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Oded Hubert
Vice President
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BY COURIER

October 7, 2016

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-2016-0160 Hydro One Networks Inc.'s 2017 and 2018 Transmission Cost-of-Service Application – Technical Conference Undertaking Responses

Please find enclosed responses to undertakings from the Technical Conference held on September 22, 2016 and September 23, 2016 in regards to the above noted proceeding.

Please be advised that Hydro One Networks Inc. is no longer seeking confidential treatment for undertaking response XTCJ2.21.

This filing has been submitted electronically using the Board's Regulatory Electronic Submission System and two (2) hard copies will be sent via courier.

Sincerely,

ORIGINAL SIGNED BY ODED HUBERT

Oded Hubert

cc. Intervenors (electronic)

Encls.

UNDERTAKING – TCJ1.1

Undertaking

Provide a revised version of the revenue requirement table provided at Exhibit A, Tab 3, Schedule 1, Page 8.

Response

Revenue Requirement ($ Millions)

Comparison of Rates Revenue Requirement	**Board - approved 2016**	**2017**	**2018**
OM&A	436.7	412.7	409.3
Depreciation	397.3	435.7	470.7
Income Taxes	72.2	88.1	96.2
Cost of Capital	661.5	676.1	714.9
Total Revenue Requirement	**1,567.6**	**1,612.6**	**1,691.1**
Deduct External Revenues	(32.2)	(28.2)	(28.5)
Revenue Requirement less External Revenues	**1,535.4**	**1,584.4**	**1,662.6**
Deduct Export Revenue Credit	(31.7)	(39.2)	(40.1)
Deduct Regulatory Accounts Disposition	(36.1)	(47.8)	(47.8)
Add Low Voltage Switch Gear	13.0	14.0	14.7
Rates Revenue Requirement	**1,480.7**	**1,511.4**	**1,589.4**
Rate Increase Required, excl. Load		**2.1%**	**5.2%**
Estimated Load Impact		2.1%	0.0%
Rate Increase Required		**4.2%**	**5.2%**

Note 1: OM&A updates reflect revised OM&A pension costs, as outlined below:

- Correction to OM&A pension update: reduction to OM&A of $0.4M and $1.9M in 2017 and 2018, respectively

Note 2: Income tax updates reflect schedule 1 adjustments for capitalized pension reductions and associated CCA impacts

Witness: Joel Jodoin

UNDERTAKING – TCJ1.2

Undertaking

Provide a table similar to that provided in SEC IR 43, the difference being with the inclusion of Hydro One in the table.

Response

Company	Gross Transmission Assets ($000)	Customers	Service Territory (sq. km)	KM of Transmission Lines	MWH Transmitted	Ownership*	Regulatory Regime**	Susceptible to Storms
HydroOne	4,489,620,901	1,300,000	650,000	27,582	139,803,825	IOU/Provincial	Open	Yes
Baltimore Gas & Electric	1,179,098,656	1,351,891	3,701	2,090	30,562,078	IOU		Yes
B.C. Hydro	5,111,155,732	1,945,599	42,370	18,508	54,637,557	Provincial		Yes
CenterPoint Energy	2,059,764,178	2,299,248	8,045	5,984	101,741,203	IOU	Open	Yes
Commonwealth Edison	3,389,679,995	3,842,198	18,388	8,656	89,977,031	IOU	Open	Yes
CPS Energy	877,775,489	771,603	2,438	2,407	26,334,008	Municipal	Open	
East Kentucky Power Coop.	569,099,123		N/A	4,728	22,790,243	Cooperative		
Kansas City Power & Light	1,297,124,005	903,776	28,838	4,273	24,731,534	IOU		Yes
Manitoba Hydro	1,055,000,000	555,760	650,000	12,800	30,000,000	Provincial		
Oncor Electric Delivery	7,005,354,033	3,310,530	86,032	25,776	114,905,829	IOU	Open	Yes
PECO Energy	1,439,589,112	1,234,338	3,379	1,757	37,501,023	IOU	Open	Yes
PPL Electric Utilities	2,408,545,384	1,400,118	26,000	8,771	40,599,247	IOU	Open	Yes
PSE&G	5,845,024,497	2,259,205	2,011	2,317	40,746,702	IOU		Yes
Southern California Edison	11,071,660,300	4,967,691	80,450	26,206	88,986,000	IOU	Open	
Tucson Electric Power	936,496,126	414,748	1,617	3,114	18,278,352	IOU		
Westar Energy	2,053,092,375	695,972	16,251	9,952	30,436,785	IOU		Yes

* IOU/Municipal/Provincial
** Open Access or not

UNDERTAKING – TCJ1.3

Undertaking

To request from Navigant if they have the data underlying the two charts found at pages 32 and 33 of B-2-21, Attachment 4, Page 32 (Reference SEC IR 48).

Response

The table below provides the underlying data used by Navigant for the two charts. Participant identification numbers have been provided for the participants found in other charts in the charts. Not all participants were assigned identification numbers.

Participant Identification Number		Admin per Asset	O&M per Asset	CapEx per Asset	Total
Hydro One Networks	29	2.66%	4.29%	5.15%	12.09%
		0.77%	0.67%	0.25%	1.69%
		0.29%	0.29%	1.42%	2.00%
		0.84%	1.28%	0.00%	2.12%
		0.81%	1.06%	1.15%	3.01%
		0.27%	1.21%	3.32%	4.80%
		0.63%	1.09%	3.09%	4.81%
		0.25%	0.66%	4.08%	4.99%
		1.59%	2.62%	1.45%	5.66%
		0.93%	1.64%	3.31%	5.88%
		2.15%	1.71%	2.20%	6.06%
		2.12%	2.45%	1.50%	6.07%
		1.79%	1.85%	2.50%	6.14%
		2.26%	1.82%	2.14%	6.23%
		2.25%	1.86%	2.44%	6.55%
		1.40%	1.19%	4.49%	7.08%
		0.81%	2.06%	4.62%	7.49%
		2.87%	2.37%	2.50%	7.74%
		1.26%	2.45%	4.21%	7.93%
		1.66%	3.18%	3.35%	8.19%
		2.38%	2.28%	3.67%	8.32%
		2.45%	2.06%	3.98%	8.48%
		2.62%	1.72%	4.30%	8.65%

Witness: Ben Grunfeld

Participant Identification Number		Admin per Asset	O&M per Asset	CapEx per Asset	Total
		0.83%	1.25%	6.71%	8.80%
		0.48%	0.97%	7.51%	8.96%
		0.68%	2.18%	6.15%	9.01%
		0.80%	1.40%	7.27%	9.47%
		0.71%	1.98%	6.82%	9.51%
		0.68%	1.55%	7.34%	9.58%
		1.51%	4.29%	3.79%	9.59%
		2.77%	2.36%	4.48%	9.61%
		3.34%	2.84%	3.71%	9.89%
		0.70%	1.78%	7.46%	9.94%
		3.17%	2.21%	4.60%	9.97%
		1.87%	2.55%	5.55%	9.98%
		1.43%	2.37%	6.24%	10.03%
		3.55%	3.46%	3.02%	10.04%
		1.24%	1.47%	7.41%	10.12%
		1.56%	2.54%	6.37%	10.47%
		0.89%	2.34%	7.53%	10.76%
		3.19%	2.17%	5.43%	10.79%
		3.34%	2.43%	5.02%	10.79%
		1.38%	2.47%	7.04%	10.90%
		2.02%	2.14%	6.77%	10.92%
		0.81%	2.25%	7.87%	10.93%
		2.61%	2.89%	5.45%	10.95%
		2.13%	2.26%	6.57%	10.96%
		3.75%	5.85%	1.45%	11.06%
		0.47%	3.80%	6.83%	11.11%
		1.56%	2.43%	7.19%	11.18%
		0.66%	1.83%	9.06%	11.55%
		3.09%	3.39%	5.07%	11.55%
		2.54%	3.33%	5.93%	11.80%
		2.74%	3.39%	5.90%	12.03%
		0.81%	5.78%	5.49%	12.08%
		0.81%	1.30%	10.14%	12.24%
		0.29%	0.38%	11.64%	12.30%
		7.78%	4.14%	0.58%	12.51%
		1.71%	2.63%	8.25%	12.59%

Participant Identification Number		Admin per Asset	O&M per Asset	CapEx per Asset	Total
		3.19%	3.78%	5.73%	12.70%
		3.85%	3.42%	5.52%	12.79%
		3.81%	5.16%	3.84%	12.81%
		2.54%	1.63%	8.82%	12.99%
		2.14%	2.12%	8.85%	13.11%
		1.30%	2.44%	9.41%	13.15%
		1.21%	2.76%	9.21%	13.19%
	22	1.36%	0.91%	10.92%	13.19%
	40	3.32%	3.82%	6.09%	13.22%
	31	3.02%	1.48%	8.76%	13.26%
		3.40%	4.33%	5.58%	13.31%
		1.40%	6.77%	5.27%	13.44%
		2.44%	2.21%	8.93%	13.58%
		2.43%	2.26%	9.06%	13.75%
		1.47%	2.46%	10.06%	13.99%
		2.45%	1.73%	9.91%	14.09%
		0.68%	1.30%	12.12%	14.10%
	37	7.18%	3.90%	3.13%	14.22%
		3.36%	2.37%	8.69%	14.42%
		4.80%	4.09%	5.57%	14.46%
		4.63%	2.71%	7.18%	14.51%
	28	2.86%	10.04%	1.65%	14.54%
		6.78%	3.14%	4.69%	14.61%
		14.37%	0.59%	0.00%	14.95%
		9.40%	3.44%	2.27%	15.11%
		3.28%	5.23%	6.84%	15.35%
		3.50%	3.82%	8.61%	15.92%
		4.25%	6.98%	4.77%	16.01%
	25	1.85%	2.35%	12.70%	16.91%
		1.77%	3.85%	11.43%	17.05%
		7.87%	3.58%	5.61%	17.06%
		4.51%	4.26%	8.49%	17.27%
		0.88%	1.40%	15.00%	17.28%
		2.49%	2.33%	12.53%	17.35%
		1.72%	2.14%	14.20%	18.06%

Participant Identification Number		Admin per Asset	O&M per Asset	CapEx per Asset	Total
		3.81%	4.93%	9.41%	18.15%
		3.16%	1.93%	13.54%	18.64%
		8.08%	3.13%	7.52%	18.73%
		1.26%	1.27%	16.27%	18.79%
		1.12%	2.41%	16.96%	20.48%
		7.89%	7.36%	5.56%	20.81%
		3.78%	3.68%	13.64%	21.10%
	24	2.24%	5.69%	14.15%	22.07%
		3.77%	4.05%	14.84%	22.65%
		3.98%	4.17%	15.00%	23.15%
		7.15%	10.46%	5.65%	23.25%
		3.15%	3.28%	16.90%	23.33%
	18	0.86%	1.81%	20.67%	23.34%
		3.69%	8.26%	12.20%	24.15%
		4.44%	6.46%	13.99%	24.89%
		0.66%	1.36%	23.18%	25.21%
		5.58%	3.59%	16.60%	25.76%
		13.28%	9.69%	3.14%	26.12%
		7.52%	3.93%	14.84%	26.29%
		3.01%	4.60%	19.77%	27.38%
		1.93%	1.60%	26.12%	29.65%
	27	7.33%	11.68%	11.70%	30.72%
		2.44%	5.31%	23.22%	30.97%
	23	0.33%	1.53%	33.35%	35.21%
		8.89%	15.15%	11.78%	35.81%

UNDERTAKING – TCJ1.4

Undertaking

To provide the number for the Business Performance Cost Management related to Table 1 at Exhibit 1, Tab 3, Schedule 3, Page 2 of 26.

Response

The Business Performance group was moved from Finance under Corporate Controller to Regulatory Affairs in mid-2015. The planned 2016, 2017 and 2018 costs are approximately $2 million annually.

UNDERTAKING – TCJ1.5

Undertaking

To provide a breakdown of the $10.4 million allotted for legal costs with respect to how much is internal and how much is external.

Response

Of the $10.4M planned costs for General Counsel and Corporate Secretariat in 2017 approximately $3.5 million are planned for external legal consultants.

UNDERTAKING – TCJ1.6

Undertaking

To confirm impact of pay bands down to median.

Response

The difference between Management pay bands and market median is indicated in the table below.

Bands Above P50	# of Hydro One Benchmarked Incumbents	Avg. Hydro One total	Avg. P50 total	Total Compensation Amount Above P50 ($)
Band 5	35	$240,000	$208,000	1,120,000
Band 6	54	$180,000	$138,000	2,268,000
Band 7	104	$144,000	$116,000	2,912,000

Witness: Keith McDonell

UNDERTAKING – TCJ1.7

Undertaking

To provide answers to the VECC questions filed September 19.

Response

VECC-43

Reference: Exhibit I/Tab1/Schedule 144, page 2, lines 5-7 / OEB Decision, EB-2006-0501, Page 91

Preamble: EB-2006-0501 Decision states: The Board agrees with the consumer group intervenors with respect to the impact of demand response programs. Hydro One's base forecast is weather-normal, which means that extreme weather events are excluded. It would seem logical to reduce the impact of demand response programs, which are most effective in extreme weather situations, when adjusting a weather-normal forecast.

a) Please confirm that Hydro One has exclude DR savings from its load forecast consistent with the Board's decision in EB-2006-0501.

Response:

a) In EB-2006-0501, the Board directed Hydro One to reduce the expected impact of CDM on total Ontario peak demand by 350MW to address a variety of issues raised during the proceeding. In the EB-2006-0501 proceeding, the CDM information used was from the OPA's Integrated Power System Plan (1.0).

   In Hydro One's current application, Hydro One's CDM information was based on the OPA's 2013 *Long-term Energy Plan* ("2013 LTEP") and Hydro One's discussion with the IESO. In the 2013 LTEP, there is no change in CDM peak impact from DR sources between 2015 and 2018. As such, Hydro One used the DR impact reflected in the 2015 actual peak when establishing its 2017-2018 load forecast.

VECC-44

a) The responses to VECC-27 b) & c) indicate that actual MW savings from energy efficiency, programs are assumed to be the same as forecast in the 2013 LTEP, however, in response to VECC 36 the actual MW savings from efficiency programs are reported to be different than forecast in both 2013 and 2014, please reconcile.

Response:

a) The responses to VECC 27 b) & c) (Exhibit I, Tab 12, Schedule 27) are based on the following IESO reports:
   - Comparison of 2013 Long-Term Energy Plan to 2013 Actual Results (published in June 2015); and
   - LTEP: Comparison of 2014 Forecast vs. 2014 Actual Results (published in December 2015).

In Exhibit I, Tab 12, Schedule 27, Hydro One's response pertained to all energy efficiency programs over the period 2006-2018. The response to VECC 36 (Exhibit I, Tab 12, Schedule 3) was focused on a variance calculation for only the energy efficiency target programs over a shorter period of time (2011-2014). The total energy efficiency program savings shown in Exhibit I, Tab 12, Schedule 27 was published by the IESO in December 2015. There is no detailed breakdown for the historical programs (2006-2013) and target programs (2011-2014). As such, it is not possible to reconcile the numbers.

VECC-45

a) Please explain /clarify what is meant by the following statement:

> "Considering there is no incremental peak reduction from existing and further demand response resources over the forecast period, hydro one uses the implicit method to incorporate demand response impacts in load forecasting".

Response:

a) As mentioned in the response to VECC-43, there is no incremental CDM savings due to the DR sources based on the forecast in the 2013 LTEP. In addition to that, there will be substantial changes to how the IESO manages DR programs over next two years and there is no better DR (now called "capacity-based demand response") forecast information from the IESO. Hydro One only added back peak savings, which are attributable to energy efficiency ("EE") and codes and standards ("C&S"), to the actual load for the historical period and deducted forecasted EE and C&S peak savings from the gross peak for the forecast period. The DR impact for the historical period and forecast period is constant, so Hydro One did not add and then deduct the DR impact when calculating its load forecast, as the net effect would have been nil.

VECC-46

a) Did Hydro One test to determine if the 20 trend was statistically significant? If yes, what were the results? If not, what would the results be?

Response:

a) Yes, Hydro One did test to determine if the 20-year trend was statistically significant. Hydro One found that it was not.

The *t* statistic for the trend coefficient for summer months is 1.45, which is much less than the critical value of *t* distribution at 5% significance (2.10) and also at 10% significance (1.73). Similarly, the *t* statistic for the trend coefficient for winter months is 0.06, which is much less than the critical values of t distribution noted above.

VECC-47

a) How do actual electricity prices for 2013-2015 compare with those forecast in the 2013 LTEP?

Response:

a) A uniform electricity price for each sector (residential, commercial, and industrial) is not publicly available for the years 2012 to 2015, so it is not possible to make a comparison with the corresponding 2013 LTEP figures.

VECC-48

Reference: Exhibit I/Tab 4/Schedule 47, part b) / Exhibit I/Tab 12/Schedule 28

a) VECC is aware that the IESO has produced 2015 Verified Results for individual distributors. VECC also notes (per VECC #28 a)) that the actual results for 2014 were available as of June 2015. When does Hydro One expect that 2015 province-wide results will be available?

Response:

a) The IESO has produced a detailed, 2015 annual verified conservation results report for each LDC in Ontario. The reports track the progress of each LDC against its individual six-year target in terms of energy saving, but not peak savings because there are no peak targets established. The reports are available at http://www.ieso.ca/Pages/Conservation/Conservation-First-Framework/2015-LDC-Conservation-Results.aspx.

VECC-49

Reference: Exhibit I/Tab 12/Schedule 36 / EB-2014-0099, Exhibit 4, Appendix 4-N

a) A review of the actual OPA Report for 2013 Verified Results indicates that the values used in the calculation rely on the first year results for 2011 and 2012 Energy Efficiency Programs and do not appear to account for the loss of persistence for 2013. Please confirm if this is the case and, if required, provide a revised calculation for 2013 that includes the projected loss in persistence.

Response:

a) The revised calculation for 2013 that includes loss in persistence for peak demand saving from 2011 and 2012 is as follows:

	Annual				
Implementation Period	2011	2012	2013 (1)	The MW used in HONI variance analysis (2)	Difference (2)-(1)
2011	216.3	136.6	135.8	137	0.8
2012	1.4	253.3	109.8	109	(0.6)
2013	0.6	7	405.5		
				Total Difference	0.20

VECC-50

Reference: Exhibit I/Tab 1/Schedule 147

a) Rather than the revenues projected from Wholesale Meter Service fees, can Hydro One provide the revenue requirement for the Wholesale Meter rate pool, as requested in the original question?

Response:

a) As discussed in Section 3.4 of Exhibit G1, Tab 2, Schedule 1 and in Exhibit H1, Tab 3, Schedule 1; Hydro One is proposing to streamline the transmission cost allocation and rate design process by including the wholesale meter revenue requirement as part of the Transformation Connection pool. Hydro One is also proposing to establish an annual fee approach for the remaining customer making use of wholesale meter service provider services. The Wholesale Meter Services ("WMS") fee proposed is $7900/meter point/year for both 2017 and 2018, consistent with the current approved rate that has been in place since 2012. The revenue from these WMS fees would be credited against the costs of the Transformation Pool, as shown in Exhibit G2, Tab 5, Schedule 1, to ensure the Transformation Pool customers are held harmless.

This proposed WMS annual fee will yield revenue of $0.3 million which closely approximates the revenue requirement associated with wholesale meters in 2015 and 2016, as shown in the response to interrogatory Exhibit I, Tab 1, Schedule 147. Therefore, Hydro One believes the WMS fee revenue is a good approximation of the revenue requirement for providing wholesale meter services in 2017 and 2018 while avoiding the complication and effort associated with running the cost allocation model to assign costs to a separate wholesale meter pool that represents less than 0.02% of Hydro One's revenue requirement.

VECC-51

Reference: Exhibit I/Tab 4/Schedule 66, part b)

a) Why is it appropriate to consider only the change in export volumes when calculating the "average effective change to the ETS rate"?

b) What would be the average effective change if the change in total volumes for both Ontario and exports was used?

Response:

a) The response provided in Exhibit I, Tab 6, Schedule 66, part b) addresses the suggestion in the SEC interrogatory that the approved ETS rate of $1.85/MWh could simply be adjusted to reflect the overall revenue requirement increase Hydro One is applying for. The response clarifies that if the ETS is to be recalculated for a change in overall revenue requirement, then it would also be appropriate to take into account the change in the charge determinant (i.e. export volumes) used to calculate the ETS rate. The -0.5% average effective change referenced to the ETS in the response considers both average increase in export volumes as well as the average increase in revenue requirement for the Network pool over 2017 and 2018.

b) The change in total volumes for Ontario and exports would potentially impact the cost allocation model used to calculate the revenue requirement for the ETS rate; however, Hydro One has not rerun the ETS cost allocation model as the approved ETS rate of $1.85/MWh was not calculated using a model, it is a settled amount that was informed by, but does not directly align with, the actual cost of providing export service.

VECC-52

Reference: Exhibit I/Tab 11/Schedule 4, part a)

a) Are the historical values presented weather-corrected? If not, please also provide the weather-corrected values.

Response:

a) Yes, the historical values presented in the reference noted above are weather-corrected.

VECC-53

Reference: Exhibit I/Tab 12/Schedule 25, part a)

a) Please confirm whether the values reported in the table provided are correct as they are larger than the overall totals in Exhibit H1, Table 1.

Response:

a) The values presented in the table in Exhibit I, Tab 12, Schedule 25 part a) for transmission connected generators are correct but were mislabeled as being “MW” amounts. The values shown are actually “kW” amounts.

UNDERTAKING – TCJ1.8

Undertaking

To file the latest quarterly report and associated press release.

Response

Attachment 1: Hydro One Inc. Condensed Interim Consolidated Financial Statements (Unaudited) For the three and six months ended June 30, 2016 and 2015

Attachment 2: Hydro One Inc. Management's Discussion and Analysis
For the three and six months ended June 30, 2016 and 2015

Attachment 3: Hydro One Second Quarter 2016 Earnings Teleconference
Analyst Call Slides

Witness: Samir Chhelavda

HYDRO ONE INC.
CONDENSED INTERIM CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (unaudited)
For the three and six months ended June 30, 2016 and 2015

	Three months ended June 30		Six months ended June 30	
(millions of Canadian dollars, except per share amounts)	**2016**	**2015**	**2016**	**2015**
Revenues				
Distribution (includes related party revenues of $41 (2015 – $40) and $81 (2015 – $80) for three and six months ended June 30, respectively) *(Note 19)*	1,152	1,185	2,438	2,574
Transmission (includes related party revenues of $375 (2015 – $364) and $752 (2015 – $770) for three and six months ended June 30, respectively) *(Note 19)*	381	364	767	770
Other	–	14	–	27
	1,533	1,563	3,205	3,371
Costs				
Purchased power (includes related party costs of $337 (2015 – $475) and $1,049 (2015 – $1,274) for three and six months ended June 30, respectively) *(Note 19)*	803	838	1,699	1,808
Operation, maintenance and administration *(Note 19)*	254	282	502	560
Depreciation and amortization	191	190	379	377
	1,248	1,310	2,580	2,745
Income before financing charges and income taxes	**285**	**253**	**625**	**626**
Financing charges	97	93	193	187
Income before income taxes	**188**	**160**	**432**	**439**
Income taxes *(Notes 5, 19)*	32	23	64	68
Net income	**156**	**137**	**368**	**371**
Other comprehensive income	–	–	–	–
Comprehensive income	**156**	**137**	**368**	**371**
Net income and comprehensive income attributable to:				
Noncontrolling interest	1	1	2	3
Preferred shareholder	–	5	–	9
Common shareholder	155	131	366	359
	156	**137**	**368**	**371**
Earnings per common share *(Note 17)*				
Basic and diluted	$1,086	$1,313	$2,571	$3,594
Dividends per common share declared *(Note 16)*	–	$250	$14	$500

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

HYDRO ONE INC.
CONDENSED INTERIM CONSOLIDATED BALANCE SHEETS (unaudited)
At June 30, 2016 and December 31, 2015

(millions of Canadian dollars)	**June 30, 2016**	**December 31, 2015**
Assets		
Current assets:		
Cash and cash equivalents	1	89
Accounts receivable *(Note 6)*	752	772
Due from related parties *(Note 19)*	216	184
Other current assets *(Note 7)*	115	100
	1,084	1,145
Property, plant and equipment *(Note 8)*	18,343	17,893
Other long-term assets:		
Regulatory assets	3,073	3,015
Deferred income tax assets *(Note 3)*	1,339	1,610
Intangible assets (net of accumulated amortization – $301; 2015 – $274)	335	336
Goodwill	165	163
Other assets	6	7
	4,918	5,131
Total assets	**24,345**	**24,169**
Liabilities		
Current liabilities:		
Bank indebtedness	34	–
Short-term notes payable *(Note 11)*	948	1,491
Accounts payable and other current liabilities *(Note 9)*	915	858
Due to related parties *(Note 19)*	15	132
Long-term debt payable within one year *(Note 11)*	50	500
	1,962	2,981
Long-term liabilities:		
Long-term debt (includes $51 measured at fair value; 2015 – $51) *(Notes 11, 12)*	9,551	8,207
Regulatory liabilities	217	236
Deferred income tax liabilities *(Note 3)*	40	206
Other long-term liabilities *(Note 10)*	2,739	2,714
	12,547	11,363
Total liabilities	**14,509**	**14,344**
Contingencies and Commitments (Notes 21, 22)		
Subsequent Events (Note 24)		
Noncontrolling interest subject to redemption	23	23
Equity		
Common shares *(Note 15)*	5,649	6,000
Retained earnings	4,123	3,759
Accumulated other comprehensive loss	(9)	(9)
Hydro One shareholder's equity	9,763	9,750
Noncontrolling interest	50	52
Total equity	**9,813**	**9,802**
	24,345	**24,169**

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

HYDRO ONE INC.
CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY (unaudited)
For the six months ended June 30, 2016 and 2015

Six months ended June 30, 2016 *(millions of Canadian dollars)*	**Common Shares**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Hydro One Shareholder's Equity**	**Non-controlling Interest**	**Total Equity**
January 1, 2016	6,000	3,759	(9)	9,750	52	9,802
Net income	–	366	–	366	1	367
Other comprehensive income	–	–	–	–	–	–
Distributions to noncontrolling interest	–	–	–	–	(3)	(3)
Dividends on common shares	–	(2)	–	(2)	–	(2)
Return of stated capital *(Note 15)*	(351)	–	–	(351)	–	(351)
June 30, 2016	**5,649**	**4,123**	**(9)**	**9,763**	**50**	**9,813**

Six months ended June 30, 2015 *(millions of Canadian dollars)*	**Common Shares**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Hydro One Shareholder's Equity**	**Non-controlling Interest**	**Total Equity**
January 1, 2015	3,314	4,249	(9)	7,554	49	7,603
Net income	–	368	–	368	2	370
Other comprehensive income	–	–	–	–	–	–
Distributions to noncontrolling interest	–	–	–	–	(1)	(1)
Dividends on preferred shares	–	(9)	–	(9)	–	(9)
Dividends on common shares	–	(50)	–	(50)	–	(50)
June 30, 2015	**3,314**	**4,558**	**(9)**	**7,863**	**50**	**7,913**

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

HYDRO ONE INC.
CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)
For the three and six months ended June 30, 2016 and 2015

	Three months ended June 30		Six months ended June 30	
(millions of Canadian dollars)	**2016**	**2015**	**2016**	**2015**
Operating activities				
Net income	156	137	368	371
Environmental expenditures	(7)	(5)	(10)	(9)
Adjustments for non-cash items:				
Depreciation and amortization (excluding removal costs)	168	162	332	332
Regulatory assets and liabilities	(12)	(16)	(22)	72
Deferred income taxes	36	1	57	3
Other	(2)	1	–	3
Changes in non-cash balances related to operations *(Note 20)*	(56)	7	(68)	(59)
Net cash from operating activities	283	287	657	713
Financing activities				
Long-term debt issued	–	350	1,350	350
Long-term debt retired	–	–	(450)	–
Short-term notes repaid	(7)	–	(543)	–
Return of stated capital	(125)	–	(351)	–
Change in bank indebtedness	24	(35)	34	(2)
Distributions paid to noncontrolling interest	(1)	(2)	(4)	(2)
Dividends paid	–	(30)	(2)	(59)
Other	–	(1)	(6)	(1)
Net cash from financing activities	(109)	282	28	286
Investing activities				
Capital expenditures *(Note 20)*				
Property, plant and equipment	(398)	(418)	(755)	(757)
Intangible assets	(15)	(4)	(28)	(9)
Net cash paid for Haldimand Hydro	–	(58)	–	(58)
Other	–	–	10	(5)
Net cash used in investing activities	(413)	(480)	(773)	(829)
Net change in cash and cash equivalents	(239)	89	(88)	170
Cash and cash equivalents, beginning of period	240	181	89	100
Cash and cash equivalents, end of period	**1**	**270**	**1**	**270**

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the Business Corporations Act (Ontario) and is wholly owned by Hydro One Limited. On October 31, 2015, Hydro One Limited, a subsidiary of the Province of Ontario (Province), acquired Hydro One. The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

These unaudited condensed interim Consolidated Financial Statements (Consolidated Financial Statements) include the accounts of the Company and its wholly owned subsidiaries. Intercompany transactions and balances have been eliminated.

Earnings for interim periods may not be indicative of results for the year due to the impact of seasonal weather conditions on customer demand and market pricing.

Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars.

