0.294807492
84	2010	0	14215.85645	2349	16212	0.05924	4817	0.252869602
84	2011	0	16519.26953	2999	16605	0.06711	4122	0.265749582
84	2012	0	17115.08008	3158	17084	0.06842	4243	0.2697734
84	2013	0	16853.01367	3280	20448	0.06522	11801	0.319425349
84	2014	0	17020.23047	3345	24170	0.06266	15789	0.343639938
84	2015	0	17394.42578	3257	25503	0.06662	16032	0.346321389
84	2016	0	18614.87109	3082	25699	0.07557	17069	0.33918998
85	2004	1		2973	22521	0.02283	4112	#DIV/0!
85	2005	1		3739	19954	0.02507	1828	#DIV/0!
85	2006	1		4116	20506	0.02996	2336	#DIV/0!
85	2007	1		4532	22045	0.0299	2410	#DIV/0!
85	2008	1		5653	22515	0.04079	3036	#DIV/0!
85	2009	1		6155	22654	0.04199	2799	#DIV/0!
85	2010	1		6154	20515	0.04063	2734	#DIV/0!
85	2011	1		6738	21103	0.04103	2271	#DIV/0!
85	2012	1		7165	23680	0.04962	5841	#DIV/0!

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
85	2013	1		7724	21610	0.04977	5974	#DIV/0!
85	2014	1		8337	24262	0.042	6409	#DIV/0!
85	2015	1		7736	24443	0.04273	7449	#DIV/0!
85	2016	1		7309	25098	0.04276	6488	#DIV/0!
86	2004	1	10389.9707	2951	5859	0.13527	455	0.366227672
86	2005	0	10478.58789	3171	5079	0.13398	270	0.371009821
86	2006	0	9479.75586	3685	5474	0.12205	502	0.465662921
86	2007	0	10238.67383	4179	4527	0.11986	1037	0.473293819
86	2008	0	12514.31641	3305	5264	0.12893	1284	0.331558952
86	2009	0	15757.96484	4435	5784	0.13672	732	0.337979401
86	2010	0	14552.03223	4731	7634	0.11125	1505	0.394976706
86	2011	0	16382.89941	5263	8053	0.12823	720	0.389916438
86	2012	0	16562.8125	4950	7865	0.12968	328	0.363010101
86	2013	0	17457.9375	6242	8058	0.12085	951	0.419908575
86	2014	0	19381.42188	6242	9046	0.12324	1117	0.386684123
86	2015	0	18598.99219	7272	10082	0.11452	835	0.458208421
86	2016	0	20104.78711	6249	11228	0.13153	1109	0.3915329
87	2004	0	20135.49609	7240	27454	0.05971	12918	0.479283554
87	2005	0	20042.0332	7082	29578	0.0556	9284	0.461167143
87	2006	0	22787.51563	8613	34789	0.05515	10499	0.487575451
87	2007	0	21385.98242	8884	28376	0.05549	12336	0.521047323
87	2008	0	23085.20703	9650	27678	0.04716	14035	0.503230708
87	2009	0	24584.68164	10206	34946	0.05616	9556	0.516794665
87	2010	0	26692.09766	11641	37225	0.04362	12728	0.517754357
87	2011	0	35599.05078	13238	39640	0.05523	13203	0.453846901
87	2012	0	34341.98438	13961	34827	0.06259	11626	0.491191571
87	2013	0	45838.16406	15476	37697	0.07104	15257	0.419690722
87	2014	0	50637.51172	16997	40627	0.07801	13206	0.418593087
87	2015	0	46757.05469	16991	43108	0.07266	15543	0.454532087
87	2016	0	45599.65234	17027	42957	0.07417	18652	0.473611934
88	2004	1	46951.65234	13964	15641	0.0987	44078	0.422951362
88	2005	1	57675.51563	13583	18284	0.11434	56235	0.383238922
88	2006	1	51240.74609	13183	14939	0.10023	54106	0.392331921
88	2007	0	57716.81641	14251	16215	0.09374	48972	0.35278504
88	2008	0	56310.85156	15343	11986	0.08494	55921	0.374901462
88	2009	0	63294.71484	19685	11501	0.08792	55837	0.404541786
88	2010	0	61623.76563	19534	6649	0.08688	54255	0.402853335
88	2011	0	65330.5625	19204	8555	0.09441	52841	0.382675357
88	2012	0	81208.23438	21423	7280	0.10369	59717	0.349347811
88	2013	0	98126.01563	22403	6596	0.11246	67098	0.312767486
88	2014	0	101305.6953	26268	6828	0.11584	55295	0.330330178
88	2015	0	108504.3203	29952	10031	0.12532	76615	0.37611845
88	2016	0	131593.4844	27635	6332	0.16128	81415	0.317544872
89	2004	0	14671.5	4410	11253	0.07035	16248	0.432450353

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
89	2005	0	13900.16797	3590	7559	0.07719	15585	0.386792834
89	2006	0	12274.14453	3417	6078	0.06744	14529	0.391614753
89	2007	0	16207.29883	3864	6106	0.08628	15490	0.353378002
89	2008	0	13953.41699	4249	3317	0.07782	15147	0.407489326
89	2009	0	14010.4541	3852	5202	0.07292	14621	0.378110026
89	2010	0	14524.14746	3873	5082	0.06912	12990	0.352663497
89	2011	0	12132.49512	2996	4805	0.06001	16659	0.35310582
89	2012	0	11429.99512	2317	5789	0.0555	18865	0.322423322
89	2013	0	16485.73828	2690	6774	0.07353	19698	0.281242252
89	2014	0	15386.87305	3258	6707	0.07807	23447	0.364734457
89	2015	0	20614.29297	2204	4448	0.06721	38507	0.246964839
89	2016	0	14245.75586	4183	4555	0.04729	26864	0.39792936
90	2004	0	281841.1563	9475	20956	0.40861	2253	0.067266363
90	2005	0	268160.4375	10693	3348	0.38419	33200	0.092237231
90	2006	0	326885	12369	16411	0.39322	35628	0.100438306
90	2007	0	160020.1563	15022	12650	0.21334	56757	0.186409575
90	2008	0	144454.5625	15753	19024	0.18419	53474	0.201491778
90	2009	0	108521.9219	17306	14290	0.13257	58295	0.248139666
90	2010	0	136044.2031	17790	17201	0.15831	60412	0.221081923
90	2011	0	95665.51563	17432	21679	0.09974	57371	0.264635034
90	2012	0	110289.7422	19114	18842	0.11175	60419	0.253617573
90	2013	0	156686.6406	21456	24202	0.11542	90933	0.221747569
90	2014	0	166635.2344	20342	41445	0.15993	155504	0.311098993
90	2015	0	156746.9219	20460	29373	0.1685	142156	0.314919336
90	2016	0	147756.2813	21428	30638	0.16296	93114	0.281508343
91	2004	1	7275.88721	3030	13608	0.06138	4385	0.568234529
91	2005	1	6287.72656	3314	14492	0.04806	11656	0.726919791
91	2006	1	8458.41602	3621	14870	0.04708	4830	0.5377456
91	2007	1	10666.06836	3944	14755	0.05505	7456	0.484406754
91	2008	1	14666.14648	4707	14593	0.10783	5688	0.470055324
91	2009	1	11864.99805	4256	20493	0.05288	7214	0.482186861
91	2010	1	13357.05859	4291	16041	0.08278	7516	0.467247217
91	2011	1	15202.88965	4325	19792	0.12573	3983	0.481107929
91	2012	1	12376.97559	4003	21338	0.07474	5764	0.487082118
91	2013	1	19757.58398	4046	18710	0.13297	5579	0.368248888
91	2014	1	16225.40137	4304	15390	0.12762	4784	0.423940568
91	2015	1	18403.57617	4228	13999	0.10931	4174	0.337678426
91	2016	1	21462.90234	4508	14327	0.22325	4065	0.401344323
92	2004	0	11824.29297	3035	42524	0.03396	14953	0.421751976
92	2005	0	17909.28906	2889	40017	0.04932	15221	0.313431658
92	2006	0	21119.5332	3896	23752	0.05661	13954	0.285543085
92	2007	0	21480.7832	4469	39768	0.05355	15135	0.344915527
92	2008	0	23128.87305	5255	47339	0.05579	15320	0.378347254
92	2009	0	24371.79297	5630	42527	0.06235	12269	0.371188554

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
92	2010	0	21782.45898	6149	48148	0.05282	14872	0.435107735
92	2011	0	20258.76953	6389	42945	0.05014	13724	0.455624101
92	2012	0	23658.61914	6318	51785	0.05598	13731	0.422069675
92	2013	0	24205.96094	5499	49262	0.05744	11467	0.371283494
92	2014	0	25793.45117	7534	55094	0.05834	13867	0.44806663
92	2015	0	21310.32813	6442	56641	0.04736	15283	0.462138386
92	2016	0	21876.54883	7039	63603	0.04723	13515	0.488252659
93	2004	0	1875.92615	598	8906	0.02001	8998	0.509753031
93	2005	0	3584.46851	963	10790	0.03491	10463	0.47564715
93	2006	0	3678.75708	872	9399	0.03437	10793	0.425686993
93	2007	0	5231.91064	1236	12424	0.04466	12218	0.446588614
93	2008	0	11770.27148	1390	8973	0.08305	13617	0.277487185
93	2009	0	14351.82031	1321	11141	0.10705	15751	0.292631075
93	2010	0	18774.53125	1511	12360	0.13467	15243	0.278478112
93	2011	0	18461.10156	1640	14515	0.12107	13792	0.274475955
93	2012	0	16140.83008	1575	14609	0.10182	13150	0.272688663
93	2013	0	18066.72852	1570	15755	0.11054	13025	0.262988465
93	2014	0	20413.67188	1676	15933	0.12163	12444	0.251179432
93	2015	0	23423.59961	1672	13775	0.15082	12967	0.243567536
93	2016	0	27908.60156	2051	15258	0.17268	13126	0.24911134
94	2004	0	21364.81641	5233	43624	0.03249	25338	0.349807611
94	2005	0	30158.86328	5567	43986	0.04552	34356	0.302833955
94	2006	0	18773.52539	4847	40453	0.02752	37421	0.372337765
94	2007	0	27109.02344	5468	48493	0.03489	40364	0.316065267
94	2008	0	31412.86719	6462	64092	0.03954	36576	0.332424693
94	2009	0	31619.75391	6681	56323	0.04289	31686	0.330670063
94	2010	0	33028.04297	6579	41255	0.04696	34555	0.306982694
94	2011	0	34110.24219	6364	81647	0.03729	28966	0.307495875
94	2012	0	35974.37109	7117	46953	0.05433	27658	0.310515939
94	2013	0	32871.83984	6616	48393	0.03889	29195	0.293059268
94	2014	0	40165.9375	7271	57481	0.0489	37506	0.296665908
94	2015	0	39696.99609	8523	63454	0.04001	33987	0.312910689
94	2016	0	45526.00391	8601	54762	0.05583	38740	0.303589498
95	2004	1	2167.67188	351	2629	0.10032	1062	0.332744603
95	2005	1	3413.66162	370	2982	0.132	1018	0.263060637
95	2006	1	4327.56982	395	6730	0.05527	1929	0.201864549
95	2007	1	4637.7124	464	8173	0.06011	2392	0.23698368
95	2008	1	5055.42041	378	7829	0.06771	5346	0.251231183
95	2009	1	5374.62842	718	6622	0.0598	3754	0.249037644
95	2010	1	5693.29688	661	9213	0.06743	3452	0.266102573
95	2011	1	8482.71484	643	5493	0.10738	3256	0.186552024
95	2012	1	2980.90283	708	9299	0.03296	3366	0.377549509
95	2013	1	1601.76013	663	4823	0.01996	3906	0.522694269
95	2014	1	2209.01855	1005	5110	0.02512	2774	0.544606599

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
95	2015	1	2445.09106	1048	6098	0.02889	2186	0.526493586
95	2016	1	4497.96777	1173	6651	0.04739	1553	0.347220709
96	2004	1	862.24664	0	59276	0.00164	5301	0.12282597
96	2005	1	2314.61377	0	53458	0.00389	5104	0.098420818
96	2006	1	3443.01343	0	61576	0.00468	10663	0.098192623
96	2007	1	2447.05054	0	58822	0.00348	1278	0.085469424
96	2008	1	7254.62402	814	61458	0.00831	6166	0.189665989
96	2009	1	7161.68066	3055	59585	0.00888	5756	0.507594272
96	2010	1	4026.44287	2129	62732	0.00422	8601	0.603516637
96	2011	1	6715.26904	2532	64961	0.00705	5129	0.450634886
96	2012	1	5415.20898	2678	63383	0.00631	6321	0.57575474
96	2013	1	4953.17871	2690	61046	0.00527	5104	0.613466761
96	2014	1	4716.50781	2558	58114	0.00521	5694	0.612834707
96	2015	1	4861.1416	2719	52537	0.00504	4377	0.6183417
96	2016	1	5704.11816	2756	46333	0.00594	7694	0.53942087
97	2004	1	1326.74731	0	14615	0.00586	5954	0.090849508
97	2005	1	2074.14673	588	17386	0.0099	6200	0.396067158
97	2006	1	3944.1272	1017	16934	0.02139	5696	0.380579942
97	2007	1	2318.11328	1032	21333	0.01083	4468	0.565729398
97	2008	1	4356.60596	847	22886	0.0205	6007	0.330373349
97	2009	1	2972.67676	644	30898	0.01291	6829	0.380483874
97	2010	1	2756.86646	447	23221	0.0121	8814	0.302743536
97	2011	1	2661.21191	287	22127	0.01159	7754	0.237982097
97	2012	1	3010.97827	468	24890	0.01382	6762	0.300709789
97	2013	1	2207.72144	525	26187	0.00922	7935	0.380303794
97	2014	1	2479.82178	595	27273	0.00933	8942	0.376190724
97	2015	1	3805.70337	663	28549	0.01486	9642	0.323335305
97	2016	1	11460.12305	417	17405	0.04459	8929	0.138849561
98	2004	1		0	0		0	#DIV/0!
98	2005	1		0	0		0	#DIV/0!
98	2006	1		0	0		0	#DIV/0!
98	2007	1		0	0		0	#DIV/0!
98	2008	1		0	0		0	#DIV/0!
98	2009	1		0	0		0	#DIV/0!
98	2010	1		80	1159	0.02379	416	#DIV/0!
98	2011	1		46	1551	0.0227	1075	#DIV/0!
98	2012	1		28	1543	0.03534	202	#DIV/0!
98	2013	1		20	1681	0.01444	599	#DIV/0!
98	2014	1		30	1671	0.0211	1942	#DIV/0!
98	2015	1		17	1962	0.01262	744	#DIV/0!
98	2016	1		0	0		0	#DIV/0!
99	2004	1		0	1424	0.20317	1776	#DIV/0!
99	2005	1		0	1267	0.17639	1932	#DIV/0!
99	2006	1		0	1649	0.20475	1807	#DIV/0!

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
99	2007	1		0	1439	0.20351	1300	#DIV/0!
99	2008	1		0	1315	0.18076	1808	#DIV/0!
99	2009	1		0	1506	0.19537	1547	#DIV/0!
99	2010	1		0	1068	0.19293	1967	#DIV/0!
99	2011	1		0	1067	0.20145	1796	#DIV/0!
99	2012	1		0	800	0.20092	1078	#DIV/0!
99	2013	1		0	1014	0.2348	1456	#DIV/0!
99	2014	1		1283	975	0.19117	2067	#DIV/0!
99	2015	1		1133	1473	0.17043	2389	#DIV/0!
99	2016	1		1119	1139	0.1918	1237	#DIV/0!
100	2004	0	73386.72656	9537	39462	0.09605	15941	0.202467924
100	2005	0	69611.40625	8919	42465	0.08737	16545	0.202189619
100	2006	0	82401.09375	10824	49188	0.09672	16829	0.208846308
100	2007	0	90276.80469	12220	42892	0.10577	16712	0.205194625
100	2008	0	91792	13418	44731	0.09992	19979	0.216618259
100	2009	0	99011.78906	14921	54229	0.10433	12125	0.220617292
100	2010	0	105171.9531	16974	57448	0.09669	13817	0.226910428
100	2011	0	115575.9688	15572	60134	0.10247	9622	0.19657977
100	2012	0	125204.8906	16614	58050	0.11282	15630	0.199086293
100	2013	0	139596.75	16861	62254	0.11911	19912	0.190891208
100	2014	0	146971.9063	17953	66301	0.1135	23331	0.191371485
100	2015	0	167312.0469	16879	76300	0.13953	23829	0.184386002
100	2016	0	189338.4375	23861	72783	0.15494	28050	0.208536975
101	2004	1		33	1130	0.05517	300	#DIV/0!
101	2005	1		15	1163	0.03229	302	#DIV/0!
101	2006	1		31	1232	0.03009	261	#DIV/0!
101	2007	1		29	1256	0.0422	568	#DIV/0!
101	2008	1		39	1272	0.04574	1492	#DIV/0!
101	2009	1		111	1271	0.05446	371	#DIV/0!
101	2010	1		100	1406	0.05928	366	#DIV/0!
101	2011	1		136	1489	0.06226	322	#DIV/0!
101	2012	1		104	1544	0.07518	367	#DIV/0!
101	2013	1		166	1642	0.07544	285	#DIV/0!
101	2014	1		174	1578	0.07785	352	#DIV/0!
101	2015	1		123	1833	0.06861	375	#DIV/0!
101	2016	1		221	1842	0.08974	264	#DIV/0!
102	2004	1		0	816	0.01033	218	#DIV/0!
102	2005	1		0	506	0.00532	600	#DIV/0!
102	2006	1		0	734	0.00146	289	#DIV/0!
102	2007	1		0	1239	0.38806	603	#DIV/0!
102	2008	1		0	1385	0.00028	1496	#DIV/0!
102	2009	1		0	2057	0.00093	683	#DIV/0!
102	2010	1		0	2418	0.00363	583	#DIV/0!
102	2011	1		59	3535	0.02659	611	#DIV/0!

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
102	2012	1		94	3854	0.03064	748	#DIV/0!
102	2013	1		105	4503	0.03388	689	#DIV/0!
102	2014	1		169	5535	0.04348	869	#DIV/0!
102	2015	1		280	6269	0.04831	897	#DIV/0!
102	2016	1		365	5556	0.06067	946	#DIV/0!
103	2004	1		0	5	0	6034	#DIV/0!
103	2005	1		0	55	0	5061	#DIV/0!
103	2006	1		0	48	0.01469	3998	#DIV/0!
103	2007	1		0	45	0.02154	3861	#DIV/0!
103	2008	1		38	43	0.02581	4356	#DIV/0!
103	2009	1		81	41	0.03673	3856	#DIV/0!
103	2010	1		89	35	0.02985	4599	#DIV/0!
103	2011	1		86	39	0.02591	4224	#DIV/0!
103	2012	1		84	35	0.0217	4522	#DIV/0!
103	2013	1		63	25	0.02735	4823	#DIV/0!
103	2014	1		56	24	0.02781	4978	#DIV/0!
103	2015	1		62	31	0.02909	5017	#DIV/0!
103	2016	1		48	30	0.03592	5284	#DIV/0!
104	2004	1		650	686	0.22084	56	#DIV/0!
104	2005	1		735	420	0.2266	44	#DIV/0!
104	2006	1		798	559	0.24211	200	#DIV/0!
104	2007	1		850	528	0.21425	223	#DIV/0!
104	2008	1		873	493	0.22925	300	#DIV/0!
104	2009	1		815	481	0.24571	249	#DIV/0!
104	2010	1		593	609	0.14972	291	#DIV/0!
104	2011	1		598	459	0.14696	312	#DIV/0!
104	2012	1		674	444	0.21911	171	#DIV/0!
104	2013	1		720	491	0.21088	81	#DIV/0!
104	2014	1		781	512	0.18997	89	#DIV/0!
104	2015	1		946	610	0.19281	120	#DIV/0!
104	2016	1		1129	531	0.20732	219	#DIV/0!
105	2004	1		104	11	0.03364	2442	#DIV/0!
105	2005	1		95	30	0.02927	2321	#DIV/0!
105	2006	1		79	26	0.04198	2398	#DIV/0!
105	2007	1		92	26	0.04314	2315	#DIV/0!
105	2008	1		84	28	0.04135	2851	#DIV/0!
105	2009	1		94	28	0.06051	4018	#DIV/0!
105	2010	1		76	26	0.04448	2353	#DIV/0!
105	2011	1		86	54	0.03759	2688	#DIV/0!
105	2012	1		87	18	0.02396	2802	#DIV/0!
105	2013	1		48	19	0.02778	2452	#DIV/0!
105	2014	1		36	31	0.02894	2743	#DIV/0!
105	2015	1		46	41	0.04565	3004	#DIV/0!
105	2016	1		66	38	0.03766	2922	#DIV/0!

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
106	2004	1		3	677	0.01151	240	#DIV/0!
106	2005	1		0	691	0.00547	114	#DIV/0!
106	2006	1		7	716	0.142	180	#DIV/0!
106	2007	1		0	793	0.0601	33	#DIV/0!
106	2008	1		0	858	0.06997	120	#DIV/0!
106	2009	1		0	1256	0.06181	253	#DIV/0!
106	2010	1		0	1386	0.09407	469	#DIV/0!
106	2011	1		2	1851	0.07202	569	#DIV/0!
106	2012	1		3	2464	0.06463	3473	#DIV/0!
106	2013	1		8	1834	0.0601	3102	#DIV/0!
106	2014	1		8	2009	0.04672	3240	#DIV/0!
106	2015	1		15	2509	0.04838	2612	#DIV/0!
106	2016	1		17	2730	0.05786	2361	#DIV/0!
107	2004	1		0	0		0	#DIV/0!
107	2005	1		716	2181	0.07352	1854	#DIV/0!
107	2006	1		869	2260	0.06365	2051	#DIV/0!
107	2007	1		890	2221	0.05933	3787	#DIV/0!
107	2008	1		917	2368	0.06518	72	#DIV/0!
107	2009	1		0	2298	0.05639	3116	#DIV/0!
107	2010	1		0	2683	0.0592	3689	#DIV/0!
107	2011	1		0	2936	0.06701	2626	#DIV/0!
107	2012	1		0	3211	0.07157	2389	#DIV/0!
107	2013	1		0	3428	0.06077	3109	#DIV/0!
107	2014	1		1036	3399	0.06041	3728	#DIV/0!
107	2015	1		1405	2681	0.1381	5529	#DIV/0!
107	2016	1		1629	2956	0.08543	5145	#DIV/0!
108	2004	1		174	720	0.05119	956	#DIV/0!
108	2005	1		242	818	0.06317	800	#DIV/0!
108	2006	1		210	834	0.07545	849	#DIV/0!
108	2007	1		184	822	0.07154	776	#DIV/0!
108	2008	1		211	773	0.07842	694	#DIV/0!
108	2009	1		209	908	0.04609	496	#DIV/0!
108	2010	1		160	969	0.10298	634	#DIV/0!
108	2011	1		156	795	0.06611	624	#DIV/0!
108	2012	1		230	731	0.06872	563	#DIV/0!
108	2013	1		227	756	0.07447	81	#DIV/0!
108	2014	1		127	736	0.10198	199	#DIV/0!
108	2015	1		1	830	0.09038	211	#DIV/0!
108	2016	1		3	791	0.09362	160	#DIV/0!
109	2004	1		69	296	0.08045	105	#DIV/0!
109	2005	1		80	313	0.09965	143	#DIV/0!
109	2006	1		68	316	0.09921	217	#DIV/0!
109	2007	1		79	303	0.10791	301	#DIV/0!
109	2008	1		92	267	0.09202	257	#DIV/0!

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
109	2009	1		91	295	0.09189	420	#DIV/0!
109	2010	1		70	342	0.09605	280	#DIV/0!
109	2011	1		97	402	0.0975	274	#DIV/0!
109	2012	1		95	528	0.07525	251	#DIV/0!
109	2013	1		119	621	0.0929	370	#DIV/0!
109	2014	1		165	672	0.11363	341	#DIV/0!
109	2015	1		161	719	0.07395	417	#DIV/0!
109	2016	1		159	772	0.0808	505	#DIV/0!
110	2004	1		645	2088	0.0589	1417	#DIV/0!
110	2005	1		717	2128	0.0526	1602	#DIV/0!
110	2006	1		590	2146	0.05562	1875	#DIV/0!
110	2007	1		770	2199	0.04852	1923	#DIV/0!
110	2008	1		623	2578	0.04745	1866	#DIV/0!
110	2009	1		0	2510	0.05304	2272	#DIV/0!
110	2010	1		0	2918	0.05338	2174	#DIV/0!
110	2011	1		0	3207	0.06181	2406	#DIV/0!
110	2012	1		0	3182	0.06886	2942	#DIV/0!
110	2013	1		0	3568	0.06214	3094	#DIV/0!
110	2014	1		1097	3286	0.08173	5059	#DIV/0!
110	2015	1		892	1828	0.06974	6280	#DIV/0!
110	2016	1		949	2071	0.06894	5569	#DIV/0!
111	2004	0	11652.8916	3372	24467	0.0889	3085	0.499564657
111	2005	0	13345.64746	3642	26028	0.09991	5203	0.50670372
111	2006	0	17475.94336	4265	27569	0.1135	4636	0.453209726
111	2007	0	17024.64648	4294	26083	0.11127	5421	0.458126992
111	2008	0	21987.49609	4732	29655	0.1199	6107	0.410226966
111	2009	0	18326.64648	5212	29392	0.112	5205	0.495827974
111	2010	0	24912.00586	6716	26945	0.12044	5699	0.427410118
111	2011	0	25980.39453	7077	33604	0.1207	79	0.428882559
111	2012	0	31055.80664	8870	34527	0.14906	9932	0.499006795
111	2013	0	32494.5293	9327	35320	0.15032	11386	0.503095329
111	2014	0	33913.69531	9155	33293	0.14984	11172	0.466408495
111	2015	0	34383.98828	10256	33172	0.16102	10402	0.502335137
111	2016	0	29791.38672	9717	33103	0.15622	12700	0.566349758
112	2004	1		10	301	-0.18308	86	#DIV/0!
112	2005	1		47	298	0.04057	123	#DIV/0!
112	2006	1		40	353	0.02973	145	#DIV/0!
112	2007	1		61	357	0.05877	55	#DIV/0!
112	2008	1		31	374	0.03181	85	#DIV/0!
112	2009	1		36	406	0.03148	230	#DIV/0!
112	2010	1		80	433	0.04229	86	#DIV/0!
112	2011	1		38	466	0.05142	127	#DIV/0!
112	2012	1		60	505	0.08838	119	#DIV/0!
112	2013	1		33	544	0.04242	139	#DIV/0!

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
112	2014	1		32	569	0.03753	103	#DIV/0!
112	2015	1		22	781	0.02995	119	#DIV/0!
112	2016	1		26	1133	0.02448	89	#DIV/0!
113	2004	1		0	294	0.00263	70	#DIV/0!
113	2005	1		0	312	0.00209	79	#DIV/0!
113	2006	1		0	301	0.03565	66	#DIV/0!
113	2007	1		0	304	0.0359	29	#DIV/0!
113	2008	1		0	263	0.02668	49	#DIV/0!
113	2009	1		0	368	0.0432	100	#DIV/0!
113	2010	1		0	431	0.03893	85	#DIV/0!
113	2011	1		0	465	0.03051	311	#DIV/0!
113	2012	1		0	210	0.03578	360	#DIV/0!
113	2013	1		0	477	0.01607	780	#DIV/0!
113	2014	1		0	659	0.02683	583	#DIV/0!
113	2015	1		0	801	0.01608	324	#DIV/0!
113	2016	1		0	778	0.02282	366	#DIV/0!
114	2004	0	10741.96582	3754	24882	0.0308	7760	0.443063558
114	2005	0	16628.98828	3593	31173	0.08681	27976	0.524850012
114	2006	0	18839.32813	3464	29511	0.11582	13750	0.449829684
114	2007	0	12946.17578	3741	34493	0.02591	19913	0.397851809
114	2008	0	18737.95898	4466	33292	0.06778	18842	0.426921765
114	2009	0	15408.99121	4712	42464	0.02972	13515	0.413764652
114	2010	0	15553.70801	4302	37046	0.03811	13704	0.400938638
114	2011	0	18191.81055	4765	46595	0.05302	8809	0.423405909
114	2012	0	18892.50977	4368	50964	0.05483	10285	0.408960099
114	2013	0	50793.41797	4621	44098	0.17813	15993	0.301712514
114	2014	0	96394.97656	4383	35586	0.22434	12718	0.157887059
114	2015	0	54795.71484	4040	30456	0.1042	6436	0.143882536
114	2016	0	86595.35156	4554	30899	0.37985	9899	0.231549615
115	2004	1		0	0		0	#DIV/0!
115	2005	1		0	0		0	#DIV/0!
115	2006	1		0	62	0.02381	13	#DIV/0!
115	2007	1		0	63	0.01441	14	#DIV/0!
115	2008	1		0	70	0.01247	19	#DIV/0!
115	2009	1		0	63	0.01736	18	#DIV/0!
115	2010	1		0	64	0.01149	24	#DIV/0!
115	2011	1		0	70	0.01279	124	#DIV/0!
115	2012	1		0	55	0.02642	42	#DIV/0!
115	2013	1		0	58	0.01161	47	#DIV/0!
115	2014	1		0	68	0.01396	24	#DIV/0!
115	2015	1		0	60	0.00864	20	#DIV/0!
115	2016	1		0	61	0.00114	27	#DIV/0!
116	2004	1	26786.35547	2559	6763	0.08822	2132	0.124829109
116	2005	1	27850.53906	2561	7591	0.07373	1900	0.117081089

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
116	2006	1	32742.51367	2697	9072	0.07953	2221	0.109800131
116	2007	1	36019.46094	2963	8432	0.08061	2511	0.106751049
116	2008	1	40233.13281	3068	7264	0.08317	2188	0.095794749
116	2009	1	45365.39453	3229	9849	0.09377	1301	0.094224586
116	2010	1	50863.89063	3705	10825	0.09802	1879	0.097323386
116	2011	1	52443.33203	3885	10891	0.09631	1829	0.097439713
116	2012	1	55198.02344	4561	9878	0.10088	1693	0.103776949
116	2013	1	49321.37109	4864	10602	0.08771	2311	0.121582168
116	2014	1	61661.41797	4817	10909	0.10478	2391	0.100720584
116	2015	1	48804.29688	4827	12256	0.0852	2927	0.125410916
116	2016	1	69887.10156	6388	11466	0.11999	3635	0.117331651
117	2004	1		40	253	0.03951	50	#DIV/0!
117	2005	1		40	284	0.04852	40	#DIV/0!
117	2006	1		44	324	0.04895	36	#DIV/0!
117	2007	1		57	280	0.0355	26	#DIV/0!
117	2008	1		66	284	0.04009	33	#DIV/0!
117	2009	1		81	256	0.06562	54	#DIV/0!
117	2010	1		82	215	0.04038	46	#DIV/0!
117	2011	1		72	211	0.0394	72	#DIV/0!
117	2012	1		98	193	0.06884	70	#DIV/0!
117	2013	1		114	194	0.05481	76	#DIV/0!
117	2014	1		129	161	0.05892	57	#DIV/0!
117	2015	1		81	140	0.04162	89	#DIV/0!
117	2016	1		103	156	0.05889	70	#DIV/0!
118	2004	0	205247.1875	4680	42830	0.38437	60345	0.216019402
118	2005	0	327595.6875	6639	12388	0.5116	75103	0.156898877
118	2006	0	334185.1563	8895	13740	0.45791	93264	0.173236903
118	2007	0	346362.2813	10665	16599	0.47158	77001	0.158229954
118	2008	0	354437.1875	12266	13367	0.42611	59212	0.121862601
118	2009	0	329514.2188	13521	17219	0.45406	60784	0.148518757
118	2010	0	331020.5313	14444	27312	0.4037	56895	0.146330397
118	2011	0	189852.625	14760	20632	0.25468	72888	0.203198
118	2012	0	174161.0938	13273	19253	0.23244	86522	0.217381162
118	2013	0	170996.4375	14326	17163	0.24845	80588	0.225807254
118	2014	0	153381.9219	13965	18599	0.19423	77894	0.213237877
118	2015	0	201465.7031	14188	21100	0.27269	76778	0.202904768
118	2016	0	241045.6719	14070	22282	0.30501	86346	0.195824409
119	2004	1		0	67	0.00535	10	#DIV/0!
119	2005	1		0	64	0.00518	6	#DIV/0!
119	2006	1		0	67	0.0037	429	#DIV/0!
119	2007	1		0	56	0.0077	575	#DIV/0!
119	2008	1		0	67	0.0105	202	#DIV/0!
119	2009	1		0	89	0.00957	4	#DIV/0!
119	2010	1		0	108	0.0134	66	#DIV/0!

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
119	2011	1		0	120	0.0157	93	#DIV/0!
119	2012	1		0	126	0.00685	73	#DIV/0!
119	2013	1		1	207	0.00377	13	#DIV/0!
119	2014	1		1	219	0.04752	15	#DIV/0!
119	2015	1		12	225	0.0261	12	#DIV/0!
119	2016	1		0	0		0	#DIV/0!
120	2004	1		0	45	0	13	#DIV/0!
120	2005	1		0	120	0	16	#DIV/0!
120	2006	1		0	65	0	7	#DIV/0!
120	2007	1		0	84	0	23	#DIV/0!
120	2008	1		0	95	0	30	#DIV/0!
120	2009	1		0	71	0	30	#DIV/0!
120	2010	1		0	40	0	60	#DIV/0!
120	2011	1		0	60	0	33	#DIV/0!
120	2012	1		0	74	0	85	#DIV/0!
120	2013	1		0	60	0	74	#DIV/0!
120	2014	1		0	61	0	62	#DIV/0!
120	2015	1		0	76	0	135	#DIV/0!
120	2016	1		0	10	0	253	#DIV/0!
121	2004	0	35099.85156	7553	55812	0.07822	33021	0.413150387
121	2005	0	44076.71484	7285	56800	0.11579	37673	0.413461592
121	2006	0	42236.55859	7722	68087	0.05856	35044	0.325816113
121	2007	0	51212.57813	8044	72109	0.10245	30464	0.362266547
121	2008	0	43049.43359	7085	59572	0.07465	41872	0.340487513
121	2009	0	32957.67578	8433	53481	0.05621	39634	0.414683191
121	2010	0	48317.80859	7545	79123	0.0927	32695	0.370681724
121	2011	0	31504.5293	7976	39875	0.05479	43090	0.397455624
121	2012	0	37294.76172	8285	61410	0.06868	34789	0.399303994
121	2013	0	40072.24219	8431	40321	0.06976	32802	0.337691622
121	2014	0	34242.18359	9377	41059	0.05401	26289	0.380071132
121	2015	0	39076.76172	10223	47169	0.06387	22222	0.375031157
121	2016	0	44539.28906	11643	52962	0.08255	16782	0.390674561
122	2004	1	3467.83276	1005	12916	0.01491	5904	0.370723241
122	2005	1	5946.18652	1082	13061	0.02656	4671	0.261169392
122	2006	1	6601.67871	1278	13242	0.02329	5292	0.258973048
122	2007	1	8787.91992	665	18585	0.02779	8555	0.161496761
122	2008	1	11403.66895	1914	20812	0.03034	9493	0.248468604
122	2009	1	14522.64355	3076	22653	0.03779	14806	0.309280855
122	2010	1	14255.36719	3048	24284	0.03496	12275	0.303471849
122	2011	1	11317.74707	3425	23753	0.02558	11612	0.382552877
122	2012	1	22838.64844	7325	23812	0.05105	13221	0.40350613
122	2013	1	23249.98828	7676	26791	0.04997	11611	0.412686141
122	2014	1	26024.30078	8362	29051	0.05514	7501	0.398761041
122	2015	1	23733.87305	8758	29598	0.04978	8265	0.448423235

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
122	2016	1	24897.38281	9088	29862	0.05	13442	0.45198325
123	2004	1		813	1675	0.09945	240	#DIV/0!
123	2005	1		797	1862	0.08214	167	#DIV/0!
123	2006	1		576	1721	0.05752	203	#DIV/0!
123	2007	1		467	1856	0.0746	350	#DIV/0!
123	2008	1		499	2167	0.09467	497	#DIV/0!
123	2009	1		509	2620	0.0546	517	#DIV/0!
123	2010	1		573	2728	0.05704	426	#DIV/0!
123	2011	1		600	3172	0.05452	543	#DIV/0!
123	2012	1		630	2876	0.05886	244	#DIV/0!
123	2013	1		857	2730	0.064	414	#DIV/0!
123	2014	1		857	2933	0.09301	404	#DIV/0!
123	2015	1		775	3142	0.06578	297	#DIV/0!
123	2016	1		779	3880	0.04403	376	#DIV/0!
124	2004	1		0	390	0.01015	849	#DIV/0!
124	2005	1		75	535	-0.0375	283	#DIV/0!
124	2006	1		90	472	0.01032	346	#DIV/0!
124	2007	1		53	658	0.11111	657	#DIV/0!
124	2008	1		21	672	0.02106	967	#DIV/0!
124	2009	1		54	704	0.02266	920	#DIV/0!
124	2010	1		52	820	0.02192	1418	#DIV/0!
124	2011	1		23	1197	0.02251	2014	#DIV/0!
124	2012	1		18	1295	0.01718	-36	#DIV/0!
124	2013	1		13	1648	0.00988	2230	#DIV/0!
124	2014	1		38	1703	0.01724	1476	#DIV/0!
124	2015	1		84	1458	0.05106	2118	#DIV/0!
124	2016	1		56	1372	0.04876	1519	#DIV/0!
125	2004	1		31	524	0.01771	540	#DIV/0!
125	2005	1		11	529	0.00729	670	#DIV/0!
125	2006	1		0	649	0.01442	788	#DIV/0!
125	2007	1		6	620	0.03142	798	#DIV/0!
125	2008	1		0	744	0.02632	812	#DIV/0!
125	2009	1		0	515	0.02237	818	#DIV/0!
125	2010	1		0	431	0.02454	960	#DIV/0!
125	2011	1		0	600	0.04058	1001	#DIV/0!
125	2012	1		13	629	0.0521	874	#DIV/0!
125	2013	1		1	530	0.07281	1021	#DIV/0!
125	2014	1		4	533	0.02824	980	#DIV/0!
125	2015	1		8	538	0.02527	965	#DIV/0!
125	2016	1		3	747	0.02146	1146	#DIV/0!
126	2004	1		0	782	0.09542	985	#DIV/0!
126	2005	1		0	892	0.11182	792	#DIV/0!
126	2006	1		0	821	0.08837	846	#DIV/0!
126	2007	1		0	814	0.10062	788	#DIV/0!

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
126	2008	1		1	722	0.07936	700	#DIV/0!
126	2009	1		2	881	0.07846	584	#DIV/0!
126	2010	1		1	911	0.08367	615	#DIV/0!
126	2011	1		4	810	0.11676	863	#DIV/0!
126	2012	1		1	928	0.14025	746	#DIV/0!
126	2013	1		0	1173	0.12591	77	#DIV/0!
126	2014	1		0	1177	0.09497	590	#DIV/0!
126	2015	1		1	4211	0.04047	838	#DIV/0!
126	2016	1		0	3937	0.04767	876	#DIV/0!
127	2004	0	2664.58472	970	4384	0.07275	5034	0.621169778
127	2005	0	3468.25293	1030	7472	0.0849	8726	0.693493309
127	2006	0	2488.90381	931	10149	0.05918	2011	0.663195096
127	2007	0	2788.47974	1172	9759	0.06419	1622	0.682288045
127	2008	0	2938.67651	1125	10110	0.05674	1855	0.613845755
127	2009	0	3796.09058	1109	12001	0.07317	2411	0.569935304
127	2010	0	4382.0542	1065	8793	0.07374	2457	0.4323486
127	2011	0	6464.66992	1136	13514	0.09998	2304	0.420359225
127	2012	0	6587.77734	1278	16401	0.10165	2698	0.488694925
127	2013	0	6385.53271	1195	16918	0.09475	3030	0.483134789
127	2014	0	7519.13086	1327	18028	0.10989	2599	0.477941014
127	2015	0	7266.75684	1484	14218	0.11397	2364	0.464285597
127	2016	0	8125.60107	1749	12896	0.12952	2682	0.463554945
128	2004	0	16936.89063	3893	30868	0.0582	12502	0.378885011
128	2005	0	18115.80664	4119	36259	0.05735	11684	0.379145747
128	2006	0	18264.44336	3950	42489	0.06098	8671	0.387076499
128	2007	0	17413.70313	3853	28988	0.05794	9428	0.349082731
128	2008	0	18867.625	3786	39405	0.05739	12215	0.357674683
128	2009	0	16929.45117	3180	41428	0.05023	9989	0.340393546
128	2010	0	20364.69727	3610	40563	0.05638	9903	0.316983503
128	2011	0	20406.95117	3239	49919	0.0517	15677	0.324904644
128	2012	0	22149.02148	3302	33216	0.05911	15151	0.27816007
128	2013	0	21321.28711	3285	42272	0.05412	12449	0.292970142
128	2014	0	21845.04688	2699	39419	0.05449	14928	0.259114483
128	2015	0	21515.16211	3322	38532	0.05359	16256	0.290868778
128	2016	0	20874.16406	3449	40102	0.05568	13436	0.308036088
129	2004	1	15257.69922	3875	30781	0.05824	10854	0.412894651
129	2005	1	15395.49902	3970	24559	0.05268	18186	0.404131532
129	2006	1	15169.00586	3981	34054	0.05231	12097	0.421593799
129	2007	1	16452.38477	4190	34263	0.04723	11567	0.386238894
129	2008	1	18280.70117	4738	25875	0.0524	14361	0.374513337
129	2009	1	20524.52148	4841	28560	0.05997	17295	0.369846593
129	2010	1	24094.48047	4933	38360	0.06542	14893	0.349325285
129	2011	1	30023.76953	5230	41828	0.08291	14117	0.328686241
129	2012	1	31682.42578	4878	31304	0.08297	18680	0.284863683

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
129	2013	1	31104.00586	4307	34226	0.08595	13611	0.270659355
129	2014	1	30314.55469	4018	36046	0.08286	14285	0.270115354
129	2015	1	30473.98828	4805	36727	0.08312	15813	0.300982094
129	2016	1	31814.63477	4363	43025	0.09741	15121	0.315169479
130	2004	1		16331	44417	0.14789	83897	#DIV/0!
130	2005	1		17953	40572	0.16344	64583	#DIV/0!
130	2006	1		36775	33331	0.14556	64001	#DIV/0!
130	2007	1		19570	37228	0.15623	59927	#DIV/0!
130	2008	1		21433	27244	0.15756	58923	#DIV/0!
130	2009	1		21211	35363	0.15592	79803	#DIV/0!
130	2010	1		22595	43366	0.16008	74519	#DIV/0!
130	2011	1		23454	50223	0.16386	79117	#DIV/0!
130	2012	1		24070	50748	0.17299	96111	#DIV/0!
130	2013	1		27239	56927	0.17901	96215	#DIV/0!
130	2014	1		26238	58679	0.17398	101833	#DIV/0!
130	2015	1		27957	67814	0.16938	92715	#DIV/0!
130	2016	1		29775	70340	0.17542	82263	#DIV/0!
131	2004	1		0	564	0	321	#DIV/0!
131	2005	1		145	800	0.00862	224	#DIV/0!
131	2006	1		0	749	0.01532	257	#DIV/0!
131	2007	1		7	1373	0.00963	106	#DIV/0!
131	2008	1		0	3461	0.00623	591	#DIV/0!
131	2009	1		0	3838	0.0101	611	#DIV/0!
131	2010	1		64	3651	0.00961	654	#DIV/0!
131	2011	1		0	3247	0.00581	362	#DIV/0!
131	2012	1		0	3187	0.01531	290	#DIV/0!
131	2013	1		0	3163	0.01217	376	#DIV/0!
131	2014	1		113	2887	0.00959	462	#DIV/0!
131	2015	1		130	3607	0.01023	1347	#DIV/0!
131	2016	1		168	3114	0.02842	1620	#DIV/0!
132	2004	1		2369	17279	0.29868	6589	#DIV/0!
132	2005	1		2419	15921	0.30723	4783	#DIV/0!
132	2006	1		2469	16668	0.28254	5862	#DIV/0!
132	2007	1		2852	20957	0.2318	6578	#DIV/0!
132	2008	1		3059	23599	0.24914	6402	#DIV/0!
132	2009	1		3278	24247	0.28285	5670	#DIV/0!
132	2010	1		3248	32756	0.29883	5720	#DIV/0!
132	2011	1		3785	26169	0.36284	6571	#DIV/0!
132	2012	1		3632	26584	0.3646	5459	#DIV/0!
132	2013	1		3782	24559	0.43405	7154	#DIV/0!
132	2014	1		3735	30337	0.42161	12498	#DIV/0!
132	2015	1		3891	31214	0.42128	14654	#DIV/0!
132	2016	1		3547	27468	0.42971	15971	#DIV/0!
133	2004	1		0	495	0.00773	501	#DIV/0!

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
133	2005	1		0	541	0.01471	308	#DIV/0!
133	2006	1		0	667	0.08037	658	#DIV/0!
133	2007	1		0	723	0.14735	612	#DIV/0!
133	2008	1		0	1178	0.24525	887	#DIV/0!
133	2009	1		0	676	0.32717	1174	#DIV/0!
133	2010	1		136	3604	0.38553	1573	#DIV/0!
133	2011	1		183	4262	0.32843	4729	#DIV/0!
133	2012	1		-195	3576	0.37697	2281	#DIV/0!
133	2013	1		1484	5194	0.41386	1812	#DIV/0!
133	2014	1		3492	6767	0.31992	4145	#DIV/0!
133	2015	1		4155	6819	0.29687	3487	#DIV/0!
133	2016	1		4830	8056	0.31453	3290	#DIV/0!
134	2004	1		54	704	0.02703	2428	#DIV/0!
134	2005	1		44	921	0.02315	2742	#DIV/0!
134	2006	1		33	1219	0.03436	2433	#DIV/0!
134	2007	1		44	2748	0.02557	923	#DIV/0!
134	2008	1		75	3296	0.01912	1351	#DIV/0!
134	2009	1		64	3683	0.03258	1005	#DIV/0!
134	2010	1		57	3744	0.02445	1247	#DIV/0!
134	2011	1		99	3533	0.02337	1121	#DIV/0!
134	2012	1		108	3711	0.01948	1024	#DIV/0!
134	2013	1		97	4214	0.02403	1685	#DIV/0!
134	2014	1		131	4078	0.02119	2571	#DIV/0!
134	2015	1		88	4971	0.02249	1975	#DIV/0!
134	2016	1		115	4834	0.02533	2473	#DIV/0!
135	2004	1		0	0		0	#DIV/0!
135	2005	1		0	0		0	#DIV/0!
135	2006	1		3297	29746	0.08328	10522	#DIV/0!
135	2007	1		3926	28347	0.06061	11159	#DIV/0!
135	2008	1		3545	23912	0.08242	14700	#DIV/0!
135	2009	1		3742	21076	0.13157	11033	#DIV/0!
135	2010	1		3934	22822	0.08928	13760	#DIV/0!
135	2011	1		4115	25251	0.09322	17865	#DIV/0!
135	2012	1		4024	23258	0.13105	16734	#DIV/0!
135	2013	1		3919	29040	0.06749	17053	#DIV/0!
135	2014	1		3902	36522	0.08289	28069	#DIV/0!
135	2015	1		1062	19109	0.09393	11219	#DIV/0!
135	2016	1		5463	63752	0.09485	53956	#DIV/0!
136	2004	1		0	0		0	#DIV/0!
136	2005	1		0	0		0	#DIV/0!
136	2006	1		0	0		0	#DIV/0!
136	2007	1		0	0		0	#DIV/0!
136	2008	1		0	0		0	#DIV/0!
136	2009	1		5971	16708	0.12645	1350	#DIV/0!

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
136	2010	1		6202	18068	0.12656	1135	#DIV/0!
136	2011	1		6140	17445	0.12114	794	#DIV/0!
136	2012	1		6226	18694	0.12545	1050	#DIV/0!
136	2013	1		6228	20664	0.12039	1218	#DIV/0!
136	2014	1		6339	20846	0.12412	1209	#DIV/0!
136	2015	1		6528	22271	0.1265	1778	#DIV/0!
136	2016	1		6517	22525	0.12487	1353	#DIV/0!
137	2004	1		0	0		0	#DIV/0!
137	2005	1		0	0		0	#DIV/0!
137	2006	1		0	0		0	#DIV/0!
137	2007	1		0	0		0	#DIV/0!
137	2008	1		1909	13002	0.95409	10625	#DIV/0!
137	2009	1		1996	14207	0.06309	11084	#DIV/0!
137	2010	1		2208	16216	0.17597	13891	#DIV/0!
137	2011	1		2230	17022	0.14813	14465	#DIV/0!
137	2012	1		2218	15936	0.10595	16835	#DIV/0!
137	2013	1		2247	20274	0.28001	18926	#DIV/0!
137	2014	1		2369	21049	0.25527	13531	#DIV/0!
137	2015	1		2133	20060	0.11453	11337	#DIV/0!
137	2016	1		2194	21676	0.13022	16199	#DIV/0!
138	2004	1		0	0		0	#DIV/0!
138	2005	1		0	0		0	#DIV/0!
138	2006	1		0	0		0	#DIV/0!
138	2007	1		0	0		0	#DIV/0!
138	2008	1		384	3473	0.074	1425	#DIV/0!
138	2009	1		1098	8362	0.11038	2700	#DIV/0!
138	2010	1		992	7876	0.09966	2669	#DIV/0!
138	2011	1		837	9644	0.10546	1910	#DIV/0!
138	2012	1		926	11452	0.1214	1722	#DIV/0!
138	2013	1		863	13078	0.10064	2088	#DIV/0!
138	2014	1		1024	12669	0.11043	2050	#DIV/0!
138	2015	1		1453	11471	0.13729	1895	#DIV/0!
138	2016	1		1527	11260	0.13466	1799	#DIV/0!
139	2004	1		0	0		0	#DIV/0!
139	2005	1		0	0		0	#DIV/0!
139	2006	1		0	0		0	#DIV/0!
139	2007	1		0	0		0	#DIV/0!
139	2008	1		0	0		0	#DIV/0!
139	2009	1		0	0		0	#DIV/0!
139	2010	1		6550	35868	0.0707	18686	#DIV/0!
139	2011	1		7397	40268	0.08301	12849	#DIV/0!
139	2012	1		8615	40263	0.09263	11495	#DIV/0!
139	2013	1		9777	41013	0.08672	12840	#DIV/0!
139	2014	1		10631	47517	0.08252	16173	#DIV/0!

UTILITY	Year	Exclude	Tx O&M	Tx Salaries	A&G Salaries	Allocation	Outsourced Expenses	% Labour in O&M
139	2015	1		11659	49932	0.08138	16023	#DIV/0!
139	2016	1		12281	49606	0.08556	15895	#DIV/0!
140	2004	1		0	0		0	#DIV/0!
140	2005	1		0	0		0	#DIV/0!
140	2006	1		0	0		0	#DIV/0!
140	2007	1		0	0		0	#DIV/0!
140	2008	1		0	0		0	#DIV/0!
140	2009	1		0	0		0	#DIV/0!
140	2010	1		0	0		0	#DIV/0!
140	2011	1		0	0		0	#DIV/0!
140	2012	1		0	0		0	#DIV/0!
140	2013	1		0	0		0	#DIV/0!
140	2014	1		0	0		0	#DIV/0!
140	2015	1		0	0		0	#DIV/0!
140	2016	1		16	39	1	42	#DIV/0!

OEB Staff Interrogatory # 68

Reference:

Exhibit D, Tab 1, Attachment 1, Section 6 (Productivity Results)

Interrogatory:

With respect to PSE's TFP analysis of Hydro One Networks Transmission and U.S. electricity transmitters:

a) Please confirm that most U.S. power transmitters are regulated by the FERC using formula rate plans.

b) How do the performance incentives generated by formula rate plans differ from those of an IR mechanism such as Hydro One SSM has proposed? Can weak performance incentives be another cause of the negative productivity growth that you have reported?

c) Please provide all information in your possession about the importance of aging capital infrastructure as a reason for negative power transmission productivity growth. Has this been more important than system growth?

d) Please prepare tables decomposing the TFP growth rates of Hydro One Networks Transmission and the U.S. sample into O&M and capital productivity.

e) Please discuss the impact of conservation and other demand management programs on peak demand in Ontario. In your opinion, have conservation and other demand management efforts been more (or less) effective in containing maximum demand growth in Ontario versus the U.S.?

Response:

a) Confirmed.

b) PSE believes that the incentives generated by Hydro One SSM's plan are greater than those generally generated by formula rate plans. FERC has used formula rate plans for transmission utilities throughout the sample period of the TFP study. While incentives are weaker under formula rates, those weaker incentives have been consistent throughout the sample period for the U.S. sample.

c) PSE mentioned aging infrastructure as a possible source of negative productivity growth. However, we mentioned it as a possibility, and not a fact, because we only have our experience within the industry and no empirical evidence. We are aware of no empirical evidence for the impact or magnitude of that impact. We have no evidence to compare the impacts of aging infrastructure against system growth; therefore, we do not know how they compare.

d) The following table provide the partial factor productivity (PFP) for O&M and capital. For the output index, we used the output quantity index that uses the output weights from the total cost model. We note that if the research objective was to calculate PFPs, ideally a new econometric model would be produced to provide specific output weightings for O&M and capital.

	Industry			**HON**		
	Capital PFP	OM&A PFP	TFP	Capital PFP	OM&A PFP	TFP
2004	1.000	1.000	1.000	1.000	1.000	1.000
2005	1.011	0.816	0.945	1.009	1.092	1.026
2006	1.011	0.864	0.963	1.030	1.001	1.024
2007	1.011	0.940	0.987	1.027	0.906	1.000
2008	0.999	0.914	0.971	1.036	1.072	1.042
2009	0.981	0.945	0.967	1.022	0.930	1.003
2010	0.959	0.905	0.940	1.001	0.956	0.992
2011	0.944	0.971	0.946	0.987	1.014	0.992
2012	0.911	0.977	0.922	0.960	1.029	0.971
2013	0.876	0.970	0.893	0.955	0.993	0.962
2014	0.843	0.991	0.871	0.939	1.116	0.967
2015	0.817	0.943	0.841	0.943	1.023	0.956
2016	0.793	0.905	0.814	0.933	1.137	0.964
2017	NA	NA	NA	0.917	1.202	0.958
2018	NA	NA	NA	0.907	1.256	0.954
2019	NA	NA	NA	0.901	1.222	0.945
2020	NA	NA	NA	0.887	1.224	0.933
2021	NA	NA	NA	0.872	1.225	0.920
2022	NA	NA	NA	0.857	1.227	0.906
2004-2016	-1.93%	-0.84%	-1.71%	-0.58%	1.07%	-0.31%
2010-2016	-3.17%	0.00%	-2.40%	-1.17%	2.90%	-0.47%
2019-2022	NA	NA	NA	-1.67%	0.12%	-1.43%

e) It is PSE’s understanding that CDM programs have reduced the peak demands in Ontario. PSE has no opinion on the comparative effectiveness of these programs relative to the U.S.

OEB Staff Interrogatory # 69

Reference:

Exhibit D, Tab 1, Schedule 1, Attachment 1

Interrogatory:

PEG would like to calculate an X factor using the Kahn Method and Hydro One Networks Transmission data. Please submit the following data required for this exercise for the years 2002-2017:

a) Total net plant value

b) Allowed and actual rate of return

c) Total depreciation and amortization expenses

d) Total OM&A expenses

e) Total taxes

f) km of transmission route, percentage km (and/or plant value) underground, ratcheted maximum peak demand, substation capacity, number of substations, MWh delivered (sales plus wheeling delivered), and number of customers

Response:

(a)-(e) Please refer to the table below:

Amounts are in CAD millions of dollars

Year	(a) Total Net Book Value	(b) Allowed ROE (%)[1]	(b) Actual Regulatory ROE (%)[2]	(c) Total Depreciation and Amortization Expense	(d) Total OM&A Expenses	(e) Total Taxes[3]
2002	5,774	N/A	N/A	183	444	134
2003	5,827	N/A	N/A	228	367	146
2004	5,937	N/A	N/A	241	358	131
2005	6,069	N/A	N/A	246	342	148
2006	6,166	N/A	N/A	241	375	114
2007	6,435	8.35	N/A	242	413	116
2008	6,620	8.35	N/A	253	374	39
2009	7,009	8.01	N/A	242	417	5
2010	7,617	8.39	N/A	272	421	40
2011	8,125	9.66	N/A	299	415	77
2012	8,994	9.42	12.41	320	415	80
2013	9,375	8.93	13.22	326	388	79
2014	9,446	9.36	13.12	342	400	87
2015	9,743	9.30	10.93	366	442	64
2016	10,285	9.19	10.02	380	408	76
2017	10,775	8.78	9.03	402	385	67

Amounts are in CAD millions of dollars unless otherwise noted.

f) Please refer to the table below:

Year	(f) km of transmission route	(f) percentage km (and/or plant value) underground	(f) ratcheted maximum peak demand (MW)	(f) substation capacity (MVA)	(f) number of substations	(f) kWh delivered (sales plus wheeling delivered)[4]	(f) number of customer delivery points
2002	20,399	1%	25,414	99,580	240	152,959,761,000	598
2003	20,367	1%	24,753	100,083	242	151,719,470,000	603
2004	20,336	1%	24,979	100,307	243	153,436,836,000	602
2005	20,277	1%	26,160	101,981	243	156,971,220,000	605
2006	20,355	1%	27,005	100,813	244	151,056,770,000	601
2007	20,349	1%	25,737	103,294	246	152,205,265,000	606

[1] Hydro One Transmission did not have rate applications between 2002 and 2006. As such allowed ROE is not provided for those years.
[2] Hydro One Transmission did not start calculating and reporting actual achieved regulatory ROE prior to 2012
[3] Income tax expense as per Hydro One Transmission financial statements.
[4] Annual Kilowatt Hours Transmitted

Year	(f) km of transmission route	(f) percentage km (and/or plant value) underground	(f) ratcheted maximum peak demand (MW)	(f) substation capacity (MVA)	(f) number of substations	(f) kWh delivered (sales plus wheeling delivered)[4]	(f) number of customer delivery points
2008	20,386	1%	24,195	103,553	247	148,675,912,000	618
2009	20,384	1%	24,380	104,185	248	139,165,604,000	620
2010	20,395	1%	25,075	103,877	248	142,194,790,000	623
2011	20,414	1%	25,450	104,636	250	141,470,733,000	631
2012	20,609	1%	24,636	106,643	252	141,287,663,000	641
2013	20,622	1%	24,927	106,081	252	140,736,784,000	649
2014	20,611	1%	22,774	106,308	253	139,803,825,000	664
2015	20,674	1%	22,516	106,036	254	137,011,780,000	669
2016	20,672	1%	23,213	106,641	254	136,989,747,000	669
2017	20,689	1%	22,178	108,567	256	135,104,305,239	667

It is unclear from the interrogatory as to the precise definition for number of “customers” that is being requested by OEB staff. For the purpose of transmission cost allocation and rate design, Hydro One uses customer delivery points (e.g. Ontario Power Generation is one customer from the perspective of the point of contact with Hydro One but represents more than 30 points of connection to Hydro One’s transmission system). Similarly, the IESO uses customer delivery points for the purpose of transmission settlements.

Hydro One believes that customer delivery points is a consistent and appropriate measure of transmission “customers” as it reflects how transmitted power is delivered to customers and is less susceptible to year-over-year variations due to factors such as distributor consolidations.

OEB Staff Interrogatory # 70

Reference:

Exhibit D, Tab 1, Schedule 1, Attachment 1
Exhibit B, Tab 1, Schedule 1, Page 9

Table 1-2 HOSSM Electrical Assets Overview

System Components	Counts / Units
Transmission Lines (560 circuit km of overhead assets): Conductor and ancillary equipment supported by a mix of Wooden, Composite and Steel Structures.	
230 kV Lines	318 cct. km
115 kV Lines	232 cct. km
44 kV Lines*	11 cct. km
Transmission Stations (15 stations): 230/115 and 115/44 kV stations of various configurations, equipped with 1 to 3 power transformers and other standard operating and safety equipment.	
Station Transformers	20
Circuit Breakers	105
Switches	156
Protection Relays	338
Circuit Switchers	5
Shunt Reactors	3
Capacitor Banks	2

**HOSSM's 44 kV lines and equipment have been deemed by the OEB as serving transmission function under Section 84 of the Ontario Energy Board Act, 1998.*

Interrogatory:

To better understand the Hydro One Networks transmission data that PSE has used in its TFP and total cost benchmarking analyses:

a) Please provide an analogous table for the entirety of Hydro One Networks Transmission.

b) Please also provide data on the length of the Company's 44 kV distribution lines.

c) Do any Hydro One Networks transmission lines operate with direct current?

d) Please provide maps of Hydro One Networks' transmission and distribution systems.

Response:

a) HOSSM has obtained high level statistics from Hydro One's readily available asset listing.

Hydro One Electrical Assets Overview

System Component	Count/Units
Transmission Lines - 29,182 cct km Breakdown by voltage is not readily available	
Transmission Stations - 293	
Station Transformers	717
Circuit Breakers	4,524
Switches	14,331
Protection Relays	11,263
Shunt Reactors	69
Capacitor Banks	350

Please note that a simple comparison of the count of components between the systems is not instructive given that the systems include different component types.

b) According to Hydro One *Distribution System Plan* EB-2017-0040 Exhibit B1-1-1 DSP section 2.2 Table 35, Hydro One Network has 9830km of 44kV lines.

c) Hydro One does not own any direct current

d) Please reference Ex-2016-0160 B1-Tab1, Schedules 2 and 3.

OEB Staff Interrogatory # 71

Reference:

Exhibit D, Tab 1, Schedule 1, Attachment 1

Interrogatory:

Please provide answers to the following general background questions about Hydro One Transmission:

a) How does the scope of transmission services provided by Hydro One Networks differ from those that are typically provided by U.S. transmitters?

b) Does Hydro One Networks or do the generators typically own the generation substations in Ontario? How does this differ from U.S. practice?

c) Does Hydro One Networks Transmission typically own and operate the substation when power is delivered directly to power distributors or large industrial customers? How does this differ from U.S. practice?

d) What rules does Hydro One Networks use to categorize its assets as transmission or distribution facilities?

e) Are lines of sub transmission voltage typically classified as transmission or distribution? Are these lines extensive?

f) What customer contributions are expected from generators, LDCs, and large industrial customers? How do these policies differ from those of U.S. transmitters?

g) Please provide data on the average age of transmission assets and the share of transmission assets that are close to replacement age.

h) On balance, does Hydro One Networks consider that its transmission system is older or younger than it was in 2004?

i) Does Hydro One Networks Transmission have in place an asset management program to contain the cost of capital expenditures? If so, when did it start?

j) Does Hydro One Networks participate in transmission reliability benchmarking studies undertaken by the Canadian Electricity Association or other organizations? If so, how does the Hydro One Networks' transmission reliability compare to its peers? Please provide details of pertinent studies.

k) What accounting standard does Hydro One Networks Transmission use? Did this change materially during the sample period? If yes, how were the cost data used in this study affected?

l) Please explain Hydro One Networks' capitalization policy. How does policy this differ from the typical policies of sampled U.S. transmitters?

Response:

a) Hydro One follows the provincial electricity regulatory framework under the OEB oversight and in accordance with the Transmission System Code and Market Rules. Under Section 26 of the Electricity Act, Hydro One must provide generators, retailers, market participants and consumers with non-discriminatory access to its transmission systems in accordance with its licence. Under the NERC functional model Hydro One is registered as a Transmission Operator and Owner and generally the scope of transmission services provided will be similar to US transmitters. We cannot comment on specific US transmitters and regulatory framework that may vary from state to state.

b) Normally there is clear demarcation between a Transmitter's and Generator's assets. Typically in Ontario, Hydro One owns the switching stations and generators own the step up transformer that connects into the switching station. We cannot comment on specific US jurisdictions; however it is expected that other organizations will have a similar arrangement and others may own both transmission and generation with no demarcation required

c) Typically Hydro One owns and operates most stations to deliver power to LDC's. Some LDC's and large industrial customers own their step down station to supply their load. It is understood that most US jurisdictions follow the same arrangements.

d) Hydro One assets that operate at voltage levels at or above 50kV including transformers and the connected low voltage Transmission Station are categorized as transmission assets. The related distributions assets are typically the feeders emanating from the Transmission Stations.

e) Typically Hydro One does not have employ a formal sub transmission classification. Lines below 50kV are classified as distribution and those at or above 50kV are transmission. The two groups make up the entire Hydro One owned Distribution and Transmission system.

f) Hydro One collects customer contributions, where appropriate, in line with Distribution and Transmission System Codes issued by the OEB. Hydro One has not aligned the OEB's practice with US jurisdictions to be able to draw a comprehensive comparison.

g)

Asset Type	**Quantity**	**Average Age (years)**	**% of Fleet Beyond ESL (%)**
Circuit Breakers	**4,524**	28	11
Transformers	**717**	32	26
Protection Relays	**11,263**	24	47
Conductor (km)	**29,107**	55	5
Wood Poles	**52,250**	41	30
Steel Structures	**42,000**	58	18

h) Hydro One's transmission system consists of many asset types which have varying demographic profiles over time. Broadly speaking, the current average age of Hydro One's in-service assets, overall, is roughly the same as it was in 2006. Hydro One notes that this conclusion may vary by individual asset class and is not representative of asset condition.

i) Yes, Hydro One has a mature asset management program that has been in place since the implementation of the Energy Competition Act that named Hydro One a successor company to Ontario Hydro. Prior to that the parent company Ontario Hydro had a mature asset management program for many years

j) Hydro One Networks does participate in benchmarking studies undertaken by the Canadian Electricity Association and the North American Transmission Forum. Hydro One Networks compares well with its CEA peers. Participation is contingent upon observance of a non-disclosure agreement. Sharing of specific details regarding the performance of other utilities could potentially violate that agreement and risk Hydro One's ability to participate in the future. Not participating would be detrimental to HONI and its customers since; in that case, this reliable, relevant source of benchmarking would no longer be available.

k) On January 1, 2012, Hydro One Networks adopted United States (US) Generally Accepted Accounting Principles (GAAP). Prior to this, the Company applied accounting principles generally accepted in Canada.

l) Hydro One Networks' capitalization policy is in accordance with US GAAP. Hydro One has not conducted a comprehensive study of policies applied by U.S transmitters.

OEB Staff Interrogatory # 72

Reference:

PSE Working Papers

Interrogatory:

Preamble:

The OEB has determined that the PSE Working Papers will remain confidential. OEB staff and its consultant, Pacific Economics Group, have prepared the following questions in an appropriate format for the public record, but OEB staff understands that it may be necessary for the Applicant to request confidential treatment of all or part of its responses to these questions. It is not OEB staff's intention to have the Applicant place information on the public record that should properly be treated as confidential as determined by the OEB in the Decision on Confidentiality and Procedural Order No. 2.

a) Please provide a variable key and indicate which variables have been transformed e.g. by the natural log.

b) Please state each variable's source.

c) Please provide a brief explanation for why each company that filed a Form 1 and had transmission plant was excluded from each of the TFP and benchmarking samples.

d) Was any consideration given to excluding companies that have sizable transfers of plant between transmission and distribution classification?

e) Please list all *a priori* model assumptions and discuss their appropriateness. For example:

    a. Given the use of Driscoll-Kraay standard errors, it would appear PSE assumes the data to be spatially dependent. Please confirm this assumption. Please also confirm that this assumption was not made in the OEB's 4GIR[1] benchmarking methodology nor in PSE's benchmarking evidence[2] for Hydro One Distribution.

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[1] November 21, 2013, EB-2010-0379, *Report of the Board, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors.*

[2] May 18, 2017. EB-2017-0049. *Econometric Benchmarking Study: Total Distribution Costs of Hydro One Network (Updated with 2016 Actual Hydro One Data and Projections to 2022).*

b. A second order moving average model was selected for the structure of error autocorrelation. This implies that dependence in the error within panels drops off after 2 years. What was the reason for choosing 2 years?

f) The translog specification can be found in econometric output tables in the "Final Dataset and Tables Used" spreadsheet.

a. Due to symmetry restrictions (i.e.$\beta_{ij} = \beta_{ji}\ \forall\ i \neq j$), is it correct to multiply the output interaction term (maxpeakm*totsnlm) by ½? If so, please state PSE's definition of the translog cost function using math language and derive the result with ½ on the interaction term.

g) Why was percent of transmission lines underground not logged in the cost function? If the presence of zeros in the variable prevented logging, was a percentage overhead variable considered?

h) It would appear that PSE used multiple programs to estimate the total cost models e.g. EViews and STATA. Please confirm that PSE used only STATA to estimate the model(s) submitted in the report[3] and whose output tables are shown in the "Econometric Model" tab of the "Final Dataset and Tables Used" spreadsheet.

a. Please provide all non-proprietary[4] STATA code (or other program code) used to estimate the final total cost model.

i) Please explain the reasoning behind demeaning some variables but not others.

j) Please interpret the parameter estimate on LOG (TTOTSNLM) given that LOG (NSUB/TTOTSNL) is also in the model which is equivalent to adding and subtracting LOG (TTOTSNL).

k) How is "transmission" in transmission substation capacity variable defined? For example, perhaps by voltage or by individual company classification?

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[3] Filed 2018-07-26. EB-2018-0218. Exhibit D-1-1. Attachment 1. *Transmission Study for Hydro One Networks Inc.: Recommended CIR Parameters and Productivity Comparisons.*
[4] For example, the STATA program, xtscc, and commands therein are not proprietary to PSE.

l) How is "transmission" in the number of transmission substations variable defined? For example, perhaps by voltage or by individual company classification?

m) Please confirm that substation data were only used for the years 2013-2016 in the model. If so, what is the interpretation of the parameter on average substation capacity in periods before 2013?

n) On page 31 of the PSE report[5], it says, "A statistical test of a cost efficiency hypothesis, based on the t-test, can also be constructed to identify whether the cost performance identified…is statistically significantly different from average." Was the hypothesis test performed? If not, please perform the test and provide the results. If so, is the Company's cost performance "statistically significantly different from average?" Please also indicate the alpha level.

o) Please confirm there is no size-weighting in the cost benchmarking.

Response:

a) Please see the Excel spreadsheet titled, I-01-72-01.

b) Please see the Excel spreadsheet titled, I-01-72-01.

c) Please see the working papers and the final dataset titled "Final Dataset and Tables used.xls". There are several "bad" variables in columns E through J. With the exception of the "badtfp" variable found in column F, if one of these columns has a "1" in it, this meant that the observation was excluded in the benchmarking study. If one or more observations for a particular variable were triggered for exclusion in the benchmarking study, then all of the observations were excluded for the TFP study, since a TFP trend study needs all of the observations for a utility to be included.

A description of the "bad" variables in the dataset are:

- Column E (bad): If this has a "1" it typically indicates that the observation is missing multiple data items.
- Column F (badtfp): This is set at "1" and excludes all of the utilities' observations if one or more of its observations were excluded.

[5] Filed 2018-07-26. EB-2018-0218. Exhibit D-1-1. Attachment 1. Transmission Study for Hydro One Networks Inc.: Recommended CIR Parameters and Productivity Comparisons.