The accounting policies applied are consistent with those outlined in Hydro One's annual audited consolidated financial statements for the year ended December 31, 2015, except as described in Note 3, New Accounting Pronouncements – Recently Adopted Accounting Guidance. These Consolidated Financial Statements reflect adjustments, that are, in the opinion of management, necessary to reflect fairly the financial position and results of operations for the respective periods. These Consolidated Financial Statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2015 annual audited consolidated financial statements. Certain comparative figures have been reclassified to conform with the current period's presentation.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board (FASB) that are applicable to Hydro One:

Recently Adopted Accounting Guidance

ASU	Date issued	Description	Effective date	Impact on Hydro One
2015-03	April 2015	Debt issuance costs are required to be presented on the balance sheet as a direct deduction from the carrying amount of the related debt liability consistent with debt discounts or premiums.	January 1, 2016	Reclassification of deferred debt issuance costs and net unamortized debt premiums as an offset to long-term debt. Applied retrospectively. (See note 11)
2015-17	November 2015	All deferred tax assets and liabilities are required to be classified as noncurrent on the balance sheet.	January 1, 2017	To simplify reporting, this ASU was early adopted as of April 1, 2016 and applied prospectively. As a result, the current portions of the Company's deferred income tax assets are reclassified as noncurrent assets on the consolidated Balance Sheet. Prior periods were not retrospectively adjusted. (See note 7)

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-02	February 2016	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. An exemption election is available for short-term leases.	January 1, 2019	Under assessment
2016-09	March 2016	This guidance simplifies several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows.	January 1, 2017	Under assessment
2016-10	April 2016	This guidance clarifies the identification of performance obligations and the implementation of the licensing guidance with respect to revenue from contracts with customers.	January 1, 2018	Under assessment
2016-12	May 2016	This guidance aims to simplify the transition to the new standard on accounting for revenue from contracts with customers (ASU 2014-09) and to clarify certain aspects of the new standard.	January 1, 2018	Under assessment

4. BUSINESS COMBINATIONS

Great Lakes Power Transmission Purchase Agreement

On January 28, 2016, Hydro One reached an agreement to acquire Great Lakes Power Transmission LP, an Ontario regulated electricity transmission business operating along the eastern shore of Lake Superior, north and east of Sault Ste. Marie, Ontario from Brookfield Infrastructure, for $222 million in cash, subject to customary adjustments, plus the assumption of approximately $151 million in outstanding indebtedness. The acquisition is pending regulatory approval by the Ontario Energy Board (OEB).

5. INCOME TAXES

Income taxes / provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Six months ended June 30 *(millions of Canadian dollars)*	**2016**	**2015**
Income taxes / provision for PILs at statutory rate	115	116
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(23)	(23)
Pension contributions in excess of pension expense	(8)	(12)
Overheads capitalized for accounting but deducted for tax purposes	(7)	(7)
Interest capitalized for accounting but deducted for tax purposes	(9)	(7)
Environmental expenditures	(4)	(3)
Non-refundable investment tax credits	(1)	(1)
Other	1	4
Net temporary differences	(51)	(49)
Net permanent differences	–	1
Total income taxes / provision for PILs	64	68
Effective income tax rate	14.8%	15.5%

6. ACCOUNTS RECEIVABLE

The following table shows the details of accounts receivable at June 30, 2016 and December 31, 2015:

(millions of Canadian dollars)	**June 30, 2016**	**December 31, 2015**
Accounts receivable – billed	410	374
Accounts receivable – unbilled	382	459
Accounts receivable, gross	792	833
Allowance for doubtful accounts	(40)	(61)
Accounts receivable, net	752	772

The following table shows the movements in the allowance for doubtful accounts for the six months ended June 30, 2016 and year ended December 31, 2015:

(millions of Canadian dollars)	**Six months ended June 30, 2016**	**Year ended December 31, 2015**
Allowance for doubtful accounts – beginning	(61)	(66)
Write-offs	17	37
Change in allowance for doubtful accounts	4	(32)
Allowance for doubtful accounts – ending	(40)	(61)

7. OTHER CURRENT ASSETS

(millions of Canadian dollars)	**June 30, 2016**	**December 31, 2015**
Regulatory assets	40	36
Materials and supplies	20	21
Deferred income tax assets *(Note 3)*	–	19
Prepaid expenses and other assets	55	24
	115	100

8. PROPERTY, PLANT AND EQUIPMENT

(millions of Canadian dollars)	**June 30, 2016**	**December 31, 2015**
Property, plant and equipment in service	26,395	25,911
Less: accumulated depreciation	(9,604)	(9,319)
	16,791	16,592
Construction in progress	1,393	1,144
Future use land, components and spares	159	157
	18,343	17,893

9. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

(millions of Canadian dollars)	**June 30, 2016**	**December 31, 2015**
Accounts payable	169	152
Accrued liabilities	622	591
Accrued interest	101	96
Regulatory liabilities	23	19
	915	858

10. OTHER LONG-TERM LIABILITIES

(millions of Canadian dollars)	**June 30, 2016**	**December 31, 2015**
Post-retirement and post-employment benefit liability *(Note 13)*	1,576	1,541
Pension benefit liability *(Note 13)*	935	952
Environmental liabilities *(Note 14)*	177	185
Due to related parties *(Note 19)*	21	10
Asset retirement obligations	9	9
Long-term accounts payable and other liabilities	21	17
	2,739	2,714

11. DEBT AND CREDIT AGREEMENTS

Short-Term Notes and Credit Facilities

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under its Commercial Paper Program which has a maximum authorized amount of $1.5 billion. These short-term notes are denominated in Canadian dollars with varying maturities up to 365 days. The Commercial Paper Program is supported by the Company's committed revolving credit facilities totalling $2.3 billion. At June 30, 2016, Hydro One had $948 million in commercial paper borrowings outstanding (December 31, 2015 – $1,491 million).

Long-Term Debt

The Company issues notes for long-term financing under its Medium-Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under the current MTN Program filed in December 2015 is $3.5 billion. At June 30, 2016, $2,150 million remained available for issuance until January 2018.

The following table presents Hydro One's outstanding long-term debt at June 30, 2016 and December 31, 2015:

(millions of Canadian dollars)	**June 30, 2016**	**December 31, 2015**
Notes and debentures	9,623	8,723
Add: Net unamortized debt premiums[2]	16	17
Add: Unrealized mark-to-market loss[1]	1	1
Less: Deferred debt issuance costs[2]	(39)	(34)
Less: Long-term debt payable within one year	(50)	(500)
Long-term debt	9,551	8,207

[1] The unrealized mark-to-market loss relates to $50 million of Series 33 notes due 2020. The unrealized mark-to-market loss is offset by a $1 million (2015 – $1 million) unrealized mark-to-market gain on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges.

[2] Effective January 1, 2016, deferred debt issuance costs and net unamortized debt premiums were reclassified from other long-term assets and other long-term liabilities, respectively, as an offset to long-term debt upon adoption of ASU 2015-03 (see Note 3). Balances as at December 31, 2015 were updated to reflect the retrospective adoption of ASU 2015-03.

On February 24, 2016, Hydro One issued the following notes under its MTN Program:
- $500 million notes (MTN Series 34 notes) with a maturity date of February 24, 2021 and a coupon rate of 1.84%;
- $500 million notes (MTN Series 35 notes) with a maturity date of February 24, 2026 and a coupon rate of 2.77%; and
- $350 million notes (MTN Series 36 notes) with a maturity date of February 23, 2046 and a coupon rate of 3.91%.

On March 3, 2016, Hydro One repaid $450 million of maturing long-term debt notes (MTN Series 10 notes) under its MTN Program.

Principal repayments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	Long-term Debt Principal Repayments *(millions of Canadian dollars)*	Weighted Average Interest Rate *(%)*
1 year	50	1.3
2 years	600	5.2
3 years	978	2.4
4 years	650	2.9
5 years	500	1.8
	2,778	3.0
6 – 10 years	1,100	3.0
Over 10 years	5,745	5.4
	9,623	4.4

Interest payment obligations related to long-term debt are summarized by year in the following table:

Year	Interest Payments *(millions of Canadian dollars)*
Remainder of 2016	212
2017	423
2018	392
2019	369
2020	359
	1,755
2021-2025	1,638
2026 +	4,367
	7,760

12. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Non-Derivative Financial Assets and Liabilities

At June 30, 2016 and December 31, 2015, the Company's carrying amounts of cash and cash equivalents, accounts receivable, due from related parties, bank indebtedness, short-term notes payable, accounts payable, and due to related parties are representative of fair value because of the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at June 30, 2016 and December 31, 2015 are as follows:

	June 30, 2016		December 31, 2015	
(millions of Canadian dollars)	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt				
$50 million of MTN Series 33 notes[1]	51	51	51	51
Other notes and debentures[2]	9,550	11,333	8,656	9,942
	9,601	11,384	8,707	9,993

[1] The fair value of the $50 million MTN Series 33 notes subject to hedging is primarily based on changes in the present value of future cash flows due to a change in the yield in the swap market for the related swap (hedged risk).

[2] The fair value of other notes and debentures represents the market value of the notes and debentures and is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

Fair Value Measurements of Derivative Instruments

At June 30, 2016, Hydro One had an interest-rate swap in the notional amount of $50 million (December 31, 2015 – $50 million) that was used to convert fixed-rate debt to floating-rate debt. This swap is classified as a fair value hedge. Hydro One's fair value hedge exposure was equal to about 1% (December 31, 2015 – 1%) of the principal amount of its total long-term debt of $9,623 million (December 31, 2015 – $8,723 million).

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at June 30, 2016 and December 31, 2015 is as follows:

June 30, 2016 *(millions of Canadian dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	1	1	1	–	–
Derivative instruments					
Fair value hedge – interest-rate swap	1	1	1	–	–
	2	2	2	–	–
Liabilities:					
Bank indebtedness	34	34	34	–	–
Short-term notes payable	948	948	948	–	–
Long-term debt, including current portion	9,601	11,384	–	11,384	–
	10,583	12,366	982	11,384	–

December 31, 2015 *(millions of Canadian dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	89	89	89	–	–
Derivative instruments					
Fair value hedge – interest-rate swap	1	1	1	–	–
	90	90	90	–	–
Liabilities:					
Short-term notes payable	1,491	1,491	1,491	–	–
Long-term debt, including current portion	8,707	9,993	–	9,993	–
	10,198	11,484	1,491	9,993	–

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no significant transfers between any of the fair value levels during the six months ended June 30, 2016 or year ended December 31, 2015.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss that results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates as its regulated return on equity is derived using a formulaic approach that takes into account anticipated interest rates. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. The Company may also utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

Fair Value Hedges
For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Operations and Comprehensive Income. The net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the three and six months ended June 30, 2016 and 2015 was not significant.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At June 30, 2016 and December 31, 2015, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any single customer. At June 30, 2016 and December 31, 2015, there was no significant accounts receivable balance due from any single customer.

At June 30, 2016, the Company's provision for bad debts was $40 million (December 31, 2015 – $61 million). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. At June 30, 2016, approximately 8% (December 31, 2015 – 6%) of the Company's net accounts receivable were aged more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly-rated counterparties; limiting total exposure levels with individual counterparties; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. The Company monitors current and forward credit exposure to counterparties both on an individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the Consolidated Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At June 30, 2016 and December 31, 2015, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not significant. At June 30, 2016, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with one financial institution as the counterparty.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, and the revolving standby facilities. The short-term liquidity under the Commercial Paper Program, and anticipated levels of funds from operations are expected to be sufficient to fund normal operating requirements.

13. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Estimated 2016 annual pension plan contributions are approximately $108 million, based on an actuarial valuation as at December 31, 2015 and projected levels of 2016 pensionable earnings. Employer contributions made during the six months ended June 30, 2016 were $75 million (2015 – $89 million).

The following table provides the components of the net periodic benefit costs for the three and six months ended June 30, 2016 and 2015:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Three months ended June 30 *(millions of Canadian dollars)*	**2016**	**2015**	**2016**	**2015**
Current service cost	36	37	10	11
Interest cost	77	76	16	16
Expected return on plan assets, net of expenses[1]	(108)	(102)	–	–
Actuarial loss amortization	24	30	2	3
Net periodic benefit costs	29	41	28	30
Charged to results of operations[2]	3	22	11	14

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Six months ended June 30 *(millions of Canadian dollars)*	**2016**	**2015**	**2016**	**2015**
Current service cost	72	74	21	22
Interest cost	154	152	33	32
Expected return on plan assets, net of expenses[1]	(217)	(204)	–	–
Actuarial loss amortization	48	60	4	6
Net periodic benefit costs	57	82	58	60
Charged to results of operations[2]	25	41	24	26

[1] The expected long-term rate of return on pension plan assets for the year ending December 31, 2016 is 6.5% (2015 – 6.5%).

[2] The Company follows the cash basis of accounting consistent with the inclusion of pension costs in OEB-approved rates. During the three and six months ended June 30, 2016, pension costs of $7 million (2015 – $48 million) and $57 million (2015 – $90 million), respectively, were attributed to labour, of which $3 million (2015 – $22 million) and $25 million (2015 – $41 million), respectively, were charged to operations, and $4 million (2015 – $26 million) and $32 million (2015 – $49 million), respectively, were capitalized as part of the cost of property, plant and equipment and intangible assets.

14. ENVIRONMENTAL LIABILITIES

Hydro One records a liability for the estimated future expenditures for land assessment and remediation and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Future expenditures have been discounted using factors ranging from approximately 2.0% to 6.3%, depending on the period over which expenditures are expected to be incurred.

During the six months ended June 30, 2016, total environmental expenditures were $10 million (2015 – $9 million) and interest accretion was $4 million (2015 – $5 million). At June 30, 2016, total environmental liabilities, including the current portion, were $201 million (December 31, 2015 – $207 million).

15. SHARE CAPITAL

Common Shares

The Company is authorized to issue an unlimited number of common shares. At June 30, 2016, the Company had 142,239 common shares issued and outstanding.

During the three and six months ended June 30, 2016, a return of stated capital in the amount of $125 million (2015 – $nil) and $351 million (2015 – $nil), respectively, was paid.

Preferred Shares

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At June 30, 2016 and December 31, 2015, the Company had no issued and outstanding preferred shares.

16. DIVIDENDS

During the three months ended June 30, 2016, preferred share dividends in the amount of $nil (2015 – $5 million) and common share dividends in the amount of $nil (2015 – $25 million) were declared.

During the six months ended June 30, 2016, preferred share dividends in the amount of $nil (2015 – $9 million) and common share dividends in the amount of $2 million (2015 – $50 million) were declared.

17. EARNINGS PER SHARE

Basic and diluted earnings per common share (EPS) is calculated by dividing net income attributable to common shareholder of Hydro One by the weighted average number of common shares outstanding. The weighted average number of shares outstanding during the six months ended June 30, 2016 was 142,239 (2015 – 100,000). There were no dilutive securities during six months ended June 30, 2016 and 2015.

18. STOCK-BASED COMPENSATION

Long-term Incentive Plan

On March 31, 2016, Hydro One Limited granted awards under the Long-term Incentive Plan. These awards consist of approximately 124,120 Performance Stock Units and 149,120 Restricted Stock Units, all of which are equity settled in Hydro One Limited shares. The grant date fair value of the awards was $7 million. The compensation expense recognized by the Company relating to these awards during the three and six months ended June 30, 2016 was not significant. No long-term incentives were awarded during the three and six months ended June 30, 2015.

19. RELATED PARTY TRANSACTIONS

The Province is the majority shareholder of Hydro One Limited. The Independent Electricity System Operator (IESO), Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), the OEB, Hydro One Brampton Networks Inc. (Hydro One Brampton) and Hydro One Telecom Inc. (Hydro One Telecom) are related parties to Hydro One because they are controlled or significantly influenced by the Province or by Hydro One Limited.

		Three months ended June 30		Six months ended June 30	
		2016	2015	2016	2015
Related Party	**Transaction**	*(millions of Canadian dollars)*			
Province	Dividends paid	–	30	–	59
IESO	Power purchased	335	471	1,045	1,262
	Revenues for transmission services (based on OEB-approved uniform transmission rates)	375	363	751	768
	Distribution revenues related to rural rate protection	32	32	63	64
	Distribution revenues related to the supply of electricity to remote northern communities	8	8	16	16
	Funding received related to Conservation and Demand Management programs	17	11	24	23
OPG	Power purchased	1	2	3	8
	Revenues related to provision of construction and equipment maintenance services	–	1	1	3
	Costs expensed related to the purchase of services	–	–	1	1
OEFC	Payments in lieu of corporate income taxes	–	14	–	32
	Power purchased from power contracts administered by the OEFC	1	2	1	4
	Indemnification fee paid (terminated effective October 31, 2015)	–	–	–	5
OEB	OEB fees	3	3	7	6
Hydro One Limited	Return of stated capital	125	–	351	–
	Dividends paid	–	–	2	–
	Stock-based compensation costs	6	–	11	–
Hydro One Brampton	Revenues from management, administrative and smart meter network services	1	–	2	–
Hydro One Telecom	Services provided to Hydro One – costs expensed	7	–	13	–
	Services provided to Hydro One – costs capitalized	3	–	6	–

Sales to and purchases from related parties are based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are interest free and settled in cash.

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

(millions of Canadian dollars)	June 30, 2016	December 31, 2015
Due from related parties[1]	216	184
Due to related parties[1]	(36)	(142)

[1] At June 30, 2016, amounts due from related parties included net amount due from the IESO of $17 million in respect of power purchases (December 31, 2015 – amounts due to related parties included amounts owing to the IESO of $134 million).

20. CONSOLIDATED STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

	Three months ended June 30		Six months ended June 30	
(millions of Canadian dollars)	2016	2015	2016	2015
Accounts receivable	92	100	20	15
Due from related parties	(53)	21	(32)	47
Materials and supplies	–	–	1	(1)
Prepaid expenses and other assets	(23)	(3)	(30)	(2)
Accounts payable	15	19	21	7
Accrued liabilities	32	(4)	25	18
Due to related parties	(120)	(130)	(117)	(175)
Accrued interest	(19)	(17)	5	(1)
Long-term accounts payable and other liabilities	4	1	4	(3)
Post-retirement and post-employment benefit liability	16	20	35	36
	(56)	7	(68)	(59)

Capital Expenditures

The following table provides a reconciliation between investments in property, plant and equipment and the amount presented in the Consolidated Statements of Cash Flows after accounting for capitalized depreciation and the net change in related accruals:

	Three months ended June 30		Six months ended June 30	
(millions of Canadian dollars)	2016	2015	2016	2015
Capital investments in property, plant and equipment	(400)	(425)	(766)	(765)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	2	7	11	8
Capital expenditures – property, plant and equipment	(398)	(418)	(755)	(757)

The following table provides a reconciliation between investments in intangible assets and the amount presented in the Consolidated Statements of Cash Flows after accounting for the net change in related accruals:

	Three months ended June 30		Six months ended June 30	
(millions of Canadian dollars)	2016	2015	2016	2015
Capital investments in intangible assets	(16)	(4)	(28)	(9)
Net change in accruals included in capital investments in intangible assets	1	–	–	–
Capital expenditures – intangible assets	(15)	(4)	(28)	(9)

Supplementary Information

	Three months ended June 30		Six months ended June 30	
(millions of Canadian dollars)	2016	2015	2016	2015
Net interest paid	122	122	202	207
Income taxes / PILs paid	5	14	13	32

21. CONTINGENCIES

Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Transfer of Assets

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the OEFC holds these assets. Under the terms of the transfer orders, the Company is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. If the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on the Company's results of operations if the Company is not able to recover them in future rate orders.

22. COMMITMENTS

The following table presents a summary of Hydro One's commitments under leases, outsourcing and other agreements due in the next 5 years and thereafter.

June 30, 2016 *(millions of Canadian dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Outsourcing agreements	144	117	91	46	2	10
Long-term software/meter agreement	16	17	17	17	9	5
Operating lease commitments	10	8	5	5	4	2

Hydro One currently has outstanding bank letters of credit of $139 million relating to retirement compensation arrangements. Hydro One also provides prudential support to the IESO in the form of letters of credit. At June 30, 2016, Hydro One provided a letter of credit to the IESO in the amount of $5 million to meet its current prudential requirements. In addition, Hydro One provided prudential support to the IESO on behalf of its subsidiaries as required by the IESO's Market Rules, using parental guarantees of $330 million.

23. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the transmission of high voltage electricity across the province, interconnecting more than 70 local distribution companies and certain large directly connected industrial customers throughout the Ontario electricity grid;
- The Distribution Business, which comprises the delivery of electricity to end customers and certain other municipal electricity distributors; and
- Other Business, which includes certain corporate activities. The comparative information also includes the operations of Hydro One Telecom.

The designation of segments has been based on a combination of regulatory status and the nature of the services provided. Operating segments of the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of each of the segments. The Company evaluates segment performance based on income before financing charges and income taxes from continuing operations (excluding certain allocated corporate governance costs).

Segment information is as follows:

Three months ended June 30, 2016 *(millions of Canadian dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	381	1,152	–	1,533
Purchased power	–	803	–	803
Operation, maintenance and administration	97	146	11	254
Depreciation and amortization	94	97	–	191
Income (loss) before financing charges and income taxes	190	106	(11)	285
Capital investments	238	178	–	416

Three months ended June 30, 2015 *(millions of Canadian dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	364	1,185	14	1,563
Purchased power	–	838	–	838
Operation, maintenance and administration	98	168	16	282
Depreciation and amortization	94	94	2	190
Income (loss) before financing charges and income taxes	172	85	(4)	253
Capital investments	234	192	3	429

Six months ended June 30, 2016 *(millions of Canadian dollars)*	**Transmission**	**Distribution**	**Other**	**Consolidated**
Revenues	767	2,438	–	3,205
Purchased power	–	1,699	–	1,699
Operation, maintenance and administration	198	289	15	502
Depreciation and amortization	189	190	–	379
Income (loss) before financing charges and income taxes	380	260	(15)	625
Capital investments	473	321	–	794

Six months ended June 30, 2015 *(millions of Canadian dollars)*	**Transmission**	**Distribution**	**Other**	**Consolidated**
Revenues	770	2,574	27	3,371
Purchased power	–	1,808	–	1,808
Operation, maintenance and administration	197	334	29	560
Depreciation and amortization	188	186	3	377
Income (loss) before financing charges and income taxes	385	246	(5)	626
Capital investments	445	324	5	774

Total Assets by Segment:

(millions of Canadian dollars)	**June 30, 2016**	**December 31, 2015**
Transmission	12,259	12,045
Distribution	9,218	9,200
Other	2,868	2,924
Total assets	24,345	24,169

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

24. SUBSEQUENT EVENTS

Return of Stated Capital

On August 11, 2016, a return of stated capital in the amount of $129 million was approved.

The following Management's Discussion and Analysis (MD&A) of the financial condition and results of operations should be read together with the condensed interim unaudited consolidated financial statements and accompanying notes (the Consolidated Financial Statements) of Hydro One Inc. (Hydro One or the Company) for the three and six months ended June 30, 2016, as well as the Company's audited consolidated financial statements and accompanying notes thereto, and MD&A, for the year ended December 31, 2015. The Consolidated Financial Statements are presented in Canadian dollars and have been prepared in accordance with United States (US) Generally Accepted Accounting Principles (GAAP). All financial information in this MD&A is presented in Canadian dollars, unless otherwise indicated.

The Company has prepared this MD&A in accordance with National Instrument 51-102 – Continuous Disclosure Obligations of the Canadian Securities Administrators. Under the US/Canada Multijurisdictional Disclosure System, the Company is permitted to prepare this MD&A in accordance with the disclosure requirements of Canada, which vary from those of the US. This MD&A provides information for the three and six months ended June 30, 2016, based on information available to management as of August 11, 2016.

CONSOLIDATED FINANCIAL HIGHLIGHTS AND STATISTICS

	Three months ended June 30			Six months ended June 30		
(millions of Canadian dollars, except as otherwise noted)	**2016**	**2015**	**Change**	**2016**	**2015**	**Change**
Revenues	1,533	1,563	(1.9%)	3,205	3,371	(4.9%)
Purchased power	803	838	(4.2%)	1,699	1,808	(6.0%)
Revenues, net of purchased power	730	725	0.7%	1,506	1,563	(3.6%)
Operation, maintenance and administration costs	254	282	(9.9%)	502	560	(10.4%)
Depreciation and amortization	191	190	0.5%	379	377	0.5%
Financing charges	97	93	4.3%	193	187	3.2%
Income tax expense	32	23	39.1%	64	68	(5.9%)
Net income attributable to common shareholder of Hydro One	**155**	**131**	**18.3%**	**366**	**359**	**1.9%**
Basic and diluted earnings per common share (EPS)	$1,086	$1,313	(17.3%)	$2,571	$3,594	(28.5%)
Net cash from operating activities	283	287	(1.4%)	657	713	(7.9%)
Funds from operations (FFO)[1]	338	273	23.8%	721	761	(5.3%)
Capital investments	416	429	(3.0%)	794	774	2.6%
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	19,799	18,986	4.3%	20,177	20,182	–
Distribution: Electricity distributed to Hydro One customers *(TWh)*	6.2	6.7	(7.5%)	13.2	15.4	(14.3%)

	June 30, 2016	December 31, 2015
Debt to capitalization ratio[2]	52.0%	50.9%

[1] See section "Non-GAAP Measures" for description and reconciliation of FFO.

[2] Debt to capitalization ratio has been calculated as total debt (includes total long-term debt and short-term borrowings, net of cash) divided by total debt plus total shareholder's equity, including preferred shares but excluding any amounts related to non-controlling interest.

OVERVIEW

Hydro One is the largest electricity transmission and distribution company in Ontario. Hydro One owns and operates substantially all of Ontario's electricity transmission network, and an approximately 123,000 circuit km low-voltage distribution network. Hydro One has three business segments: (i) transmission; (ii) distribution; and (iii) other business.

Transmission Business – Hydro One's transmission business accounted for approximately 50% of the Company's total assets as at June 30, 2016, and approximately 51% of its total revenues, net of purchased power, for the six months ended June 30, 2016.

Distribution Business – Hydro One's distribution business accounted for approximately 38% of its total assets as at June 30, 2016 and approximately 49% of its total revenues, net of purchased power, for the six months ended June 30, 2016.

Other Business – Hydro One's other business segment accounted for approximately 12% of its total assets as at June 30, 2016 and none of its 2016 revenues.

RESULTS OF OPERATIONS

Net Income

Net income attributable to common shareholder for the quarter ended June 30, 2016 of $155 million is an increase of $24 million or 18.3% from the prior year, principally driven by cost reductions and improvements in transmission revenues.

The increase of $7 million or 1.9% in net income for the six months ended June 30, 2016 was the result of similar factors noted above and in addition was negatively impacted by an overall lower average monthly Ontario 60-minute peak demand in the first six months of 2016 due to an unseasonably milder winter in 2016 which negatively impacted transmission revenues.

Revenues

	Three months ended June 30			Six months ended June 30		
(millions of Canadian dollars)	2016	2015	Change	2016	2015	Change
Transmission	381	364	4.7%	767	770	(0.4%)
Distribution	1,152	1,185	(2.8%)	2,438	2,574	(5.3%)
Other	–	14	(100.0%)	–	27	(100.0%)
	1,533	1,563	(1.9%)	3,205	3,371	(4.9%)
Transmission:						
Average monthly Ontario 60-minute peak demand *(MW)*	19,799	18,986	4.3%	20,177	20,182	–
Distribution:						
Electricity distributed to Hydro One customers *(TWh)*	6.2	6.7	(7.5%)	13.2	15.4	(14.3%)

Transmission Revenues

The increase of $17 million or 4.7% in transmission revenues for the quarter ended June 30, 2016 was primarily due to higher average monthly Ontario 60-minute peak demand and increased Ontario Energy Board (OEB)-approved transmission rates for 2016.

The decrease of $3 million or 0.4% in transmission revenues for the six months ended June 30, 2016 was primarily due to lower average monthly Ontario 60-minute peak demand due to an unseasonably milder winter in 2016, partially offset by increased OEB-approved transmission rates for 2016.

Distribution Revenues

The decrease of $33 million or 2.8% in distribution revenues for the quarter ended June 30, 2016 was primarily due to lower power costs, the divestiture of Hydro One Brampton in August 2015, partially offset by increased OEB-approved distribution rates for 2016.

The decrease of $136 million or 5.3% in distribution revenues for the six months ended June 30, 2016 was the result of similar factors as noted above, and were also negatively impacted by lower energy consumption resulting from a milder winter in 2016 compared to the prior year.

Operation, Maintenance and Administration (OM&A) Costs

	Three months ended June 30			Six months ended June 30		
(millions of Canadian dollars)	2016	2015	Change	2016	2015	Change
Transmission	97	98	(1.0%)	198	197	0.5%
Distribution	146	168	(13.1%)	289	334	(13.5%)
Other	11	16	(31.3%)	15	29	(48.3%)
	254	282	(9.9%)	502	560	(10.4%)

Transmission OM&A Costs

Transmission OM&A costs for the three and six months ended June 30, 2016 did not change significantly, compared to the same periods in 2015. In both periods of 2016, lower volume of work associated with transformer equipment refurbishments and stations maintenance was offset by costs for certain network and carrier management, engineering and other services provided by Hydro One Telecom Inc. (Hydro One Telecom).

Distribution OM&A Costs

The decrease of $22 million or 13.1% in distribution OM&A costs for the quarter ended June 30, 2016 was primarily due to a decrease in bad debt expense, the effect of the divestiture of Hydro One Brampton in August 2015, lower outsourcing support services costs, and lower costs associated with underground distribution cable locates.

The decrease of $45 million or 13.5% in distribution OM&A costs for the six months ended June 30, 2016 was the result of similar factors as noted above, partly offset by increased OM&A costs associated with restoring power services as a result of an ice storm in March 2016.

Other OM&A Costs

The decrease in other OM&A costs for the quarter and six months ended June 30, 2016 was primarily due to decreased costs resulting from the spin-off of Hydro One Telecom to Hydro One Limited in November 2015, partially offset by increased consulting costs in 2016.

Income Tax Expense

Income tax expense for the six months ended June 30, 2016 decreased by $4 million compared to 2015. The effective tax rate for the six months ended June 30, 2016 was 14.8%, compared to 15.5% in the six months ended June 30, 2015. The difference in effective tax rates is primarily due to changes in temporary differences included in rates.

During the fourth quarter of 2015, in the course of the sale by the Province of Ontario (Province) of a stake of approximately 15% in Hydro One Limited, Hydro One exited the Province's payments in lieu of corporate income taxes regime (PILs Regime) and transitioned to becoming taxable under the *Income Tax Act* (Canada). As part of this transition, there was a revaluation of the tax basis of the assets of Hydro One and its subsidiaries to fair market value. This step-up of the tax basis of the Company's assets resulted in the recording of a $2.6 billion deferred tax asset. The inclusion of this non-cash deferred tax asset in the consolidated results of the Company during the fourth quarter of 2015 caused certain cash flow metrics including working capital and FFO to become non-comparable, and has the impact of increasing shareholder's equity, resulting in the consolidated return on equity (ROE) appearing significantly below the ROE allowed by regulators for the Company's transmission and distribution businesses.

QUARTERLY RESULTS OF OPERATIONS

Quarter ended (*millions of Canadian dollars, except EPS*)	**Jun. 30, 2016**	**Mar. 31, 2016**	**Dec. 31, 2015**	**Sep. 30, 2015**	**Jun. 30, 2015**	**Mar. 31, 2015**	**Dec. 31, 2014**	**Sep. 30, 2014**
Revenues	1,533	1,672	1,513	1,645	1,563	1,808	1,662	1,556
Revenues, net of purchased power	730	776	727	789	725	838	769	776
Net income to common shareholder	155	211	132	188	131	228	216	169
Basic and diluted EPS	$1,086	$1,485	$1,036	$1,869	$1,313	$2,281	$2,170	$1,693

Variations in revenues and net income over the quarters are primarily due to the impact of seasonal weather conditions on customer demand and market pricing.

SUMMARY OF SOURCES AND USES OF CASH

Hydro One's primary sources of cash flows are funds generated from operations, capital market debt issuances and bank credit facilities that are used to satisfy Hydro One's capital resource requirements, including the Company's capital expenditures, servicing and repayment of debt, and distributions to shareholder.

The following table presents the Company's sources and uses of cash during the three and six months ended June 30, 2016 and 2015:

	Three months ended June 30		Six months ended June 30	
(millions of Canadian dollars)	2016	2015	2016	2015
Operating activities				
Net income	156	137	368	371
Changes in non-cash balances related to operations	(56)	7	(68)	(59)
Other	183	143	357	401
	283	287	657	713
Financing activities				
Long-term debt issued	–	350	1,350	350
Long-term debt retired	–	–	(450)	–
Short-term notes repaid	(7)	–	(543)	–
Return of stated capital	(125)	–	(351)	–
Dividends paid	–	(30)	(2)	(59)
Other	23	(38)	24	(5)
	(109)	282	28	286
Investing activities				
Capital expenditures	(413)	(422)	(783)	(766)
Acquisitions	–	(58)	–	(58)
Other	–	–	10	(5)
	(413)	(480)	(773)	(829)
Net change in cash and cash equivalents	(239)	89	(88)	170

Cash from Operating Activities

Cash from operations during the second quarter of 2016 totalled $283 million compared to $287 million during the second quarter of 2015. The decrease was mainly due to decreased purchased power accrual and an increase in other assets primarily due to prepaid pension contributions resulting from an updated pension actuarial valuation completed in the second quarter of 2016, partially offset by an increase in net income, and changes in accrual balances, mainly related to timing of capital projects.

Cash from operations during the six months ended June 30, 2016 totalled $657 million compared to $713 million during the same period in 2015. The decrease was mainly due to changes in regulatory variance and deferral accounts that impact revenue, and an increase in other assets primarily due to prepaid pension contributions resulting from an updated pension actuarial valuation completed in the second quarter of 2016.

Cash from Financing Activities

Cash used in financing activities was $109 million during the second quarter of 2016, compared to $282 million of cash received during the second quarter of 2015. The decrease in 2016 was primarily due to cash proceeds from issuance of long-term debt in the second quarter of 2015, and a return of stated capital in 2016.

Cash from financing activities was $28 million during the six months ended June 30, 2016, compared to $286 million during the same period in 2015. The decrease in 2016 was primarily due to repayment of short-term notes and long-term debt and a return of stated capital, partially offset by higher cash proceeds from issuance of long-term debt in 2016.

During the six months ended June 30, 2016, Hydro One issued $1,350 million of long-term debt under its Medium-Term Note (MTN) Program, and repaid $450 million in maturing long-term debt, all in the first quarter. In 2015, $350 million of long-term debt was issued in the second quarter, and no long-term debt was repaid during the six months ended June 30, 2015. See section entitled "Liquidity and Financing Strategy" for details of the Company's liquidity and financing strategy.

During the second quarter of 2016, Hydro One paid no dividends compared to dividends totalling $30 million paid during the second quarter of 2015 ($25 million of common share dividends and $5 million of preferred share dividends). In addition, during the second quarter of 2016, Hydro One made a return of stated capital in the amount of $125 million.

During the six months ended June 30, 2016, Hydro One paid dividends in the amount of $2 million ($2 million of common share dividends), compared to dividends totalling $59 million paid during the six months ended June 30, 2015 ($50 million of common share dividends and $9 million of preferred share dividends). In addition, during the six months ended June 30, 2016, Hydro One made a return of stated capital in the amount of $351 million.

Cash from Investing Activities

Cash used in investing activities during the second quarter of 2016 was $413 million compared to $480 million during the second quarter of 2015. The higher cash used in 2015 was mainly due to the acquisition of Haldimand Hydro in the second quarter of 2015.

Cash used in investing activities during the six months ended June 30, 2016 was $773 million compared to $829 million during the same period in 2015. The decrease in 2016 was mainly due to cash used for the acquisition of Haldimand Hydro in the second quarter of 2015, and increased capital contributions received in 2016, partially offset by higher capital investments in 2016.

See section entitled "Capital Investments" for details of the Company's capital investments.

LIQUIDITY AND FINANCING STRATEGY

Short-term liquidity is provided through funds from operations, Hydro One's Commercial Paper Program, and bank credit facilities. Under the commercial paper program, Hydro One is authorized to issue up to $1.5 billion in short-term notes with a term to maturity of up to 365 days. At June 30, 2016, Hydro One had $948 million in commercial paper borrowings outstanding, compared to $1,491 million outstanding at December 31, 2015. In addition, the Company has revolving bank credit facilities totalling $2.3 billion that mature between 2018 and 2020. The Company may use the credit facilities for working capital and general corporate purposes. The short-term liquidity under the Commercial Paper Program, the credit facilities and anticipated levels of funds from operations are expected to be sufficient to fund the Company's normal operating requirements.

At June 30, 2016, all of the Company's long-term debt in the principal amount of $9,623 million was issued under its MTN Program. At June 30, 2016, the maximum authorized principal amount of notes issuable under the current MTN Program filed in December 2015 was $3.5 billion, with $2,150 million remaining available for issuance until January 2018. The long-term debt consists of notes and debentures that mature between 2016 and 2064, and at June 30, 2016, had an average term to maturity of approximately 16.4 years and a weighted average coupon of 4.4%.

At June 30, 2016, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

At June 30, 2016, Hydro One's long-term and short-term debt ratings were as follows:

Rating Agency	Short-term Debt Rating	Long-term Debt Rating
DBRS Limited (DBRS)	R-1 (low)	A (high)
Moody's Investors Service (Moody's)	Prime-2	A3
S&P	A-1	A

CAPITAL INVESTMENTS

The following table presents Hydro One's capital investments during the three and six months ended June 30, 2016 and 2015:

	Three months ended June 30			Six months ended June 30		
(millions of Canadian dollars)	2016	2015	Change	2016	2015	Change
Transmission						
Sustaining	187	193	(3.1%)	368	362	1.7%
Development	40	40	–	80	73	9.6%
Other	11	1	–	25	10	–
	238	234	1.7%	473	445	6.3%
Distribution						
Sustaining	111	123	(9.8%)	197	193	2.1%
Development	52	57	(8.8%)	91	101	(9.9%)
Other	15	12	25.0%	33	30	10.0%
	178	192	(7.3%)	321	324	(0.9%)
Other	–	3	(100.0%)	–	5	(100.0%)
Total capital investments	416	429	(3.0%)	794	774	2.6%

Transmission Capital Investments

The increase of $4 million or 1.7% in transmission capital investments during the second quarter of 2016 was primarily due to the following:

- greater volume of work on overhead line refurbishments and insulator replacements; and
- increased volume of integrated station component replacements to sustain the aging assets at transmission stations, including the Hanmer transmission station, DeCew Falls switching station, and the Allanburg transmission station; partially offset by
- decreased investments in certain system re-investment projects, primarily due to the refurbishment work at the Dunnville, Dundas, and Wiltshire Transmission stations last year.

The increase of $28 million or 6.3% in transmission capital investments for the six months ended June 30, 2016 was the result of similar factors as noted above. In addition, continued work on major local area supply and inter-area network development projects, such as the Holland Transmission Station, Guelph Area Transmission Refurbishment, Toronto Midtown Transmission Reinforcement, Northwest Special Protection Scheme Replacement, and Clarington Transmission Station projects, also contributed to the overall increase in transmission capital investments during the six months ended June 30, 2016.

Distribution Capital Investments

The decrease of $14 million or 7.3% in distribution capital investments during the second quarter of 2016 was primarily due to the following:

- reduced capital expenditures due to the divestiture of Hydro One Brampton in August 2015;
- lower volume of work within station refurbishment programs and lower volume of spare transformer purchases; and
- lower volume of work on the Joint Use and Relocations program, which enables certain of Hydro One's assets to be jointly used by the telecommunications and cable television industries, as well as relocation of poles, conductors and other equipment as required by municipal and provincial road authorities; partially offset by
- increased investments related to information technology equipment, upgrade and enhancement projects, including investments to integrate mobile technology with the Company's existing work management tools; and
- increased number of wood pole replacements.

The decrease of $3 million or 0.9% in distribution capital investments for the six months ended June 30, 2016 was the result of similar factors as noted above. In addition, increased storm restoration work mainly as a result of an ice storm in March 2016, contributed to offset the overall decrease in distribution capital investments during the six months ended June 30, 2016.

Major Transmission Projects

The following table summarizes the status of certain major transmission projects of Hydro One at June 30, 2016:

Project Name	Location	Type	Anticipated In-Service Date	Estimated Cost	Capital Cost To-Date
Development Projects:					
Guelph Area Transmission Refurbishment	Guelph area Southwestern Ontario	Transmission line upgrade	September 2016	$103 million	$79 million
Toronto Midtown Transmission Reinforcement	Toronto Southwestern Ontario	New transmission line	December 2016	$123 million	$107 million
Supply to Essex County Transmission Reinforcement	Windsor-Essex area Southwestern Ontario	New transmission line and station	2018	$73 million	$6 million
Clarington Transmission Station	Oshawa area Southwestern Ontario	New transmission station	2018	$297 million	$162 million
Northwest Bulk Transmission Line	Thunder Bay Northwestern Ontario	New transmission line	As early as 2020	To be determined	–
East-West Tie Station Expansion Work	Northern Ontario	Station expansion	2020	$166 million	–
Sustainment Projects:					
Bruce A Transmission Station	Tiverton Southwestern Ontario	Station sustainment	2019	$109 million	$69 million
Richview Transmission Station Circuit Breaker Replacement	Toronto Southwestern Ontario	Station sustainment	2019	$102 million	$54 million
Lennox Transmission Station Circuit Breaker Replacement	Napanee Southeastern Ontario	Station sustainment	2020	$95 million	$4 million
Beck #2 Transmission Station Circuit Breaker Replacement	Niagara area Southwestern Ontario	Station sustainment	2021	$93 million	$8 million

OTHER OBLIGATIONS

Off-Balance Sheet Arrangements

There are no off-balance sheet arrangements that have, or are reasonably likely to have, a material current or future effect on the Company's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of Hydro One's debt and other major contractual obligations, as well as other major commercial commitments:

June 30, 2016 *(millions of Canadian dollars)*	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Contractual obligations *(due by year)*					
Long-term debt – principal repayments	9,623	50	1,578	1,150	6,845
Long-term debt – interest payments	7,760	423	789	717	5,831
Short-term notes payable	948	948	–	–	–
Pension contributions[1]	257	94	163	–	–
Environmental and asset retirement obligations	238	24	53	61	100
Outsourcing agreements	410	144	208	48	10
Operating lease commitments	34	10	13	9	2
Long-term software/meter agreement	81	16	34	26	5
Total contractual obligations	19,351	1,709	2,838	2,011	12,793
Other commercial commitments *(by year of expiry)*					
Credit facilities	2,300	–	800	1,500	–
Letters of credit[2]	144	144	–	–	–
Guarantees[3]	330	330	–	–	–
Total other commercial commitments	2,774	474	800	1,500	–

[1] Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2016, 2017 and 2018 minimum pension contributions are based on an actuarial valuation as at December 31, 2015 and projected levels of pensionable earnings.

[2] Letters of credit consist of a $139 million letter of credit related to retirement compensation arrangements, and a $5 million letter of credit provided to the Independent Electricity System Operator (IESO) as prudential support.

[3] Guarantees consist of prudential support provided to the IESO by Hydro One on behalf of its subsidiaries using parental guarantees of $330 million.

REGULATION

Hydro One Networks – 2017-2018 Transmission Rate Application

On May 31, 2016, Hydro One Networks filed a cost-of-service application with the OEB for 2017 and 2018 transmission rates, and an update to evidence was filed on June 20, 2016. The application seeks approval of rate base of $10,554 million for 2017 and $11,226 million for 2018, and reflects a return on equity (ROE) of 9.19% for each year. The application also includes a proposed future transmission capital investment program for the next five years, with investments in capital spending primarily to address safety and customer and reliability needs, in a cost effective manner. An OEB decision is anticipated in the fourth quarter of 2016 or the first quarter of 2017. Future transmission rate applications are anticipated to be filed under the OEB's incentive-based regulatory framework.

OEB Pension and Other Post-Employment Benefits (OPEB) Generic Hearing

In 2015, the OEB began a consultation process to examine pensions and OPEBs in rate-regulated utilities, with the objectives of developing standard principles to guide its review of pension and OPEB related costs in the future, and to establish specific requirements for applications and appropriate and consistent regulatory mechanisms for cost recovery. Hydro One and other stakeholders filed written submissions with respect to initial OEB questions meant to solicit views on the key issues of interest to the OEB. Following a stakeholder forum in July 2016, updated written submissions will be accepted by the OEB until September 2016. It is anticipated that subsequent to the OEB's review of the updated written submissions, the OEB will outline principles to guide its review of pension and OPEB related costs in the future, and provide further guidance on application requirements and regulatory mechanisms for cost recovery.

OTHER DEVELOPMENTS

Great Lakes Power Transmission Purchase Agreement

On January 28, 2016, Hydro One reached an agreement to acquire Great Lakes Power Transmission LP, an Ontario regulated electricity transmission business operating along the eastern shore of Lake Superior, north and east of Sault Ste. Marie, Ontario from Brookfield Infrastructure, for $222 million in cash, subject to customary adjustments, plus the assumption of approximately $151 million in outstanding indebtedness. The acquisition is currently pending regulatory approval by the OEB. Upon completion of this acquisition, Hydro One's transmission system will account for approximately 98% of Ontario's transmission capacity, an increase of approximately 2%.

Share-based Compensation – Long-term Incentive Plan

On March 31, 2016, Hydro One Limited granted awards under the Long-term Incentive Plan. These awards consist of approximately 124,120 Performance Stock Units and 149,120 Restricted Stock Units, all of which are equity settled in Hydro One Limited shares.

Pension Plan

In June 2016, Hydro One filed an actuarial valuation of its Pension Plan as at December 31, 2015. Based on this valuation and projected levels of pensionable earnings, the estimated total employer annual pension contributions for 2016, 2017 and 2018 are approximately $108 million, $105 million and $102 million, respectively. The estimated 2016 annual employer contributions have decreased by approximately $72 million from $180 million based on improvements in the funded status of the plan and future actuarial assumptions, and also reflect the impact of changes implemented by management to improve the balance between employee and Company contributions to the Pension Plan. The updated actuarial valuation resulted in a $15 million decrease in revenue for the three and six months ended June 30, 2016, with a corresponding decrease in OM&A costs, which will be refunded to ratepayers through the pension cost variance deferral account in future rate applications.

NON-GAAP MEASURES

FFO

FFO is defined as net cash from operating activities, adjusted for the following: (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) distributions to noncontrolling interest. Management believes that FFO is helpful as a supplemental measure of the Company's operating cash flows as it excludes timing-related fluctuations in non-cash operating working capital and cash flows not attributable to common shareholder. As such, this measure provides a consistent measure of the cash generating performance of the Company's assets.

The following table presents the reconciliation of net cash from operating activities to FFO:

	Three months ended June 30		Six months ended June 30	
(millions of Canadian dollars)	**2016**	**2015**	**2016**	**2015**
Net cash from operating activities	283	287	657	713
Changes in non-cash balances related to operations	56	(7)	68	59
Preferred share dividends	–	(5)	–	(9)
Distributions to noncontrolling interest	(1)	(2)	(4)	(2)
FFO	338	273	721	761

RELATED PARTY TRANSACTIONS

Hydro One is owned by Hydro One Limited. The Province is the majority shareholder of Hydro One Limited. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), the OEB, Hydro One Brampton and Hydro One Telecom are related parties to Hydro One because they are controlled or significantly influenced by the Province or by Hydro One Limited. The following is a summary of the Company's related party transactions during the three and six months ended June 30, 2016:

		Three months ended June 30		Six months ended June 30	
		2016	2015	2016	2015
Related Party	**Transaction**	*(millions of Canadian dollars)*			
Province	Dividends paid	–	30	–	59
IESO	Power purchased	335	471	1,045	1,262
	Revenues for transmission services (based on OEB-approved uniform transmission rates)	375	363	751	768
	Distribution revenues related to rural rate protection	32	32	63	64
	Distribution revenues related to the supply of electricity to remote northern communities	8	8	16	16
	Funding received related to Conservation and Demand Management programs	17	11	24	23
OPG	Power purchased	1	2	3	8
	Revenues related to provision of construction and equipment maintenance services	–	1	1	3
	Costs expensed related to the purchase of services	–	–	1	1
OEFC	Payments in lieu of corporate income taxes	–	14	–	32
	Power purchased from power contracts administered by the OEFC	1	2	1	4
	Indemnification fee paid (terminated effective October 31, 2015)	–	–	–	5
OEB	OEB fees	3	3	7	6
Hydro One Limited	Return of stated capital	125	–	351	–
	Dividends paid	–	–	2	–
	Stock-based compensation costs	6	–	11	–
Hydro One Brampton	Revenues from management, administrative and smart meter network services	1	–	2	–
Hydro One Telecom	Services received – costs expensed	7	–	13	–
	Services received – costs capitalized	3	–	6	–

At June 30, 2016, the amounts due from and due to related parties as a result of the transactions described above were $216 million and $36 million, compared to $184 million and $142 million at December 31, 2015, respectively. At June 30, 2016, amounts due from related parties included net amount due from the IESO of $17 million in respect of power purchases, compared to $134 million due to the IESO included in amounts due to related parties at December 31, 2015.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

There have been no changes in Hydro One's internal controls over financial reporting during the six months ended June 30, 2016 that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board (FASB) that are applicable to Hydro One:

Recently Adopted Accounting Guidance

ASU	Date issued	Description	Effective date	Impact on Hydro One
2015-03	April 2015	Debt issuance costs are required to be presented on the balance sheet as a direct deduction from the carrying amount of the related debt liability consistent with debt discounts or premiums.	January 1, 2016	Reclassification of deferred debt issuance costs and net unamortized debt premiums as an offset to long-term debt. Applied retrospectively.
2015-17	November 2015	All deferred tax assets and liabilities are required to be classified as noncurrent on the balance sheet.	January 1, 2017	To simplify reporting, this ASU was early adopted as of April 1, 2016 and applied prospectively. As a result, the current portions of the Company's deferred income tax assets are reclassified as noncurrent assets on the consolidated Balance Sheet. Prior periods were not retrospectively adjusted.

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-02	February 2016	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. An exemption election is available for short-term leases.	January 1, 2019	Under assessment
2016-09	March 2016	This guidance simplifies several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows.	January 1, 2017	Under assessment
2016-10	April 2016	This guidance clarifies the identification of performance obligations and the implementation of the licensing guidance with respect to revenue from contracts with customers.	January 1, 2018	Under assessment
2016-12	May 2016	This guidance aims to simplify the transition to the new standard on accounting for revenue from contracts with customers (ASU 2014-09) and to clarify certain aspects of the new standard.	January 1, 2018	Under assessment

FORWARD-LOOKING STATEMENTS AND INFORMATION

The Company's oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about the Company's business and the industry, regulatory and economic environments in which it operates, and include beliefs and assumptions made by the management of the Company. Such statements include, but are not limited to: statements regarding the Company's transmission and distribution rates resulting from rate applications; statements regarding the Company's liquidity and capital resources and operational requirements; statements about the standby credit facilities; expectations regarding the Company's financing activities; statements regarding the Company's maturing debt; statements related to credit ratings; statements regarding ongoing and planned projects and/or initiatives, including expected results and completion dates; statements regarding expected future capital and development investments, the timing of these expenditures and the Company's investment plans; statements regarding contractual obligations and other commercial commitments; statements related to the OEB; statements regarding future pension contributions and valuations; statements about non-GAAP measures; statements regarding recent accounting-related guidance; expectations related to tax impacts; and statements related to the Company's acquisitions, including statements about Great Lakes Power Transmission LP. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. Hydro One does not intend, and it disclaims any obligation, to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to, the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding and future rate and other applications; no unexpected delays in obtaining the required approvals; no unforeseen changes in rate orders or rate setting methodologies for the Company's distribution and transmission businesses; continued use of US GAAP; a stable regulatory environment; no unfavourable changes in environmental regulation; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to the Company, including information obtained from third party sources. Actual results may differ materially from those predicted by such forward-looking statements. While Hydro One does not know what impact any of these differences may have, the Company's business, results of operations, financial condition and credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- risks associated with the Province's significant share ownership of Hydro One's parent corporation and other relationships with the Province, including potential conflicts of interest that may arise between Hydro One, the Province and related parties;
- regulatory risks and risks relating to Hydro One's revenues, including risks relating to rate orders, actual performance against forecasts and capital expenditures;
- the risk that the Company may be unable to comply with regulatory and legislative requirements or that the Company may incur additional costs for compliance that are not recoverable through rates;
- the risk of exposure of the Company's facilities to the effects of severe weather conditions, natural disasters or other unexpected occurrences for which the Company is uninsured or for which the Company could be subject to claims for damage;
- public opposition to and delays or denials of the requisite approvals and accommodations for the Company's planned projects;
- the risk that Hydro One may incur significant costs associated with transferring assets located on Reserves (as defined in the *Indian Act* (Canada));
- the risks associated with information system security and maintaining a complex information technology system infrastructure;
- the risks related to the Company's workforce demographic and its potential inability to attract and retain qualified personnel;
- the risk of labour disputes and inability to negotiate appropriate collective agreements on acceptable terms consistent with the Company's rate decisions;
- risk that the Company is not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures;
- risks associated with fluctuations in interest rates and failure to manage exposure to credit risk;
- the risk that the Company may not be able to execute plans for capital projects necessary to maintain the performance of the Company's assets or to carry out projects in a timely manner;
- the risk of non-compliance with environmental regulations or failure to mitigate significant health and safety risks and inability to recover environmental expenditures in rate applications;
- the risk that assumptions that form the basis of the Company's recorded environmental liabilities and related regulatory assets may change;
- the risk of not being able to recover the Company's pension expenditures in future rates and uncertainty regarding the future regulatory treatment of pension, other post-employment benefits and post-retirement benefits costs;
- the potential that Hydro One may incur significant expenses to replace functions currently outsourced if agreements are terminated or expire before a new service provider is selected;
- the risks associated with economic uncertainty and financial market volatility;
- the inability to prepare financial statements using US GAAP; and
- the impact of the ownership by the Province of lands underlying the Company's transmission system.

Hydro One cautions the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section entitled "Risk Management and Risk Factors" in the 2015 MD&A.

In addition, Hydro One cautions the reader that information provided in this MD&A regarding the Company's outlook on certain matters, including potential future investments, is provided in order to give context to the nature of some of the Company's future plans and may not be appropriate for other purposes.

Additional information about Hydro One, including the Company's Annual Information Form for the year ended December 31, 2015, is available on SEDAR at www.sedar.com, the US Securities and Exchange Commission's EDGAR website at www.sec.gov/edgar.shtml, and the Company's website at www.HydroOne.com/Investors.

hydro One

Second Quarter 2016 Earnings Teleconference

August 12, 2016

One of North America's largest electric utilities

TSX: H

Hydro One Limited – Second Quarter Financial Summary

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($ millions)	Second Quarter 2016	Second Quarter 2015	Change	Year to Date 2016	Year to Date 2015	Change
Revenue						
Transmission	$381	$364	4.7%	767	770	(0.4%)
Distribution (Gross)	*1,152*	*1,185*	*(2.8%)*	*2,438*	*2,574*	*(5.3%)*
Distribution (Net of Purchased Power)	349	347	0.6%	739	766	(3.5%)
Other	13	14	(7.1%)	27	27	–
Consolidated (Gross)	*1,546*	*1,563*	*(1.1%)*	*3,232*	*3,371*	*(4.1%)*
Consolidated (Net of Purchased Power)	**743**	**725**	**2.5%**	**1,533**	**1,563**	**(1.9%)**
Earnings Before Financing Charges and Income Taxes (EBIT)						
Transmission	195	172	13.4%	390	385	1.3%
Distribution	108	85	27.1%	264	246	7.3%
Other	(15)	(4)	–	(22)	(5)	–
Consolidated	**288**	**253**	**13.8%**	**632**	**626**	**1.0%**
Capital Investments						
Transmission	*238*	*234*	1.7%	473	445	6.3%
Distribution	*178*	*192*	(7.3%)	321	324	(0.9%)
Other	*1*	*3*	–	2	5	–
Consolidated	**417**	**429**	**(2.8%)**	**796**	**774**	**2.8%**
Net Income[1]	**152**	**131**	**16.0%**	**360**	**359**	**0.3%**
Adjusted EPS	**$0.26**	**$0.22**	**16.0%**	**$0.61**	**$0.60**	**0.3%**
Diluted Adjusted EPS	**$0.25**	**$0.22**	**13.6%**	**$0.60**	**$0.60**	**–**

Financial Statements reported under U.S. GAAP
(1) Net Income is attributable to common shareholders and is after non-controlling interest and dividends to preferred shareholders

Regulatory Rate Filings

	Current Rate Methodology	Approved rate base	Effective term of next application	Comments
Transmission	Cost of Service	2016 $10.04 billion	Filed May 31, 2016 for 2017-18	Two-year cost of service filing made May 31, 2016 incorporating OEB's Renewed Regulatory Framework for Electricity utilities principles. Incentive based rate model to become effective in 2019.

- Capital investment supported by rigorous customer consultations, risk based metrics, total-cost benchmarking and asset condition assessments
- OM&A expected to remain flat despite upward pressure from inflation, a growing rate base, and various compliance obligations

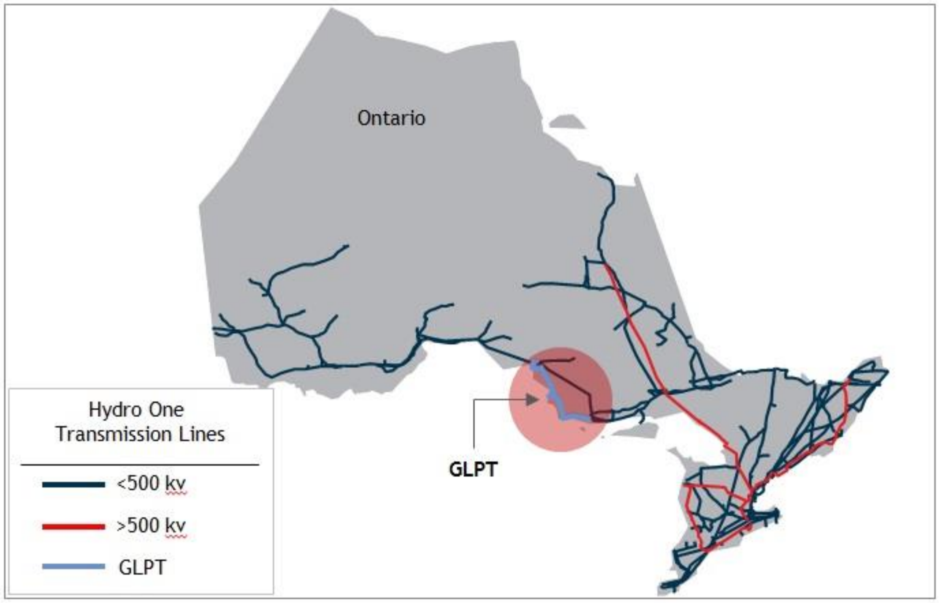
	Current Rate Methodology	Approved rate base	Effective term of next application	Comments
Distribution	Cost of Service	2016 $6.86 billion	File in first half of 2017 for 2018-22	Five-year incentive based rate filing anticipated in first half of 2017. Decision for phased transition to fixed residential rates (decoupling) already in place.