- Column G (badcosts): This is set at “1” if the costs of the utility are suspect or if a merger occurred which created an inconsistent cost series.
- Column H (badpeak): This is set at “1” if the observation has a missing or suspect peak demand value.
- Column I (badmiles): This is set at “1” if the observation has a missing or suspect length of line value.
- Column J (badsub): This is set at “1” if the observation has missing or suspect substation data.

d) No. PSE uses the classification of the plant as it went into service. An exclusion based on a particular level of plant transfers between transmission and distribution would be arbitrary.

e) (a) Yes, PSE does assume this and has used the Driscoll-Kraay approach to correct for autocorrelation within the sample. As stated in Section 3.4.2 of the PSE report, this correction for autocorrelation does not alter the underlying coefficient values and thus does not alter the benchmark result. PSE uses the Driscoll-Kraay standard errors to test statistical significance of the included variables, but this does not alter the estimates themselves.

PSE can confirm the autocorrelation assumption was not made in PSE’s benchmarking evidence for Hydro One Distribution, although a model was produced by PSE in response to an OEB Staff interrogatory asking if PSE made this assumption. This response can be found in EB-2017-0049, Exhibit I, Tab 1, Schedule Staff-35, part a. The question posed to PSE was, “Why did the estimation procedure not correct for autocorrelation as well as heteroskedasticity?” In response to that question PSE produced a model that used the Driscoll-Kraay standard errors and the result. The result showed that using the Driscoll-Kraay approach had a very small impact on the result.

It is PSE’s understanding that the OEB’s 4GIR benchmarking methodology did not correct for autocorrelation.

(b) PSE used the standard Driscoll-Kraay approach to correct for autocorrelation in the standard errors found in the STATA software package. No choice was made, nor is one available to be made for a specific time period.

f) Multiplying a variable by a constant, ½ in this case, produces the exact same result. The benchmark values for Hydro One are unchanged if the ½ multiplication is removed.

g) The “transmission lines underground” variable was not logged because of the presence of zeros in the variable. Yes, PSE did consider including percentage overhead. The result is nearly identical with either approach, and PSE decided it would be a bit more understandable to include the underground variable, since it is undergrounding that is driving the cost. Either approach is acceptable in PSE’s view. If the overheading variable is included (and logged), Hydro One’s 2014-2016 result stays at -27.3% and the 2019-2022 result goes from -31.8% to -31.4%.

h) Both the EViews and STATA models provide the exact same parameter estimates submitted in the report. PSE only used STATA to estimate the Driscoll-Kraay standard errors. The working papers contain all of the code PSE has for STATA. If one is trying to re-produce the STATA results, the steps to produce the STATA results are 1) import the data, 2) declare the data to be a panel dataset, 3) create the variables needed for the regression, and 4) use the Driscoll-Kraay procedure with the command “xtscc”.

i) The output variables (line length and peak demand) are divided by their sample means prior to estimation. Similar to our response in part f) of this response, dividing or multiplying by a constant will produce the exact same benchmark results. The reason that PSE divided the outputs by their sample mean is purely for easier interpretation of the output elasticities. The reported coefficients for line length and peak demand are now the cost elasticities at the mean of the sample. Without the mean-scaling, a separate calculation would be necessary to determine the cost elasticities at the sample mean. To reiterate, if PSE did not do this mean-scaling procedure, the result would be exactly the same as the one reported.

j) The parameter estimate contributes to the cost elasticity of line length. If the variable LOG(NSUB/TTOTSNL), which measures substations per KM of line, is changed to only LOG(NSUB), the benchmarking results remain exactly the same. PSE included the LOG(NSUB/TOTSNL) for ease of interpretation. However, the question raises a good point in that the presence of the variable LOG(NSUB/TTOTSNL) will influence the cost elasticity of the outputs at the sample mean. This will have a slight influence on the TFP result. If the variable is changed to LOG(NSUB), the TFP trend estimate changes from -1.71% for 2004-2016 to 1.66% and the TFP trend estimate changes from -2.40% for 2010-2016 to 2.42%.

k) Transmission is defined based on the individual company’s classification.

l) Transmission is defined based on the individual company’s classification.

m) Confirmed. PSE used the 2013 value as a proxy for substation capacity per substation in years prior to 2013. Given that the variable is relatively stable from year to year and the large manual effort it takes to gather this data, PSE believed this was a good balance of using research resources wisely. The variable continues to be highly statistically significant, and the interpretation of the parameter remains the same. It is the cost elasticity of substation capacity per substation.

n) The company's 2014-2016 result of -27.3% and the projected CIR time period of 2019-2022 result of -31.8% are both statistically significantly different from average at a 90% confidence level (alpha = 0.1).

o) Confirmed.

Variable in Total Cost Model	Variable name in SST code	Transformed with natural log?	Source
Total transmission Kilometres of line	TTOTSNLM	Yes	FERC Form 1 via SNL
Maximum peak demand	MAXPEAKM	Yes	FERC Form 1 via SNL
Percent of transmission plant in total electric utility plant	PCTTX	Yes	FERC Form 1 via SNL
Average capacity (MVa) per substation	MVA/NSUB	Yes	FERC Form 1
Number of transmission substations per KM of line	NSUB/TTOTSNL	Yes	FERC Form 1 (for the NSUB numerator and SNL for the TTOTSNL denominator)
Average voltage of transmission lines	AVGVOLT	Yes	FERC Form 1
Construction standards of building transmission pole	LOAD_TX	Yes	GIS mappings with NERC standards
Percent of transmission lines underground	PUG	No	FERC Form 1
Time trend (current year minus 2003)	YEAR-2003	No	Calculation

OEB Staff Interrogatory # 73

Reference:

Exhibit D, Tab 2, Schedule 1, Page 1
Exhibit D, Tab 2, Schedule 1, Page 6, Table 4 – Proposed 2019 UTRs

Interrogatory:

Preamble:

In the above-noted reference, Hydro One SSM stated the following:

UTRs are established by aggregating the revenue requirement for the five transmitters and allocating the revenue requirements to the UTR Rate Pools: Network, Line Connection and Transformation Connection, based on a cost allocation study conducted by Hydro One on a regular basis. This study determines the proportionate allocation of the revenue requirement of the transmitters to the appropriate rate pools. The exception is B2M Limited Partnership whose costs are 100% allocated to the Network pool as the assets only provide Network services. The costs are then divided by forecast consumption (charge determinants) of each transmitter to establish the UTRs.

a) Please describe the cost allocation study used by Hydro One SSM that was conducted by Hydro One.

b) Please describe in more detail how the cost allocation study determined the proportionate allocation of the revenue requirement of the transmitters to the appropriate rate pools, including the allocation of the Hydro One SSM proposed 2019 revenue requirement to the Network, Line Connection, and Transformation Connection rate pools, in Table 4 – Proposed 2019 UTRs.

c) Please indicate when the cost allocation study was completed and describe whether or not it has been tested in a prior Hydro One proceeding. Please explain.

Response:

a) The allocation of Hydro One Networks' transmission costs to the UTR rate pools is fully detailed in Exhibits G1 and G2 of Hydro One's most recent transmission cost of service application EB-2016-0160. The cost allocation methodology was approved by the Board in its September 22, 2017 (Revised October 11, 2017) Decision in that proceeding.

b) Per the methodology first approved by the Board in setting UTR rates for market opening in 2002 under joint docket numbers RP-1999-0044, RP-2001-0035, RP-2001-0034, RP-2011-0036, the approved revenue requirement for other transmitters is split across the Network, Line Connection, and Transformation Connection pools using the same proportion of revenue requirement allocated to those pools by Hydro One Networks. This approach has been approved in the setting of all subsequent UTRs, and most recently under proceeding EB-2017-0359. As approved by the Board in its Decision on 2015 UTRs under EB-2014-0357, the full revenue requirement associated with B2M LP is assigned entirely to the Network pool.

c) See response to part a).

OEB Staff Interrogatory # 74

Reference:

Exhibit E, Tab 1, Schedule 2
Filing Requirements, page 11 (section 2.3.3), page 36 (section 2.10.1)

Interrogatory:

a) Hydro One SSM has not provided non-consolidated audited financial statements of the utility. Please provide 2017 audited financial statements as required under the Filing Requirements.

b) Please provide a reconciliation between the audited financial statements and the regulatory financial results filed in the application. Reconciliation must include the separation of non-utility businesses.

c) Please provide a statement that the balances proposed for disposition before forecasted interest are consistent with the last Audited Financial Statements and provide explanations for any variances.

d) Hydro One SSM stated:

   HOSSM's cumulative in-service additions were less than the Board-approved amount of in-service additions for 2015 and 2016 of $19,228,700 by $927,203. Therefore, HOSSM has recorded a credit balance of $143,935, which is the calculated amount of revenue requirement owed to ratepayers to cover this shortfall.

   Please provide 2015 and 2016 audited financial statements and reconcile in-service additions per the evidence provided to Hydro One SSM's audited financial statements for 2015 and 2016.

e) Please provide the calculation for Net Cumulative Asymmetrical Variance Account amounts recorded in 2015 and 2016 and reflected in the application.

Response:

a) The 2017 financial statements are attached as Attachment 1.

b) Refer to response 74 (c).

c) The audited financial statements were prepared in accordance with IFRS and therefore do not include regulatory accounts.

d) Please refer to the Attachments 2 and 3 included with this Exhibit.

In thousands of Canadian dollars:

	PPE Transfers	Intangible Assets Transfers	Total
2015	8,160	583	**8,743**
2016	8,216	1,342	**9,558**
			18,301
		Board approved in-service additions (2015 and 2016)	19,229
		Difference	(928)

e) Please refer to the Attachment 4 included with this Exhibit.

HYDRO ONE SAULT STE. MARIE LIMITED PARTNERSHIP

FINANCIAL STATEMENTS

DECEMBER 31, 2017

KPMG LLP
111 Elgin Street, Suite 200
Sault Ste. Marie ON P6A 6L6
Canada
Telephone (705) 949-5811
Fax (705) 949-0911

INDEPENDENT AUDITORS' REPORT

To the Partners of Hydro One Sault Ste. Marie Limited Partnership

We have audited the accompanying financial statements of Hydro One Sault Ste. Marie Limited Partnership, which comprise the statement of financial position as at December 31, 2017, the statements of comprehensive income, statement of changes in partners' equity and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Hydro One Sault Ste. Marie Limited Partnership as at December 31, 2017, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards**.**

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Sault Ste. Marie, Canada
April 13, 2018

HYDRO ONE SAULT STE. MARIE LIMITED PARTNERSHIP
STATEMENT OF FINANCIAL POSITION
At December 31, 2017, with comparative information for 2016
(expressed in thousands of Canadian dollars)

December 31	2017	2016
Assets		
Current assets:		
Cash	2,967	1,682
Trade and other receivables	74	35
Due from related parties *(Note 20)*	3,594	3,283
Prepaid expenses and other	601	623
	7,236	5,623
Long-term assets:		
Property, plant and equipment, net *(Note 5)*	217,586	217,303
Intangible assets, net *(Note 6)*	7,153	3,708
	224,739	221,011
Total assets	**231,975**	**226,634**
Liabilities		
Current liabilities:		
Trade and other payables *(Note 7)*	1,981	1,689
Due to related parties *(Note 20)*	599	70
Current portion of Trans senior bonds *(Note 9)*	2,649	2,483
	5,229	4,242
Long-term liabilities:		
Pension liability *(Note 8)*	5,925	4,450
Trans senior bonds *(Note 9)*	105,943	108,364
	111,868	112,814
Total liabilities	**117,097**	**117,056**
Partners' equity	114,878	109,578
Total liabilities and partners' equity	**231,975**	**226,634**

See accompanying notes to Financial Statements.

HYDRO ONE SAULT STE. MARIE LIMITED PARTNERSHIP
STATEMENT OF CHANGES IN PARTNERS' EQUITY
For the year ended December 31, 2017, with comparative information for 2016
(expressed in thousands of Canadian dollars)

Year ended December 31, 2017	Capital		Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Deficit)	Total Partners' Equity
	Hydro One Sault Ste. Marie Holdings LP	Hydro One Sault Ste. Marie Inc.			
January 1, 2017	112,405	11	383	(3,221)	109,578
Net income	—	—	—	11,880	11,880
Distributions paid	—	—	—	(4,956)	(4,956)
Other comprehensive loss	—	—	(1,624)	—	(1,624)
December 31, 2017	**112,405**	**11**	**(1,241)**	**3,703**	**114,878**

Year ended December 31, 2016	Capital		Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Deficit)	Total Partners' Equity
	Hydro One Sault Ste. Marie Holdings LP	Hydro One Sault Ste. Marie Inc.			
January 1, 2016	112,405	11	1,796	(3,832)	110,380
Net income	—	—	—	11,684	11,684
Distributions paid	—	—	—	(11,073)	(11,073)
Other comprehensive loss	—	—	(1,413)	—	(1,413)
December 31, 2016	**112,405**	**11**	**383**	**(3,221)**	**109,578**

See accompanying notes to Financial Statements.

HYDRO ONE SAULT STE. MARIE LIMITED PARTNERSHIP
STATEMENT OF COMPREHENSIVE INCOME
For the year ended December 31, 2017, with comparative information for 2016
(expressed in thousands of Canadian dollars)

Year ended December 31	2017	2016
Revenues	38,421	40,204
Operating Expenses		
Operating and administration *(Note 12)*	8,042	9,473
Depreciation and amortization *(Note 15)*	9,084	9,296
Maintenance *(Note 13)*	1,395	1,616
Taxes, other than income taxes	119	117
	18,640	20,502
Net operating income	**19,781**	**19,702**
Finance income	(57)	(46)
Finance costs *(Note 14)*	7,396	7,528
Loss on property, plant and equipment	625	600
Other income	(63)	(64)
Income for the period	**11,880**	**11,684**
Other comprehensive loss		
Items that will not be reclassified subsequently to profit or loss:		
Remeasurement of pension liability	(1,624)	(1,413)
Total comprehensive income	**10,256**	**10,271**

See accompanying notes to Financial Statements.

HYDRO ONE SAULT STE. MARIE LIMITED PARTNERSHIP
STATEMENT OF CASH FLOWS
For the year ended December 31, 2017, with comparative information for 2016
(expressed in thousands of Canadian dollars)

Year ended December 31	2017	2016
Operating activities		
Net income	11,880	11,684
Items not affecting cash:		
Depreciation and amortization	9,084	9,296
Finance costs	7,396	7,528
Loss on disposal of property, plant and equipment	625	600
Net change in non-cash working capital and other *(Note 17)*	351	(874)
Operating cash flows before interest	29,336	28,234
Cash interest paid	(7,383)	(7,539)
	21,953	**20,695**
Investing activities		
Proceeds on disposition of property, plant and equipment *(Note 5)*	19	6
Additions to property, plant and equipment and intangible assets *(Notes 5, 6)*	(13,248)	(8,959)
	(13,229)	**(8,953)**
Financing activities		
Principal repayments on Trans senior bonds	(2,483)	(2,327)
Distributions paid	(4,956)	(11,073)
	(7,439)	**(13,400)**
Increase (decrease) in cash	1,285	(1,658)
Cash, beginning of year	1,682	3,340
Cash, end of year	**2,967**	**1,682**

See accompanying notes to Financial Statements.

1. GENERAL INFORMATION

Hydro One Sault Ste. Marie Limited Partnership, formerly Great Lakes Power Transmission Limited Partnership (the Partnership) was formed on May 17, 2007 for the purpose of acquiring the assets and liabilities of the transmission division of Great Lakes Power Limited (GLPL), previously a related party due to common ownership. On October 31, 2016, Hydro One Inc. (HOI) completed the share purchase of the Great Lakes Power Transmission entities following approval by the Ontario Energy Board (OEB) on October 13, 2016. As part of the transaction, Great Lakes Power Transmission Limited Partnership legally changed their name to Hydro One Sault Ste. Marie Limited Partnership on January 16, 2017. The address of the Partnership's registered office is 2 Sackville Road, Suite B, Sault Ste. Marie, Ontario, Canada, P6B 6J6.

Hydro One Sault Ste. Marie Holdings LP is the Limited Partner and holds a 99.99% interest in the Partnership. Hydro One Sault Ste. Marie Inc., the General Partner, holds a 0.01% limited interest in the Partnership and is responsible for management of the Partnership. Both the General and Limited Partners are wholly-owned subsidiaries of HOI, the ultimate parent company and controlling party of the group.

The Partnership is engaged in the transmission of electricity to the area adjacent to Sault Ste. Marie, Canada and is subject to the regulations of the OEB.

2. BASIS OF PRESENTATION

Statement of compliance

These financial statements, including comparatives, have been prepared in accordance with International Financial Reporting Standards (IFRS). Accounting policies are consistently applied to both years presented, unless otherwise stated.

The financial statements were approved and authorized for issue by those charged with governance of the Partnership on April 13, 2018.

Basis of measurement

The financial statements have been prepared on a going concern assumption using the historical cost basis except where otherwise noted. Historical cost is generally based on the fair value of the consideration given in exchange for assets or settlement of liabilities as at the date the transaction occurs.

Critical judgments and estimation uncertainties

In the preparation of these financial statements in conformity with IFRS, management makes judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of revenues, expenses, assets and liabilities. Facts and circumstances may change and actual results could differ from those estimates.

Estimates and Judgments

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Information about critical judgments and estimates in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements are included in the following notes:

Impairment

Assets, including property, plant and equipment and intangible assets are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amounts exceed their recoverable amounts. Intangible assets with indefinite useful lives are tested for impairment annually and whenever events or changes in circumstances indicate that their carrying amounts exceed their recoverable amounts. The assessment of fair value often requires estimates and assumptions on items such as approved uniform transmission rates, discount rates, rehabilitation and restoration costs, future capital requirements and future operating performance. Changes in such estimates could impact recoverable values of these assets. Estimates are reviewed annually by management.

Judgment is involved in assessing whether there is any indication that an asset or cash generating unit (CGU) may be impaired. A CGU is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets. This assessment is made based on the analysis of changes in the market or business environment, and events that have transpired that have impacted the asset or CGU.

Depreciation of property, plant and equipment and intangible assets

Each property, plant and equipment and intangible asset is assessed annually for both its physical life limitations and its economic recoverability. Those assets with a finite life are depreciated on a straight-line basis over a useful life estimated by management. Asset useful lives and residual values are re-evaluated annually.

Fair value disclosures of Trans senior bonds

The Partnership has estimated the fair value for disclosure purposes of its Trans senior bonds (Bonds) as they are not separately traded. The fair value is based on future cash flows and the timing of settlement and assumptions about discount rate, credit risk and by incorporating other assumptions made by market participants.

Pension

Significant estimates and assumptions are made in determining pension and employee future benefits as there are numerous factors that will affect the pension obligation. The actuarial determination of the accrued benefit obligation for pensions and post-employment benefits uses the projected unit credit method prorated on service which incorporates management's best estimate of future salary levels, other cost escalation, mortality rates, retirement ages of employees and other actuarial factors. In addition, actuarial determinations used in estimating obligations relating to the defined benefit plans incorporate assumptions using management's best estimates of factors including plan performance, salary escalation, retirement dates of employees and drug cost escalation rates.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Partnership has consistently applied the following accounting policies to both periods presented in these financial statements:

Financial instruments

The Partnership recognizes all financial instruments at fair value upon initial recognition and subsequently classifies them into one of the following categories: Financial assets and financial liabilities at fair value through profit or loss, held-to-maturity, loans and receivables, available-for-sale and other liabilities. At December 31, 2017, the Partnership held the following financial instruments: trade and other payables, Bonds (which are classified as other financial liabilities), and trade and other receivables (which are classified as loans and receivables).

The Partnership initially recognizes other financial liabilities and loans and receivables on the trade date. The Partnership derecognizes a financial liability when its contractual obligations are discharged, cancelled, or expired.

Other financial liabilities including borrowings are initially measured at fair value net of transaction costs, and subsequently measured at amortized cost using the effective interest method. Subsequent to initial recognition, loans and receivables are measured at amortized cost using the effective interest method, less any impairment losses.

Property, plant and equipment

Recognition and measurement

Property, plant and equipment are measured at cost less accumulated depreciation and any accumulated impairment losses. When significant parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment. The cost of major inspections or overhauls is capitalized and costs relating to the replacement of a major part of property, plant and equipment are recognized in the carrying amount of the asset to which that part relates, if it is probable that the inspection, overhaul or replacement part will generate future economic benefits and its cost can be measured reliably. The carrying amount of previous inspections and overhauls, or the part being replaced is derecognized and any gain or loss is recognized against income. The cost of the day-to-day servicing of property, plant and equipment is recognized in operating and administration or maintenance expense as incurred.

Costs included in the carrying amount of property, plant and equipment include expenditures that are directly attributable to the acquisition or construction of the asset. The cost of self-constructed assets includes: materials, services, direct labour and directly attributable overheads.

Borrowing costs associated with major projects are capitalized during the construction period, if those projects meet the definition of a qualifying asset, meaning those projects that are under construction for a substantial period of time. Capitalization of borrowing costs is suspended during extended periods in which construction development is interrupted. Assets under construction are recorded as work-in-progress until they become available for use.

When property, plant and equipment is disposed of or retired, the related cost, accumulated depreciation and any accumulated impairment losses are eliminated. Any resulting gains or losses are reflected in income in the period the asset is disposed of or retired.

Depreciation

The cost, net of estimated residual values, of an asset classified as property, plant and equipment is depreciated over the estimated useful life of the asset using a straight-line method. Land is not depreciated. The estimated useful lives of property, plant and equipment are as follows:

	Depreciation Rate
Transmission assets	5 to 60 years
Equipment and other assets	5 to 30 years

The estimated useful lives, residual values and method of depreciation are are based on depreciation studies and are reviewed annually for reasonableness.

Construction work-in-progress assets are not depreciated until the assets become available for their intended use.

Impairment

At each reporting date, the Partnership reviews the carrying amount of its non-financial assets to determine whether there is any indication of impairment. Impairment assessments are conducted at the CGU level. If any such indication exists, the recoverable amount of the CGU is estimated.

The recoverable amount of the CGU is the greater of its value in use and its fair value less costs to sell. Value in use is based on the estimated future cash flows, discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized in income if the carrying amount of a CGU exceeds its recoverable amount.

Impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. If such indications exist, the Partnership estimates the recoverable amount of that CGU. A reversal of an impairment loss is recognized up to the lesser of the recoverable amount or the carrying amount that would have been determined (net of depreciation charges) had no impairment loss been recognized on the CGU.

Intangible assets

Acquired intangible assets having finite useful lives are measured at cost less accumulated amortization and any accumulated impairment losses. Intangible assets are capitalized if: (i) It is probable that the asset acquired or developed will generate future economic benefits, (ii) the intangible asset is identifiable, and (iii) the Partnership exerts control over the economic benefit to be derived from the asset. The costs incurred to establish technological feasibility or to maintain existing levels of performance are recognized in operating or maintenance expense as incurred.

The carrying costs of intangible assets include expenditures that are directly attributable to the acquisition or development of the asset. The cost of self-developed assets includes materials, services, direct labour and directly attributable overheads. Borrowing costs associated with major projects (qualifying assets) are capitalized during the development period. Qualifying assets are those projects that are under development for a substantial period of time. Assets under development are recorded as in progress until they become available for use.

Subsequent expenditures are capitalized only when it increases the future economic benefits embodied in the specific asset to which it relates. All other expenditures are recognized against income as incurred.

Amortization is based on the cost of the asset less its residual value and is calculated using the straight-line method over the estimated useful life of the asset from the date the asset is available for use, and is generally recognized against income. The useful lives of intangible assets range from 5 to 15 years. Land rights with indefinite lives are not amortized.

The estimated useful lives, residual values and method of amortization are reviewed annually for reasonableness.

Intangible assets with an indefinite life are tested for impairment on an annual basis.

Employee benefits

Short-term employee benefits

Short-term employee benefits are expensed as the related service is provided by the employee. A liability is recognized for the amount expected to be paid if the Partnership has a present legal or constructive obligation to pay this amount as a result of past service provided by the employee and the obligation can be estimated reliably.

Defined contribution plans

Obligations for contributions to defined contribution plans are expensed as the related service is provided by the employee. Prepaid contributions are recognized as an asset to the extent that a cash refund or a reduction in future payments is available.

Defined benefit plans

The Partnership's net obligation in respect to defined benefit plans is calculated separately for each plan by estimating the amount of future benefit that employees have earned in the current and prior periods, discounting that amount and deducting the fair value of any plan assets.

The calculation of defined benefit obligations is performed annually by a qualified actuary using the projected unit credit method. When the calculation results in a potential asset for the Partnership, the recognized asset is limited to the present value of economic benefits available in the form of any future refunds from the plan or reductions in future contributions to the plan. To calculate the present value of economic benefits, consideration is given to any applicable minimum funding requirements.

Remeasurements of the net defined benefit liability, which comprise actuarial gains and losses, the return on plan assets (excluding interest) and the effect of the asset ceiling (if any, excluding interest), are recognized immediately in other comprehensive income. The Partnership determines the net interest expense (income) on the net defined benefit liability (asset) for the period by applying the discount rate used to measure the defined benefit obligation at the beginning of the annual period to the then-net defined benefit liability (asset), taking into account any changes in the net defined benefit liability (asset) during the period as a result of contributions and benefit payments. Net interest expense and other expenses related to defined benefit plans are recognized against income.

When the benefits of a plan are changed or when a plan is curtailed, the resulting change in benefit that relates to past service or the gain or loss on curtailment is recognized immediately against income. The Partnership recognizes gains and losses on the settlement of a defined benefit plan when the settlement occurs. The gain or loss on curtailment or settlement comprises any resulting change in the fair value of plan assets, any change in the present value of the defined benefit obligation, and any relating actuarial gains or losses and past service costs that had not been previously been recognized.

Other long-term employee benefits

The Partnership's net obligation in respect of long-term employee benefits is the amount of future benefit that employees have earned in return for their service in the current and prior periods. That benefit is discounted to determine its present value. Remeasurements are recognized in income in the period in which they arise.

Revenue

Revenue is measured at the fair value of the consideration received or receivable. Revenue is recognized by the Partnership when a sales arrangement exists, delivery of goods or services has occurred, the amount of revenue and costs incurred or to be incurred in respect of the transaction can be measured reliably and it is probable that future economic benefits will flow to the Partnership.

The Partnership recognizes revenue on an accrual basis, when electricity is wheeled, at the regulated rate established by the OEB.

Foreign currency

Transactions in foreign currencies are translated to the functional currency of the Partnership at exchange rates at the dates of the transactions.

Borrowing costs

Borrowing costs that are directly attributable to the acquisition, construction or development of a qualifying asset are added to the cost of that asset, until it is available for use. Qualifying assets are those that take a substantial period of time to get ready for their intended use. The Partnership capitalizes borrowing costs by applying its cost of debt. All other borrowing costs are recognized in finance expense in the period in which they are incurred.

Changes in accounting policies

Effective January 1, 2017, the Partnership has adopted amendments to IAS 7, Financial Statement Disclosure. The amendments require disclosures that enable users of financial statements to evaluate changes in liabilities arising from financing activities, including both, cash and non-cash changes. Refer to notes 9 for the reconciliation between the opening and closing balances for liabilities from financing activities related to the Bonds.

4. FUTURE CHANGES IN ACCOUNTING POLICIES

A number of new standards, amendments to standards and interpretations are effective for annual periods beginning after December 31, 2017 and have not been applied in preparing these financial statements. Those which may be relevant to the Partnership are set out below. The Partnership does not plan to early adopt any of these standards.

Revenue

On May 28, 2014 the IASB issued IFRS 15, Revenue from Contracts with Customers (IFRS 15). This standard outlines a single comprehensive model with prescriptive guidance for entities to use in accounting for revenue arising from contracts with its customers. IFRS 15 uses a control based approach to recognize revenue which is a change from the risk and reward approach under the current standard. This standard replaces IAS 18 Revenue, IAS 11 Construction Contracts and related interpretations. The effective date is for reporting periods beginning on or after January 1, 2018 with early application permitted. The Partnership has completed its review of its various revenue streams and has concluded that there will be no material impact upon adoption of IFRS 15 on its financial statements.

Financial instruments

On July 24, 2014 the IASB issued IFRS 9, Financial Instruments (IFRS 9) as a complete standard. This standard replaces the guidance in IAS 39 Financial Instruments: Recognition and Measurement on the classification and measurement of financial assets and financial liabilities. IFRS 9 utilizes a single approach to determine whether a financial asset is measured at amortized cost or fair value and a new mixed measurement model for debt instruments having only two categories: amortized cost and fair value. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. Final amendments released on July 24, 2014 also introduce a new expected loss impairment model and limited changes to the classification and measurement requirements for financial assets. The IASB has tentatively decided to require an entity to apply IFRS 9 for annual periods beginning on or after January 1, 2018. The Partnership has not yet determined the effect of adoption of IFRS 9 on its financial statements.

Leases

IFRS 16, Leases (IFRS 16) was issued by the IASB on January 13, 2016, and will replace IAS 17, Leases. IFRS 16 will bring most leases onto the balance sheet for lessees under a single model, eliminating the distinction between operating and financing leases. Lessor accounting remains largely unchanged. The new standard is effective for annual periods beginning on or after January 1, 2019. The Partnership has not yet determined the effect of adoption of IFRS 16 on its financial statements.

(expressed in thousands of Canadian dollars)

5. PROPERTY, PLANT AND EQUIPMENT, NET

December 31, 2017	Land	Equipment and Other Assets	Transmission Assets	Work-In-Progress	Total
Cost					
Balance - December 31, 2015	236	10,639	238,966	2,054	251,895
Additions	—	—	—	8,329	8,329
Transfers	—	1,046	7,170	(8,216)	—
Disposals	—	(42)	(765)	(268)	(1,075)
Balance - December 31, 2016	236	11,643	245,371	1,899	259,149
Additions	—	—	—	9,722	9,722
Transfers	—	208	10,915	(11,123)	—
Disposals	—	(23)	(1,488)	—	(1,511)
Balance - December 31, 2017	236	11,828	254,798	498	267,360
Accumulated Depreciation					
Balance - December 31, 2015	—	3,119	29,933	—	33,052
Additions (Depreciation)	—	917	8,078	—	8,995
Disposals	—	(42)	(159)	—	(201)
Balance - December 31, 2016	—	3,994	37,852	—	41,846
Additions (Depreciation)	—	1,025	7,770	—	8,795
Disposals	—	(23)	(844)	—	(867)
Balance - December 31, 2017	—	4,996	44,778	—	49,774
Carrying Amounts					
Balance - December 31, 2016	236	7,649	207,519	1,899	217,303
Balance - December 31, 2017	236	6,832	210,020	498	217,586

In 2017, the Partnership disposed of assets with a total net book value of $644 (2016 - $606) for net proceeds of $19 (2016 - $6). A resultant loss on disposal of property, plant and equipment of $625 (2016 - $600) was recorded to the statement of comprehensive income. There were no write-offs of work-in-progress assets to the statement of comprehensive income during 2017 (2016 - $268).

In 2017, the Partnership identified a number of projects which were considered to be qualifying assets for purposes of capitalizing borrowing costs. During 2017, the Partnership capitalized borrowing costs of $208 (2016 - $225). The capitalization rate on funds borrowed was 6.6% in 2017 (2016 - 6.6%).

(expressed in thousands of Canadian dollars)

6. INTANGIBLE ASSETS, NET

December 31, 2017	Land Rights	Computer Software	Work-In-Progress	Total
Cost				
Balance - December 31, 2015	1,226	3,341	219	4,786
Additions	—	—	1,123	1,123
Transfers	970	372	(1,342)	—
Balance - December 31, 2016	2,196	3,713	—	5,909
Additions	—	—	3,734	3,734
Transfers	3,339	26	(3,365)	—
Balance - December 31, 2017	5,535	3,739	369	9,643
Accumulated Amortization				
Balance - December 31, 2015	—	1,900	—	1,900
Additions (Amortization)	5	296	—	301
Balance - December 31, 2016	5	2,196	—	2,201
Additions (Amortization)	12	277	—	289
Balance - December 31, 2017	17	2,473	—	2,490
Carrying Amounts				
Balance - December 31, 2016	2,191	1,517	—	3,708
Balance - December 31, 2017	5,518	1,266	369	7,153

The Partnership owns land rights and other land easements that are needed as part of the normal business operations. Land rights have been obtained through contractual rights where the transferor has transferred land rights and land easements to specific parcels of land. The Partnership has identified these land rights as intangible assets with having either indefinite useful lives (in instances where contractual rights give access to specific land parcels in perpetuity) or where land rights are over a finite period, amortize over the term of the agreement with the land owner. The Partnership accounts for land rights at cost less depreciation and cumulative impairment losses, if any.

The Partnership has not identified events or changes in circumstances that indicate that the land rights' carrying amounts exceed their recoverable amounts. The Partnership has tested land rights for impairment in accordance with annual impairment tests.

The Partnership has identified the recoverable amount of land rights to be their fair values less cost of disposal. In arriving at the fair value less cost of disposal, the Partnership has used a recent purchase transaction which it believes is indicative of the fair value less cost of disposal of the land rights owned. The Partnership has determined that as at December 31, 2017, the fair value less cost of disposal is greater than the carrying amount and hence no impairment loss has been recorded.

The Partnership uses fair value less cost of disposal to determine the recoverable amount as it believes that this will generally result in a value greater than or equal to the value in use. For the purpose of the intangible impairment test, the Partnership used a recent purchase agreement. The inputs used in the fair value measurement constitute Level 2 inputs under the fair value hierarchy. Level 2 inputs are quoted prices in markets that are not active, quoted prices for similar assets or liabilities in active markets, inputs other than quoted prices that are observable for the asset or liability (for example, interest rate and yield curves observable at commonly quoted intervals, forward pricing curves used to value currency and commodity contracts), or inputs that are derived principally from or corroborated by observable market data or other means.

7. TRADE AND OTHER PAYABLES

December 31	2017	2016
Trade payables and accruals	1,115	667
Payroll liabilities	287	433
Accrued interest	298	305
Connection deposits	60	69
Other payables	221	215
	1,981	1,689

The Partnership retains connection deposits for power generating entities as reimbursement to the Partnership for costs to be incurred in connecting those power generating entities to the Partnership's power transmission property assets. Any unused connection deposit balance will be refunded to the appropriate power generating entity.

8. PENSION AND EMPLOYEE FUTURE BENEFITS

The Partnership is part of a registered defined benefit, final pay pension plan and other post-employment benefit plan (Plans).

The other post-employment benefit plan includes benefits such as health and dental care, and life insurance. The obligation under these plans is determined periodically through the preparation of actuarial valuations. The Partnership contributions to the Plans for 2017 were $1,032 (2016 - $1,116).

The Partnership also participates in a defined contribution pension plan provided to certain employees. The Partnership contributes based on the level of employee contributions for this plan. In 2017, the total employer expense for the Partnership's defined contribution pension plan was $115 (2016 - $146). The minimum employer's contribution for 2018 is estimated to be $105.

(expressed in thousands of Canadian dollars)

The Plans' information is provided in the following tables:

	December 31, 2017			December 31, 2016		
	Defined Benefit Pension Plan	Non-Pension Benefit Plans	Total	Defined Benefit Pension Plan	Non-Pension Benefit Plans	Total
Change in the present value of the accrued benefit obligation						
Balance, beginning of year	23,857	5,392	29,249	22,664	4,877	27,541
Current service cost	441	151	592	417	134	551
Past service cost	-	-	-	-	-	-
Interest expense	911	213	1,124	921	202	1,123
Benefit payments from plan	(1,536)	(133)	(1,669)	(985)	(125)	(1,110)
Employee contributions	99	-	99	116	-	116
Increases (decreases) due to other significant events	-	-	-	(325)	-	(325)
Remeasurements:						
Effect of changes in demographic assumptions	-	-	-	309	113	422
Effect of changes in financial assumptions	1,560	572	2,132	713	191	904
Effect of experience adjustments	975	-	975	27	-	27
Effect of changes in foreign exchange rates				-	-	-
Balance, end of year	**26,307**	**6,195**	**32,502**	**23,857**	**5,392**	**29,249**
Change in fair value of the plan assets						
Fair value, beginning of year	24,799	-	24,799	24,084	-	24,084
Return on plan assets	1,529	-	1,529	(97)	-	(97)
Contributions:						
Employer	899	133	1,032	991	125	1,116
Employee	99	-	99	116	-	116
Benefit payments from plan	(1,536)	(133)	(1,669)	(985)	(125)	(1,110)
Administrative expenses paid from plan assets	(180)	-	(180)	(124)	-	(124)
Interest income	967	-	967	1,001	-	1,001
Decreases due to other significant events	-	-	-	(187)	-	(187)
Fair value, end of year	**26,577**	**-**	**26,577**	**24,799**	**-**	**24,799**
Net Defined Benefit Liability						
Accrued benefit obligation	(26,307)	(6,195)	(32,502)	(23,857)	(5,392)	(29,249)
Fair value of plan assets	26,577	-	26,577	24,799	-	24,799
Net Defined Benefit Liability	270	(6,195)	(5,925)	942	(5,392)	(4,450)
Total expense recognized in profit and loss						
Current service cost	441	151	592	417	134	551
Past service cost	-	-	-	-	-	-
Net interest expense	(56)	213	157	(80)	202	122
Administrative expenses and taxes	135	-	135	160	-	160
Total expense recognized in profit and loss	**520**	**364**	**884**	**497**	**336**	**833**
Actuarial losses recognized in statement of comprehensive income						
Effect of changes in demographic assumptions	-	-	-	309	113	422
Effect of changes in financial assumptions	1,560	572	2,132	713	191	904
Effect of experience adjustments	975	-	975	27	-	27
Return on plan assets	(1,483)	-	(1,483)	60	-	60
Total actuarial losses recognized in statement of comprehensive income	**1,052**	**572**	**1,624**	**1,109**	**304**	**1,413**

Effects of changes in assumptions:

December 31, 2017	Defined Benefit Pension Plan	Non-Pension Benefit Plans	Total
Discount Rate			
Increase by 100 basis points			
Decrease by 100 basis points	21,805	858	22,663
	29,956	994	30,950
Inflation Rate			
Increase by 100 basis points	27,822	922	28,744
Decrease by 100 basis points	23,014	922	23,936

(expressed in thousands of Canadian dollars)

The following table presents significant actuarial assumptions:

	Defined Benefit Pension Plan	Non-Pension Benefit Plans	Defined Benefit Pension Plan	Non-Pension Benefit Plans
	December 31, 2017		December 31, 2016	
Weighted-average actuarial assumptions used:				
Discount rate	3.50%	3.50%	3.90%	4.00%
Rate of compensation increase	3.00%	3.00%	3.00%	3.00%
Inflation rate	2.00%	n/a	2.00%	n/a

The following table presents Defined Benefit Pension Plan asset allocations:

December 31	2017	2016
Fixed income	35%	34%
Equity	65%	66%
Total	100%	100%

9. TRANS SENIOR BONDS

The Bonds have an initial principal amount of $120,000 and are secured by a charge on the Partnership's transmission real property assets, both present and future. On behalf of the Partnership, HOI maintains a letter of credit in the amount of $3,960 to cover six months of interest payments on the Bonds.

The fair market value of the Bonds as at December 31, 2017 is $131,583 based on current market prices for debt with similar terms (2016 - $140,821). Amortization of deferred financing fees for the year related to the Partnership's Bonds are included in finance costs and totaled $228 (2016 - $220).

The Bonds bear interest at the rate of 6.6% per annum. Semi-annual payments of interest are due and payable on June 16 and December 16 each year up until and including June 16, 2023. Equal blended semi-annual payments of principal and interest on the Bonds commenced on December 16, 2013 and will continue until and including June 16, 2023. The Bonds will not be fully amortized by their maturity date. The remaining principal balance of the Bonds will be fully due on June 16, 2023.

December 31	2017	2016
Bonds - principal balance	109,994	112,477
Less: unamortized deferred financing fees	(1,402)	(1,630)
Less: current portion	(2,649)	(2,483)
	105,943	108,364

As at December 31, 2017, principal repayments due in each of the next five years were as follows:

	2018	2019	2020	2021	2022
Principal repayments	2,649	2,827	3,017	3,219	3,435

Reconciliation of movements of liabilities to cash flows arising from financing activities:

Year ended December 31	2017	2016
Bonds, including current portion - beginning	110,847	112,954
Less: cash outflows for principal repayments	(2,483)	(2,327)
Add: non-cash amortization of deferred financing costs	228	220
Bonds, including current portion - ending	108,592	110,847

10. PARTNERSHIP UNITS

The Partnership is authorized to issue an unlimited number of Class A and Class B partnership units, of which 20,285,007 Class A units and 2 Class B units were issued and outstanding as at December 31, 2017 (2016 - 20,285,007 Class A and 2 Class B units).

(expressed in thousands of Canadian dollars)

11. COMMITMENTS AND CONTINGENCIES

Letters of credit

On behalf of the Partnership, HOI maintains a letter of credit totaling $3,960 to cover six months of interest payments on the Bonds. No amounts have been drawn against this letter of credit.

Commitments

As at December 31, 2017, future minimum lease payments for operating leases entered into by the Partnership, as lessee, were as follows:

December 31, 2017	Year 2018	Years 2019-2022	Thereafter
Minimum lease payments	343	343	$nil

Contingencies

The Partnership may, from time to time, be involved in legal proceedings, claims and litigation that arises in the ordinary course of business which the Partnership believes would not reasonably be expected to have a material adverse effect on the financial condition of the Partnership.

There are no specified decommissioning costs relating to the Partnership's assets. The Partnership has a comprehensive repair and capital expenditure program to ensure that its transmission lines are maintained to industry standards. Replacement of the assets occurs in accordance with a long term capital plan and would involve typical costs of removal as part of that process. In the circumstance where a portion of a line or other assets were removed completely, there may be some contractual obligations under private or crown easements or other land rights which require the transmission owner to reinstate the land to a certain standard, typically the shape it was prior to the construction of the transmission assets. As well, certain environmental, land use and/or utility legislation, regulations and policy may apply in which the Partnership would have to comply with remediation requirements set by the government. The requirements will typically depend on the specific property characteristics and what criteria the government determines to be appropriate to meet safety and environmental concerns. These asset lives are indeterminate given their nature. As the individual assets or components reach the end of their useful lives, they are retired and replaced. Historically, certain asset components have been replaced a number of times, thus creating a perpetual asset with an indeterminate life. As such, the retirement date for these lines cannot be reasonably estimated and therefore, the fair value of the associated liability cannot be determined at this time. As a result, no liability has been accrued in these financial statements.

12. OPERATING AND ADMINISTRATION EXPENSES

Year ended December 31	2017	2016
Compensation expenses	4,381	5,276
Contract expenses	2,289	2,238
Materials	321	295
Other	1,051	1,664
	8,042	9,473

13. MAINTENANCE EXPENSES

Year ended December 31	2017	2016
Compensation expenses	519	544
Contract expenses	446	616
Materials	64	99
Other	366	357
	1,395	1,616

(expressed in thousands of Canadian dollars)

14. FINANCE COSTS

Year ended December 31	2017	2016
Interest expense on Bonds	7,376	7,533
Amortization of deferred financing fees on Bonds	228	220
Less: capitalized interest	(208)	(225)
	7,396	7,528

15. DEPRECIATION AND AMORTIZATION

Year ended December 31	2017	2016
Property, plant and equipment	8,795	8,995
Intangible assets	289	301
	9,084	9,296

16. INCOME TAXES

The Partnership does not record income tax expenses as it is not subject to income taxation as a result of its formation as a limited partnership.

17. STATEMENTS OF CASH FLOWS

The net change in non-cash working capital related to operations consist of the following:

Year ended December 31	2017	2016
Trade and other receivables	(39)	3,051
Prepaid expenses and other	22	38
Due from related parties	(311)	(3,188)
Trade and other payables	299	(227)
Due to related parties	529	(128)
Pension liability	(149)	(420)
	351	(874)

18. CAPITAL RISK MANAGEMENT

The Partnership's primary capital management objective is to ensure the sustainability of its capital to support continuing operations, meet its financial obligations, allow for growth opportunities and provide stable distributions to its partners. The Partnership manages its capital to maintain an investment grade credit rating while prudently making use of leverage in order to provide its ultimate parent with enhanced returns. In addition, the Partnership manages its capital to ensure access to incremental borrowings needed to fund new growth initiatives.

The Partnership manages its capital structure in accordance with changes in economic conditions. Generally, capital expenditures are funded with external borrowings. In order to adjust the capital structure, the Partnership may elect to adjust the distribution amount paid to its partners, increase or reduce the equity participation in new and existing operations, adjust the level of capital spending or issue new partnership units.

The Partnership manages its capital in order to maintain a debt to capitalization ratio below 75%. At December 31, 2017, the ratio was 49% (2016 - 51%). The table below presents the details of the Partnership's capitalization and the calculation of the ratio:

December 31	2017	2016
Bonds - principal balance	109,994	112,477
Total debt	109,994	112,477
Equity	114,878	109,578
Total capitalization	224,872	222,055
Debt to capitalization	49%	51%

(expressed in thousands of Canadian dollars)

There has been no change in the Partnership's approach to managing capital in the year.

19. FINANCIAL INSTRUMENTS

Fair value measurement

The Partnership defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

The Partnership classifies its financial assets and liabilities as outlined below:

		December 31, 2017		December 31, 2016	
	Class	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial assets					
Cash	LAR	2,967	2,967	1,682	1,682
Trade and other receivables	LAR	74	74	35	35
Financial liabilities					
Trade and other payables	OL	1,981	1,981	1,689	1,689
Bonds	OL	108,592	131,583	110,847	140,821

Classification details:
LAR - loans and receivables
OL - other liabilities

The carrying amounts for cash, trade and other receivables, trade and other payables, and due to and from related parties approximate fair value due to their short-term nature. Due to the use of subjective judgments and uncertainties in the determination of fair values, these values should not be interpreted as being realizable in an immediate settlement of the financial instruments.

Fair value hierarchy

The following provides a description of financial instruments that are measured subsequent to initial recognition at fair value, grouped into Levels 1 to 3 based on the degree to which the fair value is observable:

(a) Level 1 fair value measurements are those derived from quoted market prices (unadjusted) in active markets for identical assets or liabilities;

(b) Level 2 fair value measurements are those derived from inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices); and

(c) Level 3 fair value measurements are those derived from valuation techniques that include inputs for the asset or liability that are not based on observable market data (unobservable inputs).

No financial instruments have been ranked level 2 or 3, except for the Bonds which are ranked as level 2.

There were no transfers between Level 1, 2 and 3 during the reporting periods. The fair values of financial assets and liabilities carried at amortized cost are approximated by their carrying values, except for the Bonds.

Financial risk management

The Partnership has exposure to the following risks from its use of financial instruments: market risk, credit risk and liquidity risk.

The Partnership's management has overall responsibility for the establishment and oversight of the Partnership's risk management framework. Risk management policies are established to identify and analyze the risks faced by the Partnership, to set appropriate risk limits and controls and to monitor risks and ensure adherence to these limits. Risk management policies and systems are reviewed regularly to reflect changes in market conditions and the Partnership's activities. The Partnership, through its training and management standards and procedures, aims to maintain a disciplined and constructive control environment in which all employees understand their roles and obligations. The objectives, policies and processes for managing risk were consistent with those in the prior year.

(expressed in thousands of Canadian dollars)

Market Risk

Market risk is the risk that changes in market prices (interest rates) will affect the Partnership's income or the value of its holdings of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return.

The Partnership's Bonds are subject to a fixed interest rate of 6.6% per annum, payable semi-annually on June 16 and December 16. As a result of having fixed rate debt, fluctuations in market interest rates are not expected to materially affect the Partnership's cash flows.

Credit Risk

Credit risk is the risk of financial loss to the Partnership if a counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Partnership's receivables from counterparties. The carrying amount of financial assets represents the maximum credit exposure.

The Partnership actively manages its exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts, and continually monitors these exposures.

The majority of trade receivable transactions entered by the Partnership are with the Independent Electricity System Operator (IESO). The IESO operates the provincial transmission system, and is a reliable counterparty. The quality of the Partnership's counterparties mitigates the Partnership's exposure to credit risk.

The Partnership's maximum exposure to credit risk as at December 31 is as follows:

December 31	2017	2016
Trade and other receivables	74	35

The Partnership is also exposed to credit risk on cash. Credit risk is mitigated by ensuring the majority of the financial assets are placed with a major Canadian financial institution with strong investment-grade ratings by a primary ratings agency. The credit risk of cash has been assessed as low.

Liquidity Risk

Liquidity risk is the risk that the Partnership will encounter difficulty in meeting the obligations associated with its financial liabilities that are settled by delivering cash or another financial asset. The Partnership manages liquidity risk by forecasting cash flows required by operations and anticipating investing and financing activities to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when they are due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Partnership's reputation.

The table below analyzes the Partnership's financial liabilities into relevant maturity groupings based on the remaining period at the date of the statement of financial position to the contractual maturity date. The amounts disclosed in the table are the contractual undiscounted cash flows:

		Contractual Maturities				
December 31, 2017	Carrying Amount	Less than 1 year	Years 2-3	Years 4-5	More than 5 years	Total
Trade and other payables	1,981	1,981	—	—	—	1,981
Bonds	108,592	9,866	19,732	19,732	97,976	147,306
	110,573	11,847	19,732	19,732	97,976	149,287

At December 31, 2017, the Partnership's relatively stable operating cash flows provide sufficient liquidity to fund these contractual obligations.

20. RELATED PARTY TRANSACTIONS AND BALANCES

Through the normal course of business, the Partnership enters into transactions with parties that meet the definition of a related party. During 2017, the Partnership entered into the following transactions with entities considered to be related:

(a) The Partnership has received services from entities under common control in the normal course of operations. The balances payable and receivable for these services are non-interest bearing and unsecured.

Revenue

The IESO is a related party because they are controlled or significantly influenced by the Province, which is a shareholder of Hydro One Limited. Total revenue recorded during 2017 was $38,421 (last two months of 2016 - $6,325).

Corporate Costs

In accordance with a Services Agreement between Hydro One Networks Inc. and the Partnership in effect until December 31, 2018, the Partnership records a corporate cost allocation for services received. The Partnership may request such services as, but not limited to, information technology management, human resource administration, and financial administration. The total corporate cost allocation recorded as an expense during 2017 was $341 (last two months of 2016 - $57).

(b) In accordance with a Services Agreement between HOI and the Partnership in effect until December 31, 2018, the Partnership records a corporate cost allocation for services received. The Partnership may request such services as, but not limited to, strategic financial services, general counsel and secretary services. The total corporate cost allocation recorded as an expense during 2017 was $82 (last two months of 2016 - $13).

General Manager Secondment

In accordance with an Agreement between Hydro One Networks Inc. and the Partnership in effect until May 11, 2018, the Partnership records a cost allocation for the secondment of a General Manager. The total cost recorded as an expense during 2017 was $106 (last two months of 2016 - $nil).

Capital Project Upgrades

During 2017, the Partnership incurred costs to assist with protection upgrades as part of a capital project at one of its transmission stations. The total cost recorded during 2017 was $20 (last two months of 2016 - $nil).

Transmission System Operating Services

In accordance with an Operating Services Agreement between Hydro One Networks Inc. and the Partnership in effect until December 31, 2017, the Partnership recorded cost allocation for services received relating to operation of its transmission system. The total cost recorded as an expense during 2017 was $257 (last two months of 2016 - $nil).

During the first ten months of 2016, the Partnership was owned by Brookfield Infrastructure Partners LP (BIP) and entered into the following transactions with entities considered to be related:

(a) In the normal course of operations, Riskcorp Inc., an insurance broker related through common control, entered into transactions with the Partnership to provide insurance. The total cost allocated to the Partnership during the first ten months of 2016 was $200.

(b) The Partnership has provided services to and received services from entities under common control in the normal course of operations. The balances payable and receivable for these services were non-interest bearing and unsecured.

Office Complex

The office complex in which the Partnership conducts its operations is owned by Great Lakes Power Limited (GLPL), and leased by the Partnership. Lease payments are made to GLPL on a monthly basis, with the lease cost for the first ten months of 2016 equaling $286.

Communication Equipment

The Partnership uses a fiber optic network that is owned by GLPL and is licensed by the Partnership. License fee payments are made to GLPL on a quarterly basis, with the lease cost for the first ten months of 2016 equaling $139.

The Partnership owns Radio Systems Assets and issues licenses for the use of these assets to GLPL. License fee payments are received from GLPL on a quarterly basis, with the lease payments for the first ten months of 2016 equaling $38.

Pole Rental

The Partnership owns transmission poles and receives license fee payments in accordance with a Licensed Attachment Agreement between the Partnership and GLPL. This agreement allows GLPL to affix and maintain its apparatus and equipment to the transmission poles owned by the Partnership. Payments are received by the Partnership annually. Total payments received by the Partnership during the first ten months of 2016 are equal to $27.

(expressed in thousands of Canadian dollars)

Road Maintenance

The Partnership shares a remote roadway in the northern portion of its service territory with GLPL. The roadway is used for access to various generating stations and transmission stations. The road maintenance costs are shared between the Partnership and GLPL, with GLPL incurring the initial cost and passing a predetermined portion on to the Partnership. Payments for this road maintenance are made to GLPL as the costs are incurred by GLPL, with the total portion borne by the Partnership in the first ten months of 2016 being equal to $119.

Corporate Costs

In accordance with the Services Agreement between Brookfield Infrastructure Holdings (Canada) Inc. and the Partnership in effect from January 1, 2012 until January 1, 2017, the Partnership recorded corporate cost allocation of $349 for services received during the first ten months of 2016. These services included, but were not limited to, information technology management, human resource administration, and financial administration.

As a result, the following balances are receivable and payable at December 31:

December 31	2017	2016
Due from related parties		
Services provided to entities under common control	3,594	3,283
Due to related parties		
Services received from entities under common control	599	70

Transactions with key management personnel:

A summary of key management and director compensation for the year ended December 31, 2017 and 2016 are as follows:

Year ended December 31	2017	2016
Sales, management bonus and fees	321	814
Other benefits	40	110
Director fees	—	15
	361	939

Financial Statements

GREAT LAKES POWER TRANSMISSION LIMITED PARTNERSHIP

December 31, 2015

Deloitte.

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Independent Auditor's Report

To the Partners of
Great Lakes Power Transmission Limited Partnership

We have audited the accompanying financial statements of Great Lakes Power Transmission Limited Partnership, which comprise the statement of financial position as at December 31, 2015 and the statement of comprehensive income, statement of changes in partners' equity and statement of cash flows for the year then ended and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Great Lakes Power Transmission Limited Partnership as at December 31, 2015, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

Deloitte LLP

Chartered Professional Accountants
Licensed Public Accountants
April 5, 2016

Great Lakes Power Transmission Limited Partnership

Statement of Financial Position

Expressed in thousands of Canadian dollars

	Note		December 31, 2015		December 31, 2014
Assets					
Current Assets					
Cash		$	**3,340**	$	5,201
Trade and other receivables			**3,086**		3,422
Due from related parties	*20*		**95**		89
Prepaid expenses and other			**661**		696
			7,182		9,408
Property, plant and equipment, net	*5*		**218,843**		219,941
Intangible assets, net	*6*		**2,886**		2,742
		$	**228,911**	$	232,091
Liabilities					
Current liabilities					
Trade and other payables	*7*	$	**1,922**	$	3,223
Due to related parties	*20*		**198**		218
Current portion of Trans senior bonds	*9*		**2,327**		2,180
			4,447		5,621
Pension liability	*8*		**3,457**		7,677
Trans senior bonds	*9*		**110,627**		112,743
			118,531		126,041
Partners' equity			**110,380**		106,050
		$	**228,911**	$	232,091

Great Lakes Power Transmission Limited Partnership
Statement of Changes in Partners' Equity
Expressed in thousands of Canadian dollars

	Capital				
	Great Lakes Power Transmission Holdings LP	Great Lakes Power Transmission Inc.	Accumulated other comprehensive income (loss)	Retained earnings (deficit)	Total partners' equity
Balance at January 1, 2015	**$ 112,405**	**$ 11**	**$ (2,423)**	**$ (3,943)**	**$ 106,050**
Net income	-	-	-	11,449	11,449
Distributions paid	-	-	-	(11,338)	(11,338)
Other comprehensive income	-	-	4,219	-	4,219
Balance at December 31, 2015	**$ 112,405**	**$ 11**	**$ 1,796**	**$ (3,832)**	**$ 110,380**

	Capital				
	Great Lakes Power Transmission Holdings LP	Great Lakes Power Transmission Inc.	Accumulated other comprehensive income (loss)	Retained earnings (deficit)	Total partners' equity
Balance at January 1, 2014	$ 112,405	$ 11	$ (1,298)	$ (768)	$ 110,350
Net income	-	-	-	11,663	11,663
Distributions paid	-	-	-	(14,838)	(14,838)
Other comprehensive loss	-	-	(1,125)	-	(1,125)
Balance at December 31, 2014	$ 112,405	$ 11	$ (2,423)	$ (3,943)	$ 106,050

Great Lakes Power Transmission Limited Partnership
Statement of Comprehensive Income
Expressed in thousands of Canadian dollars

Years ended December 31,	*Note*	**2015**	2014
Revenue		**$ 39,887**	$ 39,805
Operating expenses			
Operating and administration	*12*	**9,473**	9,122
Depreciation and amortization	*15*	**9,645**	9,302
Maintenance	*13*	**1,257**	1,573
Taxes, other than income taxes		**111**	107
		20,486	20,104
Net operating income		**19,401**	19,701
Finance income		**(48)**	(66)
Finance costs	*14*	**7,651**	7,901
Loss on disposal of property, plant & equipment	*5*	**406**	215
Other income		**(57)**	(12)
Income for the period		**11,449**	11,663
Other comprehensive loss			
Items that will not be reclassified subsequently to profit or loss:			
Remeasurement of pension liability	*8*	**4,219**	(1,125)
Total comprehensive income		**$ 15,668**	$ 10,538

Great Lakes Power Transmission Limited Partnership
Statement of Cash Flows
Expressed in thousands of Canadian dollars

Years ended December 31,	*Note*		**2015**		2014
Operating Activities					
Net income		**$**	**11,449**	$	11,663
Items not affecting cash;					
Depreciation and amortization	*15*		**9,645**		9,302
Finance costs	*14*		**7,651**		7,901
Loss on disposal of property, plant & equipment	*5*		**406**		215
Net change in non-cash working capital and other	*17*		**(957)**		(942)
Operating cash flows before interest			**28,194**		28,139
Cash interest paid			**(7,686)**		(7,823)
			20,508		20,316
Investing activities					
Proceeds on disposition of property, plant and equipment	*5*		**48**		18
Additions to property, plant and equipment and intangible assets			**(8,899)**		(3,845)
			(8,851)		(3,827)
Financing activities					
Principal repayments on Trans senior bonds			**(2,180)**		(2,043)
Distributions paid			**(11,338)**		(14,838)
			(13,518)		(16,881)
Decrease in cash			**(1,861)**		(392)
Cash, beginning balance			**5,201**		5,593
Cash, ending balance		**$**	**3,340**	$	5,201

1. GENERAL INFORMATION

Ontario-based Great Lakes Power Transmission Limited Partnership (the "Partnership") was formed on May 17, 2007 for the purpose of acquiring the assets and liabilities of the transmission division of Great Lakes Power Limited ("GLPL"), a related party due to common ownership. The address of the Partnership's registered office is 2 Sackville Road, Suite B, Sault Ste. Marie, Ontario, Canada, P6B 6J6.

Great Lakes Power Transmission Holdings LP is the Limited Partner and holds a 99.99% interest in the Partnership. Great Lakes Power Transmission Inc., the General Partner, holds a 0.01% limited interest in the Partnership and is responsible for management of the Partnership. Both the General and Limited Partners are wholly owned subsidiaries of Brookfield Infrastructure Partners LP ("BIP"), the ultimate parent company and controlling party of the group.

The Partnership is engaged in the transmission of electricity to the area adjacent to Sault Ste. Marie, Canada and is subject to the regulations of the Ontario Energy Board ("OEB").

2. BASIS OF PRESENTATION

Statement of compliance

These financial statements, including comparatives, have been prepared in accordance with International Financial Reporting Standards ("IFRS"). Accounting policies are consistently applied to both years presented, unless otherwise stated.

The financial statements were approved and authorized for issue by those charged with governance of the Partnership on April 5, 2016.

Basis of measurement

The financial statements have been prepared on a going concern assumption using the historical cost basis except where otherwise noted. Historical cost is generally based on the fair value of the consideration given in exchange for assets or settlement of liabilities as at the date the transaction occurs.

Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Partnership's functional currency. All amounts have been rounded to the nearest thousand, unless otherwise indicated.

Critical judgments and estimation uncertainties

In the preparation of these financial statements in conformity with IFRS, management makes judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of revenues, expenses, assets and liabilities. Facts and circumstances may change and actual results could differ from those estimates.

Estimates and Judgments

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods

2. BASIS OF PRESENTATION (continued)

affected. Information about critical judgments and estimates in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements are included in the following notes:

Impairment

Assets, including property, plant and equipment and intangible assets are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amounts exceed their recoverable amounts. Intangible assets with indefinite useful lives are tested for impairment annually and whenever events or changes in circumstances indicate that their carrying amounts exceed their recoverable amounts. The assessment of fair value often requires estimates and assumptions on items such as approved uniform transmission rates, discount rates, rehabilitation and restoration costs, future capital requirements and future operating performance. Changes in such estimates could impact recoverable values of these assets. Estimates are reviewed annually by management.

Judgment is involved in assessing whether there is any indication that an asset or cash generating unit ("CGU") may be impaired. A CGU is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets. This assessment is made based on the analysis of changes in the market or business environment, and events that have transpired that have impacted the asset or CGU.

Depreciation of property, plant and equipment and intangible assets

Each property, plant and equipment and intangible asset is assessed annually for both its physical life limitations and its economic recoverability. Those assets with a finite life are depreciated on a straight-line basis over a useful life estimated by management. Asset useful lives and residual values are re-evaluated annually. At December 31, 2015 the carrying value of property plant and equipment and intangible assets is $218,843 (2014 - $219,941) and $2,886 (2014 - $2,742) respectively.

Fair value disclosures of Trans senior bonds

The Partnership has estimated the fair value of its Trans senior bonds for disclosure purposes, as they are not separately traded. The fair value is based on future cash flows and the timing of settlement, along with assumptions about the discount rate, credit risk and by incorporating other assumptions made by market participants. At December 31, 2015 the carrying value of Trans senior bonds is $112,954 (2014 - $114,923).

Pension

Significant estimates and assumptions are made in determining pension and employee future benefits as there are numerous factors that will affect the pension obligation. The actuarial determination of the accrued benefit obligation for pensions and post-employment benefits uses the projected unit credit method prorated on service which incorporates management's best estimate of future salary levels, other cost escalation, mortality rates, retirement ages of employees and other actuarial factors. In addition, actuarial determinations used in estimating obligations relating to the defined benefit plans incorporate assumptions using management's best estimates of factors including plan performance, salary escalation, retirement dates of employees

2. BASIS OF PRESENTATION (continued)

and drug cost escalation rates. At December 31, 2015 the carrying value of pension liabilities is $3,457 (2014 - $7,677).

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Partnership has consistently applied the following accounting policies to both periods presented in these financial statements:

Financial instruments

The Partnership recognizes all financial instruments at fair value upon initial recognition and subsequently classifies them into one of the following categories: Financial assets and financial liabilities at fair value through profit or loss, held-to-maturity, loans and receivables, available-for-sale and other liabilities. As at December 31, 2015, the Partnership only holds the following financial instruments: Trade and other payables, Trans Senior Bonds (which are classified as other financial liabilities) and trade and other receivables (which are classified as loans and receivables).

The Partnership initially recognizes other financial liabilities and loans and receivables on the trade date. The Partnership derecognizes a financial liability when its contractual obligations are discharged, cancelled, or expired.

Other financial liabilities including borrowings are initially measured at fair value net of transaction costs, and subsequently measured at amortized cost using the effective interest method. Subsequent to initial recognition, loans and receivables are measured at amortized cost using the effective interest method, less any impairment losses.

Property, plant and equipment

Recognition and measurement

Property, plant and equipment are measured at cost less accumulated depreciation and any accumulated impairment losses. When significant parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment. The cost of major inspections or overhauls is capitalized and costs relating to the replacement of a major part of property, plant and equipment are recognized in the carrying amount of the asset to which that part relates, if it is probable that the inspection, overhaul or replacement part will generate future economic benefits and its cost can be measured reliably. The carrying amount of previous inspections and overhauls, or the part being replaced is derecognized and any gain or loss is recognized against income. The cost of the day-to-day servicing of property, plant and equipment is recognized in operating and administration or maintenance expense as incurred.

Costs included in the carrying amount of property, plant and equipment include expenditures that are directly attributable to the acquisition or construction of the asset. The cost of self-constructed assets includes: materials, services, direct labour and directly attributable overheads.

Borrowing costs associated with major projects are capitalized during the construction period, if those projects meet the definition of a qualifying asset, meaning those projects that are under construction for a substantial period of time. Capitalization of borrowing costs is suspended during

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

extended periods in which construction development is interrupted. Assets under construction are recorded as work-in-progress until they become available for use.

When property, plant and equipment is disposed of or retired, the related cost, accumulated depreciation and any accumulated impairment losses are eliminated. Any resulting gains or losses are reflected against income in the period the asset is disposed of or retired.

Depreciation

The cost, net of estimated residual values, of an asset classified as property, plant and equipment is amortized over the estimated useful life of the asset using a straight-line method. Land is not depreciated.

The estimated useful lives of property, plant and equipment are as follows:

	Method	Rate
Transmission assets	Straight-line	5 to 60 years
Equipment and other assets	Straight-line	5 to 30 years

The estimated useful lives, residual values and method of depreciation are based on depreciation studies and are reviewed annually for reasonableness.

Construction work-in-progress assets are not depreciated until the assets become available for their intended use.

Impairment

At each reporting date, the Partnership reviews the carrying amount of its non-financial assets to determine whether there is any indication of impairment. Impairment assessments are conducted at the CGU level. If any such indication exists, the recoverable amount of the CGU is estimated.

The recoverable amount of the CGU is the greater of its value in use and its fair value less costs to sell. Value in use is based on the estimated future cash flows, discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized against income if the carrying amount of a CGU exceeds its recoverable amount.

Impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. If such indications exist, the Partnership estimates the recoverable amount of that CGU. A reversal of an impairment loss is recognized up to the lesser of the recoverable amount or the carrying amount that would have been determined (net of depreciation charges) had no impairment loss been recognized on the CGU.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Intangible assets

Acquired intangible assets having finite useful lives are measured at cost less accumulated amortization and any accumulated impairment losses. Intangible assets are capitalized if: (i) It is probable that the asset acquired or developed will generate future economic benefits, (ii) the intangible asset is identifiable, and (iii) the Partnership exerts control over the economic benefit to be derived from the asset. The costs incurred to establish technological feasibility or to maintain existing levels of performance are recognized in operating or maintenance expense as incurred.

The carrying costs of intangible assets include expenditures that are directly attributable to the acquisition or development of the asset. The cost of self-developed assets includes materials, services, direct labour and directly attributable overheads. Borrowing costs associated with major projects (qualifying assets) are capitalized during the development period. Qualifying assets are those projects that are under development for a substantial period of time. Assets under development are recorded as in progress until they become available for use.

Subsequent expenditures are capitalized only when it increases the future economic benefits embodied in the specific asset to which it relates. All other expenditures are recognized against income as incurred.

Amortization is based on the cost of the asset less its residual value and is calculated using the straight-line method over the estimated useful life of the asset from the date the asset is available for use, and is generally recognized against income. The useful lives of intangible assets range from 5 to 15 years. Land rights with indefinite lives are not amortized.

The estimated useful lives, residual values and method of amortization are reviewed annually for reasonableness.

Intangible assets with an indefinite life are tested for impairment on an annual basis.

Employee benefits

Short-term employee benefits

Short-term employee benefits are expensed as the related service is provided by the employee. A liability is recognized for the amount expected to be paid if the Partnership has a present legal or constructive obligation to pay this amount as a result of past service provided by the employee and the obligation can be estimated reliably.

Defined contribution plans

Obligations for contributions to defined contribution plans are expensed as the related service is provided by the employee. Prepaid contributions are recognized as an asset to the extent that a cash refund or a reduction in future payments is available.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Defined benefit plans

The Partnership's net obligation in respect to defined benefit plans is calculated separately for each plan by estimating the amount of future benefit that employees have earned in the current and prior periods, discounting that amount and deducting the fair value of any plan assets.

The calculation of defined benefit obligations is performed annually by a qualified actuary using the projected unit credit method. When the calculation results in a potential asset for the Partnership, the recognized asset is limited to the present value of economic benefits available in the form of any future refunds from the plan or reductions in future contributions to the plan. To calculate the present value of economic benefits, consideration is given to any applicable minimum funding requirements.

Remeasurements of the net defined benefit liability, which comprise actuarial gains and losses, the return on plan assets (excluding interest) and the effect of the asset ceiling (if any, excluding interest), are recognized immediately in other comprehensive income. The Partnership determines the net interest expense (income) on the net defined benefit liability (asset) for the period by applying the discount rate used to measure the defined benefit obligation at the beginning of the annual period to the then-net defined benefit liability (asset), taking into account any changes in the net defined benefit liability (asset) during the period as a result of contributions and benefit payments. Net interest expense and other expenses related to defined benefit plans are recognized against income.

When the benefits of a plan are changed or when a plan is curtailed, the resulting change in benefit that relates to past service or the gain or loss on curtailment is recognized immediately against income. The Partnership recognizes gains and losses on the settlement of a defined benefit plan when the settlement occurs. The gain or loss on curtailment or settlement comprises any resulting change in the fair value of plan assets, any change in the present value of the defined benefit obligation, and any relating actuarial gains or losses and past service costs that had not been previously been recognized.

Other long-term employee benefits

The Partnership's net obligation in respect of long-term employee benefits is the amount of future benefit that employees have earned in return for their service in the current and prior periods. That benefit is discounted to determine its present value. Remeasurements are recognized against income in the period in which they arise.

Revenue

Revenue is measured at the fair value of the consideration received or receivable. Revenue is recognized by the Partnership when a sales arrangement exists, delivery of goods or services has occurred, the amount of revenue and costs incurred or to be incurred in respect of the transaction can be measured reliably and it is probable that future economic benefits will flow to the Partnership.

The Partnership recognizes revenue on an accrual basis, when electricity is wheeled, at the regulated rate established by the OEB.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Foreign currency

Transactions in foreign currencies are translated to the functional currency of the Partnership at exchange rates at the dates of the transactions.

Borrowing costs

Borrowing costs that are directly attributable to the acquisition, construction or development of a qualifying asset are added to the cost of that asset, until it is available for use. Qualifying assets are those that take a substantial period of time to get ready for their intended use. The Partnership capitalizes borrowing costs by applying its cost of debt. All other borrowing costs are recognized in finance expense in the period in which they are incurred.

Changes in accounting policies

In 2015, there have been no new or amended accounting pronouncements that have had a material impact on the Partnership's financial statements.