- Deemed debt / equity capital structure of 60% / 40% in both transmission and distribution segments
- Allowed ROE reset annually by a formula linked to long-term government bond yields and corporate bond spreads

Road map for transitions to incentive based regulatory model now set for both Transmission and Distribution segments

Pending Great Lakes Power Transmission Acquisition

GLPT Relative to Hydro One Transmission Operations



Key Points

- "No-action" letter received from the Competition Bureau in July, 2016
- Rare opportunity to expand already significant transmission footprint in Ontario
- Increases Hydro One's transmission coverage to ~98% of province-wide grid
- Expected to be earnings accretive in first year
- 560km of high voltage transmission lines, towers and stations
- $222 million cash purchase price plus $151 million of assumed debt
- Targeted transaction closing second half of 2016 subject to OEB approval

A contiguous and already interconnected strategic transmission asset

Equity Market Cap Overview

- Equity market capitalization of ~$15 billion and public float of ~$4.5 billion
- Average daily trading volume of approximately 1.3 million shares
- Equity market capitalization amongst the top 30 of all listed Canadian companies
- Secondary offerings by Province increase liquidity without diluting public shareholders
- Equity index inclusions to date:

S&P/TSX Composite Index

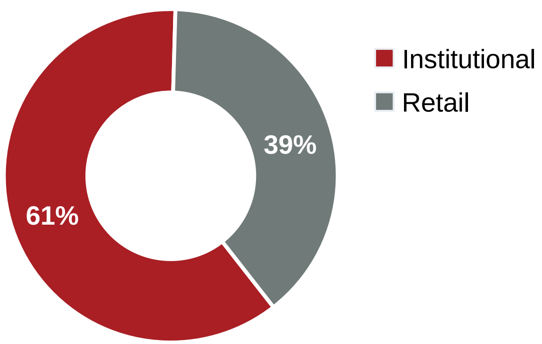
S&P/TSX Utilities Index

Dow Jones Canada Select Utilities

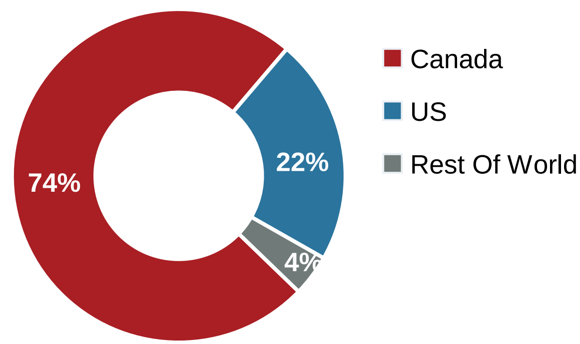
FTSE All-World (Canada)

MSCI World (Canada)

Approximate Ownership of Public Float



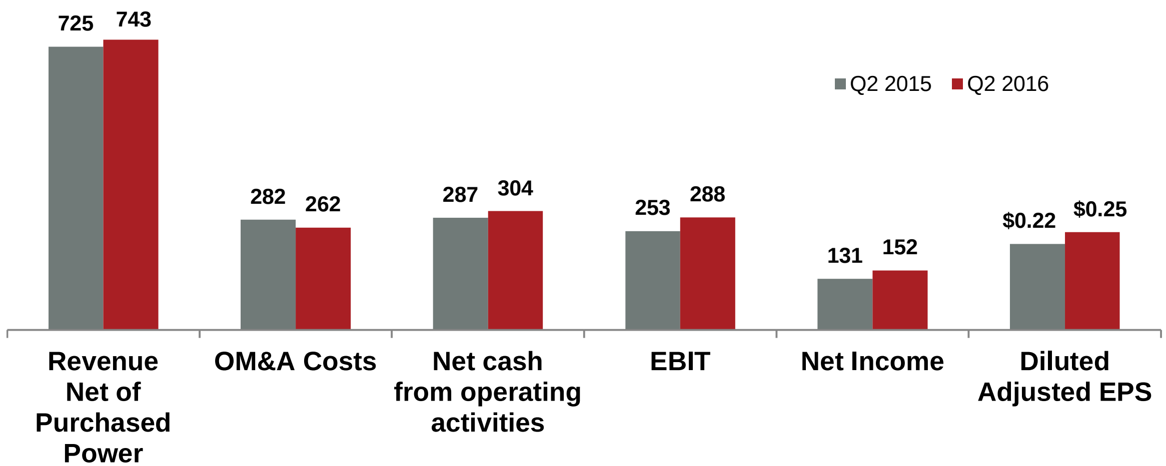
Approximate Geographic Dispersion of Public Float



2016 Second Quarter Financial Highlights

hydroOne

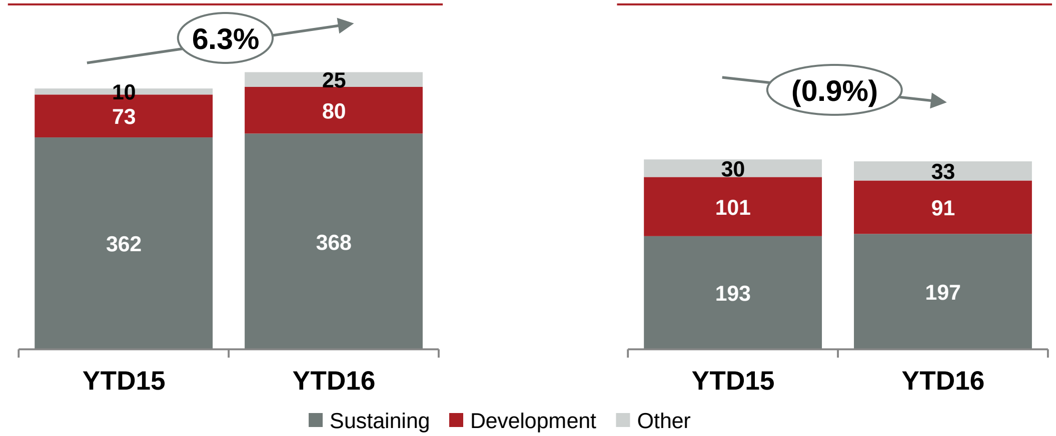
Financial Highlights ($M) – 2Q16 Year over Year Comparison



Key drivers

- Revenue growth driven by Dx rate changes and higher average monthly Tx peak demand, partially offset by lower pension cost deferral
- Operating cost improvements from:
  - Lower bad debt costs
  - Lower outsourcing support related costs
  - Lower transformer refurbishment and station maintenance costs
- Lower pension costs due to actuarial revaluation (offset in Revenue)
- Hydro One Brampton divestiture (rev. net of purchased power: -$18mn, net income: -$7mn)
- Higher interest expense on IPO recapitalization

Regulated Capital Investments ($M) – Year to Date Comparison



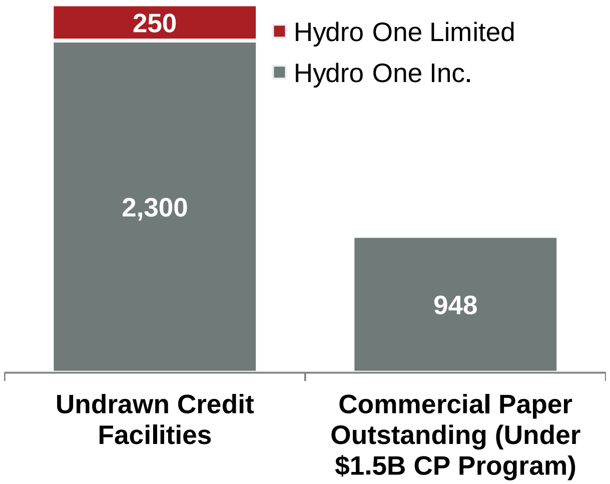
Key drivers

- Capital investment growth in every category of the Tx segment
- Dx segment capital investment up $17mn YTD adjusting for -$20mn impact of Hydro One Brampton in 2015
- $518mn of new regulated assets placed in-service YTD 2016

Revenue, efficiencies and earnings all positive year over year

Strong Balance Sheet and Liquidity

Significant Available Liquidity ($M)



Strong Investment Grade Credit Ratings (LT/ST/Outlook)

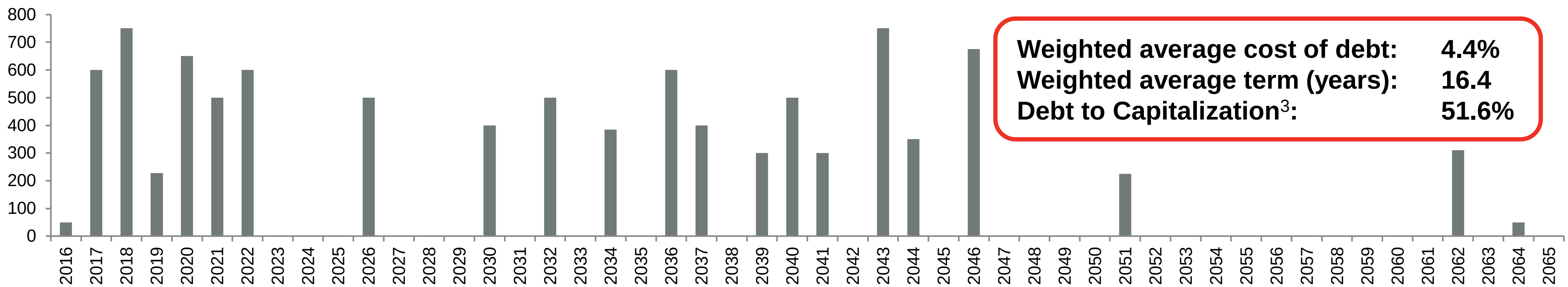
Hydro One Inc. (HOI)	
S&P	A / A-1/ stable
DBRS	A (high) / R-1 (low) / stable
Moody's	A3 / Prime-2 / stable

Shelf Registrations

HOL:
Universal Shelf[1]
$8B

HOI:
Medium Term Note Shelf [2]
$3.5B

Debt Maturity Schedule ($M)



Weighted average cost of debt:	**4.4%**
Weighted average term (years):	**16.4**
Debt to Capitalization[3]:	**51.6%**

Investment grade balance sheet with one of lowest debt costs in utility sector

(1) $1,970 million was drawn from the Universal Shelf during April 2016 with respect to a secondary share offering by the Province, leaving $6,030 million remaining available until April 2018.

(2) $1,350 million was drawn from the Medium Term Note Shelf on February 24, 2016, leaving $2,150 million remaining available until January 2018.

(3) Debt to capitalization ratio has been calculated as total debt (includes total long-term debt and short-term borrowings, net of cash) divided by total debt plus total shareholder's equity, including preferred shares but excluding any amounts related to non-controlling interest.

Disclaimers

DISCLAIMERS
In this presentation, all amounts are in Canadian dollars, unless otherwise indicated. Any graphs, tables or other information in this presentation demonstrating the historical performance of the Company or any other entity contained in this presentation are intended only to illustrate past performance of such entitles and are not necessarily indicative of future performance of Hydro One. In this presentation, “Hydro One” refers to Hydro One Limited and its subsidiaries and other investments, taken together as a whole.

Forward-Looking Information
This presentation contains “forward-looking information” within the meaning of applicable Canadian securities laws. Forward-looking information in this presentation is based on current expectations, estimates, forecasts and projections about Hydro One’s business and the industry in which Hydro One operates and includes beliefs of and assumptions made by management. Such statements include, but are not limited to: statements related to dividends, including expectations regarding the ability of continued rate base expansion through capital investments to drive growth in dividends; statements related to the Great Lakes Power transmission acquisition; expectations regarding the core priorities of the Company; statements regarding the Company’s maturing debt, shelf registrations, and credit facilities; expectations regarding funding for planned capital investments; and statements related to rate applications.

Words such as “aim”, “could”, “would”, “expect”, “anticipate”, “intend”, “attempt”, “may”, “plan”, “will”, “believe”, “seek”, “estimate”, “goal”, “target”, and variations of such words and similar expressions are intended to identify such forward-looking information. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking information. Hydro One does not intend, and it disclaims any obligation to update any forward-looking information, except as required by law.

The forward-looking information in this presentation is based on a variety of factors and assumptions, as described in the financial statements and management’s discussion and analysis. Actual results may differ materially from those predicted by such forward-looking information. While Hydro One does not know what impact any of these differences may have, Hydro One’s business, results of operations and financial condition may be materially adversely affected if any such differences occur. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking information are described in the financial statements and management’s discussion and analysis.

Non-GAAP Measures
Hydro One prepares and presents its financial statements in accordance with U.S. GAAP. “Funds from Operations” or “FFO” and “Adjusted Earnings Per Share” are not recognized measures under U.S. GAAP and do not have a standardized meanings prescribed by U.S. GAAP. This is therefore unlikely to be comparable to similar measures presented by other companies. Funds from Operations should not be considered in isolation nor as a substitute for analysis of Hydro One’s financial information reported under U.S. GAAP. “Funds from Operations” or “FFO” is defined as net cash from operating activities, adjusted for the following: (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) non-controlling interest distributions. Adjusted EPS utilizes the end of period shares outstanding instead of an average which would otherwise include share amounts for a prior entity prior to Hydro One Limited’s IPO. Management believes that these measures will be helpful as a supplemental measure of the Company’s operating cash flows and earnings. For more information, see “Non-GAAP Measures” in the Initial Public Offering Prospectus.

UNDERTAKING – TCJ1.9

Undertaking

To provide an update of the schedules that are found at Exhibit C2, Tab 1 and C2, Tab 2.

Response

Please see below the updated exhibits:

Exhibit C2-1-1 - Cost of Service

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Service
Test (2017 and 2018) Years
Year Ending December 31
($ Millions)

Line No.	Particulars	2017	2018
		(a)	(b)
1	Total Operation, Maintenance & Administrative Expenses	412.7	409.3
2	Depreciation & Amortization Expenses	435.7	470.7
3	Capital Taxes	0.0	0.0
4	Income Taxes	88.1	96.2
5	**Total Cost of Service**	**936.5**	**976.2**

Exhibit C2-2-1 - Comparison of OM&A Expense by Major Category– Historic, Bridge and Test Years

Transmission OM&A ($millions)	2012	2013	2014	2015	2016	2017	2018
Sustaining OM&A							
Transmission Stations							
Land Assessment and Remediation	1.9	3.1	3.1	3.6	3.0	2.2	1.2
Environment Management	11.3	11.9	10.7	9.8	10.4	18.4	18.0
Power Equipment	55.7	60.2	61.4	64.5	54.3	60.0	57.0
Ancillary System Maintenance	10.1	10.1	10.0	9.2	10.8	11.2	11.2
Protection, Control, Monitoring, Metering and Telecommunications	44.9	49.4	52.1	63.9	61.2	60.9	62.0
Site Infrastructure Maintenance	22.7	25.2	24.5	24.0	25.1	25.7	25.3
Total Transmission Stations OM&A	**146.5**	**159.9**	**161.9**	**175.0**	**164.8**	**178.5**	**174.8**
Transmission Lines							
Rights of Way	27.1	31.1	35.5	32.6	35.8	33.8	34.8
Overhead Lines	17.9	15.7	17.6	15.9	18.0	20.9	20.8
Underground Cables	3.6	3.6	4.0	4.1	5.0	5.1	5.2
Total Transmission Lines OM&A	**48.6**	**50.4**	**57.1**	**52.6**	**58.8**	**59.8**	**60.8**
Engineering & Environmental Support	9.5	10.7	9.6	6.0	4.0	2.9	2.9
Total Sustaining OM&A	**204.7**	**221.0**	**228.6**	**233.6**	**227.5**	**241.2**	**238.5**
Development OM&A							
Technical Standards	2.5	3.1	3.3	2.8	3.0	2.5	2.6
Research Development and Demonstration	0.0	0.0	0.0	0.0	2.1	2.1	2.2
Customer Power Quality	0.0	0.0	0.0	0.0	0.2	0.2	0.2
Technology Studies	3.5	3.2	2.8	3.0	0.0	0.0	0.0
Smart Grid	2.4	2.2	1.4	0.3	0.0	0.0	0.0
Total Development OM&A	**8.4**	**8.6**	**7.5**	**6.1**	**5.3**	**4.8**	**5.0**
Operations OM&A							
Operations Contracts	21.4	21.3	20.9	22.4	22.9	23.6	24.3
Environmental, Health and Safety	1.3	1.5	1.1	1.1	1.6	1.9	1.8
Operators	32.1	33.9	34.6	35.5	35.5	35.9	36.1
Total Operations OM&A	**54.8**	**56.7**	**56.6**	**59.0**	**60.0**	**61.3**	**62.1**
Customer Service OM&A	**4.4**	**5.3**	**5.4**	**5.1**	**4.1**	**4.0**	**3.9**
OM&A Common Corporate Costs and Other Costs							
Asset Management	32.3	31.8	32.6	31.0	36.6	36.5	35.8
Common Corporate Functions & Services	80.5	87.7	93.1	95.7	98.9	98.3	97.6

Transmission OM&A ($millions)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Information Technology (including Cornerstone)	60.7	61.1	55.2	55.1	61.4	59.8	57.6
Cost of Sales	11.4	13.9	11.1	8.8	5.0	5.0	5.0
Other	-104.2	-118.6	-154.8	-116.8	-129.6	-149.7	-148.5
Total OM&A Common Corporate Costs and Other Costs	**80.7**	**75.8**	**37.2**	**73.9**	**72.3**	**49.9**	**47.5**
Property Taxes & Rights Payments	**62.1**	**21.2**	**64.1**	**63.9**	**62.9**	**63.6**	**64.3**
Blue Page Pension Adjustment	-	-	-	-	-	-11.0	-8.0
Blue Page B2M LP Adjustment	-	-	-	-	-	-0.8	-2.1
Post Blue Page Pension Adjustment	-	-	-	-	-	-0.4	-1.9
Total Transmission OM&A	**415.1**	**388.4**	**399.5**	**441.6**	**432.1**	**412.7**	**409.3**

UNDERTAKING – TCJ1.10

Undertaking

To provide written answers to Mr. Aiken's questions.

Response

LPMA TCQ 1

Exhibit I, Tab 1, Schedule 131: The table provided in the response to part (b) (i) of the interrogatory response shows the amount included in rates for OM&A and capital, but does not show the impact on rates. Please provide the revenue requirement impact of the OM&A and capital amounts included in rates for the years shown based on the accrual basis and confirm that this would be comparable to the revenue requirement based on the cash payments made in the years shown.

Response:
The level of effort require to produce the requested information is very significant. In order to conduct a meaningful comparison between the accrual basis and cash basis, Hydro One would have to run the revenue requirement under each scenario going back to 1999 and consider the amounts that have been capitalized each year under the accrual basis to arrive at the revenue requirement and then do the same under the cash basis (as under the cash basis, amounts would have been capitalized as well).

Hydro One believes this issue is better addressed in the OEB's Consultation on the Regulatory Treatment of Pension and Other Post-employment Benefit Costs (EB-2015-0040).

LPMA TCQ 2

Exhibit I, Tab 4, Schedule 12: Table 1 provided in the response shows the change in CCF&S costs by department. The response also indicates that between 2016 and 2018 the move to a more commercially-oriented culture is one of the drivers of the increased costs. Please provide the total costs associated with the move to a more commercially-oriented culture that are included in Table 1 for 2016, 2017, 2018 and for the TX allocation for 2017 and 2018.

Response:
As outlined in Board Staff #1 (I-1-1), the ongoing costs associated with Hydro One becoming a publicly traded entity and the move to a more commercially-oriented culture, are related solely to the company's new governance structure.

To improve the performance of the company, the new Board of Directors determined that it was necessary to increase the commercial orientation of the organization by hiring senior managers with proven track-records of delivering on targeted commercial objectives. The new senior managers, whose costs are reflected in Hydro One's current application are the new CEO and CFO costs.

The compensation of the new CEO and CFO functions is detailed in Attachment 1 to Exhibit I, Tab 11, Schedule 23. The 2014 costs for the CEO and CFO functions are provided in paragraph d) of the same Exhibit. Applying an inflation assumption of 2% to those 2014 figures, the aggregate cost increase for the two functions in 2017 is approximately $4.0 million, of which $1.6 million is allocated to Hydro One's transmission business.

The immediate benefits associated with the new senior management team are reflected in: (a) a reduction in the originally proposed revenue requirement occasioned by the CFO's decision to accelerate a pension valuation report, which reduced costs as discussed in Exhibit I, Tab 1, Schedule 131; and (b) the projected savings discussed in Exhibit I, Tab 13, Schedule 9 and Exhibit TCJ1.17.

LPMA TCQ 3

Exhibit I, Tab 4, Schedule 15:

(a) The interrogatory requested a table that showed for each of 2012 through 2016 the total Board approved depreciation and amortization expense, the actual depreciation and amortization expense and the difference. The table provided in the response appears to reflect depreciation expense only as shown in Table 1 of Exhibit C1, Tab 7, Schedule 1. Please provide another table, similar to Table 2 of Exhibit C1, Tab 7, Schedule 1 that shows the requested information for the amortization expenses.

(b) Approximately how much of the variance between actual depreciation and amortization from the Board approved levels is directly related to the variance in in-service additions noted in the response to Exhibit I, Tab 3, Schedule 47?

(c) What are the other sources the difference between actual and Board approved figures?

Response:

(a)

Amortization Expense	2012	2013	2014	2015	2016
Actuals	5.9	6.1	10.9	7.0	N/A
OEB Approved	8.9	8.5	9.3	6.5	6.1
Variance	**(3.0)**	**(2.4)**	**1.6**	**0.5**	**N/A**

(b) The variance in Depreciation Expense is as follows:

- Actual Depreciation expense in 2012 is lower than OEB approved mainly due to lower In-Service additions, partially offset by higher asset removal costs
- For the period 2013-2015, the aggregate actual depreciation expense is lower than OEB approved mainly due to lower In-Service additions and lower asset removal costs

(c) Actual amortization expense in 2012 and 2013 is lower than OEB approved due to lower environmental expenditures in those years.

LPMA TCQ 4

Exhibit I, Tab 4, Schedule 19: For each of the adjustments for tax purposes shown in the table (other than land and CEC adds), please explain the tax treatment associated with the adjustment. For example, is interest capitalized deducted as an expense for tax purposes if it is removed from the capital cost included in CCA?

Response:
Below are the explanations of the tax treatment for each of the adjustments shown in Exhibit I, Tab 4, Schedule 19.

<u>Asset Removal Costs</u>
The offset to the asset removal cost, which is reflected in the in-service capital additions, is included in the depreciation amount added back for tax purposes.

<u>Interest Capitalized</u>
Interest capitalized is reversed from in-service capital additions and deducted for tax purposes.

<u>Overheads Capitalized</u>
Overheads capitalized is reversed from in-service capital additions and deducted for tax purposes.

<u>Depreciation Capitalized</u>
Depreciation capitalized is reversed from in-service capital additions as it does not represent an addition for tax purposes.

<u>Capital Contribution</u>
The capital contribution true-up adjustment to in-service capital additions relates to amounts included in income for tax purposes that are not recovered through rates.

<u>OPEB Capitalized</u>
OPEB capitalized is reversed from in-service capital additions as OPEB cash payments are deducted for tax purposes.

<u>Pension Capitalized</u>
Pension capitalized is reversed from in-service capital additions as pension cash payments are deducted for tax purposes.

Miscellaneous Other

These are miscellaneous adjustments to in-service capital additions.

UNDERTAKING – TCJ1.11

Undertaking

To provide information on when the annual update is done on the audit plans and if any emerging risks have been identified that would impact the 2016 and 2017 audit plans.

Response

Requests for audits from Senior Management or the Board of Directors, or changes in risk/controls for any function or activity could result in a change to the annual audit plan at any time. In addition, deferral of an audit for any reason can also result in a change to the annual audit plan at any time.

The annual update to the audit plan is done in the second half of the year when the next cycle's work program is compiled for submission for approval by the Audit Committee of the Board. The update process involves reviewing the risks for the audit entities included in the work program through discussion or risk workshops with line management to determine if there are any significant changes to the risk profile resulting from external influences, or changes in people, processes or technology. This process may result in audits being added to, or removed from, the annual work plan.

For years 2017 to 2019, the update process was done during July and August 2016. There were no emerging risks which resulted in changes to the 2016 audit plan. Heightened global awareness of cyber-security risks have resulted in proposed changes to the 2017 audit plan, which have not yet been finalized.

UNDERTAKING – TCJ1.12

Undertaking

To provide for the years 2010 to 2016 the actual year-end dollar amounts for overtime.

Response

The table below shows the year-end overtime dollar amounts.

Year	Overtime Hours Worked	Overtime Amount Paid Including Premium
2010	1,009,830	$72,577,241
2011	1,203,824	$89,506,988
2012	995,526	$77,503,562
2013	1,240,211	$98,308,189
2014	1,104,225	$88,369,941
2015	1,036,656	$85,685,398
2016	701,746	$59,239,734

UNDERTAKING – TCJ1.13

Undertaking

To advise the overtime component in the assumptions that go into coming up with the standard labour rate.

Response

When deriving the standard labour rates, total payroll including base overtime component and expense costs (including assigned support activities) are divided by total billable hours to derive the standard labour rate. Total billable hours include overtime hours, which are estimated based on historical trends.

UNDERTAKING – TCJ1.14

Undertaking

To update Figure 3, Exhibit E1, Tab 3, Schedule 1, Page 13 with data for 2016.

Response

Please see below the updated graph as of September 30, 2016.

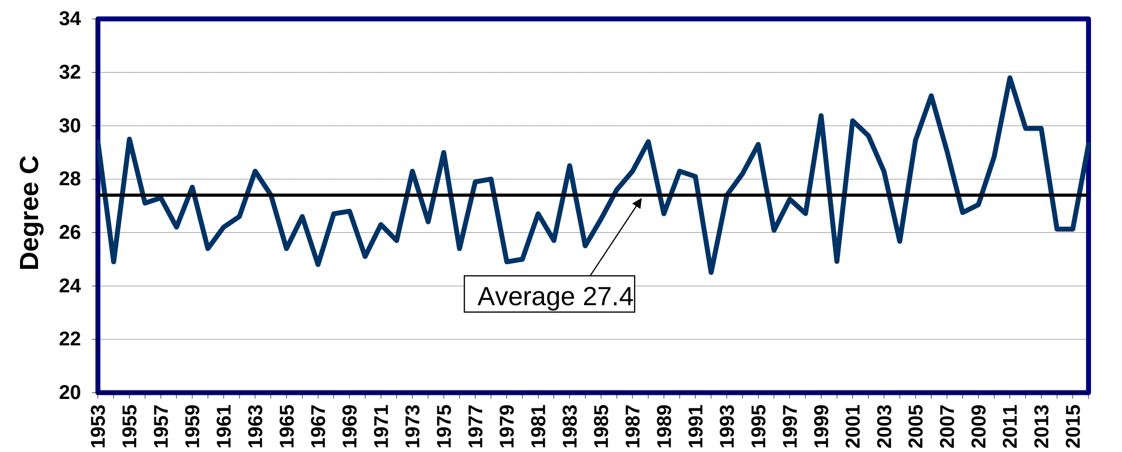


Figure 3. Toronto Pearson International Airport:
Maximum of Average Daily Temperature

UNDERTAKING – TCJ1.15

Undertaking

To talk about the number of customers within the R1 and R2 population in the first table, and then the number of R1 customers that are referenced in the second table.

Response

Reference: Exhibit I, Tab 10, Schedule 2, part d

The number of First Nations residential customers in Northern Ontario within the R1 and R2 population, as referenced in the first table, are 4,542 and 2,588 respectively. This information is based on 2015 data for all non-remote R1 and R2 First Nations customers in Northern Ontario where 12 complete months of billing data was available.

The number of Hydro One residential customers in Southern Ontario within the R1 population, as referenced in the second table, is 337,424. This information is based on 2015 data for all non-remote R1 customers in Southern Ontario where 12 complete months of billing data was available.

UNDERTAKING – TCJ1.16

Undertaking

To clarify as to where in the PILS calculations these losses get utilized and, if they're excluded, why exclusion is appropriate.

Response

The tax loss carry forwards arose as a consequence of the IPO and the resultant departure from the PILs regime.

Please see the response to Board Staff Interrogatory 134 (Exhibit I Tab 1 Schedule 134) for the explanation of why this deferred tax asset (utilization of the tax losses) is appropriately excluded from the PILs calculations.

UNDERTAKING – TCJ1.17

Undertaking

To clarify whether or not the amounts shown at Exhibit B, Tab T-1 – B2, T1, S1 are amounts that are just examples, or if they're amounts in aggregate; to provide a list of additional examples of productivity initiatives.

Response

The amounts provided in response to Exhibit I, Tab 13, Schedule 9 were only a few examples of procurement related savings.

Currently embedded in the investment plan are the following savings.

In $M	2017	2018
Procurement		
OM&A	2.1	2.8
Capital	11.2	21.4
Information Solutions Division (ISD)		
OM&A	3.4	4.5
Stations		
OM&A	2.9	3.5
Total		
OM&A	8.4	10.8
Capital	11.2	21.4

The forecasted savings are in the areas of procurement, information technology and stations. The procurement and information technology savings are explained below. For a breakdown of the stations savings, refer to Exhibit I, Tab 1, Schedule 116.

Procurement Savings

Following the initial public offering (IPO), Hydro One identified opportunities for cost savings and productivity improvements.

As described in Exhibit C1, Tab 5, Schedule 1, Hydro One's Supply Chain division is refining its current approaches and introducing new approaches to increase both savings potential and productivity efficiencies for Hydro One.

Specifically, there are seven planned enhancements to sourcing approaches.

1. Bundling/Volume Discounts – Renew view of sourcing categorization, grouping materials/services supplied by like-suppliers to maximize savings and volume discount opportunities, and addressing multiple sub-categories at once. Bundle multiple contracts with a single supplier, and negotiate volume discounts across multiple categories and contracts.

2. Feedback Rounds – Maximize competitive pressure through multiple feedback rounds on rates, with an opportunity for vendors to improve their proposals.

3. 'Lean' RFPs – Emphasize leaner, "bidder-friendly" scope and value in RFP formats with fewer onerous requirements and redundancies.

4. Standardization of Spend and Specifications – Standardize requirements to allow direct, like-for-like comparisons across bidders. Move towards industry-standard specifications where reasonable, rather than Hydro One specifications, to reduce unnecessary costs.

5. Streamlined Evaluation – Compress timelines and streamline evaluation process to meet business needs and accelerate the realization of negotiated savings.

6. Cost Transparency – Increase knowledge of bidders' prices and composition to improve Hydro One's ability to challenge and negotiate less competitive pricing.

7. Transition Pricing – Where contracts are being renegotiated with incumbent vendors, implement new negotiated rates before the renegotiated contract execution.

The table below lists spending categories and their associated potential savings (expressed as percentages) over the test years. The savings assumptions for procurement are against the 2015 spend.

<u>Procurement Productivity – Category Overview</u>

Category	Potential Savings (%)	Potential Approach/Levers
Electrical Hardware	5 – 15	• Conduct broad RFP with multiple feedback rounds • Consolidate spend across common suppliers thus increasing volume discount potential
EPC Services	10 – 15	• Establish competitive rate cards for project work through RFP with rate decomposition and quartile feedback
Engineering Services	10 – 15	• Establish competitive rate cards through RFP with cost transparency • Review distribution of work strategy to maximize use of best rates
Fleet	5 – 7	• Conduct broad RFP with multiple feedback rounds • Renegotiate Fleet Management contract
Staff Aug	5 – 15	• Conduct RFP with consolidated roles and conduct multiple feedback rounds on cost transparency
Professional Services	10 – 20	• Renegotiate rate cards and greater cost transparency
Equipment Rentals	5 – 10	• Conduct RFP to lock-in rates and consolidate spend for rentals with preferred suppliers(s) with provincial capacity • Bundling other services as part of the same RFP process
IT Software	5 – 15	• Renegotiate IT software contract (s)
Transformers	5 – 10	• Conduct broad RFP with multiple feedback rounds leveraging an expanded supplier base
Construction Services	2 – 5	• Conduct RFP to establish competitive rate cards preferred suppliers(s) through multiple feedback rounds
General Hardware	10 – 15	• Conduct broad RFP with multiple feedback rounds • Consolidate suppliers thus increasing volume discount potential
Construction Materials	5 – 10	• Conduct broad RFP with multiple feedback rounds • Consolidate suppliers thus increasing volume discount potential

Telecom	0 – 5	• Conduct broad RFP with telecoms and networks carrier services spend to leverage scale • Consolidate bulk of spend with fewer preferred suppliers
IT Hardware	5 – 15	• Conduct broad RFP with telecoms and networks carrier services spend to leverage scale
Enviro. Services	5 – 10	• Conduct RFP to lock-in prices with preferred suppliers through multiple feedback rounds • Bundling other services as part of the same RFP process
Engineered Hardware	5 – 10	• Re-establish prices with insulator suppliers and conduct broad RFP to rebase prices for top repeat items • Negotiate volume discount agreements to maximize savings
Travel & Ent.	10 – 20	• Rationalize and lock-in preferred supplier rates for hotels and accommodations and negotiate volume discounts
Office Supplies	5 – 15	• Conduct broad RFP with multiple feedback rounds • Evaluate market alternatives and renegotiate printing supplies

The majority of the savings are embedded in OM&A forecasts for Real Estate and Facilities, IT, Power Equipment, and NERC Cyber Security Compliance. In aggregate, the savings for 2017 and 2018 are $1.5 million and $1.9 million.

Embedded capital savings are reflected in the areas of transmission High Voltage Yard Investments, Overhead Lines, IT, Fleet and Load Customer Connections. They total $9.4 million in 2017 and $16.5 million in 2018.

Information Technology Savings

The following list of initiatives is driving the majority of the OM&A savings in IT.

1. <u>Backup and Storage Optimization</u>

Based on an assessment of industry best practices as well as project and application support requirements, Hydro One has determined opportunities to change its practices regarding frequency of full backups on non-production environments with resultant savings of disc space and staff time.

Procedures have been changed regarding the backup and archiving policies related to full backups and daily incremental backups of its SAP production environment, with some routines changed to weekly rather than daily. For no material change in risk profile, this change resulted in a SAP storage savings of over 75%. Specifically, Hydro One's monthly storage requirement has decreased by fifty percent.

2. Project Environment Optimization

Hydro One has consolidated IT environments where there were redundancies and, in some cases, decommissioned them outright. This has resulted in a reduction in its monthly invoices from its service provider.

3. Infrastructure and Database Decommissioning

After an assessment of all IT infrastructure components and databases, Hydro One began decommissioning servers and databases that had very little or no utilization. To date, 138 servers and 38 databases have been decommissioned, and Hydro One plans to decommission an additional 76 servers and seven databases by January 1, 2017. An ongoing monthly review of all servers and database has been implemented to ensure unused infrastructure is decommissioned in a timely manner. This has reduced Hydro One's monthly server and database fees.

4. Software Contract Renegotiation

A review of all 3rd party contracts was performed to determine opportunities for renegotiation based on overall cost and current contract renewal timelines. Hydro One renegotiated its contract with a significant provider with savings to take effect in 2017. Hydro One is continuing its analysis of other 3rd party contracts and opportunities for renegotiation.

5. 3rd Party Contractor Rate Reduction

Hydro One has engaged its primary vendor in negotiations to reduce its rates by 20 to 30% effective as of 2017.

6. Mobility Contract Reduction

Hydro One has negotiated a significant per user rate reduction with its mobility providers Bell and Rogers for a period of five years.

7. Implementation of Cloud Infrastructure

Hydro One plans on implementing secure cloud platform technology for certain applications. This will result in a reduction in infrastructure resource effort, ongoing management and support and reduced costs.

UNDERTAKING – TCJ1.18

Undertaking

To explain how the 14.9% and the $80 million are calculated.

Response

These figures were each derived by taking the net present value of the aggregate estimated net savings ($120 million) achieved over the ten year contract term, relative to the estimated cost if Hydro One were to perform or manage the work. The savings are net of the costs of retained staff, contingency and stranded overhead.

The $80 million is the net present value of the estimated net savings. The 14.9% is the associated percentage savings.

UNDERTAKING – TCJ1.19

Undertaking

To provide the manner in which the budget estimate was derived and details underlying that budget.

Response

The Corporate Relations budget is broken out below into labour and non-labour components, which are described in Exhibit I, Tab 13, Schedule 19.

		2017	2018	2017 Tx	2018 Tx
Corporate Affairs	**Labour**	5.8	5.9	3.3	3.3
	Non-Labour	5.0	5.0	2.1	2.1
	Total	**10.8**	**10.9**	**5.4**	**5.5**

As described in Exhibit C1, Tab 3, Schedule 3, the Corporate Relations group is accountable for corporate reputation, executive support, customer and employee communications, media relations, community investment, web communications and corporate brand identity. In addition, the group is responsible for ensuring that all internal and external communications are consistent with the corporate brand identity.

There are no costs for corporate branding initiatives in the forecasts provided above.

UNDERTAKING – TCJ1.20

Undertaking

To provide the cost of Black & Veatch Study.

Response

Black & Veatch provided several reports relating to common corporate costs allocation, common asset allocation and overhead capitalization. The cost for these studies was approximately $188,000 split between Transmission and Distribution.

UNDERTAKING – TCJ1.21

Undertaking

To revise and update the statements made in SEP IR No. 1 2

Response

Please see attachments 1 and 2 to this Exhibit.

defined benefit pension plan as at December 31, 2015. To ensure that Hydro One's rates for the 2017 and 2018 test years reflect the anticipated reduction in costs, Hydro One will submit an update to this Application to reflect the actual changes shortly after the final valuation is received.

8. COST OF CAPITAL

Table 11 summarizes the cost of capital parameters reflected in the Application, details of which can be found at Exhibit D1, Tab 4, Schedule 1.

Table 11: Cost of Capital

Comparison of Cost of Capital and Rate Base	**Board-approved 2016**	**2017**	**2018**	**Exhibit Reference**
Cost of Debt	4.77%	4.48%	4.42%	D2-4-2
Cost of Equity	9.19%	9.19%	9.19%	D2-4-1
Total Debt ($Millions)	6,024.0	6,332.6	6,735.3	
Total Equity ($Millions)	4,016.0	4,221.7	4,490.2	
Rate Base ($ Millions)	**10,040.0**	**10,554.3**	**11,225.5**	D2-1-1
Weighted Average Cost of Capital		**6.4%**	**6.3%**	

Hydro One's deemed capital structure for transmission ratemaking purposes is 60% debt and 40% common equity. The 60% deemed debt component is comprised of 4% short-term debt and 56% long-term debt. Hydro One will continue to use the Board's cost of capital parameters for its deemed short-term debt rate and return on equity, consistent with the Board's report on cost of capital.

- improving the ratio of employer and employee cost sharing by moving towards the 50%-50% cost sharing ratio.

As described in Exhibit C1, Tab 4, Schedule 1, the employee contribution rate to the pension plan has increased and Hydro One engaged Willis Towers Watson to provide an estimate of the resultant savings to the company. These savings were are reflected in cash pension costs provided in the Table 4, as well as the pension expense that is included in Hydro One's operating and capital expenses provided in this application for the test years 2017 and 2018.

15. SUMMARY

Attracting, motivating and retaining the right people is key to Hydro One's success. Hydro One will continue to utilize a mix of regular, non-regular and contract staff in order to maintain the necessary flexibility to meet the needs of the company's investment plan. In an industry with aging demographics and a competitive labour market, Hydro One needs to be positioned as an attractive employer if it is to succeed in recruiting and retaining staff with the requisite skills. To do so, it must provide challenging and rewarding job opportunities and a competitive compensation package.

Compensation levels at Hydro One are reasonable and have a declining trend. Hydro One's demographic challenge requires the Company to be active in the labour market with competitive compensation.

Recent fundamental changes in the compensation and pension programs for both represented and non-represented employees are a reasonable balance between rewarding

UNDERTAKING – TCJ1.22

Undertaking

To clarify the response to SEP IR No. 9.

Response

The term "modest" was intended to suggest that the savings expected in the early years of the contract will be a small fraction of the savings expected in the later years.

The undiscounted net savings expected from 2015 to 2018 ranged from $4.6 million in the first contract year (2015) to $7.1 million in the fourth contract year (2018). Annual net savings are expected to increase each year as a result of gradual attrition of retained staff over the term of the agreement. (Please see TCJ 1.18.)

For clarity, the figure of $0.8 million savings in 2015 provided in Exhibit I, Tab 8, Schedule 9 is incremental to the anticipated savings of $4.6 million and reflects the difference between the budgeted and actual costs of the BGIS services for 2015.

Witness: Gary Schneider

UNDERTAKING – TCJ1.23

Undertaking

To determine whether there has been any material changes to the numbers presented.

Response

There has been no material change to the forecasted savings.

UNDERTAKING – TCJ1.24

Undertaking

To examine the answer that has been provided and determine if there is additional information that can be provided that addresses the question.

Response

Reference is made to response (d) in Exhibit I, Tab 8, Schedule 9. BGIS' key measurements and critical service levels along with the annual results for each item are set out below.

Key Measurements

Ref #	Key Measurement Name	Target	Minimum Exception	Achievement
KM - 1	Work Protection Code violations	0	1	Work did not start in 2015
KM - 2	Preventative Maintenance Work Accomplishment	100%	80%	98%
KM - 3	Capital Work Accomplishments	100%	80%	100%
KM - 4	Customer Complaints	<2%	4%	2%
KM - 5	Carbon Reduction	50	25	14.37
KM - 6	Incident Reporting	100%	95%	100%
KM - 7	Financial Expense Actuals to Budget	<5%	10%	-8%
KM - 8	Financial Capital Actuals to Budget	<5%	10%	<5%
KM - 9	Promises Kept	>70%	50%	87%
KM - 10	Special Reporting	95%-100%	90%	100%
KM - 11	Customer Survey Satisfaction Levels	90%-95%	85%	81%
KM - 12	Timely Issues Resoultion	90%-100%	80%	100%
KM - 13	Asset Identification & System Input	90%-100%	80%	100%

Critical Service Levels

Ref #	Service Level Name	Target	Minimum Exception	Achievement
CSL - 1	Lost Time Injuries	0	0	0
CSL - 2	Medical Attentions	0	0	0
CSL - 3	Unplanned Outages	0	1	0
CSL - 4	Ministry Notices/Orders	0	1	1
CSL - 5	Environmental Spills	0	1	0
CSL - 6	Regulatory Accomplishment Reporting	100%	91%	100%
CSL - 7	Performance against agreed budget	100%	96%	108%
CSL - 8	Delivery of Sustainment Capital Projects to Budget	>90%	76%	97%
CSL - 9	Delivery of Capital Projects to Schedule	>90%	76%	100%

Witness: Gary Schneider

UNDERTAKING – TCJ1.25

Undertaking

To provide data for second tier MCP staff.

Response

The table below shows the employee pension contributions for second tier MCP staff.

	2013			2014			2015			2016		
	Employee Contribution		Ratio	Employee Contribution		Ratio	Employee Contribution		Ratio	Employee Contribution		Ratio
MCP - Pre 2004	4.75%	6.75%	3.5	5.50%	7.50%	2.8	6.25%	8.25%	2.4	7.00%	9.00%	2.2
MCP -Post 2004	4.75%	6.75%	2.5	5.50%	7.50%	1.9	6.25%	8.25%	1.6	7.00%	9.00%	1.4

Witness: Keith McDonell

UNDERTAKING – TCJ1.26

Undertaking

With respect to SEC No. 18 to provide the amounts spent on diversity initiatives, to advise current active programs and current costs.

Response

The table below provides a list of the diversity programs that are currently active and the budget amount for each.

Active Initiative	Budget Amount
The Tri-Partite Diversity Committee (Equal representations of PWU, MCP, Society)	$0K
Hydro One Diversity Calendar	$10K
Diversity Lunch and Learns Series (3 per year)	$6K
Hydro One Women in Engineering University Partnership	$1.4 M
The Hydro One Women In Engineering Scholarship	$50K
Women In Trades Technology and Engineering Network	$10k allocated for Symposium
Ontario Engineering Competition	$7K
Women In Trees through Fleming College	$3K
OnWiE Sponsorship and Go Eng Girl	TBD
Catalyst Membership	$15K
EHRC Connected Women Steering Committee	$0K
Hydro One Women In Leadership Program	$50K
WXN – Women's Executive Network Membership	$9,750
Skills Canada – Ontario – Mentorships and Workshops and Career Fairs	$25K
Confederation College Pre-Tech program for Aboriginals	$750K over 3 years
Leonard S. (Tony) Mandamin Scholarship	$75K
Aboriginal Network Circle	TBD
First Nation & Métis Relations Department	$0K
Nation Talk Membership	$4,520
The Aboriginal Procurement Procedure	$0K
William Peyton Hubbard Memorial Award	$10K
The Hydro One AID Network (Accessibility, Inclusivity, Disability)	$0K

UNDERTAKING – TCJ1.27

Undertaking

Provide additional clarification or update around that last sentence in the response to Staff 97.

Response

The ongoing benchmarking initiative is focusing on benchmarking at the functional discipline level (i.e. Project Management, Construction, Commissioning etc.) categorizing investments to identify similar scopes of work across projects. The scope of this exercise includes projects that have been completed in 2015 that have a gross project cost in excess of $5M and will expand to other years once complete. Determining and defining an optimal and consistent comparative level will help in data and trend analysis which is essential for meaningful benchmarking statistics.

In parallel to this initiative, Hydro One is in the final stages of revamping the WBS (Work Breakdown Structure) used to estimate and capture project costs. This WBS revamp will align our control accounts to better reflect our commodity and asset capitalization rules. For example, the foundations installation commodity would include all activities associated with the installation of the foundation (i.e. pad and pier, pile, anchor to rock etc.) The stripping and grading commodity will be comprised of the following activities: stripping, permanent road, backfill, drainage, soil removal, etc. This will enable Hydro One to capture costs in a more detailed, practical and accurate manner which will aid in cost comparisons for future projects, and serve as a better means to benchmarking. Furthermore it will enable Hydro One to provide a more detailed and accurate comparison between projects internally and have a basis for comparison with other utilities companies that deliver similar commodities/assets such as transformers, breakers, steel structures, protection systems, etc.

UNDERTAKING – TCJ1.28

Undertaking

To see if there is any more information we can provide with respect to the attachment that was included as Exhibit I31, Exhibit 2, Attachment 1.

Response

Hydro One has further reviewed the content of the audit reports requested by SEC. It has also considered prior Board rulings that address the production of audit reports (i.e. EB-2013-0416). Hydro One understands that it is the recommendations and the actions described in the requested audit reports that are relevant areas of inquiry in this proceeding. The summary document found in Hydro One's response to AMPCO's interrogatory #001 (Exhibit I, Tab 3, Schedule 1, Attachment 2) describes the recommendations and actions arising from the audit reports. The issues giving rise to the recommendations are self-evident from the descriptions provided. Parties seeking to ask questions about such matters may do so through the oral hearing process.

UNDERTAKING – TCJ1.29

Undertaking

To advise how the audit plan is established, to advise the trigger that brought about that audit.

Response

Hydro One's internal audit process is a feature of Hydro One's governance process and is consistent with good corporate governance practices.

The annual audit plan is risk based and is established through the following processes:

- discussions with Enterprise Risk Management organization within Hydro One to understand key corporate risks;
- extensive discussions with management around business objectives and key activities;
- identification and ranking of inherent risks that could impact achievement of those business objectives;
- identification of key controls in place to mitigate those risks and an estimate of the degree of that mitigation to determine the criticality of the controls to, in turn, define the population of potential audits;
- development of a list of audits based on ranking of the critical residual risks;
- ranking audits on the list;
- selecting the highest ranked audits to developing a plan based on available resources; and
- securing endorsement for the annual audit plan from executive management followed by its approval by the Audit Committee of the Board of Directors.

There were no specific triggering events for the internal audits discussed at the Technical Conference on September 22, 2016 leading to this undertaking, namely, the "Audit of Investment Planning #2014-29" and the "Transmission Line Preventative Maintenance Optimization 2015-33". These processes were selected because of their relative importance to Hydro One's business.

UNDERTAKING – TCJ1.30

Undertaking

To provide information regarding: as a result of the optimization to understand for programs which programs were selected at an optimal level, which programs were selected at a vulnerable level, which were selected at the intermediate level.

Response

The following outlines program levels as a result of optimization:

Program Level	2017	2018
Accelerated	18%	19%
Asset Optimal	18%	18%
Intermediate	7%	7%
Vulnerable	58%	56%

UNDERTAKING – TCJ1.31

Undertaking

To provide the chart in excel format.

Response

Please see attached Excel Spreadsheet.

UNDERTAKING – TCJ1.32

Undertaking

To provide the rationale behind what occurred, or the explanation of what occurred in those years.

Response

Explanation for Sustainment variances between Board Approved and Actuals from 2012 to 2015

The following provides examples of main projects or programs contributing to the variances in capital expenditures for Sustainment capital.

2012 Sustainment Capital Expenditures Variances

- Station Reinvestment: Delays associated with scope for Beck #1 SS reinvestment as the project underwent re-evaluation for potential lower cost alternatives, a one-time CCRA adjustment for historic work completed on Toronto Hydro's behalf and increased capital expenditures on work at Abitibi Canyon SS and Pinard TS resulted in a reduction of approximately $20M.
- Protection and Automation, Telecom: Delays associated with equipment selection for the Bruce Special Protection System replacement and revised requirements from the IESO, lack of resource availability due to other priority work, including the Bruce by Milton transmission lines, customer and outage coordination with international transmitters, and lower than estimated costs for DC signaling replacements in the GTA resulted in a $10M reduction.
- Transmission Underground Cables: Delayed project start of H2JK due to unexpected difficulties with obtaining land easements resulted in a $20M reduction.
- Increased capital expenditures across asset-centric program work at transmission stations and transmission line reinvestment contributed to a $25M increase (e.g. Claireville TS).

2013 Sustainment Capital Expenditures Variances

- Station Reinvestment: Timing of multi-year projects driven by customer commitments (e.g. Metal clad switchgear replacements), outage availability (e.g. Richview, Hanmer, Bruce A and Burlington Air Blast Circuit Breaker projects), resulted in a $25M reduction.
- Power Transformers: Timing of capital expenditures for the Claireville TS autotransformer replacement project as work was accelerated and largely completed within 2012 resulted in a $20M reduction.
- Protection and Automation, Telecom: Delays associated with equipment selection for the Bruce Special Protection System replacement, lack of resource availability due to other priority work, including the Bruce by Milton transmission lines, customer and outage coordination with international transmitters resulted in a $20M reduction.
- Cyber Security: Delays resulting from the delayed approval of NERC CIP Version 5 standards as investments were deferred until final approval of standards to ensure no assets or systems would be stranded or require additional investment due to the final requirements resulted in an $11M reduction.

2014 Sustainment Capital Expenditures Variances

- Power Transformers: The failure of the Trafalgar T15 autotransformer and advancement of transformer replacement at Gerrard TS resulted in a $25M increase.
- Protection and Automation and Telecom: Delays associated with equipment selection for the Bruce Special Protection System replacement, and customer and outage coordination with international transmitters contributed to an $8M reduction.
- Station Infrastructure: Increased spending to upgrade transmission station fire detection systems to required standards and upgrade station perimeter fencing to address security concerns resulted in an $11M increase.
- Cyber Security: Delays resulting from the delayed approval of NERC CIP Version 5 standards as investments were deferred until final approval of standards to ensure no assets or systems would be stranded or require additional investment due to the final requirements resulted in an $8M reduction.
- Transmission Overhead Lines: Increased wood pole replacements to address deteriorating condition of the fleet resulted in an $11M increase

- Transmission Lines Reinvestment: Increased capital costs associated with the C25H Line refurbishment resulted in a $5M increase.

<u>2015 Sustainment Capital Expenditures Variances</u>

- Station Investments: Increased costs associated with timing of the Bruce A 230 kV ABCB Breaker Replacement project expenditures and improved station investment execution approach enabled the delivery of emerging sustainment work at several notable transformer stations including Beach TS, Allanburg, Buchanan, Gerrard, and Hinchinbrooke to account for project delays at Gage, Elgin, and Beck contributed to an overall increase of about $90M.
- Transmission Lines Reinvestment and Overhead Lines: Increased investment to address asset needs on circuits, C25H, C22J/C24Z/C21J/C23Z, Q11S/Q12S, and D2L resulted in a $20M increase.
- Transmission Underground Cables: Delays associated with H2JK cable replacement resulted in a decrease of $10M.

<u>Explanation for Development variances between Board Approved and Actuals from 2012 to 2015</u>

The variances were mainly due to external factors (e.g. changes in government and OPA direction, customer cancellation or deferrals), project execution delays, and lower project costs. The following provides examples of main projects contributing to the variances in the capital expenditures for each particular year.

<u>2012 Development Capital Expenditures Variances</u>

- Nine projects to facilitate the Green Energy Act policy direction established in 2009 were subsequently cancelled and resulted in a $90 million reduction.
- The “Ancaster TS: Build New Transformer Station and Line Connection” project was cancelled at the customer’s request and resulted in an $11 million reduction.
- The “Toronto Area Station Upgrades for Short Circuit Capability: Leaside TS Equipment Uprate” was delayed due to outage cancellations and construction complexities. This resulted in a $15 million reduction.

2013 Development Capital Expenditures Variances

- Following the extension of Pickering NGS operating license to 2018, the "Clarington TS: Build new 500/230kV Station" project was deferred from 2015 to 2017 and resulted in a $65 million reduction.
- The "Installation of Static Var Compensator at Milton SS" project was cancelled by the OPA in August 2013 and resulted in a $30 million reduction.
- The "Nelson TS: Replace T1/T2 DESN with new DESN" project was cancelled at the customer's request and resulted in an $11 million reduction.

2014 Development Capital Expenditures Variances

- The "Installation of Static Var Compensator at Milton SS" project was cancelled by the OPA in August 2013 and also resulted in a $40 million reduction in 2014.
- The "Reconductor the Lambton TS to Longwood TS 230 kV Circuits" project was completed $13 million lower than forecasted.
- The "Midtown Transmission Reinforcement Plan" was delayed due to a tunnel shaft shoring failure and difficulty in obtaining outages. This resulted in a $10 million reduction.

2015 Development Capital Expenditures Variances

- The "Clarington TS: Build new 500/230kV Station" project was delayed due to difficulties obtaining the Environmental Assessment approval and resulted in a $13 million reduction.
- The KWCG Regional Infrastructure Plan determined that the need for the "Preston TS Transformation" project can be deferred to beyond 2025. This resulted in a $10 million reduction.
- Delays in obtaining major approvals for the "Supply to Essex County Transmission Reinforcement" project resulted in a $9 million reduction.
- The "Guelph Area Transmission Reinforcement" project cost is lower than forecast and resulted in a $6 million reduction.
- The scope for the "Seaton TS: Build New 230-28 kV Transformation Station" project has changed as the customer is now building their own transformer station. The project scope now only involves a connection line facility. This has resulted in a $6 million reduction.

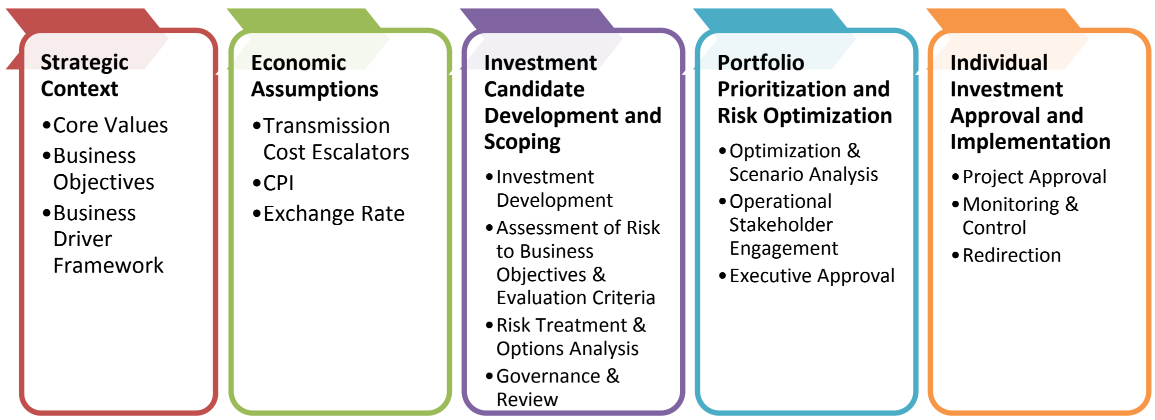
UNDERTAKING – TCJ1.33

Undertaking

To provide some examples of the method described in Exhibit B1, Tab 2, Schedule 5.

Response

Reference is made to Figure 1 in Exhibit B1, Tab 2, Schedule 7, which is reproduced below.



The decision to repair, replace or do nothing with an asset is made in the third box ‘Investment Candidate Development and Scoping’.

Once an individual project is determined to be a priority (using the optimization process in the fourth box), authorization to proceed with the project occurs in the fifth box ‘Individual Investment Approval and Implementation’. A business case summary document is prepared after the individual project has been determined to be a priority and for the purposes of authorizing the expenditure of funds for execution.

The third box uses the Asset Risk Assessment methodology described in Exhibit B1, Tab 2, Schedule 5. Four examples are provided below that demonstrate how this process works.

The investment candidate development and scoping process starts with asset planners assessing various relevant data at asset level as described in Exhibit B1, Tab 2, Schedule 5. After considering the information available, a site assessment is carried out to verify and update information, refine requirements and improve accuracy. A station assessment report is produced at this stage to document the findings. Attachment 2, 4, 5, 8 and 9 are examples of these reports.

Subsequent to this step, a detailed examination of major assets, such as transformers, is carried out to verify their condition. Attachment 6 is an example of transformer assessment reports.

The final step in the investment candidate develop and scoping process involves experienced asset planners making a recommendation based on the technical data and findings. Exhibit I, Tab 2, Schedule 40 provides additional details on this part of the process. These recommendations are provided in an Asset Risk Assessment report. Three examples of these reports have been provided in Attachments 1, 3 and 7 to this undertaking.

Example 1: 500kV 750MVA Auto Transformer Repair Vs Replace.

This example demonstrates the economic assessment carried out to support a repair and delay capital replacement of a 500kV 750MVA auto transformer. This type of equipment is one of the most expensive power equipment assets within the Hydro One transmission system.

The transformer in question is a 40 year-old unit**.** A detailed condition assessment revealed it requires refurbishment to repair an oil leak and to mitigate a design deficiency advised by the original equipment manufacturer. These are necessary repairs to ensure safe and reliable operation of this asset. The cost for refurbishing this transformer was analyzed using the economics model described in Ex I-1-28. Details of such an analysis can be found in Ex. I-9-6, Attachment 6 - Strachan Transformer Assessment Report, Section 7- Economics.

Specific to this 500kV 750MVA auto transformer, the outcome of the economic assessment resulted in a net present value (NPV) cost of $17.2M for repair vs $18.9M for replacement. Therefore, a decision was made to proceed with repair.

Example 2: Beck #2 TS – Air Blast Circuit Breaker Replacement Project (Exhibit B1-03-11 - S02):

This example demonstrates the need to replace the air blast circuit breakers (ABCB) at Beck #2 TS due to deteriorating conditions, obsolescence, and poor performance.

Economic evaluations comparing repair vs replace alternatives at the individual ABCB level are not used by Hydro One given the historical operating experience Hydro One has regarding this equipment, namely, the significantly higher operating cost profile and the fact that this type of equipment will become obsolete and not supported by parts manufacturers. The result of this assessment was to include the Beck #2 ABCB Replacement Project because of the deteriorating conditions, obsolescence and poor performance. See Exhibit B1, Tab 2, Schedule 6, Page 15 for additional information on ABCBs in general and Exhibit B1, Tab 3, Schedule 11, S02 for information on this specific project.

Attachment 1: Asset Risk Assessment Report – Beck 2
Attachment 2: Station Assessment Report – Beck 2

Example 3. Dufferin TS – Integrated Station Component Replacement (Exhibit B1-03-11 – S30):

This example demonstrates the need to replace the T1, T3 and T4 transformers at Dufferin TS due to deteriorating condition. This project does not include replacing the T2 transformer, which is still in good condition. Further, the nature of the degraded condition, including insulation degradation and other issues, make repairs nonfeasible. The attached Asset Risk Assessment report and Station Assessment Reports demonstrates the risk assessment process and justification for replacement of T1 and T4. The subsequent detailed assessment of the transformers revealed that T3 also requires replacement.

Attachment 3: Asset Risk Assessment Report - Dufferin
Attachment 4: Station Assessment Report – Dufferin (T1 & T3)
Attachment 5: Station Assessment Report – Dufferin (T2 & T4)
Attachment 6: Transformer Condition Assessment Reports (T1, T3, T4)

Example 4. Pleasant TS – Integrated Station Component Replacement:

This example demonstrates a possible investment at Pleasant TS that was not selected because the ARA process determined it was not necessary at this time. Planners originally identified this station as a possible concern based on the demographics of major assets at the station. A station assessment was carried out and based on overall asset condition and the other risk factors discussed in Exhibit B1, Tab 2, Schedule 5, it was determined that investment as this station was not necessary at this time. The attached Asset Risk Assessment Report, and supporting Station Assessment Reports, provide the relevant details that led to this decision.