4. FUTURE CHANGES IN ACCOUNTING POLICIES

A number of new standards, amendments to standards and interpretations are effective for annual periods beginning after December 31, 2015 and have not been applied in preparing these financial statements. Those which may be relevant to the Partnership are set out below. The Partnership does not plan to early adopt any of these standards.

Depreciation

On May 12, 2014, the IASB issued amendments to IAS 16, Property, Plant and Equipment ("IAS 16"), and IAS 38, Intangible Assets ("IAS 38"). In issuing the amendments, the IASB has clarified that the use of revenue-based methods to calculate the depreciation of a tangible asset is not appropriate because revenue generated by an activity that includes the use of a tangible asset generally reflects factors other than the consumption of the economic benefits embodied in the asset. The IASB has also clarified that revenue is generally presumed to be an inappropriate basis for measuring the consumption of the economic benefits embodied in an intangible asset. This presumption for an intangible asset, however, can be rebutted in certain limited circumstances. The standard is to be applied prospectively for reporting periods beginning on or after January 1, 2016 with early application permitted. The adoption of these amendments is not expected to have an impact on the Partnership's financial statements.

Revenue

On May 28, 2014 the IASB issued IFRS 15, Revenue from Contracts with Customers ("IFRS 15"). This standard outlines a single comprehensive model with prescriptive guidance for entities to use in accounting for revenue arising from contracts with its customers. IFRS 15 uses a control based approach to recognize revenue which is a change from the risk and reward approach under the current standard. This standard replaces IAS 18 Revenue, IAS 11 Construction Contracts and related interpretations. The effective date is for reporting periods beginning on or after January 1, 2018 with early application permitted. The Partnership has not yet determined the effect of adoption of IFRS 15 on its financial statements.

4. FUTURE CHANGES IN ACCOUNTING POLICIES (continued)

Financial instruments

On July 24, 2014 the IASB issued IFRS 9, Financial Instruments ("IFRS 9") as a complete standard. This standard replaces the guidance in IAS 39 Financial Instruments: Recognition and Measurement on the classification and measurement of financial assets and financial liabilities. IFRS 9 utilizes a single approach to determine whether a financial asset is measured at amortized cost or fair value and a new mixed measurement model for debt instruments having only two categories: amortized cost and fair value. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. Final amendments released on July 24, 2014 also introduce a new expected loss impairment model and limited changes to the classification and measurement requirements for financial assets. The IASB has tentatively decided to require an entity to apply IFRS 9 for annual periods beginning on or after January 1, 2018. The Partnership has not yet determined the effect of adoption of IFRS 9 on its financial statements.

Presentation of Financial Statements

On December 18, 2014 the IASB amended IAS 1, Presentation of Financial Statements ("IAS 1"). The amendments to existing IAS 1 requirements relate to materiality; order of the notes; subtotals; accounting policies; and disaggregation. The amendments are effective for annual periods beginning on or after January 1, 2016. The adoption of these amendments is not expected to have a significant impact on the Partnership's financial statements.

Employee Benefits

IAS 19, Employee Benefits ("IAS 19") was amended on July 30, 2014. These amendments clarify the application of the requirements of IAS 19 on determination of the discount rate to a regional market consisting of multiple countries sharing the same currency. These amendments are effective for annual periods beginning on or after January 1, 2016. The adoption of these amendments is not expected to have an impact on the Partnership's financial statements.

Leases

IFRS 16, Leases ("IFRS 16") was issued by the IASB on January 13, 2016, and will replace IAS 17, Leases. IFRS 16 will bring most leases onto the balance sheet for lessees under a single model, eliminating the distinction between operating and financing leases. Lessor accounting remains largely unchanged. The new standard is effective for annual periods beginning on or after January 1, 2019. The Partnership has not yet determined the effect of adoption of IFRS 16 on its financial statements.

Joint Arrangements

IFRS 11, Joint Arrangements ("IFRS 11") was amended by the IASB on May 6, 2014. The amendments add new guidance on how to account for the acquisition of an interest in a joint operation that constitutes a business. The amendments are effective for annual periods beginning on or after January 1, 2016. The adoption of these amendments is not expected to have an impact on the Partnership's financial statements.

(expressed in thousands of Canadian dollars)

5. PROPERTY, PLANT AND EQUIPMENT, NET

	Land	Equipment and other assets	Transmission assets	Work-in-progress	Total
Cost					
Balance, December 31, 2013	$ 236	$ 9,460	$ 230,145	$ 1,941	$ 241,782
Additions	-	-	-	4,044	4,044
Transfers	-	540	3,726	(4,266)	-
Disposals	-	(6)	(322)	(102)	(430)
Balance, December 31, 2014	$ 236	$ 9,994	$ 233,549	$ 1,617	$ 245,396
Additions	-	-	-	8,597	8,597
Transfers	-	808	7,352	(8,160)	-
Disposals	-	(163)	(1,935)	-	(2,098)
Balance, December 31, 2015	$ 236	$ 10,639	$ 238,966	$ 2,054	$ 251,895
Accumulated Depreciation					
Balance, December 31, 2013	$ -	$ 1,414	$ 15,283	$ -	$ 16,697
Additions (Depreciation)	-	920	7,933	-	8,853
Disposals	-	(6)	(89)	-	(95)
Balance, December 31, 2014	$ -	$ 2,328	$ 23,127	$ -	$ 25,455
Additions (Depreciation)	-	952	8,289	-	9,241
Disposals	-	(161)	(1,483)	-	(1,644)
Balance, December 31, 2015	$ -	$ 3,119	$ 29,933	$ -	$ 33,052
Carrying amounts					
Balance, December 31, 2014	$ 236	$ 7,666	$ 210,422	$ 1,617	$ 219,941
Balance, December 31, 2015	$ 236	$ 7,520	$ 209,033	$ 2,054	$ 218,843

During the year, the Partnership disposed of assets with a total net book value of $454 (2014 - $233) for net proceeds of $48 (2014 - $18). A resultant loss on disposal of property, plant and equipment of $406 (2014 - $215) was recorded to the statement of comprehensive income.

(expressed in thousands of Canadian dollars)

6. INTANGIBLE ASSETS, NET

	Land rights	Computer software	Work-in-progress	Total
Cost				
Balance, December 31, 2013	$ 1,102	$ 2,839	$ 271	$ 4,212
Additions	-	-	139	139
Transfers	-	46	(46)	-
Disposals	-	-	(110)	(110)
Balance, December 31, 2014	1,102	2,885	254	4,241
Additions	-	-	623	623
Transfers	124	459	(583)	-
Disposals	-	(3)	(75)	(78)
Balance, December 31, 2015	$ 1,226	$ 3,341	$ 219	$ 4,786
Accumulated Depreciation				
Balance, December 31, 2013	$ -	$ 1,050	$ -	$ 1,050
Additions (Amortization)	-	449	-	449
Disposals		-	-	-
Balance, December 31, 2014	-	1,499	-	1,499
Additions (Amortization)	-	404	-	404
Disposals	-	(3)	-	(3)
Balance, December 31, 2015	$ -	$ 1,900	$ -	$ 1,900
Carrying amounts				
Balance, December 31, 2014	$ 1,102	$ 1,386	$ 254	$ 2,742
Balance, December 31, 2015	$ 1,226	$ 1,441	$ 219	$ 2,886

During the year, the Partnership wrote off $75 (2014 - $110) in work-in-progress assets, which was recorded to the statement of comprehensive income under operating and administration expense.

The Partnership owns land rights and other land easements that are needed as part of the normal business operations. Land rights have been obtained through contractual rights where the transferor has transferred land rights and land easements to specific parcels of land. The Partnership has identified land rights as intangible assets with an indefinite useful life since contractual rights give access to specific land parcels in perpetuity. The Partnership accounts for land rights at cost less cumulative impairment losses, if any. At December 31, 2015 the carrying amounts of land rights is $1,226 (2014 - $1,102).

The Partnership has not identified events or changes in circumstances that indicate that the land rights' carrying amounts exceed their recoverable amounts. The Partnership has tested land rights for impairment in accordance with annual impairment tests.

(expressed in thousands of Canadian dollars)

6. INTANGIBLE ASSETS, NET (continued)

The Partnership has identified the recoverable amount of land rights to be their fair values less cost of disposal. In arriving at the fair value less cost of disposal, the Partnership has used a recent sale proposal which it believes is indicative of the fair value less cost of disposal of the land rights owned. The Partnership has determined that as at December 31, 2015 the fair value less cost of disposal is greater than the carrying amount and hence no impairment loss has been recorded.

The Partnership uses fair value less cost of disposal to determine the recoverable amount as it believes that this will generally result in a value greater than or equal to the value in use. For the purpose of the intangible impairment test, the Partnership used a non-binding sale agreement. The inputs used in the fair value measurement constitute Level 2 inputs under the fair value hierarchy. Level 2 inputs are quoted prices in markets that are not active, quoted prices for similar assets or liabilities in active markets, inputs other than quoted prices that are observable for the asset or liability (for example, interest rate and yield curves observable at commonly quoted intervals, forward pricing curves used to value currency and commodity contracts), or inputs that are derived principally from or corroborated by observable market data or other means.

7. TRADE AND OTHER PAYABLES

	Dec 31, 2015	Dec 31, 2014
Trade payables and accruals	$ 404	$ 955
Payroll liabilities	426	527
Accrued interest	311	322
Connection deposits	593	1,076
Other payables	188	343
	$ 1,922	$ 3,223

The Partnership retains connection deposits for power generating entities as reimbursement to the Partnership for costs to be incurred in connecting those power generating entities to the Partnership's power transmission property assets. Any unused connection deposit balance will be refunded to the appropriate power generating entity.

8. PENSION AND EMPLOYEE FUTURE BENEFITS

The Partnership is part of a registered defined benefit, final pay pension plan and other post-employment benefit plan (the "Plans").

The other post-employment benefit plan includes benefits such as health and dental care, and life insurance. The obligation under these plans is determined periodically through the preparation of actuarial valuations. The Partnership contributions for the benefit plans for 2015 was $1,142 (2014 - $1,193).

The Partnership also participates in a defined contribution pension plan provided to certain employees. The Partnership contributes based on the level of employee contributions for this plan. In 2015, the total employer expense for the Partnership's defined contribution pension plan was $138 (2014 - $140). The minimum employer's contribution for 2016 is estimated to be $82.

The Partnership's pension plan information is provided in the following tables:

(expressed in thousands of Canadian dollars)

8. PENSION AND EMPLOYEE FUTURE BENEFITS (continued)

	December 31, 2015			December 31, 2014		
	Defined Benefit Pension Plan	Non-Pension Benefit Plans	Total	Defined Benefit Pension Plan	Non-Pension Benefit Plans	Total
Change in the present value of the accrued benefit obligation						
Balance, beginning of year	22,645	6,869	29,514	20,415	5,708	26,123
Current service cost	415	259	674	376	195	571
Past service cost	-	-	-	-	(315)	(315)
Interest expense	888	278	1,166	989	269	1,258
Benefit payments from plan	(922)	(95)	(1,017)	(892)	(142)	(1,034)
Employee contributions	115	-	115	117	-	117
Increases (decreases) due to other significant events	-	-	-	(25)	-	(25)
Remeasurements:						
Effect of changes in demographic assumptions	-	(1,775)	(1,775)	200	102	302
Effect of changes in financial assumptions	(499)	(11)	(510)	1,966	1,052	3,018
Effect of experience adjustments	22	(648)	(626)	(501)	-	(501)
Balance, end of year	**22,664**	**4,877**	**27,541**	**22,645**	**6,869**	**29,514**
Change in fair value of the plan assets						
Fair value, beginning of year	21,837	-	21,837	19,070	-	19,070
Return on plan assets	1,213	-	1,213	1,763	-	1,763
Contributions:						
Employer	1,047	95	1,142	1,051	142	1,193
Employee	115	-	115	117	-	117
Benefit payments from plan	(922)	(95)	(1,017)	(892)	(142)	(1,034)
Administrative expenses paid from plan assets	(61)	-	(61)	(208)	-	(208)
Interest income	875	-	875	956	-	956
Decreases due to other significant events	-	-	-	(20)	-	(20)
Fair value, end of year	**24,084**	**-**	**24,084**	**21,837**	**-**	**21,837**
Net Defined Benefit Liability						
Accrued benefit obligation	(22,664)	(4,877)	(27,541)	(22,645)	(6,869)	(29,514)
Fair value of plan assets	24,084	-	24,084	21,837	-	21,837
Net Defined Benefit Liability	1,420	(4,877)	(3,457)	(808)	(6,869)	(7,677)
Total expense recognized in profit and loss						
Current service cost	415	259	674	376	195	571
Past service cost	-	-	-	-	(315)	(315)
Net interest expense	13	278	291	32	266	298
Administrative expenses and taxes	175	-	175	140	-	140
Total expense recognized in profit and loss	**603**	**537**	**1,140**	**548**	**146**	**694**
Actuarial losses/(gains) recognized in statement of comprehensive income						
Effect of changes in demographic assumptions	-	(1,775)	(1,775)	200	102	302
Effect of changes in financial assumptions	(499)	(11)	(510)	1,966	1,052	3,018
Effect of experience adjustments	22	(648)	(626)	(501)	-	(501)
Return on plan assets	(1,308)	-	(1,308)	(1,694)	-	(1,694)
Total actuarial losses/(gains) recognized in statement of comprehensive income	**(1,785)**	**(2,434)**	**(4,219)**	**(29)**	**1,154**	**1,125**

Effects of changes in assumptions

	Revalued pension obligation	Revalued pension obligation	Total
Discount Rate			
Increase by 100 basis points	18,875	832	19,707
Decrease by 100 basis points	25,443	968	26,411
Inflation Rate			
Increase by 100 basis points	23,778	895	24,673
Decrease by 100 basis points	19,840	895	20,735

Significant Actuarial Assumptions	Defined Benefit Pension Plan	Non-Pension Benefit Plans	Defined Benefit Pension Plan	Non-Pension Benefit Plans
	December 31, 2015		December 31, 2014	
Weighted-Average actuarial assumptions used:				
Discount rate	4.15%	4.20%	4.00%	4.10%
Rate of compensation increases	3.00%	3.00%	3.00%	3.00%
Inflation Rate	2.00%	2.00%	2.00%	2.00%

Plan Assets by asset class allocation (%)	31-Dec-15	31-Dec-14
Fixed Income	37%	33%
Equities	63%	67%
Other	0%	0%
Total	100%	100%

(expressed in thousands of Canadian dollars)

9. TRANS SENIOR BONDS

The Trans Senior Bonds (the "Bonds") have a principal amount of $120,000 and are secured by a charge on the Partnership's transmission real property assets, both present and future. On behalf of the Partnership, a company related through common control, BIP, continues to maintain a letter of credit in the amount of $3,960 to cover six months of interest payments on the Bonds.

The fair market value of the Bonds as at December 31, 2015 is $143,002 based on current market prices for debt with similar terms (2014 - $144,112). Amortization of deferred financing fees for the year related to the Partnership's Bonds are included in finance costs and totaled $211 (2014 - $203).

The Bonds bear interest at the rate of 6.6% per annum. Semi-annual payments of interest only were due and payable on June and December 16 each year up until and including June 16, 2013. Equal blended semi-annual payments of principal and interest on the Bonds commenced on December 16, 2013 and will continue until and including June 16, 2023. The Bonds will not be fully amortized by their maturity date. The remaining principal balance of the Bonds will be fully due on June 16, 2023.

	Dec 31, 2015	Dec 31, 2014
Trans senior bonds	$ 114,803	$ 116,984
Less: unamortized deferred financing fees	(1,849)	(2,061)
Less: current portion	(2,327)	(2,180)
	$ 110,627	$ 112,743

As at December 31, 2015, principal repayments due in each of the next five years were as follows:

	2016	2017	2018	2019	2020
Principal repayments	$ 2,327	$ 2,483	$ 2,649	$ 2,827	$ 3,017

During the year, the Partnership identified a number of projects which were considered to be qualifying assets for purposes of capitalizing borrowing costs. For the year ended December 31, 2015, the Partnership capitalized borrowing costs of $235 (2014 - $125). The capitalization rate on funds borrowed amounted to 6.6% (2014 - 6.6%).

10. PARTNERSHIP UNITS

The Partnership is authorized to issue an unlimited number of Class A and Class B partnership units, of which 20,285,007 Class A units and 2 Class B units were issued and outstanding as at December 31, 2015. 20,285,007 Class A units and 2 Class B units were issued and outstanding as at December 31, 2014.

(expressed in thousands of Canadian dollars)

11. COMMITMENTS AND CONTINGENCIES

Letters of credit

On behalf of the Partnership, BIP continues to maintain a letter of credit totaling $3,960 to cover six months of interest payments on the Bonds. No amount has been drawn against this letter of credit.

Commitments

As at December 31, 2015 future minimum lease payments for operating leases entered into by the Partnership, as lessee, were as follows:

	2016	2017-2020	Thereafter
Minimum lease payments	$336	$1,009	$nil

Contingencies

The Partnership may, from time to time, be involved in legal proceedings, claims and litigation that arises in the ordinary course of business which the Partnership believes would not reasonably be expected to have a material adverse effect on the financial condition of the Partnership.

There are no specified decommissioning costs relating to the Partnership's assets. The Partnership has a comprehensive repair and capital expenditure program to ensure that its transmission lines are maintained to industry standards. Replacement of the assets occurs in accordance with a long term capital plan and would involve typical costs of removal as part of that process. In the circumstance where a portion of a line or other assets were removed completely, there may be some contractual obligations under private or crown easements or other land rights which require the transmission owner to reinstate the land to a certain standard, typically the shape it was prior to the construction of the transmission assets. As well, certain environmental, land use and/or utility legislation, regulations and policy may apply in which the Partnership would have to comply with remediation requirements set by the government. The requirements will typically depend on the specific property characteristics and what criteria the government determines to be appropriate to meet safety and environmental concerns. These asset lives are indeterminate given their nature. As the individual assets or components reach the end of their useful lives, they are retired and replaced. Historically, certain asset components have been replaced a number of times, thus creating a perpetual asset with an indeterminate life. As such, the retirement date for these lines cannot be reasonably estimated and therefore, the fair value of the associated liability cannot be determined at this time. As a result, no liability has been accrued in these financial statements.

12. OPERATING AND ADMINISTRATION EXPENSES

	2015	2014
Compensation expenses	$ 6,025	$ 5,989
Contract expenses	1,635	1,780
Materials	771	801
Other	1,042	552
	$ 9,473	$ 9,122

(expressed in thousands of Canadian dollars)

13. MAINTENANCE EXPENSES

	2015	2014
Compensation expenses	$ 328	$ 393
Contract expenses	463	545
Materials	107	146
Other	359	489
	$ 1,257	$ 1,573

14. FINANCE COSTS

	2015	2014
Interest expense on Trans senior bonds	$ 7,675	$ 7,823
Amortization of deferred financing fees on Trans senior bonds	211	203
Less: capitalized interest	(235)	(125)
	$ 7,651	$ 7,901

15. DEPRECIATION AND AMORTIZATION

	2015	2014
Depreciation on property, plant and equipment	$ 9,241	$ 8,853
Amortization of intangible assets	404	449
	$ 9,645	$ 9,302

16. INCOME TAXES

The Partnership does not record income tax expenses as it is not subject to income taxation as a result of its formation as a limited partnership.

17. STATEMENT OF CASH FLOWS

Net change in non-cash working capital related to operations

	2015	2014
Trade and other receivables	$ 336	$ 54
Prepaid expenses and other	35	(326)
Due from related parties	(6)	(53)
Trade and other payables	(1,301)	250
Due to related parties	(20)	(367)
Pension liability	(1)	(500)
	$ (957)	$ (942)

(expressed in thousands of Canadian dollars)

18. CAPITAL RISK MANAGEMENT

The Partnership's primary capital management objective is to ensure the sustainability of its capital to support continuing operations, meet its financial obligations, allow for growth opportunities and provide stable distributions to its partners. The Partnership manages its capital to maintain an investment grade credit rating while prudently making use of leverage in order to provide its ultimate parent with enhanced returns. In addition, the Partnership manages its capital to ensure access to incremental borrowings needed to fund new growth initiatives.

The Partnership manages its capital structure in accordance with changes in economic conditions. Generally, capital expenditures are funded with external borrowings. In order to adjust the capital structure, the Partnership may elect to adjust the distribution amount paid to its partners, increase or reduce the equity participation in new and existing operations, adjust the level of capital spending or issue new partnership units.

The Partnership manages its capital in order to maintain a debt to capitalization ratio below 75%. As at December 31, 2015, the ratio was 52% (2014 – 52%). The table below presents the detail of the Partnership's capitalization and the calculation of the ratio:

	Dec 31, 2015	Dec 31, 2014
Trans senior bonds	$ 114,803	$ 116,984
	114,803	116,984
Partners' equity	110,380	106,050
Total capitalization	$ 225,183	$ 223,034
Debt to capitalization	51%	52%

There has been no change in the Partnership's approach to managing capital in the year.

(expressed in thousands of Canadian dollars)

19. FINANCIAL INSTRUMENTS

Fair value measurement

The Partnership defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

The Partnership classifies its financial assets and liabilities as outlined below:

		Dec 31, 2015		Dec 31, 2014	
	Class	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial assets					
Cash	LAR	$ 3,340	$ 3,340	$ 5,201	$ 5,201
Trade and other receivables	LAR	3,086	3,086	3,422	3,422
Financial liabilities					
Trade and other payables	OL	1,922	1,922	3,223	3,223
Trans senior bonds	OL	112,954	143,002	114,923	144,112

Classification details:
FVTPL – fair value through profit or loss
LAR – loans and receivables
OL – other liabilities

The statements of financial position carrying amounts for cash, trade and other receivables, trade and other payables, and due to and from related parties approximate fair value due to their short-term nature. Due to the use of subjective judgments and uncertainties in the determination of fair values, these values should not be interpreted as being realizable in an immediate settlement of the financial instruments.

Fair value hierarchy

The following provides a description of financial instruments that are measured subsequent to initial recognition at fair value, grouped into Levels 1 to 3 based on the degree to which the fair value is observable:

(a) Level 1 fair value measurements are those derived from quoted market prices (unadjusted) in active markets for identical assets or liabilities;
(b) Level 2 fair value measurements are those derived from inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices); and
(c) Level 3 fair value measurements are those derived from valuation techniques that include inputs for the asset or liability that are not based on observable market data (unobservable inputs).

No financial instruments have been ranked level 2 or 3, except for the Bonds which are ranked as level 2.

19. FINANCIAL INSTRUMENTS (continued)

There were no transfers between Level 1, 2 and 3 during the reporting periods. The fair values of financial assets and liabilities carried at amortized cost are approximated by their carrying values, except for the Bonds whose fair market value is presented in note 9.

Financial risk management

The Partnership has exposure to the following risks from its use of financial instruments: market risk, credit risk and liquidity risk.

The Partnership's management has overall responsibility for the establishment and oversight of the Partnership's risk management framework. Risk management policies are established to identify and analyze the risks faced by the Partnership, to set appropriate risk limits and controls and to monitor risks and ensure adherence to these limits. Risk management policies and systems are reviewed regularly to reflect changes in market conditions and the Partnership's activities. The Partnership, through its training and management standards and procedures, aims to maintain a disciplined and constructive control environment in which all employees understand their roles and obligations. The objectives, policies and processes for managing risk were consistent with those in the prior year.

Market Risk

Market risk is the risk that changes in market prices (interest rates) will affect the Partnership's income or the value of its holdings of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return.

The Partnership's Bonds are subject to a fixed interest rate of 6.6% per annum, payable semi-annually on June 16 and December 16. As a result of having fixed rate debt, fluctuations in market interest rates are not expected to materially affect the Partnership's cash flows.

Credit Risk

Credit risk is the risk of financial loss to the Partnership if a counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Partnership's receivables from counterparties. The carrying amount of financial assets represents the maximum credit exposure.

The Partnership actively manages its exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts, and continually monitors these exposures.

The majority of trade receivable transactions entered by the Partnership are with the Independent Electricity System Operator ("IESO"). The IESO operates the provincial transmission system, and is a reliable counterparty. The quality of the Partnership's counterparties mitigates the Partnership's exposure to credit risk.

(expressed in thousands of Canadian dollars)

19. FINANCIAL INSTRUMENTS (continued)

The Partnership's maximum exposure to credit risk as at December 31 is as follows:

	Dec 31, 2015	Dec 31, 2014
Trade and other receivables	$ 3,086	$ 3,422

The Partnership is also exposed to credit risk on cash. Credit risk is mitigated by ensuring the majority of the financial assets are placed with a major Canadian financial institution with strong investment-grade ratings by a primary ratings agency. The credit risk of cash has been assessed as low.

Liquidity Risk

Liquidity risk is the risk that the Partnership will encounter difficulty in meeting the obligations associated with its financial liabilities that are settled by delivering cash or another financial asset. The Partnership manages liquidity risk by forecasting cash flows required by operations and anticipating investing and financing activities to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when they are due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Partnership's reputation.

The table below analyzes the Partnership's financial liabilities into relevant maturity groupings based on the remaining period at the date of the statement of financial position to the contractual maturity date. The amounts disclosed in the table are the contractual undiscounted cash flows:

		Contractual Maturities				
	Carrying Amount	Less Than 1 Year	1-2 Years	3-5 Years	More Than 5 Years	Total
Trade and other payables	$ 1,922	$ 1,922	$ -	$ -	$ -	$ 1,922
Trans senior bonds	112,954	9,866	9,866	29,598	117,709	167,039
	$114,876	$11,788	$9,866	$29,598	$117,709	$168,961

At year end, the Partnership's relatively stable operating cash flows provide sufficient liquidity to fund these contractual obligations.

20. RELATED PARTY TRANSACTIONS AND BALANCES

Through the normal course of business, the Partnership enters into transactions with parties that meet the definition of a related party. Throughout the year ended December 31, 2015 the Partnership entered into the following transactions with entities considered to be related:

(a) In the normal course of operations, Riskcorp Inc., an insurance broker related through common control, entered into transactions with the Partnership to provide insurance. The total cost allocated to the Partnership in 2015 was $323 (2014 - $373) and no amount remains outstanding at year end.

(b) The Partnership has provided services to and received services from entities under common control in the normal course of operations. The balances payable and receivable for these services are non-interest bearing and unsecured. The balances payable to and receivable from related parties will come due during the following year.

Office Complex

The office complex in which the Partnership conducts its operations is owned by GLPL, and leased by the Partnership. Lease payments are made to GLPL on a monthly basis, with the annual lease cost for 2015 equal to $340 (2014 - $334).

Communication Equipment

The Partnership uses a fiber optic network that is owned by GLPL and is licensed by the Partnership. License fee payments are made to GLPL on a quarterly basis, with the annual lease cost for 2015 equal to $166 (2014 – $166).

The Partnership owns Radio Systems Assets and issues licenses for the use of these assets to GLPL. License fee payments are received from GLPL on a quarterly basis, with the annual lease payments for 2015 equal to $41 (2014 - $37).

Pole Rental

The Partnership owns transmission poles and receives license fee payments in accordance with a Licensed Attachment Agreement between the Partnership and GLPL. This agreement allows GLPL to affix and maintain its apparatus and equipment to the transmission poles owned by the Partnership. Payments are received by the Partnership annually. Total payments received by the Partnership in 2015 are equal to $33 (2014 - $33).

Road Maintenance

The Partnership shares a remote roadway in the northern portion of its service territory with GLPL. The roadway is used for access to various generating stations and transmission stations. The road maintenance costs are shared between the Partnership and GLPL, with GLPL incurring the initial cost and passing a predetermined portion on to the Partnership. Payments for this road maintenance are made to GLPL as the costs are incurred by GLPL, with the total portion borne by the Partnership in 2015 being equal to $135 (2014 - $136).

(expressed in thousands of Canadian dollars)

20. RELATED PARTY TRANSACTIONS AND BALANCES (continued)

Corporate Costs

In accordance with the Services Agreement between Brookfield Infrastructure Holdings (Canada) Inc. and the Partnership in effect January 1, 2012 until January 1, 2017, the Partnership records a corporate cost allocation for services received. The Partnership may request such services as but not limited to information technology management, human resource administration, and financial administration. The total corporate cost allocation recorded as an expense in 2015 was $412 (2014 - $400).

(c) As a result, the following balances are receivable (payable) as at:

	Dec 31, 2015	Dec 31, 2014
Due from related parties		
Services provided to entities under common control	$ 95	$ 89
Due to related parties		
Services received from entities under common control	$ 198	$ 218

(d) Transactions with key management personnel

A summary of key management and director compensation for the year ended December 31 is as follows:

	2015	2014
Salaries, management bonus and fees	$ 916	$ 881
Other benefits	124	129
Director fees	15	15
	$ 1,055	$ 1,025

21. SUBSEQUENT EVENT

On January 29th, 2016, Hydro One Inc. entered into a purchase agreement to acquire all of the issued and outstanding voting securities of the Partnership.

The transaction is conditional upon the satisfaction of customary closing conditions, including receipt of *Competition Act (Canada)* approval and approval of the OEB.

Financial Statements

Hydro One Sault Ste. Marie Limited Partnership

December 31, 2016

KPMG LLP
111 Elgin Street, Suite 200
Sault Ste. Marie ON P6A 6L6
Canada
Telephone (705) 949-5811
Fax (705) 949-0911

INDEPENDENT AUDITORS' REPORT

To the Partners of Hydro One Sault Ste. Marie Limited Partnership
(formerly known as Great Lakes Power Transmission Limited Partnership)

We have audited the accompanying financial statements of Hydro One Sault Ste. Marie Limited Partnership (formerly known as Great Lakes Power Transmission Limited Partnership), which comprise the statement of financial position as at December 31, 2016, the statements of comprehensive income, statement of changes in partners' equity and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Hydro One Sault Ste. Marie Limited Partnership as at December 31, 2016, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards**.**

Other Matter

The financial statements of Hydro One Sault Ste. Marie Limited Partnership as at and for the year ended December 31, 2015 were audited by another auditor who expressed an unmodified opinion on those statements on April 5, 2016.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

April 20, 2017
Sault Ste. Marie, Canada

Hydro One Sault Ste. Marie Limited Partnership

Statement of Financial Position

Expressed in thousands of Canadian dollars

	Note		**December 31, 2016**		December 31, 2015
Assets					
Current Assets					
Cash		**$**	**1,682**	$	3,340
Trade and other receivables			**35**		3,086
Due from related parties	*20*		**3,283**		95
Prepaid expenses and other			**623**		661
			5,623		7,182
Property, plant and equipment, net	*5*		**217,303**		218,843
Intangible assets, net	*6*		**3,708**		2,886
		$	**226,634**	$	228,911
Liabilities					
Current Liabilities					
Trade and other payables	*7*	**$**	**1,689**	$	1,922
Due to related parties	*20*		**70**		198
Current portion of Trans senior bonds	*9*		**2,483**		2,327
			4,242		4,447
Pension liability	*8*		**4,450**		3,457
Trans senior bonds	*9*		**108,364**		110,627
			117,056		118,531
Partners' equity			**109,578**		110,380
		$	**226,634**	$	228,911

Hydro One Sault Ste. Marie Limited Partnership

Statement of Changes in Partners' Equity

Expressed in thousands of Canadian dollars

	Capital				
	Hydro One Sault Ste. Marie Holdings LP	Hydro One Sault Ste. Marie Inc.	Accumulated other comprehensive income (loss)	Retained earnings (deficit)	Total partners' equity
Balance at January 1, 2016	**$ 112,405**	**$ 11**	**$ 1,796**	**$ (3,832)**	**$ 110,380**
Net income	-	-	-	11,684	11,684
Distributions paid	-	-	-	(11,073)	(11,073)
Other comprehensive loss	-	-	(1,413)	-	(1,413)
Balance at December 31, 2016	**$ 112,405**	**$ 11**	**$ 383**	**$ (3,221)**	**$ 109,578**

	Capital				
	Hydro One Sault Ste. Marie Holdings LP	Hydro One Sault Ste. Marie Inc.	Accumulated other comprehensive income (loss)	Retained earnings (deficit)	Total partners' equity
Balance at January 1, 2015	$ 112,405	$ 11	$ (2,423)	$ (3,943)	106,050
Net income	-	-	-	11,449	11,449
Distributions paid	-	-	-	(11,338)	(11,338)
Other comprehensive income	-	-	4,219	-	4,219
Balance at December 31, 2015	$ 112,405	$ 11	$ 1,796	$ (3,832)	$ 110,380

Hydro One Sault Ste. Marie Limited Partnership

Statement of Comprehensive Income

Expressed in thousands of Canadian dollars

Years ended December 31,	*Note*		**2016**		2015
Revenue		**$**	**40,204**	$	39,887
Operating expenses					
Operating and administration	*12*		**9,473**		9,473
Depreciation and amortization	*15*		**9,296**		9,645
Maintenance	*13*		**1,616**		1,257
Taxes, other than income taxes			**117**		111
			20,502		20,486
Net operating income			**19,702**		19,401
Finance income			**(46)**		(48)
Finance costs	*14*		**7,528**		7,651
Loss on disposal of property, plant & equipment			**600**		406
Other income			**(64)**		(57)
Income for the period			**11,684**		11,449
Other comprehensive (loss) income					
Items that will not be reclassified subsequently to profit or loss:					
Gain (loss) on remeasurement of pension liability			**(1,413)**		4,219
Total comprehensive income		**$**	**10,271**	$	15,668

Hydro One Sault Ste. Marie Limited Partnership

Statement of Cash Flows

Expressed in thousands of Canadian dollars

Years ended December 31,	*Note*		**2016**		2015
Operating Activities					
Net income		**$**	**11,684**	$	11,449
Items not affecting cash;					
Depreciation and amortization	*15*		**9,296**		9,645
Finance costs	*14*		**7,528**		7,651
Loss on disposal of property, plant & equipment			**600**		406
Net change in non-cash working capital and other	*17*		**(874)**		(957)
Operating cash flows before interest			**28,234**		28,194
Cash interest paid			**(7,539)**		(7,686)
			20,695		20,508
Investing activities					
Proceeds on disposition of property, plant and equipment			**6**		48
Additions to property, plant and equipment and intangible assets			**(8,959)**		(8,899)
			(8,953)		(8,851)
Financing activities					
Principal repayments on Trans senior bonds			**(2,327)**		(2,180)
Distributions paid			**(11,073)**		(11,338)
			(13,400)		(13,518)
Decrease in cash			**(1,658)**		(1,861)
Cash, beginning balance			**3,340**		5,201
Cash, ending balance		**$**	**1,682**	$	3,340

1. GENERAL INFORMATION

Hydro One Sault Ste. Marie Limited Partnership, formerly Great Lakes Power Transmission Limited Partnership (the "Partnership") was formed on May 17, 2007 for the purpose of acquiring the assets and liabilities of the transmission division of Great Lakes Power Limited ("GLPL"), previously a related party due to common ownership. On October 31, 2016, Hydro One Inc. ("HOI") completed the share purchase of the Great Lakes Power Transmission entities following approval by the Ontario Energy Board ("OEB") on October 13, 2016. As part of the transaction, Great Lakes Power Transmission LP legally changed their name to Hydro One Sault Ste. Marie LP on January 16, 2017. The address of the Partnership's registered office is 2 Sackville Road, Suite B, Sault Ste. Marie, Ontario, Canada, P6B 6J6.

Hydro One Sault Ste. Marie Holdings LP is the Limited Partner and holds a 99.99% interest in the Partnership. Hydro One Sault Ste. Marie Inc., the General Partner, holds a 0.01% limited interest in the Partnership and is responsible for management of the Partnership. Both the General and Limited Partners are wholly owned subsidiaries of HOI, the ultimate parent company and controlling party of the group.

The Partnership is engaged in the transmission of electricity to the area adjacent to Sault Ste. Marie, Canada and is subject to the regulations of the OEB.

2. BASIS OF PRESENTATION

Statement of compliance

These financial statements, including comparatives, have been prepared in accordance with International Financial Reporting Standards ("IFRS"). Accounting policies are consistently applied to both years presented, unless otherwise stated.

The financial statements were approved and authorized for issue by those charged with governance of the Partnership on April 20, 2017.

Basis of measurement

The financial statements have been prepared on a going concern assumption using the historical cost basis except where otherwise noted. Historical cost is generally based on the fair value of the consideration given in exchange for assets or settlement of liabilities as at the date the transaction occurs.

Critical judgments and estimation uncertainties

In the preparation of these financial statements in conformity with IFRS, management makes judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of revenues, expenses, assets and liabilities. Facts and circumstances may change and actual results could differ from those estimates.

Estimates and Judgments

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Information about critical judgments and estimates in applying accounting policies that have

2. BASIS OF PRESENTATION (continued)

the most significant effect on the amounts recognized in the financial statements are included in the following notes:

Impairment

Assets, including property, plant and equipment and intangible assets are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amounts exceed their recoverable amounts. Intangible assets with indefinite useful lives are tested for impairment annually and whenever events or changes in circumstances indicate that their carrying amounts exceed their recoverable amounts. The assessment of fair value often requires estimates and assumptions on items such as approved uniform transmission rates, discount rates, rehabilitation and restoration costs, future capital requirements and future operating performance. Changes in such estimates could impact recoverable values of these assets. Estimates are reviewed annually by management.

Judgment is involved in assessing whether there is any indication that an asset or cash generating unit ("CGU") may be impaired. A CGU is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets. This assessment is made based on the analysis of changes in the market or business environment, and events that have transpired that have impacted the asset or CGU.

Depreciation of property, plant and equipment and intangible assets

Each property, plant and equipment and intangible asset is assessed annually for both its physical life limitations and its economic recoverability. Those assets with a finite life are depreciated on a straight-line basis over a useful life estimated by management. Asset useful lives and residual values are re-evaluated annually. At December 31, 2016 the carrying value of property plant and equipment and intangible assets is $217,303 (2015 - $218,843) and $3,708 (2015 - $2,886) respectively.

Fair value disclosures of Trans senior bonds

The Partnership has estimated the fair value of its Trans senior bonds for disclosure purposes, as they are not separately traded. The fair value is based on future cash flows and the timing of settlement, along with assumptions about the discount rate, credit risk and by incorporating other assumptions made by market participants. At December 31, 2016 the carrying value of Trans senior bonds is $110,847 (2015 - $112,954).

Pension

Significant estimates and assumptions are made in determining pension and employee future benefits as there are numerous factors that will affect the pension obligation. The actuarial determination of the accrued benefit obligation for pensions and post-employment benefits uses the projected unit credit method prorated on service which incorporates management's best estimate of future salary levels, other cost escalation, mortality rates, retirement ages of employees and other actuarial factors. In addition, actuarial determinations used in estimating obligations relating to the defined benefit plans incorporate assumptions using management's best estimates of factors including plan performance, salary escalation, retirement dates of employees

2. BASIS OF PRESENTATION (continued)

and drug cost escalation rates. At December 31, 2016 the carrying value of pension liabilities is $4,450 (2015 - $3,457).

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Partnership has consistently applied the following accounting policies to both periods presented in these financial statements:

Financial instruments

The Partnership recognizes all financial instruments at fair value upon initial recognition and subsequently classifies them into one of the following categories: Financial assets and financial liabilities at fair value through profit or loss, held-to-maturity, loans and receivables, available-for-sale and other liabilities. As at December 31, 2016, the Partnership only holds the following financial instruments: Trade and other payables, Trans Senior Bonds (which are classified as other financial liabilities) and trade and other receivables (which are classified as loans and receivables).

The Partnership initially recognizes other financial liabilities and loans and receivables on the trade date. The Partnership derecognizes a financial liability when its contractual obligations are discharged, cancelled, or expired.

Other financial liabilities including borrowings are initially measured at fair value net of transaction costs, and subsequently measured at amortized cost using the effective interest method. Subsequent to initial recognition, loans and receivables are measured at amortized cost using the effective interest method, less any impairment losses.

Property, plant and equipment

Recognition and measurement

Property, plant and equipment are measured at cost less accumulated depreciation and any accumulated impairment losses. When significant parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment. The cost of major inspections or overhauls is capitalized and costs relating to the replacement of a major part of property, plant and equipment are recognized in the carrying amount of the asset to which that part relates, if it is probable that the inspection, overhaul or replacement part will generate future economic benefits and its cost can be measured reliably. The carrying amount of previous inspections and overhauls, or the part being replaced is derecognized and any gain or loss is recognized against income. The cost of the day-to-day servicing of property, plant and equipment is recognized in operating and administration or maintenance expense as incurred.

Costs included in the carrying amount of property, plant and equipment include expenditures that are directly attributable to the acquisition or construction of the asset. The cost of self-constructed assets includes: materials, services, direct labour and directly attributable overheads.

Borrowing costs associated with major projects are capitalized during the construction period, if those projects meet the definition of a qualifying asset, meaning those projects that are under construction for a substantial period of time. Capitalization of borrowing costs is suspended during

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

extended periods in which construction development is interrupted. Assets under construction are recorded as work-in-progress until they become available for use.

When property, plant and equipment is disposed of or retired, the related cost, accumulated depreciation and any accumulated impairment losses are eliminated. Any resulting gains or losses are reflected against income in the period the asset is disposed of or retired.

Depreciation

The cost, net of estimated residual values, of an asset classified as property, plant and equipment is amortized over the estimated useful life of the asset using a straight-line method. Land is not depreciated.

The estimated useful lives of property, plant and equipment are as follows:

	Method	Rate
Transmission assets	Straight-line	5 to 60 years
Equipment and other assets	Straight-line	5 to 30 years

The estimated useful lives, residual values and method of depreciation are based on depreciation studies and are reviewed annually for reasonableness.

Construction work-in-progress assets are not depreciated until the assets become available for their intended use.

Impairment

At each reporting date, the Partnership reviews the carrying amount of its non-financial assets to determine whether there is any indication of impairment. Impairment assessments are conducted at the CGU level. If any such indication exists, the recoverable amount of the CGU is estimated.

The recoverable amount of the CGU is the greater of its value in use and its fair value less costs to sell. Value in use is based on the estimated future cash flows, discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized against income if the carrying amount of a CGU exceeds its recoverable amount.

Impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. If such indications exist, the Partnership estimates the recoverable amount of that CGU. A reversal of an impairment loss is recognized up to the lesser of the recoverable amount or the carrying amount that would have been determined (net of depreciation charges) had no impairment loss been recognized on the CGU.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Intangible assets

Acquired intangible assets having finite useful lives are measured at cost less accumulated amortization and any accumulated impairment losses. Intangible assets are capitalized if: (i) It is probable that the asset acquired or developed will generate future economic benefits, (ii) the intangible asset is identifiable, and (iii) the Partnership exerts control over the economic benefit to be derived from the asset. The costs incurred to establish technological feasibility or to maintain existing levels of performance are recognized in operating or maintenance expense as incurred.

The carrying costs of intangible assets include expenditures that are directly attributable to the acquisition or development of the asset. The cost of self-developed assets includes materials, services, direct labour and directly attributable overheads. Borrowing costs associated with major projects (qualifying assets) are capitalized during the development period. Qualifying assets are those projects that are under development for a substantial period of time. Assets under development are recorded as in progress until they become available for use.

Subsequent expenditures are capitalized only when it increases the future economic benefits embodied in the specific asset to which it relates. All other expenditures are recognized against income as incurred.

Amortization is based on the cost of the asset less its residual value and is calculated using the straight-line method over the estimated useful life of the asset from the date the asset is available for use, and is generally recognized against income. The useful lives of intangible assets range from 5 to 15 years. Land rights with indefinite lives are not amortized.

The estimated useful lives, residual values and method of amortization are reviewed annually for reasonableness.

Intangible assets with an indefinite life are tested for impairment on an annual basis.

Employee benefits

Short-term employee benefits

Short-term employee benefits are expensed as the related service is provided by the employee. A liability is recognized for the amount expected to be paid if the Partnership has a present legal or constructive obligation to pay this amount as a result of past service provided by the employee and the obligation can be estimated reliably.

Defined contribution plans

Obligations for contributions to defined contribution plans are expensed as the related service is provided by the employee. Prepaid contributions are recognized as an asset to the extent that a cash refund or a reduction in future payments is available.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Defined benefit plans

The Partnership's net obligation in respect to defined benefit plans is calculated separately for each plan by estimating the amount of future benefit that employees have earned in the current and prior periods, discounting that amount and deducting the fair value of any plan assets.

The calculation of defined benefit obligations is performed annually by a qualified actuary using the projected unit credit method. When the calculation results in a potential asset for the Partnership, the recognized asset is limited to the present value of economic benefits available in the form of any future refunds from the plan or reductions in future contributions to the plan. To calculate the present value of economic benefits, consideration is given to any applicable minimum funding requirements.

Re-measurements of the net defined benefit liability, which comprise actuarial gains and losses, the return on plan assets (excluding interest) and the effect of the asset ceiling (if any, excluding interest), are recognized immediately in other comprehensive income. The Partnership determines the net interest expense (income) on the net defined benefit liability (asset) for the period by applying the discount rate used to measure the defined benefit obligation at the beginning of the annual period to the then-net defined benefit liability (asset), taking into account any changes in the net defined benefit liability (asset) during the period as a result of contributions and benefit payments. Net interest expense and other expenses related to defined benefit plans are recognized against income.

When the benefits of a plan are changed or when a plan is curtailed, the resulting change in benefit that relates to past service or the gain or loss on curtailment is recognized immediately against income. The Partnership recognizes gains and losses on the settlement of a defined benefit plan when the settlement occurs. The gain or loss on curtailment or settlement comprises any resulting change in the fair value of plan assets, any change in the present value of the defined benefit obligation, and any relating actuarial gains or losses and past service costs that had not been previously been recognized.

Other long-term employee benefits

The Partnership's net obligation in respect of long-term employee benefits is the amount of future benefit that employees have earned in return for their service in the current and prior periods. That benefit is discounted to determine its present value. Re-measurements are recognized against income in the period in which they arise.

Revenue

Revenue is measured at the fair value of the consideration received or receivable. Revenue is recognized by the Partnership when a sales arrangement exists, delivery of goods or services has occurred, the amount of revenue and costs incurred or to be incurred in respect of the transaction can be measured reliably and it is probable that future economic benefits will flow to the Partnership.

The Partnership recognizes revenue on an accrual basis, when electricity is wheeled, at the regulated rate established by the OEB.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Foreign currency

Transactions in foreign currencies are translated to the functional currency of the Partnership at exchange rates at the dates of the transactions.

Borrowing costs

Borrowing costs that are directly attributable to the acquisition, construction or development of a qualifying asset are added to the cost of that asset, until it is available for use. Qualifying assets are those that take a substantial period of time to get ready for their intended use. The Partnership capitalizes borrowing costs by applying its cost of debt. All other borrowing costs are recognized in finance expense in the period in which they are incurred.

Changes in accounting policies

In 2016, there have been no new or amended accounting pronouncements that have had a material impact on the Partnership's financial statements.

4. FUTURE CHANGES IN ACCOUNTING POLICIES

A number of new standards, amendments to standards and interpretations are effective for annual periods beginning after December 31, 2016 and have not been applied in preparing these financial statements. Those which may be relevant to the Partnership are set out below. The Partnership does not plan to early adopt any of these standards.

Revenue

On May 28, 2014 the IASB issued IFRS 15, Revenue from Contracts with Customers ("IFRS 15"). This standard outlines a single comprehensive model with prescriptive guidance for entities to use in accounting for revenue arising from contracts with its customers. IFRS 15 uses a control based approach to recognize revenue which is a change from the risk and reward approach under the current standard. This standard replaces IAS 18 Revenue, IAS 11 Construction Contracts and related interpretations. The effective date is for reporting periods beginning on or after January 1, 2018 with early application permitted. The Partnership has not yet determined the effect of adoption of IFRS 15 on its financial statements.

Financial instruments

On July 24, 2014 the IASB issued IFRS 9, Financial Instruments ("IFRS 9") as a complete standard. This standard replaces the guidance in IAS 39 Financial Instruments: Recognition and Measurement on the classification and measurement of financial assets and financial liabilities. IFRS 9 utilizes a single approach to determine whether a financial asset is measured at amortized cost or fair value and a new mixed measurement model for debt instruments having only two categories: amortized cost and fair value. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. Final amendments released on July 24, 2014 also introduce a new expected loss impairment model and limited changes to the classification and measurement requirements for financial assets. The IASB has tentatively decided to require an

4. FUTURE CHANGES IN ACCOUNTING POLICIES (continued)

entity to apply IFRS 9 for annual periods beginning on or after January 1, 2018. The Partnership has not yet determined the effect of adoption of IFRS 9 on its financial statements.

Leases

IFRS 16, Leases ("IFRS 16") was issued by the IASB on January 13, 2016, and will replace IAS 17, Leases. IFRS 16 will bring most leases onto the balance sheet for lessees under a single model, eliminating the distinction between operating and financing leases. Lessor accounting remains largely unchanged. The new standard is effective for annual periods beginning on or after January 1, 2019. The Partnership has not yet determined the effect of adoption of IFRS 16 on its financial statements.

Financial Statement Disclosure

On January 7, 2016 the IASB issued Disclosure Initiative (Amendments to IAS 7). The amendments apply prospectively for annual periods beginning on or after January 1, 2017, earlier application is permitted. The amendments require disclosures that enable users of financial statements to evaluate changes in liabilities arising from financing activities, including both changes arising from cash flow and non-cash changes. One way to meet this new disclosure requirement is to provide a reconciliation between the opening and closing balances for liabilities from financing activities. The Partnership intends to adopt the amendments to IAS 7 in its financial statements for the annual period beginning on January 1, 2017. The Partnership does not expect the amendments to have a material impact on the financial statements.

5. PROPERTY, PLANT AND EQUIPMENT, NET

	Land	Equipment and other assets	Transmission assets	Work-in-progress	Total
Cost					
Balance, December 31, 2014	$ 236	$ 9,994	$ 233,549	$ 1,617	$ 245,396
Additions	-	-	-	8,597	8,597
Transfers	-	808	7,352	(8,160)	-
Disposals	-	(163)	(1,935)	-	(2,098)
Balance, December 31, 2015	$ 236	$ 10,639	$ 238,966	$ 2,054	$ 251,895
Additions	-	-	-	8,329	8,329
Transfers	-	1,046	7,170	(8,216)	-
Disposals	-	(42)	(765)	(268)	(1,075)
Balance, December 31, 2016	$ 236	$ 11,643	$ 245,371	$ 1,899	$ 259,149
Accumulated Depreciation					
Balance, December 31, 2014	$ -	$ 2,328	$ 23,127	$ -	$ 25,455
Additions (Depreciation)	-	952	8,289	-	9,241
Disposals	-	(161)	(1,483)	-	(1,644)
Balance, December 31, 2015	$ -	$ 3,119	$ 29,933	$ -	$ 33,052
Additions (Depreciation)	-	917	8,078	-	8,995
Disposals	-	(42)	(159)	-	(201)
Balance, December 31, 2016	$ -	$ 3,994	$ 37,852	$ -	$ 41,846
Carrying amounts					
Balance, December 31, 2015	$ 236	$ 7,520	$ 209,033	$ 2,054	$ 218,843
Balance, December 31, 2016	$ 236	$ 7,649	$ 207,519	$ 1,899	$ 217,303

During the year, the Partnership disposed of assets with a total net book value of $606 (2015 - $454) for net proceeds of $6 (2015 - $48). A resultant loss on disposal of property, plant and equipment of $600 (2015 - $406) was recorded to the statement of comprehensive income. The Partnership also wrote off $268 (2015 - $nil) in work-in-progress assets, which was recorded to the statement of comprehensive income under operating and administration expense.

6. INTANGIBLE ASSETS, NET

	Land rights	Computer software	Work-in-progress	Total
Cost				
Balance, December 31, 2014	$ 1,102	$ 2,885	$ 254	$ 4,241
Additions	-	-	623	623
Transfers	124	459	(583)	-
Disposals	-	(3)	(75)	(78)
Balance, December 31, 2015	1,226	3,341	219	4,786
Additions	-	-	1,123	1,123
Transfers	970	372	(1,342)	-
Disposals	-	-	-	-
Balance, December 31, 2016	$ 2,196	$ 3,713	-	$ 5,909
Accumulated Depreciation				
Balance, December 31, 2014	$ -	$ 1,499	$ -	$ 1,499
Additions (Amortization)	-	404	-	404
Disposals	-	(3)	-	(3)
Balance, December 31, 2015	-	1,900	-	1,900
Additions (Amortization)	5	296	-	301
Disposals	-	-	-	-
Balance, December 31, 2016	$ 5	$ 2,196	$ -	$ 2,201
Carrying amounts				
Balance, December 31, 2015	$ 1,226	$ 1,441	$ 219	$ 2,886
Balance, December 31, 2016	$ 2,191	$ 1,517	$ -	$ 3,708

During the year, the Partnership did not write off any work-in-progress assets (2015 - $75).

The Partnership owns land rights and other land easements that are needed as part of the normal business operations. Land rights have been obtained through contractual rights where the transferor has transferred land rights and land easements to specific parcels of land. The Partnership has identified these land rights as intangible assets with having either indefinite useful lives (in instances where contractual rights give access to specific land parcels in perpetuity) or where land rights are over a finite period, amortize over the term of the agreement they have with the land owner. The Partnership accounts for land rights at cost less depreciation and cumulative impairment losses, if any. At December 31, 2016 the carrying amounts of land rights is $2,191 (2015 - $1,226).

The Partnership has not identified events or changes in circumstances that indicate that the land rights' carrying amounts exceed their recoverable amounts. The Partnership has tested land rights for impairment in accordance with annual impairment tests.

6. INTANGIBLE ASSETS, NET (continued)

The Partnership has identified the recoverable amount of land rights to be their fair values less cost of disposal. In arriving at the fair value less cost of disposal, the Partnership has used a recent purchase transaction which it believes is indicative of the fair value less cost of disposal of the land rights owned. The Partnership has determined that as at December 31, 2016 the fair value less cost of disposal is greater than the carrying amount and hence no impairment loss has been recorded.

The Partnership uses fair value less cost of disposal to determine the recoverable amount as it believes that this will generally result in a value greater than or equal to the value in use. For the purpose of the intangible impairment test, the Partnership used a recent purchase agreement. The inputs used in the fair value measurement constitute Level 2 inputs under the fair value hierarchy. Level 2 inputs are quoted prices in markets that are not active, quoted prices for similar assets or liabilities in active markets, inputs other than quoted prices that are observable for the asset or liability (for example, interest rate and yield curves observable at commonly quoted intervals, forward pricing curves used to value currency and commodity contracts), or inputs that are derived principally from or corroborated by observable market data or other means.

7. TRADE AND OTHER PAYABLES

	2016	2015
Trade payables and accruals	$ 667	$ 404
Payroll liabilities	433	426
Accrued interest	305	311
Connection deposits	69	593
Other payables	215	188
	$ 1,689	$ 1,922

The Partnership retains connection deposits for power generating entities as reimbursement to the Partnership for costs to be incurred in connecting those power generating entities to the Partnership's power transmission property assets. Any unused connection deposit balance will be refunded to the appropriate power generating entity.

8. PENSION AND EMPLOYEE FUTURE BENEFITS

The Partnership is part of a registered defined benefit, final pay pension plan and other post-employment benefit plan (the "Plans").

The other post-employment benefit plan includes benefits such as health and dental care, and life insurance. The obligation under these plans is determined periodically through the preparation of actuarial valuations. The Partnership contributions for the benefit plans for 2016 was $1,116 (2015 - $1,142).

The Partnership also participates in a defined contribution pension plan provided to certain employees. The Partnership contributes based on the level of employee contributions for this plan. In 2016, the total employer expense for the Partnership's defined contribution pension plan was $147 (2015 - $138). The minimum employer's contribution for 2017 is estimated to be $137.

The Partnership's pension plan information is provided in the following tables:

8. PENSION AND EMPLOYEE FUTURE BENEFITS (continued)

	December 31, 2016			December 31, 2015		
	Defined Benefit Pension Plan	**Non-Pension Benefit Plans**	**Total**	**Defined Benefit Pension Plan**	**Non-Pension Benefit Plans**	**Total**
Change in the present value of the accrued benefit obligation						
Balance, beginning of year	22,664	4,877	27,541	22,645	6,869	29,514
Current service cost	417	134	551	415	259	674
Interest expense	921	202	1,123	888	278	1,166
Benefit payments from plan	(985)	(125)	(1,110)	(922)	(95)	(1,017)
Employee contributions	116	-	116	115	-	115
Increases (decreases) due to other significant events	(325)	-	(325)	-	-	-
Remeasurements:						
Effect of changes in demographic assumptions	309	113	422	-	(1,775)	(1,775)
Effect of changes in financial assumptions	713	191	904	(499)	(11)	(510)
Effect of experience adjustments	27	-	27	22	(648)	(626)
Balance, end of year	**23,857**	**5,392**	**29,249**	**22,664**	**4,877**	**27,541**
Change in fair value of the plan assets						
Fair value, beginning of year	24,084	-	24,084	21,837	-	21,837
Return on plan assets	(97)	-	(97)	1,213	-	1,213
Contributions:						
Employer	991	125	1,116	1,047	95	1,142
Employee	116	-	116	115	-	115
Benefit payments from plan	(985)	(125)	(1,110)	(922)	(95)	(1,017)
Administrative expenses paid from plan assets	(124)	-	(124)	(81)	-	(81)
Interest income	1,001	-	1,001	875	-	875
Decreases due to other significant events	(187)	-	(187)	-	-	-
Fair value, end of year	**24,799**	**-**	**24,799**	**24,084**	**-**	**24,084**
Net Defined Benefit Liability						
Accrued benefit obligation	(23,857)	(5,392)	(29,249)	(22,664)	(4,877)	(27,541)
Fair value of plan assets	24,799	-	24,799	24,084	-	24,084
Net Defined Benefit Liability	942	(5,392)	(4,450)	1,420	(4,877)	(3,457)
Total expense recognized in profit and loss						
Current service cost	417	134	551	415	259	674
Net interest expense	(80)	202	122	13	278	291
Administrative expenses and taxes	160	-	160	175	-	175
Total expense recognized in profit and loss	**497**	**336**	**833**	**603**	**537**	**1,140**
Actuarial losses/(gains) recognized in statement of comprehensive income						
Effect of changes in demographic assumptions	309	113	422	-	(1,775)	(1,775)
Effect of changes in financial assumptions	713	191	904	(499)	(11)	(510)
Effect of experience adjustments	27	-	27	22	(648)	(626)
Return on plan assets	60	-	60	(1,308)	-	(1,308)
Total actuarial losses/(gains) recognized in statement of comprehensive income	**1,109**	**304**	**1,413**	**(1,785)**	**(2,434)**	**(4,219)**

Effects of changes in assumptions

	Revalued pension obligation	**Revalued pension obligation**	**Total**
Discount Rate			
Increase by 100 basis points	19,813	852	20,665
Decrease by 100 basis points	26,922	989	27,911
Inflation Rate			
Increase by 100 basis points	25,240	916	26,156
Decrease by 100 basis points	20,739	916	21,655

Significant Actuarial Assumptions	**Defined Benefit Pension Plan**	**Non-Pension Benefit Plans**	**Defined Benefit Pension Plan**	**Non-Pension Benefit Plans**
	December 31, 2016		**December 31, 2015**	
Weighted-Average actuarial assumptions used:				
Discount rate	3.90%	4.00%	4.15%	4.20%
Rate of compensation increases	3.00%	3.00%	3.00%	3.00%
Inflation Rate	2.00%	n/a	2.00%	n/a

Plan Assets by asset class allocation (%)	**31-Dec-16**	**31-Dec-15**
Fixed Income	34%	37%
Equities	66%	63%
Other	0%	0%
Total	100%	100%

9. TRANS SENIOR BONDS

The Trans Senior Bonds (the “Bonds”) having an original principal amount of $120,000 and are secured by a charge on the Partnership’s transmission real property assets, both present and future. On behalf of the Partnership, HOI maintains a letter of credit in the amount of $3,960 to cover six months of interest payments on the Bonds.

The fair market value of the Bonds as at December 31, 2016 is $140,821 based on current market prices for debt with similar terms (2015 - $143,002). Amortization of deferred financing fees for the year related to the Partnership’s Bonds are included in finance costs and totaled $220 (2015 - $211).

The Bonds bear interest at the rate of 6.6% per annum. Semi-annual payments of interest only were due and payable on June and December 16 each year up until and including June 16, 2023. Equal blended semi-annual payments of principal and interest on the Bonds commenced on December 16, 2013 and will continue until and including June 16, 2023. The Bonds will not be fully amortized by their maturity date. The remaining principal balance of the Bonds will be fully due on June 16, 2023.

	2016	2015
Trans senior bonds	$ 112,477	$ 114,803
Less: unamortized deferred financing fees	(1,630)	(1,849)
Less: current portion	(2,483)	(2,327)
	$ 108,364	$ 110,627

As at December 31, 2016, principal repayments due in each of the next five years were as follows:

	2017	2018	2019	2020	2021
Principal repayments	$ 2,483	$ 2,649	$ 2,827	$ 3,017	$ 3,219

During the year, the Partnership identified a number of projects which were considered to be qualifying assets for purposes of capitalizing borrowing costs. For the year ended December 31, 2016, the Partnership capitalized borrowing costs of $225 (2015 - $235). The capitalization rate on funds borrowed amounted to 6.6% (2015 - 6.6%).

10. PARTNERSHIP UNITS

The Partnership is authorized to issue an unlimited number of Class A and Class B partnership units, of which 20,285,007 Class A units and 2 Class B units were issued and outstanding as at December 31, 2016. 20,285,007 Class A units and 2 Class B units were issued and outstanding as at December 31, 2015.

11. COMMITMENTS AND CONTINGENCIES

Letters of credit

On behalf of the Partnership, HOI maintains a letter of credit totaling $3,960 to cover six months of interest payments on the Bonds. No amount has been drawn against this letter of credit.

Commitments

As at December 31, 2016 future minimum lease payments for operating leases entered into by the Partnership, as lessee, were as follows:

	2017	2018-2021	Thereafter
Minimum lease payments	$343	$686	$nil

Contingencies

The Partnership may, from time to time, be involved in legal proceedings, claims and litigation that arises in the ordinary course of business which the Partnership believes would not reasonably be expected to have a material adverse effect on the financial condition of the Partnership.

There are no specified decommissioning costs relating to the Partnership's assets. The Partnership has a comprehensive repair and capital expenditure program to ensure that its transmission lines are maintained to industry standards. Replacement of the assets occurs in accordance with a long term capital plan and would involve typical costs of removal as part of that process. In the circumstance where a portion of a line or other assets were removed completely, there may be some contractual obligations under private or crown easements or other land rights which require the transmission owner to reinstate the land to a certain standard, typically the shape it was prior to the construction of the transmission assets. As well, certain environmental, land use and/or utility legislation, regulations and policy may apply in which the Partnership would have to comply with remediation requirements set by the government. The requirements will typically depend on the specific property characteristics and what criteria the government determines to be appropriate to meet safety and environmental concerns. These asset lives are indeterminate given their nature. As the individual assets or components reach the end of their useful lives, they are retired and replaced. Historically, certain asset components have been replaced a number of times, thus creating a perpetual asset with an indeterminate life. As such, the retirement date for these lines cannot be reasonably estimated and therefore, the fair value of the associated liability cannot be determined at this time. As a result, no liability has been accrued in these financial statements.

12. OPERATING AND ADMINISTRATION EXPENSES

	2016	2015
Compensation expenses	$ 5,276	$ 6,025
Contract expenses	2,238	1,635
Materials	295	771
Other	1,664	1,042
	$ 9,473	$ 9,473

13. MAINTENANCE EXPENSES

	2016	2015
Compensation expenses	$ 544	$ 328
Contract expenses	616	463
Materials	99	107
Other	357	359
	$ 1,616	$ 1,257

14. FINANCE COSTS

	2016	2015
Interest expense on Trans senior bonds	$ 7,533	$ 7,675
Amortization of deferred financing fees on Trans senior bonds	220	211
Less: capitalized interest	(225)	(235)
	$ 7,528	$ 7,651

15. DEPRECIATION AND AMORTIZATION

	2016	2015
Depreciation on property, plant and equipment	$ 8,995	$ 9,241
Amortization of intangible assets	301	404
	$ 9,296	$ 9,645

16. INCOME TAXES

The Partnership does not record income tax expenses as it is not subject to income taxation as a result of its formation as a limited partnership.

17. STATEMENT OF CASH FLOWS

Net change in non-cash working capital related to operations

	2016	2015
Trade and other receivables	$ 3,051	$ 336
Prepaid expenses and other	38	35
Due from related parties	(3,188)	(6)
Trade and other payables	(227)	(1,301)
Due to related parties	(128)	(20)
Pension liability	(420)	(1)
	$ (874)	$ (957)

18. CAPITAL RISK MANAGEMENT

The Partnership's primary capital management objective is to ensure the sustainability of its capital to support continuing operations, meet its financial obligations, allow for growth opportunities and provide stable distributions to its partners. The Partnership manages its capital to maintain an investment grade credit rating while prudently making use of leverage in order to provide its ultimate parent with enhanced returns. In addition, the Partnership manages its capital to ensure access to incremental borrowings needed to fund new growth initiatives.

The Partnership manages its capital structure in accordance with changes in economic conditions. Generally, capital expenditures are funded with external borrowings. In order to adjust the capital structure, the Partnership may elect to adjust the distribution amount paid to its partners, increase or reduce the equity participation in new and existing operations, adjust the level of capital spending or issue new partnership units.

The Partnership manages its capital in order to maintain a debt to capitalization ratio below 75%. As at December 31, 2016, the ratio was 51% (2015 – 51%). The table below presents the detail of the Partnership's capitalization and the calculation of the ratio:

	2016	2015
Trans senior bonds	$ 112,477	$ 114,803
	112,477	114,803
Partners' equity	109,578	110,380
Total capitalization	$ 222,055	$ 225,183
Debt to capitalization	51%	51%

There has been no change in the Partnership's approach to managing capital in the year.

19. FINANCIAL INSTRUMENTS

Fair value measurement

The Partnership defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

The Partnership classifies its financial assets and liabilities as outlined below:

		2016		2015	
	Class	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial assets					
Cash	LAR	$ 1,682	$ 1,682	$ 3,340	$ 3,340
Trade and other receivables	LAR	35	35	3,086	3,086
Financial liabilities					
Trade and other payables	OL	1,689	1,689	1,922	1,922
Trans senior bonds	OL	110,847	140,821	112,954	143,002

Classification details:
FVTPL – fair value through profit or loss
LAR – loans and receivables
OL – other liabilities

The statements of financial position carrying amounts for cash, trade and other receivables, trade and other payables, and due to and from related parties approximate fair value due to their short-term nature. Due to the use of subjective judgments and uncertainties in the determination of fair values, these values should not be interpreted as being realizable in an immediate settlement of the financial instruments.

Fair value hierarchy

The following provides a description of financial instruments that are measured subsequent to initial recognition at fair value, grouped into Levels 1 to 3 based on the degree to which the fair value is observable:

(a) Level 1 fair value measurements are those derived from quoted market prices (unadjusted) in active markets for identical assets or liabilities;
(b) Level 2 fair value measurements are those derived from inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices); and
(c) Level 3 fair value measurements are those derived from valuation techniques that include inputs for the asset or liability that are not based on observable market data (unobservable inputs).

No financial instruments have been ranked level 2 or 3, except for the Bonds which are ranked as level 2.

19. FINANCIAL INSTRUMENTS (continued)

There were no transfers between Level 1, 2 and 3 during the reporting periods. The fair values of financial assets and liabilities carried at amortized cost are approximated by their carrying values, except for the Bonds whose fair market value is presented in note 9.

Financial risk management

The Partnership has exposure to the following risks from its use of financial instruments: market risk, credit risk and liquidity risk.

The Partnership's management has overall responsibility for the establishment and oversight of the Partnership's risk management framework. Risk management policies are established to identify and analyze the risks faced by the Partnership, to set appropriate risk limits and controls and to monitor risks and ensure adherence to these limits. Risk management policies and systems are reviewed regularly to reflect changes in market conditions and the Partnership's activities. The Partnership, through its training and management standards and procedures, aims to maintain a disciplined and constructive control environment in which all employees understand their roles and obligations. The objectives, policies and processes for managing risk were consistent with those in the prior year.

Market Risk

Market risk is the risk that changes in market prices (interest rates) will affect the Partnership's income or the value of its holdings of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return.

The Partnership's Bonds are subject to a fixed interest rate of 6.6% per annum, payable semi-annually on June 16 and December 16. As a result of having fixed rate debt, fluctuations in market interest rates are not expected to materially affect the Partnership's cash flows.

Credit Risk

Credit risk is the risk of financial loss to the Partnership if a counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Partnership's receivables from counterparties. The carrying amount of financial assets represents the maximum credit exposure.

The Partnership actively manages its exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts, and continually monitors these exposures.

The majority of trade receivable transactions entered by the Partnership are with the Independent Electricity System Operator ("IESO"). The IESO operates the provincial transmission system, and is a reliable counterparty. The quality of the Partnership's counterparties mitigates the Partnership's exposure to credit risk.

19. FINANCIAL INSTRUMENTS (continued)

The Partnership's maximum exposure to credit risk as at December 31 is as follows:

	2016	2015
Trade and other receivables	$ 35	$ 3,086

The Partnership is also exposed to credit risk on cash. Credit risk is mitigated by ensuring the majority of the financial assets are placed with a major Canadian financial institution with strong investment-grade ratings by a primary ratings agency. The credit risk of cash has been assessed as low.

Liquidity Risk

Liquidity risk is the risk that the Partnership will encounter difficulty in meeting the obligations associated with its financial liabilities that are settled by delivering cash or another financial asset. The Partnership manages liquidity risk by forecasting cash flows required by operations and anticipating investing and financing activities to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when they are due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Partnership's reputation.

The table below analyzes the Partnership's financial liabilities into relevant maturity groupings based on the remaining period at the date of the statement of financial position to the contractual maturity date. The amounts disclosed in the table are the contractual undiscounted cash flows:

		Contractual Maturities				
	Carrying Amount	Less Than 1 Year	1-2 Years	3-5 Years	More Than 5 Years	Total
Trade and other payables	$ 1,689	$ 1,689	$ -	$ -	$ -	$ 1,689
Trans senior bonds	110,847	9,866	9,866	29,598	107,843	157,173
	$112,536	$11,555	$9,866	$29,598	$107,843	$158,862

At year end, the Partnership's relatively stable operating cash flows provide sufficient liquidity to fund these contractual obligations.

20. RELATED PARTY TRANSACTIONS AND BALANCES

Through the normal course of business, the Partnership enters into transactions with parties that meet the definition of a related party. During the first ten months of the year ended December 31, 2016, the Partnership was owned by Brookfield Infrastructure Partners LP ("BIP") and entered into the following transactions with entities considered to be related:

(a) In the normal course of operations, Riskcorp Inc., an insurance broker related through common control, entered into transactions with the Partnership to provide insurance. The total cost allocated to the Partnership during the first ten months of 2016 was $200 (twelve months of 2015 - $323).

(b) The Partnership has provided services to and received services from entities under common control in the normal course of operations. The balances payable and receivable for these services are non-interest bearing and unsecured.

Office Complex

The office complex in which the Partnership conducts its operations is owned by Great Lakes Power Limited ("GLPL"), and leased by the Partnership. Lease payments are made to GLPL on a monthly basis, with the lease cost for the first ten months of 2016 equaling $286 (twelve months of 2015 - $340).