Attachment 7: Asset Risk Assessment Report – Pleasant
Attachment 8: Station Assessment Report – Pleasant T1/T2
Attachment 9: Station Assessment Report – Pleasant T5/T6

Asset Risk Assessment Report

Project: Beck#2 TS, ABCB Replacement and Yard Upgrade

Recommendation

Proceed - This project to completely replace all 230 kV ABCBs and associated equipment at Beck 2 TS will result in eliminating operational risks associated with the failure of end of life equipment and improve the reliability of the bulk electricity system in the Niagara area by replacing ABCB breakers with SF6 breakers that are about 5x more reliable than ABCBs. In addition to improved reliability, SF6 breakers are significantly lower cost to operate than ABCBs with approximately 90% savings in ongoing maintenance expenditures. It will also satisfy regulatory requirements with the upgrade of protection and control systems to meet current NPCC requirements. . Not proceeding with this investment at this time would result in a significant risk of further equipment deterioration and declining system reliability

Project Summary

Beck #2 TS is a critical network station that connects hydraulic generation from OPG to the 230 kV network. The Beck #2 TS 230 kV switchyard was originally placed in-service in 1955 and many assets are approaching end of life and are in need of major work to sustain their functionality. Assessments and site inspections have identified end of life issues with the ABCBs, as well as with the free standing current transformers, high pressure air system, disconnect switches, station service systems, and insulators in the switchyard. This project to replaces twenty ABCBs units with new SF6 breakers in the Beck #2 switchyard, upgrades EOL protection, control, telecom (PCT) facilities and nonstandard AC/DC station service switchgear to meet present HONI standards and to comply with Northeast Power Coordinating Council (NPCC) bulk power system requirements. ABCBs also require high pressure air systems in order to operate. These air systems include compressors, holding tanks, valves and extensive piping and are susceptible to temperature fluctuations that cause air leaks resulting in equipment outages. Replacement of these ABCBs will simultaneously reduce preventive maintenance costs and enable the decommissioning and removal of the high pressure air system at Beck #2 TS.

Proposed Investment

1. Replace twenty ABCBs, associated breaker disconnect switches, AC and DC systems and protection and control equipment.
2. Protection & control facilities are to be upgraded, including full A & B separation, to meet NPCC requirements and standards.
3. Removal of forty sets of 230kV free standing instrument transformers along with the entire high pressure air system which will no longer be required.
4. Based on recommendations from the 2013 Richview TS flood investigation and site specific conditions, equipment in the basements of the two 230 kV relay buildings are to be relocated to above grade.

Prepared by

Fred Kouhdani, P.Eng.
Senior Network Management Engineer

Appendix 1 - Risk Assessment

Risk Factor	Risk Assessment*	Comments
Demographics	Very High	Breakers are approximately 50 years old and are operating beyond their expected service life
Condition	Very High	There is a very high expected failure rate for these ABCB over the next 5 years. ABCBs also require high pressure air system which is comprised of many parts (compressors, air receivers, condensate collectors, control systems, dryers and hydrometers) as a whole the High Pressure air system is in poor condition. No. of Trouble Call (TC) & Corrective (DR) Work Orders (TC & DR) over Last 8 Years: 4443 Annual TC & DR Frequency: 555
Economics	Very High	Due to the extensive systems required to operate ABCBs the planned and corrective maintenance is very high as compared to SF6 breakers. Because of the complexity of ABCBs and their dependence on auxiliary systems (high pressure air, additional instrument transformers, etc.), annual historic costs of approximately $30,000 per breaker have been incurred. Comparing with Hydro One's years of experience using newer high voltage SF6 breakers built on today's technology, annual average maintenance costs are approximately $3,000 per breaker. Replacing ABCBs with modern SF6 breakers results in approximately 90% savings for ongoing maintenance expenditures O&M$ Spent over last 8 years: $7.6M Annual O&M$: $950k
Performance	Very High	ABCB performance is approximately 5x worse than an SF6 breaker. Number of Outages over last 8 year: 101 Annual Frequency: 12.6 DP Performance: N/A
Utilization	High	Station fault levels have increased to a point where it is reaching breaker nameplate capacity and now require 80 kA capability.
Criticality	Very High	Beck #2 TS is a NPCC bulk power station that connects 1250 MW of generation and is the termination point for eight 230 kV circuits and four interconnections with New York.
Customer	Satisfied	
Obsolescence	Very High	ABCB breaker technology is no longer supported by the vendor and there are very limited parts availability.
Health & Safety	Fair	Since the ABCBs have porcelain structures if there is moisture ingress in the air system there is potential for explosive failure. Mitigating techniques have been used to minimize this from occurring.
Environment	Very High	Very high risk of flooding (i.e. three times in the last 5 years) and based on recommendations from the 2013 Richview TS flood investigation and site specific conditions, equipment in the basements, including DC Station Service equipment, are to be relocated above grade.

**Available Selections: Very High, High, Fair, Low, Very Low, N/A* *ł VS - Very Satisfied, SS – Somewhat Satisfied*

Beck #2 TS

Station Assessment

Keywords: Beck, Transmission, Station, Assessment

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REVISION HISTORY

Date	Revision	Revision Comments
December 8, 2014	0	Initial Revision

APPROVAL SIGNATURES

	Prepared By	Reviewed By:	Approved By:
Signature:			
Name:	Mark Truchanowicz, P.Eng	Fred Kouhdani, P.Eng	Bruno Jesus, P. Eng
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Date:	December 8, 2014	December 8, 2014	December 8, 2014

TABLE OF CONTENTS

1.0 INTRODUCTION

This assessment provides an overview of the current state of the station. The recommendations offered in this document will allow Asset Management make well-informed capital investment decisions.

Integration of the replacement of multiple end of life components into a single investment allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work. A station assessment will ensure that all the replacement needs are captured and integrated into the investment before release.

2.0 STATION SUMMARY

Beck #2 TS is a critical network station that connects hydroelectric generation from OPG to the 230 kV network. The Beck #2 TS switchyard was originally placed in service in 1955 and many assets are approaching end of life and are in need of major work to sustain their functionality. Assessments and site inspections have identified end of life issues with the air blast circuit breakers (ABCBs), as well as with the free standing current transformers, high pressure air system, disconnect switches, station service systems, and insulators in the switchyard.

There are twenty 230kV ABCBs at Beck #2 TS. These breakers are manufactured by Brown Boveri (eight - type DMVF) and Delle (twelve - type PK4PB) and are operating beyond their expected service life. In addition, the breakers are technically obsolete with vendor support for parts and service no longer available. ABCBs are the poorest performing breakers in the Hydro One transmission system and as ABCBs and their auxiliary systems age, the condition of components degrade, forced outages increase and maintenance costs increase.

A project that will result in replacing existing aged and degraded infrastructure has been deemed to be prudent at this time. Equipment to be addressed within this project should include the replacement of all 230 kV ABCBs and associated high pressure air systems, as well as the associated disconnect switches, protection and control systems, and other auxiliary components.

3.0 DESKSIDE STATION ASSESSMENT

3.1 Station Fault Current Rating

Table 1: 2014 Station Fault Current Ratings for Beck #2 TS [1]

	Symmetrical		Asymmetrical		Symmetrical Rating		Asymmetrical Rating	
	3ph kA	LG kA	3ph kA	LG kA	3ph kA	LG kA	3ph kA	LG kA
230 kV	57.743	64.455	79.467	91.724	70.00	70.00	92.00	92.00

3.2 Station 5 Year Loading

Table 2: Station LTR Ratings and Average and Peak Loading

	LTR Rating		2009		2010		2011		2012		2013	
	Sum 10d LTR	Win 10d LTR	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]
R27	400	480	152.92	507.12	128.47	630.62	121.68	455.28	156.68	456.60	157.47	422.73
R76	643	725	0.00	0.00	0.00	2.06	0.00	0.00	181.47	337.15	175.53	454.76
T11	186	186	136.30	363.98	145.64	297.73	139.52	297.49	120.18	225.41	134.23	322.27
T13	186	186	146.01	272.19	144.72	288.08	144.05	299.92	132.51	227.30	132.66	305.96
T15	-	-	142.33	216.25	146.89	214.65	159.52	212.07	150.64	231.63	129.45	302.38
T17	210	210	139.90	297.37	155.06	335.62	152.19	324.61	147.49	248.84	153.33	825.20

	LTR Rating		2009		2010		2011		2012		2013	
	Sum 10d LTR	Win 10d LTR	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]
T19	210	210	140.21	298.03	152.58	323.42	156.62	328.09	148.50	203.24	155.01	993.37
T21	-	-	142.31	297.50	139.59	333.75	138.62	323.49	128.43	219.48	136.73	343.38
T23	210	210	136.25	267.42	142.05	274.19	143.43	297.47	131.18	224.61	138.51	420.59
T25	210	210	144.13	275.31	136.69	288.20	144.95	298.02	129.59	244.14	138.68	360.59
T301	1224	1370	269.85	627.63	217.60	1136.61	210.99	631.81	239.72	654.23	262.52	623.50
T302	1224	1370	263.21	627.63	216.76	1136.61	218.30	631.82	237.05	652.67	286.21	622.01

Highlighted transformers are owned and operated by OPG – not all LTR data available

The above average annual transformer loading is summarized graphically in Figure 1 below.

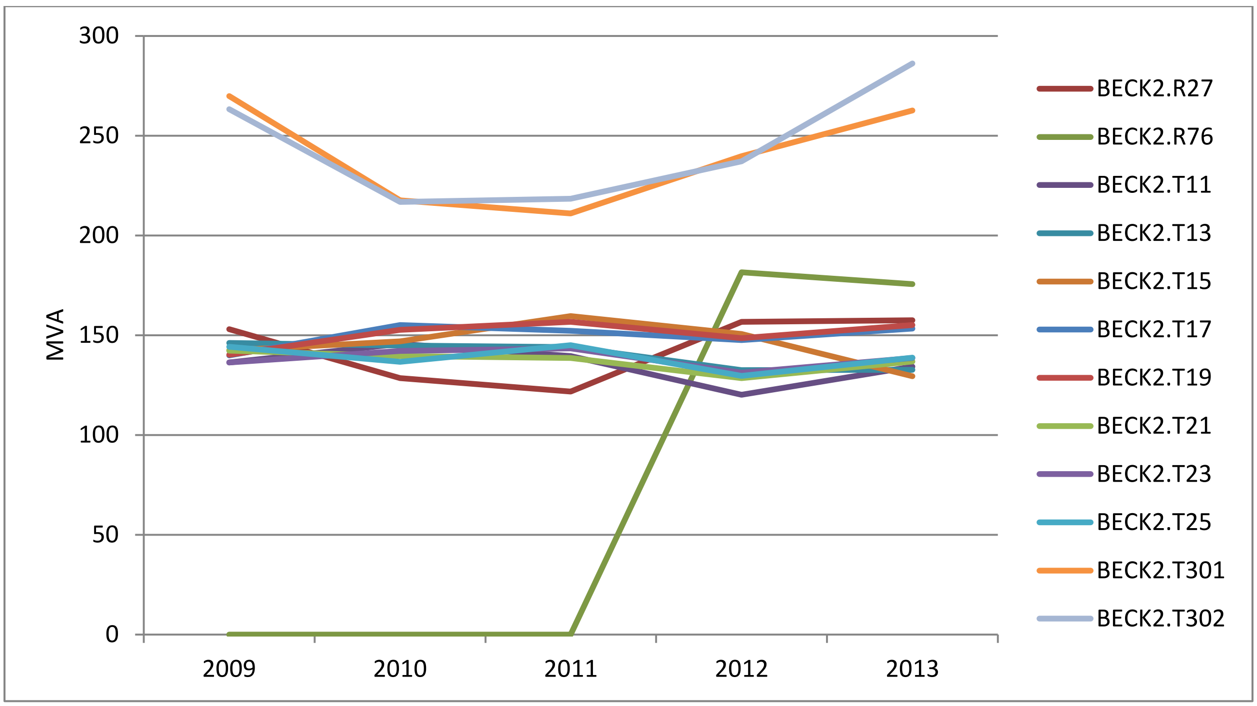


Figure 1 - Average Annual Transformer Loading at Beck #2 TS

3.3 Customer Information

Table 3: Customer Satisfaction Summary

Not Applicable because this is a bulk power station

3.4 Outage Information

Beck #2 TS experienced significant equipment outages based on the analysis of Transmission Equipment Outage Performance Data as seen in Appendix 4. Breaker related outages have increased in recent years due to further deterioration of asset condition combined with below seasonal winter temperatures that have impacted high pressure air system performance.

A condition assessment of air blast circuit breakers identified several concerns both in performance and supportability of the existing fleet of air blast breakers which includes those currently in service at Beck #2 TS. Air blast breakers are the poorest performing and least reliable circuit breaker sub-type within the Hydro One Transmission network.

The recent increase in the frequency of forced outages, lack of technical expertise, vendor support and spare parts will continue to contribute to longer and more frequent outages if the air blast breakers at Beck #2 TS are not rebuilt or replaced within a timely manner. Beck #2 TS is a critical station in the 230 kV network facilitating the transmission of hydroelectric generation from OPG's Beck #2 GS and is a connection point for four (4) international tie-lines; BP27, PA27, PA301 and PA302, between Canada and the United States.

3.5 Station Spill Risk Ranking

Beck #2 TS has six oil-filled power transformers within the station. The station is ranked 203rd out of 256 stations based on existing risk score from a 2011 spill risk report by Conestoga-Rogers & Associates [2] and is identified as having spill risks mitigated at this time.

3.6 Asset Analytics

Based off the Composite score in Asset Analytics, the following station equipment, not previously identified under the asset-centric work program, with a *Composite* score greater than 29 or a *Demographic* score greater than 74 should be considered for replacement. Assert that are considered low-to-medium risk, along with their individual asset risk factors are captured in **Error! Reference source not found.**.

Table 4: Summary of Assets Considered for Replacement Due to Demographic and Composite Score

Func. Location	Asset Class	Age	Condition	Demographics	Economics	Performance	Utilization	Criticality	Composite
N-TS-BECK2TS -BR-1D2	Breaker: Air Blast_230 kV	45	31	100	25	1	90	37	38
N-TS-BECK2TS -BR-1K2	Breaker: Air Blast_230 kV	45	17	100	1	57	96	37	47
N-TS-BECK2TS -BR-DL24	Breaker: Air Blast_230 kV	46	17	100	1	1	96	37	32
N-TS-BECK2TS -BR-DL27	Breaker: Air Blast_230 kV	46	31	100	58	60	77	37	55
N-TS-BECK2TS -BR-DT301	Breaker: Air Blast_230 kV	32	31	60	20	21	81	37	37
N-TS-BECK2TS -BR-DT302	Breaker: Air Blast_230 kV	32	59	60	49	66	73	37	60
N-TS-BECK2TS -BR-KL23	Breaker: Air Blast_230 kV	46	31	100	16	2	97	37	38
N-TS-BECK2TS -BR-KL25	Breaker: Air Blast_230 kV	32	31	60	100	62	83	37	56
N-TS-BECK2TS -BR-KL26	Breaker: Air Blast_230 kV	32	28	60	30	64	84	37	49
N-TS-BECK2TS -BR-KL29	Breaker: Air Blast_230 kV	32	59	60	1	39	82	37	50
N-TS-BECK2TS -BR-KL76	Breaker: Air Blast_230 kV	32	31	60	5	1	81	37	31
N-TS-BECK2TS -BR-L25T302	Breaker: Air Blast_230 kV	32	14	60	1	57	85	37	40
N-TS-BECK2TS -BR-L28T301	Breaker: Air Blast_230 kV	32	28	60	46	61	88	37	50
N-TS-BECK2TS -BR-L30L35	Breaker: Air Blast_230 kV	32	31	60	46	48	88	37	48
N-TS-BECK2TS -BR-L35L76	Breaker: Air Blast_230 kV	32	31	60	6	60	89	37	48
N-TS-BECK2TS -BR-TL21L23	Breaker: Air Blast_230 kV	45	67	100	38	64	97	37	69
N-TS-BECK2TS -BR-TL21L24	Breaker: Air Blast_230 kV	45	59	100	13	60	93	37	63

Func. Location	Asset Class	Age	Condition	Demographics	Economics	Performance	Utilization	Criticality	Composite
N-TS-BECK2TS -BR-TL26L27	Breaker: Air Blast_230 kV	46	42	100	70	81	87	37	67
N-TS-BECK2TS -BU-D2	Bus: Air Insulated_230 kV	0	1	1	1	81	0	48	30
N-TS-BECK2TS -BU-K1	Bus: Air Insulated_230 kV	0	1	1	1	100	0	48	36
N-TS-BECK2TS -BU-K2	Bus: Air Insulated_230 kV	0	1	1	74	100	0	48	43
N-TS-BECK2TS -CN-BK23RTU	Control System_RTU	0	100	1	52	99	0	10	75
N-TS-BECK2TS -HP-AR KL29	HP: Air Receiver	0	0	1	100	100	0	42	72
N-TS-BECK2TS -HP-CMP 4	HP: Compressor	41	1	41	46	48	100	48	38
N-TS-BECK2TS -HP-COL	HP: Condensate Collector	21	0	0	69	50	0	30	51
N-TS-BECK2TS -HP-DRY 1	HP: Dryer	21	1	1	40	63	100	48	37
N-TS-BECK2TS -HP-DRY 2	HP: Dryer	21	1	1	51	83	79	48	41
N-TS-BECK2TS -HP-DRY 3	HP: Dryer	11	1	1	43	81	20	48	32
N-TS-BECK2TS -IT-D1CVT	IT: CVT	1	1	100	1	1	0	34	16
N-TS-BECK2TS -IT-D1CVT	IT: CVT	1	1	100	1	1	0	34	16
N-TS-BECK2TS -IT-D1CVT	IT: CVT	1	1	100	1	1	0	34	16
N-TS-BECK2TS -IT-KL26CTK	IT: Current Transformer	38	1	90	1	1	0	34	15
N-TS-BECK2TS -IT-L25CVT	IT: CVT	48	1	100	1	1	0	34	16
N-TS-BECK2TS -IT-L27CVT	IT: CVT	48	1	100	1	1	0	34	16
N-TS-BECK2TS -IT-PA27CT	IT: Current Transformer	1	1	100	1	1	0	34	16
N-TS-BECK2TS -IT-PA27CT	IT: Current Transformer	1	1	100	1	1	0	34	16
N-TS-BECK2TS -IT-PA27CT	IT: Current Transformer	1	1	100	1	1	0	34	16
N-TS-BECK2TS -IT-Q25BMCVT	IT: CVT	1	1	100	1	1	0	34	16
N-TS-BECK2TS -IT-Q25BMCVT	IT: CVT	1	1	100	1	1	0	34	16
N-TS-BECK2TS -IT-Q25BMCVT	IT: CVT	1	1	100	1	1	0	34	16
N-TS-BECK2TS -IT-Q26MCVT	IT: CVT	48	1	100	1	1	0	34	16
N-TS-BECK2TS -PR-1D2 BF	Protection: Electro Mechanical	45	1	75	100	42	0	70	39
N-TS-BECK2TS -PR-1K2 BF	Protection: Electro Mechanical	45	1	75	69	80	0	70	47
N-TS-BECK2TS -PR-BP76 A	Protection: Microprocessor	2	1	1	37	68	0	72	31
N-TS-BECK2TS -PR-D2 BU	Protection: Electro Mechanical	49	0	100	1	1	0	65	29
N-TS-BECK2TS -PR-D2 MAIN	Protection: Electro Mechanical	49	0	100	1	1	0	65	29
N-TS-BECK2TS -PR-DL24 BF	Protection: Microprocessor	6	1	1	99	44	0	70	30
N-TS-BECK2TS -PR-DL27 BF A	Protection: Microprocessor	1	0	1	87	100	0	67	73
N-TS-BECK2TS -PR-DL30 BF	Protection: Electro Mechanical	45	1	75	100	89	0	70	53
N-TS-BECK2TS -PR-DT302 BF	Protection: Solid State	31	1	100	66	96	0	70	55
N-TS-BECK2TS -PR-K1 BU	Protection: Electro Mechanical	49	1	100	1	1	0	65	19
N-TS-BECK2TS -PR-K1 MAIN	Protection: Electro Mechanical	49	1	100	1	1	0	65	19

Func. Location	Asset Class	Age	Condition	Demographics	Economics	Performance	Utilization	Criticality	Composite
N-TS-BECK2TS -PR-K2 BU	Protection: Electro Mechanical	49	0	100	1	1	0	65	29
N-TS-BECK2TS -PR-K2 MAIN	Protection: Electro Mechanical	49	0	100	1	1	0	65	29
N-TS-BECK2TS -PR-KL25 BF	Protection: Electro Mechanical	45	1	75	100	100	0	70	57
N-TS-BECK2TS -PR-KL26 BF	Protection: Solid State	31	1	100	1	1	0	70	19
N-TS-BECK2TS -PR-KL29 BF	Protection: Electro Mechanical	45	1	75	30	42	0	70	32
N-TS-BECK2TS -PR-L25T302 BF	Protection: Electro Mechanical	13	1	1	100	100	0	70	48
N-TS-BECK2TS -PR-L30L35 BF	Protection: Solid State	31	1	100	1	1	0	70	19
N-TS-BECK2TS -PR-MPS MAIN2	Protection: Electro Mechanical	31	0	25	100	80	0	24	65
N-TS-BECK2TS -PR-PA301 A	Protection System	31	1	100	1	1	0	35	16
N-TS-BECK2TS -PR-PA301 B	Protection System	31	1	100	1	1	0	35	16
N-TS-BECK2TS -PR-PA302 B	Protection: Solid State	31	1	100	1	1	0	72	19
N-TS-BECK2TS -PR-Q21P A	Protection: Microprocessor	3	1	1	100	48	0	70	31
N-TS-BECK2TS -PR-Q22P A	Protection: Microprocessor	3	0	1	42	84	0	70	58
N-TS-BECK2TS -PR-Q29HM B	Protection: Microprocessor	7	1	1	1	88	0	70	34
N-TS-BECK2TS -PR-T301 A	Protection System	31	1	100	1	1	0	35	16
N-TS-BECK2TS -PR-T301 B	Protection System	31	1	100	1	1	0	35	16
N-TS-BECK2TS -PR-TL28L29 BF	Protection: Electro Mechanical	45	1	75	100	100	0	70	57
N-TS-BECK2TS -SA-R27SA1	Surge Arrester_230 kV	0	0	0	0	0	0	38	38
N-TS-BECK2TS -SA-R27SA1	Surge Arrester_230 kV	0	0	0	0	0	0	38	38
N-TS-BECK2TS -SA-R27SA1	Surge Arrester_230 kV	0	0	0	0	0	0	38	38
N-TS-BECK2TS -SA-R27SA2	Surge Arrester_230 kV	0	0	0	0	0	0	38	38
N-TS-BECK2TS -SA-R27SA2	Surge Arrester_230 kV	0	0	0	0	0	0	38	38
N-TS-BECK2TS -SA-R27SA2	Surge Arrester_230 kV	0	0	0	0	0	0	38	38
N-TS-BECK2TS -SA-R76SA1	Surge Arrester_230 kV	4	0	0	0	0	0	38	38
N-TS-BECK2TS -SA-R76SA1	Surge Arrester_230 kV	4	0	0	0	0	0	38	38
N-TS-BECK2TS -SA-R76SA1	Surge Arrester_230 kV	4	0	0	0	0	0	38	38
N-TS-BECK2TS -SA-R76SA2	Surge Arrester_230 kV	4	0	0	0	0	0	38	38
N-TS-BECK2TS -SA-R76SA2	Surge Arrester_230 kV	4	0	0	0	0	0	38	38
N-TS-BECK2TS -SA-R76SA2	Surge Arrester_230 kV	4	0	0	0	0	0	38	38
N-TS-BECK2TS -SA-T301SA1	Surge Arrester_230 kV	0	0	0	0	0	0	38	38
N-TS-BECK2TS -SA-T301SA1	Surge Arrester_230 kV	0	0	0	0	0	0	38	38
N-TS-BECK2TS -SA-T301SA1	Surge Arrester_230 kV	0	0	0	0	0	0	38	38
N-TS-BECK2TS -SA-T301SA2	Surge Arrester_345 kV	0	0	0	0	0	0	44	44
N-TS-BECK2TS -SA-T301SA2	Surge Arrester_345 kV	0	0	0	0	0	0	44	44
N-TS-BECK2TS -SA-T301SA2	Surge Arrester_345 kV	0	0	0	0	0	0	44	44

Func. Location	Asset Class	Age	Condition	Demographics	Economics	Performance	Utilization	Criticality	Composite
N-TS-BECK2TS -SA-T302SA1	Surge Arrester_230 kV	0	0	0	0	0	0	38	38
N-TS-BECK2TS -SA-T302SA1	Surge Arrester_230 kV	0	0	0	0	0	0	38	38
N-TS-BECK2TS -SA-T302SA1	Surge Arrester_230 kV	0	0	0	0	0	0	38	38
N-TS-BECK2TS -SA-T302SA2	Surge Arrester_345 kV	0	0	0	0	0	0	44	44
N-TS-BECK2TS -SA-T302SA2	Surge Arrester_345 kV	0	0	0	0	0	0	44	44
N-TS-BECK2TS -SA-T302SA2	Surge Arrester_345 kV	0	0	0	0	0	0	44	44
N-TS-BECK2TS -SI-EN-SPILT301	Spill Containment	0	100	1	100	100	0	65	85
N-TS-BECK2TS -SI-EN-SPILT302	Spill Containment	0	1	1	100	100	0	65	47
N-TS-BECK2TS -SW-1D2-1	Switch: Air Break_230 kV	0	73	1	40	1	20	45	34
N-TS-BECK2TS -SW-1D2-2	Switch: Air Break_230 kV	46	73	92	10	1	10	38	39
N-TS-BECK2TS -SW-1K2-1	Switch: Air Break_230 kV	46	73	92	40	1	20	45	44
N-TS-BECK2TS -SW-28-PA301	Switch: Air Break_230 kV	0	73	1	40	1	80	49	42
N-TS-BECK2TS -SW-28-PA302	Switch: Air Break_230 kV	0	73	1	40	1	80	49	42
N-TS-BECK2TS -SW-28-Q22P	Switch: Air Break_230 kV	0	73	1	40	1	80	45	42
N-TS-BECK2TS -SW-28-Q23BM	Switch: Air Break_230 kV	0	73	1	40	1	80	45	42
N-TS-BECK2TS -SW-28-Q24HM	Switch: Air Break_230 kV	0	73	1	40	1	80	45	42
N-TS-BECK2TS -SW-28-Q25BM	Switch: Air Break_230 kV	0	73	1	40	1	80	45	42
N-TS-BECK2TS -SW-28-Q26M	Switch: Air Break_230 kV	8	73	18	40	1	80	45	43
N-TS-BECK2TS -SW-28Q26M-G	Switch: Ground_230 kV	8	73	16	10	1	10	38	31
N-TS-BECK2TS -SW-28-Q28A	Switch: Air Break_230 kV	0	73	1	40	1	80	45	42
N-TS-BECK2TS -SW-28-Q29HM	Switch: Air Break_230 kV	43	73	96	40	1	80	45	52
N-TS-BECK2TS -SW-28-Q30M	Switch: Air Break_230 kV	0	73	1	40	1	80	45	42
N-TS-BECK2TS -SW-28-Q35M	Switch: Air Break_230 kV	46	73	92	40	1	80	45	52
N-TS-BECK2TS -SW-28Q35M-G	Switch: Ground_230 kV	8	73	18	10	1	10	38	31
N-TS-BECK2TS -SW-28T301-1	Switch: Air Break_230 kV	0	73	1	40	1	100	45	44
N-TS-BECK2TS -SW-302-2	Switch: Air Break_230 kV	0	73	1	40	1	0	45	36
N-TS-BECK2TS -SW-DL24-D	Switch: Air Break_230 kV	0	73	1	40	1	20	45	34
N-TS-BECK2TS -SW-DL27-D	Switch: Air Break_230 kV	0	73	1	40	1	80	45	42
N-TS-BECK2TS -SW-DL27-L	Switch: Air Break_230 kV	59	73	100	10	1	40	38	44
N-TS-BECK2TS -SW-DL30-3	Switch: Air Break_230 kV	0	73	1	40	1	20	45	34
N-TS-BECK2TS -SW-DL30-D	Switch: Air Break_230 kV	0	73	1	40	1	20	45	34
N-TS-BECK2TS -SW-DT301-1	Switch: Air Break_230 kV	0	73	1	40	1	20	45	34
N-TS-BECK2TS -SW-DT301-D	Switch: Air Break_230 kV	0	73	1	40	1	80	45	42
N-TS-BECK2TS -SW-DT302-2	Switch: Air Break_230 kV	0	73	1	40	1	20	45	34
N-TS-BECK2TS -SW-DT302-D	Switch: Air Break_230 kV	0	73	1	40	1	80	45	42

Func. Location	Asset Class	Age	Condition	Demographics	Economics	Performance	Utilization	Criticality	Composite
N-TS-BECK2TS -SW-F21-SS21	Switch: Air Break_< 69 kV	3	73	8	10	1	0	27	32
N-TS-BECK2TS -SW-F22-SS22	Switch: Air Break_< 69 kV	3	73	8	10	1	0	27	32
N-TS-BECK2TS -SW-KL23-K	Switch: Air Break_230 kV	0	73	1	40	1	20	45	34
N-TS-BECK2TS -SW-KL25-K	Switch: Air Break_230 kV	0	73	1	40	1	20	45	34
N-TS-BECK2TS -SW-KL25-L	Switch: Air Break_230 kV	0	73	1	40	1	20	45	34
N-TS-BECK2TS -SW-KL26-6	Switch: Air Break_230 kV	0	73	1	40	1	20	45	34
N-TS-BECK2TS -SW-KL26-K	Switch: Air Break_230 kV	0	73	1	40	1	20	45	34
N-TS-BECK2TS -SW-KL29-K	Switch: Air Break_230 kV	0	73	1	40	1	20	45	34
N-TS-BECK2TS -SW-KL29-L	Switch: Air Break_230 kV	0	73	1	40	1	20	45	34
N-TS-BECK2TS -SW-KL76-K	Switch: Air Break_230 kV	0	73	1	40	1	80	45	42
N-TS-BECK2TS -SW-KL76-L	Switch: Air Break_230 kV	0	73	1	40	1	80	45	42
N-TS-BECK2TS -SW-L25T302-2	Switch: Air Break_230 kV	0	73	1	40	1	20	45	34
N-TS-BECK2TS -SW-L25T302-5	Switch: Air Break_230 kV	0	73	1	40	1	20	45	34
N-TS-BECK2TS -SW-L28T301-1	Switch: Air Break_230 kV	0	73	1	40	1	20	45	34
N-TS-BECK2TS -SW-L28T301-8	Switch: Air Break_230 kV	0	73	1	40	1	20	45	34
N-TS-BECK2TS -SW-L30L35-L30	Switch: Air Break_230 kV	8	73	18	40	1	20	45	36
N-TS-BECK2TS -SW-L30L35-L35	Switch: Air Break_230 kV	8	73	18	40	1	0	45	38
N-TS-BECK2TS -SW-L35L76-L35	Switch: Air Break_230 kV	8	73	18	40	1	0	45	38
N-TS-BECK2TS -SW-L35L76-L76	Switch: Air Break_230 kV	8	73	18	40	1	80	45	43
N-TS-BECK2TS -SW-PA301-G	Switch: Ground_230 kV	0	73	1	10	1	10	42	30
N-TS-BECK2TS -SW-PA302-G	Switch: Ground_230 kV	0	73	1	10	1	10	42	30
N-TS-BECK2TS -SW-R27-L27	Switch: Air Break_230 kV	0	73	1	40	1	100	45	44
N-TS-BECK2TS -SW-R27-PA27	Switch: Air Break_230 kV	0	73	1	40	1	100	45	44
N-TS-BECK2TS -SW-R27-S	Switch: Air Break_230 kV	0	73	1	40	1	100	45	44
N-TS-BECK2TS -SW-R76-BP76	Switch: Air Break_230 kV	2	45	5	40	1	100	45	35
N-TS-BECK2TS -SW-R76-L76	Switch: Air Break_230 kV	2	45	5	40	1	100	45	35
N-TS-BECK2TS -SW-T301-1	Switch: Air Break_230 kV	0	73	1	10	1	70	38	37
N-TS-BECK2TS -SW-T301-2	Switch: Air Break_230 kV	31	73	69	40	1	100	45	52
N-TS-BECK2TS -SW-T302-1	Switch: Air Break_230 kV	0	73	1	10	1	70	38	37
N-TS-BECK2TS -SW-T302-2	Switch: Air Break_230 kV	0	73	1	40	1	100	45	44
N-TS-BECK2TS -SW-TL26L27-6	Switch: Air Break_230 kV	0	73	1	40	1	20	45	34
N-TS-BECK2TS -SW-TL28L29-8	Switch: Air Break_230 kV	0	73	1	40	1	20	45	34
N-TS-BECK2TS -SW-TL28L29-9	Switch: Air Break_230 kV	0	73	1	40	1	20	45	34
N-TS-BECK2TS -TC-LEASED_PSTS	Telecom: Leased Circuit	0	33	0	100	100	0	1	62
N-TS-BECK2TS -TC-NT0001M	Telecom: NT	32	100	50	42	1	0	1	49

Func. Location	Asset Class	Age	Condition	Demographics	Economics	Performance	Utilization	Criticality	Composite
N-TS-BECK2TS -TC-NT0001M	Telecom: NT	32	100	47	1	100	0	1	75
N-TS-BECK2TS -TC-T1MX0021M	Telecom: MUX Interfaces	11	1	19	100	100	0	27	46
N-TS-BECK2TS -TC-T1MX0022M	Telecom: MUX Interfaces	11	1	19	61	100	0	27	42
N-TS-BECK2TS -TC-T1MX0105M	Telecom: MUX Interfaces	11	1	19	1	100	0	79	40
N-TS-BECK2TS -TC-T1MX0110M	Telecom: MUX Interfaces	11	1	19	100	85	0	79	46
N-TS-BECK2TS -TC-T1MX0112M	Telecom: MUX Interfaces	11	1	19	100	100	0	79	51
N-TS-BECK2TS -TC-TETTTTTTT17	Telecom: Tone Equipment	22	1	88	1	1	0	17	13
N-TS-BECK2TS -TF-R27	Transformer: Regulator_230 kV	53	6	100	12	23	20	59	27
N-TS-BECK2TS -TF-SS5	Transformer: Stn Serv_< 69 kV	2	1	100	1	1	11	34	16
N-TS-BECK2TS -TF-SS6	Transformer: Stn Serv_< 69 kV	2	1	100	1	1	11	34	16

3.7 Asset Centric Program Work

The following station equipment has been previously identified in Asset Centric Programs prior to the adoption of the Station Centric planning model:

Table 5: Summary of Assets Identified in Asset-Centric Work Programs

Func. Location	Asset Class	Age	Condition	Demographics	Economics	Performance	Utilization	Criticality	Composite
Disturbance Monitoring Equipment Compliance									
N-TS-BECK2TS	TS	59	16	33	14	20	65	18	24
Station Battery Replacement Program									
N-TS-BECK2TS -DC-BA250B	DCSS: Battery_0.250 kV	2	8	10	1	1	0	36	8
Telecom Charger Replacement Program									
N-TS-BECK2TS -DC-CH48A	DCSS: Charger_0.250 kV	2	1	13	1	1	0	28	5
N-TS-BECK2TS -DC-CH48B	DCSS: Charger_0.250 kV	2	1	13	1	1	0	28	5
Protection Replacement Program									
N-TS-BECK2TS -PR-D1 BU	Protection: Electro Mechanical	49	100	100	100	100	0	70	98
N-TS-BECK2TS -PR-D1 MAIN	Protection: Electro Mechanical	49	1	100	1	1	0	70	19
N-TS-BECK2TS -PR-TL21 A	Protection: Electro Mechanical	45	1	75	38	55	0	70	36
N-TS-BECK2TS -PR-TL21 B	Protection: Electro Mechanical	45	1	75	1	84	0	70	42
N-TS-BECK2TS -PR-TL26 BU	Protection: Electro Mechanical	45	1	75	81	42	0	70	37
N-TS-BECK2TS -PR-TL26 MAIN	Protection: Electro Mechanical	45	1	75	1	1	0	70	16
N-TS-BECK2TS -PR-TL28 BU	Protection: Electro Mechanical	45	1	75	88	51	0	70	40

Func. Location	Asset Class	Age	Condition	Demographics	Economics	Performance	Utilization	Criticality	Composite
N-TS-BECK2TS -PR-TL28 MAIN	Protection: Electro Mechanical	45	1	75	1	84	0	70	42
N-TS-BECK2TS -PR-TL35 BU	Protection: Electro Mechanical	45	1	75	1	100	0	70	47
N-TS-BECK2TS -PR-TL35 MAIN	Protection: Electro Mechanical	45	1	75	1	1	0	70	16

3.8 Station Security

Beck #2 TS is classified as ***Low Risk*** and as of July 2014 has experienced no break-ins since 2007. The history of break-ins at Beck #2 TS is shown in Table 6.

Table 6: Count of Break-Ins by Year at Beck #2 TS

2007	2008	2009	2010	2011	2012	2013	2014 (JUL)
0	0	0	0	0	0	0	0

As per ***SP-14-001-R1:*** *Functional Requirements for Preventing Copper Theft*, and ***SP-14000-001-R0:*** *Functional Requirements for Transmission and Distribution Security Detection and Verification Systems*, all stolen/missing *below grade* fence grounding and power equipment grounding conductors are to be replaced with copper-clad steel conductors whenever safely possible and when the original copper conductor was 4/0# or smaller. In addition, all stolen/missing *above grade* fence grounding is to be replaced with aluminum grounding material.

Defined as a Low Risk station, current functional requirements dictate that the station be enclosed by a standard 8' (2.44 m) chain link perimeter fence.

For reference, criteria for station security risk classification are summarized in Table 7, below.

Table 7: Security Risk Classifications

Security Risk Level	Description
High	10+ break-ins from 2007- present
Medium	1-9 break-ins from 2007- present
Low	0 break-ins from 2007- present

3.9 Potential Need & Deficiency Report Notifications

Below is a summary of Potential Needs (PN) and Deficiency Report (DR) notification that have been issued by Field Staff and currently outstanding.

Table 8: Listing of Open and Outstanding Potential Needs (PN) Notifications

Notification	Type	Functional Loc.	Notif.date	Description
10475301	PN	N-TS-BECK2TS -PR	03/11/2010	Beck II swyd interface modification
10467996	PN	N-TS-BECK2TS -TC	02/10/2010	Telemetering to NYPA is an issue (ZFB)
10409890	PN	N-TS-BECK2TS -SI-YA	12/11/2009	Wooden cable pan covers need replacing
10374874	PN	N-TS-BECK2TS -TC	10/16/2009	Beck2 legacy telemetries to New York IS0
10370192	PN	N-TS-BECK2TS -PR	10/08/2009	Beck2 Q21P&Q22P protection upgrade

Notification	Type	Functional Loc.	Notif.date	Description
10339902	PN	N-TS-BECK2TS -TF-T302	07/28/2009	T302 - leaks (1300L)
10269323	PN	N-TS-BECK2TS -BU	03/04/2009	Beck 2 has low conductors in many areas
10262531	PN	N-TS-BECK2TS -DC-CH48A	02/06/2009	Beck 2 Station 48 volt battery chargers
10265807	PN	N-TS-BECK2TS -PR	02/18/2009	No disconnect switches discrepancy alarm
10262469	PN	N-TS-BECK2TS -DC-CH48A	02/06/2009	Beck 2 Station 48 volt battery chargers

Table 9: Listing of Open and Outstanding Deficiency Report Notifications

Notification	Type	Functional Loc.	Notif.date	Description
13467089	DR	N-TS-BECK2TS -HP-DRY 2	12/05/2014	BECK 2 D2 CHECK VALVE REPAIR
13467087	DR	N-TS-BECK2TS -HP-DRY 1	12/05/2014	BECK 2 D1 CHECK VALVE REPAIR
13466228	DR	N-TS-BECK2TS -BR-DT302	12/04/2014	Beck#2 DT302 Phase Discrepancy
13466392	DR	N-TS-BECK2TS -CN-BK23LCC	12/04/2014	Beck#2 230 LCC/LMC Keyboard & Monitor
13466394	DR	N-TS-BECK2TS -CN-BK23LMC	12/04/2014	Beck#2 230 LMC Re-Image
13461395	DR	N-TS-BECK2TS -PR	11/28/2014	assist customer Beck2 Q21P test trips
13460662	DR	N-TS-BECK2TS -BR-DT302	11/27/2014	Beck #2 DT302 pole box leak in B phase
13455442	DR	N-TS-BECK2TS -HP-DRY 3	11/25/2014	dryer #3 hygrometer diagnostic
13451942	DR	N-TS-BECK2TS -PR-BP76 A	11/24/2014	Beck#2 BP76 Telemetery Scaling
13451940	DR	N-TS-BECK2TS -PR-PA27 A	11/24/2014	Beck#2 PA27 Telemetery Scaling
13451941	DR	N-TS-BECK2TS -PR-PA301 A	11/24/2014	Beck#2 PA301 Telemetery Scaling
13450007	DR	N-TS-BECK2TS -BR-DL24	11/24/2014	DL24 Phase Discrepancy
13447309	DR	N-TS-BECK2TS -HP-DRY 3	11/19/2014	BECK 2 D3 CHECK VALVE REPAIR
13438452	DR	N-TS-BECK2TS -SI-BLDG PCT A	11/17/2014	Beck 2 TS Replace eyewash PCT A
13438453	DR	N-TS-BECK2TS -SI-BLDG PCT B	11/17/2014	replace eyewash fluid PCT Bldg B
13424790	DR	N-TS-BECK2TS -SW-TL26L27-6	10/31/2014	wHITE PHASE COMES UP OFF STOP
13424791	DR	N-TS-BECK2TS -BR-TL26L27	10/31/2014	TL26L27 AIR LEAK
13423431	DR	N-TS-BECK2TS -HP-CMP 4	10/30/2014	BECK 2 C4 SUPPLY BREAKER REPLACEMENT
13421883	DR	N-TS-BECK2TS -IT-Q26MCVT	10/29/2014	Beck2 Q26MCVT Secondary Isolation Box
13418160	DR	N-TS-BECK2TS -SI-BLDG D	10/22/2014	Beck 2 Control Room Lights
13416333	DR	N-TS-BECK2TS -CN-BEK2DFR	10/20/2014	Beck 2 DFR Q26M Voltage Fluctuation
13409125	DR	N-TS-BECK2TS -PR-DL30 BF	10/14/2014	Beck#2 DL30(H22) Pallet Muilt DC Supply
13409122	DR	N-TS-BECK2TS -PR-KL25 BF	10/14/2014	Beck#2 KL25(H10) Pallet Muilt DC Supply
13409123	DR	N-TS-BECK2TS -PR-KL29 BF	10/14/2014	Beck#2 KL29(H18) Pallet Muilt DC Supply
13409124	DR	N-TS-BECK2TS -PR-TL28L29 BF	10/14/2014	Beck#2 TL28L29(H17)PalletMuilt DC Supply
13398185	DR	N-TS-BECK2TS -TC	09/29/2014	Beck#2 Norantel Hard Wired Alarms
13397732	DR	N-TS-BECK2TS -BR-L28T301	09/29/2014	Counter and Indicating light failed
13360974	DR	N-TS-BECK2TS -TC-T1MX0017M	09/26/2014	T1MX0017 & 18 & 19 No Hardwired Alarms
13360978	DR	N-TS-BECK2TS -TC-T1MX0020M	09/26/2014	T1MX0020 & 21 & 22 Hardwired Alarms

Notification	Type	Functional Loc.	Notif.date	Description
13361040	DR	N-TS-BECK2TS -TC-T1MX0023M	09/26/2014	T1MX0023 & 24 & 25 & 26
13352956	DR	N-TS-BECK2TS -SI	09/25/2014	Beck 345 swy repair cable trench covers
13346713	DR	N-TS-BECK2TS -DC-PNL 1	09/16/2014	BT1 Breaker failure to operate
13341580	DR	N-TS-BECK2TS -SI-BLDG A	09/12/2014	BECK 2 NOMENCLATURE UPDATE
13339064	DR	N-TS-BECK2TS -HP-DRY 3	09/12/2014	BECK 2 D3 CHECK VALVES
13334895	DR	N-TS-BECK2TS -HP	09/11/2014	Beck#2 MOV 3C117A
13326611	DR	N-TS-BECK2TS -PR-TL26L27 BFA	09/09/2014	TL26L27 A Multiplier Pallet Chatter
13276485	DR	N-TS-BECK2TS -SI-BLDG C	08/27/2014	Beck II Cyber secure window not closing
13240365	DR	N-TS-BECK2TS -SW-28-Q21P	08/15/2014	BECK 2 - 28-Q21P SW CHECK CLOSE CONTROL
13014552	DR	N-TS-BECK2TS -TF-T302	06/02/2014	Beck #2 345 yard T302 fan
13004036	DR	N-TS-BECK2TS -TF-T301	05/28/2014	Beck #2 T301 Trojan dry out unit
12965070	DR	N-TS-BECK2TS -SW-R27-L27	05/09/2014	Beck #2 R27-L27 won't open electrically
12952822	DR	N-TS-BECK2TS -SI-BLDG PCT A	05/07/2014	345 pct bldgs ground wires through floor
12944414	DR	N-TS-BECK2TS -BR-DT302	05/02/2014	White Phase Swag Lock MCT Samples Bent
12920987	DR	N-TS-BECK2TS -IT-Q26MCVT	04/22/2014	Secondary box
12920996	DR	N-TS-BECK2TS -IT-L302VT	04/22/2014	oil level gauges.
12920985	DR	N-TS-BECK2TS -IT-L24CVT	04/22/2014	Beck #2 L24CVT Secondary box
12878819	DR	N-TS-BECK2TS -SI-BLDG A	03/10/2014	BECK 2 AIR SYSTEM PRINT VERIFICATION
12858312	DR	N-TS-BECK2TS -HP-DRY 1	01/18/2014	BECK 2 DRYER #1 HYG REPLACEMENT
12858310	DR	N-TS-BECK2TS -HP-DRY 3	01/18/2014	BECK 2 DRYER #3 HYG REPLACEMENT
12840094	DR	N-TS-BECK2TS -SW-TL21L24-1	12/20/2013	Beck #2 TL21L24 hotspot w phase
12829302	DR	N-TS-BECK2TS -BR-KL29	12/10/2013	Beck #2 KL29 B phase leak
12826600	DR	N-TS-BECK2TS -HP-DRY 3	12/09/2013	BECK 2 DRYER #3 HIGH DIFFERENTIAL
12826409	DR	N-TS-BECK2TS -SW-L30L35-L35	12/09/2013	L30L35-L35 red phase does not close
12805121	DR	N-TS-BECK2TS -BR-L35L76	11/26/2013	L35L76 Red Phase
12752735	DR	N-TS-BECK2TS -SW-Q25BM-G	11/04/2013	28Q25BM-G Nomenclature
12752734	DR	N-TS-BECK2TS -SW-Q25BM-G	11/04/2013	Beck #2 Q25BM-G not closing properly
12752935	DR	N-TS-BECK2TS -SW-TL26L27-6	11/04/2013	Beck #2 TL26L27-6 w phase not closing
12741879	DR	N-TS-BECK2TS -BR-KL23	10/30/2013	NF28KL23 Air Leak
12569220	DR	N-TS-BECK2TS -SW-TL28L29-8	09/11/2013	Beck#2 TL28L29-8 No Operation
12480828	DR	N-TS-BECK2TS -HP-CMP 1	08/08/2013	BECK 2 C1 TEMPERATURE GAUGES
12097775	DR	N-TS-BECK2TS -BR-KL23	03/06/2013	KL23 heater fail
11149658	DR	N-TS-BECK2TS -PR-DL30 BF	04/26/2012	H22 (DL30) Multiplier Silver Migration
11149653	DR	N-TS-BECK2TS -PR-KL25 BF	04/26/2012	H10 (KL25) BF Prot. Silver Migration
11149652	DR	N-TS-BECK2TS -PR-KL29 BF	04/26/2012	H18 (KL29) Multiplier Silver Migration
11149608	DR	N-TS-BECK2TS -PR-DL30 BF	04/26/2012	H22 (DL30) Reclose Case Silver Migration
11149628	DR	N-TS-BECK2TS -PR-TL28L29 BF	04/26/2012	H17 (TL28L29) Reclose Silver Migration

Notification	Type	Functional Loc.	Notif.date	Description
10864680	DR	N-TS-BECK2TS -SW-28-Q25BM	02/10/2012	Beck #2 28-Q25BM
10864681	DR	N-TS-BECK2TS -SW-KL25-L	02/10/2012	Beck #2 KL25-L
10488917	DR	N-TS-BECK2TS -HP-DRY 1	04/14/2010	Niagara- Stephens Dryers parts issues
10269062	DR	N-TS-BECK2TS -HP-CMP 4	03/03/2009	COMPRESSOR DUMP VALVE SEAT MACHINING

4.0 RECOMMENDATIONS

The recommendations for Beck #2 TS are as follows;

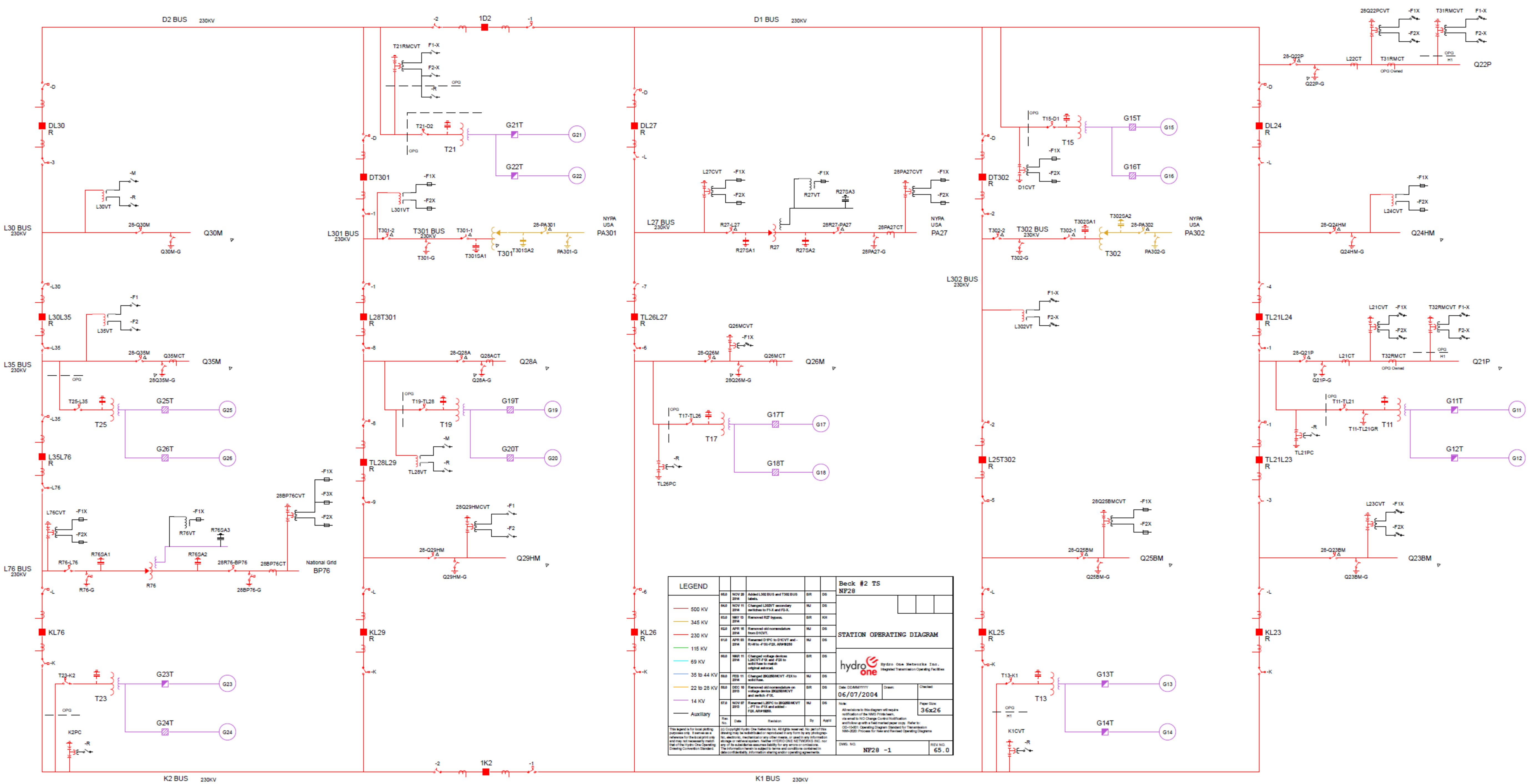
- As part of Hydro One's asset management strategy, all air blast circuit breakers across the province are to be replaced. The strategy establishes a plan to minimize both the breakers' life cycle costs (capital and O&MA) and the risks associated with the breakers' age, condition, performance, utilization, obsolescence, and criticality.
- Due to limitations on real-estate and outage constraints, investigate the following options for breaker replacements;
    - In-situ ABCB breaker replacement
    - Air Insulated Switchgear - Bay-by-Bay
    - Gas Insulated Switchgear (GIS) – "Greenfield" on available space east of current switchyard

5.0 REFERENCE SOURCES

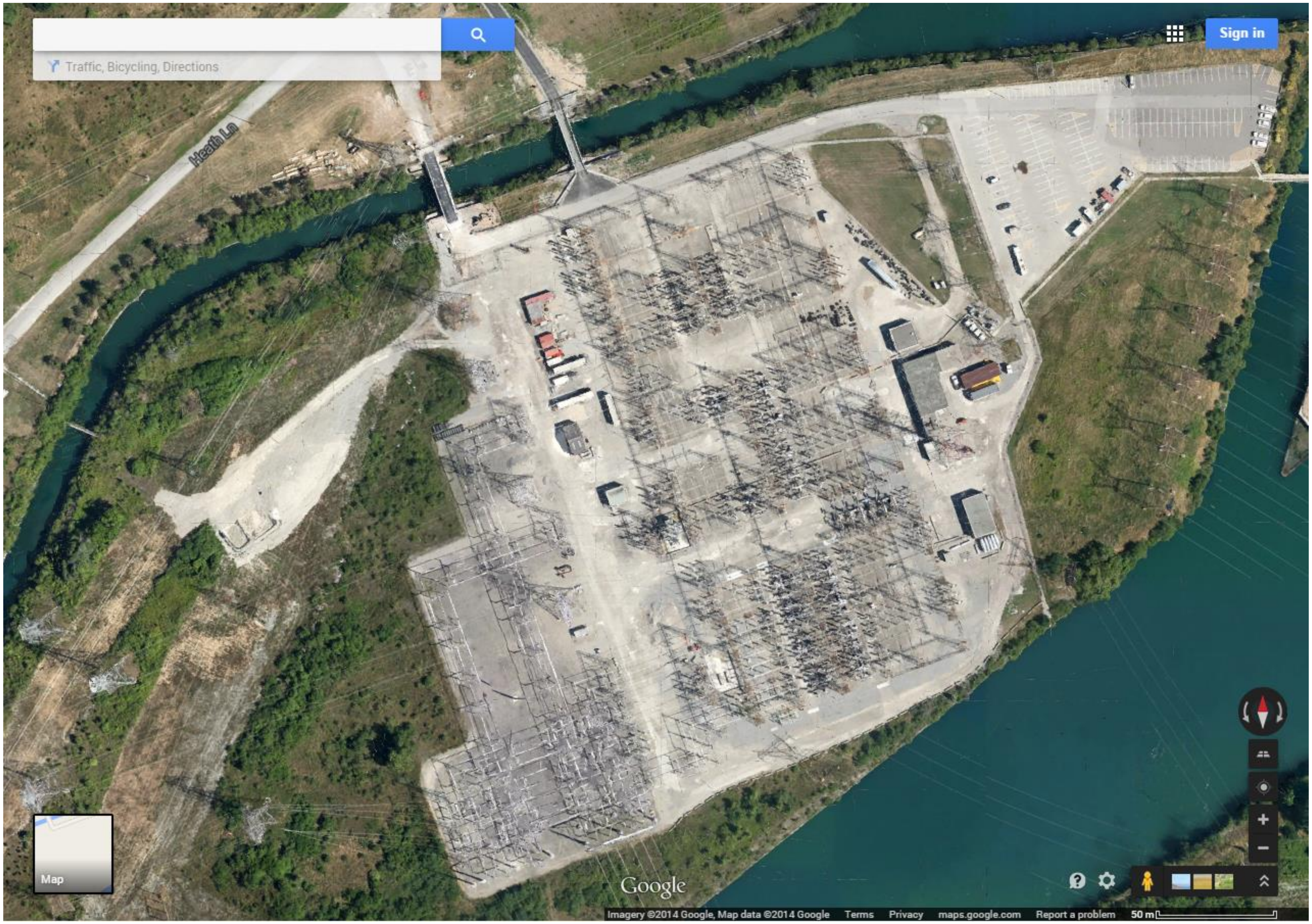
[1] Special Studies, "2014 Update of Short Circuit Survey and Breaker Ratings," [Online]. Available: https://teams.hydroone.com/sites/TPD/TPD/ss_pd/Short Circuit/Surveys/Breakers.

[2] Conestoga-Rogers & Associates, "Hydro One Station Spill Risk Model," Mississauga, 2011.