Communication Equipment

The Partnership uses a fiber optic network that is owned by GLPL and is licensed by the Partnership. License fee payments are made to GLPL on a quarterly basis, with the lease cost for the first ten months of 2016 equaling $139 (twelve months of 2015 – $166).

The Partnership owns Radio Systems Assets and issues licenses for the use of these assets to GLPL. License fee payments are received from GLPL on a quarterly basis, with the lease payments for the first ten months of 2016 equaling $38 (twelve months of 2015 - $41).

Pole Rental

The Partnership owns transmission poles and receives license fee payments in accordance with a Licensed Attachment Agreement between the Partnership and GLPL. This agreement allows GLPL to affix and maintain its apparatus and equipment to the transmission poles owned by the Partnership. Payments are received by the Partnership annually. Total payments received by the Partnership during the first ten months of 2016 are equal to $27 (twelve months of 2015 - $33).

Road Maintenance

The Partnership shares a remote roadway in the northern portion of its service territory with GLPL. The roadway is used for access to various generating stations and transmission stations. The road maintenance costs are shared between the Partnership and GLPL, with GLPL incurring the initial cost and passing a predetermined portion on to the Partnership. Payments for this road maintenance are made to GLPL as the costs are incurred by GLPL, with the total portion borne by the Partnership in the first ten months of 2016 being equal to $119 (twelve months of 2015 - $135).

20. RELATED PARTY TRANSACTIONS AND BALANCES (continued)

Corporate Costs

In accordance with the Services Agreement between Brookfield Infrastructure Holdings (Canada) Inc. and the Partnership in effect January 1, 2012 until January 1, 2017, the Partnership records a corporate cost allocation for services received. The Partnership may request such services as but not limited to information technology management, human resource administration, and financial administration. The total corporate cost allocation recorded as an expense during the first ten months in 2016 was $349 (twelve months of 2015 - $412).

During the last two months of the year ended December 31, 2016, the Partnership was owned by HOI and entered into the following transactions with entities considered to be related:

(a) The Partnership has provided received services from entities under common control in the normal course of operations. The balances payable and receivable for these services are non-interest bearing and unsecured.

Revenue

The IESO is a related party because they are controlled or significantly influenced by the Province, which is a majority shareholder of Hydro One Limited. Total revenue recorded during the last two months in 2016 was $6,325 (2015 - $ Nil).

Corporate Costs

In accordance with a Services Agreement between Hydro One Networks Inc. and the Partnership in effect until December 31, 2018, the Partnership records a corporate cost allocation for services received. The Partnership may request such services as but not limited to information technology management, human resource administration, and financial administration. The total corporate cost allocation recorded as an expense during the last two months in 2016 was $70 (2015 – $ Nil).

(b) As a result, the following balances are receivable & payable as at:

	2016	2015
Due from related parties		
Services provided to entities under common control	$ 3,283	$ 95
Due to related parties		
Services received from entities under common control	$ 70	$ 198

20. RELATED PARTY TRANSACTIONS AND BALANCES (continued)

(c) Transactions with key management personnel

A summary of key management and director compensation for the year ended December 31, 2016 and 2015 are as follows:

	2016	2015
Salaries, management bonus and fees	$ 814	$ 916
Other benefits	110	124
Director fees	15	15
	$ 939	$ 1,055

Great Lakes Power Transmission LP
Assymetrical Capital Variance Account
Impact on Revenue Requirement

OPTION 1:

Approved in-service additions for 2015	9,460.0	716.4		
Approved in-service additions for 2016	9,768.7	210.8		
Total Approved in-service additions	**19,228.7**	**927.2**		
Actual in-service additions for 2015	8,743.6	"Transfers" per Note 5 & 6 of audited f/s		
Actual in-service additions for 2016	9,557.9	"Transfers" per Note 5 & 6 of audited f/s		
Total actual in-service additions	**18,301.5**			
Shortfall of in-service additions	**927.2**			

Revenue Requirement Impact:

	2016 (Half Year Rule)		**2015**	
Approved ROE	9.19%		9.30%	
Approved Cost of Long-term Debt	6.87%		6.87%	
Approved Cost of Short-term Debt	1.65%		2.16%	
Total Cost of Capital	**7.59%**	61.5	**7.66%**	27.4
Approximate Depreciation Rate (30 years)	3.33%	27.4	3.33%	11.9
Income Tax Impact @ 26.5%		8.0		3.5
Income Tax Gross-up		2.9		1.3
Net Annual Revenue Requirement Impact		**99.8**		**44.2**
Total Additions to Variance Account				**143.935**

RRWF without change	$39,868,020	$39,604,915
RRWF with reduction to rate base and reduction to Depreciation of $11,600	$39,825,434	$39,562,050
	42,585.9	42,864.8

OEB Staff Interrogatory # 75

Reference:

Exhibit E, Tab 1, Schedule 1
Exhibit E, Tab 1, Schedule 2

Interrogatory:

Preamble:

The list of Account 1508 Sub-Accounts per Schedule 1 lists Infrastructure Investment as a separate Sub-Account. Schedule 2 lists this account as part of Infrastructure Investment, Green Energy Initiatives and Preliminary Planning Costs.

a) Please clarify whether Hydro One SSM has two separate Sub-accounts or just one.

Response:

Hydro One SSM has 1 sub-account: Infrastructure Investment, Green Energy Initiatives and Preliminary Planning Costs.

OEB Staff Interrogatory # 76

Reference:
Exhibit E, Tab 1, Schedule 2
Exhibit E, Tab 1, Schedule 4

Interrogatory:
Preamble:

On page 5, Hydro One SSM stated:

In 2017, negotiations with Batchewana First Nations resulted in total costs incurred

a) Where on the Continuity of Deferral and Variance Accounts is this amount reflected?

b) In which account is this amount reflected in Hydro One SSM’s 3.1.1 reporting?

Response:
a) These costs have not yet been captured in the continuity of deferral and variance accounts. Once all costs are final, management will review the totality of the costs and make a determination on what portion of these costs will be proposed for recovery in the future.

b) Please see response to part (a) – the values are not yet included in 3.1.1 reporting.

OEB Staff Interrogatory # 77

Reference:

Exhibit E, Tab 1, Schedule 2
Exhibit E, Tab 1, Schedule 4

Interrogatory:

Preamble:

On page 5, Hydro One SSM stated:

> …HOSSM incurred a loss on disposal in both 2015 and 2016, net of proceeds from disposition. However, HOSSM is not seeking to disburse the balance of this account at this time as rate base will not be rebased as part of this application….

a) How much loss on disposal was recorded in each year?

b) Where is it shown in this application?

c) In which account was it reported in 3.1.1 reporting, and how much for each year?

Response:

a) A loss of $453,765.11 was recorded in 2015, and a loss of $605,785.73 was recorded in 2016.

b) As HOSSM will not be rebasing for the duration of the deferral period, net losses on disposal were not included in the regulatory continuity accounts for this application.

c) The 2015 and 2016 activity was recorded in a 1508 account for 3.1.1 reporting.
   - Net balance (including carrying charges) of $404,865.72 recorded in 2015.
   - Net balance (including carrying charges) of $225,272.15 recorded in 2016.
   - Losses on disposal are offset by any gains on disposal incurred as well as depreciation credits

OEB Staff Interrogatory # 78

Reference:

Exhibit E, Tab 1, Schedule 4, Tables 4 & 5
RRR section 3.1.1

Interrogatory:

a) Please reconcile the 2017 ending balances for each sub-account presented in the evidence to the 3.1.1 reporting as of December 31, 2017.

Response:

		A		**B**		**C = A - B**
Per Evidence in Application				**Per 3.1.1 Reporting**		
USofA	**Account Name**	**Account Balance at Dec 31, 2017**		**Account Balance at Dec 31, 2017**		**Difference**
1508	Green Energy Deferral	-				-
1508	Cumulative Asymmetrical Variance	(145,530.00)		(145,530.28)		0.28
1508	OEB Cost Assessment Variance	(83,386.00)		(83,386.39)		0.39
1508	Legal Claim (Comstock)	98,071.00		98,935.93		(864.93)
1508	Property Tax Variances	17,663.00		17,662.73		0.27
1508	BES	20,404.00		20,404.44		(0.44)
1508	IFRS Gains and Losses	-		630,137.87		(630,137.87)
1592	Changes in Tax Legislation	-				-
1575	IFRS-CGAAP Transitional PPE Amounts	(51,715.00)		62,370.53		(114,085.53)
1595	Aggregate Regulatory Asset-2017	(177,509.00)		190,458.94		(367,967.94)
	Total	**(322,002.00)**		**791,053.77**		**(1,113,055.77)**

The values reported in the Continuity Schedule in Exhibit E, Tab 1, Schedule 4 are correct. The differences outlined in the shaded cells of Column C above represent prior period corrections that didn't get processed until 2018, which cause 3.1.1 to be aligned with the correct values.

OEB Staff Interrogatory # 79

Reference:

Exhibit E, Tab 1, Schedule 1

Interrogatory:

Preamble:

Hydro One SSM is proposing to dispose of a number of deferral and variance accounts for a total credit of $94,909. However, an annual recovery of approximately $0.8 million which was to be recovered to the end of 2017 has continued, and a credit balance of approximately $1 million has already built up in the account.

a) Please calculate the revenue requirement including the projected credit to December 31, 2018 in Account 1595 which was approved in 2015 with a 3-year recovery.

Response:

HOSSM has calculated the annual Revenue Requirement that would be allocated to the UTR's for 2019 to 2021 (assuming the same inflation factor for the three years). This calculation includes both the balance of the Deferral and Variance account disposition requested in included in HOSSM's prefiled evidence and the forecast 2018 closing balance of Account 1595.

Table 1 – Calculation of the Annual Deferral Account Balance

	$'s
Deferral and Variance Account Balance.[1]	94,909
Account 1595 - Forecast 2018 Closing Balance[2]	1,115,593
Total	**1,094,909**
Period of Disposition (Years)	3
Annual Amount of Disposition	**364,970**

[1] Balance requested for approval per Exhibit E, Tab 1, Schedule 1
[2] Forecast balance of Deferral Account 1595 per Exhibit E, Tab 1, Schedule 4, page 6

Table 2 – Forecast Revenue Requirement – 2019 to 2021

	Year		
	2019	**2020**	**2021**
Prior Year Base Revenue Requirement	$39,778,120[3]	$40,255,457	$40,738,523
Inflation factor[4]	1.012	1.012	1.012
Current Year Base Revenue Requirement	**$40,255,457**	**$40,738,523**	**$41,227,385**
Deferral Account Disposition[5]	$364,970	$364,970	$364,970
Total Revenue Requirement for UTR's	**$39,890,488**	**$40,373,553**	**$40,862,416**

[3] 2018 Base Revenue Requirement per Exhibit D, Tab 2, Schedule 1, Table 3
[4] The inflation factor for the three year period assumes the value used for 2019 per Exhibit D, Tab 2, Schedule 1, Table 3.
[5] Per *Table 1 – Calculation of the Annual Deferral Account Balance, from* this interrogatory response.

PWU Interrogatory # 1

Reference:

Exhibit B, Tab 1, Schedule 1, Page 19, Table 2-2

Interrogatory:

Preamble:

Table 2-2 indicates that investment on Lines equipment accounts for 69% of the Plan Period System Renewal investment.

a) What per cent of this investment budget for Lines equipment is allocated to replacement of wooden support structures?

Response:

a) Exhibit B1, Tab 1, Schedule 1, p. 127 provides a table indicating the amount allocated to replacement of wooden support structures over the 2018-2026 period. It is estimated that of the total $42.1M, 59% ($24.8M) of the "Lines equipment" budget will be allocated to replacement of wooden support structures.

PWU Interrogatory # 2

Reference:

Exhibit B1, Tab 1, Schedule 1, Page 27

Interrogatory:

Preamble:

In paragraph 3 of the above-noted reference Hydro One Sault Ste. Marie LP (HOSSM) states:

> *Contractor Labour Efficiencies*
> *Given its relatively small staffing complement, HOSSM has historically relied on third party supplier labour for a number of capital work execution tasks, maintenance and equipment testing services, and preparation of planning and engineering studies, among other activity areas. As with equipment and materials, the ongoing integration will enable HOSSM to explore opportunities for leveraging a larger labour force and more preferential contractual arrangements. The scope, scale and timing of these potential efficiencies will depend on multiple factors; including the terms of the existing arrangements and the availability of internal Hydro One resources to undertake previously contracted work.*

a) Please provide HOSSM's total staff complement – Regular and Temporary.

b) Does HOSSM expect its staff complement to increase or decrease owing to the ongoing integration with Hydro One?

c) What activities or work programs has HOSSM been contracting out on a regular basis?

d) Has HOSSM conducted any preliminary studies or surveys with respect to the cost-effectiveness of contracted labour compared to the use of internal labour for all work programs that HOSSM outsources?

Response:

a) As of October 1st, HOSSM no longer has staff complement (all employees moved to HONI). The staff complement leading up to integration was: July 31st (32 Reg, 5 Temp), Aug 31 (32 Reg, 3 Temp), Sept 30 (30 Reg, 1 Temp).

b) As part of integration, all HOSSM staff will be transferred over to HONI. Some staff will continue to be responsible for ongoing support to Hydro One SSM assets.

c) The wood structure replacement program and major station capital work has been contracting out on a regular basis. HOSSM's collective agreements permitted the contracting out of work to third parties, provided it did not result in employee layoffs.

d) No, HOSSM has not conducted any studies/surveys on cost-effectiveness of contracted versus internal labour.

PWU Interrogatory # 3

Reference:

Exhibit B1, Tab 1, Schedule 1, Page 122

Interrogatory:

Preamble:

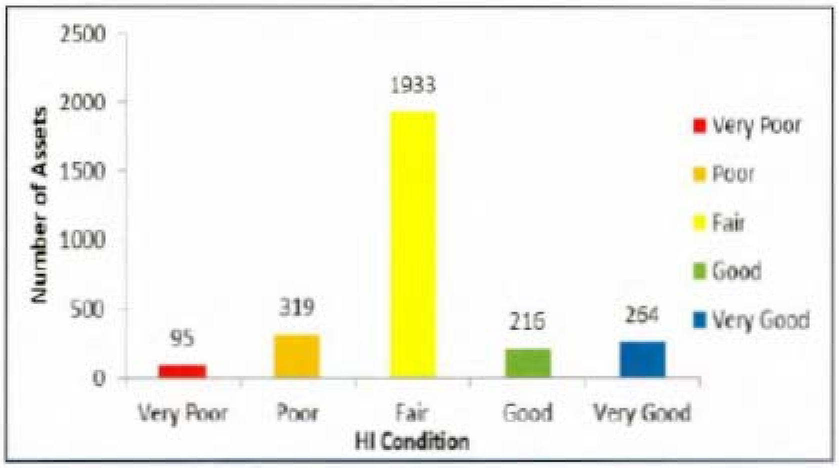

Figure 2 – Structures Health Index Distribution

HOSSM notes:

All Very Poor, Poor and 98% of Fair structures depicted in the figure are Wood support structures. As Figure 3 showcases, a significant portion of HOSSM wood structures appear to reach Poor and Very Poor condition significantly ahead of the 40-year lifecycle typically used for the planning purposes when installing these assets.

For example, as many as 30% of wood structures aged up to 15 years appear to have reached Very Poor condition on the basis of information available for the Health Index calculation. Among the reasons for this is the extensive woodpecker damage that the wood structures are subjected to in the area, along with other issues such as pole top rot and carpenter ant damage. Installing composite fibreglass structures, consistent with the ongoing program for the last five years, provide a solution that aims to extend the lifecycles of deteriorated poles.

a) Please confirm that according to Figure 2, HOSSM's total number of structures (wood and composite fibreglass) is 2827.

b) How many of these structures are wood and how many are composite fibre glass structures?

c) Please provide the average age of the structures in each condition category: Very poor, Poor, Fair, Good and Very Good?

d) Please populate the following table to show the number of structures for each of the following age categories:

Category	< 15 yrs	15-30 yrs	31-40 yrs	41-50 yrs	51-60 Yrs	>60	Total
Very Poor							95
Poor							319
Fair							1933
Good							216
Very Good							264

Response:

a) As stated in Table 3-3 in Exhibit B1-1-1 (p. 84) the total number of structures on the HOSSM system is 3104. As such, the number of structures included in METSCO's condition assessment amounts to over 91% of the total population.

b) Please refer to in Table 3-3 in Exhibit B1-1-1 (p. 84) and section 6.1.13 of the METSCO Report (Exhibit B1-1-1, Appendix B pp. 68-72).

c) The average age for the "Very Good" category is 18 years. The average age for the "Fair" category is 27 years. The average age for the "Poor" category is 27 years. The average age for the ""Very Poor" category is 32.5 years. The average age for assets in the "Good" category is unknown, as assets within this category do not have age data available. Note that due to low data availability for structure ages, especially for older structures in the system, these numbers are heavily skewed towards inaccurately younger average asset ages.

d) Populating this table is currently impossible with the data availability of structure ages. Average ages have been provided in response c) to best fulfill this request.

PWU Interrogatory # 4

Reference:

Exhibit B1, Tab 1, Schedule 1, Pages 126-127

Interrogatory:

Preamble:

In the above-noted reference, HOSSM stated the following:

Note that capital investment for the wood pole replacement program will continue throughout the Plan period. However, the break in program expenditures for the 2019 to 2021 period corresponds to the timing of work on the Sault No. 3 line upgrades (ISD# SR-02), which includes conductor and associated wood support structure replacement to composite structures. The replacement of the wood structure with composite structures continues, but the associated expenditures are captured in the dedicated project budget.

Project Costs:

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Capital Expenditures ($M)	$4.8	-	-	-	$4.0	$4.0	$4.0	$4.0	$4.0	$24.8

a) How many wood poles are replaced as a result of the Sault No. 3 line upgrades (ISD# SR-02) during the 2019-2021 period and how many of those to be replaced are in Very Poor, Poor, Fair, Good and Very Good condition?

b) What is the number of wood poles replaced in each year of the 2018 -2026 replacement plan corresponding to the project cost table in the reference?

c) What will be the share of wood poles in Very Poor and Poor condition by the end of the plan?

d) At the given rate of replacement, how many years will it take to replace all wood poles that are currently in Very Poor and Poor condition?

Response:

a) The specific number of wood poles to be replaced on the Sault #3 line circuit will ultimately depend on engineering work conducted in 2019.

However, approximately 60 structures in the Sault No. 3 line will be classified as being in “Poor” or “Very Poor” condition during the 2019-2021 period. It is planned within the scope of IDS# SR-02 that all structures falling within these condition categories be replaced in tandem with conductor replacement. This will yield a three year average replacement rate of 20 wood structures per year.

b) HOSSM has not identified the specific number of wood poles to be replaced in each year beginning in 2019 as part of the referenced project.

c) HOSSM does not have that information available.

d) Due to access issues related to terrain and weather considerations, the number of structures that can be replaced varies year-to-year. Hydro One SSM estimates that between 35 and 65 (average of 50) wooden structures can be replaced per year over the 2018-2026 period. So far in 2018, 37 wood pole structures (containing 2 or 3 poles) have been replaced.

Currently, there are 414 “Poor” and “Very Poor” structures in the system, 187 of which are wood. It is expected therefore that all of the current “Poor” and “Very Poor” wood structures in the Hydro One SSM system can be replaced by 2026. The remaining structures in “Poor” and “Very Poor” condition by the end of the plan will therefore be a population of structures having transitioned from higher condition categories to “Poor” or “Very Poor” over the next evaluation period.

PWU Interrogatory # 5

Reference:

Exhibit Bl, Tab 1, Schedule 1 — Transmission System Plan, Page 79

Interrogatory:

Preamble:

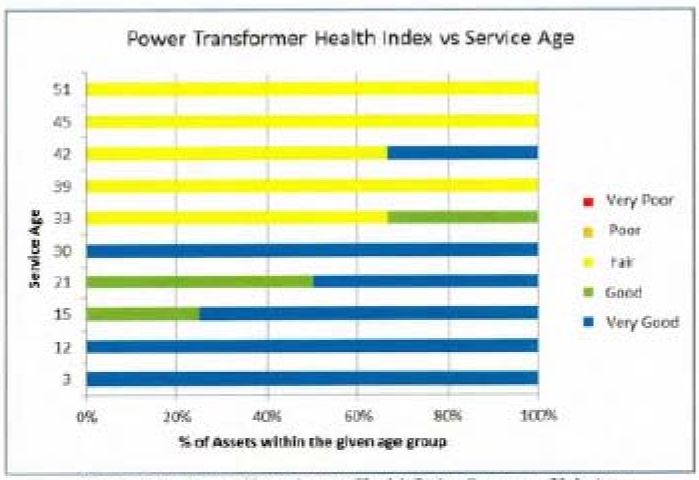

Figure 3-12: Power Transformer Health Index Scores vs. Unit Age

a) Please explain how 100% of transformers that are 39 years old are in Fair condition whereas approximately over 30% of transformers that are 42 years old are in a Very Good condition?

Response:

a) The scoring in question of the 30% of transformers in the 42-year-old age bracket corresponds to a single unit, T1 at the Anjigami Transmission station. The condition assessment corresponds to the data available to METSCO to perform the assessment and illustrates the reality that the relationship between age in condition is not linear in 100% of cases. Individual asset factors such as usage, manufacturer, model can potentially affect the condition score of discrete units, despite the majority of similarly aged population being in a worse condition.

PWU Interrogatory # 6

Reference:

Exhibit C, Tab 1, Schedule 1 — Performance Measurement and Continuous Improvement, Pages 13-14 (proposed HOSSM Scorecard)

Total OM&A and Capital per Gross Fixed Asset Value, Sustainment Capital per Gross Fixed Asset Value and OM&A per Gross Fixed Asset Value

Interrogatory:

a) How are the targets for the Cost Control measures, viz., Total OM&A and Capital per Gross Fixed Asset Value, Sustainment Capital per Gross Fixed Asset Value and OM&A per Gross Fixed Asset Value determined?

Response:

a) (OM&A + Sustainment CapEx) / Total Gross Fixed Assets

Sustainment CapEx / Total Gross Fixed Assets

OM&A / Total Gross Fixed Assets

Energy Probe Interrogatory # 1

Reference:
Exhibit B1, Tab 1, Schedule 1, Page 30

Interrogatory:
"Given the increasingly volatile weather patterns observed in recent years, HOSSM's ability to plan for and execute the requisite outages may be affected by the local, regional and inter-area transfer capability constraints that may emerge as a result of unpredictable weather patterns such as abnormal temperatures, major storms, or water levels affecting the operations of hydroelectric generators directly connected to the HOSSM system."

a) Please define "increasingly volatile weather patterns".

b) Please provide the year when such increasingly volatile weather patterns started in the region of Ontario where HOSSM is located

Response:
a) The term, "increasingly volatile weather patterns" is a subjective characterization and is not meant to infer to a statistical definition. The occurrence of increasing weather variations in Canada is well publicized.

b) HOSSM's intention in providing this passage is to point out that weather, among many factors, is having an effect on operations. There is not a defined starting point to this activity.

Energy Probe Interrogatory # 2

Reference:

Exhibit B1, Tab 1, schedule 1, page 70.

Interrogatory:

"Challenge sessions are designed to provide a structured approach to stress-test the investments comprising the planned portfolio, ensuring that the right investments are included in the Plan. The discussions allow for the merits of an investment and its resultant benefits to be considered from both risk and non-risk perspectives. Various levels and types of stakeholders attend, incorporating execution feasibility and strategic alignment considerations.

Preamble:

It appears that Challenge Sessions are a key source of information for the probability risk assessment. Energy Probe would like to have more information about these sessions.

a) How many Challenge Sessions were held? Please give dates.

b) Who attended the Challenge Sessions and how were they selected? Please provide job titles of individuals who attended.

c) What material was presented to the people attending Challenge Sessions? Please file copies of documents.

d) Please provide documents that were used to record the information at the Challenge Sessions including any summary reports and spreadsheets.

Response:

a) HOSSM and HONI held a total of four Challenge Sessions in preparation of the TSP. The dates of the sessions were April 25, May 9, May 30, 2018, and June 28, 2018.

b) The challenge sessions were attended by members of HOSSM's engineering and field operations teams, members of Hydro One's Regulatory and Investment Planning Teams, and METSCO representatives who completed the Asset Condition Assessment work. Selection occurred on the basis of conversations between HOSSM, HONI and METSCO staff leading the project. The job titles of individuals were:

METSCO:
- Director Utility Strategy and Economic Regulation,
- Director, Asset Management and Analytics,
- Senior Associate, Transmission Planning,
- Associate, Asset Management Analytics (2),
- Student Intern

HOSSM:
- Managing Director,
- Engineers (multiple),
- Manager, Grid Operations

Hydro One:
- Director, Regulatory Affairs,
- Manager, Regulatory Affairs,
- Manager, Investment Planning (3),
- Network Management Officer (multiple)

c) Please refer to I-5-10 (SEC IR# 10) – Attachment 1.

d) HOSSM did not prepare any formal summary reports or spreadsheets at the conclusion of the challenge sessions. All changes were made directly into the affected documents such as risk templates or notes supplied in response to part c).

Energy Probe Interrogatory # 3

Reference:

Exhibit B1, Tab 1, schedule 1, page 70.

Interrogatory:

"At present, HOSSM's capital work program is largely performed by outside contractors. HOSSM expects this to remain the case for the early stages of its integrated operations with Hydro One."

In estimating the cost of the capital work program, did HOSSM assume that the costs would be the same whether the work was done by outside contractors or Hydro One employees? Please give reasons for any assumptions.

Response:

In estimating the cost of the capital work program, HOSSM assumed that the work would be done by outside contractors, which is its normal estimating method.

HOSSM also assumed for planning purposes that the costs would be the same irrespective of whether the work would be done by outside contractors or Hydro One employees.

Energy Probe Interrogatory # 4

Reference:

Exhibit B1, Tab 1, Schedule 1, page 71

Interrogatory:

"As the operational integration between Hydro One and HOSSM moves forward, the decisions regarding the potential changes to HOSSM's investment portfolio will become subject to the review of Hydro One's recently formed Redirection Committee, tasked with overseeing the redirection process wherein investment changes are approved, documented, systemized and communicated to the relevant stakeholders, to ensure an enterprise-wide understanding regarding issues affecting the execution of HOSSM's investment plan."

a) Please provide more information about the Redirection Committee, including job titles of individual members, the mandate of the committee, and who does it report to.

b) Please provide copies of Redirection Committee minutes of meetings and any reports that the committee produced.

Response:

a) Please see attached Redirection Committee Terms of Reference.

b) The redirection step of the Investment Planning process described in the application applies to the annual budget for Hydro One Networks Transmission and Distribution regulated businesses. HOSSM assets will be integrated into the HONI process going forward and thus will be included in the corporate redirection process starting in 2019 – the first year of the planning period of this application. A formal redirection process similar to HONI's was not conducted independently by HOSSM. Minutes and materials pertaining to HOSSM redirection therefore are not available.

INVESTMENT REDIRECTION COMMITTEE – TERMS OF REFERENCE

1. PURPOSE

The purpose of the Investment Redirection Committee is to

- Oversee the redirection process whereby investment changes from the business plan are approved, documented, systemized and communicated to stakeholder line management to ensure that due process is followed when expenditure adjustments are made to capital, OM&A and in-service additions.

- Provide advice and direction on investment adjustments that are required to the business plan to address emerging business needs/risks or to seize opportunities related to the planning and execution of Hydro One's Investment Plan.

- Ensure integration and a common understanding across the enterprise regarding issues affecting the execution of Hydro One's business plan.

2. SCOPE

The Investment Redirection Committee shall advise regarding:

- The status of the release and execution of the Investment Plan over the business plan horizon including:
  - projects to fulfill customer and regulatory commitments or compliance to industry standards;
  - factors that are adversely affecting the timely release or execution of work; and
  - deviations from the approved Investment Plan and alternatives (including the redirection of future work releases) to address the deviations.
- The review and recommendation of adjustments to the execution of the approved Investment Plan, from Capital, OM&A and In-Service Addition perspectives, in response to prevailing industry and / or corporate circumstances[1].
- Redirection requirements and funding trade-offs which exceed the noted threshold (Appendix "A"), including those as a result of forecast updates, pending interim review of variances (IROVs) and business case summaries (BCS) with insufficient funding identified; while forecast changes will be identified retrospectively as redirection candidates, pending IROVs and BCS with insufficient funding shall be discussed, identified, and agreed to prospectively at the Redirection Committee prior to the approval.

[1] These adjustments will not change the current year's budget, which is approved annually by the Board of Directors; however approved redirection decisions will provide clear visibility to deviations from the approved budget and the resulting future year impacts.

- The management and review of capital and OM&A work programs and corporate common costs on a monthly basis; the redirection of OM&A must be balanced off with shareholder value with clear decisions to roll forward funds, redirect funds or bank funds (productivity).

Approval of redirection must be done in accordance with the EAR and adjustments must remain consistent with the funding levels, investment strategies, and performance outcomes approved by the Board of Directors.

When core committee members have insufficient EAR authority to approve redirection opportunities or the identified redirection impacts a business unit not represented on the committee (or invited as a guest), the COO shall table a redirection recommendation with the Executive Leadership Team (ELT) for approval at the Quarterly Capital Review meeting, or as required.

3. MEMBERSHIP

Membership of the Advisory Committee is outlined in Appendix "B".

IRC members may delegate an alternate person to attend the meetings.

Other staff may be invited to attend a portion of a meeting to provide briefings, updates or assistance on specific topics related to the release and execution of Hydro One's approved Investment Plan; this includes other members of the ELT (and their direct reports) who are not regularly represented at this forum to attend if/as items come up that are within their purview

4. REPORTING REQUIRMENTS

Following the review and recommendation of adjustments to the approved Investment Plan, investment level decisions will be documented and communicated, including the recommended change and rationale.

Updates on significant Investment Redirection Committee decisions, as well as recommendations related to reprioritization options that require an approval authority that exceeds that of members of the committee should be presented at the ELT's Quarterly Capital Review meeting.

5. MEETINGS and FORMAT

Meetings are scheduled once a month, typically during the fourth week of the month.

The output of the Redirection Committee Meeting shall be presented and discussed at the Operations Work Program Review and / or Monthly Operations Review, typically the second week of the subsequent month.

6. APPROVAL AND REVIEW OF TERMS OF REFERENCE

The terms of reference shall be approved by the committee.

Appendix "A"

Redirection Thresholds

Threshold	Description and Scope	Rationale
Tier 1	Individual investments with an absolute forecasted annual variance against the approved redirection budget greater than \$3M for Transmission and \$1M for Distribution for: • Capital Expenditures (net); • OM&A (net); or • In-service additions.	Aligned with the OEB filed Investment Summary Document (ISD) threshold: • Transmission = \$3M • Distribution = \$1M
Tier 2	Individual investments with an absolute forecasted annual variance against the approved redirection budget greater than \$1M within a driver with an absolute variance greater than \$3M for: • Capital Expenditures (net); • OM&A (net); or • In-service additions.	Aligned with the OEB filed Investment Summary Document (ISD) threshold: • Transmission = \$3M • Distribution = \$1M

Appendix "B"

Membership

Business Unit	Title	Members	Alternate
Operations	VP, Planning (Chair)	Darlene Bradley	Bruno Jesus
Operations	Vice President, Transmission and Stations	Andrew Spencer	Kathleen McCorriston
Operations	Vice President, Distribution	Brad Bowness	
Operations	Vice President, Engineering	Bing Young	
Operations	Vice President, Shared Services	Rob Berardi	
Operations	Vice President, System Operations	Martin Huang	
Corporate Finance	Senior Vice President, Finance	Chris Lopez	
Technology	Interim CIO	Maureen Higgins	
Customer Service	Vice President, Customer Service	Warren Lister	
Office of the President & CEO	Vice President, Office of the President & CEO	Stefanie Stocco	

Non-Voting Members

Business Unit	Title	Members	Alternate
Operations	Manager, Investment Planning & Process	Kevin Mancherjee	
Operations	Advisor, Program Integration	Cheryl MacKay	

Energy Probe Interrogatory # 5

Reference:

Exhibit B1, Tab 1, Schedule 1, Page 96, Table 4-1 and Exhibit B1, Tab 1, Schedule 1, page 105, Table 4-1

Interrogatory:

Please provide more information on the Land Acquisition of $2 million in 2019 for the Greenfield TS project. If there is a business case, please file it. If there is no business case, please explain why not. Why is the land being purchased in 2019 while the Greenfield TS is scheduled for execution in 2023?

Response:

A feasibility study was conducted via a third party (One Line Engineering) in 2016. No further business cases have been prepared since that time. Per Exhibit B2, Tab 2, Schedule 1 (pg. 19 - Table 7), the current capital investment plan for Hydro One SSM has the Greenfield Station scheduled for execution from 2019 to 2022.

Energy Probe Interrogatory # 6

Reference:

Exhibit B1, Tab 1, Schedule 1, page 105, Table 4-1, Project GP-03 General Plant Renewal Program, Description:" Enable regular upkeep and replacement of HOSSM's IT hardware and software, vehicle fleet, tools, and office equipment. "

Interrogatory:

Please explain why this program is capital and not OM&A. Please provide reference to capitalization rules that HOSSM follows in justifying which projects to capitalize.

Response:

The objective of Project GP-03 is as follows, per Exhibit B1, Tab 1, Schedule 1 in the Application:

Enable regular upkeep of HOSSM's General Plant assets including IT software and hardware, vehicle fleet, office furniture, and other similar items through periodic replacement as assets reach the end of their respective lifecycles.

Capitalizing the cost of an asset that is replacing an end of life capital asset is in line with IAS 16 Property, Plant and Equipment and HOSSM's capitalization policy.

Per IAS 16:

Items of property, plant and equipment may also be acquired to make a less frequently recurring replacement, such as replacing the interior walls of a building, or to make a nonrecurring replacement. Under the recognition principle in paragraph 7, an entity recognises in the carrying amount of an item of property, plant and equipment the cost of replacing part of such an item when that cost is incurred if the recognition criteria are met.

The recognition principle in paragraph 7 is as follows:

The cost of an item of property, plant and equipment shall be recognized as an asset if, and only if:
(a)it is probable that future economic benefits associated with the item will flow to the entity; and
(b)the cost of the item can be measured reliably.

Energy Probe Interrogatory # 7

Reference:

Exhibit B1, Tab 1, Schedule 1, Page 113

Interrogatory:

"Moreover, as the integration between HOSSM and Hydro One continues, HOSSM plans to utilize a range of studies prepared by the Electric Power Research Institute ("EPRI") on a number of topics concerning asset management best practices. HOSSM will leverage these insights to continually improve the efficiency and cost effectiveness of its operations."

If there are differences between Hydro One practice and the best practices identified in EPRI studies, which practice will HOSSM follow.

Response:

As of Oct 1st, Hydro One is providing asset management service to HOSSM via an established service level agreement. If differences are found between Hydro One practice and the best practices identified in EPRI studies, Hydro One will review the recommendation(s) from EPRI and assess if it will provide additional operational efficiency and cost effectiveness before adopting. It is expected that HOSSM practice will follow that of HONI.

Energy Probe Interrogatory # 8

Reference:

Exhibit B1, Tab 1, Schedule 1, Page 115

Interrogatory:

For each project listed on page 115 please provide capital cost estimates and annual operating cost estimates of all alternatives considered.

Response:

Starting on Page 115 running through to page 188 of Exhibit B1, Tab 1, Schedule 1 (TSP), are detailed Investment Summary Documents that describe all of the material projects that HOSSM intends to complete over the planning period. They include the alternatives analysis that HOSSM conducted for each project, the rationales for selecting the preferred alternatives relative to the other options considered, along with the expected capital expenditure levels to complete the preferred option.

In most cases, the alternatives that HOSSM rejected fell short of the utility's needs in terms of the type and volume of operating benefits and other technical factors such as the extent of addressing the present need, where HOSSM was sufficiently confident to make a selection on balance of information considered. Provision of capital and operating financial estimates for all alternatives as requested is not available.

Energy Probe Interrogatory # 9

Reference:

Exhibit B1, Tab 1, Schedule 1, Pages 128-13, SR-02 Sault #3 115 KV Line Reconductoring

Interrogatory:

Please provide capital cost estimates and annual operating cost estimates of all alternatives considered for each project or program on the list.

Response:

Please refer to answer of Energy Probe Interrogatory # 8 at Exhibit I, Tab 3, Schedule 8.

Energy Probe Interrogatory # 10

Reference:

Exhibit B1, Tab 1, Appendix B, Page 3

Interrogatory:

Why is the METSCO report filed as a "Final Draft Report"? Does that mean that the report is still being revised? If that is the case, when will the final report be available?

Response:

The word "Draft" on in the report's title on p.3 is a minor production oversight. Please refer to p.4 of the report that clearly states that the July 6 report filed in HOSSM's evidence is a Final report.

Energy Probe Interrogatory # 11

Reference:

Exhibit B1, Tab 1, Appendix B, Page 8

Interrogatory:

Please explain how METSCO was selected by HOSSM to do this work. Did HOSSM use a competitive bidding process? If not, why not? Please file the statement of work and or terms of reference that were given by HOSSM to METSCO.

Response:

In preparation for developing the evidence for this filing, HOSSM identified that it would require assistance on 2 major pieces of work:

1. Preparation of a detailed, up-to-date Asset Condition Assessment ("ACA")
2. Compiling and authoring the Transmission System Plan

A full competitive process was not undertaken. HOSSM chose METSCO on a sole-source basis based largely on the following factors:

- Hydro One had a positive experience with METSCO as they recently assisted with the successful development of the Hydro One Remote Communities Inc. ("Remotes") rate application and Distribution System Plan;
- METSCO's developed a number of templates and processes for the Remotes' application that would be applicable and usable in the HOSSM application. Use of these already made templates would reduce time and cost;
- METSCO demonstrated a strong competency in knowledge of the OEB filing requirements; and
- METSCO was currently performing a similar review of Hydro One's ACA process to positive reviews by involved staff.
- The work on the Hydro One ACA would allow METSCO to quickly and economically apply much of these learning and processes to the HOSSM assets.

HOSSM received a proposal from METSCO on February 13, 2018 and shortly after signed an agreement to move forward with the work. While conducting a full competitive process with other vendors was considered, it was felt that the efficiencies gained from METSCO's prior engagements with Hydro One offered the best value and timing to complete the work.
Please see Attachment 1 to this Exhibit which includes a copy of the Metsco Proposal.

February 13, 2018

Mr. Jeffery Smith,
Director, Regulatory Affairs
Hydro One Networks Inc.

Re: Scope of Work and Budgetary Proposal for Hydro One Sault Ste. Marie Asset Condition Assessment and Transmission System Plan Development Project

Dear Mr. Smith,

Pursuant to our discussion earlier this week, please find attached a proposal by METSCO Energy Solutions Inc. for the completion of an Asset Condition Assessment (ACA) study and a five-year Transmission System Plan (TSP) for Hydro One Sault Ste. Marie system.

As discussed during our last conversation, the attached preliminary task assessment and the ensuing budget are reflective of our current assumptions as to the scope, nature, quality and completeness of information available for METSCO's analysis for the purposes of completing the ACA and TSP work. Based on these estimates (detailed below, and reflective of the Existing Master Service Agreement with Hydro One), our firm price offers for the Asset Condition Assessment and the Transmission System Plan are $50,652 and $62,104 respectively, for a total firm cost estimate of $112,756 for the entire project. For additional services related to witnessing and preparation and substantiation of Interrogatories and/or Undertakings we are happy to offer an hourly rate based on time and materials, to be applied as needed depending on the scope and nature of work required.

Should the assumptions supporting our estimate be materially different from the state of requisite data repositories and/or availability of other necessary information, METSCO may be required to perform additional work to address the potential data gaps. Should the need for such work occur, its parameters will be cleared with Hydro One as soon as practicable.

I trust that you will find our proposal to be both comprehensive and competitively priced. My team and I look forward to the continuation of our collaboration with Hydro One Networks.

Sincerely,

Thor Hjartarson, P. Eng., M. Eng.
CEO, METSCO Energy Solutions

1.0 Project Context Relevant to the Proposal Development:

1.1 Hydro One's Business Objectives and Past Regulatory Commitments

In preparation for the upcoming 2019 rates application, Hydro One Sault Ste. Marie (HOSSM) is seeking to produce a standalone Transmission System Plan (TSP) for the system, as mandated by the Ontario Energy Board (OEB) in the decision on the 2017 rates application. Having secured the purchase of the HOSSM assets in late 2016 (formerly owned by Great Lakes Power Transmission), Hydro One seeks to supplement the development of a TSP with a comprehensive Asset Condition Assessment (ACA).

Apart from being a TSP requirement, Hydro One views the ACA as a means of confirming their understanding of the state of the asset base, and validating the accuracy and completeness of records that have been made available at the time of the acquisition. METSCO also understands that the staffing changes that followed the transfer of ownership have resulted in a degree of workforce attrition, which may complicate the knowledge transfer with respect to the following parameters critical for the development of the ACA, namely:

- current state of the assets, including priority areas (if any);
- location, comprehensiveness and currency of available asset records;
- scope, nature and rigour of historical field activities underlying the records;
- context surrounding the completion of past independent asset condition assessments.

Hydro One's regulatory staff have indicated their near-term plans to inquire with local technical counterparts in the Sault area as to the detailed status of these issues, which may involve an in-person visit to the local offices. Notwithstanding the outcomes of these discussions, Hydro One has indicated their preference to provide the ACA proponent with the sufficient data and/or access to facilities for the purposes of data collection, such that the proponent could confidently stand behind their findings in the context of a future regulatory proceeding.

Of note is also the fact that Hydro One Networks (Transmission) is in the process of finalizing a 2019 TSP for the majority company's transmission assets. While the contemplated ACA and TSP for the HOSSM assets are being developed separately, it is nevertheless important to maintain a clear view of the larger plan's parameters, in lieu of the eventual integration of both entities' rate bases at the conclusion of the rate harmonization period. Accordingly, METSCO anticipates that general consistency with the key technical and business process underpinnings of the larger plan is among the current project's key success factors. As such, close coordination with the development and approval of the larger plan is anticipated to be an ongoing requirement.

1.2 Timing of the Contemplated Deliverables

METSCO understands that the HOSSM rate application is expected to be filed in mid-July of 2018, mandating an **early July 2018 final sign-off** on the TSP, preceded by the sign-off on the ACA no later than **beginning of June 2018**. These and other milestones are subject to further changes reflecting Hydro One's plans or other relevant external circumstances.

1.3 Regulatory Requirements as to the Content of the Contemplated Deliverables

Section 2.4 of the OEB's 2016 Filing Requirements for Transmission Rate Applications points to the Chapter 5 of the Distribution System Plan Filing Requirements as a reference point for plan content and structure. The requirements further specify that plans are to include a discussion of the utilities' strategic underpinnings, the nature of planning assumptions and the assessment frameworks used to select among potential investments, reflect customer preferences and provincial policy requirements (including regional planning), and optimize the trade-offs between capital investments and maintenance expenditures.

Among other requirements of note concerning the development of Transmission System Plans in particular, are the stipulations regarding (a) the establishment of need for proposed material investments, along with their evaluation against a range of potential alternatives, (b) the identification of magnitude and manner of achieving of quantifiable efficiency gains, (c) the discussion of the overall planning approach to ensure that the proposed investments comprise as integrated plan, and (d) evidence of coordination with the third parties. A number of other specific evidentiary parameters are also prescribed.

While METSCO is unaware of any specific regulatory requirements regarding the scope and nature of third-party Asset Condition Assessments (ACA), the expectations of background information quality and comprehensiveness, along with the underlying analytical rigour are effectively established by a range of previous ACAs submitted in the context of past transmission and distribution rate applications. Having prepared a number of these assessments as a proponent, while reviewing others as a third-party expert, METSCO is intimately familiar with stakeholder expectations and common pitfalls associated with ACAs. It is, however, important to note that a robust ACA is first and foremost a product of the quality and availability of the input data collected by way of operating and maintenance activities.

The following section of this proposal lists METSCO's proposed budget estimate for both parts of the deliverable, along with their core components and the assumptions underlying the current estimates.

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2.0 Project Requirements and Cost Estimate

2.1 Project Team

METSCO estimates that the completion of the project requires three dedicated resources – namely a Project Lead and Head Engineer, a Project Manager and Principal Author, and a Project Engineer, along with occasional participation by Engineers in Training (EITs) and issue area Subject Matter Experts. For the purposes of this project, METSCO proposes the following team:

Project Lead and Head Engineer – Mr. Thor Hjartarson, P.Eng., M. Eng. Mr. Hjartarson is the METSCO CEO, and a professional engineer recognized in several jurisdictions. Mr. Hjartarson has held senor managerial positions the area of asset management in a number of electric utilities in North America and Europe, is an author of multiple published papers and independent expert studies, including system plans and asset condition assessments. Mr. Hjartarson is familiar with Hydro One's system and asset management principles, as he is currently overseeing several METSCO projects performed on behalf of the utility.

Project Manager and Principal Author – Mr. Dmitry Balashov, MBA, MPA. Mr. Balashov has over 10 years of experience in the area of electricity sector regulation, asset management and utility productivity in Ontario. Prior to joining METSCO, Mr. Balashov served as a Lead of Regulatory Process and Analytics at Toronto Hydro, where he co-led the development of a successful 5-year Distribution System Plan, OM&A Programs and Productivity and Performance Measurement Strategy. Earlier in his career, Mr. Balashov closely tracked Hydro One's regulatory and financial affairs as a Senior Advisor in the Ontario Ministry of Energy, which equipped him with an in-depth understanding of Hydro One's asset management principles and the utility's regulatory history.

Project Engineer – Ms. Melika Jafarian, P. Eng. Ms. Jafarian is among METSCO's most experienced engineers, having been involved in preparation of empirical studies and planning and design assignments for the past seven years. Ms. Jafarian possesses a combination of field experience and command of advanced analytical tools and frameworks employed in modern electricity sector planning work.

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2.2 Project Tasks

The Project is proposed to consists of two primary Phases, namely the Asset Condition Assessment (ACA) and the Transmission System Plan (TSP) Preparation. The following tables outline the main components of each phase, along with the current estimate of hours required:

2.2.1 Phase I - Asset Condition Assessment Preparation

Task Description	Hours Included
Project Management, Workplan and Scheduling. Preparation of Information Requests to the Client.	20
Review of Existing Third-Party ACA Studies[1]	30
Assessment and Scrub of Existing Condition Data	60
Identification of Critical Missing Data Deemed Obtainable	30
Development of Asset Health Index Methodologies for Each Asset Class based on available data	45
Calculation of Health Indices per Asset Class and Verification of Asset Demographics	75
Assessment of Data Integrity and Recommendations for Continuous Improvement	15
Development of Assets Requiring Attention Listing Based on the ACA results	30
Detailed Deliverable Reviews (2 rounds) and Periodic Reporting Meetings	22
Interrogatories Support	15
Argument Support	5
Time Estimate for Phase I (ACA)	**347 hrs**

2.2.2 Phase II – Transmission System Plan Preparation

Task Description	Hours Included
Project Management, Workplan and Scheduling.	28
Review of Commentary and Commitments in prior GLPT applications.	25
Review of internal planning input documents, Interviews with local and central SMEs, compatibility assessment of legacy and current planning standards	60
Integrate Regional Planning and Customer Engagement Evidence	30
Assist in Development of AM Strategy	40
Prepare Core Project Narratives	96
Assist in Clarification of IT and General Plant Strategy	20
Assist in development of the Productivity Plan, Capital/Maintenance Trade-offs Evidence, Scorecard etc.	25
Assist in development of the Develop Renewables and CDM-related Plan Evidence	20
DSP Review and Comments (2 cycles each section)	46
Interrogatories Support	30
Argument Support	10
Time Estimate for Phase II (TSP)	**430 hrs**

[1] METSCO's preliminary research has identified a 2009 pole integrity study completed for Great Lakes by PoleCare International Inc., and has been made aware of a more recent 2016 ACA prepared by another proponent.

2.3 Project Scope Assumptions

The following are the key assumptions in terms of the project scope underlying the preceding cost estimates. Should the state of requisite data sources and/or availability of other qualitative and quantitative inputs deemed critical for the preparation of the plan be materially different from these assumptions, METSCO maybe required to dedicate greater resources to the affected tasks, with the ensuing changes to the project costs. Should this occur, METSCO will notify the Client as soon as possible.

Phase I Core Assumptions:

- Available field condition reports, asset demographic data, and prior third-party studies provide a sufficient coverage of ACA parameters for all major asset classes to enable the assessment of statistically significant samples and computation of multi-parameter health indices deemed acceptable by industry standards.

- Requisite site visits / field inspections by METSCO staff are limited to short-term engagements to confirm the methodologies, rectify minor data gaps, or verify the reference assessment parameters through direct asset inspection (a total of 20 hours of direct field visits have been budgeted in the current proposal).

- All existing condition and demographics data is available in standard electronic formats and does not require extensive manual reproduction to enable further assessments.

- HOSSM or its legal predecessor do not have any major prior commitments to the OEB or any other party to a past hearing related to asset condition or demographics that exceed the scope of typical ACA studies produced on behalf of utilities.

Phase II Core Assumptions

- All key input requirements expected to be generated primarily outside of the technical planning function for the electrical and supporting civil plant (e.g. customer engagement, regional planning, overall utility strategy, etc.) are available, or readily obtainable by way of occasional interviews, facilitated brainstorming sessions, and/or synthesis of existing material judged to be of relevance.

- No site visits (e.g. plant inspections or large customer engagements) are expected to take place as a part of Phase II of the project.

- Requisite elements of Hydro One Networks' 2019 Transmission System Plan are available for reference and/or incorporation at least one month in advance of the final sign-off.

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2.4 Cost Estimate

Title/Position	Rate	Phase I: ACA		Phase II: TSP	
		Hours (est.)	Cost (est.)	Hours (est.)	Cost (est.)
Principal/Expert	$176.40	208	$36,726	258	$45,511
Senior Engineer	$110.25	87	$9,564	86	$9,482
Engineer	$88.20	42	$3,673	64.5	$5,689
Technologist	$73.50	0	$0	0	$0
Project Support Staff	$66.15	10	$689	21.5	$1,422
Senior Business Consultant	$176.40	0	$0	0	$0
Business Consultant	$88.20	0	$0	0	$0
Total estimate, per project		**$50,652**		**$62,104**	
Total estimate for both projects		**$112,756**			

***Costs do not include HST**

**** Travel and Accommodations are not included**

***** See sections 2.2 and 2.3 for key assumptions.**

For the potential part 3 of the project, which may involve additional witnessing and/or preparation of interrogatory and undertaking responses, METSCO offers the following rates:

Principal/Expert: $264.60
Senior Engineer: $165.38

METSCO expects that the sequential and synergetic nature of the project elements should enable it to manage its costs within the current envelope across the two phases. In any case, detailed reporting on hours completed can be incorporated into the regular project management review meetings with the client.

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3.0 Contact Information

We encourage Hydro One Staff to contact us directly to discuss any matters associated with this proposal at their convenience.

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Email: thir.hjartarson@metsco.ca

Dmitry Balashov, Director, Utilities Strategy and Economic Regulation

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Energy Probe Interrogatory # 12

Reference:

Exhibit B1, Tab 1, Appendix B, Page 9

Interrogatory:

Please provide additional information on the five site visits by METSCO.

a) When did the site visits take place?

b) What were the sites visited and why?

c) Please provide names of METSCO staff who conducted these visits?

d) Did HOSSM staff accompany METSCO staff on these visits?

e) Did the information obtained from these visits cause METSCO to change any aspect of the report? Please explain.

Response:

a) The site visits took place from May 7^{th} to 11^{th}.

b) The sites visited were all stations and select line circuits in the vicinity of Sault Ste Marie. Please refer to section 4.2 of METSCO's report (E1-1-1 Appendix B, pp. 28-31) for the detailed discussion of the rationale of METSCO's visits.

c) METSCO Staff members who conducted the site visits were Robert Otal and David Baynard.

d) HOSSM staff accompanied METSCO staff on all site visits.

e) No. All METSCO site visits were conducted ahead of the first draft of the report being written or any health indices calculated.

Energy Probe Interrogatory # 13

Reference:

Exhibit B1, Tab 1, Appendix B, Page 11

Interrogatory:

Did METSCO use an industry standard Asset Condition Assessment methodology in its work in producing this report? If it did, please provide reference. If it did not, please explain why.

Response:

METSCO is not aware of any single "industry standard Asset Condition Assessment methodology." METSCO used the same methodology that it has used in more than 50 asset condition assessments produced in its existence, many of which have been filed before, and accepted by the Ontario Energy Board in a number of regulatory applications.

Energy Probe Interrogatory # 14

Reference:
Exhibit B1, Tab 1, Appendix B, Page 10 and Page 19.

Interrogatory:
"METSCO's work included collection, digitization, analysis and verification of HOSSM's asset records, along with its own site inspection data."

Please explain the process used by METSCO to verify asset records of HOSSM.

Response:
Please refer to section 4.2 of METSCO's report (E1-1-1 Appendix B, pp. 28-31).

Energy Probe Interrogatory # 15

Reference:

Exhibit B1, Tab 1, Appendix B, Page 15

Interrogatory:

"In any case, given the customer-centric nature of the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF) that currently governs the operations of Ontario's regulated transmitters, facilities that ensure service continuity for specific customers warrant being placed into a separate category to help the utility plan the scope and sequencing of future intervention activities across the system."

The quoted sentence suggests that METSCO has some concerns with "the customer-centric nature" of the OEB's RRF. If that is not the impression METSCO intended to make please explain what is meant by that sentence. If METSCO has some concerns, please explain what they are.

Response:

METSCO has no concerns with the customer-centric nature of the RRFE. The quoted sentence, along with the preceding part of the paragraph, state METSCO's conviction that customer-serving facilities warrant special consideration given the impact that they have on service continuity of individual transmission customers – particularly in the context of a smaller system such as HOSSM's that lacks supply redundancies in many points.

Energy Probe Interrogatory # 16

Reference:

Exhibit B1, Tab 1, Appendix B, Page 90

Interrogatory:

It appears that of the three authors of the METSCO report, only one has prior experience in asset condition assessments. Please provide a list of electric utility asset condition assessments that the authors of the report have completed including the name of utility and a description of the scope of work.

Response:

Mr. Otal has been involved in a large number of Asset Condition Assessment studies or asset management projects that utilized asset data or required analysis similar to that performed in the course of the ACA. As such, only a short subset of recent projects where Mr. Otal led or contributed to asset condition-related work is provided.

Aside from the current ACA, Mr. Balashov contributed to three projects involving the subject matter relevant in ACA analysis. HOSSM ACA's was Mr. Saltan's first formal Asset Condition Assessment study. However, his extensive experience in the area of transmission system planning and in particular the issue of transmission equipment's performance over time spans several decades in a variety of consulting projects, as described in his CV appended to the report."

Please see the following table listing a subset of Mr. Otal's and Mr. Balashov's past projects that incorporate elements of asset condition assessment work.

Author Name	Utility	Role	Scope of Work/Assets
Robert Otal	Toronto Hydro, 2012, 2015	Principal Author	Distribution Asset Condition Information Collection and Analysis
Robert Otal	SaskPower, 2017-2018	Principal Author	Transmission Asset Risk-Based Analytics Framework Development
Robert Otal	City of Medicine Hat, 2018	Contributing Author	Distribution System Asset Risk-Based Model Development
Robert Otal	Epcor, 2016-2018	Contributing Author	Multiple Distribution risk-based asset intervention modelling engagements, incorporating condition data.

Author Name	**Utility**	**Role**	**Scope of Work/Assets**
Robert Otal	EnMax, 2017-2018	Contributing Author	Distribution Asset Risk based intervention model development and refinement.
Robert Otal	ChemTrade, 2018	Principal Author	ACA and replacement recommendations for an industrial manufacturing client.
Robert Otal	Landsnet, 2018	Principal Author	Transmission Risk-Based Asset Condition model for Iceland's Transmission Company.
Dmitry Balashov	Toronto Hydro, 2015	Contributing Author	Distribution System Plan development, condition data analysis.
Dmitry Balashov	Manitoba Hydro 2017/2018-2018/2019 General Rate Application	Contributing Author	Expert third-part review of Manitoba Hydro's Sustainment Capital forecast, including the matter of collection and utilization of condition information in asset planning.
Dmitry Balashov	SaskPower 2017-2018	Supporting SME	Transmission Asset Risk-Based Analytics Framework Development.

Energy Probe Interrogatory # 17

Reference:

Exhibit B1, Tab 1, Appendix B, Page 33, Figure 5.2

Interrogatory:

Why is METSCO using both a letter score and a numerical score condition indicators when both a have identical meaning?

Response:

Please refer to section 5.1.1 of the METSCO report and particularly figure 5.1 on p. 33.

Energy Probe Interrogatory # 18

Reference:

Exhibit B1, Tab 1, Appendix B, Page 33, Figure 5.2

Interrogatory:

How is the “weight” component number determined? Please provide full explanation with a numerical example.

Response:

METSCO determines the weight for each component of each asset class on a relative basis among the available condition information. As stated throughout our report, a higher weight indicates a higher probability that degradation of a given aspect of an asset’s overall health can result in asset failure. Moreover, METSCO always assigns relative higher scores to objective numerical data (such as dissolved gas analysis results, age, oil moisture content, degree of polymerization, etc.) rather than visual assessments that can be subjected to individual assessors’ frames of reference. For a numerical example, see Figure 6.1 in METSCO’s report (p.38).

Energy Probe Interrogatory # 19

Reference:

Exhibit B1, Tab 1, Appendix B, Page 78

Interrogatory:

Should the OEB be concerned with the results of the METSCO report? Please explain your answer.

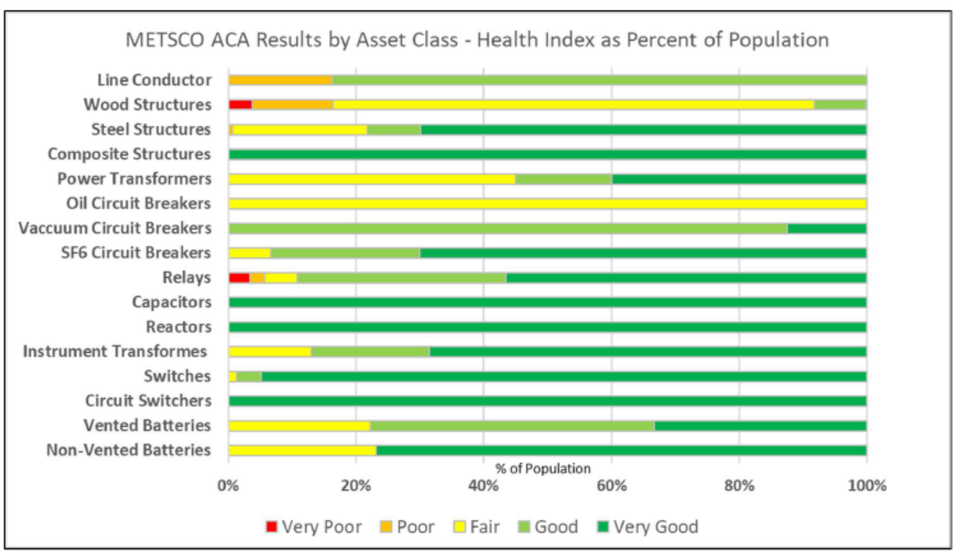
Response:

On balance, HOSSM considers the METSCO ACA to be a generally positive report.

- As displayed in Figure 7.1 from the report (for convenience a copy is included below), the assets rated as "Poor" or "Very Poor" are a small proportion of the Plant assets and they pertain to 3 specific asset classes.
- Development of the report has helped to better target HOSSM's spending to the benefit of the system and customers.
- The information from the report and the underlying datasets are proving very helpful in the integration of HOSSM in to Hydro One.

Therefore, we see no reason why the Metsco ACA developed for HOSSM should cause the OEB to be "concerned".

Figure 7.1: Asset Condition Findings by Asset Class



Taken from Section 7.1.1 of Exhibit B, Tab1, Schedule 1 (TSP), Appendix B (Metsco ACA)

Energy Probe Interrogatory # 20

Reference:
Exhibit B1, Tab 1, Schedule 1, Appendix D, Pages 3 and 4

Interrogatory:
The Needs Assessment Report was prepared in 2014 using 2013 data. Have there been any changes since 2014 that would impact the findings of the report? Please explain the reasons for your answer.

Response:
The regularly occurring Regional Planning Needs Assessment reports are products of collaboration between multiple parties, including the IESO, and several local distributors and transmitters. Being only one of these parties, HOSSM has not determined that there have been any substantial changes since 2014 that would impact the findings. That notwithstanding, as stated in I-1-16 (Staff IR# 16), any changes arising from a future round of regional planning will be reflected in a future application.

Energy Probe Interrogatory # 21

Reference:

Exhibit B1, Tab 1, Schedule 1, Appendix E

Interrogatory:

The Replacement of Protection Relays Study was produced in 2008. Have there been any changes since that time that would impact the findings of the study? Please explain the reasons for your answer.

Response:

Since the time of the study, HOSSM has replaced a variety of P&C equipment across its stations, while other relays have reached the end of vendor support periods, or were found to have defects by way of inspections. In light of these events that occurred over the past decade, the findings of the 2008 study would have been impacted.

Energy Probe Interrogatory # 22

Reference:
Exhibit B2, Tab 2, Schedule 1, Page 6

Interrogatory:
"In the process of integration after an acquisition, Capital expenditure reductions are expected to result from asset redundancy, the economic scale of operations and adopting new asset management and investment planning processes."

Please explain the management decision process used in capital expenditure reductions, including job titles of management staff involved in the process and responsible for the decisions.

Response:
The investment plan presented in this application was approved by HOSSM management based on advice and guidance from the Planning organization in Hydro One and Metsco analysis via the production of the ACA report.

The key person ultimately responsible for the execution of the plan is the Managing Director of HOSSM.

Energy Probe Interrogatory # 23

Reference:

Exhibit D, Tab 1, Schedule 1, Attachment 1 (the "PSE Report"), p.6

Interrogatory:

Preamble:

PSE reports (Table 12, p.47) an average annual industry TFP growth rate of -1.71% based on 12 observations (2004-2016) and -2.40% based on 7 observations (2010-2016).

The PSE Report notes that its industry TFP trend research is used as the basis for the X factor recommendation and states that incentive regulation principles dictate that a proper analysis should use an industry TFP. The PSE Report has used the historical period of 2004 to 2016.

The Board has previously[1] indicated its requirement for an X factor based on the "long-term trend" in TFP growth.

a) Does PSE contend that its reported average annual TFP growth rates of -1.71% (for 2004-2016) and -2.4% (for 2010-2016) accurately reflect the historical long-term TFP growth rate for electricity transmission?

b) Are there any factors or developments in the period 2004-2016 that suggest the observed industry TFP growth rate may be different from the long-term trend? If so, please identify and describe briefly.

Response:

a) PSE contends the -1.71% and -2.40% results accurately reflect the TFP trends of the electric transmission industry during the 2004-2016 and 2010-2016 time period, respectively. PSE's objective in calculating the industry's TFP trend is to provide an empirical and external basis for our productivity factor recommendation during the CIR period of 2019 to 2022. Given the TFP trend results, we find it most reasonable to assume a continuation of zero or negative TFP within the industry for the 2019 to 2022 CIR time frame.

[1] EB-2007-0673. Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors. July 14, 2008 at p.12.

The 2004-2016 TFP sample period includes 13 years (12 growth rate periods). This is longer than the Australian Energy Regulator's transmission productivity study cited in PSE's response to Exhibit I, Tab 1, Schedule Staff #63. The AER results were based on a productivity analysis of five Australian transmission utilities for the period of 2006 to 2015. The AER study also showed declining TFP during this period.

b) PSE stated some possibilities for negative TFP growth in Section 6.1 of our report. These possibilities have not been empirically tested.

Energy Probe Interrogatory # 24

Reference:

Exhibit D, Tab 1, Schedule 1, Attachment 1 (the "PSE Report"), p.30

Interrogatory:

Preamble:

The PSE Report discusses the precision of parameter estimates and the use of the t-test in its cost estimation analysis.

Did PSE undertake t-tests in connection with the sample means that it calculated for its TFP growth rate study? If so, please describe how it analyzed that data and the results of statistical significance. If not, please indicate the reason for not doing so.

Response:

No t-tests were undertaken. The industry TFP is calculated on an aggregated basis. This means that the outputs and input quantities are summed for all included utilities to formulate one aggregated "industry" number for each category. The TFP is then calculated from this industry aggregate. The rationale for using the aggregate number, rather than an average or median, is because of Hydro One's large size relative to the sample. An aggregate number will give more weight to larger utilities and is more appropriate for a relatively large utility like Hydro One. The aggregation calculation is also the same method used in the 4th Generation IR TFP trend research for the electric distribution industry.

Energy Probe Interrogatory # 25

Reference:

Exhibit D, Tab 1, Schedule 1, Attachment 1 (the "PSE Report"), page 46

Interrogatory:

Preamble:

The PSE Report states that the average annual rate of Industry TFP growth was -1.71% for the study period 2004-2016 and -2.40% for the period 2010-2016 (Table 12, p.46).

Please explain how the Industry TFP Index was calculated. For example, is it an average of the utility-specific indexes or has it been calculated from aggregated output and input quantity data calculated from the data on the firms in its sample?

Response:

It is an aggregation of the industry, as described in the response to Exhibit I, Tab 3, Schedule 24 (Energy Probe IR#24).

Energy Probe Interrogatory # 26

Reference:

Exhibit D, Tab 1, Schedule 1, Attachment 1 (the "PSE Report"), and p.6

Interrogatory:

Preamble:

The following table presents multifactor productivity growth rates in the aggregate business sectors of Canada and the United States and in their respective utility sectors. The growth rates presented are taken, or calculated, from Statistics Canada and the U.S. Bureau of Labor Statistics data on their respective MFP indexes.

CANADA			UNITED STATES		
Business Sector MFP Growth[1]	Average Annual Growth Rate		Private Business Sector[2]	Average Annual Growth Rate	
1961-2016	0.475%		1987-2017	0.9%	
1961-2004	0.675%		1987-2005	1.1%	
2005-2016	-0.241%	Most recent 12 years	2006-2017	0.5%	Most recent 12 years
Utilities Sector MFP Growth[3]			Utilities Sector MFP Growth[4]		
1961-2016	0.556%		1987-2016	0.6%	
1961-2004	0.961%		1987-2004	1.341%	
2005-2016	-0.897%	Most recent 12 years	2005-2016	0.058%	Most recent 12 years

[1] Source: CANSIM Table: 36-10-0208-01. Energy Probe calculations of growth rates for all periods shown.

[2] Source: US Bureau of Labor Statistics, Multifactor Productivity Tables, 1987-2017 Major Sector Multifactor Productivity, Private Business and Private Nonfarm Business Multifactor Productivity Tables, Spreadsheets PG Indexes=100.000 (levels) and PG % Change Year Ago (growth rates); Energy Probe calculations of growth rates for sub-periods 1987-2005 and 2006-2017.

[3] Source: CANSIM Table: 36-10-0208-01. Energy Probe calculations of growth rates for all periods shown.

[4] Source: US Bureau of Labor Statistics, Multifactor Productivity Tables, 1987-2016 Combined Sector and Industry Multifactor Productivity, Combined Sectors and Industry KLEMS Multifactor Productivity Tables by Measure, Spreadsheets 1-10.2 (level) and 1-10.3 (growth rates); Energy Probe calculations of growth rates for sub-periods 1987-2004 and 2005-2016.

a) Would PSE agree that, on the available evidence from Statistics Canada and the U.S. Bureau of Labor Statistics, the best available estimate of long-term annual average MFP growth rate in the business sector is 0.475% for Canada and 0.9% for the United States?

b) Recognizing that Statistics Canada and the U.S. Bureau of Labor Statistics define their respective utilities sectors differently and at a high level of industry aggregation, would PSE agree that the best available estimate of long-term annual average MFP growth rate in the utilities sector as defined by these agencies is 0.556% for Canada and 0.6% for the United States?

c) Please confirm/disconfirm that the MFP growth rates shown in the table for the most recent 12-year periods are significantly lower in both countries than in the other periods shown.

d) Does PSE think it likely that the pattern of historical MFP growth rates shown in the table would also be seen in the US electricity-transmission industry TFP growth rates had it been able to calculate them starting from 1987? If not, please explain why not.

Response:

a) PSE would agree that the longer time periods provide a more historical look at MFP in the business sectors. However, this does not mean that the longer time period should be used to formulate an expectation of what will happen in the next three to five years. In both the Canadian and U.S. cases, there does appear to be a pronounced slowdown in MFP in more recent years. Perhaps underlying factors have changed in more recent years (e.g., slowing birth rates, full adoption of computers) that make the more historical MFP less relevant to predicting the MFP for upcoming years.

b) PSE has the same response as we gave in our answer to part a of this interrogatory, with the addition that other factors may be in play that are further slowing the MFP relative to the business sector. One of the possibilities is aging infrastructure. Due to the long service lives of utility assets and the baby boom post-WWII, the utility sector may have now entered a period where assets need to be replaced at a higher rate. Another possibility may be conservation programs that are lowering output growth of the sector. Another possibility may be the demand for better reliability, customer service, etc. that are not being measured in the MFP calculations.

We would note that electric transmission is a small portion of the "utilities" sector definition used by Statistics Canada or the Bureau of Labor Statistics.

c) Confirmed.

d) That is a possibility. However, PSE is unable to respond with certainty on this question without conducting or reviewing a reliable empirical study that starts in 1987. We believe it is reasonable to assume a zero or negative TFP growth rate for the transmission industry will persist from 2019 to 2022, given the -1.71% 2004-2016 finding and the -2.40% TFP trend result for 2010-2016.

Energy Probe Interrogatory # 27

Reference:

Exhibit D, Tab 1, Schedule 1, Attachment 1 (the "PSE Report"), and p.47

Interrogatory:

Preamble:

The PSE Report provides possible reasons for the negative TFP growth rates that it has reported and states that negative TFP growth does not necessarily indicate declining efficiency.

a) With regard to possible unmeasured outputs, does PSE believe that the cost of regulation is an important source of declining TFP growth? If so, how does assigning a utility a zero X factor mitigate this decline?

b) With regard to PSE's suggestion that slower economic growth has reduced a utility's output index and TFP growth, does PSE believe that slower growth would not cause reductions in a utility's input index as well?

c) Please explain why "aging capital infrastructure" leads to a decline in TFP. What is preventing the utility from upgrading/replacing its infrastructure? If the reason is a lack of funds, is it because the regulator has failed to allow a utility to make those necessary capital improvements and recover the costs thereof? Alternately, could the reason be a lack of management capacity?

Response:

a) An increase in regulatory requirements is a possible cause of declining TFP growth. PSE does not see how any X factor value (negative, zero, or positive) would have an impact on mitigating the possible impact of regulatory requirements.

b) Yes. Over time a reduction in economic growth should also reduce the utility's input quantity index as well.

c) As capital infrastructure ages, it needs to be replaced at a greater pace than when it was newer. This will increase capital expenditures and put downward pressure on TFP. It is precisely the utility trying to catch up and upgrade the infrastructure that is causing the decline in TFP.

Energy Probe Interrogatory # 28

Reference:

Exhibit D, Tab 1, Schedule 1 Attachment 1 (the "PSE Report"), and p.13

Interrogatory:

Preamble:

The PSE Report states that the "allowed revenue escalation within the revenue escalation formula should mimic the expected growth in costs."

Please provide the rationale for this statement, as it appears contrary to the basic concept of incentive regulation that the PSE Report recognizes at p.15 where it states "This is because incentive regulation seeks to decouple the link between a utility's cost increases to the allowed revenue escalation."

Response:

There is nothing contrary in the two statements. On p. 13 of the PSE report, we derived generally how cost growth is related to inflation, productivity, and growth. This derivation is then used to calculate industry measures of inflation and productivity to formulate the recommendation for the external inflation and productivity factors for Hydro One. These external measures decouple the link between Hydro One's actual cost increases and allowed revenue escalation during the CIR period, because they are calculated externally from the industry and not from Hydro One itself. In other words, Hydro One's cost levels and productivity does not influence the productivity factor nor the inflation factor. Therefore, the allowed revenue escalation during CIR is external to the cost levels of Hydro One. The exception to this is the stretch factor when it is based on total cost benchmarking. However, in the case of the stretch factor, it serves to increase incentives. If the utility's costs are found to be high and a higher stretch factor is given, this will tend to dampen allowed revenue increases. Conversely, if the utility's costs are found to be lower than benchmark costs and a lower stretch factor is given, this will tend to increase the allowed revenue increases.

Energy Probe Interrogatory # 29

Reference:

Exhibit D, Tab 1, Schedule 1, Attachment 1 (the "PSE Report"), pages 45 and 46

Interrogatory:

Preamble:

The PSE Report states that the average annual rate of Industry TFP growth was -1.71% for the study period 2004-2016 and -2.40% for the period 2010-2016 (Table 12, p.46).

a) Please explain how the Industry TFP Index was calculated. For example, is it an average of the utility-specific indexes or has it been calculated from aggregated output and input quantity data calculated from the data on the firms in its sample?

b) Please indicate which of the working papers that PSE has provided on a confidential basis contains the names of the variables shown in the SST spreadsheet that is part of the Excel workbook named "Final Dataset and Tables Used".

c) Please provide the Excel formulas that PSE has used to calculate numerical values in the cells of the SST spreadsheet that is part of the Excel workbook named "Final Dataset and Tables Used". If these Excel formulae have already been provided on a confidential basis, please indicate what working paper(s) they are located in.

d) Please confirm/disconfirm that the annual TFP index values for Hydro One and the 48 utilities in the sample is the variable "tpfi" in column AJ of the SST spreadsheet that is part of the Excel workbook named "Final Dataset and Tables Used".

e) Please confirm/disconfirm that the TFP growth rates by utility and by year in the industry sample can be calculated based on the data for "tpfi" in Column AJ of the SST spreadsheet that is part of the Excel workbook named "Final Dataset and Tables Used".

f) Please confirm/disconfirm that (i) the arithmetic average of the 552 observations of annual TFP growth in the sample is -1.775%, (ii) the median is -1.596%, (iii) the standard deviation is 7.9407 percentage points and (iv) a conventional one-sample t-test (2-tailed, 5% significance) shows that the sample average is statistically significant

Response:

a) The industry TFP index is calculated using an aggregation of the output and input quantity data from the individual firms. Each utility's outputs and inputs are summed in each year of the sample to formulate one aggregated industry value for outputs and inputs. Given Hydro One's relative large size, an aggregation method gives more weight to the larger utilities within the sample. PSE believes this is a more appropriate measure for Hydro One than averaging or taking the median of the TFP indexes for the individual companies. This is also the same calculation method used in the 4th Generation IR TFP research.

b) The variables shown in the SST spreadsheet that is part of the Excel workbook are calculated in the file hontx.prg found in the working papers. This code can be opened and viewed using Microsoft Notepad.

c) See response to part (b). The calculations can be found in the hontx.prg file.

d) We confirm that the annual TFP index values for each utility are found in column AJ. The variable is labeled "tfpi".

e) Confirmed. These are the calculated TFP indexes and growth rates by utility and by year can be calculated from them.

f) PSE calculates there are 576 observations with growth rates, rather than the 552 stated in the question. This matches the fact that there are 48 utilities in the sample with 12 years of growth rates each. The sample average of the 576 observations is -2.01%. However, PSE believes the more appropriate number to apply to Hydro One is the aggregate TFP trend of -1.71%. The median observation when looking at all 576 observations has a TFP trend of -1.56%. The standard deviation of all the individual observations by year is 7.916%. This would show that the sample average TFP trend of -2.01% is not statistically significant.

The TFP trend that PSE calculated is an industry aggregate trend, and is not based on the sample average. However, even if the trend were based on a sample average, rather than examining the standard deviation of all individual observations, PSE's contention is that it would be more appropriate to examine the standard deviation of each utility's 2004-2016 TFP growth rates when attempting to ascertain statistical significance. The standard deviation of the 48 utilities 2004-2016 growth rates is 2.32%. This is still not a statistically significant finding, and the null hypothesis that the true TFP growth rate is zero cannot be rejected. However, even though the TFP estimate is not statistically significant, the best estimate and most likely industry TFP growth rate remains at -1.71%.

AMPCO Interrogatory # 1

Reference:

A-2-2 P4

Interrogatory:

The evidence states "HOSSM will apply for an Incremental Capital Module ("ICM") funding in the event HOSSM encounters unplanned capital expenditures prior to any rebasing application to be filed for 2026 rates.

a) At this point in time, is HOSSM aware of any potential significant capital expenditures that could materialize prior to 2026 that would have a significant impact on the utility?

Response:

HOSSM is not currently aware of any specific, material capital expenditures that would have a significant impact on the utility or that would warrant an ICM filing prior to 2026.

AMPCO Interrogatory # 2

Reference:

A-3-1 P4

Interrogatory:

The evidence states "To better understand the asset and system requirements, asset health condition and risk and value to customers, and to ensure HOSSM's investment plan was developed using sufficient rigour, Hydro One hired METSCO Energy Solutions to perform an in-depth Asset Condition Assessment ("ACA") on HOSSM's assets. Data was gathered from numerous sources including two different electronic systems (Sunguard and Elkie), paper copies of inspection reports and test results, inspections, interviews and team meetings that included staff from Hydro One, HOSSM, and METSCO.

a) Please discuss any known deficiencies with respect to the accuracy, completeness, consistency and quality of the data sources and underlying data.

b) Please discuss any plans to rectify data issues identified in part (a).

Response:

a) When Hydro One acquired HOSSM, it took over a company that had not had a full Asset Condition Assessment in several years and it faced the reality that the asset data possessed by HOSSM was across multiple systems as described. While those sources were generally comprehensive, the compilation, digitizing and updating of the information took considerable effort. Moreover, site visits where required in a number of cases to understand and update the information. This included significant work around data and file format transformation; necessary to make the data usable on a holistic scale. A further description of the challenges faced is included in Section 4.2.3 of Exhibit B1, Tab 1, Schedule 1 (TSP), Appendix B (Metsco ACA).

b) The completion of this work is proving to be immensely valuable as the process of transferring the HOSSM data into the Hydro One SAP systems takes place. In any large data transfer, fields must be validated to 'fit' into a new system. This work will continue over the deferral period. As this effort was anticipated Hydro One is not experiencing any unexpected, significant issues.

AMPCO Interrogatory # 3

Reference:

B1-1-1 P5

Interrogatory:

The evidence states "As the integration between the Hydro One and HOSSM asset management functions continues over the coming years, HOSSM expects that additional investment drivers may emerge, driven by considerations such as equipment standardization, interoperability, or operational efficiency, among others.

a) Please discuss intergration plans for equipment standardization. Is the intent to align with Hydro One's material and equipment standards?

b) Please provide examples of key asset categories where material and/or equipment standards are not aligned between HOSSM and Hydro One and discuss the potential cost implications of equipment standardization with Hydro One.

Response:

a) The standardization of HOSSM equipment to HONI standard will take place gradually, leveraging on investments proposed and covered in the time span of the submitted Transmission System Plan. Where practical, HONI will also take advantage of demand/ emergency circumstances that forces replacement of assets. Purchase of new equipment will follow Hydro One Technical Specification as far as safety and maintenance are concerned.

b) Example of key asset categories is power transformer, of which existing HONI equipment standards do not cover 34.5kV as nominal voltage on selected HOSSM LV systems. HONI is in the process of reviewing and amending its equipment specifications to adequately account for this change. The internal cost of this review is absorbed within HONI. Hydro One will need to engage vendors for pricing of equipment.

AMPCO Interrogatory # 4

Reference:

B1-1-1 P9
B1-1-1 P76

Interrogatory:

The asset populations differ between reference 1 and reference 2 for switches and protection relays. Please reconcile.

Response:

The minor inconsistencies between the two references (156 switches vs. 163 and 338 relays vs. 361) are a function of an administrative oversight at the time of the application’s assembly. HOSSM thanks AMPCO for helping it reconcile this discrepancy. The second reference (drawn from the METSCO report) constitutes the correct number of assets.

AMPCO Interrogatory # 5

Reference:

B1-1-1 P12 Table 1-4

Interrogatory:

For each of the four investment categories in Table 1-4, please provide the Plan Total ($M and %) for the years 2013 to 2017.

Response:

Actual Capital Expenditure Totals by Investment Category for the 5 year period 2013-2017 are:

Investment Category	Plan Total ($M)
System Access	**$0.0** *0%*
System Renewal	**$29.4** *74%*
System Service	**$2.1** *5%*
General Plant	**$8.3** *21%*

AMPCO Interrogatory # 6

Reference:

B1-1-1 P12 Table 1-4

Interrogatory:

a) With respect to the expenditure driver Asset Failure under System Renewal, please provide the amount built into rates for the reactive replacement of assets failed in service.

b) Please provide the amount budgeted in the capital plan for each of the years 2018 to 2026 for the reactive replacement of assets failed in service.

c) For each of the years 2013 to 2017, please provide the total quantity of assets replaced reactively by asset type.

Response:

a) Per table 1-4, there are no planned projects built into rate for reactive replacement of assets failed in service.

b) Per table 1-4, there are no planned projects budgeted in the capital plan from 2018 to 2026 for reactive replacement of assets failed in service.

c) There is only one instance of an asset being replaced reactively due to failure - Power Transformer, Northern Avenue TS (2013).

AMPCO Interrogatory # 7

Reference:

B1-1-1 P14

Interrogatory:

HOSSM states "By virtue of acquisition of HOSSM's predecessor GLPT by Hydro One Inc. and through the ongoing integration with Hydro One's Asset Management function, the investments comprising this plan underwent assessment using a similar asset management and investment planning processes employed by the acquiring utility, modified to reflect the current state of integration of the two entities' information technology systems and the availability of pertinent data.

a) Please define pertinent data.

b) Please provide an evaluation of the current state of the availability of pertinent data.

c) Please discuss the modifications made to the investment planning process to reflect the current state of availability of pertinent data.

d) Please identify the most significant data caps and what needs to be done to close the gaps.

Response:

a) "Pertinent data" refers to the type of asset health and operating performance data that the two utilities collected prior to Hydro One's acquisition of HOSSM and further integration of the two utilities.

b) In a number of cases, Hydro One collects more types of asset data than HOSSM and its predecessor have historically collected.

c) Hydro One's investment planning process has been improved upon since the previous applications (EB-2016-0160 & EB-2017-0049). The process used by HOSSM is documented within the existing application and evidence. Below is a listing of key improvements and where the information is specifically located within the application:

- Condition Data: Refer to comprehensive condition data as part of the application, in B1-1-1 section 2.2.2.
- Customer Feedback: outcomes of the engagement with HOSSM's customers, in B1-1-1 section 3.1.3.2,
- Deficiencies in Prioritization: Hydro One updated it's prioritization criteria to focus on Safety, Reliability and the Environment, in B1-1-1 section 3.1.3.4

As part of the challenge session, investments scored with less pertinent data would have been reviewed and considered for inclusion within the plan. Given the scope of HOSSM's investment plan is smaller than Hydro One Networks, the HOSSM challenge session was a single session with all relevant participants involved and if any data was subpar, the expert knowledge at the session would have acted as a mitigating control to ensure the proposed investments are worthy of inclusion. Challenge Sessions are described B1-1-1 section 3.1.3.4 "Challenge Sessions."

d) At this stage of the two entities integration, HOSSM is not in a position to opine as to the most significant data gaps. HOSSM notes, however that sufficient asset data was available to create multi-factor numerical health indices for all of its major asset classes, as evidenced in the METSCO report.

AMPCO Interrogatory # 8

Reference:

B1-1-1 P19

Interrogatory:

HOSSM plans to dedicate a larger of proportion of the Plan period System Renewal investments to line infrastructure and power transformer replacements as the Asset Condition Assessment (ACA) performed by METSCO (See Appendix B) confirmed that a material proportion of these asset populations are in a "Fair" condition or worse.

a) Did METSCO make these specific targeted spending recommendations? If yes, please provide references.

b) Please provide HOSSM's most recent condition assessment of the power transformer asset population prior to METSCOE's ACA.

c) Please provide the number of power transformer failures for each of the years 2013 to 2017.

Response:

a) A summary of Metsco findings and recommendations are included in Section 7 of Exhibit B, Tab 1, Schedule 1 (TSP), Appendix B (Metsco ACA).

b) Attachment 1 to this exhibit is an Independent Technical Advisor Report to Great Lakes Power Transmission performed by Hatch as of July 2016. Please note, unlike the METSCO study, the Hatch transformer ACA assessed asset health at a much higher level, relying primarily on visual inspections. On the other hand, METSCO's ACA incorporates such critical asset condition data as Dissolved Gas Analysis (DGA) results, transformer oil moisture content, loading history, and others. Moreover, given that the Hatch report was finalized in 2016, insights have been updated to reflect the most recent operating realities.

c) There was one Power Transformer failure in 2013 - Northern Avenue TS.

Great Lakes Power Transmission

Independent Technical Advisor Report on Great Lakes Power Transmission

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Project Report

Monday, July 4, 2016

Great Lakes Power Transmission

Distribution:
Duane Fecteau
Scott Seabrook
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Independent Technical Advisor Report on Great Lakes Power Transmission

Conditions of Use and Limitations of Liability

Great Lakes Power Transmission (“GLPT”) commissioned Hatch Ltd. (“Hatch”) to prepare this Report pursuant to the Hatch agreed proposal dated 1 June, 2016 (the “Proposal”).

This Report has been prepared by Hatch for the sole and exclusive use of the Client in connection with its assessment of the company assets and operations covered herein and may not be used nor relied upon by the Client for any other purpose. The use of this Report by the Client is subject to the Terms and Conditions attached to the Proposal, including the limitations of liability set out therein.

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Hatch has conducted this investigation in accordance with the methodology set out in the Proposal. The methods of evaluation employed, while performed in accordance with generally accepted methodologies aimed at minimizing the risk of unidentified factors and/or circumstances, cannot guarantee or warrant their absence.

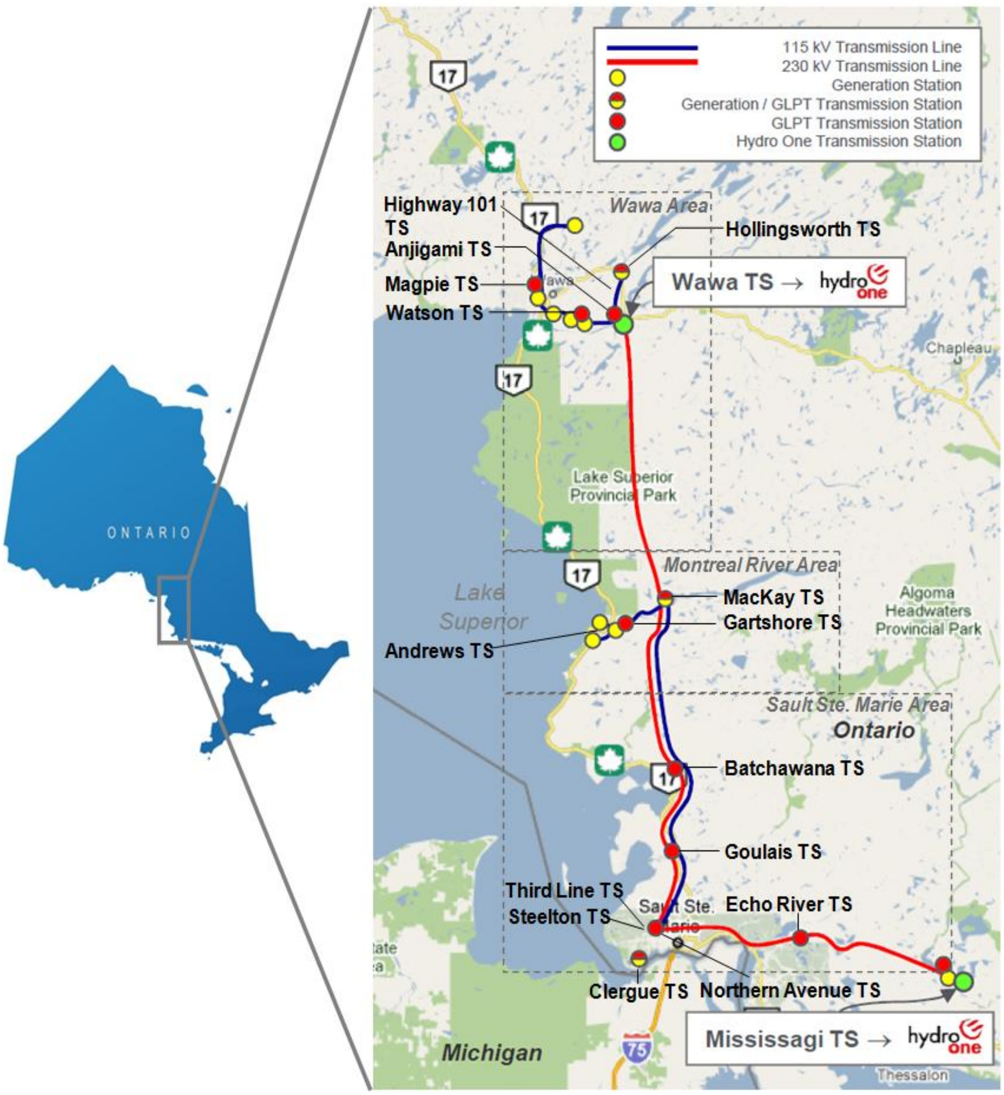
While it is believed that the information contained in the Report is reliable subject to the conditions and limitations set forth therein, the Report is based, in part, on information provided by the Client and/or third parties neither produced by nor within the control of Hatch at the time of its creation. Hatch cannot and does not guarantee the accuracy of any such information. Accordingly, the contents of the Report reflect the best professional judgment of Hatch in light of the circumstances under which the Report was prepared and the information made available to Hatch at the time of preparation.

This report contains some high level commentary pertaining to the environment. As the principles, procedures, standards and techniques involved in an environmental investigation are neither regulated nor universally accepted, such commentary cannot and does not constitute a legal opinion regarding the applicability or probability of compliance with any laws, ordinances, judgments, regulation, codes or standards affecting the environment.

Executive Summary

Introduction and Background

Hatch Ltd. has been employed by Great Lakes Power Transmission LP (GLPT) to prepare an Independent Engineer's Report on the assets and operations of GLPT. This is a high level technical review and assessment of the assets, operations, overall competence of technical management of these assets and operations, and future capital expenditures.



Map of the GLPT System and Principal Assets

GLPT is an Ontario regulated electricity transmission business operating along the eastern shore of Lake Superior, north and east of Sault Ste. Marie. GLPT consists of 15 transmission stations, approximately 560 kilometres (350 miles) of high and medium voltage (44 kV to 230 kV) transmission lines and related infrastructure covering an area of 12,000 square kilometres (the “System”). GLPT manages transmission lines (steel towers, wood poles, composite poles, conductors, fittings) and transmission substations as part of the System. GLPT is interconnected with 4 industrial customers, 16 power generators, 2 local distribution companies (LDCs) connecting in 4 locations, and with the Ontario bulk transmission system in 2 locations: Hydro One’s Wawa TS and Mississagi TS.

Scope and Approach of this Assessment

The objective of the Hatch mandate was to provide an Independent Engineer’s Report on the condition, operation, maintenance, renewal, and capital expenditures associated with the GLPT assets. Hatch undertook a review of technical documentation and made a site visit to the 15 transmission stations and selected sections of the 560 km of transmission lines. Hatch sought to assess the condition of the transmission lines, transmission substations, other assets at a high level (the operations centre, buildings, tools, vehicles, and related assets), the operations and maintenance management practices, and future capital expenditures.

Asset Health Comments

Hatch undertook a 3 day visit Oct 19 - 21, 2015 accompanied by GLPT operations staff. This was essentially a visual inspection of all the transmission stations and a limited selection of accessible sections of the transmission lines (less than 5%) plus an office discussion of the assets and the future capital program.

Transmission Lines Health

Based upon these limited visits, Hatch is of the following opinions.

Vegetation management along the right-of-way is generally in good condition.

The condition of the wood structures (poles, cross-arms, structural elements) varies from good (recent replacements) to fair. Hatch observed a number of structures where replacements or reinforcements are required in the short to midterm future. GLPT staff was aware of these and the company has plans for corrective rectification. In 2010, PoleCare carried out a comprehensive inspection on a large number of the older wood poles (approximately 3700 of 5200) in the GLPT system. From discussion with GLPT, Hatch understands that its replacement plans are taking direct account of the PoleCare recommended timelines for replacements. LineWise Aerial completed an aerial inspection in December 2014 of 72 km of lines using infrared and corona testing methods, as well as visual inspection of 29 km of structures and right-of-way vegetation on the ground. GLPT is managing necessary corrective actions.

A number of broken bells (glass type insulators) were noted in the Hatch inspections. GLPT staff has advised that they are aware of these and carry out routine replacement when the number of broken insulators (in any given assembly) exceeds their intervention criteria. These replacements are made by GLPT staff. No visible damage (e.g. broken strands) was seen on the conductors, though a number of repairs were noted. GLPT has experienced some conductor failures recently and has sent various conductor samples to Kinectrics for testing and is awaiting recommendations regarding replacement.

During the field visit, Hatch was able to cross-check a number of its observations against the available recently recorded GLPT inspections and confirmed those sample observations were found in the condition record.

In summary, close to 85% of the GLPT transmission lines system (as factored for kV importance) has a Health Index of 73.5 denoting Fair-to-Good condition in our assessment. This is consistent with the expected results as approximately 90% (in terms of importance) of the GLPT transmission line system is comprised of four major transmission lines. Two of these lines (K24G, W23K) are in good condition and the other two (P21G, P22G) are in lower-fair to fair condition. With the planned replacements on the P21G and P22G lines, their individual Health Index (HI) will improve (estimated to 80% for each). That will increase the overall HI for the transmission line system to 77% which is close to ‘Good’ condition. For Sault No.3, GLPT plans to replace conductors as well as a large number of structures. With a new conductor and many structures replaced, its condition would become ‘Good’.

Transmission Stations Health

Transmission station equipment was visually inspected and discussed with accompanying staff. The condition of power equipment at site as well as yard and fence, drainage and other elements of the stations were reviewed during this visual inspection. Subsequently, Hatch received inspection reports on selected transformers, circuit breakers, grounding transformers, voltage transformers, batteries, disconnect switches and circuit switches. Some defects were observed in the field but the assets are generally in Fair-to-Good condition. In 2012, GLPT’s largest station, Third Line TS, was substantially refurbished and those assets are new.

Environmentally, several corrective action initiatives are underway or have been completed:

- Oil containment has been upgraded at 7 of 12 locations with the other 5 due for completion in the near future
- GLPT is now essentially PCB free – Northern Avenue TS was dealt with over 5 years ago
- Hollingsworth and Third Line – environmental test holes have been completed and no additional clean up requirement has been identified

GLPT has certain spares for its operations and it is noted that, excluding one backup spare transformer for the Andrews TS, there are no other backup spare transformers at the time of this review. This is a continuation of past operations and level of service (not a deterioration). GLPT is developing a capital plan to propose to the OEB to address this situation. As a small company, GLPT reports to be fortunate to have good working relationships with its contractors, who are responsive in an emergency time frame (along with local contracts) to assist GLPT staff and crews in the restoration of power including valuable access to necessary aerial equipment and parts.

In summary, the 15 transmission stations have an average Health Index of 78.5 (Fair-to-Good condition) and the two largest stations (Third Line TS and MacKay TS) have Health Indices of 93 and 96.3 respectively (very good condition).

Other Assets

GLPT operates several other asset classes besides transmission stations and transmission lines in order to execute its day-to-day operations and maintenance. Building space is generally leased (Sackville, main operations). Active communications systems include fibre optics and a radio system used by crews. GLPT leases bandwidth from the fibre optics system outside the stations.

GLPT operates various other assets including: (1) a fleet of vehicles, which includes one bucket truck and various pick-up trucks and smaller vehicles, (2) computers, test equipment, and (3) protective relay equipment.

GLPT Asset and Operational Management

GLPT uses a systematic approach to asset management, which is consistent with industry best practices:

- Periodic asset performance reviews (field inspections, capacity reviews, reliability reviews, etc.)
- Defect Log and prioritization of corrective action
- Investment planning based on declining condition, increased electrical load and declining reliability
- Contracting out of the construction work for capital investment projects

GLPT collects real time data on a continuous basis using its SCADA system. The data collected relates to power flow, fault data and power quality and supplements the information collected through the inspection and maintenance activities identified above.

The majority of high expenditure assets have defined maintenance directives and practices as observed during the site inspections and as proposed in the capital plan and are consistent with current good engineering practices and meet or exceed accepted industry standards.

Operations and Maintenance Program

GLPT has a well-defined maintenance program, which relies on the condition data derived from various activities of GLPT staff and external contractors when needed. Transmission lines and stations are visited on a periodic basis to assess the condition of elements. This information is recorded, for later use. Defects and other items of concern are added to a corrective action list, where priorities are set. Solutions vary between corrective maintenance of various degrees to a capital investment plan.

Performance data also provides input to this process. This includes information from the SCADA system (voltage, current, power, etc.), as well as reliability information (outage management system). GLPT is required to report its reliability statistics. GLPT measures itself against the same standard that Hydro One is held to, based on several classes of delivery points: 0-15MW, 15-40MW, 40-80MW, and >80MW.

GLPT has generally met these standards in the past, but there is concern for the smallest delivery class of 0-15MW which appears to have seen an exceptional event in the 2011-2013 time window. There is also a general trend for over 6 years of increasing interruption durations to a point that 2013-15 average numbers appear to exceed the standard in spite of the 2015 calendar year not being compete at the time of the Hatch review. GLPT identified this issue to the OEB and put forward a plan to address it and has received approval in the 2015/16 rate application of projects to improve reliability to the 44kV portion of the GLPT system to remedy trending issues with delivery points in the 0-15MW load block.

Future Capital Expenditure

GLPT has produced a 10 year capex projection to 2025. It has used asset condition analysis, reliability of supply risk assessment, history of operations experience and prior sustaining capital works to define the individual asset projects requiring corrective attention including replacements. It has adopted an approach to assemble a package of works in its remote asset areas to allow a holistic attention to corrective action (i.e., poles replacement plus conductor tensioning, guy wire tightening, insulator replacement, etc.) and its compatible scheduling.

Hatch conducted brief site visits to the transmission stations and selected accessible sections of transmission lines and discussed with management its process for the need, timing and costing of its capex plans.

The Hatch review confirms that the proposed 10 year capex planning is consistent with appropriate T&D utility practice taking into account the existing condition and life expectancy of the assets and the requirement to maintain the present levels of service reliability. It should be noted that the scheduling of projects may move to reflect changing priorities (impacting annual capex totals but always within the total OEB approved capex envelope) which is as expected given the long service life expectancies of transmission assets.

Hatch has not reviewed any individual project cost estimates but it has discussed the estimating process. Assuming all other factors remain the same and there are no intervening causes, the overall 10 year expenditures are observed to be reasonable.

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List of Appendices

1. Introduction

Hatch Ltd. has been employed by Great Lakes Power Transmission LP (GLPT) to prepare an Independent Engineer's Report on the assets and operations of GLPT. This is a high level technical review and assessment of the assets, operations, overall competence of technical management of these assets and operations, and future capital expenditures. It includes:

- Commentary on the system development history
- Identification, assessment and commentary on the principal operating assets:
  - Transmission lines and stations assets including asset inventory, asset condition, performance, management and future plans
  - Selected commentary on secondary assets such as the management office, backup control room, equipment, resources, principal spares
- Organization of operations
- High level commentary on the reasonableness of future capital projects, including whether the capex planning process is observed to be consistent with appropriate T&D utility practice

This work was undertaken by using information provided by GLPT, discussions with management and brief site visits to transmission lines and stations.

Any use of this report is subject to the disclaimer included herein and the contractual terms and conditions agreed between Hatch Ltd. and Great Lakes Power Transmission.

1.1 Structure of this Report

The structure of this report addresses at a high level the remit defined above. It does so in summary terms in the main body of the report. More detailed asset commentaries are included in the Appendices. The sections are as follows:

- Introduction
- Background
- Scope and Approach of this Assessment
- Transmission Lines
- Transmission Substations
- Other GLPT Assets
- GLPT Asset and Operational Management
- Operations and Maintenance Program

- Future Capital Expenditure
- Management's Growth Opportunities for GLPT

Each of these is addressed with appropriate weight for the benefit of the reader's expectations of an Independent Engineer's Report.

In addition, there are three Appendices with supporting information:

- Transmission Line Asset Condition Assessment
- Transmission Substation Asset Condition Assessment
- GLPT 10 Year Capital Plan

1.2 List of Abbreviations

Table 1-1 provides a listing of abbreviations used throughout this report with associated definitions.

Table 1-1: List of Abbreviations and Definitions

Abbreviation	Definition
ACA	Asset Condition Assessment
BES	Bulk Electric System
CT	Current Transformer (instrument transformer; see PT)
DSC	Distribution System Code; see Transmission System Code
EA	Environmental Assessment
GIS	Geographic Information System
GLPT	Great Lakes Power Transmission
HI	Health Index– a measure for the condition/health of an asset. Calculated using a weighted average of indicators
HS&E	Health, Safety and Environment
IESO	Independent Electric System Operator
kV	Kilovolt, i.e. one thousand volts
LDC	Local Distribution Company
LiDAR	Light Detection and Ranging – a survey method for measuring ground profile, structure placement, wire sag, and other objects, based on an aerial fly by
MSP	Meter Service Provider
OEB	Ontario Energy Board
OM&A	Operations, Maintenance and Administration

Abbreviation	Definition
PCB	Polychlorinated Biphenyl
PLC	Power Line Carrier
PT	Potential Transformer (instrument transformer; see CT)
RACS	Radio Access Control System
ROW	Right-of-Way
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SF_6	Sulphur Hexafluoride
SRR	Site Registration Report
TS	Transmission Station
TSC	Transmission System Code; see Distribution System Code

2. Background

GLPT is an Ontario regulated electricity transmission business operating along the eastern shore of Lake Superior, north and east of Sault Ste. Marie, Ontario, Canada. GLPT is an electricity transmission company that is solely in the business of owning and operating its electricity transmission system in accordance with Section 71 of the Ontario Energy Board (OEB) Act, 1998, under a traditional cost-of-service setting framework.

GLPT consists of 15 transmission stations, approximately 560 kilometres (348 miles) of high and medium voltage (44 to 230 kV) transmission lines and related infrastructure covering an area of 12,000 square kilometres (the "System"). GLPT manages transmission lines, steel towers, wood poles, composite poles and transmission substations as part of the System. GLPT is interconnected with 4 industrial customers, 16 power generators, 2 local distribution companies (LDCs) connected in 4 locations, and with the Ontario bulk transmission system in 2 locations: Hydro One's Wawa and Mississagi transmission stations. GLPT switches and controls its transmission equipment remotely through a SCADA centre located in the city of Sault Ste. Marie upon receiving instructions from the Independent Electricity System Operator (IESO). GLPT's head office and operations are located in Sault Ste. Marie with a Backup control centre in Montreal River, Ontario. GLPT's transmission system is divided into three operating areas:

- Wawa Area
- Montreal River Area
- Sault Ste. Marie Area

GLPT's system statistics are summarized in Table 2-1 and a map of the transmission system and the principal assets is provided in Figure 2-1.

Table 2-1: GLPT System Statistics

Parameter	Units	Wawa	Montreal River	Sault Ste. Marie	Total
230 kV	km	74	-	245	319
115 kV	km	74	37	121	232
44 kV	km	10	-	-	10
Total Transmission Line Length	km	157	37	366	560
Transmission Stations	-	5	3	7	15
Connected Customers	-	2	-	2	4
LDCs	-	1	1	2	4
Generators	-	7	5	4	16
Connecting TS	-	Wawa	-	Mississagi	-

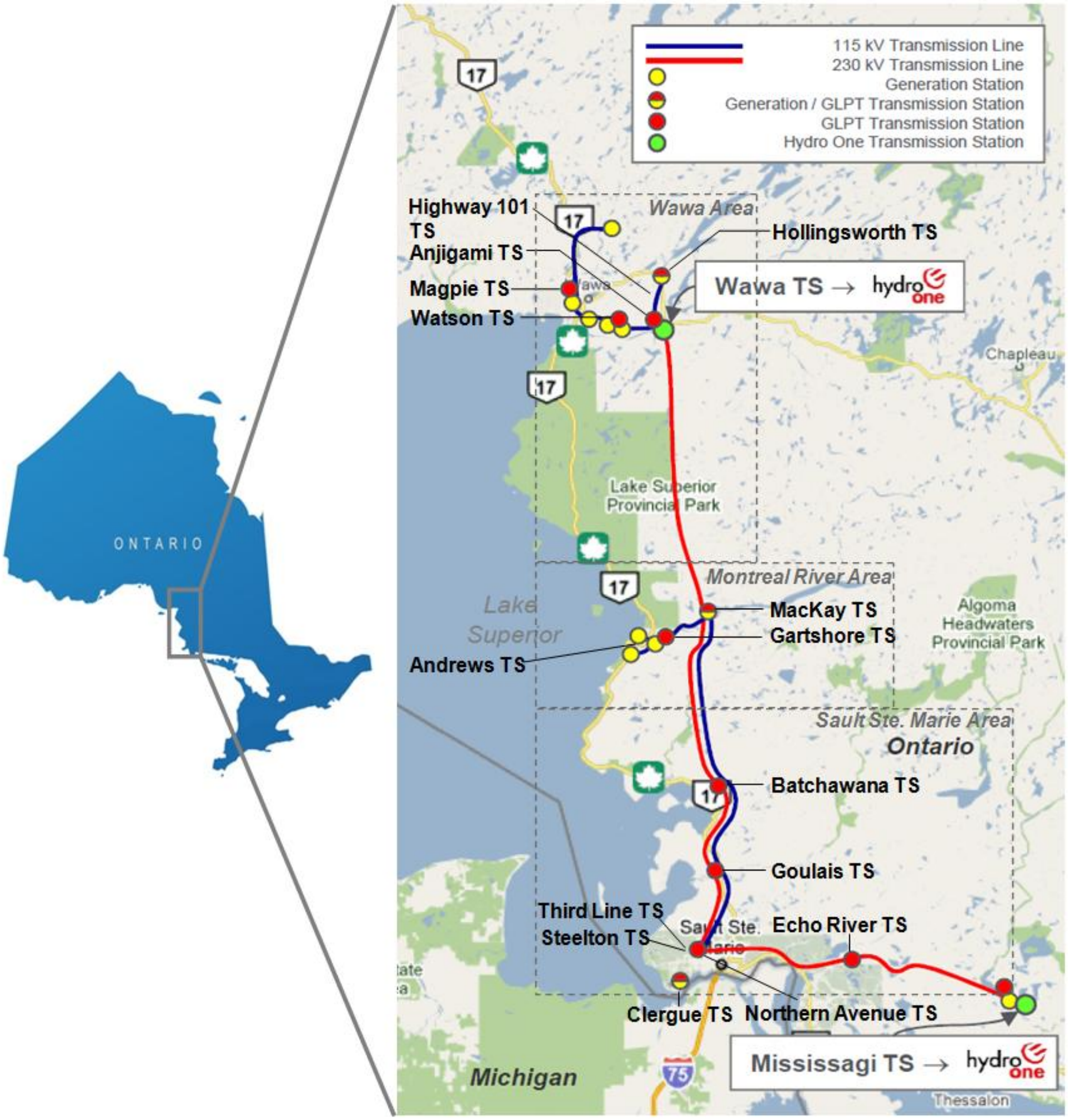

Figure 2-1: Map of the GLPT System and Principal Assets

3. Scope and Approach of this Assessment

3.1 Scope and Objectives

The objective of the Hatch mandate was to produce an independent technical assessment of the assets and operations of GLPT.

Hatch undertook a brief technical review of the fifteen (15) transmission stations and selected sections of the 560 km of transmission lines making a visual assessment of the condition of the assets, the operations centre, and at a desktop level of review, the buildings, tools, vehicles, related items to operate and maintain the aforementioned infrastructure, and the nature of forecasted capital projects.

GLPT made a large number of documents available to facilitate the Hatch review.

Figure 2-1 (previous page) presents an overview of the GLPT Transmission System.

3.2 Exclusions

The transmission system connections with Hydro One, commonly demarked at the first structure outside the station (i.e., GLPT owns the P22G 230kV circuit up to the first structure outside the Hydro One Mississagi TS, same as W23K with Wawa TS).

The low voltage demarcation of the GLPT assets is at the first switch after the feeder circuit breakers at the fifteen stations. All assets within the station from the high voltage connection to the low voltage demarcation point belong to GLPT. The feeders leaving the station are the property of the downstream customer. In some cases, there are distribution assets owned by the downstream customer, within the station fence.

Protection and control equipment in each station is the property of GLPT, including the applicable SCADA equipment. Fibre communications equipment is included, up to and but not including the box where the external fibre connections are made (patch panel). The external fibre optics cable is not included in the transmission assets and the patch panel is not included in the station assets.

GLPT does not own any revenue metering equipment.

At Steelton TS, the Patrick TS transformers and related equipment are excluded. They are located within the station fence, but belong to an industrial market participant. Any protection systems exclusively for Patrick TS belong to the 3rd party. Conversely, any protection system elements (CT's, PT's, etc.) located on GLPT owned or controlled equipment belongs to GLPT. Any protection elements that protect GLPT assets belong to GLPT, even if located on 3rd party equipment.

3.3 Approach to Site Visit and Assessment

In order to assess the condition of the Transmission System of GLPT, a field investigation was conducted by Hatch from Oct. 19 to Oct. 21, 2015.

The site visits were completed using ground based inspections. Hatch and GLPT staff drove sections of the transmission line, using trucks, and entered the substations as part of the visual inspections. No equipment was climbed by Hatch staff and no equipment was taken out of service.

Furthermore, a sampling of maintenance records was reviewed to assess the 'reported condition' in comparison with the 'as found' condition at site.

The field assessment, data collection and interviews with managers allowed Hatch to assess:

- The extent to which interventions are required to improve the operational performance of the transmission system so as to reach commonly accepted technical standards
- The condition of the assessments used for elaborating the need for upgrading and the creation of programs of renewal which are used for estimating the investments required

3.4 Methodology of Asset Health and Functionality Assessment

A key source of data in the Hatch assessment was the documentation provided by GLPT.

The initial basis for the work was the review of GLPT past and present reports. The reports provided useful information on the fifteen stations and the transmission lines, in addition to identifying the main aspects of technical issues. Hatch used the data gathered during its site visits to complement this and other available technical reports.

GLPT gave full access to key individuals during the site visit to discuss and review available information.

3.4.1 Asset Health Index

Hatch has implemented a high level Asset Health Index (HI) to summarize the available information. This allows comparisons to be made between assets and to separately identify any items of major concern. The proposed HI includes information from GLPT's asset condition/health inspection results. This Asset Health Index may be adjusted in the future as more information becomes available.

GLPT has identified that the development of a Health Index is important and a key element of continuous improvement in evolving its Asset Management capabilities.

The use of a Health Index has the advantage that staff can focus on gathering data and not spend significant time on interpreting the results. The Health Index is known to help standardize reporting activities, help with asset to asset comparison, as well as the comparison of different assets in different asset classes.

As GLPT's HI approach and data collection practices are at a younger maturity relative to other utilities, the proposed HI is high level. For example, there is only one Health Index per station using this method. Other utilities have Health Indices for asset classes within a station and then aggregate the Health Index results.

This present Health Index mirrors the management practices at GLPT. If more than one major component of a station is to be replaced, then the whole station is reviewed for additional investment opportunities in order to take advantage of the planned outage. As a result, the number of future planned outages is reduced and potential customer interruption and/or outage times are minimized.

Section 3.4.2 and 3.4.3 present the Health Index for transmission lines and substations respectively. Section 3.4.4 presents a summary level interpretation of the Health Index results.

3.4.2 High Voltage Transmission Lines

For the high voltage transmission lines, the following components (indicators) and weights were used in our system of scoring the asset health:

- 75% pole structure soundness
- 5% stay condition (bending, inappropriate location, not standing vertically, suitable angle relative to the ground)
- 10% insulation and cross arm condition
- 10% conductor condition

The transmission line conductors are fixed to poles. The materials of the poles are mostly wood, but some metal, composite, and other materials are in use. A pole that breaks because of poor structural soundness could present not only a danger for the general public (live lines may fall to the ground) but could also result in interruption of service. This interruption of service may last several days depending on the location of the event, severity of weather and number of affected elements of the transmission line. Therefore, the structural soundness of the pole is critical and is given the highest weight.

The pole's stay condition reflects the standing condition. It may be located in the wrong place (too close to street, building or other structures), or it may not be suitably aligned. The stay condition, while important, is not costly to fix. As a result, it is assigned a low percentage.

The cross arms (and conductors) are less exposed to damage caused by human activity in comparison to the poles, and they are also relatively easy to repair at a much lower cost than poles. A good maintenance program can reduce the number and duration of localized network failures caused by defects in cross-arms or conductors.

Finally, for the total asset condition of an HV line, a Health Index (HI) is calculated as the weighted average of the above indicators, with the average assessed condition for the line sections. For example:

- If the HV line scores 100% for all four indicators, then the HI is 100% (near perfect condition)

- If the HV line scores below 50% for all indicators, then the HI is <50% (likely towards or at end of life, requiring immediate intervention)

If the line scores 80% for the pole structure indicator and 100% for the rest of the indicators, then the HI = 85%.

3.4.3 Transmission Substation – Health Index Formulation

For the transmission stations, the following components (indicators) and weights were used:

- 60% protection, including safety measures of the personnel
- 10% grounding system
- 10% bushings and connectors
- 10% building condition
- 10% transformer condition

The Health Index calculation of substations is similar to that of HV lines.

Protection includes the safety measures for personnel: relays, guarding, structures, elevation of electrical equipment, monitoring equipment, communications, circuit breakers, switches battery system, and other devices not explicitly included in the other categories. Fencing is included in the protection category as well.

The grounding system consists of the land, the ground grid beneath, the connections from equipment and structures to the ground grid.

Bushing and connectors are all items where transitions occur, between air and inside containers (vessels), as well as where physical connections are made between conducting materials (same or different type).

Buildings consist of all elements of the building, including but not limited to the roof, walls, foundation, and drainage system.

Transformers include the transformer, its foundation, any containment that exists to catch the oil in case of a leak.

Finally, for the total asset condition of an HV station, a Health Index (HI) is calculated as the weighted average of the above indicators, with the average assessed condition for the elements. For example:

- If the HV station scores 100% for all indicators, then the HI is 100% (near perfect condition)
- If the HV station scores below 50% for all indicators, then the HI is <50% (likely towards or at end of life, requiring immediate intervention)

If the station scores 80% for the protection indicator and 100% for the rest of the indicators, then the HI = 88%.

3.4.4 *Health Index Interpretation*

Health assessment for the transmission lines and transmission stations is tabulated in various forms and metrics. The use of the HI and its interpretation standardizes the interpretation across lines and stations, thereby permitting standardization across the major assets.

The evaluation criteria are shown in Table 3-1.

Table 3-1: Health Assessment Criteria

HI	Health	Description	Requirements
80-100	Good	Limited signs of deterioration	Normal inspection and maintenance
60-80	Fair	Some deterioration	Increased inspection and remedial treatment
40-60	Poor	Less than 5-10 years of life remaining	Replace within 5 years
Below 40	Very Poor	At end of life	Replace at next opportunity

Using these numerical values, it is possible to set relative priorities given the condition of the equipment. This permits GLPT to set priorities in degrees of maintenance and/or replacement.

3.4.5 *Systematic Condition Reporting, Data Archive and Software*

The majority of transmission utilities in Canada are able to report on condition of assets on a structure by structure basis (transmission lines) and on components in the substation (transformer, circuit breakers, switches, revenue meters, instrument transformers, geotechnical, grounding, etc.).

GLPT collects condition reports from field staff and archives the information. Some of the condition reports are in the form of paper files and some are in the form of PDF scans. Only the most recent inspection information is put into a database. GLPT does not yet have a formulation to calculate the Health Index of an element on a transmission line or an element in a substation (asset class). Similarly, GLPT does not have a method to aggregate results from the asset class, to a physical group of elements (substation or transmission line section), or the entire system. It is recommended that GLPT investigate this further.

GLPT has identified the need for a data archive and software to manage the data as a need for future purchase, and has included it in the forward capital plan. Hatch concurs with this intent. However, given the size of the GLPT system and the success at managing reliability, the lack of a data archive and software is not considered a serious gap in the asset management practices of GLPT.

4. Transmission Lines

4.1 GLPT Overhead Transmission Lines System

The GLPT transmission lines system assets can be best recognized into four groupings:

- Group 1 – Backbone Interconnections
- Group 2 – Sault Ste. Marie Connections
- Group 3 – Montreal River Connections
- Group 4 – Wawa Area Connections

Each of the groupings has a set of transmission lines, length and voltage detailed shown in Table 4-1.

Table 4-1: Transmission Line Groups – Summary

Line Characteristics		Group 1	Group 2	Group 3	Group 4	Total
230 kV TL	Count	4				4
	Length (km)	318.3-km				318.3-km
115 kV TL	Count	1	7	7	7	22
	Length (km)	92.2-km	29.2-km	38.1-km	72.7-km	232.2-km
44 kV TL	Count				2	2
	Length (km)				9.7-km	9.7-km
Total	Count	5	7	7	9	28
	Length (km)	410.5-km	29.2-km	38.1-km	82.4-km	560.2-km

The overall component inventory (conductors, structures, etc.) for these transmission lines is provided in the summary Table 4-2, which is derived from information provided by GLPT.

Table 4-2: GLPT Transmission Line System

Line Description	No.	Voltage	Approx. Length	Year		Conductor		Structures					Wood Pole Details				
				Cond.	Str.	Size (kcmil)	Name	Lattice	Steel	Comp.	Wood	Total	1-pole	2-pole	3-pole	4-pole	Poles
Group-1 Backbone Interconnections																	
Third Line TS to MacKay TS	K24G	230 kV	92.2-km	2007	2007	1272	Bittern				426	426		331	95		947
MacKay TS to Wawa TS	W23K	230 kV	73.6-km	2006	2006	1272	Bittern				362	362		271	91		815
Third Line TS to MacKay TS	No.3 Sault	115 kV	92.2-km	1956	1990	266.8	Partridge				524	524	2	452	70		1,116
Third Line TS to Mississagi TS	P21G	230 kV	75.9-km	1969	1969	864.9	Les Boules	13	2	144	136	295		120	14	2	290
Third Line TS to Mississagi TS	P22G	230 kV	76.6-km	1959	1995	864.9	Les Boules	1	2		291	294		249	42		624
Group-2 Sault Ste. Marie Connections																	
Third Line TS to Patrick St TS	No.1 Algoma	115 kV	6.3-km	1956	1964-2014	336.4	Linnet	3	17	10	24	54	19	4	1		30
Third Line TS to Steelton TS	No.2 Algoma	115 kV	5.7-km	1977	1977-2014	477	Hawk		1		12	13	11		1		14
Third Line TS to Steelton TS	No.3 Algoma	115 kV	5.8-km	1965	1965-2013	477	Hawk	3	18	17	20	58	18	1	1		23
Third Line TS to Northern Avenue TS	Northern Ave	115 kV	2.4-km	1964	2013	477	Hawk			2		2					
Steelton TS to Clergue TS	No.1 Clergue	115 kV	2.0-km	1982	1982	336.4	Linnet		27			27					
Steelton TS to Clergue TS	No.2 Clergue	115 kV	2.0-km	1982	1982	336.4	Linnet					-					
Patrick TS to Flakeboard	Leigh's Bay	115 kV	5.0-km	1995	1995	556.5	Dahlia (AAC)	1	61			62					
Group-3 Montreal River Connections																	
MacKay TS to MacKay GS	No.1 MacKay	115 kV	0.6-km	1960	1960	336.4	Linnet				5	5		3	2		12
MacKay TS to MacKay GS	No.2 MacKay	115 kV	0.6-km	1960	1960	336.4	Linnet				3	3		3			6
MacKay TS to Gartshore TS	No.1 Gartshore	115 kV	12.8-km	1962	2004-2015	336.4	Linnet			65	11	76	1	7	3		24
MacKay TS to Gartshore TS	No.2 Gartshore	115 kV	12.8-km	2004	2004	336.4	Linnet				72	72	2	56	14		156
Gartshore TS to Gartshore GS	No.3 Gartshore	115 kV	0.8-km	2006	2006	336.4	Linnet				5	5	1	4			9
Gartshore TS to Andrews TS	Andrews	115 kV	5.3-km	1975	1975	3/0 AWG	Pigeon				40	40	24	16			56
Gartshore TS to Hogg GS	Hogg	115 kV	5.2-km	1964	2015	4/0 AWG	Penguin			33		33					
Group-4 Wawa Area Connections																	
Hollingsworth TS to Anjigami TS	Hollingsworth	115 kV	9.7-km	1959	1959	266.8	Partridge				58	58		52	6		122
Watson TS to Anjigami TS	No.1 High Falls	115 kV	15.0-km	1989	1989	266.8	Partridge				72	72		49	23		167
Watson TS to Anjigami TS	No.2 High Falls	115 kV	15.0-km	1929	1998	266.8	Partridge				75	75		51	24		174
Steephill GS to Magpie TS	Steephill	115 kV	19.5-km	1990	1990	336.4	Linnet			2	286	288	248	35	3		327
Harris GS to Magpie TS	Harris	115 kV	0.8-km	1990	1990	336.4	Linnet				11	11	8	3			14
Mission Falls GS to Magpie TS	Mission	115 kV	2.0-km	1990	1990	336.4	Linnet			2	30	32	21	9			39
Magpie TS to Watson TS	Magpie	115 kV	10.7-km	1989	1989	477	Hawk			2	73	75	15	37	21		152
Hollingsworth TS to Hwy101TS	Limer	44 kV	3.0-km	1980	1980	336.4	Tulip (ASC)				142	142	128	14			156
Hwy101TS to Anjigami TS	Anjigami	44 kV	6.7-km	1980	1980	336.4	Tulip (ASC)										
Total			560.2-km					21	128	277	2,678	3,104	498	1,767	411	2	5,273

The 560-km GLPT transmission lines system composition is primarily 230kV and 115kV (57% and 41% respectively) plus a short length of 44kV (2%) lines. The 230 kV lines (four lines) are the principal part of the backbone interconnections between the GLPT local sub-systems and the Hydro One province-wide system.

The composition of the structures is as follows:

- 5% steel/lattice
- 9% composite
- 86% wood

Composite pole structures represent a key strategic change in the GLPT system. They reportedly represent the majority of all the wood pole replacements during the last 10 years, now aggregating to 9% of the total structures. Over half of the composite pole structures have been installed on Line P21G whose origin reference year of 1969 may be true for the original wood pole structures but the composite poles are much newer vintage.

This inventory shows that many conductor ages are unchanged from their original dates, but the structures supporting them are typically newer vintage. GLPT's earlier 'replacement' programs primarily addressed structures replacing wood poles like-for-like, with necessary replacements of other components, without the corresponding replacement of the conductor. Hatch understands that going-forward, GLPT plans to review the holistic condition of the lines and put together appropriate comprehensive work packages which will include the conductor where necessary.

GLPT has nine different conductor types, which could be considered to be a rather large quantity for a system of this size. An approach to keep future conductor replacements similar to key existing conductors would reduce the number of conductor types and therefore facilitate simpler spares inventory for conductors and associated accessories.

4.2 Hatch Drive-through of the Transmission Lines

Hatch completed a site visit drive-through of select locations of the GLPT system over a two day period (October 19 and 20, 2015) following the main roads and visiting the lines at selected accessible locations.

Day-1

- Part-1: Third Line TS to Batchawana TS
  - K24G [Between Third Line TS and Batchawana TS]
  - No.3 Sault [Between Third Line TS and Batchawana TS]
- Part-2: Batchawana TS to Wawa Area
  - Montreal River Connections and MacKay TS

- Wawa Area Connections [Magpie, Mission and Steephill lines]

Day-2

- Part-1 Hollingsworth TS to Hwy101TS to Wawa TS
    - Hollingsworth, Limer and Anjigami Lines
- Part-2 Third Line TS eastwards along Mississagi TS
    - P21G and P22G lines

4.3 Commentary on Various Transmission Lines

The section provides commentary on the various transmission line groups and the overall transmission lines system. The details of each line are provided in the appendices referred to in each table.

The assessments are based upon spot inspections and discussions with GLPT staff.

The weighted percentages for various transmission line components are defined in Section 3.4, including the general interpretation of the overall result.

4.3.1 Group 1 Transmission Lines – Backbone Interconnections

This group comprises the most critical assets of the GLPT transmission system which connect the various sub-systems within the GLPT network and interconnect to the Hydro One system (at Mississagi TS and Wawa TS).

Table 4-3 lists the lines comprising Group 1.

Table 4-3: Group 1 Transmission Lines

Line Description	Name	Voltage	Length	Appendix
Third Line TS to MacKay TS	K24G	230 kV	92.2-km	A.01
MacKay TS to Wawa TS	W23K	230 kV	73.6-km	A.02
Third Line TS to MacKay TS	No.3 Sault	115 kV	92.2-km	A.03
Third Line TS to Mississagi TS	P21G	230 kV	75.9-km	A.04
Third Line TS to Mississagi TS	P22G	230 kV	76.6-km	A.04
Total (230 kV)			318.3-km	
Total (115 kV)			92.2-km	

The details of Hatch observations for each line are provided in Appendix A.01-04.

4.3.2 Group 2 Transmission Lines – Sault Ste. Marie Connections

This asset group comprises transmission lines located in the Sault Ste. Marie Area.

Table 4-4 lists transmission lines in Group 2.

Table 4-4: Group 2 Transmission Lines

Line Description	Name	Voltage	Length	Appendix
Third Line TS to Patrick St TS	No.1 Algoma	115 kV	6.3-km	-
Third Line TS to Steelton TS	No.2 Algoma	115 kV	5.7-km	-
Third Line TS to Steelton TS	No.3 Algoma	115 kV	5.8-km	-
Third Line TS to Northern Avenue TS	Northern Ave	115 kV	2.4-km	-
Steelton TS to Clergue TS	No.1 Clergue	115 kV	2.0-km	-
Steelton TS to Clergue TS	No.2 Clergue	115 kV	2.0-km	-
Patrick TS to Flakeboard	Leigh's Bay	115 kV	5.0-km	-
Total (115 kV)			29.2-km	

These transmission lines are a group of very short lengths (5% of overall system by length). Due to shortage of time and visit priorities, Hatch was unable to visit these transmission lines except for the terminal structures at Third Line TS.

GLPT has advised that critical structures on the Northern Avenue and Algoma (No. 1, 2, 3) transmission lines have been replaced.

Algoma (No.1, 2, 3) structures consist of several different materials including but not limited to double-circuit steel monopoles (installed on foundations) and wood poles. Existing structures (i.e. older wood poles) have been recently replaced with new composite double pole H-frames.

4.3.3 Group 3 Transmission Lines – Montreal River Connections

The Group 3 transmission lines interconnect the generation on the Montreal River System to the MacKay TS and also supplies the LDC in the area.

Table 4-5 lists transmission lines in Group 3.

Table 4-5: Group 3 Transmission Lines

Line Description	Name	Voltage	Length	Appendix
MacKay TS to MacKay GS	No.1 MacKay	115 kV	0.6-km	A.05
MacKay TS to MacKay GS	No.2 MacKay	115 kV	0.6-km	A.05
MacKay TS to Gartshore TS	No.1 Gartshore	115 kV	12.8-km	A.06
MacKay TS to Gartshore TS	No.2 Gartshore	115 kV	12.8-km	A.06
Gartshore TS to Gartshore GS	No. 3 Gartshore	115 kV	0.8-km	A.07
Gartshore TS to Andrews TS	Andrews	115 kV	5.3-km	A.08
Gartshore TS to Hogg GS	Hogg	115 kV	5.2-km	A.09
Total (115 kV)			38.1-km	

These transmission lines are also a group of short lengths. Some access was made by Hatch. The details of Hatch observations for each line are provided in Appendix A.05-09.

4.3.4 Group 4 Transmission Lines – Wawa Region

The Group 4 assets transmission lines interconnect the multiple generation sites on the Michipicoten River System, and also connects two industrial customers and a LDC. This group terminates at the Wawa/Anjigami TS. Table 4-6 lists transmission lines in Group 4.

Table 4-6: Group 4 Transmission Lines

Line Description	Name	Voltage	Length	Appendix
Hollingsworth TS to Anjigami TS	Hollingsworth	115 kV	9.7-km	A.10
Watson TS to Anjigami TS	No.1 High Falls	115 kV	15.0-km	A.11
Watson TS to Anjigami TS	No.2 High Falls	115 kV	15.0-km	A.11
Steephill GS to Magpie TS	Steephill	115 kV	19.5-km	A.12
Harris GS to Magpie TS	Harris	115 kV	0.8-km	A.12
Mission Falls GS to Magpie TS	Mission	115 kV	2.0-km	A.12
Magpie TS to Watson TS	Magpie	115 kV	10.7-km	A.12
Hollingsworth TS to Hwy101TS	Limer	44 kV	3.0-km	A.13
Hwy101TS to Anjigami TS	Anjigami	44 kV	6.7-km	A.13
Total (115 kV)			72.7-km	
Total (44 kV)			9.7-km	

The details of Hatch observations for each line are provided in Appendix A.10-13.

4.4 Commentary on the Overall Transmission Lines System

This section calculates the Health Index (HI) of the transmission lines in aggregate to provide an understanding of the overall condition of the transmission system.

A relative importance factor is assigned to each line based upon line voltage (230 kV = 4, 115 kV = 2, 44 kV = 1) and its length. The individual weighted HI is then totaled to calculate an overall HI for the transmission line system. The lines for which HIs have not been assigned are excluded for the purpose of these calculations.

The results are provided in the following tables; each table represents one group. The commentary for individual lines is provided in Appendices A.01 through A.13.

Table 4-7: Health Index Results – Group 1

Line Description	Name	Importance Factor	HI Value		Weighted HI
Third Line TS to MacKay TS	K24G	25.30%	88	Good	22.27
MacKay TS to Wawa TS	W23K	20.20%	80.5	Good	16.26
Third Line TS to MacKay TS	No.3 Sault	12.70%	59.5	Poor	7.53
Third Line TS to Mississagi TS	P21G	20.80%	70.5	Fair	14.68
Third Line TS to Mississagi TS	P22G	21.00%	63	Fair	13.24
Total for Group		100.00%		Fair	73.98

Table 4-8: Health Index Results – Group 2

Line Description	Name	Importance Factor	HI Value	Weighted HI
Third Line TS to Patrick St TS	No.1 Algoma		Not evaluated	
Third Line TS to Steelton TS	No.2 Algoma		Not evaluated	
Third Line TS to Steelton TS	No.3 Algoma		Not evaluated	
Third Line TS to Northern Avenue TS	Northern Ave		Not evaluated	
Steelton TS to Clergue TS	No.1 Clergue		Not evaluated	
Steelton TS to Clergue TS	No.2 Clergue		Not evaluated	
Patrick TS to Flakeboard	Leigh's Bay		Not evaluated	
Total for Group				

Table 4-9: Health Index Results – Group 3

Line Description	Name	Importance Factor	HI		Weighted HI
MacKay TS to MacKay GS	No.1 MacKay	1.60%	42	Poor	0.68
MacKay TS to MacKay GS	No.2 MacKay	1.60%	42	Poor	0.68
MacKay TS to Gartshore TS	No.1 Gartshore	34.30%	87	Good	29.86
MacKay TS to Gartshore TS	No.2 Gartshore	34.30%	90	Good	30.88
Gartshore TS to Gartshore GS	No.3 Gartshore	0.00%	Not evaluated		
Gartshore TS to Andrews TS	Andrews	14.20%	69	Fair	9.8
Gartshore TS to Hogg GS	Hogg	13.90%	86	Good	11.99
Total for Group		100.00%		Good	83.89

Table 4-10: Health Index Results – Group 4

Line Description	Name	Importance Factor	HI		Weighted HI
Hollingsworth TS to Anjigami TS	Hollingsworth	20.40%	52	Poor	10.61
Watson TS to Anjigami TS	No.1 High Falls			Not evaluated	
Watson TS to Anjigami TS	No.2 High Falls			Not evaluated	
Steephill GS to Magpie TS	Steephill	41.00%	60	Fair	24.61
Harris GS to Magpie TS	Harris	1.70%	60	Fair	1.01
Mission Falls GS to Magpie TS	Mission	4.20%	60	Fair	2.52
Magpie TS to Watson TS	Magpie	22.50%	60	Fair	13.5
Hollingsworth TS to Hwy101TS	Limer	3.20%	60	Fair	1.89
Hwy101TS to Anjigami TS	Anjigami	7.00%	50	Poor	3.52
Total for Group		100.00%		Poor	57.66

Table 4-11 provides a summary of all transmission lines by grouping.

Table 4-11: Health Index Results – Total Transmission Line System

Group Description	Importance Factor	HI		Weighted HI
Group 1 Backbone Interconnections	89.60%	73.98	Fair	66.27
Group 2 Sault Ste. Marie Connections		Not evaluated		
Group 3 Montreal River Connections	4.60%	83.89	Good	3.85
Group 4 Wawa Area Connections	5.80%	57.66	Poor	3.37
Total for System	100.00%		Fair	73.49

The overall Health Index (HI) for the transmission lines system is calculated to be 73.49 which corresponds to a 'Fair-to-Good' condition. This is consistent with the expected results as approximately 90% (in terms of importance) of the GLPT transmission line system is comprised of four major transmission lines. Two of these lines (K24G, W23K) are in good condition and the other two (P21G, P22G) are in lower-fair to fair condition.

With the planned replacements on the P21G and P22G lines, their individual HI will improve (estimated to 80% each). That will increase the overall HI for the transmission line system to 77% which is close to 'Good' condition.

For Sault No.3, GLPT plans to replace conductors as well as a large number of structures. With a new conductor and many structures replaced, its condition would become 'Good'.

4.5 Transmission lines – Additional Notes

The following are additional notes based upon field observations and discussions with the GLPT staff.

4.5.1 Composite Poles

Woodpeckers have made holes in numbers of poles in the GLPT system. Full-length treated poles seem more susceptible than the butt-only treated poles; hence, newer poles have the greater incidence. In some cases it is severe.

As the solution for this issue, GLPT has concluded to use composite poles for all its future replacements and installations. The composite poles are resistant against wood-pecker induced damage as well as rot and shrinkage cracking. A large number of the poles replaced by GLPT during the last 10 years are composite type.

Composite poles are not in standard use in the transmission line industry. As a result, there is limited field experience and no longevity experience for these pole types. There have been concerns raised about UV impact and the 'peeling' of layers due to freeze-thaw cycles. Quality of materials and manufacturing process also present risks of shortfalls in longevity of a manufactured product.

GLPT observes that its experience (last 15 years) has been satisfactory and it has not faced any detrimental issues to-date. Management has reviewed the research materials produced by RS Industries (the principal supplier to GLPT) and is content with the risk-reward balance which composite poles offer to tackle its particular severities of circumstance.

Hatch follows the reasonableness of the logic and rationale for this conclusion but has no further basis on which to offer our own opinion to this relatively new technology.

4.5.2 Composite Insulators

GLPT has been moving to use composite insulators, especially for the 115 kV system, and has reportedly not had any adverse experience with these so far.

4.5.3 Right-of-Way Vegetation Management

GLPT has an active vegetation management program. Its staff or contractors carry out ground-based spraying in the right-of-way at select locations to impede growth of bushes which could pose a risk to the transmission line clearances. Spraying is reportedly completed once every 6 years.

On First Nations land, GLPT utilizes First Nation contractors to cut back growth on the right-of-way.

4.5.4 Conductor Clearances

A LiDAR survey of the entire GLPT transmission system was carried out in 2009. The analysis showed some spans where violations of electrical clearances exist. GLPT is attentive to these remediation requirements during maintenance plans for these areas. Where land is not generally accessible by others it is deemed that the clearance violations are acceptable.

4.5.5 *Wood Poles Inspection and Treatment*

PoleCare produced a detailed inspection report identifying the remaining life of each wood pole. This analysis is the primary basis for GLPT pole replacement plans and in particular over the next 10 years. Figure 4-1 shows an example of a tag indicating pole-butt treatment from 2010.

Figure 4-1 Example Pole-butt Treatment Tag (2010)

4.5.6 *Line Inspection Schedules*

The typical inspection intervals advised by GLPT are as follows:

- Fly-over — Every year
- Drive-through — Every 2 years
- Detailed ground inspection — Every 6 years

The observations of detailed inspections have historically been in the form of paper records. In the last two years, GLPT has been transitioning to recording observations into a database. The software being utilized is WPS (a Davey Product for tree clearing and access road conditions) modified to record transmission line components. A screenshot of the WPS software is shown in Figure 4-2.

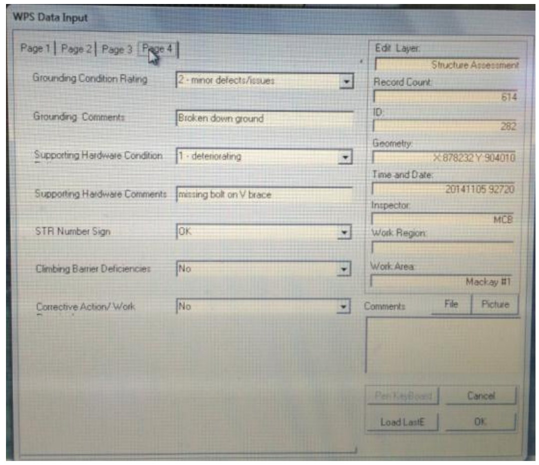

Figure 4-2: WPS Software - Screen-shot

Some recent inspections in the Wawa area were recorded with this software. Hatch did some spot checks of its own field observations against the database record. These were reasonably consistent. GLPT is progressing with the implementation of this system which has GIS functionality and includes access road and other information.

Infrared and corona inspections along the conductor are carried out by Linewise Area Solutions and some issues were identified (typically dead-end connections) but no issues were identified with composite insulators. GLPT indicates the following intervals for infrared and corona inspections:

- Close to populated areas — Every year [GLPT advises that the 2015 inspection was completed in the week of November 9, 2015 and that there were no corrective actions identified that required immediate action]
- 230 kV lines — Every 2 years
- Other lines — Every 5 years

4.5.7 *Forest Fires*

Forest fires on the right-of-way have not been observed by current GLPT staff. The few forest fires registered were not near enough to damage the transmission lines.

4.5.8 *Glowing Guy-guards*

Based on the majority of areas observed by Hatch, GLPT appears to have installed luminous bands on guy-guards for a number of guy-wires. These luminous bands provide visibility at night making passage safer for snowmobiles.

4.5.9 *Current Maintenance Capabilities*

GLPT has a small maintenance team that can carry out minor maintenance activities including right-of-way clearing, insulator replacement, conductor repairs, guy-wire tightening etc. GLPT requires contractor support for any task that cannot be completed in-house such as replacement of a complete structure or any re-conductoring work. GLPT plans to acquire requisite fleet in 2019 and 2020 to enable a step forward in such O&M tasks being capable in-house.

5. Transmission Substations

5.1 General

It is understood that GLPT carries out its transmission stations inspections based on 5 major categories of components as outlined below:

a) Protection systems including electric relaying and signaling systems and personnel safety systems

b) Grounding systems

c) Bushings and connections

d) Building condition, and

e) Transformer condition.

The individual components are weighted as follows: 60% is given to a) protection systems and a weighting of 10% each is given to the other 4 components, b), c), d), and e).

It should be noted that the 5 major component systems are further subdivided into a number of sub-components. For example for component (a) 'protection systems' it would seem to include the site condition broken into 10 measured items, the fence condition broken into 7 measured items, the electrical protection system which monitors the high voltage electrical system as well as the associated communications links, and the SCADA system. It is assumed the GLPT central system monitoring and control system as well as the emergency control and monitoring system is also included in this Protection component.

The grounding system component (b) is assumed to have items under the 'site' and 'fence', 'transformer' and all other sub-components. As a general observation, it may be noted that GLPT periodically tests its station ground grids for overall resistance to remote ground and individual connectivity to components.

The bushings and connections component (c) is assumed to contain the equipment foundations, the circuit breakers, circuit switchers, disconnect switches, instrument transformers, bus-bars, cables and potheads, and capacitor bank sub components.

The buildings (d) are assumed to include the buildings themselves, dc batteries, battery chargers and ac and dc panel subcomponents.

Lastly the transformer condition component (e) is understood to include the transformer and the grounding transformer subcomponents.

Each measured item in each subcomponent is measured on a scale of zero to three, with 3 indicating 'like perfect condition', or some such equivalent statement, and 0 indicating a need for early replacement or significant repair. The scores for each individual measured item in each station is totaled to provide a score for that component of each station, and then the components are totaled again for each station to provide an overall measure of each station.

5.2 The Hatch Review

On the days of October 19 and 20, 2015, Hatch completed brief site visits to the GLPT transmission stations and selected accessible sections of transmission lines. Hatch personnel were provided with a safety induction to advise how GLPT monitored the safety of its systems, equipment, personnel and visitors. Following this, the appropriate GLPT monitors and experts guided Hatch through a visit to the 15 transmission stations in the GLPT system, as well as Building 56 which is the backup emergency control centre. Observations were made of the age and condition of the major equipment in each station and appropriate photos were taken.

On October 21, 2015, the Hatch observations were discussed with GLPT staff and the forward capex program was discussed with a view to ensuring that Hatch understood the GLPT capital project requirements. The following paragraphs discuss Hatch observations at each of the 15 transmission stations visited as well as the visit to the backup control centre.

The following Table 5-1 summarizes the findings of the substation Health Index evaluations:

Table 5-1: Health Index Results – Transmission Stations

Station	Appendix	Weight	Health Index Value					Overall Station HI	Category
			Protection	Grounding	Bus Work	Building	Xfmr		
			60%	10%	10%	10%	10%		
Hollingsworth TS	B.01	1	90	90	90	80	70	87.0	Good
Highway 101 TS	B.02	0	---	---	---	---	---	---	Not Eval.
Anjigami TS	B.03	1	70	80	80	60	60	57.0	Poor
D.A Watson TS	B.04	1	80	95	95	95	90	85.5	Good
Magpie TS	B.05	1	80	90	90	90	100	85.0	Good
MacKay TS	B.06	1	98	95	90	100	90	96.3	Good
Gartshore TS	B.07	1	95	90	90	80	100	93.0	Good
Andrews TS	B.08	1	95	90	90	90	95	93.5	Good
Batchawana TS	B.09	1	50	90	80	100	40	57.0	Poor
Goulais Bay TS	B.10	1	70	90	70	100	70	56.0	Poor
Third Line TS	B.11	1	95	95	95	90	80	93.0	Good
Steelton TS	B.12	1	80	80	70	90	100	82.0	Good
Clergue TS	B.13	1	70	80	90	100	80	53.0	Poor
Echo River TS	B.14	1	80	90	90	90	80	83.0	Good
Northern Avenue TS	B.15	1	80	90	80	80	50	78.0	Fair
AVERAGE		**14**	**80.9**	**88.9**	**85.7**	**88.9**	**78.9**	**78.5**	**Fair**

The overall station Health Index (all stations) is based on a simple unity weighting factor.

Commentary associated with the stations showing substantially lower health scores is as follows:

- Anjigami TS has only one transformer and the structures including foundation are starting to show their age (including concrete spalling). The single transformer indicates that a potential failure or outage will result in a longer than average outage for downstream customers. Anjigami TS has the same Areva KCEG relays as Watson TS (see comments below). It is recommended that this be added to the priority list within the next three years
- Batchawana TS and Goulais TS are in poor condition. The transformers are very old and at Batchawana TS the station is operated in open delta configuration. There are three transformers but one is retained as a spare and not in service at the present time. There is insufficient clearance in the yards and worker protection can only be ensured by building internal safety fences around the transformers and some of the bus work
- Clergue TS has aging equipment, which is all outdoors and metal enclosed, and thus rusted. There is also indoor switchgear at Clergue TS. The switchgear also has significant arc flash concerns which can't be fixed or worked around as is possible at Watson TS. The relays are also very old

Other key station commentary is as follows:

- At Watson TS the Hatch judgment is that the equipment is old and needs replacement in the next 10 years or so; however, there appear to be few true safety issues, except for arc flash concerns. Some Areva KCEG type relays have failed. Furthermore, the manufacturer has deemed them obsolete and consequently there are limited spare parts available and limited/no technical support. The existing relays in the station do not facilitate remote communication to GLPT's Wide Area Network and lacks GPS clock synchronizing capability. These factors combined with the remote geographical location, weather conditions, and station access (single highway access), put the Watson TS at risk of a downstream outage (reduced reliable service for customers). Consequently, the protection equipment should be upgraded to the present standard

5.3 Conclusions on Transmission Station Health

The major stations in the GLPT system, Third Line TS and MacKay TS have very good condition. For the four stations which Hatch judges have somewhat unsatisfactory condition – Anjigami TS, Batchawana TS, Goulais TS and Clergue TS – there are provisions in the forward capital plan to upgrade the equipment and connections in these stations so they are brought back into acceptable condition comparable to the rest of the system.

5.4 Comment on Plans for Transformer Stations

5.4.1 Batchawana TS, Goulais TS

With regards to the concerns at Batchawana TS and Goulais TS, GLPT plans to replace these two stations with a combined single replacement station. The stations are in poor condition.

These stations are on Highway 17 north of Sault Ste. Marie. They are on the same stretch of highway, with Goulais TS to the south and Batchawana TS to the north. Their feeder lines connect in the middle territory between the stations. At present, neither station could serve the combined territories of the two stations largely due to relatively low distribution voltage used (12 kV). The plan of GLPT is to install a new station roughly between the two existing stations but to operate it at 25 kV. In this way the new station will be able to supply the combined territory now served by the Batchawana TS and Goulais TS stations.

This solution will require skill and careful planning to re-insulate the existing lines and simultaneously cut over existing customers to the new station when the new station is complete. However, it appears to be the least expensive solution to the problem. In addition building a new station and then moving customers to it should be less disruptive than replacing equipment and upgrading the existing station, while keeping the stations energized. It is believed that this solution, while relatively expensive, will be less expensive than retaining the two existing stations where they are and upgrading them separately in the long run.

5.4.2 Future Transformer Expenditures Provisions

In the forward capital plan, it is suggested that a number of transformer expenditures should be made. At time of writing, GLPT is evaluating if this should be in the capital plan or part of a contingency plan:

- Replace transformer T2 at Third Line
- Obtain a spare 230/115/34.5 kV transformer
- Replace transformer T1 at Anjigami
- Replace Echo TS, transformer T1
- Replace transformer T1 at Northern Ave TS
- Replace transformer T2 at Hollingsworth TS
- Mackay T1 transformer

All of the suggested transformer replacements are targeted at very old transformers, all over 35 years old. One of the units, the T2 unit at Third Line, is particularly vulnerable to failure. Not only is it old but its identical companion unit has already failed and its tertiary rating is less than is considered normally acceptable. In another instance, the unit at Northern Avenue was understood at one time to have PCB contamination. It has also had a significant leak. At present, it is not heavily loaded and may last for a while longer, but not indefinitely.

Obtaining a spare 230/115/34.5 kV transformer would be a worthwhile investment in the opinion of Hatch, particularly given the fact that the 230/115 kV unit at MacKay is rather suspect. In addition to this, it is observed that any transformer can fail at any time if subject to large enough stresses.

Section 9.3.2 provides further commentary on future transformer expenditure provisions.

6. Other GLPT Assets

This section looks at assets that are not Transmission Substations and not Transmission Lines.

6.1 SCADA System and Communications Functionally

A new SCADA system was installed in 2012, manufactured by Alstom. The system is a fully mirrored IT based system, with backup servers in the backup operations centre. The two locations are linked via fibre optic cable.

Each transmission station with operable devices can be accessed by this SCADA system. The connections to the substation are again by fibre optic cable.

6.2 Buildings

6.2.1 Sackville Building

The Sackville building is owned by Brookfield and is leased out to two companies:

- Suite A – Algoma Power (distribution company)
- Suite B – GLPT

GLPT has their operations centre, SCADA and SCADA IT at this location. GLPT also has some garages at this location and some small storage place.

Algoma Power has some storage space here as well at this property. No effort has been made at this time to categorize stored items by ownership on the property.

6.2.2 Main Operations Centre

This is located in the Sackville Building, Suite B. GLPT leases space here.

6.2.3 Backup Control Building (Building 56)

Building 56 is the backup control building to be utilized in the case of some sort of a devastating outage at the existing control centre. The building was examined and it appeared to have adequate power supply, computers and control equipment to carry out system control operations from the building, if required.

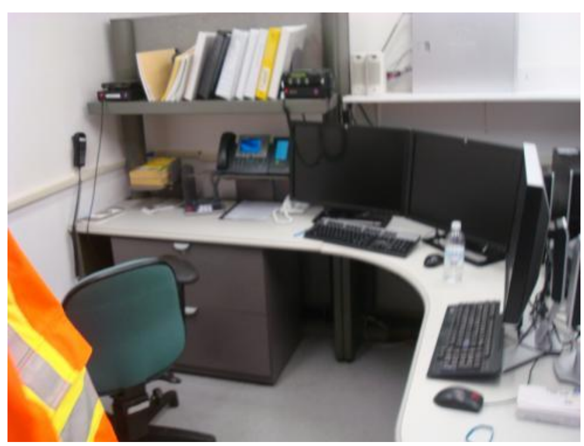

Figure 6-1: Backup Control Building (#56)

Unfortunately, the present location of the building is such that it may be impossible for staff to reach the building from Sault Ste. Marie in an emergency. Travel to the location of the building is noted to be somewhat difficult if not impossible during extreme weather conditions, which are fairly common in the Algoma area in the winter. Highways get shut down by the OPP fairly regularly.

A plan exists to move the control building location to the Echo Bay area, which is understood to be more amenable to the likelihood of safe travel in the winter. This will require major upgrades to the building and communications systems in the Echo Bay area. A proposed capital allowance has been made to carry out the building, control equipment and communications modifications, as well as to carry out the necessary location transfer. This planned future capital project is discussed further in Section 9.3.3.

A Health Index score is not applicable.

6.3 Communications Systems

GLPT has several communications systems in use. The following subsections describe each.

6.3.1 Communications Systems - Microwave

In the past, GLPT used microwave communications between stations. GLPT staff has confirmed that this has been de-commissioned and replaced with fibre optics. There may be some residual microwave equipment in the stations that has not been decommissioned and/or removed. A Health Index score is not applicable.

6.3.2 Communications Systems – Fibre Optics

GLPT uses a fibre optic communication system between stations and the operations centre. This fibre optics is mostly located on transmission lines (i.e., optical sky wire). This fibre optic communications wire is not owned by GLPT and excluded from the asset owned by GLPT.

The transition point is the patch panel inside each substation or building. The patch panel is not part of the GLPT assets. The fibre optic cable in the building is part of the GLPT assets.

This fibre optic system carries GLPT IT information, metering information to the IESO and Hydro One, SCADA information, and other information required by GLPT for day to day operations. A Health Index score is not applicable.

In the future, GLPT intends on owning fibre optic cable, and has made plans in their forward capital plan to accomplish this in the future. There are examples of utilities owning fibre optics, and can represent an opportunity for income from selling bandwidth to others.

6.3.3 Communications Systems – Radio System

GLPT field crews use radios in their day to day work. There are several radio towers used by GLPT, per below. A Health Index score is not applicable.

- Owned by GLPT: Sackville, Gartshore, Magpie. These towers are not located on substation land

- Shared towers with MTO and/or OPP – another three (3)

The existing analogue communication control system, Zetron Radio Access Control System (RACS), was installed in 1996. The manufacturer has deemed the existing RACS to be obsolete and no longer provides technical or software support. New spare parts are not available. Refurbished replacement components are particularly difficult to source. In addition, all radio tower site repeaters are no longer supported by their manufacturer's lacking spare components.

As a result, it is recommended that GLPT requires a new secure 2-way digital radio system as a replacement.

6.4 Major Equipment, Vehicles

6.4.1 Vehicles / Fleet

GLPT has one bucket truck and several pick-up trucks.

6.4.2 Computers excluding SCADA

GLPT has various computer systems and software to manage its operations. These assets are located at the Sackville location:

- Corporate financial
- Protection / control systems
- Various office equipment

6.4.3 Test Equipment

GLPT has various test equipment needed to complete the work required of the staff during maintenance and repair. This includes, but is not limited to, several Manta test sets (protection and control), one Doble unit, and Meggers equipment.

6.4.4 Protection Equipment

Protection equipment is generally located at the substations. There are over 700 elements as noted in the protection studies. Most items are computer based but there are still some electro-mechanical devices.

6.4.5 Revenue Metering Equipment

Each connected Market Participant (LDC, generator, Industrial Load, etc.) is required to install their own revenue metering and manage on their own or have a third party Meter Service Provider (MSP) manage. The Transmitter's responsibility is to ensure that revenue metering is installed during new or modified connection to the transmission system and installed to the correct standards, that the IESO has the correct customer information for each delivery point (tariff list) as well as manage administratively with the IESO any addition changes to the delivery point or metering configuration (totalizing tables and site registration reports/SRR's) while the customer is connected to the transmission system. GLPT does not own any revenue metering equipment.

6.5 Maintenance Parts / Storage

GLPT does not have a purchasing department or stores/warehouse per se. Most materials needed are delivered on an as needed basis (i.e. just in time). There is a pole yard at Sackville/Northem Ave. and a storage yard at Third Line. Some parts are stored in ‘sea cans’ (large shipping containers), at selected locations in the service area. There is no inventory of these containers at time of writing. An emergency parts trailer exists. There is some wire on hand, but most materials needed are provided by the contractor. GLPT has plans to improve storage of and inventory of critical spare parts within its capital plans.

7. GLPT Asset and Operational Management

7.1 Company Structure

GLPT, a limited partnership formed under the laws of Ontario, carries on the business of owning and operating electricity transmission facilities in the vicinity of Sault Ste. Marie, Ontario. All assets are located within Ontario. An overview of the transmission lines and substations can be found in Sections 4 and 5 of this report.

GLPT is a transmission business which has supplied power to parts of northern Ontario for more than 100 years. GLPT has 15 transmission substations. The substations are linked by 560 km of 44kV, 115kV and 230kV. The 44kV lines are located in the Wawa area, and classified as transmission despite the voltage being less than 50kV. The system is interconnected with the Ontario power grid at Wawa and via two 230kV transmission lines at Mississagi, about 75 km east of Sault Ste. Marie. GLPT provides connections to its Market Participants and generators in the area.

GLPT makes up an integral component of Ontario's transmission system that connects Northern Ontario to Southern Ontario.

7.2 Asset Management Approach

GLPT has made substantial investments in improvements over the years to their power transmission system to enhance the reliability of their assets. GLPT is committed to continuing their efforts to make the risk of aging infrastructure and minimize total life-cycle cost. Along with continuous improvement, another significant goal of GLPT is to identify industry best practices and incorporate them in their current contractual operations.

GLPT uses a systematic approach to asset management, which is consistent with industry best practices:

- Periodic asset performance reviews (Field inspections, Capacity reviews, Reliability reviews, etc.)
- Defect Log and prioritization of corrective action
- Investment planning based on declining condition, increased electrical load and declining reliability
- Contracting out of the construction work for capital investment projects

Condition is a key consideration in the asset management plans of GLPT. A field audit was completed and as found condition is recorded for various elements of the transmission lines and substations. In summary, the criteria in Figure 7-1 are used and customized for each asset component of the system as required.

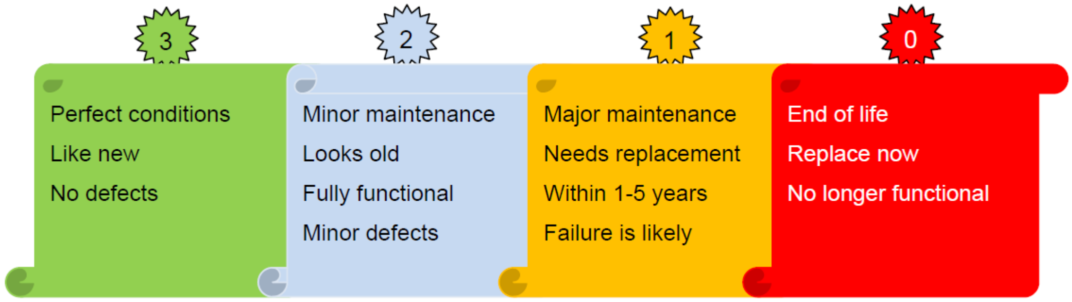

Figure 7-1: Health Index Criteria

Details of the condition assessment results can be found in the following report sections:

- Transmission Lines – Section 4
- Substations – Section 5

7.3 Operations & Maintenance Management

This section provides commentary on how Operations & Maintenance at GLPT is managed. The following sub-sections can be found:

- Section 7.3.1 – O&M Management Structure
- Section 7.3.2 – O&M Work Centre, Vehicles, Tools, Equipment and Spares
- Section 7.3.3 – O&M Project Execution Philosophy

7.3.1 O&M Management Structure

Maintenance is defined by management and is executed by staff. Maintenance is based on inspections, evaluations and corrective action.

The operation and maintenance procedures and practices of GLPT are documented in maintenance practice documents. Although there is not 100% coverage on all assets in the form of maintenance directives, the majority high expenditure assets have defined maintenance directives and practices. As observed during the site inspections and as proposed in the capital plan, GLPT's O&M practices are consistent with current good engineering practices and meet or exceed accepted industry practices.

7.3.2 O&M Work Centre, Vehicles, Tools, Equipment and Spares

Supporting the O&M activities is the work centre (work shop), vehicles, equipment, tools and spares inventory.

GLPT has one bucket truck and various pickup trucks. Major reconstruction work requiring more than one bucket truck are generally contracted out to local service providers. In addition, GLPT has established equipment access agreements with 3 local suppliers for large bucket truck and tracked units for planned maintenance and emergency response, on an as needed basis.

GLPT has one workshop, where its main operations centre is located. The space is leased.

GLPT has spare parts distributed throughout its service territory, in sea containers and a pole yard. When parts are needed that are not present in the sea containers, they are ordered in the quantity required, using 'just in time' delivery to minimize handling and storage. A yard containing several lengths of wire and cable also exists. There are five sea containers. An inventory was not available at the time of writing this report.

GLPT field crews have tools and equipment to maintain the existing infrastructure. A list of tools and equipment was not available at time of writing this report.

7.3.3 O&M Project Execution Philosophy

GLPT field crews have the ability to maintain and repair the existing assets, when small scale projects are defined.

For larger scale projects, or where more than one bucket truck is needed, external contractors are used to complete the work. The decision to contract out depends on various factors, including but not limited to:

- The work load of the in-house field crews
- The availability of tools and equipment to complete the work
- The size of the work
- Any contractual commitments made to external organizations

7.4 Overall Policies and Procedures

GLPT has various policies and procedures in place, including but not limited to:

- Hazard analysis
- Environmental
- Health and safety
- Public safety signs
- Hazard risk assessment

Furthermore, in support of maintenance, GLPT has guides to help staff and crews complete condition assessments of Power transformers, Surge arrestors, Fences, Site general, SF_6 vacuum breakers, Oil circuit breakers, Circuit switchers, Bus works, Instrument transformers, Grounding transformers, Cable and pot-heads, Capacitor banks, Building, Battery and chargers, Line inspection, and Corrective action process.

8. Operations and Maintenance Program

The operations and maintenance program involves collecting information about the condition of the stations and lines, and then determining what actions are necessary to address defects based on their potential impact on various stakeholders.

A variety of information sources are used to collect the necessary information, as detailed in the following subsections:

- Visual inspections
- Tests and measurements
- Performance data (power flows, fault current, voltage)
- Outage data

The result of the data collection activity results in a list of defects or corrective actions which are prioritized and then acted on. This optimization allows GLPT engineering staff to effectively determine which facilities require capital improvements, and maintenance is sufficient for the pending calendar year. The capital improvement plan becomes a list of capital expenditure proposals.

Similar statements can be found in the 2014 Rate application section 2-2-1.

8.1 Asset Condition Assessments (ACA)

In addition to the activities undertaken specifically for lines and stations, GLPT annually carries out ACA’s using internal staff. Periodically, GLPT retains external consultants to undertake additional ACA’s. Once complete, these ACA’s are incorporated into the asset management program and provide information for GLPT to make well informed decisions regarding maintenance and capital programs.

8.1.1 Asset Condition Assessment – Transmission Lines

For transmission lines, a variety of assessments and inspections are carried out either by GLPT crews or by external consultants and may include:

- Ground patrols
- Aerial patrols
- Infrared inspections and
- Detailed inspections

GLPT crews conduct patrol inspections of transmission lines annually, or more frequently on an as needed basis, to assess condition and to identify structural problems and hazards. Because GLPT’s transmission lines are primarily located in rural areas of northern Ontario, where the terrain is rugged and the vegetation is dense, specialized equipment or expertise is required. Analysis may also be performed by external consultants to provide additional detailed information on structures, conductors and insulators.

Where these inspections identify immediate deficiencies or potential hazards, GLPT undertakes the appropriate corrective maintenance to resolve the identified issues. It is noted that where deficiencies exist, they are listed on an internal report, prioritized and action is taken.

The information is collected in paper forms, which will be collected electronically in the future. GLPT has an initiative underway to study this. The present paper forms are stored in filing cabinets or scanned in electronically for saving on the network. A database of condition information is not generally established at this time.

The condition information is collected through inspections is used for planning and to identify trends in asset condition. An example of this approach working effectively is the current wood structure replacement program. GLPT identified the need to establish a wood structure replacement program given the age and condition of the wood structures in the system. GLPT engaged PoleCare International Inc. to carry out detailed condition assessments of most of the wood poles in the GLPT system. The result of the testing was a comprehensive database which details condition of poles and estimated remaining life. Based on this information, GLPT has been able to implement a long term plan as well as set priority for replacement.

GLPT also makes use of LiDAR data which provides detailed information on transmission lines, structures and vegetation, as well as a GIS system that supports the collection and maintenance of information regarding the transmission circuits. These tools provide valuable field information to front line crews to allow for more efficient, effective and safe programs.

8.1.2 *Asset Condition Assessments – Stations*

For transmission stations, a range of inspection and maintenance activities are carried out by GLPT on primary equipment, auxiliary equipment and the systems that ensure equipment protection. The testing and inspection of station equipment have a wide range of frequencies (1 month, to 1 year to 6 years) to ensure that the condition of the asset is known and updated regularly. These include visual inspections, functional tests, infrared inspections, oil sampling and dissolved gas analysis. These activities are conducted primarily by GLPT crews. However, where specialized equipment or expertise is required (i.e., infrared inspection), those activities are conducted by external consultants. The preventative maintenance activities are based on good utility practice and manufacturer specification.

The information gathered from these activities is documented and reviewed. Where immediate deficiencies or potential hazards are identified, GLPT undertakes the appropriate corrective maintenance to resolve the identified issue. Where corrective maintenance is not required, the information is retained in order to support GLPT's long term station planning decision making, and to assist in the identification of asset condition trends. An example of this approach working effectively was GLPT's redevelopment at Third Line TS, completed in 2012. Concerns regarding aging equipment, inadequate equipment ratings, operational maintainability and station configuration issues resulted in the need to proactively reconfigure the station and replace all station equipment that had the highest risk of affecting safety, security and customer reliability.

8.2 Asset Performance – SCADA Data

Supporting the field condition of assets is the performance data of the assets.

GLPT collects real time data on a continuous basis using its SCADA system. The data collected relates to power flow, fault data and power quality and supplements the information collected through the inspection and maintenance activities identified above.

8.3 Asset Performance – Reliability and Service Quality

GLPT collects outage data on its assets any time that an asset becomes un-available or if the power from Hydro One or the delivery points to clients becomes un-available. This information is analyzed and reported on a periodic basis, including regulatory filings.

GLPT has established policies to help staff identify what are forced outages and what are not.

8.3.1 Delivery Point Performance Standards

The performance of the delivery points is managed to meet or exceed the standards that Hydro One is expected to meet. Figure 8-1 summarizes these standards, as stated in the 2014 GLPT rate application, and as documented in the GLPT policy "Customer Delivery Point Performance Standards (CDPPS)" dated Dec. 2007.

Performance Measures	**Delivery Point Performance Standards** (Based on a Delivery Point's Total Average Station Load)							
	0 to 15MW		**>15 to 40MW**		**>40 to 80MW**		**>80MW**	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/yr)	**4.1**	**9.0**	**1.1**	**3.5**	**0.5**	**1.5**	**0.3**	**1.0**
DP Interruption Duration (min/yr)	**89**	**360**	**22**	**140**	**11**	**55**	**5**	**25**

Figure 8-1: Delivery Point Performance Standards

8.3.2 *Outage Data Management*

GLPT maintains a station log and a database for outages. Each outage is classified in various categories:

- As external (loss of supply from Hydro One)
- Planned vs. forced outage
- Duration of outage
- Customer impact (MW lost)
- Root cause analysis

This information is then reviewed by staff to identify if corrective action is immediately required, or if there are trends that require a targeted investment plan or corrective action strategy. For example, local area capital improvements to remedy trending reliability issues associated with the 44kV system in the Wawa area were reportedly approved by the OEB as part of the 2015/16 rate application.

The data is also summarized for regulatory reporting, as found in the regulatory rate applications submitted by GLPT on a periodic basis. The next section provides further information on this.

8.3.3 *Delivery Point Performance Results*

The following graphs are indicative of the information collected and evaluated to establish trends and targeted areas for further investigation and possible remediation. Similar information is found in the 2014 rate application, section 2-3-1. The following graphs include partial information for year 2015.

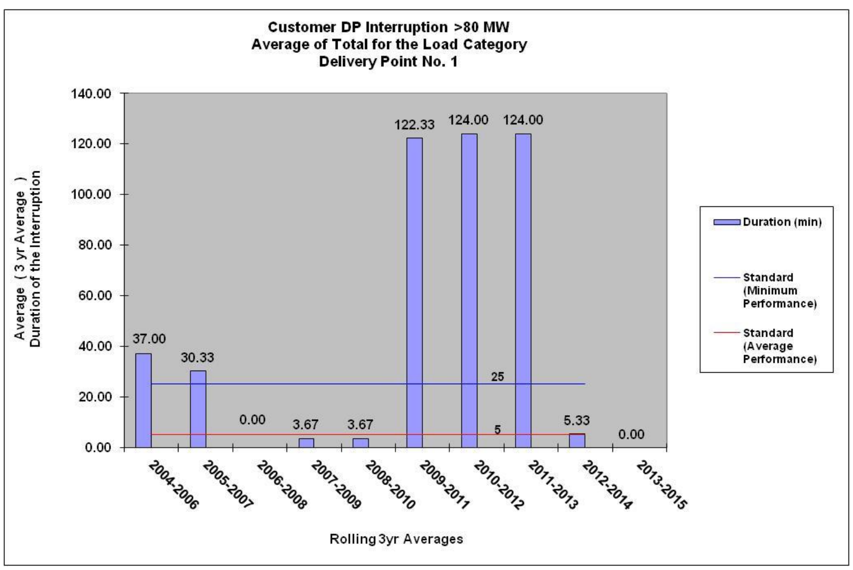

Figure 8-2: Customer DP Interruption >80MW

Figure 8-2 shows a 3 year rolling average. The high duration of interruption value of over 120 minutes is the result of an outage caused by failed equipment at the Third Line TS. As a result of the calculation process, this continued to affect statistics for 3 year post event. This impact also applies to Figure 8-3 and Figure 8-4. This issue was remedied by the Third Line TS redevelopment project which forecasted this type of issue and was underway at the time of the equipment failure.

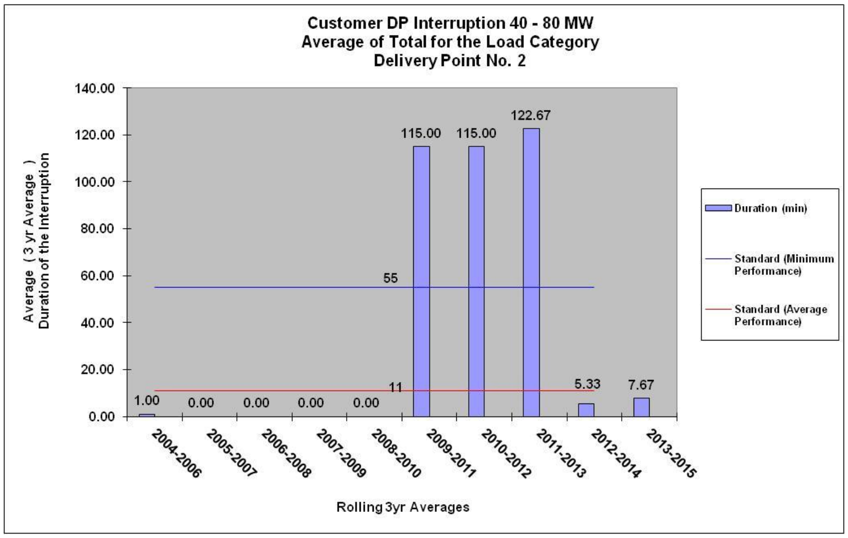

Figure 8-3: Customer DP Interruption 40-80MW

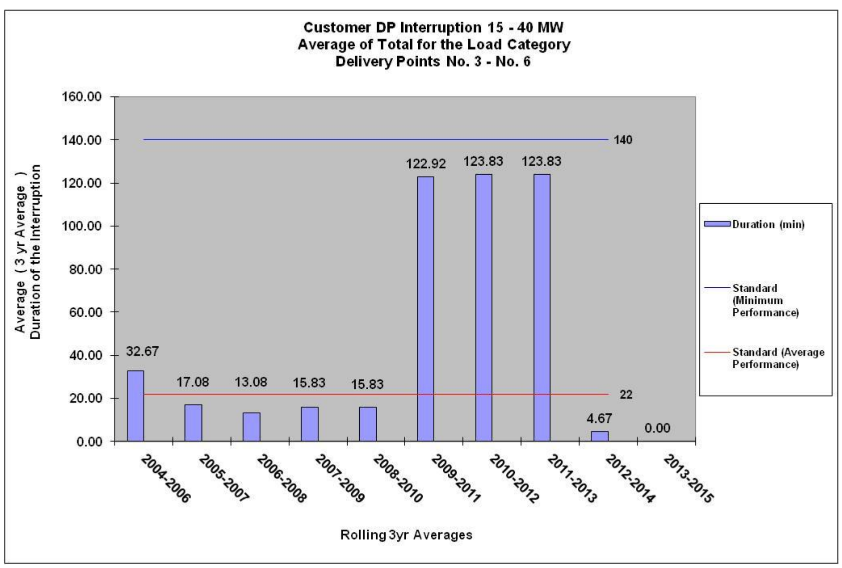

Figure 8-4: Customer DP Interruption 15-40MW

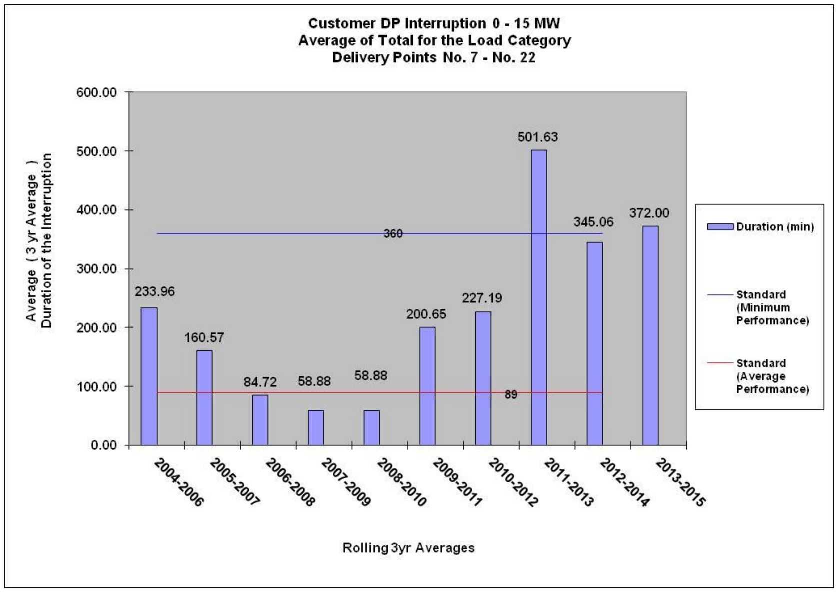

Figure 8-5: Customer DP Interruption 0-15MW

In general, the trend is improving, except for in the 0-15 MW load category as shown by Figure 8-5. It appears that in 2015 data, there were two high impact events that appear to have also occurred in 2013 data but not in the 2014 data:

- API Dist NA 12kV (Both)
- API Dist Andrews (Both)
- Weyerhauser Company Ltd (2013)
- Wesdome Gold Mines (2013)

Consequently, the results in 2011-13 are higher than presently but the trend is increasing.

In 2012-14, it was noticed that the large impact outages were:

- API Dist Goulais
- API Dist No 4 Circuit

Hatch has not reviewed the data in detail to determine what the underlying causes of these events are and to explain the increasing trend observed in Figure 8-5.

GLPT has identified projects to remediate and improve the situation. Projects submitted to OEB have reportedly received OEB approval to proceed.

8.4 Conclusion

It is evident that GLPT has a well-established maintenance program supported by internal expertise and external expertise where and when required. The information is evaluated to determine risk and criticality for action. The action plan resulting in maintenance or capital investment plans.

Hatch has reviewed various reports and documents and found evidence that most of the common practices expected in utilities today could be found.

GLPT has also evaluated changing conditions in its service territory and is adapting. For example, where excessive woodpecker damage exists on wood poles, GLPT is experimenting with composite poles in order to prolong asset life and reduce sustaining capital expenditures

9. Future Capital Expenditure

This section provides Hatch's commentary on GLPT's forecasted capital program.

9.1 Summary

GLPT has produced a 10 year capex projection to 2025. It has used asset condition analysis, reliability of supply risk assessment, history of operations experience and prior sustaining capital works to define the individual asset projects requiring corrective attention including replacements. It has adopted an approach to assemble a package of works in its remote asset areas to allow a holistic attention to corrective action (i.e., poles replacement plus conductor tensioning, guy wire tightening, insulator replacement, etc.) and its compatible scheduling.

Hatch conducted brief site visits to the transmission stations and selected accessible sections of transmission lines and discussed with management its process for the need, timing and costing of its capex plans.

The Hatch review confirms that the proposed 10 year capex planning is consistent with appropriate T&D utility practice taking into account the existing condition and life expectancy of the assets and the requirement to maintain the present levels of service reliability. It should be noted that the scheduling of projects may move to reflect changing priorities (impacting annual capex totals but always within the total OEB approved capex envelope) which is as expected given the long service life expectancies of transmission assets.

Hatch has not reviewed any individual project cost estimates but it has discussed the estimating process. Assuming all other factors remain the same and there are no intervening causes, the overall 10 year expenditures are observed to be reasonable.

9.2 Basis of Costs

Forecasted capital costs (2016 to 2025) in the following sections have been expressed in nominal (i.e. inflation adjusted) terms.

9.3 Future Sustaining Capital

GLPT's sustaining capital activities involve the refurbishment or replacement of transmission system components which are at end of life for technical and economic reasons. These investments sustain existing transmission system facilities so that they function at the required levels of performance. All sustaining capital investments contribute to ensuring that reliability, legislative, regulatory, environmental, and safety requirements are met.

GLPT accounts for capital assets in accordance with International Financial Reporting Standards (IFRS). GLPT has an established Capitalization Policy to consistently differentiate between expenditures classified as OM&A and those classified as sustaining capital.

GLPT's sustaining capital projects can be assigned to four categories based on the type of asset:

- Transmission Stations
- Transmission Lines & Structures (including Poles, Towers, Conductors and Fixtures)
- Transmission System Equipment
- Land & Buildings

Appendix C provides GLPT's 10 year forward capital plan through to 2025. The following sub-sections further describe some of the key capital projects that GLPT has planned for the next 10 years, including Hatch's commentary.

The Hatch review confirms that the proposed 10 year capex planning is consistent with appropriate T&D utility practice taking into account the existing condition and life expectancy of the assets and the requirement to maintain the present levels of service reliability. It should be noted that the scheduling of projects may move to reflect changing priorities (impacting annual capex totals yet within total OEB-approved capex envelopes) which is as expected given the long service life expectancies of transmission assets. Hatch has not reviewed any individual project cost estimates but has discussed the estimating process.

9.3.1 Transmission Line Projects

Wood Structure Replacements

In 2012, GLPT filed a rate application for the 2013 and 2014 test years and received OEB approval to establish a comprehensive multi-year Wood Structure Replacement Program. The program was based on an independent condition assessment performed on the majority of GLPT's wood structures in 2009 and 2010. With the assistance of GLPT personnel, a third party (PoleCare International Inc.) performed inspections and testing on the wood pole structures. Based on the work performed, the PoleCare issued a comprehensive wood pole database which identified the need for replacement, over time, of a number of wood structures in GLPT's system due to signs of carpenter ant infestation, woodpecker damage and surface, ground line and below grade rot. Over time, this deterioration begins to threaten structural integrity and reliability of the structures and the circuits and poses a significant risk for the reliable and safe operation of GLPT's transmission business.

GLPT has prioritized replacements based on condition assessment results, safety and reliability. The Wood Structure Replacement Program contemplates the replacement of existing wood poles and attachments with new composite (fibreglass) poles and steel attachments extending the useful life of the structures and addressing any conductor issues as required. The initial cost of installing composite poles is marginally higher than the cost of standard wood poles. However, the useful life of this type of pole is comparable to steel (typically 60 years compared to 45 years for wood poles), and this material greatly reduces maintenance costs (no woodpecker damage, no rot, no insect infestations) resulting in expected long-term cost savings that should benefit ratepayers over the life of the new structures.

GLPT will oversee this long term replacement through its asset management team and will manage on site HS&E through its project managers while outsourcing engineering and construction. Detailed scope, schedule and budget were completed in the 3rd and 4th quarter of the preceding year for the specific project with construction completed in the 2nd and 3rd quarter of the subsequent year. Additionally, a Class Environmental Assessment (EA) screening was performed by an independent environmental engineering firm with local environmental permits obtained as required.

Key project details are as follows:

- In 2014 GLPT filed a rate application for the 2015 and 2016 test years and received OEB approval to continue the program
- Recent individual project summaries:
  - **2013 and 2014** – GLPT replaced critical structures on its Northern Avenue and Algoma #1, 2 and 3 circuits within the Sault Ste. Marie Area, adding $4.9 million to the rate base
  - **2015 –** GLPT replaced structures on its Hogg and No. 1 Gartshore circuits in the Montreal River Area, adding $5.8 million to the rate base
- Summary of projects over the capex forecast period:
  - **2016 –** GLPT to replace structures on its Hollingsworth 115kV circuit in the Wawa area, adding $2.74 million to the rate base
  - **2017 and 2018, P21G and Algoma No. 1, 2 and 3 (Sky wire)** – multi-year program designed to replace wood structures identified in the PoleCare study on GLPT's P21G circuit (90 structures in 2017, 30 structures in 2018) and execute a multi-year program to replace various outstanding wood structures on GLPT's Algoma No. 1, 2 and 3 and skywire
  - **2019 onwards** – multi-year programs designed to replace wood structures primarily identified in the PoleCare study

Hatch observed that woodpeckers have made holes in numbers of poles in the GLPT system. This seems to be more applicable for full-length treated poles and less for the butt-only treated poles. Based on Hatch's review of the Wood Structure Replacement Program, the projects are agreed upon in principle. The Wood Structure Replacement Program is an appropriate measure to ensure GLPT continues to operate safely and reliably into the future.

Figure 9-1 provides an example of woodpecker damage to a wooden pole, as shown in the 2012 rate application (EB-2012-0300, Exhibit 4, Tab 2, Schedule 2, Page 14 of 35).

Figure 9-1: Example of a Wooden Pole with Woodpecker Damage

No. 3 Sault Line Upgrade

The No.3 Sault Line Upgrade Project contemplates the replacement of the existing 115 kV conductor with a new conductor, the replacement of 250 wood poles and attachments with new composite poles and steel attachments, and addressing Sky wire issues as required. GLPT will oversee the project through its asset management team and manage on site HS&E through its project managers while outsourcing engineering and construction.

Detailed scope, schedule and budget will be completed in 2018 with execution of project to occur starting in 2019 and completing in 2021. Class EA screening will be performed by an independent environmental engineering firm with local environmental permits obtained as required.

Key project details are follows:

- GLPT is evaluating the replacement of 70 km of aging conductor (installed in 1956) between Goulais TS and MacKay TS
    - In addition to the aging conductor, GLPT will replace approximately 50% of the wood structures to address clearance and condition issues
    - Sky wire issues will be addressed as required
- Over the past three years, the No. 3 Sault line has not operated to GLPT standards and to ensure HS&E, public safety and reliability is maintained, GLPT is initiating an upgrade on the line
- An independent testing lab found that while the conductor did not require immediate attention, the recommendation is replacement of the conductor within the next 5 years

- GLPT is currently evaluating a number of new conductor options to increase line rating and improve redundancy to market participants

Based on Hatch's assessment of the Transmission Lines, the asset condition of the Sault #3 115 kV Line warrants replacement of the conductor. Increased inspection and maintenance activities in the interim are also warranted.

Figure 9-2 shows the geographic footprint of the No. 3 Sault Line Upgrade.

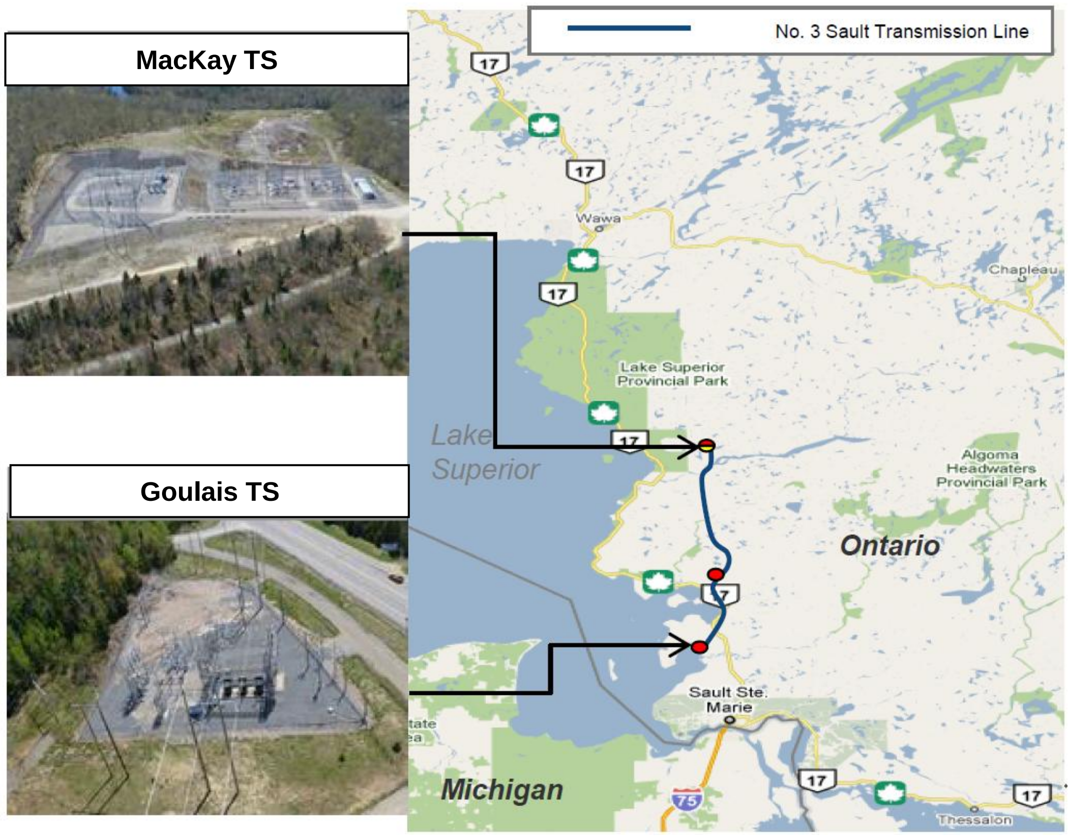

Figure 9-2: Geographic Footprint of the No. 3 Sault Line Upgrade

9.3.2 *Transmission Station Projects*

New Station – Replace Goulais & Batchawana

The Goulais TS & Batchawana TS Station Replacement Project contemplates replacing Goulais TS and Batchawana TS with a new dual transformer station with redundant north and south feeds. GLPT is working with the LDC to determine the best solutions for this project to ensure value to the rate payer. This station will provide distribution service at 25 kV rather than the existing 12 kV. GLPT will oversee the project through its asset management team and manage onsite HS&E through its project managers while outsourcing engineering and construction. Detailed scope, schedule and budget will be completed by 2018 with execution of project to occur starting in 2019 with completion in 2021. Work will be coordinated with the No. 3 Sault Upgrade and LDC improvements. Class EA screening will be performed by an independent environmental engineering firm with local environmental permits to be obtained as required.

Key project details are as follows:

- Both Goulais TS and Batchawana TS have no redundancy and have outdoor enclosures to house batteries and remote terminal units which are difficult to use in bad weather, all directly impacting reliability
- GLPT system planning has evaluated how best to address these issues, thus increasing reliability and redundancy while reducing overall capital and operating costs to the rate payer
- Through consultation with the most directly impacted market participants, it has been identified that combining the two existing transmission stations into one would best achieve the overall solution

Based on Hatch's condition assessment of Goulais TS and Batchawana TS and discussing the project with GLPT, the planned replacement of Goulais TS and Batchawana TS is agreed upon in principle.

Figure 9-3 shows the location of the Goulais TS and Batchawana TS transmission stations.

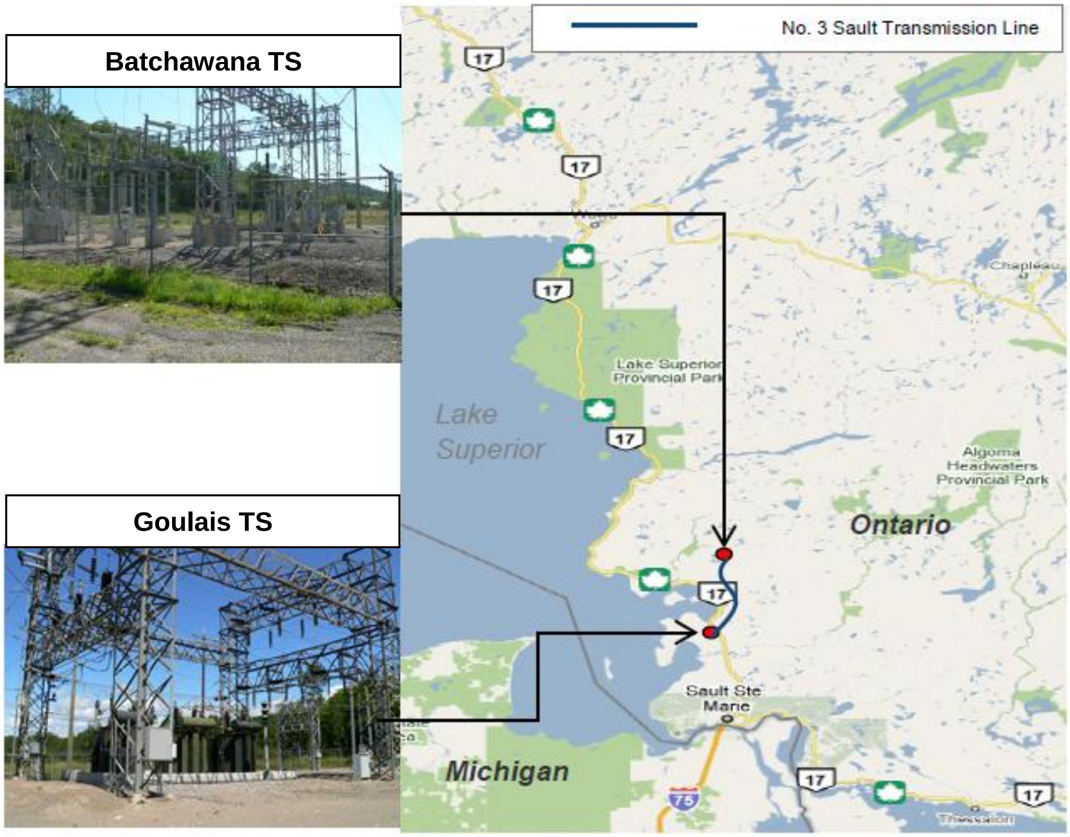

Figure 9-3: Geographic Footprint of Replacement of Goulais TS and Batchawana TS

Transformer Contingency Plan – Replacement and Spares

One of the critical aspects of managing and operating an electrical transmission system is being able to minimize the effects and interruption of service upon the failure of a critical system component. Although there are many levels of planning, the focus of this program is to review the adequacy of the GLPT transmission system and determine the overall ability to restore power in the event of a transformer failure. Further to restoring power, the ability and adequacy of GLPT to replace a failed transformer with a new or spare unit was also studied.

As an outcome from the study, GLPT has formulated a Transformer Contingency Plan focused on the Anjigami, Echo River and Northern Avenue transmission stations. GLPT will oversee the project through its asset management team and manage onside HS&E through its project managers. Detailed scope, schedule and budget will be completed by 2020 with execution of the project to occur starting in 2020 with planning until 2025.

Key project details are as follows:

- GLPT is currently completing several key stages prior to seeking OEB approval of the Transformer Contingency Plan in the future

- Establishing an acceptable standard for restoration times
- Performing a current-state analysis on GLPT's system using the newly developed restoration standards
- Performing a needs analysis and determining system deficiencies
- Research of technical solutions
- Development of an actionable plan

Based on discussing the planned project with GLPT, Hatch agrees with the Transformer Contingency Plan in principle. Refer to Section 5.4.2 for further commentary on future transformer expenditure provisions.

Figure 9-4 shows the location of the Anjigami, Echo River and Northern Avenue transmission stations.

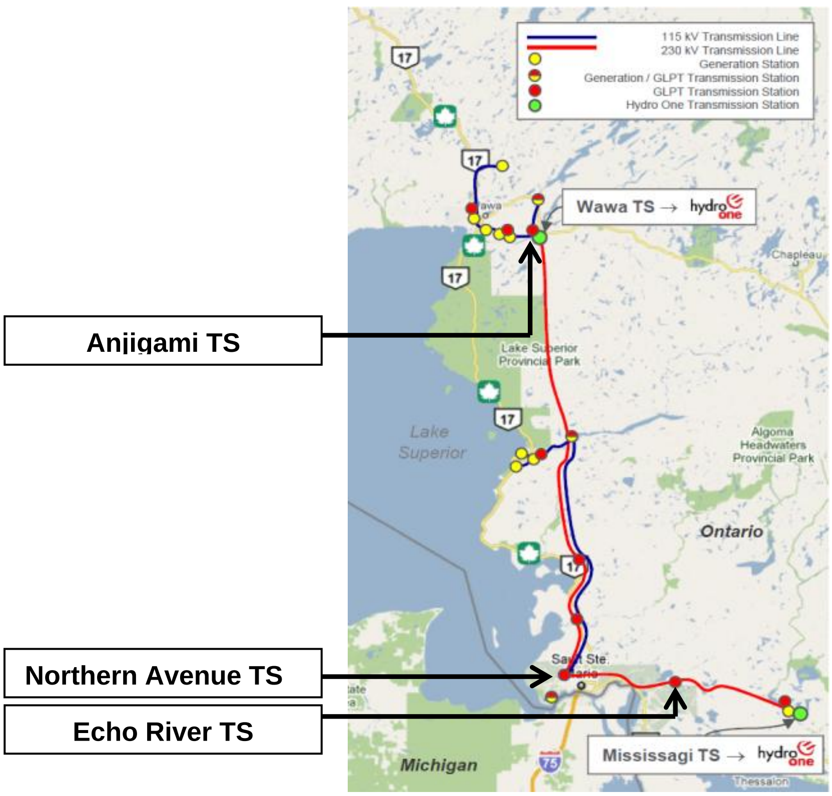

Figure 9-4: Geographic Footprint of the Transformer Contingency Plan

9.3.3 Transmission System Equipment Projects

Fibre Optic Network Upgrades

The Fibre Optic Network Upgrades project contemplates the installation of approximately 25 km of fibre from GLPT System Control to the Third Line TS and to Echo River TS, including terminal equipment at GLPT System Control and Echo River TS.

GLPT will oversee the project through its asset management team and manage onside HS&E through their project managers. Detailed scope, schedule and budget will be completed by 2016 with execution of the project to occur starting in 2017 and the Echo River scope of work ending in 2018. GLPT plans to continue work into future years until an interdependent fibre network has been developed.

Key project details are as follows:

- Echo River TS is currently connected via the P22G 230 kV grid interconnect with Hydro One, which is a critical system element. In addition, the station connects significant residential and industrial load through the Local Distribution Company
- Echo River TS is connected to GLPT System Control via a Bell leased circuit and telephone modem technology. Due to its rural location and the vulnerability of the installed equipment to weather elements, the circuit is unsuitable for high availability SCADA connectivity. Further, the current technology does not allow for remote access for operation and maintenance information access purposes
- Installation of fibre to Echo River TS will secure a reliable means of communication with the Transmission Station and provide the ability to remotely access operational data and security systems

Based on discussing the planned project with GLPT, Hatch agrees with the Fibre Optic Network Upgrades project in principle.

Figure 9-5 shows the geographic footprint of the fibre optic network upgrades project.

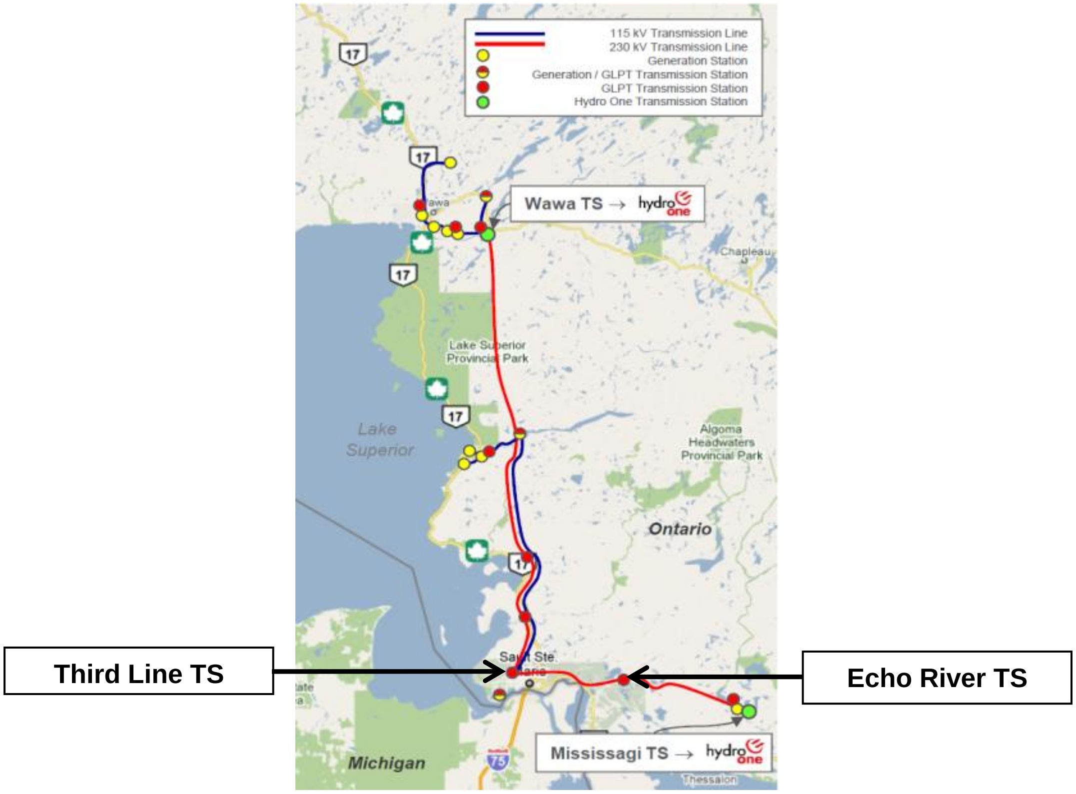

Figure 9-5: Geographic Footprint of the Fibre Optic Network Upgrades Project

Relocation of the Backup Control Centre

This project contemplates implementing a new backup control centre. The existing backup control centre is located in Montreal River, Ontario and is jointly owned and occupied by GLPT and GLPL. During the winter months, the highway required to transit to the existing backup control centre is unavailable on a frequent basis for public safety due to extreme weather conditions. In the event that an emergency happens during a winter storm, GLPT may not be able to transition from the main control centre to the backup control centre within the required amount of time.

The planned new backup control centre would include proper facilities for system operations and operators to control and monitor the system which will have a transition period between the loss of primary control centre functionality and the time to fully implement the backup functionality that is less than or equal to two hours. This would ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control centre becomes inoperable.

GLPT will oversee the project through its asset management team and manage onside HS&E through its project managers. Detailed scope, schedule and budget will be completed by 2021 with execution of the project to occur starting in 2022 and completion in 2023.

Key project details are as follows:

- The existing backup control centre in Montreal River, Ontario is located greater than 100 km from the Main control centre in Sault Ste. Marie
- GLPT system planning is evaluating the relocation of the backup control centre within a 2 hour transition radius from the main control centre
- The Fibre Optic Network Upgrades project will facilitate the relocation of the backup control centre project. Refer to the commentary above for specific details on the Fibre Optic Network Upgrades project
- GLPT is evaluating project options and will likely seek OEB approval through the 2021 and 2022 rate application

Based on discussing the planned project with GLPT, Hatch agrees with the relocation of the backup control centre project in principle. Figure 9-6 shows the location of the existing backup control centre in the Montreal River area and the Main control centre in the Sault Ste. Marie area.

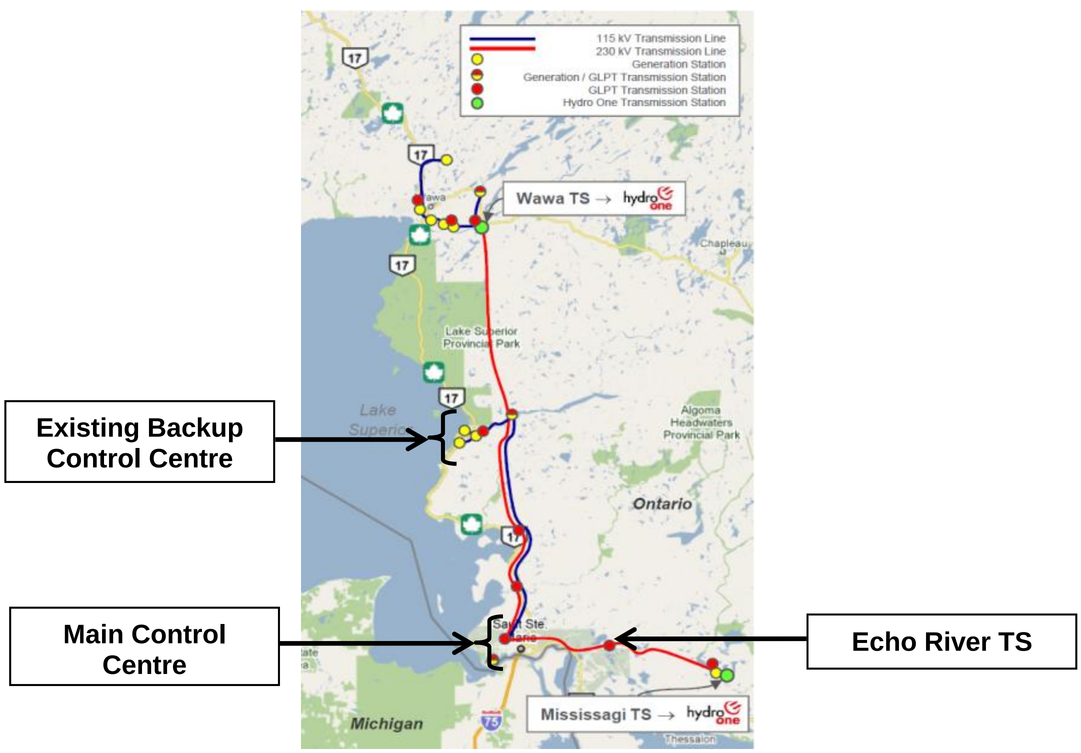

Figure 9-6: Geographic Footprint of the Relocation of the Backup Control Centre Project

9.4 Future Expansion Capital

Expansion capital activities involve projects to expand the capacity of the transmission system beyond existing levels. GLPT is not presently forecasting expansion of its system in the next 10 years, and as a result, there is no associated expansion capital forecast.

10. Management's Growth Opportunities for GLPT

10.1 Regional Planning Process

GLPT leads the regional planning activities, as lead Transmitter, which involves other utilities and stakeholders in the area, including:

- Distribution utilities (customers of GLPT)
- Large users that are direct connected customers of GLPT
- Hydro One (Transmission connection to GLPT).

The OEB mandated process requires participants to contribute to the evaluation of the regional infrastructure and identify where constraints or other technical issues may exist that impact one or more stakeholders.

Although a Regional plan was not required, the process undertaken did result in transparent planning with the LDC to produce a local wires solution.

Based on the most recent analysis, GLPT will expect to see a continuing level of historic growth.

10.2 Electrical Generation Growth

The area has several opportunities for generation growth based on various websites, and GLPT has an obligation to connect under the regulations of OEB.

Although GLPT is not directly involved in developing generation, it does benefit from new generation that connects to its system. There are regulations in place for capital contributions by the new customer and cost recovery by GLPT.

GLPT connected two large wind farms in 2015:

- Bow Lake Wind Facility[1] – This is located north of Sault Ste. Marie, and is a joint venture between Batchewana First Nation of Ojibways and BluEarth Renewables. The windfarm has 36 turbines with a total capacity of 60 MW
- Goulais Wind Farm Facility[2] – This is located north of Sault Ste. Marie, and is a joint venture between Batchewana First Nation of Ojibways and Capstone Infrastructure. The windfarm has 11 turbines and a total capacity of 25 MW

10.3 New Connection, Cost Recovery

The regulations of Ontario lay out a process whereby there is a cost recovery mechanism for GLPT, should the construction cost of a new connection exceed expected revenues from the connection. This applies to Generation as well as Load Customers.

[1] Reference: www.northernontariobusiness.com/printarticle.aspx?id=27525
[2] Reference: www.capstoneinfrastructure.com

The process also has an adjustment procedure, whereby if the actual revenues are different than the forecast, an equalization payment may be required.

Finally, should a new customer connect to an existing transmission line that was built in the last 5 years, which was funded by a large user or generator, there is a mechanism to calculate if any financial adjustment is necessary to the company who made a capital contribution to the construction of transmission assets.

As a result, there is low financial risk should there be a sudden increase in connections to the transmission system owned/operated by GLPT.

I. Brown
IB:ak/hz

Appendix A
Transmission Lines Asset Condition Assessment Field Visit

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1. A.01 – 230 kV K24G Transmission Line

The line originates at Third Line TS and terminates at MacKay TS and is parallel to the 115 kV No.3 Sault line. The line is generally accessible until Goulais TS and then veers away from the main highway coming close near Batchawana TS and then remaining in generally remote areas till its termination at MacKay TS.

The approximate line length is 92 km.

Figure 1-1: K24G and No.3 Sault at Fourth Line Crossing

The line was constructed in 2007.

The structure comprises wooden H-frames, steel cross-arms, steel cross-braces and toughened glass insulators.

Hatch was able to observe the line at few crossings in Sault St Marie, towards Goulais TS and at Batchawana TS.

The right-of-way is reasonably maintained and the structural components (poles, cross-arms, guy-wires) are in generally good condition. The poles are full-length treated, but have wood pecker damages at some locations. GLPT is aware of these damages and rectifies them as part of routine maintenances.

Some insulator discs were observed to be broken at several locations and GLPT is aware of these.

Figure 1-2: Broken Insulator Disc (Right Phase_Str-178)

Based upon these observations, Hatch's opinion of the transmission line health is as follows:

Table 1-1: Health Evaluation – K24G

Component	HI Value		Weight	Weighted HI Value
Pole structure	Good	90	75%	67.5
Stay condition	Good	90	5%	4.5
Insulator	Good	80	10%	8.0
Conductor	Good	80	10%	8.0
		Overall	Good	88.0

Other than routine maintenance activities, there are no immediate concerns regarding the remaining life for this line.

2. A.02 – 230 kV W23K Transmission Line

The line originates at Mackay TS and terminates at Wawa TS. The access is off-road and parallels the railway line.

The approximate line length is 74 km.

Figure 2-1: W23K Structure at Mackay TS

The line was constructed in 2006.

Due to access limitations throughout the line, Hatch was able to observe the line only at its terminations at MacKay and Wawa TS.

The structure types are similar to K24G transmission line and the condition can be assumed to be similar. Based upon the wood poles at Wawa end, the poles may be butt treated only.

As a result, we are of the opinion that 'pole structures' should be HI rated at a value lower than that of the K24G line poles.

Based upon these observations, Hatch's opinion of the transmission line health is as follows:

Table 2-1: Health Evaluation – W23K

Component	HI Value		Weight	Weighted HI Value
Pole structure	Good	80	75%	60
Stay condition	Good	90	5%	4.5
Insulator	Good	80	10%	8.0
Conductor	Good	80	10%	8.0
		Overall	Good	80.5

Other than routine maintenance activities, there are no immediate concerns regarding the remaining life for this line.

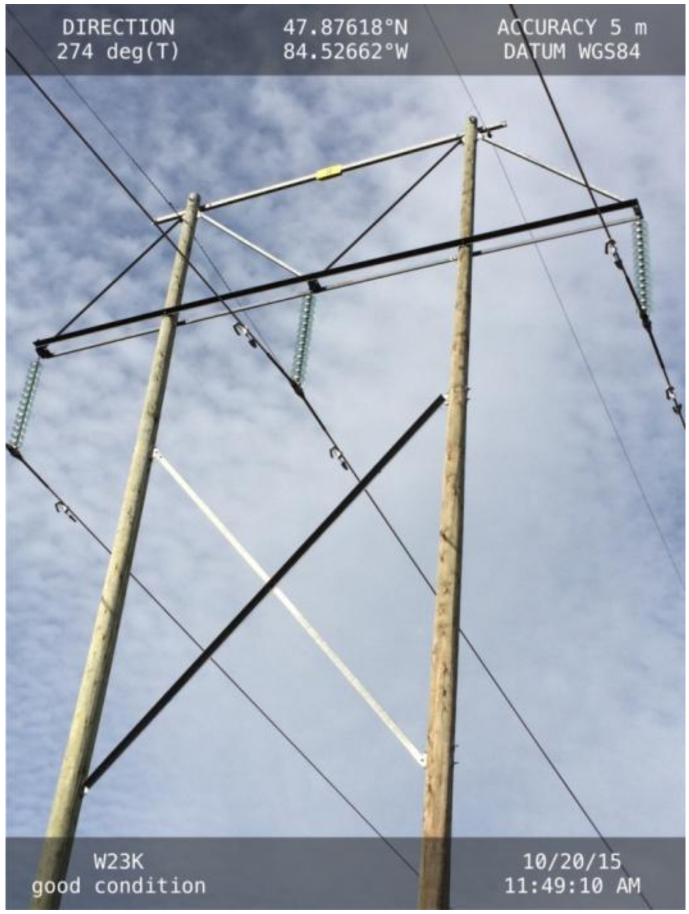

Figure 2-2: W23K Structure at Wawa TS

3. A.03 – 115 kV No. 3 Sault Transmission Line

The line originates at Third Line TS, terminates at MacKay TS, and is parallel to the 230 kV K24G line. The line is generally accessible until Goulais TS and then veers away from the main highway coming close near Batchawana TS and then remaining in generally remote areas until its termination at Mackay TS.

The approximate line length is 92 km.

Figure 3-1: No.3 Sault Structure (Towards Right)

Figure 3-2: No.3 Sault Structure with Composite Insulators

Figure 3-3: No.3 Sault Structure with Porcelain Insulators

The line was constructed in 1956. A section of the line (from Mackay TS) was re-conductored in 1980s/90s, together with replacement of insulators from porcelain to composite types.

The structure comprises wooden H-frames and wooden cross-arms. There are no cross-braces. Insulators are primarily porcelain types, with composite types for a section of line towards south.

Hatch was able to observe the line at few crossings in Sault St Marie, towards Goulais TS and at Batchawana TS.

Together with K24G, the right-of-way is reasonably maintained, and the structural components (poles, cross-arms, guy-wires) are in generally fair condition. The poles are butt-treated and bear field treatment marks for 2010.

The conductor has experienced failures over time and should be classified as Poor condition.

Based upon these observations, Hatch's opinion of the transmission line health is as follows:

Table 3-1: Health Evaluation – No.3 Sault

Component	HI Value		Weight	Weighted HI Value
Pole structure	Fair	60	75%	45
Stay condition	Fair	70	5%	3.5
Insulator	Fair	70	10%	7.0
Conductor	Poor	40	10%	4.0
		Overall	Poor	59.5

The line condition warrants increased inspection and maintenance activities, with conductor to be replaced in the short term.

4. A.04 – 230 kV P21G & P22G Transmission Lines

The two lines originate at Third Line TS and terminate at Mississagi TS. These run parallel to each other in the same corridor. There is limited access to the transmission lines.

The approximate line lengths for P21G and P22G are 76 km and 77 km respectively.

Figure 4-1: P21G and P22G Transmission Lines

The transmission lines were constructed in 1959 (P22G) and 1969 (P21G).

The structure comprises wooden H-frames, wooden cross-arms and composite insulators. The wood poles are butt-treated. A number of older wood poles have been replaced with composite poles (based upon GLPT records, the composite poles are primarily installed on the P21G line).

The wood pole structure designs vary along the length of the lines.

Conductor was re-tensioned in some sections but not replaced.

The first few structures (approximately 13 in count) near Third Line TS are self-supporting lattice steel towers that support both P21G and P22G. The insulators are porcelain type.

Figure 4-2: Lattice Towers near Third Line TS

Hatch was able to observe the line at few crossings for about 50% of line length. The line sections towards Mississagi TS could not be observed as it was late evening.

The right-of-way is reasonably maintained, and the structural components (poles, cross-arms, guy-wires) are in generally good condition. The wood poles are butt-treated, but have wood pecker damages at many locations. A number of wood poles have been replaced by composite poles.

Based upon these observations, Hatch's opinion of the transmission line health is as follows:

Table 4-1: Health Evaluation – P21G

Component	HI Value		Weight	Weighted HI Value
Pole structure	Fair	70	75%	52.5
Stay condition	Good	80	5%	4
Insulator	Good	80	10%	8.0
Conductor	Fair	60	10%	6.0
		Overall	Fair	70.5

Table 4-2: Health Evaluation – P22G

Component	HI Value		Weight	Weighted HI Value
Pole structure	Fair	60	75%	45
Stay condition	Good	80	5%	4
Insulator	Good	80	10%	8.0
Conductor	Fair	60	10%	6.0
		Overall	Fair	63.0

The line condition warrants increased inspection and maintenance activities and replacement of wood poles, where required (especially at the eastern end of line). It is also suggested that additional investigation be carried out regarding conductor condition.

5. A.05 – 115 kV MacKay (No.1 & 2) Transmission Lines

These are short interconnections between MacKay GS and MacKay TS.

Figure 5-1: No.2 MacKay

These structures were constructed in 1960s.

The condition of the structures (especially those near the MacKay GS) seems poor and should be retrofitted or replaced in short timeline.

Hatch's opinion of the transmission line health is as follows:

Table 5-1: Health Evaluation – No.1 & 2 MacKay Transmission Line

Component	HI Value		Weight	Weighted HI Value
Pole structure	Poor	40	75%	30
Stay condition	Poor	40	5%	2
Insulator	Poor	50	10%	5.0
Conductor	Poor	50	10%	5.0
		Overall	Poor	42.0

6. A.06 – 115 kV Gartshore (No.1 & 2) Transmission Lines

These two transmission line originate at Gartshore TS and terminate at MacKay TS. The approximate length for each line is 13 km. Hatch notes indicate observation at the MacKay TS only.

Gartshore No.1 and No.2 were constructed in 1962 and 2004 respectively comprised of wood pole structures with wood arms and porcelain insulators. Most of the Gartshore No.1 structures were replaced in 2004-2015 period with composite poles as reported by GLPT management.

Hatch's opinion of the transmission line health is as follows:

Table 6-1: Health Evaluation – Gartshore No.1

Component	HI Value		Weight	Weighted HI Value
Pole structure	Good	90	75%	67.5
Stay condition	Good	90	5%	4.5
Insulator	Good	90	10%	9.0
Conductor	Fair	60	10%	6.0
		Overall	Good	87.0

Table 6-2: Health Evaluation – Gartshore No.2

Component	HI Value		Weight	Weighted HI Value
Pole structure	Good	90	75%	67.5
Stay condition	Good	90	5%	4.5
Insulator	Good	90	10%	9.0
Conductor	Good	90	10%	9.0
		Overall	Good	90.0

Both lines require only routine maintenance and inspection.

7. A.07 – 115 kV Gartshore No.3 Transmission Line

The No.3 Gartshore Transmission line originates at Gartshore GS and terminates at Gartshore TS, and is less than 1 km long. Only one structure was reviewed by Hatch, and that was shared with the Andrews line.

Figure 7-1: No.3 Gartshore (Sharing Structure with Andrews Line)

No concerns were noted for this short line.

8. A.08 – 115 kV Andrews Transmission Line

The Andrews Transmission Line originates at the Andrews TS and terminates at Gartshore TS. The approximate length of the line is 5 km.

Figure 8-1: Andrews Transmission Line (Str-29)

Hatch was able to observe the line section along Hwy-17.

The line was constructed in 1975.

The structures are wood poles H-frames without cross-bracing. The cross-arms are also wood. The insulators are porcelain type.

Wood pecker holes were visible on some structures and conductor repair sleeves were also noted.

Hatch's opinion of the transmission line health is as follows:

Table 8-1 Health Evaluation – Andrews Transmission Line

Component	HI Value		Weight	Weighted HI Value
Pole structure	Fair	70	75%	52.5
Stay condition	Fair	70	5%	3.5
Insulator	Fair	70	10%	7.0
Conductor	Fair	60	10%	6.0
		Overall	Fair	69.0

The line condition warrants increased inspection and maintenance activities. It is also suggested that additional investigation be carried out regarding conductor condition.

9. A.09 – 115 kV Hogg Transmission Line

The line originates at Hogg GS and terminates at Gartshore TS.

The approximate line length is 5 km.

Figure 9-1: Hogg Transmission Line

The line was constructed in 1964, but the wood structures have recently been replaced with composite poles (RS make). The date on one of the poles indicates May 2015. The insulators are composite polymers.

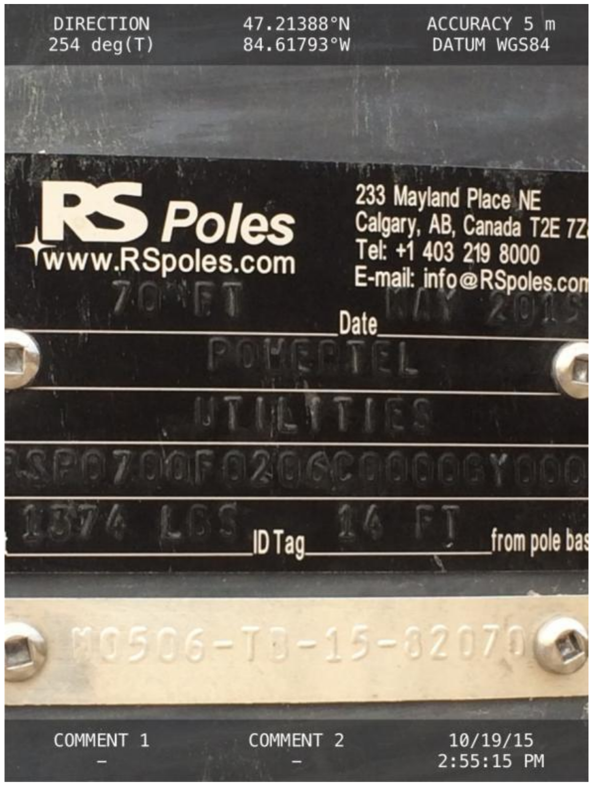

Figure 9-2: Composite Pole (RS Label)

Hatch was able to observe the line only at its Hogg GS end and at intermittent points along the line. Based upon these observations, Hatch's opinion of the transmission line health is as follows.

Table 9-1: Health Evaluation – Hogg Line

Component	HI Value		Weight	Weighted HI Value
Pole structure	Good	90	75%	67.5
Stay condition	Good	90	5%	4.5
Insulator	Good	80	10%	8.0
Conductor	Fair	60	10%	6.0
		Overall	Good	86.0

10. A.10 – 115 kV Hollingsworth Transmission Line

The Hollingsworth Transmission Line originates at Hollingsworth TS and terminates at Anjigami/Wawa TS. The line is generally accessible via a good quality access road (off Hwy-101 to Wawa) that is jointly used with Hydro One.

The approximate line length is 10 km.

Figure 10-1: Hollingsworth Transmission Line

The transmission lines were constructed in 1959.

The structure comprises wooden H-frames, wooden cross-arms and porcelain insulators. Composite insulators have replaced porcelain types on a number of structures.

The general condition of the wood poles is poor with rot visible for many pole tops, and wood-pecker holes on some.

Based upon these observations, Hatch's opinion of the transmission line health is as follows:

Table 10-1: Health Evaluation – Hollingsworth

Component	HI Value		Weight	Weighted HI Value
Pole structure	Poor	50	75%	37.5
Stay condition	Poor	50	5%	2.5
Insulator	Fair	60	10%	6.0
Conductor	Fair	60	10%	6.0
		Overall	Poor	52.0

The line condition warrants increased inspection and maintenance activities and replacement in the short term.

GLPT has advised that the future wood-structure replacement plan will concentrate on this transmission line.

11. A.11 – 115 kV High Falls (No. 1 & 2) Transmission Line

The two High Falls (No.1 & 2) Transmission Lines originates at Watson TS and terminate at Anjigami/Wawa TS.

The approximate length for each transmission line 15 km.

Figure 11-1: High Falls (No.1 & 2) Transmission Line

The No.1 and No.2 lines were constructed in 1989 and 1929 respectively.

Hatch could only observe a couple of structures at Wawa end, which is not sufficient to form an opinion. Woodpecker holes and cracks were observed on few structures. Some of the porcelain insulators have been replaced by composite insulators.

12. A.12 – 115 kV Steephill, Harris, Mission and Magpie Transmission Lines

These 115 kV transmission lines are of similar design and vintages, appeared similar in condition and these were briefly inspected later evening of the first day of the site visit. As such, the observations are presented jointly in one section.

The start and termination and length information for these lines is as follows:

- Steephill — Steephill Falls GS to Magpie TS — 20 km
- Harris — Harris GS to Magpie TS — <1.0 km
- Mission — Mission GS to Magpie TS — 2 km
- Magpie — Magpie TS to Watson TS — 11 km

Figure 12-1: Mapgie Transmission Line

The transmission lines were constructed in 1989-90.

The structures are mostly single poles with porcelain insulators. Distribution underbuilds are present at some locations.

The condition of structures is generally fair.

Based upon these observations, Hatch's opinion of the transmission lines condition is as follows:

Table 12-1: Health Evaluation – Steephill, Harris, Mission, Mapgie Transmission Lines

Component	HI Value		Weight	Weighted HI Value
Pole structure	Fair	60	75%	45
Stay condition	Fair	60	5%	3
Insulator	Fair	60	10%	6.0
Conductor	Fair	60	10%	6.0
		Overall	Fair	60.0

The line condition warrants increased inspection and maintenance activities.

13. A.13 – 44 kV Limer and Anjigami Transmission Lines

The Limer line originates at Hollingsworth TS and terminates at Hwy101TS. Anjigami line originates at Hwy101TS and terminates at Anjigami TS. These are jointly considered as the Limer line in some documents.

The approximate lengths for these lies are 3 km and 7 km respectively. Based on discussions during the site visit, the Anjigami line is older than the Limer line.

Figure 13-1: Anjigami Line (on Left)

These are generally single pole (wood) structures with composite insulators (stand-off post type).

The condition of the lines is fair (Limer) to poor (Anjigami).

Based upon these observations, Hatch's opinion of the lines condition is as follows:

Table 13-1: Health Evaluation – Limer

Component	HI Value		Weight	Weighted HI Value
Pole structure	Fair	60	75%	45
Stay condition	Fair	60	5%	3
Insulator	Fair	60	10%	6.0
Conductor	Fair	60	10%	6.0
		Overall	Fair	60.0

Table 13-2: Health Evaluation – Anjigami

Component	HI Value		Weight	Weighted HI Value
Pole structure	Poor	50	75%	37.5
Stay condition	Poor	50	5%	2.5
Insulator	Poor	50	10%	5.0
Conductor	Poor	50	10%	5.0
		Overall	Poor	50.0

The lines condition warrants increased inspection and maintenance activities and replacement (Anjigami line) in the short to midterm.

Appendix B
Transmission Stations Asset Condition Assessment Field Visit

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1. B.01 – Hollingsworth Transmission Station

The Hollingsworth station is the transmission station located generally east of Wawa, associated with the Hollingsworth generating station.

Observations were made of the following equipment, site, foundations, spill containment system, fence, structures, bus-bars, building, and protection, monitoring, communications and control equipment.

Figure 1-1: Hollingsworth TS

a) Transformers:

Three transformers were observed

- T1: Yd1 configuration manufactured in 2005, rated 115 kV HV and 12 kV LV. Power rating 21/28/35 MVA ONAN/ONAF/ONAF
- T2: Yd1 configuration, manufactured by Ferranti Packard, date illegible, rated 44 kV HV and 12 kV LV. The power rating is 21/28/35 MVA ONAN/ONAF/ONAF.
- GT1, Grounding transformer, manufactured by ABB, in 1991.

All three transformers were observed to be in good condition, with no oil leaks, no PCB stickers, properly connected on the HV and LV sides, suitably grounded and with foundations in good condition. The foundations were suitably fitted with spill containment and with Imbiber oil leak prevention.

b) The breakers are low voltage 12 kV generation voltage breakers. There are no HV breakers at the site. The 115 kV line to Anjigami is switched from Anjigami (and Wawa TS) and through the low side breaker at Hollingsworth. Similarly, the 44 kV line to local distribution and Anjigami is switched from Anjigami and the low side 12 kV breaker at Hollingsworth. This is acceptable given the radial nature of the lines with the source at Hollingsworth.

c) A high voltage manually operated load break switch serves to isolate the station at 115 kV. A similar switch serves to isolate 44 kV line, but it is motorized as required for the complex switching arrangements in the local 44 kV system.

d) The site works, the foundations, the steel structures, the insulating gravel, fence and the local drainage all appear to be in good condition.

e) The auxiliary dc system is supplied through duplicate batteries that appear to be in suitable condition. Only a single ac station service exists. However, this is probably adequate as it is understood an ac feed should be available on an emergency basis from the nearby generator building.

f) The relaying system is duplicated (except for a single transformer differential for T2, a condition which is being rectified under the present forward capital plan). The relays are Alstom Micom relays for the A relays and Schweitzer relays for the B relays. It is noted the Micom relays are becoming a bit dated and will eventually have to be replaced, probably with GE Multilin relays, which appears to be the new GLPT standard for “A” relays. The SCADA controls are by AREVA with a Schweitzer 2032 communication system. Controls and station reporting to the Sault Ste. Marie control centre are though the GLPT fibre optic system.

The following table summarizes the health of equipment found at site:

Table 1-1: Hollingsworth TS Health Evaluation

Component	Health Index Assessment		Weight	Calculated Value
Protection	Good	90	60%	54.0
Grounding	Good	90	10%	9.0
Bus Work	Good	90	10%	9.0
Building	Good	80	10%	8.0
Transformers	Good	70	10%	7.0
		Total	100%	87.0
		Overall Score	**Good**	**87.0**

2. B.02 – Highway 101 Transmission Station

The highway 101 station is on the 44 kV Limer line originating at Hollingsworth and terminating at local distribution in Hawk Junction and Anjigami. As of October 2015, it was out of service and bypassed as it was being redeveloped to ensure proper switching and selectivity of tripping on the line when faults occur. Its purpose is apparently to service a wood products customer. As of June 2016, the station is reportedly in service.

Figure 2-1: Highway 101 TS

The site was expected be completed in the relative near future in October 2015, as an E-building with the necessary switching and control equipment was understood to have been delivered to site at this time.

The station was not in service, and as such, observations were not provided at the time of Hatch's review.

Rating: Not applicable as not in service.

3. B.03 – Anjigami Transmission Station

The Anjigami station is the GLPT transmission station associated with the Hydro One 230/115 kV Wawa transmission station.

Figure 3-1: Anjigami TS Circuit Breaker

Figure 3-2: Anjigami TS Control Building

Observations were made of the following equipment, site, foundations, spill containment system, fence, structures, bus-bars, building, and protection, monitoring, communications and control equipment.

a) Transformers:

One transformer was observed to exist at Anjigami.

T1: Dy1 configuration manufactured in 1978 by Ferranti Packard, voltage rated 115 kV HV and 44 kV LV. Maximum ONAF rating is 53.3 MVA, with one step of cooling. The age of this transformer is significant in that transformers only tend to last for 35 to 40 years. The transformer is showing its age with rust showing on the radiators. However, no leaks were observed and spill containment exists. A gas in oil monitor also exists as does spill containment, with an Imbiber unit. A transformer replacement is tentatively included as part of the transformer contingency plan in the forward capital program. It was noted that the grounding connection to the transformer appeared to be untidy.

b) The 4 circuit breakers in the station are all 115 kV manufactured by Alstom. These switch the lines to High Falls (2), to Wawa TS and Hollingsworth (three ended line) and the transformer which connects to the Hollingsworth 44 kV line. All breakers were manufactured by Alstom in 1994 or earlier. There appear to be three SF_6 dead tank breakers and one live tank SF_6 insulated breaker, with separate single pole current transformers. The three ended line is unconventional and probably should be modified. Some of the breakers and other equipment in the yard, particularly the set of PTs in the middle of the yard are surrounded by fences to prevent anyone in the station to come too close to the equipment as their vertical mountings are so low as to contravene safe limits of approach rules. Given the insufficient clearances the safety rating is compromised and the station is scheduled to be upgraded with new equipment and increased clearances in the next two years.

c) Each breaker has a ganged manually operated 115 kV disconnect switch on either side of the breaker, except for the breaker that is in front of the transformer, which only has a switch on one side. 44 kV switching for this line is carried out by manually operating a set of mid span openers. A further manually operated disconnect switch is also installed on each side of the PTs that are located in the middle of the yard. Manually operated grounding switches are installed at each 115 kV line exit and to the switches on either side of the PTs in the centre of the yard.

d) The structure foundations exhibit some signs of slight spalling. The insulating gravel looked as though it might have some iron in the gravel, which should be checked to ensure safety during external and internal faults. The steel structures appear to be in acceptable condition. Local drainage appeared to be adequate, although the inspection took place during rather dry conditions, which might mean no water could be present. The fence does not have the GLPT standard height of 8 feet and the gravel is piled up on the interior of the fence. In addition, it was noted that there is a greater than acceptable 2 inch gap between the fence and the building on one side of the building. These deficiencies are once again an indication of an inadequate safety rating.

The overhead conductor appeared to be adequate and the connections properly made.

e) The auxiliary dc system is supplied by a single battery and charger. It is understood that this system will be replaced by a duplicate system as soon as next year.

f) The RTU is from Harris and soon to be replaced. The communications is through JungleMUX connecting to the leased fibre. The relaying and control system is aged and not normal GLPT accepted standard. Some electromechanical relays still exist. The system will be replaced in 2016 with appropriate relaying and controls. This spending is all within the approved capital budget.

g) Anjigami has Areva KCEG relays, just like Watson TS. Some of these relays have failed; furthermore, the manufacturer has deemed them obsolete, and consequently there are limited spare parts available and limited /no technical support.

The following table summarizes the health of equipment found at site:

Table 3-1: Anjigami TS Health Evaluation

Component	Health Index Assessment		Weight	Calculated Value
Protection	Poor	40	60%	24.0
Grounding	Good	70	10%	7.0
Bus Work	Good	80	10%	8.0
Building	Fair	60	10%	6.0
Transformers	Fair	60	10%	6.0
		Total	100%	51.0
		Overall Score	**Poor**	**51.0**

4. B.04 – Watson Transmission Station

The Watson TS connects generation from the Scott, McPhail and R.A. Dunford generating stations to the GLPT bulk 115 kV transmission system at Anjigami through the High Falls 1 and 2 lines. These generating stations and Watson TS are located on the Michipicoten River system, south of Wawa. The station is rather unique in the GLPT system in that it is a mostly indoor station with 34.5 kV metal-clad switchgear.

Figure 4-1: Watson TS High Voltage

Figure 4-2: Watson TS Indoor Switchgear

While very neat and clean looking, the station was observed to have a number of deficiencies and problems that are outlined below. The Watson TS is connected to the GLPT 115 kV bulk power system at Anjigami.

Observations were made of the following equipment, site, foundations, spill containment system, fence, structures, bus-bars, building, and protection, monitoring, communications and control equipment.

a) Transformers:

Two identical transformers exist at Watson TS. T1 and T2 are Autotransformers with a delta tertiary configuration, manufactured in 1991, rated 115 kV HV and 34.5 kV LV, rated 45/60/75 MVA. The transformer tertiary is buried and grounded. Spill containment along with an Imbiber system exists. The transformer foundations appear adequate as does the grounding connections.

A single 115 kV circuit breaker exists outside the station on the High Falls 1 line, which connects to High Falls as well as to Anjigami. There is no need for a breaker on the High

Falls number 2 line as it is radial to Anjigami. The single breaker was manufactured by ABB. It is understood there is some discussion in modifying the 115 kV circuits into a ring bus configuration, starting with another 115 kV breaker in 2016. This is contained in the capital budget.

In addition to the 115 kV breaker there is a line of metal-clad 34.5 kV draw-out switchgear composed of 12 circuit breakers (type 3 phase), as well as fuse gear for station service bus PTs line PTs etc. There are 5 breakers for 34.5 kV line connections to Dunford GS (1), McPhail GS (1), Wawa local distribution (1), Scott GS (1) and 1 to transformer T2 plus one spare on the right hand side of the switchgear. There are 5 circuit breakers for 34.5 kV line connections on the left side of the bus for connections to Dunford GS (1), McPhail GS (1), Wawa local distribution (1), Scott GS (1), and 1 to transformer T1. The 12th breaker is the bus tie breaker.

The switchgear was made by S&C using their ruptor switches, unfortunately many years ago before arc-flash exposure became a safety concern. The ruptor switches cannot now be operated locally, and remote viewing gear must be used simply to observe them.

b) Each 34.5 kV breaker servicing a line is connected to a ganged manually operated 34.5 kV disconnect switch mounted in two rows, each row mounted on its own steel structures. Each row of switches corresponds to one side of the switchgear.

c) The structure foundations seem in good shape, the steel structures also appear to be in excellent condition. The insulating gravel, the fence and the grounding connections again appear to be in very good condition. Local drainage again appears to be to be adequate.

   The overhead conductor appeared to be adequate and the connections properly made.

d) The auxiliary dc system is supplied by a single battery and charger, although space exists for another. Duplicate ac station service exists. The building is large and spacious with a basement for cabling and ac/dc services.

e) An RTU and a JungleMUX are in place for control and communications purposes. The relays are electro-mechanical for the most part. The station has Areva KCEG relays. Some of these relays have failed. Furthermore, the manufacturer has deemed them obsolete and consequently there are limited spare parts available and limited/no technical support.They also do not facilitate remote communication to GLPT’s Wide Area Network and lacks GPS clock synchronizing capability which places the Watson TS at risk of failure with extended downtime should a failure occur. Thus, the relays should be replaced along with the metal-clad switchgear. There is an allowance in the forward capital plan to make these changes.

The following table summarizes the health of equipment found at site:

Table 4-1: Watson TS Health Evaluation

Component	Health Index Assessment		Weight	Calculated Value
Protection	Good	80	60%	48.0
Grounding	Good	95	10%	9.5
Bus Work	Good	95	10%	9.5
Building	Good	95	10%	9.5
Transformers	Good	90	10%	9.0
		Total	100%	85.5
		Overall Score	**Good**	**85.5**

5. B.05 – Magpie Transmission Station

The Magpie station is a 115 kV station that connects generation from the Steephill Falls, Harris and Mission Falls generating stations to the GLPT bulk 115 kV transmission system at Anjigami through the Magpie 1/High Falls 1 line. These generating stations and the Magpie station are located on the Magpie River system, west of Wawa. The station is an outdoor 115 kV station configured in a 115 kV vertical ring.

Observations were made of the following equipment, site, foundations, spill containment system, fence, structures, bus-bars, building, and protection, monitoring, communications and control equipment.

Figure 5-1: Magpie TS

a) Transformers - there are no HV transformers at Magpie.

b) The breakers in the ring consist of 4 ABB single pole SF_6 live tank 115 kV circuit breakers with separate CTs. The breakers appear to be in good condition without leaks or other obvious signs of poor condition. Some of the Trench CTs leak, but no serious problems have occurred as yet.

c) The switches and bus work appear to be in reasonable condition. If there is a problem with the station it is that maintenance space is limited. Often the three breakers have to be taken out of service to work on a piece of equipment.

d) The structure foundations seem in good shape, the steel structures also appear to be in excellent condition. The insulating gravel appeared as though it might have rust in it, which should be checked. Grounding connections appeared properly made. The fence appears to be in very good condition. Local drainage again appears to be to be adequate.

   The overhead conductor appeared to be adequate and the connections properly made.

   Only a single ac station service exists, but a backup supply is available. The control building is well laid out, and has adequate room for the necessary equipment and facilities.

a) The RTU is from Areva and the communications is through JungleMUX connecting to the leased fibre. The incoming cables are properly laid out on cross connect racks. The relaying system is normal GLPT accepted standard with "A" protections Alstom Micom and "B" protections SEL. It is noted that the Micom system is getting to be dated.

The following table summarizes the health of equipment found at site:

Table 5-1: Magpie TS Health Evaluation

Component	Health Index Assessment		Weight	Calculated Value
Protection	Good	80	60%	48.0
Grounding	Good	90	10%	9.0
Bus Work	Good	90	10%	9.0
Building	Good	90	10%	9.0
Transformers	Good	100		0.0
		Total	90%	75.0
		Overall Score	**Good**	**83.3**

Note: Where no element exists, for instance a transformer, this element is not counted towards the weighted score.

6. B.06 – MacKay Transmission Station

The MacKay station is one of the two major transmission stations in the GLPT system. It is located on a private road off Highway 17 roughly half way between Sault Ste. Marie and Wawa. It has a 115 kV section that serves mainly to connect generation on the Montreal River into the bulk power system. Lines MacKay 1 and 2 connect to the MacKay generating which is several hundred meters from the transmission station.

Figure 6-1: MacKay TS 115kV Circuit Breaker

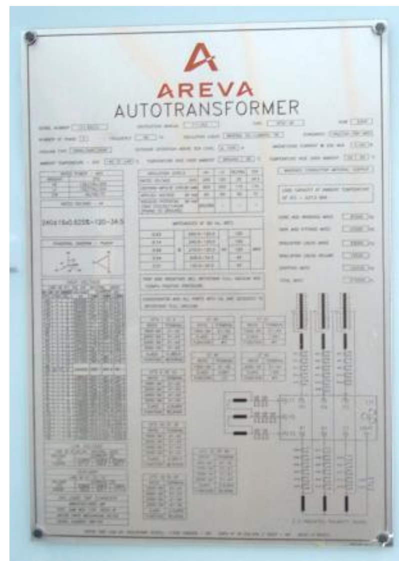

Figure 6-2: MacKay TS 230kV

Lines Gartshore 1 and 2 connect the Gartshore generating station several km away. In addition, there is the Sault 3 line that runs roughly in parallel to the 230 kV lineK24G to the Third Line station in Sault Ste. Marie.

The station also has a 230 kV section to connect to 230 kV line W23K between MacKay and the Hydro One station at Wawa, and also to 230 kV line K24G to the GLPT Third Line station in Sault Ste. Marie. There is a single autotransformer connection between the 230 and 115 kV sections of the switching station.

Observations were made of the following equipment, site, foundations, spill containment system, fence, structures, bus-bars, building, and protection, monitoring, communications and control equipment.

a) Transformers:

Two transformers were observed to exist at MacKay. The largest is an autotransformer manufactured by Areva in 2005, rated 230/115 kV, 120/160/200 MVA ONAN/ONAF/ONAF, with a full rated 34.5 kV tertiary at 42/56/70 MVA. The transformer apparently had to be repaired when it was brought to site. A hole reportedly had to be cut through the transformer wall to execute the repairs. It is noted that typically such a station would have duplicate 230/115 kV transformers.

The second transformer designated T1 is an aged station service/local distribution transformer situated in the middle of the 115 kV yard. It is switched using manually operated fuses on both the HV side and LV side. This transformer is slated to be replaced in 2016 and 2017.

In addition to the transformers, there is a set of 34.5 kV three phase air core reactors apparently supplied by ABB in the 230 kV station, connected to the autotransformer tertiary.

b) With respect to the 115 kV yard, there are eight 115 kV SF_6 dead tank breakers installed, supplied by Areva recently. The station is arranged in a 1 and ½ breaker configuration

The SF_6 230 kV breakers were supplied during the 2004/2005 station expansion executed by ABB, and they appear to be in good condition. The breakers are arranged in a three breaker ring, one for each element connected, i.e. the two lines and the one transformer.

In general the breakers appear to be in excellent condition.

c) The high voltage circuit breakers may be in general isolated using manually operated disconnect switches. The 230 kV lines and transformer connection may also be isolated using manual switches. The 115 kV lines are not fitted with line isolators. HV bus and connections appear to be suitable. The grounding connections appear to be properly made and it is understood the system has recently been tested and is in good shape.

d) For site works, the foundations, the steel structures, the insulating gravel, the fence, the cable trenches, and the local drainage all appear to be in excellent condition. In addition, the transformer spill containment is in place for the 230/115 kV transformer and Imbiber oil containment units are installed. Station cable trenches are properly installed, and appear in good repair, with proper lane marking.

e) There are two control buildings – one for the 115 kV portion of the yard and the other for the 230 kV portion. These are described below together as they are similar/ almost identical.

- The buildings are relatively new and modern looking
- The buildings are equipped with fire suppression systems
- All control wiring entering the building is connected on cross connect terminals. The A and B systems are isolated
- Station service to the building is duplicated, one off the 115 kV station service transformer and the other off the tertiary of the autotransformer
- The dc auxiliary system is supplied through duplicate batteries and chargers that appear to be in suitable condition
- A and B relays duplicate system relays are provided. It is understood the A system is GE Multilin and the B system is Schweitzer
- Communications, controls and station reporting to the Sault Ste. Marie control centre are though the GLPT fibre optic system. A backup communication link is provided over the 230 kV lines by the use of PLC (Power Line Carrier)

The following table summarizes the health of equipment found at site:

Table 6-1: MacKay TS Health Evaluation

Component	Health Index Assessment		Weight	Calculated Value
Protection	Good	98	60%	58.8
Grounding	Good	95	10%	9.5
Bus Work	Good	90	10%	9.0
Building	Good	100	10%	10.0
Transformers	Good	90	10%	9.0
		Total	100%	96.3
		Overall Score	**Good**	**96.3**

7. B.07 – Gartshore Transmission Station

The Gartshore station is a 115 kV station that connects generation from the Gartshore, Hogg, and Andrews generating stations, all on the Montreal River, to the GLPT bulk 115 kV transmission system at MacKay TS through the Gartshore Lines 1 and 2. The station is an outdoor 115 kV station configured in a 115 kV vertical ring.

Figure 7-1: Gartshore TS

Observations were made of the following equipment, site, foundations, spill containment system, fence, structures, bus-bars, building, and protection, monitoring, communications and control equipment.

a) Transformers - There are no HV transformers at Gartshore.

b) The breakers in the ring consist of 5 Mitsubishi dead tank three pole SF_6 115 kV circuit breakers with integral CTs. The breakers appear to be in good condition without leaks or other obvious signs of poor condition.

c) The 115 kV disconnect switches are centre side break switches, which apparently have experienced some problems. Each breaker may be isolated by the switches, and line isolation is also possible by using the line isolator switches. The bus work appears to be in reasonable condition. Unlike the similar station at Magpie, maintenance space is seems adequate.

d) The structure foundations seem in good shape, the steel structures also appear to be in excellent condition. The insulating gravel appears to be in good condition. Grounding connections appeared properly made. The fence appears to be in very good condition. Local drainage again appears to be to be adequate. Station cable trenches are properly installed and appear in good repair, and with proper lane marking.

   The station bus conductor appeared to be adequate and the connections properly made.

e) The ac station service is duplicated and is supplied by power PTs installed on the Gartshore 1 and 2 line exits. The dc station service is duplicated, albeit with two batteries in the same room. The control building appears well laid out, and has adequate room for the necessary equipment and facilities. Incoming cables are terminated on cross connect racks in A and B separated form.

f) The RTU is from and the communications are installed to GLPT standard practice. The incoming cables are properly laid out on cross connect racks. The relaying system is normal GLPT accepted standard with A and B protections.

The following table summarizes the health of equipment found at site:

Table 7-1: Gartshore TS Health Evaluation

Component	Health Index Assessment		Weight	Calculated Value
Protection	Good	95	60%	57.0
Grounding	Good	90	10%	9.0
Bus Work	Good	90	10%	9.0
Building	Good	80	10%	8.0
Transformers	Good	100	10%	10.0
		Total	100%	93.0
		Overall Score	**Good**	**93.0**

8. B.08 – Andrews Transmission Station

The Andrews distribution station is a very small station, tapped to the Andrew 115 kV line, which connects to Gartshore TS in a small extension to the generation owned Andrews switching station. The station is an outdoor 115 kV station configured as a radial 25 kV distribution supply feeder to local distribution. It basically consists of two sets of disconnect switches, a set of power fuses, a 115 kV/25 kV transformer and metering.

Figure 8-1: Andrews TS

Observations were made of the following equipment, site, foundations, spill containment system, fence, structures, bus-bars, building, and protection, monitoring, communications and control equipment.

a) Transformers:
The transformer was manufactured by Northern Transformer, is configured in a “Dy” 115/25 kV ratio, rated 5 MVA.

b) There are no breakers at Andrews TS. The transformer is switched in the generation switching station by a 115 kV breaker.

c) The 115 and 25 kV disconnect switches appear to be hook stick operated. The bus work appears to be in reasonable condition.

d) The structure foundations seem in good shape, the steel structures also appear to be in good condition. The insulating gravel appears to be in good condition. Grounding connections appear properly made. The fence also appears to be in very good condition. Local drainage appears to be to be adequate. Spill containment is in place and an Imbiber is also present.

The station bus conductor appeared to be adequate and the connections properly made.

e) There is single phase station service transformer mounted on the steel structure which provides station service supply to the station. The dc station service is provided by a single set of batteries in an outdoor cubicle. There is no control building, merely outdoor cubicles containing the necessary batteries, protections, indications, communications and metering equipment. The metering equipment and communications equipment are to allow connection to the IESO to report total power usage by customers connected to the 25 kV distribution line in the Montreal River area.

The following table summarizes the health of equipment found at site:

Table 8-1: Andrews TS Health Evaluation

Component	Health Index Assessment		Weight	Calculated Value
Protection	Good	95	60%	57.0
Grounding	Good	90	10%	9.0
Bus Work	Good	90	10%	9.0
Building	Good	90	10%	9.0
Transformers	Good	95	10%	9.5
		Total	100%	93.5
		Overall Score	**Good**	**93.5**

9. B.09 – Batchawana Transmission Station

The Batchawana TS is a small station, tapped to the Sault 3 line. The station is an outdoor 115 kV station configured to supply two radial 12 kV distribution feeders to local distribution in the Batchawana Bay area. It basically consists of an in and out arrangement through two 125 kV circuit switchers connected to the Sault 3 Line. The single phase transformers are fed through 115 kV power fuses.

Figure 9-1: Batchawana TS

Observations were made of the following equipment, site, foundations, spill containment system, fence, structures, bus-bars, building, and protection, monitoring, communications and control equipment.

a) Transformers:

The three single phase transformers are of similar but not identical ratings, one transformer serves as a spare and the other two are operating in open delta configuration. This is a satisfactory situation as long as no further failures occur to either the two good condition transformers, or in the secondary supply system. Should any such condition occur, the 2 MVA (approximate) load supplied from the Batchawana TS may be off line for the time it takes to rectify the problem. In the case of a transformer failure, this outage could easily last a week or more. The transformers and some of the other equipment are fenced internally to ensure the safe limits of approach are maintained. This severely lessens the protection rating.

b) There are no breakers at Batchawana TS. The transformers are switched by circuit switchers, assumed to be supplied by S&C in the distribution switchyard. The circuit switchers are arranged so that the transformers can be kept on line if either the southern or northern half of the Sault 3 line is viable. The circuit switchers may be isolated through operation of the ganged disconnect switches installed upstream of the switchers. The transformers themselves are protected by fused switches, individually hook stick operated.

c) The 115 disconnect switches are gang operated and look to be in reasonable operating condition. The bus work appears to be in reasonable condition.

d) The structure foundations seem in somewhat deteriorated condition and the steel structures also appear to have some rust on them. The insulating gravel appears to be in good condition, but local drainage sometimes can be insufficient to keep the station as dry as desired. Grounding connections appeared properly made. The fence appears to be in minimally acceptable good condition. Spill containment is in place and an Imbiber is also present.

e) The station bus conductor appeared to be copper, old, but serviceable for the time being.

f) There is single phase station service transformer mounted on the steel structure which provides station service supply to the station. The dc station service is provided by a single set of batteries in an outdoor cubicle. There is no control building, merely outdoor cubicles containing the necessary equipment. There is metering, monitoring and communications equipment to allow station condition reporting and connection to the IESO to report total power usage by customers connected to the 12 kV distribution line in the Batchawana Bay area. Batchawana TS is scheduled to be replaced, along with Goulais TS in the next several years.

The following table summarizes the health of equipment found at site:

Table 9-1: Batchawana TS Health Evaluation

Component	Health Index Assessment		Weight	Calculated Value
Protection	Poor	50	60%	30.0
Grounding	Good	90	10%	9.0
Bus Work	Good	60	10%	6.0
Building	Good	100	10%	10.0
Transformers	Poor	20	10%	2.0
		Total	100%	57.0
		Overall Score	**Poor**	**57.0**

10. B.10 – Goulais Transmission Station

The Goulais TS is a relatively small station connected to the Sault 3 line. It has a load of approximately 7 to 8 MW. The station is an outdoor 115 kV station configured to supply two radial 12 kV distribution feeders to local distribution in the Goulais Bay area. It also supplies a 25 kV feeder through a 12/25kV step up transformer to the Searchmont area to the east of the highway.

Figure 10-1: Goulais TS Transformers

Figure 10-2: Goulais TS Comm. Eqmt

The station basically consists of an in and arrangement through two 125 kV circuit switchers to the Sault 3 Line. The circuit switchers date to the 1980s. The single phase transformers are fed through 115 kV power fuses.

Observations were made of the following equipment, site, foundations, spill containment system, fence, structures, bus-bars, building, and protection, monitoring, communications and control equipment.

a) Transformers:

   The single phase 115/12 kV transformers are of similar ratings. All three transformers remain in operation. The manufacturing dates of the three transformers are 1973, 1980, and 1976. Thus, the transformers are rather old. In general it is assumed in the utility field that 40 years is a very good life span for transformers. The 25/12 kV step up transformer to Searchmont is a relatively small pole mounted transformer.

b) There are no breakers at Goulais TS. The transformers are switched by circuit switchers, assumed to be supplied by S&C in the distribution switchyard. The circuit switchers are arranged so that the transformers can be kept on line if either the southern or northern half of the Sault 3 line is viable. The circuit switchers may be isolated through operation of the ganged disconnect switches installed upstream of the switchers. The transformers themselves are protected by fused switches, individually hook stick operated.

c) The 115 disconnect switches are gang operated and look to be in reasonable operating condition. The bus work appears to be in reasonable condition.

d) The structure foundations seem in somewhat deteriorated condition, and the steel structures also appear to have significant rust on them. The insulating gravel appears to be in good condition; however, during wet conditions the station may only be traversed on foot, or by suitably equipped vehicles. Local drainage is often insufficient to keep the station even somewhat dry. Grounding connections appeared properly made. The fence appears to be in minimal acceptable good condition. Spill containment is in place and an Imbiber is also present.

   The station bus conductor appeared to be old, but serviceable for the time being.

e) There is single phase station service transformer mounted on the steel structure which provides station service supply to the station. The dc station service is provided by a single set of batteries in an outdoor cubicle. There is no control building, simply outdoor cubicles containing the necessary equipment. There is metering, monitoring and communications equipment to allow connection to the IESO to report total power usage by customers connected to the 12 kV distribution line in the Goulais Bay area. Clearances are part of the station particularly around the transformers appears less than acceptable. Thus, the plan to replace the station in the next few years appears to be appropriate.

It is noted that GLPT has plans to replace the two stations (Batchawana and Goulais TS) with one station somewhere between the two existing stations, and to provide distribution service at 25 KV rather than the existing 12 kV. This is included in the forward capital plan.

The following table summarizes the health of equipment found at site:

Table 10-1: Goulais TS Health Evaluation

Component	Health Index Assessment		Weight	Calculated Value
Protection	Good	50	60%	30.0
Grounding	Good	90	10%	9.0
Bus Work	Good	50	10%	5.0
Building	Good	50	10%	5.0
Transformers	Good	70	10%	7.0
		Total	100%	56.0
		Overall Score	**Poor**	**56.0**

11. B.11 – Third Line Transmission Station

The Third Line station is the largest and most important transmission station in the GLPT system. It is located in the City of Sault Ste. Marie, not far from the GLPT engineering office. It is configured in a one and one half breaker arrangement in the 115 kV section that serves mainly to connect to load in the Sault Ste. Marie area. Other, non-load, 115 kV connections are the connection to the Sault 3 line from MacKay and the two connections to the 230 kV portion of the station.

Figure 11-1: Third Line TS 230kV Transformer

Figure 11-2: Third Line TS 115kV Circuit Breaker

There are 17 circuit breakers of 115 kV class in the station and eleven 115 kV circuit connections.

The station also has a 230 kV section, based on a 1 and ½ breaker arrangement. It includes line connection K24G to MacKay TS, connections P21G and P22G to Mississagi TS and the two connections to the 230 to 115 kV autotransformers that are between the 230 and 115 kV portions of the station.

Observations were made of the following equipment, site, foundations, spill containment system, fence, structures, bus-bars, building, and protection, monitoring, communications and control equipment.

a) Transformers:

Two identical sized transformers were observed to exist at Third Line. One (T2) was manufactured by GE in 1968. The other (T1) was manufactured by Areva in approximately 2005. There originally were two GE transformers but the original T1 failed several years ago because of a tertiary failure. The transformers are both autotransformers, with tertiary's, which are brought out to provide station service feeds and connect to capacitors.

The T1, newer transformer, is rated 230/115 kV, 150/200/250 MVA ONAN/ONAF/ONAF, with a 34.5 kV tertiary rated at 42/56/70 MVA. The older GE transformer, T2, has the same phase arrangement, and primary load capacity, but a tertiary rated at 21/28/35 MVA. This is somewhat less than the normal 35% tertiary capacity.

Given the T2 transformer's age (it is now 47 years old), it is suggested to consider purchase of another transformer identical to T1, especially given the failure of the previous T1 transformer tertiary

The existing T2 might be considered as a fallback spare.

b) With respect to the 115 kV yard, there are 17 115 kV SF_6 breakers installed in approximately 2012. The station is arranged in a one and half breaker configuration with 5 whole diameters and 1 partly completed diameter. The breakers appear to be in excellent condition.

The SF_6 230 kV breakers were supplied during the 2004/2005 station expansion executed by ABB, and they also appear to be in good condition. The breakers are arranged in one completed three breaker diameter and one partially completed 2 breaker diameter.

c) The high voltage breakers may be isolated using manually group operated disconnect switches. The kV line and transformer connections may also be isolated using manual switches. The 115 kV lines are not fitted with line isolators. HV bus and connections appear to be suitable. The grounding connections appear to be properly made.

d) For site works, the foundations, the steel structures, the insulating gravel, the fence, the cable trenches, and the local drainage all appear to be in excellent condition. In addition the transformer spill containments are in place for the 230/115 transformers and Imbiber oil containment units are installed. Station cable trenches are properly installed, and appear in good repair with proper lane marking.

e) There are two control buildings – one for the 115 kV portion of the yard and the other for the 230 kV portion. These are described below together as they are similar/almost identical.

- The 115 kV buildings is relatively new and modern looking; the 230 kV building has been extensively refurbished
- The buildings are equipped with fire suppression systems
- All control wiring entering the buildings is connected on cross connect terminals. The A and B systems are isolated
- Station service to the building is duplicated, one off the 115 kV station service transformer and the off the tertiary of the autotransformer
- The dc auxiliary system is supplied through duplicate batteries and chargers that appear to be in suitable condition
- A and B relays duplicate system relays are provided; it is understood the A system is GE Multilin and the B system is Schweitzer
- Communications, controls and station reporting to the Sault Ste. Marie control centre are though the GLPT fibre optic system. The relaying signalling on the Mississagi lines, P21 and 22G is carried out through the use of power line carrier. This technology does limit the speed and capacity of the signalling and communications systems

As a general comment, it is noted that considerable spares equipment has been left on the ground at Third Line. In other stations, MacKay for instance, spares have been noticed in steel containers. It is understood that GLPT has no central stores, nor apparently does it keep a record of the stores it has and where they are stored. In the past, this has reportedly caused delays in obtaining critical spare parts, when such spares have been previously used and such use has not been reported.

The following table summarizes the health of equipment found at site:

Table 11-1: Third Line TS Health Evaluation

Component	Health Index Assessment		Weight	Calculated Value
Protection	Good	95	60%	57.0
Grounding	Good	95	10%	9.5
Bus Work	Good	95	10%	9.5
Building	Good	90	10%	9.0
Transformers	Good	80	10%	8.0
		Total	100%	93.0
		Overall Score	**Good**	**93.0**

12. B.12 – Steelton Transmission Station

The Steelton station is the 115 kV station that connects the Sault steel plant to the GLPT system. In addition, it connects the Clergue generation station into the GLPT system through the Clergue 1 and 2 115 kV lines. There are two 115 kV lines (Algoma 2 and 3) that connect the Steelton station to the 115 kV portion of the Third Line station. Two bus connections from the Steelton station connect to the steel plant owned Patrick Street station 115 kV transformers.

Figure 12-1: Steelton TS View 1

Figure 12-2: Steelton TS View 2

The Patrick Street station is within the same fence as Steelton, but these are in the portion of the total complex that is owned and operated by the steel plant. Furthermore, an additional line, Algoma 1, also connects to the Patrick Street station; however, this again is also not part of this discussion. The Steelton station is in effect an outdoor 115 kV station configured in as a ring bus.

Observations were made of the following equipment, site, foundations, spill containment system, fence, structures, bus-bars, building, and protection, monitoring, communications and control equipment.

a) Transformers - there are no HV transformers at Steelton. These are part of the Patrick Street station and thus not part of this discussion.

b) Four of the breakers in the ring appear to consist of ASEA HLR 115 kV minimum oil circuit breakers. These breakers are single pole live tank breakers. They are coupled with Trench 115 kV post type current transformers dated to 1993. This type of circuit breaker probably has not been manufactured for decades. No minimum oil breakers are presently manufactured. It is understood this is chiefly due to their high maintenance requirements. These breakers appear despite their appearance to be in reasonably good condition without leaks or other obvious signs of poor condition. The worn appearance of the breakers is assumed mainly due to the gases and other materials ejected by the steel plant.

Other safety hazards and maintenance issues are due to the configuration and construction in the area of the station yard. The area is currently fenced around due to the vehicle limits of approach. Furthermore, it is very difficult to provide any aerial maintenance due to the style of station construction.

The other two breakers in the Steelton station are apparently ABB live tank SF_6 breakers again associated with Trench current transformers.

c) The 115 kV disconnect switches are centre side break switches. This type of switch can experience problems with alignment and often require significant maintenance effort. Each breaker may be isolated by the switches. There are no line isolations switches, which may require that addition circuit elements must be taken out of service to maintain equipment. The bus work appears to be in reasonable condition. Maintenance space seems to be generally adequate.

d) The structure foundations seem in reasonable shape. The steel structures, particularly switch bases show signs of rusting, which given the proximity to the steel plant is not particularly surprising. The insulating gravel appears to be in reasonable condition, but perhaps should be checked for rust particles in the gravel. Grounding connections appeared properly made. The fence appears to be in acceptable condition. Local drainage again appears to be to be adequate. Station cable appear to be buried or in duct and not in trenches.

The station bus conductor seems to be adequate and the connections properly made.

e) One ac station service is supplied by power PTs installed in the station. A second supply is provided from the local PUC. The dc station service is single with a single battery and charger. The control building appears well laid out, and has adequate room for the necessary equipment and facilities. Incoming cables are terminated on cross connect racks in A and B separated form.

f) The RTU and the communications are installed to GLPT standard practice. The relaying system is installed to normal GLPT accepted standard with A and B protections.

The following table summarizes the health of equipment found at site:

Table 12-1: Steelton TS Health Evaluation

Component	Health Index Assessment		Weight	Calculated Value
Protection	Good	80	60%	48.0
Grounding	Good	80	10%	8.0
Bus Work	Good	70	10%	7.0
Building	Good	90	10%	9.0
Transformers	Good	100		0.0
		Total	90%	72.0
		Overall Score	**Good**	**80.0**

13. B.13 – Clergue Transmission Station

The Clergue transmission station connects generation from the Clergue generating station on the St Mary's River, on the riverfront in Sault Ste. Marie, to the Steelton substation through the Clergue 1 and 2 lines. In addition, facilities exist at an entity named Lake Superior Power to connect natural gas fired generation, in the same area as the Clergue transmission station to the Clergue lines; however, this facility is presently not in use.

Figure 13-1: Clergue TS

Observations were made of the following equipment, site, foundations, spill containment system, fence, structures, bus-bars, building, and protection, monitoring, communications and control equipment.

a) Transformers:

Two identical transformers exist at Clergue. T1 and T2 appear to be configured Dy1, manufactured in 1981 by Maloney, voltage rating 115 kV HV and 11.5 kV LV. A very small leak appears near one transformer which has been repaired. Spill containment along with an Imbiber system exists. The transformer foundations appear adequate as does the grounding connections. There is said to be a restriction in operating the plant in that both transformers must be connected so that the three generators can operate. There are restrictions in generation when only one transformer is available.

b) There are two 115 kV circuit breaker in the station to connect Lake Superior Power to the Clergue 1 and 2 lines. However, as noted previously these are presently not energized and their associated disconnect switches are open.

In addition to the 115 kV breakers, there is a line of outdoor metal-clad 12 kV draw-out switchgear, which is designed on a European style double bus arrangement. This is composed of 14 circuit breakers, with 5 beakers spare, 2 connecting to the 115 kV transformers, three to the generator and 2 to the station service transformers. The switchgear was made by Montel, which hasn't been in operation for many years at this point in time. There are serious concerns with arc flash exposure, and restrictions are in place when operating or maintaining the gear. The switchgear is weathered and appears as having had better days. There is an allowance in the forward capital plan to replace the switchgear. Given the problems with the switchgear, the station protection rating is significantly compromised.

c) There are two manually gang operated 115 kV centre rotating post disconnect switches to connect the transformers to the lines. The lines are switched by LV 12 kV breakers in the metal-clad gear. In addition, there are two manually operated centre rotating post 115 kV disconnect to isolate the Lake Superior Power connections from the transmission lines. The switches appear to be in suitable operating condition; however, like the remainder of the outdoor gear at Clergue they appear weathered.

d) The structure foundations seem in reasonable shape, given their age. The steel structures also appear to be in acceptable condition. The insulating gravel the fence and the grounding connections also appear to be in acceptable condition. Local drainage again to be to be adequate. The fence also appears to be in suitable condition, as do the grounding connections. It is understood that the ground grid has not been tested;

however, with a closely coupled system connecting the generators and transmission switchgear as closely as at Clergue, it is doubtful that high grounding values exist.

All the station and generator transformers have spill containment draining into a single pit, which is suitable connected to an Imbiber unit.

The overhead conductor appeared to be adequate and the connections properly made.

e) The auxiliary dc system is supplied by a single battery and charger. A second battery and charger is expected to be installed next year. Duplicate ac station service exists from the 12 kV switchgear. Terminal cross connect racks have been installed per GLPT standard.

f) The communications, monitoring, protective relaying, measurement and control systems seem consistent with GLPT standards, except there are no B relays for the Lake Superior Power connections. These are slated to be installed in 2016. Some of the relays are electro-mechanical GE IAC models, and thus should be replaced along with the metal-clad switchgear. There is an allowance in the forward capital plan for these changes.

The following table summarizes the health of equipment found at site:

Table 13-1: Clergue TS Health Evaluation

Component	Health Index Assessment		Weight	Calculated Value
Protection	Good	40	60%	24.0
Grounding	Good	80	10%	8.0
Bus Work	Good	50	10%	5.0
Building	Good	100	10%	10.0
Transformers	Good	60	10%	6.0
		Total	100%	53.0
		Overall Score	**Poor**	**53.0**

14. B.14 – Echo River Transmission Station

The Echo River station is a 230 kV transmission station located to the east Sault Ste. Marie installed to serve local distribution requirements in the area. The station is tapped into line P22G by diverting the line into and out of the station.

Observations were made of the following equipment, site, foundations, spill containment system, fence, structures, bus-bars, building, and protection, monitoring, communications and control equipment.

Figure 14-1: Echo River TS

a) Transformers:

One transformer exists at Echo River.

T1 is an autotransformer with a buried delta with a voltage ratio of 230:34.5 kV manufactured by Federal Pioneer. A manufacturing date was not observed.

The transformer was observed to be in good condition, with no oil leaks, no PCB stickers, properly connected on the HV and LV sides, suitably grounded and with foundations in good condition, suitable fitted with spill containment and with Imbiber oil leak prevention.

b) There is one 230 kV breaker, serving to spilt the line in two parts, if a serious fault should occur either east or west of the station. This will allow the transformer to remain connected by isolating the failed portion of the line. The breaker is an ASEA HLR minimum oil breaker, similar to the breakers at Steelton.

There is also a 34.5 kV breaker that feeds Echo River feeder #1 and a circuit switcher that feeds Echo River feeder #2.

The breakers and circuit switcher all appear to be in satisfactory condition.

c) The 230 kV breaker may be isolated on either side by a manually operated centre side break switch. 34.5 kV manually operated centre rotating post switches serve to isolate the 34.5 kV breaker and circuit switcher from the lines. Fused switches isolate the station service supply the metering supply and three voltage transformers. The equipment all appears to be in satisfactory condition.

d) The site works, the foundations, the steel structures, the insulating gravel, the cable trenches and the local drainage all appear to be in good condition. The transformer has spill containment and an operating Imbiber system.

e) The incoming cable is terminated on cross connect racks in A and B configuration, per GLPT standard. The auxiliary dc system is supplied through duplicate batteries and chargers that appear to be in suitable condition. Only a single ac, station service supply exists.

f) The relaying system is duplicated into A and B relay systems per GLPT standard. A SCADA system exists but without the full functionality enabled for the other parts of the GLPT system which have fibre cable communications. Given the fact that no fibre cable exists on the P21G and P22G lines, protective signalling SCADA and voice communications as well as miscellaneous other signals must be carried by power line carrier, which significantly limits the bandwidth available and thus the amount of information that may be transmitted. Power line carrier is suitable with some restrictions for normal operation of the system; however, if the backup control centre is ever moved to the Echo Bay area fibre, some other real time communications system will likely have to be installed to this station.

The following table summarizes the health of equipment found at site:

Table 14-1: Echo River TS Health Evaluation

Component	Health Index Assessment		Weight	Calculated Value
Protection	Good	80	60%	48.0
Grounding	Good	90	10%	9.0
Bus Work	Good	90	10%	9.0
Building	Good	90	10%	9.0
Transformers	Good	80	10%	8.0
		Total	100%	83.0
		Overall Score	**Good**	**83.0**

15. B.15 – Northern Avenue Transmission Station

The Northern Avenue station is a 115 kV transmission station located in Sault Ste. Marie, behind the Great Lakes Power office building and control centre. It serves to provide 34.5 kV as a local feeder and 12 kV distribution power to the GLPT building as well as to the Bonniferro welded beam steel plant. The station is served by the single Northern Avenue 115 kV line from the Third Line Station slightly over a km away.

Observations were made of the following equipment, site, foundations, spill containment system, fence, structures, bus-bars, building, and protection, monitoring, communications and control equipment.

Figure 15-1: Northern Avenue TS

a) Transformers:

There are two transformers at Northern Avenue.

T1 is a Dy1 connected transformer with a voltage ratio of 115 – 34.5 kV, rated 20/26.7 MVA, manufactured by Maloney in 1978. This transformer is very old, but isn't significantly stressed given its load level. It is understood that at one time this transformer contained PCBs but it is understood this is no longer the case. It had been subject to a leak recently, but this has been fixed. Some oil staining from the leak was noted in the rock in the containment pit.

T2 is a Dy1 connected unit with a voltage ratio of 34.5 – 12 kV, rated 5 MVA, manufactured by Northern Transformer in 2003. This unit is a replacement to the previous duplicate unit, which was destroyed by a fault caused by a racoon in the substation.

The transformers were observed to be in good condition, especially given the age of T1. The transformers appear properly connected on the HV and LV sides, suitably grounded and with foundations in good condition, suitable fitted with spill containment and with

Imbiber oil leak prevention.

b) There is no 115 kV breaker in the yard. The circuit is apparently tripped at Third Line station by protection signalling in the case of a fault in the 115 kV portion of the station. Two 34.5 kV breakers exist at Northern Ave. station: one to connect to T2, and the other to serve local distribution.

   There are also three 12 kV breakers, one to serve the GLPT building and the other two to connect a backup generator that is capable of feeder the building in case of a power outage to or in the station. Bonniferro Steel is fed at 12 kV by a circuit switcher.

   The breakers and circuit switcher all appear to be in satisfactory condition.

c) The T1 transformer may be isolated from the line by a 115 kV manually operated side break disconnect switch. The two 34.5 kV breakers may be isolated on either side by a manually operated centre side break switch. In addition, a motor operated 34.5 kV switch is able to isolate the entire station except for the 115-34.5 kV transformer. This feature is probably provided to allow isolation of the station load in the case of re-energizing the 115 kV portion of the station following a high voltage fault and circuit isolation.

d) The site works, the foundations, the steel structures, the insulating gravel, the cable trenches and the local drainage all appear to be in good condition. The transformers have spill containment and operating Imbiber systems.

e) The incoming cable in the control building is terminated on cross connect racks per GLPT standard. The auxiliary dc system is supplied through duplicate batteries and chargers that appear to be in a rather crowded cubicle, which should make maintenance access difficult. The relaying system is duplicated into A and B relay systems per GLPT standard. A suitable SCADA system exists, given the control centre is just a few steps away. Some capital spending is scheduled for the coming years to ensure suitable controls for the backup diesel generator set and additional CT for a suitable B protection for T1.

The following table summarizes the health of equipment found at site:

Table 15-1: Northern Avenue TS Health Evaluation

Component	Health Index Assessment		Weight	Calculated Value
Protection	Good	80	60%	48.0
Grounding	Good	90	10%	9.0
Bus Work	Good	80	10%	8.0
Building	Good	80	10%	8.0
Transformers	Poor	50	10%	5.0
		Total	100%	78.0
		Overall Score	**Fair**	**78.0**

Appendix C
GLPT 10 Year Capital Plan

GLPT 10 Year Capital Plan

Project Name	Category	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total	Discussed with GLPT	Agreed in Principle	Cost Estimate Reviewed?
Wood Structure Replacements	Transmission Lines	2.74	6.00	6.39	1.93	1.61	1.77	6.99	6.93	7.03	7.03	48.41	✓	✓	No
Sault #3 115kV Line Upgrade		-	-	1.02	6.16	5.24	8.55	-	-	-	-	20.97	✓	✓	No
Engineering – Transmission Lines		0.30	0.43	0.50	0.76	0.63	0.57	0.44	0.54	0.47	0.55	5.20	✓	✓	No
Sub-Total Transmission Lines		**3.04**	**6.43**	**7.91**	**8.85**	**7.48**	**10.89**	**7.43**	**7.47**	**7.50**	**7.58**	**74.59**	-	-	-
Watson Transmission Station Upgrade	Transmission Stations	1.35	-	-	-	-	-	-	-	-	-	1.35	✓	✓	No
Magpie Transmission Station CT Replacements		0.62	-	-	-	-	-	-	-	-	-	0.62	✓	✓	No
Northern Ave Supply Reinforcement		0.13	-	-	-	-	-	-	-	-	-	0.13	✓	✓	No
Anjigami Transmission Station (TS) Upgrade		1.01	1.83	-	-	-	-	-	-	-	-	2.85	✓	✓	No
Mackay TS - T1 Transformer Replacement		-	1.38	-	-	-	-	-	-	-	-	1.38	✓	✓	No
Watson TS Protection Upgrades		-	1.38	-	-	-	-	-	-	-	-	1.38	✓	✓	No
New Generation Network		-	0.51	0.52	-	-	-	-	-	-	-	1.03	✓	✓	No
Echo River TS Upgrade		-	-	-	-	-	-	-	-	-	0.38	0.38	✓	✓	No
Third Line TS - T2 Transformer Replacement		-	3.37	2.63	-	-	-	-	1.05	-	-	7.06	✓	✓	No
Critical Spare Parts		-	-	0.52	0.53	0.54	-	-	-	-	-	1.59	✓	✓	No
Transformer Contingency Plan - Replacements & Spares		-	-	-	-	1.23	0.59	2.29	1.93	2.25	0.43	8.71	✓	✓	No
Hollingsworth TS Protection Upgrades		-	-	-	0.25	-	-	-	-	-	-	0.25	✓	✓	No
Mackay TS Relay Replacements		-	-	-	0.19	0.30	-	-	-	-	-	0.49	✓	✓	No
Steelton TS Upgrade		-	-	-	2.22	2.27	-	-	-	-	-	4.49	✓	✓	No
New Station - Replace Goulais & Batchawana		-	-	0.49	1.07	2.18	3.33	-	-	-	-	7.07	✓	✓	No
Security Camera Upgrades at Transmission Stations		-	-	-	-	0.54	-	-	-	-	-	0.54	✓	✓	No
Watson TS Upgrade		-	-	-	-	-	-	-	0.83	1.51	1.17	3.51	✓	✓	No
Clergue TS Upgrade		-	-	-	-	-	-	3.8	1.8	3.64	3.85	13.01	✓	✓	No
Engineering - Transmission Stations		0.69	0.70	0.64	0.42	0.57	0.35	0.43	0.34	0.43	0.36	4.94	✓	✓	No
Transmission Line/Station Emergency Work		0.37	0.17	0.17	0.18	0.18	0.18	0.18	0.18	0.19	0.19	1.98	✓	✓	No
Sub-Total Transmission Stations		**4.17**	**9.34**	**4.97**	**4.86**	**7.80**	**4.46**	**6.68**	**6.09**	**8.01**	**6.37**	**62.75**	-	-	-
Fibre Optic Network Upgrades	Transmission System Equipment	-	0.73	0.30	-	-	-	1.64	1.66	1.69	2.33	8.35	✓	✓	No
SCADA Hardware Refresh		-	-	-	-	-	1.10	-	-	-	-	1.10	✓	✓	No
SCADA Asset Management		-	-	-	0.60	1.83	-	-	-	-	-	2.42	✓	✓	No
Relocation of Backup Control Centre		-	-	-	-	-	-	2.69	2.53	-	-	5.21	✓	✓	No
Radio System Upgrade		-	0.77	0.78	-	-	-	-	-	-	-	1.55	✓	✓	No
General SCADA, Telecom, Communications Upgrades		0.16	0.15	0.16	0.16	0.16	0.17	0.16	0.17	0.17	0.17	1.62	✓	✓	No
Information Technology Refresh - Hardware & Software		0.40	0.26	0.26	0.27	0.27	0.28	0.27	0.28	0.28	0.29	2.84	✓	✓	No
Transportation and Work Equipment		0.25	0.20	0.21	1.49	0.65	0.22	0.22	0.22	0.23	0.23	3.91	✓	✓	No
Sub-Total Transmission System Equipment		**0.81**	**2.10**	**1.70**	**2.51**	**2.91**	**1.77**	**4.98**	**4.85**	**2.36**	**3.01**	**27.01**	-	-	-
Third Line Transmission Station Storage Facility Building	Land & Buildings	-	0.71	-	-	-	-	-	-	-	-	0.71	✓	✓	No
W23K Line ROW Expansion		-	0.15	0.16	-	-	-	-	-	-	-	0.31	✓	✓	No
Land Acquisitions		0.89	-	1.04	1.06	-	-	1.09	1.06	-	-	5.14	✓	✓	No
Minor Fixed Assets		0.32	0.23	0.13	0.13	0.19	0.20	0.20	0.20	0.20	0.21	2.02	✓	✓	No
General Building Upgrades		0.50	0.39	0.33	0.21	0.22	0.22	0.22	0.22	0.23	0.23	2.76	✓	✓	No
Sub-Total Land & Buildings		**1.72**	**1.49**	**1.66**	**1.40**	**0.41**	**0.42**	**1.51**	**1.48**	**0.43**	**0.43**	**10.94**	-	-	-
Total Spend		**$9.7**	**$19.4**	**$16.2**	**$17.6**	**$18.6**	**$17.5**	**$20.6**	**$19.9**	**$18.3**	**$17.4**	**$175.3**	-	-	-

HATCH

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AMPCO Interrogatory # 9

Reference:

B1-1-1 P20

Interrogatory:

When compared to the historical period, Plan period System Service expenditures represent a significantly larger portion of total investments (16% versus 6%). Similarly, the average annual expenditures of $1.8 million over the Plan period are substantially higher than the $0.4 System Service investments over the last five years. This variance is largely due to the fact that Plan period System Service investments target larger station assets such as power transformers and breakers, whereas the historical period investments that HOSSM classified as System Service were related to smaller-scale projects, such as station P&C upgrades, installation of oil spill protection infrastructure, and other modifications to station civil infrastructure.

a) Please explain the investment driver behind targeting larger station assets such as power transformers and breakers compared to smaller scale projects done historically.

Response:

a) Please refer to the response for part (a) of Exhibit I-01-13 (Staff IR # 13).

AMPCO Interrogatory # 10

Reference:

B1-1-1 P21

Interrogatory:

Over the Plan period, HOSSM's capital expenditures in the System Access category amount to $4.8 million, or about 6% of the Plan total. These expenditures are related to a single project to procure a spare transformer for Echo River TS, where only one transformer is currently located. In the event of an outage to the single Echo River TS transformer, HOSSM's only available alternative for supplying the station load entails switching the affected load to a distribution-level emanating from Northern Avenue TS, the available capacity on which is insufficient to reliably support additional load during the peak consumption period. The solution to contingency issues at Echo River TS was among the three "wires only" alternatives identified in the course of the 2014 Regional Planning exercise.

a) How many spare transformers does HOSSM have?

b) Please discuss how Hydro One's existing spare transformers could be utilized in the event of an outage to the single Echo River TS transformer.

Response:

a) HOSSM has two spare power transformers. One of them is a 230-115kV, 250MVA Autotransformer, the other is a 34.5-11kV 27MVA unit.

b) In the case of an emergency, Hydro One's 42MVA, 230/28kV units can be deployed. However, this choice would have a number of operational complications, such as tap changer range limitation, which would not provide sufficient voltage range to comply with the IESO's ORTAC voltage requirements for a LV nominal of 34.5kV. The units would also need to use 34.5kV bushing, as opposed to the 28kV bushings for additional creepage distance. Finally, such deployment could only be temporary until a suitable transformer with the desired transformation ratio is available. Hydro One would have to install the new (appropriately sized) transformer while removing the temporarily installed 42MVA, 230/28V unit, which would lead to significant cost increases. Hydro One does not generally recommend this option as a viable alternative to the proposed replacement of the Echo River TS transformer.

AMPCO Interrogatory # 11

Reference:

B1-1-1 P30

The majority of System Service and System Renewal work underlying the planned capital work program require planning and coordination of outages on the relevant portions of the HOSSM system.

Interrogatory:

a) With respect to HOSSM's planned transmission system outage scheduling process, does HOSSM forecast and track data on the planned number of scheduled outages and length of planned outages compared to actuals?

b) Does HOSSM consider this to be a useful performance metric? Please explain.

Response:

a) HOSSM does not forecast and track data on the planned number of scheduled outages and length of planned outages compared to actuals.

b) Due to the minimal outages annually for HOSSM work activities, HOSSM does not believe there would be much value in such a metric as compared to a larger organization.

AMPCO Interrogatory # 12

Reference:

B1-1-1 P49

HOSSM performs the system operations component of the asset management process through a combination of internal staff and external contractor resources.

Interrogatory:

With respect to work execution, please discuss if HOSSM's proposed utilization of internal staff and external contractor resources differs moving forward compared to historically and why.

Response:

For the earlier years of this plan, HOSSM expects to utilize a similar mix of internal and external resources to perform its work execution. Decisions regarding the scale, nature and timing of adjustments to this approach will take place in the later stages of the asset management function integration activities described in Exhibit B-1-1, section 3.1.1.

AMPCO Interrogatory # 13

Reference:

B1-1-1 P50

Interrogatory:

HOSSM employs a systematic approach for conducting inspections, testing, and executing preventative maintenance tasks (vegetation management, insulator washing, etc.) on a six-year cyclical basis, with some deviations for specific asset classes where more or less frequent maintenance is deemed necessary, or dictated by applicable statutory and regulatory requirements, such as the TSC or the North American Electric Reliability Corporation ("NERC").

a) Please discuss how HOSSM's inspection, testing and preventative maintenance tasks differ from Hydro One's.

b) Please discuss any plans to align HOSSM's inspection, testing and preventative maintenance tasks differ from Hydro One's.

c) Please discuss HOSSM's vegetation management strategy compared to Hydro One's.

Response:

a) Most HOSSM maintenance practice generally aligned with HONI standard maintenance practices pre October 1, 2018. However, individual tasks' details, frequency or procedures might be slightly different from Hydro One's, in which HONI's practice usually requires more depth. To name a few examples :

   a. HOSSM does not test DC trip circuit during Breaker Trip Coil Tests. Proof of continuity was achieved in separated section, where HOSSM testing practice verified up to the primary relay blocking switches on the protection panels and then at the breaker control box to prove breaker tripping capabilities.
   b. HONI battery and charger visual inspection is every 4 months instead of monthly.
   c. Except oil sampling, HONI's transformer maintenance is on a 4 years cycle instead of 6 years . Tap changes maintenance planning uses a combination of time and condition base approach, while HOSSM is strictly on time base.
   d. HONI has a separated task to replace and refurbish a specific model of transformer gas relay every 8 years.

e. HONI breakers maintenance intervals varies based on manufacturer and model type. HOSSM standardized it at 6 years.
f. HONI does not normally dobble test CVTs at a regular basis.
g. HONI's switch maintenance is on an 8-year cycle. HOSSM is 6 year cycle.

b) As of Oct 1st, 2018. HOSSM will adopt HONI's practices in principal. HONI will continue utilizing HOSSM's practice on a case-by-case basis, such as when HONI does not have prior operating experience on a particular type of equipment / technology.

c) Please refer to I-01-18.

AMPCO Interrogatory # 14

Reference:

B1-1-1 P56

Interrogatory:

Preamble:

HOSSM indicates that system needs are driven by the requirement to meet current and forecasted load demand, including provision of power quality data collection capabilities and pilot cost effective mitigation measures to address specific issues faced by customers.

a) Please describe the current power quality data collection capabilities of HOSSM and if and how that will change as a result of operational integration with Hydro One Networks Inc. (HONI)

b) Please discuss the current trend with respect to power quality issues.

c) What is the proportion of total investments driven by power quality for the years 2013 to 2017 and 2018 to 2026?

Response:

a) Please refer to HOSSM's response to Exhibit I-4-26.

b) HOSSM experiences minimal power quality issues on a year-over-year basis.

c) Power quality is not a primary driver of any of the investments in HOSSM's TSP.

AMPCO Interrogatory # 15

Reference:

B1-1-1 P113

Since the current Plan does not propose any capital or OM&A expenditures in excess of the levels already embedded into HOSSM's last approved Revenue Requirement, a benchmarking study confirming the reasonableness of HOSSM's expenditures would not be instructive. However, in preparing this Plan, HOSSM staff referred to the Total Factor Productivity study prepared by Power System Engineering Inc. ("PSE") for Hydro One Transmission. Moreover, as the integration between HOSSM and Hydro One continues, HOSSM plans to utilize a range of studies prepared by the Electric Power Research Institute ("EPRI") on a number of topics concerning asset management best practices. HOSSM will leverage these insights to continually improve the efficiency and cost effectiveness of its operations.

Interrogatory:

a) Please provide a summary of the studies prepared by the ERPI that HOSSM is utilizing or plans to utilize.

Response:

Hydro One Networks engaged EPRI to perform analysis on a number of topics which will serve to inform its asset management practises and those of Hydro One SSM. These studies are summarized below.

Study Name	Summary of Analysis
PTX Analysis of Hydro One's Transformer Fleet	EPRI developed the PTX methodology for assessing the condition of transformers by analyzing dissolved gas data from a utility's historical oil data records. PTX identifies transformers with abnormal test results that are then subject to further consideration as to whether more detailed testing or increased monitoring is warranted. The resulting report from EPRI provides an overview of the PTX methodology and presents the results of its analysis for those of Hydro One's transmission system transformers for which data was provided.
Derivation of Transmission Substation Transformer Hazard Functions	The report arising from this study describes EPRI's efforts to model and develop transformer removal rates from historical replacement records and apply them to forecast the number of transformers expected to require replacement based on past practices.

Derivation of Circuit Breaker Hazard Functions	This report describes EPRI's efforts to model and develop circuit breaker removal rates from historical replacement records and apply them to forecast the number of circuit breakers expected to require replacement based on past practices.
Derivation of Overhead Conductor Hazard Functions	As with the two studies noted immediately above, this study sought to provide valuable insights into fleet mean life expectancy from careful analysis of historical condition assessment and replacement data.
Operating Spare Transformers Requirement Assessment	EPRI has developed analytics to optimize the power transformer spares practice which was compared with Hydro One Markov modeling. The purpose of this study is to verify whether Hydro One's spare transformer requirements are appropriate and consistent with industry best practices.
ESL Survey of Transformers and Circuit Breakers	EPRI designed two surveys to acquire information and insights on industry attitudes and practices related to asset management of transmission circuit breakers and transformers. This survey pools a number of electrical utilities to assess whether Hydro One's current ESLs for transformers and circuit breakers are aligned with industry best practices.
ESL Assessment of Specific Underground Transmission Cables	This study was carried out to determine the suitable ESL based on technical and engineering principles, condition assessment and operating experience.
Review of Utilities' Management of Air Blast Circuit Breakers	EPRI conducted a survey of industry best practices on the effective management of Air Blast Circuit Breakers ("ABCBs"). This survey reviewed industry experience and assessed attitudes, experience and practices related to ABCBs to assist Hydro One in understanding how peer companies are responding to similar challenges and inform its own strategies for addressing this class of assets.
Review of Utilities' Management of Oil Circuit Breakers	EPRI conducted a survey to review industry experience, assess practices related to oil circuit breakers and to understand how peer companies are responding to similar challenges.
Degradation Rates of Steel Tower Coating Systems	This report outlines a new and novel method of screening a transmission line system for structures with a high probability of coating degradation. The objective of this project is to provide accurate information so that condition assessments may be estimated for each circuit based upon the environment. Categorizing the Ontario province by corrosivity level has been completed by measuring corrosion rates of the galvanizing and the structure through field surveys and test coupons. This results in a database that may be queried to find structures with various levels of coating integrity and corrosion damage. The findings will be used to identify and optimize Hydro One's steel structure maintenance requirements and enhance its service life extension approach.

Polymer Insulator Population Assessment	EPRI performed a detailed analysis of a sampling of polymer insulators that were removed from service by Hydro One and provided insights into overall population condition to inform Hydro One's replacement needs.
Phase 2: CP/COB Porcelain Insulator Population Assessment	Approximately 600 insulators were removed from service and subjected to more detailed laboratory testing by EPRI to further assess their long-term condition and assist Hydro One in prioritizing and pacing future replacements of these assets.

AMPCO Interrogatory # 16

Reference:
B1-1-1 P115-188

Interrogatory:
With respect to the Investment Summary Documents, AMPCO notes that HOSSM has not provided cost estimates for any alternatives to the recommended alternative. Please explain.

Response:
Please refer to Exhibit I, Tab 3, Schedule 8 (Energy Probe Interrogatory #8).

AMPCO Interrogatory # 17

Reference:

1-1-1 P120

Interrogatory:

With respect to the SR-01 Wood Structure Replacement Program:

a) Please provide the number of wood structures to be replaced with composite structures under this program in each of the years 2018 to 2026.

b) Please provide the number of wood structures replaced under this program from the years 2013 to 2017 and the corresponding cost.

c) Please discuss if Hydro One has historically replaced wooden structures with composite structures. If not, why not?

Response:

a) The exact number of wood structures to be replaced is not known until engineering is completed in the year prior to construction.

b) 2013 – Algoma #3/Northern Ave. (13 structures)
2014 – Algoma No 1, 2, 3 (27 structures)
2015 – Hogg/No. 1 Gartshore (115kV) – (91 structures)
2016 – Holllingsworth - (34 structures)
2016 – Andrews (2 structures)
2017 – Magpie (3 structures)
2017 – P21G (33 structures)

Please refer to Appendix 2AA for associated costs.

c) Since 2013, Hydro One has annually replaced approximately 25% of the End-Of-life wood structures with composite structures (approximately 200-250 per year).

AMPCO Interrogatory # 18

Reference:
B1-1-1 P120

Interrogatory:
With respect to the SR-02 Sault #3 115 KV Line Reconducting:

a) Please provide the number of wood structures to be replaced with composite structures and the corresponding cost.

b) Please provide the km of conductor to be replaced and the corresponding cost.

Response:
a) The exact number of wood structures to be replaced will not be known until engineering is completed in the year prior to construction (2019).

b) The exact kilometers of conductor to be replaced will not known until engineering is completed in the year prior to construction (2019).

AMPCO Interrogatory # 19

Reference:

B1-1-1 Appendix B P32

Interrogatory:

Please add a column to Figure 5.1 to show METSCO's recommended timeframe for replacement corresponding to each Health Index Score.

Response:

METSCO's approach to Asset Condition Assessments does not include recommending specific timeframes for replacement depending solely on condition results. Doing so would ignore other important factors beyond condition that utilities must consider before undertaking a decision to replace an asset.

AMPCO Interrogatory # 20

Reference:

B1-1-1 Appendix B Page 78 Figure 7.1

Interrogatory:

a) Please provide HOSSM's most recent asset condition finding (prior to the METSCO ACA_ for the following asset class populations: line conductor, wooden structures, power transformers and protection relays.

b) Please provide the total km of line conductor and the km in poor condition

Response:

a) Please see the Hatch report filed as Attachment 1 as part of Exhibit I, Tab 4, Schedule 8 (AMPCO IR #8).

b) Please refer to Table 1-2 in the Exhibit B1-1-1 (p. 9) and p. 67 of METSCO's Report.

AMPCO Interrogatory # 21

Reference:

B2-2-1 P1

Interrogatory:

Preamble:

The evidence states "Throughout the integration process, Hydro One and Hydro One Sault Ste. Marie ("HOSSM") have committed to investigating areas of opportunity to realize savings through productivity, efficiency and synergies. HOSSM will operationally integrate on October 1, 2018 and will financially integrate at a later time. One of the areas targeted for full review was the Capital Investment Plan."

Please identify and explain any obstacles or challenges that HOSSM is facing or expects to face regarding integration and discuss how HOSSM is responding.

Response:

HOSSM is not anticipating any obstacles or challenges from the integration with HONI.

AMPCO Interrogatory # 22

Reference:

B2-1-1 Attachment #2

Interrogatory:

Please provide the in-service additions, forecast compared to actuals, for each of the years 2013 to 2017.

Response:

2013:

Actual	$4,457,100
Budget/Forecast	$4,487,000

2014:

Actual	$4,311,700
Budget/Forecast	$4,344,800

2015:

Actual	$8,743,500
Budget/Forecast	$9,460,000

2016:

Actual	$9,557,900
Budget/Forecast	$9,768,700

2017*:

Actual	$14,488,200
Budget/Forecast	$10,300,000

*Difference primarily due to capitalization of $3.3M of historical costs paid to Batchewana First Nation for land rights associated with the ROW. Once final costs have been determined upon audit completion, HOSSM will seek recover of the difference through the Property Taxes variance accounts.

AMPCO Interrogatory # 23

Reference:

B2-2-1 P13 Table 5

Interrogatory:

a) Please explain the changes in scope and timing related to Wood Structure Replacements.

Response:

a) The wood structure condition assessment (combined with management judgment) dictated a reduction in the scope of wood structures requiring replacement.

AMPCO Interrogatory # 24

Reference:

B2-2-1 P16 Table 6

Interrogatory:

a) Please explain why Transmission Line/Station Emergency Work was removed from the Capital Investment Plan.

b) Please explain why Transformer Contingency Plan – Replacements & Spares was removed from the Capital Investment Plan.

Response:

a) The items were excluded from the plan because HOSSM did not wish to proactively allocate capital dollars to reactive program.

b) Having conducted a thorough transformer ACA and the Investment Planning Process in preparation of this plan, which resulted in the addition of two new transformer replacements into the Plan, HOSSM did not feel the need to retain a broadly defined contingency fund.

AMPCO Interrogatory # 25

Reference:

B2-2-1 P19 Table 7

Interrogatory:

a) Please provide the forecast in-service additions for the years 2018 to 2026.

Response:

In-Service Additions (ISAs) are calculated in order to establish the magnitude of the impact of capital work on rates in a given year. Since the projects comprising HOSSM's TSP will not be added to rate base until the next rebasing, and since it is not requesting any incremental capital funding to finance this plan, HOSSM has not developed the ISAs schedule for them.

AMPCO Interrogatory # 26

Reference:

B2-3-1 P2

Interrogatory:

a) Please provide the number of power quality investigations for each of the years 2013 to 2017 and 2018 to date.

b) Please provide HOSSM's current strategy to track, monitor and respond to power quality issues.

c) Please discuss HOSSM's future plan to track, monitor and respond to power quality issues following operational integration with Hydro One.

Response:

a) There have been no power quality investigations from 2013 to the present.

b) HOSSM does not anticipate any power quality issues moving forward but does plan to leverage HONI resources to track, monitor and respond to power quality issues.

c) In the future, any suspected power quality issues which arise in the HOSSM system, reported via customer complaints will be investigated by asset management special study groups which may involve the installation of power quality monitors to aid in the analysis.

AMPCO Interrogatory # 27

Reference:

C-1-1 P5 Table 1

Interrogatory:

Preamble:

HOSSM provides a list of some of the KPIs that HOSSM has been tracking.

a) Please provide a list of all the KPIs that HOSSM is tracking and provide the historical targets and actuals for each KPI for the years 2013 to 2018.

b) Please identify the KPIs that have been adopted as metrics on the newly proposed corporate scorecard.

Response:

a) Please refer to response to I-01-43 (OEB Staff Interrogatory #43).

b) HOSSM is tracking all of the KPIs presented in the Scorecard proposed in this filing.

AMPCO Interrogatory # 28

Reference:
C-1-1 P9

Interrogatory:
Preamble:

HOSSM tracks actual OM&A as a percent of budget.

a) How does HOSSM measure the execution of planned OM&A work?

b) Please provide any metrics, targets and actuals for the years 2013 to 2017.

Response:
a) HOSSM collects the appropriate maintenance records (inspection forms, contractor reports, analysis data tables, etc.) following completion of commissioned activities. Maintenance records in turn help inform the scope/nature and location of future maintenance activities.

b) HOSSM and its predecessor did not employ any discrete maintenance-related execution metrics for which targets and actuals could be provided for the years requested.

AMPCO Interrogatory # 29

Reference:

C-1-1 P13-14 Figure 5

Interrogatory:

a) Please explain N/A for each metric.

b) Did HOSSM retain any consultants in the development of its proposed scorecard?

c) Please confirm the criterion applied to the System Reliability values (i.e. interruptions included vs. excluded)

d) Please provide a table of reliability figures that excludes the reliability impacts of major weather events and planned outages.

e) Please describe why a target of 4.40% was selected for the Sustainment Capital per Gross Fixed Asset Value.

Response:

a) "N/A" is used in the Scorecard to indicate a measure that was not calculated during the prior period and cannot feasibly be calculated with the information now at hand. For example, the measure "*Overall % Customer Satisfaction in Corporate Survey*" is marked as N/A because this survey was not done in the past but will be done going forward. When used in the Target variables in the Financial Ratio section, this points to measures that cannot be feasibly calculated because HOSSM no longer possesses many of its standalone financial variables (e.g. Current Ratio) since it has been acquired by Hydro One.

b) No. The scorecard was developed by HOSSM with support from Hydro One.

c) Both momentary (less than 1 minute in duration) and sustained interruptions (equal to 1 minute or more in duration) are currently included in the System Reliability metrics. More detail is available starting on Page 23 of Exhibit C, Tab 1, Schedule 1 and in Section 1.2 of Exhibit C, Tab 2, Schedule 1.

d) Planned outages were not a part of the reliability figures. For reliability impacts without weather events please reference I-01-51 (Staff IR #51).

e) In light of the significant volatility of HOSSM's historical results on this measure, management derived the target value by way of a review and approximation of Hydro One Network's past sustainment expenditures relative to the value of its gross plant.

AMPCO Interrogatory # 30

Reference:

C-1-1 P24

HOSSM tracks capital expenditures as a percent of budget.

Interrogatory:

a) How does HOSSM measure the execution of capital work against plan with respect to scope and schedule?

b) Please provide any metrics, targets and actuals for the years 2013 to 2017.

Response:

a) The relatively small number of material capital projects has enabled HOSSM and its predecessor to track the progress and consistency of its projects relative to plans/estimates on an individual basis by the project managers overseeing the projects based on their unique characteristics.

b) HOSSM and its predecessor did not deploy any specific pre-determined metrics related to individual project execution. Accordingly, no targets or actuals for such metrics can be provided.

AMPCO Interrogatory # 31

Reference:

C-1-1 P35

As the integration between HOSSM and Hydro One progresses, HOSSM will adopt Hydro One's scorecard metrics and methodologies.

Interrogatory:

a) Please identify the Hydro One scorecard metrics not included in HOSSM's proposed scorecard (Figure 5).

Response:

The following measures are in HONI's Tx scorecard but not included in HOSSM's proposed scorecard.

- T-SAIFI-M (Ave. # of Momentary interruptions per Delivery Point)
- OM&A Program Accomplishment (composite index)
- Capital Program Accomplishment (composite index)
- O&M Expenditure per Gross Book Value of In-Service Assets (%)
- Line Clearing Cost per kilometer ($/km)
- Brush Control Cost per Hectare ($/Ha)
- End-of-Life Right-Sizing Assessment Expectation

AMPCO Interrogatory # 32

Reference:

C-2-1 P8

Interrogatory:

a) Please provide the total number of power interruptions per year compared to the number of power interruptions experienced by customers for each of the years 2013 to 2017.

b) Please provide the total number of power interruption minutes per year compared to the number of power interruption minutes experienced by customers for each of the years 2013 to 2017.

c) Please provide the total number of customers impacted by a power interruption for each of the years 2013 to 2017.

Response:

a) The delivery point is the point of supply where energy is transferred from the Bulk Electricity System to the Distribution system or retail customer. The total number of power interruptions is the same as the number of interruptions experienced by customers since they are both measured at the delivery point.

	2013	**2014**	**2015**	**2016**	**2017**
Number of Interruptions	22	6	21	7	8

b) Similar to response in a), the total number of interruption minutes is the same as the number of power interruption minutes experienced by customers

	2013	**2014**	**2015**	**2016**	**2017**
Duration of Interruptions (minutes)	4,441	176	1,631	190	587

c) The number of customers based on delivery points impacted in each of the years is as follows:

	2013	**2014**	**2015**	**2016**	**2017**
Number of Delivery Points impacted	8	4	8	5	4

AMPCO Interrogatory # 33

Reference:
D-1-1

Interrogatory:
Please provide the 2019 revenue requirement impact if a stretch factor of 0.15% or 0.30% is used.

Response:
The approved 2018 Revenue Requirement for HOSSM is approximately $40.6M.
The proposed Revenue Cap Index framework detailed in Exhibit D, Tab 1, Schedule 1 yields the formula:
Revenue Adjustment = Revenue Requirement * (Inflation Factor – (Productivity Factor + Stretch factor)).

Using current/proposed variables, the formula can be re-written as:
Revenue Adjustment = $40.6M * (1.2% - (0% + 0%)).
= $0.49M

Using a Stretch Factor of 0.15% the formula would become:
Revenue Adjustment = $40.6M * (1.2% - (0% + 0.15%)).
= $0.43M

Using a Stretch Factor of 0.30% the formula would become:
Revenue Adjustment = $40.6M * (1.2% - (0% + 0.30%)).
= $0.37M

It is worth noting that, given the magnitude of the revenue collected by the Uniform Transmission Rate (UTR) pools and the fact that UTRs are rounded to two decimal places, none of the revenue adjustments shown above are sufficiently material to result in a change to the approved UTRs. As such, the proposed revenue adjustment is not expected to impact customer bills.

School Energy Coalition Interrogatory # 1

Reference:

A

Interrogatory:

Please provide a copy of materials provided to the Hydro One Board of Directors and/or the most senior decision-maker, in which approval was given for this application and the underlying Hydro One SSM TSP.

Response:

The final decision to file this application was made by the management of HOSSM. While they were advised of the pending filing, explicit approval was not solicited from the Hydro One Board of Directors and thus the minutes do not contain any such approval.

The final, specific approval was made via a summary email on July 24th from Andrew Spencer, President of Hydro One Sault Ste Marie.

School Energy Coalition Interrogatory # 2

Reference:

A-3-1, p.3

Interrogatory:

Please explain why Hydro One SSM did not file its application until July 26, 2018 and why a January 1st effective date is appropriate.

Response:

The choice of a filing date is primarily a function of the availability of the evidence including the Metsco ACA and the finalised Investment Plan. HOSSM felt it would be most advantageous to the Board and customers to have those artifacts included in prefiled evidence

January 1st coincides with the annual reset of the Uniform Transmission Rates charged by the IESO. Changes by the IESO on other dates during the year are generally not possible.

School Energy Coalition Interrogatory # 3

Reference:
B1-1-1, p.2

Interrogatory:
Based on the capital forecast contained in the TSP, does the Applicant expect to file for an ICM application during the deferred rebasing period? If so, please provide the years and the expected amounts.

Response:
Please see response in Exhibit I, Tab 4, Schedule 1 (AMPCO Interrogatory #1).

School Energy Coalition Interrogatory # 4

Reference:
B1-1-1, p.2

Interrogatory:
Is Hydro One seeking any relief or approvals related to the filing of its TSP? If so, please provide details

Response:
Specifically, No.

While HOSSM looks forward to the guidance and direction of the Board and customers in implementing its investment plan, the TSP filed as part of this application is not directly in support of any changes or relief related to its Revenue Requirement.

HOSSM has the full and genuine intention of implementing the plan described in this filing but it is not explicitly requesting approval to do so, as is consistent with the Board's approach to decisions made by utilities' management in the years between rebasing applications.

School Energy Coalition Interrogatory # 5

Reference:

B1-1-1, p.2

Interrogatory:

Please provide details regarding what Hydro One means by operational integration. Please explain how Hydro One SSM was operated after the close of the transaction and how it will be operated commencing October 1, 2018. Please provide examples to help illustrate.

Response:

Immediately upon execution of the acquisition of the former GLPT, HOSSM continued to operate under the business as usual scenario. However, to optimize operations and service for customers, Hydro One is in the process of integrating the operations of HOSSM into Hydro One Transmission organisation.

Examples of this integration are numerous but some the key items include:

- IT systems – as described elsewhere, the asset data for HOSSM is being compiled and transferred to the Hydro One SAP systems,
- Operating – the HOSSM network is now being operated from the Ontario Grid Control Centre (OGCC) owned by Hydro One,
- Planning – over time, the investment plan for HOSSM will be fully integrated and become part of the Hydro One investment plan in order to optimize execution,
- Lines and Forestry – the numerous activities associated with maintenance of the asset fleet will be combined within Hydro One to improve resourcing and provide broader capabilities to customers,
- Regulatory – after the end of the deferral period, the submissions related to HOSSM will be included and combined with Hydro One to lower regulatory burden and ultimately costs.

School Energy Coalition Interrogatory # 6

Reference:
B1-1-1, p.52

Interrogatory:
Please explain in detail how the Asset Risk Assessment process used for the purposes of this TSP is different from the process that was the basis of Hydro One's EB-2016-0160 application, and why those changes were made.

Response:
Please refer to response to I-01-19a.

School Energy Coalition Interrogatory # 7

Reference:

B1-1-1, p.52

Interrogatory:

Please provide copies of any third-party reports or analysis undertaken regarding Hydro One's transmission planning processes.

Response:

The Metsco ACA, included as Appendix B to Exhibit B, Tab 1, Schedule 1 (TSP), represents the third-party documentation provided to HOSSM to assist in its planning process by providing detailed asset-related information. No other third-party documents were obtained that relate to the HOSSM planning process.

School Energy Coalition Interrogatory # 8

Reference:

B-1-1

Interrogatory:

What cost savings has Hydro One SSM achieved and/or forecast to achieve during the term of the TSP due to acquisition by Hydro One?

Response:

In Hydro One's MAAD application to purchase GLPT, now Hydro One SSM, the following information was provided on GLPT's OM&A and Capital forecast without being acquired by Hydro One[1].

STATUS QUO FORECAST

$Million	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
OM&A	11.5	11.7	11.9	12.2	12.4	12.7	12.9	13.2	13.4	13.7
Capital	19.4	16.2	17.6	18.6	17.5	20.6	19.9	18.3	17.4	17.8

The TSP, in Table 1-3 provided a 2017 to 2026 capital expenditure summary table, and in Exhibit B, Tab 1, Schedule 1, page 97 provided an average OM&A spend over the 2018-2026 plan period of $11.3 million per year.

CURRENT ACTUALS AND FORECAST POST TRANSACTION

$Million	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
OM&A	9.4	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Capital	15.0	6.5	7.1	10.7	10.7	11.5	9.4	10.8	10.4	8.5

The following table shows the cost savings to date, and those expected to be achieved as a result of Hydro One's acquisition of HOSSM.

SAVINGS AS A RESULT OF THE TRANSACTION

$Million	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
OM&A	2.1	0.4	0.6	0.9	1.1	1.4	1.6	1.9	2.1	2.4
Capital	4.4	9.7	10.5	7.9	6.8	9.1	10.5	7.5	7.0	9.3

[1] EB-2016-0050, Exhibit A, Tab 2, Schedule 1 – Tables 2 and 4

School Energy Coalition Interrogatory # 9

Reference:

B1-1-1

Interrogatory:

Please provide a copy of all key internal guide/documents that outline and describe the planning process set out in the evidence.

Response:

Hydro One Transmission provided significant guidance in terms of improvements and changes to the HOSSM planning process to better align with Hydro One's. The essence of the guidance was to fashion a transitional planning process that replicated that of Hydro One to the extent allowable by the available information, HOSSM's technological capabilities, and the time constraints relative to other integration-related priorities. Core to the plan from Hydro One's perspective was also the objective of balancing the elements of local engineering expertise of HOSSM asset management staff. The documentation relating to Hydro One's planning process was most recently filed with the Board as part of EB-2017-0049 in Section 2.1 of Exhibit B, Tab 1, Schedule 1 (DSP).

Hydro One Transmission is planning a significant rate filing in early 2019. That filing will include a Transmission System Plan and that plan will include certain updates pertaining to the Hydro One Investment Planning process, some of which were incorporated into the process used most recently by HOSSM. The Hydro One exhibits detailing its updated Investment Planning Process are not yet available but can be filed in early 2019 commensurate with the Hydro One transmission filing if that would be helpful to the Board.

School Energy Coalition Interrogatory # 10

Reference:

B1-1-1, p.62-63

Interrogatory:

For all capital projects listed in the TSP, please provide its respective 'scoring' information as well as all applicable 'flags'.

Response:

Please see the attached risk templates in the form of Excel files that include the scoring parameters and flags as appropriate in each individual case. Eighteen Excel files are included in the electronic submission as the contents could not be feasibly printed.

School Energy Coalition Interrogatory # 11

Reference:

B1

Interrogatory:

Will Hydro One undertake a separate annual planning process and capital plan for Hydro One SSM, or will it be integrated into Hydro One's overall transmission planning process? If it is integrated, please explain how Hydro One can reasonably forecast the level of spending it will make for Hydro One SSM up until 2026.

Response:

While the plan included in this filing was developed independently for HOSSM, over the course of time, the intention is to amalgamate the two processes and incorporate the HOSSM planning into that of Hydro One.

HOSSM and Hydro One fully intend to implement the investment plan submitted as part of this application, regardless of how the planning processes are amalgamated. Furthermore, HOSSM maintains its independent leadership team to ensure that its needs and those of its customers continue to be met.

School Energy Coalition Interrogatory # 12

Reference:

B1-1-1, p.113

Interrogatory:

The evidence states "Moreover, as the integration between HOSSM and Hydro One continues, HOSSM plans to utilize a range of studies prepared by the Electric Power Research Institute ("EPRI") on a number of topics concerning asset management best practices. HOSSM will leverage these insights to continually improve the efficiency and cost effectiveness of its operations." Are these EPRI studies Hydro One currently uses in its asset management practices? If not, please explain why Hydro One SSM until it's entirely integrated would use different asset management practices then used by Hydro One.

Response:

Yes – the EPRI studies described in the referenced section are those commissioned and employed by Hydro One in its own asset management practices.

School Energy Coalition Interrogatory # 13

Reference:

B1-1-1, p.115

Interrogatory:

For each investment summary document which included an alternative other than 'do nothing', please provide the cost of the alternative.

Response:

Please refer to Exhibit I, Tab 3, Section 8 (Energy Probe Interrogatory #8).

School Energy Coalition Interrogatory # 14

Reference:

C-1-1, p.13

Interrogatory:

Please revise the proposed scorecard to show annual targets for all metrics from 2019 to 2023.

Response:

Attached below is an updated copy of the HOSSM scorecard including targets for all years from 2019 to 2023.

Please note that the scorecard originally included in prefiled evidence was found to have numerical errors in the 2023 Target column. Those areas are correct in the table included below. HOSSM apologizes for any confusion.

Transmission Scorecard - Hydro One Sault Ste. Marie LP

Performance Outcomes	Performance Categories	Measures		Historical Years							Targets						Trend
				2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	
Customer Focus **Services are provided in a manner that responds to identified customer preferences.**	**Service Quality**	Satisfaction with Outage Planning Procedures (% Satisfied)		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
		Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs		33%	24%	25%	20%	16%	0%	0%	0%	0%	0%	0%	0%	0%	▲
	Customer Satisfaction	Overall % Customer Satisfaction in Corporate Survey		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
Operational Effectiveness **Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.**	**Safety**	Lost Time Injuries or Illnesses		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-
	System Reliability	T-SAIFI (Average # Power Interruptions per Delivery Point)		2.14	2.24	1.16	0.32	1.11	0.37	0.42	0.30	0.20	0.20	0.20	0.20	0.20	▲
		T-SAIDI (Average # Minutes of Power Interruptions per Delivery Point)		296.71	176.76	233.7	9.3	85.8	10.0	30.9	20.00	10.00	10.00	10.00	10.00	10.00	▲
		System Unavailability (%)		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	▲
		Unsupplied Energy (minutes)		N/A	N/A	12.63	2.98	16.42	2.88	9.19	6.15	3.08	3.08	3.08	3.08	3.08	▲
	Asset Management	In-Service Additions (% of OEB approved plan)		120%	111%	99%	99%	92%	98%	108.5%	105%	100%	100%	100%	100%	100%	-
		CapEx as % of Budget		97%	113%	95%	95%	100%	101%	129%	91%	100%	100%	100%	100%	100%	▲
	Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)		10.69%	6.87%	4.38%	4.33%	5.76%	5.81%	6.23%	4.18%	4.83%	5.87%	5.65%	5.66%	4.93%	▲
		Sustainment Capital per Gross Fixed Asset Value (%)		7.55%	4.03%	1.29%	1.25%	2.70%	2.70%	3.69%	1.61%	1.93%	2.90%	2.77%	2.84%	2.27%	▲
		OM&A per Gross Fixed Asset Value (%)		3.15%	2.84%	3.09%	3.08%	3.06%	3.10%	2.54%	2.57%	2.90%	2.97%	2.89%	2.81%	2.61%	-
Public Policy Responsiveness **Transmitters deliver on obligations mandated by government (e.g. in legislation**	**Connection of Renewable Generation**	% on time completion of renewables connection impact assessments		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	-
	Regional Infrastructure	Regional Infrastructure Planning progress - % Deliverables met		N/A	N/A	N/A	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	-
Financial Performance **Financial viability is maintained; and savings from operational effectiveness are sustainable.**	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.21	1.34	1.69	1.67	1.62	1.33	1.38	N/A	N/A	N/A	N/A	N/A	N/A	-
		Leverage: Total Debt (includes short-term & long-term debt) to Equity Ratio		1.13	1.10	1.09	1.12	1.04	1.03	0.97	N/A	N/A	N/A	N/A	N/A	N/A	-
		Profitability: Regulatory Return on	Deemed (included in rates)	9.66%	9.42%	8.93%	9.36%	9.30%	9.19%	9.19%	N/A	N/A	N/A	N/A	N/A	N/A	-
			Achieved	10.94%	11.86%	11.51%	11.42%	9.66%	9.93%	9.21%	N/A	N/A	N/A	N/A	N/A	N/A	-

School Energy Coalition Interrogatory # 15

Reference:

C-1-1, p.27

Interrogatory:

For the purposes of the proposed metric 'Sustainment Capital as a percentage of Gross Fixed Asset Value', please explain how Hydro One defines Sustainment Capital and please provide a direct linkage to the proposed capital expenditures by OEB categories (System Renewal, etc.).

Response:

Sustainment capital refers to those planned capital expenditures that are required to refurbish, maintain or restore assets to their expected or desired functional condition.

Sustainment capital generally aligns with the "System Renewal" category of spending as detailed in the plan.

School Energy Coalition Interrogatory # 16

Reference:

D-1-1, p.1

Interrogatory:

Please confirm that the proposal of the expert, including the capital factor, will result in Hydro One rates that will NOT "increase at a rate which is less than inflation".

Response:

Please see Hydro One SSM's response to Exhibit I, Tab 1, Schedule 55 (OEB Staff Interrogatory #55) regarding the quoted statement. Hydro One SSM notes it is not proposing a capital factor for approval in this application.

School Energy Coalition Interrogatory # 17

Reference:

D-1-1, p. 1

Interrogatory:

Please explain, with numerical examples, how the proposal of the expert results in a "sharing of benefits" with customers.

Response:

PSE found the industry TFP trend for the 2004-2016 time period is -1.71%. However, PSE's recommendation is a productivity factor of 0.0%. This is an implicit stretch factor of 1.71%, which is extraordinarily large. The implicit stretch factor implies that customers benefit, because the escalation formula escalates revenue 1.71% slower per year than what the empirical TFP evidence suggests. Therefore the recommendation of PSE implies a large "sharing of benefits" with customers.

Further, while the benchmarking evaluation was for Hydro One Networks and not for Hydro One SSM, the benchmark costs findings (costs were 31% below benchmark values during the CIR period) indicates another large benefit to customers. These findings imply that the transmission portion of bills are based on a revenue requirement that is estimated to be 31% below what a transmission utility's revenue requirement would be given identical variable values. This is, again, a large "sharing of benefits" with customers.

School Energy Coalition Interrogatory # 19

Reference:

D-1-1, Attach 1, p.5

Interrogatory:

Please provide details on how the expert adjusted, if at all, for the impact of major changes in accounting rules over the period 2004 to 2016. If no adjustments were made, please explain why, and provide numerical examples to show why the results would be similar if adjustments had been made.

Response:

No adjustments were made. The U.S. utilities did not have a major change in accounting rules that PSE is aware of. It is PSE's understanding that Hydro One Networks moved from Canadian GAAP to U.S. GAAP accounting during the sample period, but that this decision had no or minimal financial impact.

School Energy Coalition Interrogatory # 20

Reference:

D-1-1, Attach 1, p.8

Interrogatory:

Please provide a table showing, for each year, the breakdown of capital and OM&A costs for both Hydro One Actual and Hydro One Benchmark. If any of the Hydro One Actual are different from the historical costs of Hydro One as reported to the Board, please reconcile the differences.

Response:

PSE cannot provide a breakdown for the capital and OM&A benchmarks because these cannot be calculated from the total cost benchmarking model that we estimated. PSE estimated a total cost model that is the sum of the capital costs and OM&A expenses. We did not estimate a separate OM&A or capital cost model to enable disaggregated benchmarks. The table below provides Hydro One Network's actual capital costs and actual OM&A expenses that were used in the benchmark study. The capital costs cannot be reconciled to what was reported to the Board, because of the benchmarking normalization procedures on depreciation rates and rate of return that enable each utility in the sample to be treated identically when calculating capital costs.

In other words, PSE does not insert the capital portion of the revenue requirement into the evaluation, but instead makes assumptions to create a consistent capital cost definition among the entire sample. If we did not do this, the different depreciation schedules and rates of return would impact each utility's measured capital costs and create unnecessary differences between utilities that are not directly due to capital expenditures, but rather a result of specific regulatory decisions.

The historical OM&A numbers come directly from filings to the OEB. The definition is the total transmission OM&A minus property taxes. The 2004 and 2005 values can be found in EB-2005-0501, Exhibit C1, Tab 2, Schedule 1, Page 2 of 4. The 2006 and 2007 values can be found in EB-2008-0272, Exhibit C1, Tab 2, Schedule 1, Page 2 of 5. The 2008 and 2009 values can be found in EB-2010-0002, Exhibit C1, Tab 2, Schedule 1, Page 2 of 6. The 2010 and 2011 values can be found in EB-2012-0031, Exhibit C1, Tab 3, Schedule 1, Page 2 of 4. The 2012, 2013, 2014, and 2015 values can be found in EB-2016-0160, Exhibit C1, Tab 2, Schedule 1, Page 2 of 7. The 2016 and 2017 values are actual values that will be provided during Hydro One's next rebasing application. The 2018 and 2019 were forecasts provided to PSE by Hydro One at the time of the research. The projections beyond 2019 used the escalation formula of inflation minus X, with X equal to 0.0%. Inflation projections used the 14% and 86% recommended weights on labour and non-labour, respectively.

	Capital Costs	OM&A Costs	Total Costs
2004	1,031,543	290,304	1,321,847
2005	1,103,563	271,302	1,374,866
2006	1,149,910	306,299	1,456,209
2007	1,239,387	350,406	1,589,793
2008	1,363,183	309,003	1,672,186
2009	1,434,339	351,909	1,786,248
2010	1,453,744	354,305	1,808,049
2011	1,640,320	347,007	1,987,327
2012	1,762,412	353,100	2,115,512
2013	1,732,797	367,207	2,100,004
2014	1,788,054	335,399	2,123,453
2015	1,852,935	377,689	2,230,624
2016	1,937,179	346,799	2,283,979
2017	2,004,655	334,308	2,338,963
2018	2,100,403	330,394	2,430,797
2019	2,163,685	347,410	2,511,095
2020	2,246,392	354,291	2,600,683
2021	2,333,967	361,332	2,695,299
2022	2,429,198	368,482	2,797,680

School Energy Coalition Interrogatory # 21

Reference:

D-1-1, Attach 1, p.12

Interrogatory:

Please explain why, if the past data used for TFP and inflation and benchmarking includes a growth factor, it is not appropriate to continue to use a growth factor in the CIR formula going forward?

Response:

If by "growth factor" the question is referring to an output index in the TFP and output variables in the benchmarking, these are separate from the "growth factor" that PSE was discussing on p. 12 of the PSE report. On p. 12 and into Chapter 2 of the PSE report, we explained and mathematically showed why a growth factor should be added to the revenue escalation formula to allow revenues to additionally increase by the growth factor. However, as we stated on p. 12, Hydro One Networks projected near zero growth for the CIR period, making the inclusion of the growth factor meaningless. Further, the capital factor will already partially account for system growth, if it existed, and therefore adding in system growth would be, at least, partially redundant.

School Energy Coalition Interrogatory # 22

Reference:
D-1-1, Attach 1, p.14

Interrogatory:
Please confirm that the expert has not reviewed the capital factor for:

a. Appropriateness of having a capital factor;
b. Amounts of capital spending forecast;
c. Methodology; or
d. Calculation of forecast capital factors each year.

Response:
It is confirmed that we have not reviewed the amount, appropriateness, methodology, or calculation of the capital factor. What we have reviewed is the impact of the proposed spending amounts on Hydro One's TFP trend and projected total costs. As PSE stated on p. 12 of the PSE report:

> PSE is not making any recommendations regarding the magnitude of the capital factor. We do, however, insert the proposed capital spending amounts into the TFP and total cost benchmarking studies, so the Board and stakeholders can ascertain the projected TFP trends and total cost benchmarking scores that result from the proposed level of capital spending. As is seen in those evaluations, the proposed capital spending by Hydro One compares favorably to the industry. The TFP trend during the CIR period continues to exceed the historic TFP trend of the industry, and Hydro One's projected total costs are 31.8% below its benchmark values throughout the CIR period.

School Energy Coalition Interrogatory # 23

Reference:
D-1-1, Attach 1, p.22

Interrogatory:
Please explain how the benchmarking analysis adjusts for:

a. Capital contributions from customers and/or distributors;
b. Expenditures by distributors on transmission assets owned by them;
c. Government and other external funding of transmission investments.

Response:
The U.S. utilities report in-service additions that go into their rate base. The U.S. definition of "in-service additions" does not include the items discussed above. Hydro One also provided in-service additions that aligns with the U.S. definition (e.g. no contributions or investments are included from outside sources). No adjustment is necessary given the consistency between the U.S. definition of "in-service definition" and the Hydro One definition.

School Energy Coalition Interrogatory # 24

Reference:

D-1-1, Attach 1, p.22

Interrogatory:

Please explain what investigations or other activities the expert undertook to reach the conclusion that "pensions and benefit expenses… could slightly inflate U.S. costs relative to Hydro One."

Response:

No investigations or other activities were undertaken. Our statement was more of a speculation than a conclusion. We said this "could" slightly inflate costs due to Canada publicly financing health care at a higher rate than the U.S., thus putting more emphasis in the U.S. on employer-funded health care benefits. Pensions and benefit expenses are excluded because of these differences.

School Energy Coalition Interrogatory # 25

Reference:

D-1-1, Attach 1, p.22

Interrogatory:

Please explain how the expert ensured that transmission costs are not skewed by allocations between transmission businesses and non-transmission businesses in the U.S. sample group or in Hydro One. In particular, and without limiting the generality of the foregoing, please explain what investigations the expert undertook to ensure that the poor productivity results of Hydro One Distribution and the apparently good productivity results of Hydro One Transmission, which are similar but in opposite directions, are not the result of the ways costs are allocated between transmission and distribution at Hydro One.

Response:

There is no practical way to ensure there are no differences between the U.S. sample group and Hydro One in the allocation of costs to transmission and non-transmission businesses. We based the analysis on the classification reported by each utility. However, in examining the minimum line voltages classified as transmission, Hydro One is not an outlier in this respect. Hydro One reports a minimum line voltage of 69 kV, with most of their transmission lines being 115 kV or higher. This cut-off is not an outlier, as there are a number of utilities above and below this transmission cut-off line.

School Energy Coalition Interrogatory # 26

Reference:

D-1-1, Attach 1, p.24, 36

Interrogatory:

Please confirm that maximum peak demand is flat for Hydro One from 2005 to date, and increases annually from 2005 to date for the U.S. sample group, with the result that the sample group uses annual peak demand, while Hydro One uses historical maximum peak demand. Please provide the annual peak demand for Hydro One if the annual figure is used instead of the historical maximum. Please provide a justification for assuming that, even if peak demand declines, costs will not decline over time.

Response:

Both the sample of U.S. utilities and Hydro One use the same definition of maximum peak demand. The maximum demand of the U.S. sample group increases during the sample period, because the individual utilities are summed, and some of the individual utilities may have an increasing maximum demand during each year, which will cause the maximum peak demand value of the U.S. sample group to increase from year to year. The assumption is that transmission utilities will need to build capacity to meet the highest peak demands on their system, not just for one year but for a number of years.

School Energy Coalition Interrogatory # 27

Reference:

D-1-1, Attach 1, p.25

Interrogatory:

Please provide the calculations for percentage of transmission plant in total electric plant for Hydro One. Please advise whether distribution plant is included in that calculation

Response:

The equation for the Hydro One calculation is:

$$\%\ \text{Tx} = \frac{\text{End of Year Tx Plant in Service}}{\text{End of Year Tx Plant in Service} + \text{End of Year Dx Plant in Service}}$$

Please see the working papers in the Excel file “HONData.xls”, worksheet “HON Data”, column K for the specific numbers in the calculation for Hydro One. Yes, distribution plant is included in the calculation.

School Energy Coalition Interrogatory # 28

Reference:

D-1-1, Attach 1, p.25

Interrogatory:

Please describe in detail the relationship between KM of lines and average voltage of transmission lines, and how they interact within the expert's model. What analysis, if any, did the expert carry out to identify the mathematical relationship (e.g. linear, step, geometric, etc.) between the two factors?

Response:

The average voltage of transmission lines is calculated by taking the sum product of line voltages and KM of each line length at that voltage, divided by the total KM of lines. The equation for the variable and how it relates to KM of lines is provided below.

$$\text{Avg. Voltage} = \frac{\sum_i \text{Voltage}_i * \text{KM of Line}_i}{\text{Total KM of lines}}$$

The average voltage variable is treated like the other explanatory variables inserted into the translog cost function. We took the natural log of the variable and included it in the model. We did not examine any other mathematical relationships between the two factors.

School Energy Coalition Interrogatory # 29

Reference:

D-1-1, Attach 1, p.26

Interrogatory:

Please provide references showing the history of the loading variable (as proposed by this expert) in other benchmarking studies in North America, as well as any relevant academic references.

Response:

To PSE's knowledge, this is the first time a loading variable or something similar has been inserted into a transmission benchmarking study. This variable is innovative and reflects the sophistication of Ontario benchmarking initiatives relative to other jurisdictions. The variable reflects the reality that transmission pole construction loading requirements vary due to the climatic conditions faced by each utility within their specific service territory. This variable aligns with engineering assumptions that higher loading requirements and more difficult climatic conditions tend to increase costs. The variable also meets the statistical requirements of being correctly signed and highly statistically significant.

School Energy Coalition Interrogatory # 30

Reference:
D-1-1, Attach 1, p.27

Interrogatory:
Please provide a complete table showing the forecast revenue requirement increases for Hydro One for the period 2018-2022 using the expert's model.

Response:
The model does not forecast revenue requirement increases. For the total cost benchmark increases, Table 11 of the PSE report provides the anticipated increases in benchmark costs projected by the total cost econometric model.

School Energy Coalition Interrogatory # 31

Reference:

D-1-1, Attach 1, p.27

Interrogatory:

For each of the business condition variables, please provide in a table the value for Hydro One, and the average and median values for the sample group. If Hydro One is in the top or bottom decile of the sample group, please so indicate.

Response:

Please see the table below.

2004-2016 Sample Variable Values

Variable	Sample Average	Sample Median	Hydro One Networks Average	Is Hydro One in Top or Bottom Decile?
KM of Line	5,721	3,448	20,743	Yes, in Top Decile when ranked largest to smallest
Maximum Peak Demand	9,403	6,045	26,818	Yes, in Top Decile when ranked largest to smallest
Percent of Tx plant in total electric plant	17.9%	16.4%	61.7%	Yes, in Top Decile when ranked largest to smallest
Average Capacity (MVa) per Substation	322	257	421	No
Number of Tx substations per KM of line	0.015	0.012	0.012	No
Average Voltage of Lines	179.1	177.3	221.9	No
Construction Standards	0.676	0.662	0.867	Yes, in Top Decile when ranked largest to smallest
Percent of Tx Lines Underground	3.02%	0.20%	1.34%	No

School Energy Coalition Interrogatory # 32

Reference:

D-1-1, Attach 1, p.28

Interrogatory:

Please provide details of any analysis the expert has done of the impact of using a different benchmark year (1989) for the U.S. utilities vs Hydro One (2002). If there is any numerical analysis of the impact, either in the possession of the expert, or in the possession of Hydro One, please provide.

Response:

The capital benchmark year is the first year that we begin building the capital stock series from where we base the capital benchmark year on the net plant value deflated by a weighted asset price index and then in all subsequent years build off that capital benchmark year using plant additions deflated by an asset price index. This should not be confused with the benchmarking results which are different than the referenced capital benchmark year.

If the same 2002 capital benchmark year is used for the U.S. sample, the industry TFP trend becomes negative 2.32% for the 2004 to 2016 time period. The 2014-2016 average Hydro One total cost benchmarking score becomes -20.5%. The 2019-2022 CIR period average Hydro One total cost benchmarking score becomes -29.2%.

The rationale for using the 1989 benchmark year for the U.S. utilities is that one of the main research objectives was to calculate the industry TFP trend. We used the earliest benchmark year readily available to produce the industry TFP trend. To remain consistent with the TFP research, we used the same 1989 benchmark year for the U.S. sample in our total cost benchmarking research. There is a trade-off between having the increased accuracy of an earlier capital benchmark year and having the same capital benchmark year for the studied utility and the sample. In the Hydro One Distribution case, PSE used the same benchmark year for the entire sample (2002). In that proceeding, we did not calculate the U.S. distribution industry TFP trend, as that was not an objective of the research. Using either capital benchmark year produces similar results for both the TFP and total cost benchmarking studies and would result in different parameter recommendations.

School Energy Coalition Interrogatory # 33

Reference:
D-1-1, Attach 1, p.29

Interrogatory:
Please provide details of any adjustments made by the expert in cost comparability arising out of different reliability expectations between regulators in Ontario and in U.S. jurisdictions.

Response:
No adjustments were made to account for different reliability expectations.

School Energy Coalition Interrogatory # 34

Reference:

D-1-1, Attach 1, p.29

Interrogatory:

Please explain why Handy-Whitman is considered applicable to Ontario.

Response:

The Handy-Whitman indexes are widely used in the electric industry, including Ontario. PSE used them in our Hydro One Distribution research and benchmarking research for Toronto Hydro. Pacific Economics Group (PEG) used them in their Ontario Power Generation (OPG) productivity research. One of the key advantages over other possible Canadian-specific asset price inflation indexes are that Handy-Whitman produces indexes that are specific to the electric transmission industry. There are no similar Ontario or Canadian alternatives that estimate electric transmission asset price inflation.

The use of the Handy-Whitman index became an issue during the Hydro One Distribution CIR application. PEG proposed using an implicit asset price deflator that encompassed the entire utility industry. PSE believes an index more specific to the industry being studied (electric transmission in this case) is more applicable than an index that includes other large utility functions (e.g. power generation, natural gas distribution, and even water and sewer utilities). The Handy-Whitman index does have the disadvantage of being a U.S. asset price inflation index, but given the interconnectedness of the two economies, we'd expect transmission asset inflation to be similar between the two countries.

School Energy Coalition Interrogatory # 35

Reference:

D-1-1, Attach 1, p.34

Interrogatory:

Please confirm that density differences are intended to be captured in the KM of transmission lines output variable. Please provide any data the expert has on the relationship between that variable and density.

Response:

The KM of transmission lines output variable measures the quantity of KM of line length. The more KM of lines, the higher the expected costs would be, due to the higher capital infrastructure and maintenance costs. Line length is not necessarily correlated with service area density. It may be correlated, but not necessarily so. PSE did not include a service territory area variable or calculate a density variable in our research.

School Energy Coalition Interrogatory # 36

Reference:
D-1-1, Attach 1, p.39

Interrogatory:
Please confirm the expert's opinion that, while Hydro One's costs have increased at greater than the rate of inflation, its productivity has improved on a benchmarking basis because the costs of U.S. utilities have increased by a rate that is even higher relative to inflation.

Response:
Confirmed. Hydro One's cost performance has improved on a benchmark basis over time because they have tended to hold cost increases below the rate that would be expected from the total cost model which is estimated from the U.S. sample and incorporates their historical cost levels into the parameter estimates.

School Energy Coalition Interrogatory # 37

Reference:
D-1-1, Attach 1, p.49

Interrogatory:
Please provide a table showing the labour percentage of each member of the sample (without identifying the utilities), and place Hydro One on that sample table to show its actual percentage as well.

Response:
The table below provides the labour percentage by utility for the 56 U.S. utilities in the sample. Hydro One did not provide expenses broken out by labour to PSE, and we did not use Hydro One in the calculations. Therefore, we cannot place Hydro One on the sample table.

Utility	% Labour
1	9.7%
2	11.6%
3	13.6%
4	9.8%
5	11.0%
6	19.9%
7	11.5%
8	16.6%
9	22.8%
10	21.3%
11	11.3%
12	12.1%
13	7.5%
14	14.6%
15	17.2%
16	11.8%
17	15.1%
18	15.3%
19	16.1%
20	15.6%
21	10.6%
22	16.4%
23	11.0%
24	19.0%
25	15.6%
26	12.7%
27	11.6%
28	14.0%
29	10.8%
30	17.4%
31	12.5%
32	14.9%
33	9.5%
34	11.8%
35	13.9%
36	17.9%
37	13.5%
38	21.0%
39	13.0%
40	8.0%
41	9.6%
42	21.3%
43	13.6%
44	24.9%
45	7.4%
46	11.5%
47	14.1%
48	11.0%
49	13.6%
50	14.4%
51	17.8%
52	9.0%
53	13.1%
54	13.1%
55	9.9%
56	12.1%
Average	**13.9%**

School Energy Coalition Interrogatory # 38

Reference:

D-1-1, Attach 1, p.51

Interrogatory:

Please explain the extent, if any, to which inclusion of a capital factor constitutes double-counting in light of the fact that inflation and productivity calculations already include capital.

Response:

The inclusion of the capital factor does not lead to double-counting. The capital factor does not enter into the productivity trends or inflation factor calculations, as these are externally-derived from the industry and not specific to Hydro One or its capital factor proposal. The capital factor does not impact, therefore, the inflation factor or productivity factor recommendations. It will have an impact on the total cost benchmarking results during the CIR period, as the requested capital expenditures are included in the projected costs of Hydro One and then benchmarked. A higher capital factor will tend to worsen the total cost benchmarking results and thus impact the stretch factor.

School Energy Coalition Interrogatory # 39

Reference:

D-1-1, Attach 1, p.56

Interrogatory:

Please provide a table showing the overall loading value for each utility in the sample, and place Hydro One on that sample table to show its actual percentage as well.

Response:

The table below provides the loading variable value for each utility including Hydro One in a ranked order from highest to lowest. The Hydro One observation is highlighted in green.

Rank	Loading Variable
1	1.0348
2	1.0143
3	**0.8668**
4	0.8597
5	0.8152
6	0.7973
7	0.7528
8	0.7528
9	0.7528
10	0.7528
11	0.7373
12	0.7354
13	0.7303
14	0.7226
15	0.7176
16	0.7110
17	0.7027
18	0.6953
19	0.6829
20	0.6637
21	0.6632
22	0.6632
23	0.6624
24	0.6624
25	0.6623
26	0.6621
27	0.6621
28	0.6621
29	0.6621
30	0.6621
31	0.6621
32	0.6621
33	0.6621
34	0.6621
35	0.6621
36	0.6621
37	0.6621
38	0.6621
39	0.6621
40	0.6621
41	0.6619
42	0.6601
43	0.6581
44	0.6559
45	0.6547
46	0.6321
47	0.6084
48	0.6017
49	0.5822
50	0.5750
51	0.5322
52	0.5021
53	0.5000
54	0.4979
55	0.4971
56	0.4971
57	0.4971

School Energy Coalition Interrogatory # 40

Reference:
E-1-2, p.2

Interrogatory:
Please provide evidence to demonstrate the reasonableness of incurring $99,338 to negotiate a mutual release.

Response:
The amount of $99,338 is the remaining balance of the portion of account 1508 related to the Comstock Claim settlement approved as part of EB-2014-0238. This is the remaining balance and does not represent the cost incurred to negotiate a mutual release.

Vulnerable Energy Consumers Coalition Interrogatory # 1

Reference:

Exhibit B1/Tab1/Schedule 1/pgs. 18, 96

Interrogatory:

a) At the above reference with respect to Table 2-2 (Plan Period System Renewal) HOSSM states *"However, since the scope of work within a number of projects calls for replacement or modification of other line and station equipment, the breakdown should not be interpreted as a forecast of capital additions by asset class."*

A similar proviso is made with respect to Table 4-1 at page 96.

Please clarify what distinction is being made with respect to the system renewal investment forecasts shown in Table 2-2/4-1. Specifically are the total forecast amounts indicative of system renewal investments forecast for the years 2018 – 2026? If yes, are there differences what type of adjustments is contemplated if one were reviewing the same totals if done by asset class.

Response:

a) HOSSM added the referenced provisos to clarify that the showcased breakdown of the total planned capital expenditures was made on the basis of the largest piece of equipment undergoing intervention in the scope of each project. HOSSM confirms that the forecasted project totals if done strictly by asset class (rather than a higher-level approach used in the referenced tables) would equal the total planned amounts referenced throughout the application.

HOSSM also notes that the Table 4-1 provided in the application appears to contain several administrative errors that result in different annual totals than those noted elsewhere in the application. HOSSM thanks VECC for the opportunity to rectify this administrative oversight and presents the following table where the errors have been corrected:

Table 4-1 (Previous Errors Corrected)

Asset Type	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**Total**	**Percentage**
Lines	$5.1	$3.0	$7.0	$7.0	$4.0	$4.0	$4.0	$4.0	$4.0	$42.1	49%
Power Transformers	$0.0	$1.0	$2.4	$3.4	$7.0	$4.1	$4.3	$0.0	$0.0	$22.1	26%
Breakers and Switches	$0.0	$0.0	$1.0	$0.0	$0.2	$1.0	$2.2	$5.0	$4.1	$13.4	16%
P&C	$1.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$1.0	$0.0	$2.1	2%
Other Station Equipment	$0.2	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$2.2	3%
Land Acquisitions	$0.0	$2.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$2.0	2%
Storage Facilities	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.8	0.9%
Other General Plant	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$1.1	1%
Total	**$6.5**	**$7.1**	**$10.7**	**$10.7**	**$11.5**	**$9.4**	**$10.8**	**$10.4**	**$8.5**	**$85.7**	**100%**

Vulnerable Energy Consumers Coalition Interrogatory # 2

Reference:

Exhibit B1/Tab1/Schedule 1, pg.111/ Exhibit B2, Tab 1, Schedule 1, pg.1

Interrogatory

Preamble:

From B2/T1/S1/pg.1 *"The expenditures in 2013 and 2014 were lower than in subsequent years due to a strategic decision made by the parent company at that time. It was a planned cut back of capital spending, and not based on issues with operations."*

a) In Hydro One's (HOSSM) assessment, did the Utility suffered from under investment in any of the assets categories/classes under the previous ownership? If yes, please describe the general areas and costs for those assets found to be in need of extensive and immediate remedial investment.

b) If prior ownership underinvestment was recognized please explain how this is being addressed as part of the DSP.

Response:

a) HOSSM is not in a position to provide qualitative assessments of the asset management decisions made by its predecessor. For a third-party assessment of the current state of the system, please refer to the following passage found in section 7.1.1 of the METSCO Asset Condition Assessment (ACA) report:

> "*On balance, our findings indicate that HOSSM has taken prudent decisions in the past to sustain the health and performance of its system for the benefit of its customers and shareholders. As with every system, however, there are areas that require HOSSM's attention in the coming years where asset populations contain material portions of equipment in or approaching Poor condition or worse*."

With respect to those areas most in need of repair, the investment plan, as informed by the Metsco ACA, is testament to what the company intends to focus on over the planning period.

b) See the answer to part a).

Vulnerable Energy Consumers Coalition Interrogatory # 3

Reference:

Exhibit B-1-1-1/ Appendix B/ METSCO Asset Condition Assessment/pgs. 13, 29

Interrogatory

Preamble:

At page 29 of the Study it states: *METSCO used a five point grading system (Very Good/Good/Fair/Poor/Very Poor), which represents an industry best practice for capturing incremental degradation over shorter periods of time, and as such, enables asset managers to derive more granular insights as to the relative health of utility plant. While METSCO discussed the relative benefits of the two approaches with HOSSM staff, the visual inspection results underlying our calculated Health Indices are based on HOSSM's inspection data.*

a) Please explain how HOSSM's 3 point data collection is converted to a five point analysis by METSCO as shown by Figure 2.2.

Response:

The scale was converted as follows:

- HOSSM "Good" was equated to METSCO "Very Good",
- HOSSM "Fair" was equated to a METSCO "Fair", and
- HOSSM "Poor" was equated to a METSCO "Very Poor".

METSCO devised this conversion scale following its two site visits to the HOSSM service area, where it had an opportunity to compare HOSSM's condition ratings recorded in the inspection to the actual state of the plant, and METSCO's own assessment using their five-point scale. This allowed the HOSSM inspection data to be integrated into the METSCO analysis framework. Notably, the conversion scale is only relevant to the visual assessments of equipment, which, in most cases were supplanted with objective quantitative data (dissolved gas analysis, infrared scan readings, etc) to derive the final numerical asset health index scores, as described in section 5.1 of the METSCO report.

Vulnerable Energy Consumers Coalition Interrogatory # 4

Reference:

Exhibit B2, Tab 2, Schedule 1, pgs.11, 16-17

Interrogatory:

Table 4 - Projects Removed from the Plan Due to Investment Prioritization (in C$ in thousands)

Investment	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
New Generation Network	-	(510.0)	(520.2)	-	-	-	-	-	-	-	**(1,030.2)**
Mackay Transmission Station Relay Replacements	-	-	-	(193.9)	(298.8)	-	-	-	-	-	**(492.7)**
Security Camera Upgrades at Transmission Stations	-	-	-	-	(541.2)	-	-	-	-	-	**(541.2)**
W23K Line ROW Expansion	-	(153.0)	(156.1)	-	-	-	-	-	-	-	**(309.1)**
Total	**-**	**(663.0)**	**(676.3)**	**(193.9)**	**(840.0)**	**-**	**-**	**-**	**-**	**-**	**(2,373.2)**

a) With respect to the projects shown in Table 4 please provide the risk analysis that was undertaken as part of the decision to remove each project.

Table 6 - Other Adjustments (in C$ in thousands)

Investment	201	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Remove: Engineering - Transmission Lines	-	-	(498.1)	(756.5)	(634.3)	(572.6)	(440.8)	(542.7)	(468.3)	(554.9)	**(4,468.1)**
Remove: Engineering - Transmission Stations	-	-	(641.2)	(423.2)	(569.0)	(351.2)	(433.3)	(344.3)	(431.9)	(358.7)	**(3,552.8)**
Remove: Transmission Line/Station Emergency Work	-	-	(171.7)	(175.1)	(178.6)	(182.2)	(180.3)	(182.9)	(185.7)	(188.4)	**(1,444.9)**
Add: Third Line TS Protection Upgrade	-	-	-	-	-	-	-	-	-	500.0	**500.0**
Remove: Information Technology Refresh - Hardware & Software	-	-	(260.1)	(265.3)	(270.6)	(276.0)	(273.1)	(277.2)	(281.3)	(285.5)	**(2,189.1)**
Remove: Minor Fixed Assets	-	-	(129.0)	(130.2)	(194.8)	(198.7)	(196.7)	(199.6)	(202.5)	(205.6)	**(1,457.0)**
Remove: General Building Upgrades	-	-	(330.3)	(212.2)	(216.5)	(220.8)	(218.5)	(221.8)	(225.1)	(228.4)	**(1,873.5)**
Add: Consolidation Capital & Minor Fixed Assets	-	-	225.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	**1,975.0**
Add: General Plant	-	-	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	**1,000.0**
Remove: Transformer Contingency Plan - Replacements & Spares	-	-	-	-	(1,226.8)	(588.8)	(2,294.3)	(1,928.4)	(2,245.0)	(428.2)	**(8,711.6)**
Investment	**201**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
Add: Echo River TS Transformer Replacement	-	-	-	-	-	-	-	1,440.0	3,360.0	-	**4,800.0**
Add: Northern Avenue TS T1 Replacement	-	-	-	-	-	-	-	400.0	950.0	-	**1,350.0**
Total	**-**	**-**	**(1,680.4)**	**(1,587.5)**	**(2,915.6)**	**(2,015.3)**	**(3,661.9)**	**(1,481.9)**	**645.2**	**(1,374.7)**	**(14,072.1)**

b) With respect to Table 6 please explain the rationale for the removals and provide the risk analysis that was undertaken as part of the decision to remove the projects.

c) Please explain/describe the addition of "consolidation capital and minor fixed assets."

Response:

a) HOSSM did not undertake formal risk analysis for the decision to remove the referenced projects. It instead relied on internal management's decision regarding the need for the projects, relative to the scope and nature of other planned initiatives. The projects in question were judged to be of low risk and not immediately necessary, due in part to the integration with HONI and the leveraging of HONI's existing assets/systems.

b) Please see a) above and also refer to the response to AMPCO 24, a and b, and section 1.3 of the Exhibit B2-2-1.

c) Please refer to the Investment Summary Document SS-04 in the Exhibit B1-1-1.

Vulnerable Energy Consumers Coalition Interrogatory # 5

Reference:

Exhibit B2, Tab 2, Schedule 1, pg. 12

Interrogatory:

Preamble:

At the above reference it states: *"…the Clergue Transmission Station Upgrade including switchgear replacement. This project was originally scheduled to commence in 2022 and be completed in 2025 for a total of $13,007,900. The scope included replacement of the two transformers."*

The above described project has been subsequently modified to prolong the life of the existing transformers at a cost of $4.8 million to be completed in 2025 and 2026.

a) Given the original replacement project was schedule to commence in 2022 what is the reason for the refurbishment project to be delayed until 2025?

b) What is the extend life estimate of the transformers after refurbishment as compared to the expected life of a new transformer?

c) Please provide the cost-benefit analysis that was undertaken to show that refurbishment provided a superior economic return as compared to replacement of the transformers.

Response:

a) HOSSM revisited the assumptions underlying the previous plan, and determined that a deferral was possible on the basis of more recent and newer information compiled in the context of TSP preparation.

b) It is inappropriate to compare the lifetime extension benefits of partial refurbishments relative to the expected lifetimes of brand-new units. By conducting the refurbishment work, HOSSM will eliminate the critical failure risk that will significantly increase the likelihood of the transformer (and its remaining, less deteriorated components) being able to serve out its full expected life.

c) HOSSM did not conduct a formal cost-benefit analysis between the refurbishment and replacement scenarios. This is in part owing to the findings of METSCO's ACA, which demonstrated that the assets in question would be in an adequate condition to remain in service, but for a single component that was restively easy and cost-effective to refurbish. As such, once HOSSM received the ACA information, it no longer saw unit replacement as a justifiable alternative to consider through cost-benefit analysis.

Vulnerable Energy Consumers Coalition Interrogatory # 6

Reference:

Exhibit C, Tab 1, Schedule 1 / Tab 2, Schedule 1

Interrogatory

a) Please explain the relationship (if any) between the proposed scorecard metrics of T-SAIFI and T-SAIDI, system unavailability for lines and stations and the use of customer delivery point performance standards (CDPPS).

b) Why did HOSSM not to include CDPPS as a Scorecard metric?

Response:

a) T-SAIFI and T-SAIDI measure the system level frequency and duration impacts across the delivery points. The CDPPS measures the outage impacts to individual customer delivery points against their individual baseline and group values, to see if their magnitude represents an outlier. Unavailability of lines and stations tracks the instances where particular pieces of equipment are down. Individual equipment outages may or may not result in a delivery point outage, but represent a scenario where the system is more vulnerable, and the removal of another piece of equipment may lead to an interruption at the delivery point.

b) HOSSM did include CDPPS in its scorecard. Measure #2 under Customer Focus / Service Quality is the measure, *"Customer Delivery Point Performance Standard Outliers as % of Total Delivery Points"*.

Vulnerable Energy Consumers Coalition Interrogatory # 7

Reference:

Exhibit C, Tab 2, Schedule 1

Interrogatory:

Table 1 - Delivery Point Performance Standards[2]

Performance Measures	Delivery Point Performance Standards (Based on a Delivery Point's Total Average Station Load)							
	0 to 15MW		>15 to 40MW		>40 to 80MW		>80MW	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/yr)	4.1	9.0	1.1	3.5	0.5	1.5	0.3	1.0
DP Interruption Duration (min/yr)	89	360	22	140	11	55	5	25

a) Hydro One Network's delivery point standards are established using data for a period (1991-2000) that is at average 23 years old. All of the data collection pre-dates the Board's regulation of Hydro One (March 1999) Please explain why standards based on such an old data set remain relevant

b) Please explain how the minimum standards were derived from the 1991-2000 data set.

Response:

a) As referenced in EB-2018-0218 Exhibit C-2-1 & Attachment 1, the HOSSM delivery point standard was based on the Hydro One's Customer Delivery Point Performance Standard as approved in RP-1999-0057/EB-2002-0424. The approved standard is based on historical 1991-2000 performance.

b) Please refer to EB-2018-02018 Exhibit C-2-1 Attachment 1, Page 3, Section 2: "GLPL will use Hydro One's Customer Delivery Point Performance Standards and triggers based on the size of load being served (as measured in megawatts by a delivery point's total average station load)."

Vulnerable Energy Consumers Coalition Interrogatory # 8

Reference:

Exhibit C, Tab 2, Schedule 1, pgs. 8-

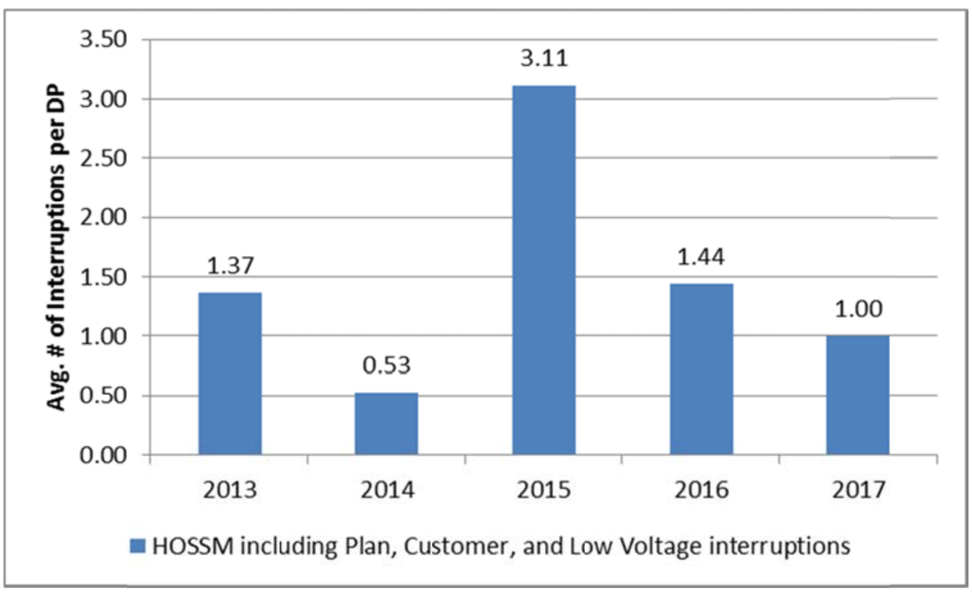
Interrogatory:

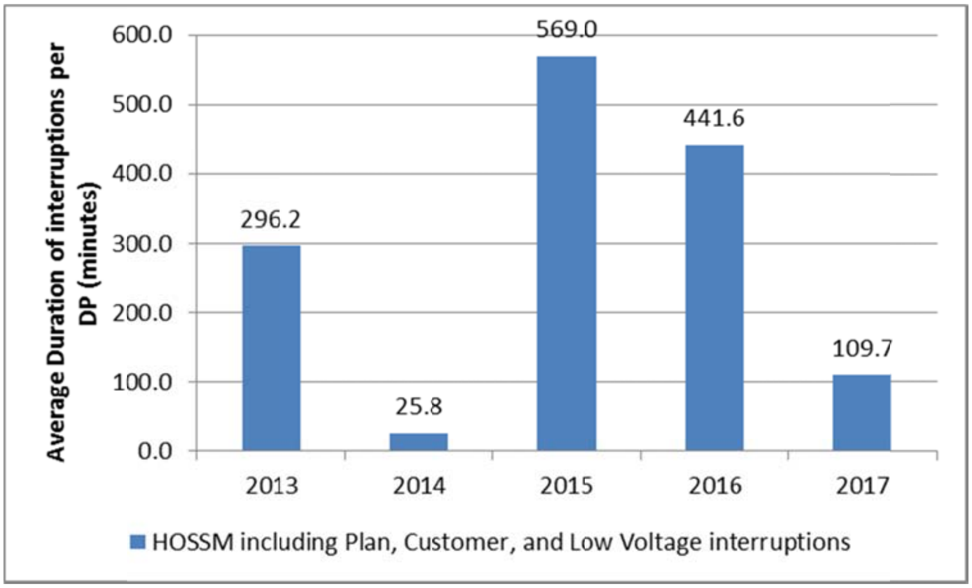
a) Please provide the T-SAIDI and T-SAIFI for HOSSM for the period 2013 through 2018 and including planned interruptions, customer caused interruptions and low voltage equipment caused interruptions.

b) Which utilities are included in the CEA composite comparison shown in HOSSM's evidence?

Response:

a)





2018 YTD numbers need to come from HOSSM.

b) Please refer to I-01-71 j).

Vulnerable Energy Consumers Coalition Interrogatory # 9

Reference:

Exhibit D, Tab 1, Schedule 1

Interrogatory

a) Please compare and contrast the PSE recommended inflation factor and the inflation factor with that is used by the Ontario Energy Board in similar incentive rate plans.

b) Please provide the past 5 years (2015-2018) historical inflation factors based on HOSSM's proposal as compared to the CPI based (calculated on a yearly basis). Please reference the source of the CPI inflation rates.

Response:

a) and b)

As stated in Exhibit D-01-01 the proposed PSE inflation factor is based on the sum of the following weightings:

- 86% of the annual percentage change in Canada's Gross Domestic Product-Implicit Price Index, Final Domestic Demand ("GDP-IPI FDD") for Canada as reported by Statistics Canada; and
- 14% of the annual percentage change in the Average Weekly Earnings ("AWE") for workers in Ontario, as reported by Statistics Canada.

The inflation factor which is used by the Ontario Energy Board for Distributors is based on the sum of the following weightings:

- 70% of the annual percentage change in Canada's Gross Domestic Product-Implicit Price Index, Final Domestic Demand ("GDP-IPI FDD") for Canada as reported by Statistics Canada; and
- 30% of the annual percentage change in the Average Weekly Earnings ("AWE") for workers in Ontario, as reported by Statistics Canada.

For 2015 to 2019 the following table summarizes the difference between the two inflation factors and provides the CPI for comparison:

Year	Inflation Factor OEB Weighting	Inflation Factor PSE Weighting	Ontario CPI Inflation Rate[1]
2015	1.6%	1.6%	1.2%
2016	2.1%	2.2%	1.8%
2017	1.9%	1.8%	1.7%
2018	1.2%	1.2%	2.4%
2019	1.5%	1.4%	1.8%

[1] Source: HIS Global Insight, November 2018

Vulnerable Energy Consumers Coalition Interrogatory # 10

Reference:

Exhibit D, Tab 1, Schedule 1 & Exhibit D-1-1, Attachment 1 PSE Study

Interrogatory

Preamble:

In the recent proceeding of the amalgamation of Union Gas Limited and Enbridge Gas Distribution the Board the Board adopted the evidence of the Pacific Economics Group stretch factor of 0.3% referencing that "…*PEG noted that it was difficult to assess the appropriate stretch factor, as the stretch factor is ordinarily determined using benchmarking analysis,…*"

"*In the absence of benchmarking evidence, the OEB is setting a stretch factor that is the mid-range of the stretch factors established for electricity distributors (0% to 0.6%). This is also the stretch factor approved in the decision for the hydroelectric generation business of Ontario Power Generation (OPG), where the OEB noted that it expects improved benchmarking going forward.34 The mid-range is the stretch factor for an average performer*."

(EB-2017-0306/307, August 30, 2018, pg. 26 & 27)

a) Does PSE agree that the preferred methodology for determining an appropriate stretch factor is benchmark analysis?

b) What benchmarking analysis was performed by PSE with respect to HOSSM (as opposed to Hydro One) in coming to its conclusion of a 0% stretch factor?

c) Given that HOSSM is not Hydro One why is it appropriate to extrapolate Hydro One's benchmarking results and apply them to a different utility?

d) Please provide HOSSM's most recent peak demand and compare that to the list of Utilities in the Benchmarking Study shown in Tables 4 and 6 of the PSE Study.

e) Given the Board's prior findings why is a stretch factor of 0.3% not appropriate for HOSSM?

f) If HOSSM is comparable to Hydro One why was in not used as a Benchmarking utility in the PSE study?

Response:

a) Yes. It is PSE's opinion that the preferred method of setting the stretch factor would be to first set the productivity factor based on the industry TFP trend result, and then base the stretch factor based on the benchmark analysis. In the current case, the productivity factor recommendation of 0.0% already contains an implicit stretch factor of 1.71%, which is extraordinarily large. In this case, PSE believes it is not appropriate to add an additional stretch factor on top of the large implicit one.

b) No benchmark analysis was performed by PSE with respect to Hydro One SSM.

c) The Hydro One Networks benchmark result is not being extrapolated to Hydro One SSM. However, both Hydro One SSM and Hydro One Networks are both owned and operated by the same company, and if Hydro One SSM were added to Hydro One Networks in the benchmark analysis (it was not), the recommendation of a 0.0% stretch factor would very likely be unchanged. Further, both Hydro One SSM and Hydro One Networks serve an industry that has shown a negative TFP trend of -1.71%. With the 0.0% productivity factor recommendation, both would be facing an implicit stretch factor of 1.71%.

d) PSE never gathered Hydro One SSM's peak demand variable. However, it is our understanding that Hydro One SSM would be a very small fraction of Hydro One Networks (likely smaller than 2% of the Hydro One system). This would result in Hydro One SSM being the smallest utility if it were included in Tables 4 and 6 of the PSE Study.

e) Please see PSE's response to part a) of this question.

f) Hydro One SSM is not comparable to Hydro One. It is significantly smaller than Hydro One and the rest of the sample.

Vulnerable Energy Consumers Coalition Interrogatory # 11

Reference:

Reference Exhibit E, Tab 1, Schedule 2

Interrogatory

a) What is the current balance in the IFRS Gains and Losses sub-account of 1508?

b) Given that the amount of gains and losses are not, in HOSSM's estimation remain in the current rate base for the 10 year deferred rebasing period what is the rationale for continuation of this account?

Response:

a) The current balance in the account it $630,137.87.

b) The balance will remain in the account with no carrying charges being accrued for the duration of the 10-year deferral period.