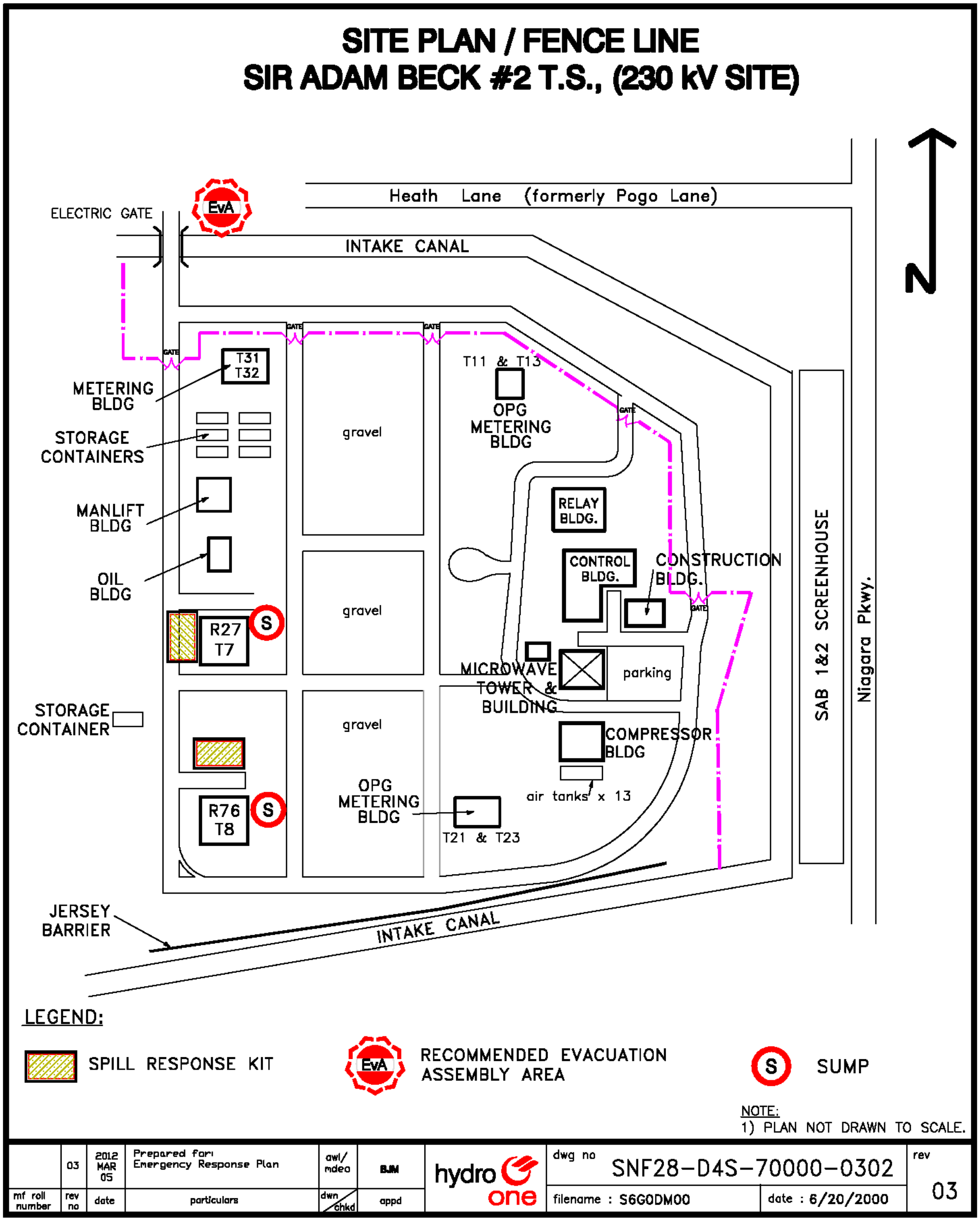
APPENDIX 1 – BECK #2 TS OPERATING DIAGRAM



APPENDIX 2 – AERIAL/SATELLITE VIEW



APPENDIX 3 – SITE PLAN / FENCE LINE



APPENDIX 4 – TRANSMISSION EQUIPMENT OUTAGE PERFORMANCE DATA

Beck #2 TS Station Equipment Sustained Outage Event Report

Period: From: 1/1/2008 To: 11/30/2014

#	Type	Op Des	Voltage	Date	Time	Duration (HR)	Cause Code	Cause Description	Outage Type	Urg.	Ext.	Remark
1	Breaker	NF28KL25	230	12-Oct-14	07:29	2.52	1MKB	Main Pwr-Bkr Eqpt-Operating Mechanism (General)	D	FA	CC	FAILURE BKR MECH-LOW AIR
2	Breaker	NF28TL21L23	230	05-Jun-14	22:19	35.55	7NA	Non Pwr Eqpt-Annunciation/Alarm Circuit	D	FM	CC	LOW AIR ALARM
3	Breaker	NF281K2	230	09-May-14	15:05	2.92	1MKB	Main Pwr-Bkr Eqpt-Operating Mechanism (General)	D	FM	CC	FAILURE BKR MECHANISM
4	Bus	NF28K1	230	09-May-14	15:05	2.92	4FC	Power System Configuration-Clearance	S	FM	CCT	CLEARANCE FOR NF281K2
5	Bus	NF28K2	230	09-May-14	15:05	2.92	4FC	Power System Configuration-Clearance	S	FM	CCT	CLEARANCE FOR NF281K2
6	Breaker	NF28TL21L23	230	02-May-14	05:00	7.63	7NA	Non Pwr Eqpt-Annunciation/Alarm Circuit	D	FM	CC	FAULTY RESISTOR IN ALARM CCT
7	Breaker	NF28TL21L23	230	26-Mar-14	03:33	33.20	1MKFA	Main Pwr-Bkr Eqpt-Interrupting Medium Air Problem	D	FM	CC	LOW AIR PRESSURE ISSUES
8	Breaker	NF28KL26	230	04-Mar-14	17:26	377.65	1MKFA	Main Pwr-Bkr Eqpt-Interrupting Medium Air Problem	D	FM	CC	AIR ISSUES-REFILLING/BLOWING
9	Breaker	NF28TL21L23	230	25-Feb-14	03:26	367.55	1MKB	Main Pwr-Bkr Eqpt-Operating Mechanism (General)	D	FM	CC	STUCK BREAKER
10	Breaker	NF28DT302	230	07-Jan-14	08:25	10.98	7NA	Non Pwr Eqpt-Annunciation/Alarm Circuit	D	FA	CC	EXCESSIVE FILL TIME ALARM
11	Breaker	NF28KL25	230	07-Jan-14	08:51	2.85	7NA	Non Pwr Eqpt-Annunciation/Alarm Circuit	D	FA	CC	EXCESSIVE FILL TIME ALARM
12	Breaker	NF28KL26	230	07-Jan-14	06:30	4.00	7NA	Non Pwr Eqpt-Annunciation/Alarm Circuit	D	FA	CC	EXCESSIVE FILL TIME ALARM
13	Breaker	NF28L25T302	230	07-Jan-14	06:33	5.92	7NA	Non Pwr Eqpt-Annunciation/Alarm Circuit	D	FA	CC	EXCESSIVE TIME FILLING ALARM
14	Breaker	NF28L28T301	230	07-Jan-14	08:06	2.87	7NA	Non Pwr Eqpt-Annunciation/Alarm Circuit	D	FA	CC	EXCESSIVE FILL TIME ALARM
15	Breaker	NF28L35L76	230	07-Jan-14	07:08	7.50	7NA	Non Pwr Eqpt-Annunciation/Alarm Circuit	D	FA	CC	EXCESSIVE FILL TIME ALARM
16	Breaker	NF28DT302	230	29-Nov-13	11:28	289.65	1MKFA	Main Pwr-Bkr Eqpt-Interrupting Medium Air Problem	D	FM	CC	AIR LEAKING ISSUES
17	Breaker	NF28TL21L24	230	03-Nov-13	02:13	7.65	7NA	Non Pwr Eqpt-Annunciation/Alarm Circuit	D	FM	CC	CIRC TRIP FAIL ALARM
18	Breaker	NF28TL26L27	230	02-Nov-13	05:50	28.68	7NA	Non Pwr Eqpt-Annunciation/Alarm Circuit	D	FM	CC	SUST LOW AIR PRESSURE ALARM
19	Breaker	NF28TL26L27	230	07-Oct-13	03:23	33.77	1MKFA	Main Pwr-Bkr Eqpt-Interrupting Medium Air Problem	D	FM	CC	LOW AIR PRESSURE
20	Breaker	NF28TL26L27	230	29-Sep-13	19:38	22.32	1MKFA	Main Pwr-Bkr Eqpt-Interrupting Medium Air Problem	D	FM	CC	LOW AIR PRESSURE ISSUES
21	Breaker	NF28L28T301	230	27-Sep-13	09:10	76.32	1MKBC	Main Pwr-Bkr Eqpt-Operating Mechanism Pole Discrep.	D	FM	CC	POLE DISCREPANCY ISSUES
22	Breaker	NF28TL21L24	230	25-Apr-13	00:41	12.20	1MI	Main Pwr-Investigation-No Defect/Problem Found	D	FM	CC	INVESTIGATION
23	Breaker	NF28DT302	230	17-Apr-13	00:44	6.65	1MKFA	Main Pwr-Bkr Eqpt-Interrupting Medium Air Problem	D	FM	CC	AIR PRESSURE PROBLEM
24	Breaker	NF28DL27	230	03-Apr-13	11:36	1.35	1MKDA	Main Pwr-Bkr Eqpt-Insulation Air Problem	D	FM	CC	NF28DL27 O/S-AIR LINE DEFECT
25	Transformer	NF28R27	230	29-Mar-13	14:35	0.88	4FS	Power System Configuration-Series Connection	S	FM	CCT	ADJUSTMENTS TO L27CVT WIRING
26	Breaker	NF28KL25	230	22-Jan-13	09:50	230.17	1MKDA	Main Pwr-Bkr Eqpt-Insulation Air Problem	D	FM	CC	SIGNIFICANT AIR LEAK
27	Bus	NF28LR76	230	14-Dec-12	16:46	0.03	4FS	Power System Configuration-Series Connection	S	FM	CCT	F28R76 O/S
28	Transformer	NF28R76	230	14-Dec-12	16:46	138.13	1TP	Term Pwr Eqpt-Potential Transformer (General)	D	FM	CCT	AUX VT OUTPUT VOLTAGE CONCERNS

#	Type	Op Des	Voltage	Date	Time	Duration (HR)	Cause Code	Cause Description	Outage Type	Urg.	Ext.	Remark
29	Bus	NF28D2	230	14-May-12	11:20	2.33	4FU	Power System Configuration-Customer or Other Utility	S	FA	CCT	CAUSED BY OPG T21 TRIP
30	Breaker	NF28TL26L27	230	07-May-12	13:14	45.23	1MKDA	Main Pwr-Bkr Eqpt-Insulation Air Problem	D	FM	CC	REPAIR AIR LEAK
31	Breaker	NF28TL26L27	230	29-Apr-12	19:19	18.03	7NCKH	Non Pwr Eqpt-Control-Breaker-Air/Gas/Oil Control	D	FM	CC	STUCK-AIR VALVE SOLENOID DEFEC
32	Breaker	NF28TL26L27	230	24-Apr-12	16:44	0.12	7NA	Non Pwr Eqpt-Annunciation/Alarm Circuit	D	FM	CC	RESET BKR LOW AIR ALARM
33	Breaker	NF28TL26L27	230	24-Apr-12	20:57	16.78	7NCKB	Non Pwr Eqpt-Control-Breaker-Switch Defect	D	FM	CC	REPLACE 8 POLE DC SWITCH
34	Breaker	NF28TL26L27	230	26-Jan-12	06:45	7.03	1MKDA	Main Pwr-Bkr Eqpt-Insulation Air Problem	D	FM	CC	BKR LOW AIR PRESSURE
35	Breaker	NF28TL26L27	230	18-Jan-12	19:27	1.93	1MKDA	Main Pwr-Bkr Eqpt-Insulation Air Problem	D	FM	CC	BKR LOW AIR
36	Breaker	NF28DL27	230	10-Jan-12	17:22	42.27	7NCKH	Non Pwr Eqpt-Control-Breaker-Air/Gas/Oil Control	D	FM	CC	REPL.DEFECTIVE AGASTAT RELAY
37	Transformer	NF28R27	230	04-Jan-12	04:05	153.30	1MTAA	Main Pwr-Transformer Eqpt-Bushing Defect	D	FM	CCT	REPLACE Y WNDY TERT.BUSHING
38	Breaker	NF28L30L35	230	01-Jan-12	00:00	3322.58	7NCK	Non Pwr Eqpt-Control-Breaker (General)	D	FM	CC	*2DISTNO=20111123303
39	Breaker	NF28KL29	230	03-Dec-11	19:37	1.72	7NCKH	Non Pwr Eqpt-Control-Breaker-Air/Gas/Oil Control	D	FM	CC	ADJUST AIR RELIEF VALVE
40	Breaker	NF28DT301	230	23-Nov-11	15:00	1.33	7NCK	Non Pwr Eqpt-Control-Breaker (General)	D	FM	CC	CHECK BKR FOR OPEN PHASE
41	Breaker	NF28L30L35	230	23-Nov-11	16:05	919.92	7NCK	Non Pwr Eqpt-Control-Breaker (General)	D	FM	CC	RED/WHITE PHASE BAD CONTACT
42	Bus	NF28K2	230	24-Oct-11	13:40	3.18	4FU	Power System Configuration-Customer or Other Utility	S	FA	CCT	OPG PULLING CABLE-'B'PRT TP K2
43	Breaker	NF28DT302	230	31-Aug-11	13:10	723.92	1MKDB	Main Pwr-Bkr Eqpt-Insulation Oil Problem	D	FM	CC	OIL HAS HIGH MOISTURE CONTENT
44	Breaker	NF28DL27	230	13-May-11	15:35	117.28	7NCKH	Non Pwr Eqpt-Control-Breaker-Air/Gas/Oil Control	D	FM	CC	AIR PRESSURE SWITCH REPLACED
45	Breaker	NF28KL25	230	21-Jan-11	12:10	69.87	1MKDA	Main Pwr-Bkr Eqpt-Insulation Air Problem	D	FM	CC	REPAIR AIR LEAK
46	Breaker	NF28TL28L29	230	30-Dec-10	08:12	2.05	1MKDA	Main Pwr-Bkr Eqpt-Insulation Air Problem	D	FM	CC	BKR LOW AIR
47	Bus	NF28LR27	230	02-Dec-10	03:55	0.12	4FZ	Power System Configuration-Common Trip Zone	S	FA	CCT	PA27
48	Transformer	NF28R27	230	02-Dec-10	03:55	0.12	4FZ	Power System Configuration-Common Trip Zone	S	FA	CCT	PA27
49	Breaker	NF28L28T301	230	25-Nov-10	14:00	49.77	1MKDA	Main Pwr-Bkr Eqpt-Insulation Air Problem	D	FM	CC	REPAIR AIR LEAK
50	Breaker	NF28L35L76	230	25-Nov-10	09:28	4.32	1MKDA	Main Pwr-Bkr Eqpt-Insulation Air Problem	D	FM	CC	AIR LEAK-B-PH GASKET REPLACED
51	Breaker	NF28KL25	230	09-Jun-10	12:13	1.08	1TC	Term Pwr Eqpt-Current Transformer (General)	D	FM	CC	TAKE OIL SAMPLES-GAS PROBLEM
52	Breaker	NF28L28T301	230	25-Mar-10	07:29	2.08	7NCKH	Non Pwr Eqpt-Control-Breaker-Air/Gas/Oil Control	D	FM	CC	REPAIR B-PH AIR RELIEF VALVE
53	Breaker	NF28L28T301	230	24-Mar-10	13:03	2.95	7NCKH	Non Pwr Eqpt-Control-Breaker-Air/Gas/Oil Control	D	FM	CC	REPAIR SAFETY RELIEF VALVE
54	Breaker	NF28DT301	230	04-Dec-09	22:44	0.65	1MKDA	Main Pwr-Bkr Eqpt-Insulation Air Problem	D	FA	CC	LOW AIR TRIP-AIR ADDED
55	Breaker	NF28KL23	230	25-Nov-09	11:22	73.78	1TDB	Term Pwr Eqpt-Disconnect Jaw or Blade Defect	D	FM	CC	REPAIR HOT SPOTS
56	Breaker	NF28DL27	230	06-Nov-09	13:20	0.05	5AB	Human Element-Accidental-Maintenance	D	FA	CC	INADVEERTENT BY P&C
57	Breaker	NF28TL28L29	230	22-May-09	09:25	0.13	5AB	Human Element-Accidental-Maintenance	D	FA	CC	INADV.-P&C PROT.FUNCTION TEST
58	Breaker	NF28KL25	230	18-Apr-09	18:43	111.12	7NCKD	Non Pwr Eqpt-Control-Breaker-Trip Coil Defect	D	FM	CC	REPAIR TWO TRIP COILS
59	Breaker	NF28L25T302	230	18-Jan-09	16:10	94.28	7NCKH	Non Pwr Eqpt-Control-Breaker-Air/Gas/Oil Control	D	FM	CC	AIR VALVE O-RING DEFECTIVE
60	Bus	NF28LR27	230	18-Dec-08	16:18	1.80	4FS	Power System Configuration-Series Connection	S	FM	CCT	PA27

#	Type	Op Des	Voltage	Date	Time	Duration (HR)	Cause Code	Cause Description	Outage Type	Urg.	Ext.	Remark
61	Transformer	NF28R27	230	18-Dec-08	16:18	1.80	4FS	Power System Configuration-Series Connection	S	FM	CCT	PA27
62	Transformer	NF28R27	230	12-Dec-08	08:26	0.02	1TDF	Term Pwr Eqpt-Disconnect Flashed During Operation	D	FA	CCT	DISCONNECT F/OVER WHEN OPEN
63	Bus	NF28LR76	230	30-Jan-08	06:21	0.13	4FZ	Power System Configuration-Common Trip Zone	S	FA	CCT	NF28R76 FAULT
64	Transformer	NF28R76	230	30-Jan-08	06:21	41.65	1MTBA	Main Pwr-Transformer Eqpt-Winding Failure	D	FA	CCT	INTERNAL FAULT

Asset Risk Assessment Report

Project: Integrated Station Component Replacement - Dufferin TS

Recommendation

Proceed - Multiple assets at Dufferin TS are in need of replacement due to degraded condition and asset demographics that directly impact the operability and reliability of the transmission station.

Project Summary

Built in the mid 1960's Dufferin TS is a 52 year old transformer station that supplies load to THESL customers in the downtown Toronto area via two switchyards. Oil analysis results of three transformers at the Dufferin TS have shown evidence of overheating which leads to degradation of the internal transformer insulation, indicating that there is a higher probability of failure. All three units are leaking oil, while two of the units have obsolete tap-changers components which require increased maintenance. The associated protection and control facilities are also obsolete and deemed end of life. THESL has requested that the capacity of the three transformers be increased in order to meet future load growth in the area.

The project entails the replacement of assets at Dufferin TS that are deteriorating in condition with new equipment built to current standards, including: three 115kV power transformers, surge arresters, neutral grounding reactors, line disconnect switches, and protection and control systems. In addition, supporting infrastructure such as drainage, wall structures, foundations, and high and low voltage bus work will need to be adjusted to facilitate replacement of the major assets.

Proposed Investment

1. Replace three power transformers and associated ancillary equipment.

2. Replace associated protection & control facilities.

3. Upgrade station noise mitigation infrastructure and transformer fire protection infrastructure.

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Network Management Engineer

Appendix 1 - Risk Assessment

Risk Factor	Risk Assessment*	Comments
Demographics	Very High	Transformers T1 & T3 are dual secondary transformers that are each 52 years old and are operating beyond their ESL. The T2 transformer is 42 years old which is about its ESL while the T4 transformer is 31 years old and below its ESL.
Condition	Very High	Due to the condition of the T1, T3 & T4 transformers, there is an increased probability of failure. Oil analysis results show increased gas levels indicating increasing internal degradation. T2 transformer is performing well and gas analysis shows a declining DGA trend. Oil quality measurements are acceptable and furan levels are low. Leaks have been repaired and the tapchanger it still supported by manufacturer (T2 is not recommended for replacement at this time). No. of Trouble Call (TC) & Corrective (DR) Notifications since 2010 for all T1, T3, T4: 59 Annual TC & DR Frequency: 10
Economics	High	The T4 transformer is experiencing high corrective maintenance costs. Also, multiple leak points on T4 would require costly refurbishment. O&M$ Spent since 2010: $827k Annual O&M$: $138k
Performance	High	The T4 performance has been poor. Number of direct outages over last 5 years: 6 (all T4) Duration of outages: 2939 hours (T4) DP Performance: Frequency and duration of delivery point outages is generally below the group target in last 5 years.
Utilization	High	A capacity increase has been requested for the T1, T3 & T4 replacement transformers in order to meet future load requirements in the area.
Criticality	Fair	Dufferin TS supplies load in the city of Toronto. There is very limited ability to transfer load from the station. The station supplies approximately 135MVA of peak load.
Customer	Very Satisfied	Toronto Hydro Electric System Limited
Obsolescence	High	T1 & T3 transformer tap changers are obsolete and difficult to maintain.
Health & Safety	N/A	Health and Safety is not a prevailing factor in this investment.
Environment	Fair	Dufferin TS is 63rd out of 256 stations in regards to Station Spill Risk Rankings. The station is located in an urban area and the existing spill containment is up to standard.

**Available Selections: Very High, High, Fair, Low, Very Low, N/A*

Dufferin TS
T1/T3 Yard

Station Assessment

Keywords: Dufferin, Transmission, Station, Assessment

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REVISION HISTORY

Date	Revision	Revision Comments
January 27 , 2015	0	Initial Revision
February 20, 2015	1	Updated following on-site assessment

APPROVAL SIGNATURES

	Prepared By	Reviewed By:	Approved By:
Signature:			
Name:	Mark Truchanowicz, P.Eng	Michael Xavier, P.Eng	Bruno Jesus, P.Eng
Title:	Network Mgmt Eng.	Sr. Network Mgmt Eng/Off	Manger, Transmission Capital Investment Planning
Date:	January 27, 2015	January 27, 2015	January 27, 2015

TABLE OF CONTENTS

1.0 INTRODUCTION

This assessment provides an overview of the current state of the station. The recommendations offered in this document will allow Asset Management make well-informed capital investment decisions.

Integration of the replacement of multiple end of life components into a single investment allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work. A station assessment will ensure that all the replacement needs are captured and integrated into the investment before release.

2.0 STATION SUMMARY

Dufferin TS is a transmission station that provides transformation of 115 kV to 13.8 kV. Dufferin TS serves as the supply for Toronto Hydro customers in downtown Toronto via two (2) DESN units, T1/T3 and T2/T4.

The T1/T3 13.8 kV switchyard was originally placed in-service in 1964 and many assets are in degraded condition and are in need of replacement. Previous assessments have identified that transformer banks T1 and T3 and associated equipment are candidates for replacement.

3.0 DESKSIDE STATION ASSESSMENT

3.1 Station Fault Current Rating

Table 1: 2014 Station Fault Current Ratings for Dufferin TS [1]

T1/T3	Symmetrical		Asymmetrical		Symmetrical Rating		Asymmetrical Rating	
	3ph kA	LG kA	3ph kA	LG kA	3ph kA	LG kA	3ph kA	LG kA
A1/A2 @ 13.8 kV	18.369	10.47	19.528	12.684	25.00	25.00	26.90	26.90
A3/A4 @ 13.8 kV	18.225	10.423	19.397	12.64	19.10	19.10	20.60	20.60

3.2 Station 5 Year DESN Loading

Table 2: Transformer MVA Ratings, 5-Yr Avg, 5-Yr Peaks & Loading Deviation %'s

DESN	TF Max Rating (MVA)	StDev % of Max Avg	Max Avg (MVA) 2010-14	Max Avg % of TF Max Rtg	Max Peak vs Max Avg	StDev % of Max Peak	Max Peak (MVA) 2010-14	Max Peak % of TF Max Rtg	Max Peak MVA as % of LTR Avg	LTR Load Risk	LTR vs TF Max Rtg
T1/T3	80.0	10.1%	40.04	50.1%	284.3%	53.2%	113.84	142.3%	107.6%	Y	1.2

Table 3: Station LTR Ratings and Average and Peak Loading

	LTR Rating		2010		2011		2012		2013		2014	
DESN	Sum 10d LTR	Win 10d LTR	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]
T1/T3	92.80	105.80	37.53	61.18	34.67	57.09	33.41	52.61	36.27	113.84	40.04	86.88

3.2.1 Stranded Load

Station	Breakers	Connections	Stranded
Dufferin TS	ALL	Toronto Hydro	100%

3.3 Customer Information

Table 4: Customer Satisfaction Summary

Customer Name	Customer Satisfaction Rating					Trend
	2010	2011	2012	2013	2014	
Toronto Hydro Electric System	Not Surveyed	Not Disclosed	Neither	Somewhat satisfied	Somewhat satisfied	Improving

3.4 Outage Information

Dufferin TS T1/T3 has experienced few equipment outages and delivery point interruptions based on the analysis of Transmission Equipment Outage Performance Data and Delivery Point Interruptions as seen in Appendix 4 and Appendix 5.

In 2013, the 13.8 kV A1A2 and A3A4 delivery points saw better than standard performance in the frequency and duration of outages. This is a notable increase in performance with respect to the duration of outages from the 2009-2011 window, which had exceeded Delivery Point Performance Standards. All delivery points at Dufferin TS T1/T3 are **NOT** identified as Group or Individual Outliers. Data for 2014 is currently being prepared by the performance management group.

The Frequency and Duration of outages at the A1A2 and A3A4 Delivery Points at Dufferin TS are summarized in Table 5 and Table 6 below.

The 10 year and rolling 3 year averages highlight that overall delivery point performance at Dufferin TS is performing better than Delivery Point Performance Standards for frequency and duration of outages for the 15-40 MW load category.

Table 5: Delivery Point Performance - Frequency

	Frequency>>>	10 yr avg	3 yr average										
NAME	OPDES	13-04	13-11	12-10	11-09	10-08	09-07	08-06	07-05	06-04	Indiv. Outlier Baseline (Freq)	Group Outlier Freq Target	Group Outlier Freq UB
DUFFERIN	A1A2	0.2	0.0	0.3	0.7	0.7	0.3	0.0	0.0	0.0	0.4	1.1	3.5
DUFFERIN	A3A4	0.2	0.0	0.3	0.7	0.7	0.3	0.0	0.0	0.0	0.0	1.1	3.5

Table 6: Delivery Point Performance – Duration

	Duration>>>	10 yr avg	3 yr average										
NAME	OPDES	13-04	13-11	12-10	11-09	10-08	09-07	08-06	07-05	06-04	Indiv. Outlier Baseline (Dur)	Group Outlier Duration Target	Group Outlier Duration UB
DUFFERIN	A1A2	54.6	0.0	5.0	182.0	182.0	177.0	0.0	0.0	0.0	0.0	22.0	140.0
DUFFERIN	A3A4	94.5	0.0	5.0	315.0	315.0	310.0	0.0	0.0	0.0	0.0	22.0	140.0

3.5 Station Spill Risk Ranking

Dufferin TS has four oil-filled power transformers as part of the T1/T3 and T2/T4 DESN stations. The station is ranked 147th out of 256 stations based on existing risk score from a 2011 spill risk report by Conestoga-Rogers & Associates [2] and is considered Low-Moderate risk.

3.6 Asset Analytics

Based off the Composite score in Asset Analytics, the following station equipment, not previously identified under the asset-centric work program, with a *Composite* score greater than 29 or a *Demographic* score greater than 74 should be considered for replacement.

Table 7: Summary of Assets Considered for Replacement Due to Demographic and Composite Score

Functional Location	Asset Class	Age	Condition	Demographics	Economics	Performance	Utilization	Criticality	Composite
N-TS-DUFFERINTS-BR-T3A1A2	Breaker: M/C Air-Mag_< 69 kV	50	17	100	1	1	95	29	31
N-TS-DUFFERINTS-BR-T1A1A2	Breaker: M/C Air-Mag_< 69 kV	50	17	100	1	1	94	29	31
N-TS-DUFFERINTS-BR-T3A3A4	Breaker: M/C Air-Mag_< 69 kV	39	17	95	1	1	40	29	24
N-TS-DUFFERINTS-IT-T3PT1	IT: Instrument Transformer	31	1	100	1	1	0	22	15
N-TS-DUFFERINTS-IT-T3PT2	IT: Instrument Transformer	31	1	100	1	1	0	22	15
N-TS-DUFFERINTS-IT-T1PT1	IT: Instrument Transformer	36	1	100	1	1	0	22	15
N-TS-DUFFERINTS-IT-T1PT2	IT: Instrument Transformer	36	1	100	1	1	0	22	15
N-TS-DUFFERINTS-PR-T1 B	Protection: Electro Mechanical	39	1	50	1	80	0	1	32
N-TS-DUFFERINTS-PR-T1A1A2 BF	Protection: Solid State	39	1	100	1	95	0	10	43
N-TS-DUFFERINTS-PR-T3 B	Protection: Solid State	29	1	75	1	1	0	1	10
N-TS-DUFFERINTS-PR-T3A1A2 BF	Protection: Solid State	39	1	100	1	1	0	10	14
N-TS-DUFFERINTS-PR-T3A3A4 BF	Protection: Solid State	39	1	100	1	1	0	10	14
N-TS-DUFFERINTS-CN-DUFFRTU	Control System_RTU	0	100	1	46	97	0	10	74
N-TS-DUFFERINTS-PR-L13W RT GBU	Protection: Electro Mechanical	5	0	1	1	84	0	1	43
N-TS-DUFFERINTS-TC-LEASED_PSTS	Telecom: Leased Circuit	0	33	0	1	46	0	10	32

3.7 Asset Centric Program Work

The following station equipment has been previously identified in Asset Centric Programs prior to the adoption of the Station Centric planning model:

Table 8: Summary of Assets Identified in Asset-Centric Work Programs

Functional Location	Asset Class	Age	Condition	Demographics	Economics	Performance	Utilization	Criticality	Composite
Transformer Replacement Program									
N-TS-DUFFERINTS-TF-T3	Transformer: Step-dn_115 kV	50	13	100	14	1	33	21	23
N-TS-DUFFERINTS-TF-T1	Transformer: Step-dn_115 kV	50	55	100	8	1	33	21	36

3.8 Station Security

Dufferin TS is classified as ***Low Risk*** and as of November 2014 has experienced zero (0) break-ins since 2007.

Table 9: Count of Break-Ins by Year at Dufferin TS

2007	2008	2009	2010	2011	2012	2013	2014 (Nov)
0	0	0	0	0	0	0	0

As per ***SP-14000-002:*** *Functional Requirements for Preventing Copper Theft*, and ***SP-14000-001:*** *Functional Requirements for Transmission and Distribution Security Detection and Verification Systems*, all stolen/missing *below grade* fence grounding and power equipment grounding conductors are to be replaced with copper-clad steel conductors whenever safely possible and when the original copper conductor was 4/0# or smaller. In addition, all stolen/missing *above grade* fence grounding is to be replaced with aluminum grounding material.

Defined as a *Low Risk* station, Dufferin TS does not require any further security upgrades at this time.

For reference, criteria for station security risk classification are summarized in Table 10, below.

Table 10: Security Risk Classifications

Security Risk Level	Description
High	10+ break-ins from 2007- present
Medium	1-9 break-ins from 2007- present
Low	0 break-ins from 2007- present

3.9 Potential Need & Deficiency Report Notifications

Table 11 provides a summary of Deficiency Report (DR) notifications that have been issued by Field Staff and are currently outstanding. There are currently no outstanding Potential Needs (PN) notifications for Dufferin TS.

Table 11: Listing of Open and Outstanding Deficiency Report Notifications

Notification	Type	Functional Loc.	Notif.date	Description
13507367	DR	N-TS-DUFFERINTS-BR	01/21/2015	Dufferin TS Non Arc Proof Labels
13437947	DR	N-TS-DUFFERINTS	12/02/2014	AR22676 NT9 ARC FLASH LABELS EMD
13330457	DR	N-TS-DUFFERINTS-PR-L13W RT GBU	09/10/2014	LM1 RGBU Timer Relay to be replaced
12941152	DR	N-TS-DUFFERINTS-TF	04/30/2014	Dufferin Deluge monitoring
12768510	DR	N-TS-DUFFERINTS-SI-BLDG A	11/12/2013	BLDG - Doors Need Painting
12637418	DR	N-TS-DUFFERINTS-SI-BLDG A	09/25/2013	AR#19275 NT9 TX BLDG Bsmnt Survey
12492941	DR	N-TS-DUFFERINTS-SI-BLDG A	08/14/2013	Dufferin TS A/C Unit Replacement
12312979	DR	N-TS-DUFFERINTS-PR-T1 B	06/12/2013	NT9 T1 CT LINK REPAIR RF PANEL
12312821	DR	N-TS-DUFFERINTS-PR-T1A1A2 BF	06/12/2013	NT9 52-T1A CT LINK REPAIR PNL CC,RF,MB
12311313	DR	N-TS-DUFFERINTS-PR-T3 A	06/12/2013	NT9 T3 CT LINK REPAIR F&L RACK
12046903	DR	N-TS-DUFFERINTS-SI-IF	01/08/2013	600 volt disconect rusted closed
11941419	DR	N-TS-DUFFERINTS-SI-BLDG A	11/12/2012	Roof Grounding Required
10506146	DR	N-TS-DUFFERINTS-CA-T3Y	05/20/2010	Dufferin TS T3Y hot spot
10491429	DR	N-TS-DUFFERINTS-TF-T1	04/17/2010	Water found in T1 X T/C RS1000 Gas relay
10489522	DR	N-TS-DUFFERINTS-TF-T3	04/16/2010	Repair T3 Gas relay
10439433	DR	N-TS-DUFFERINTS-SI	01/27/2010	AR#18743 NT9 Deluge upgrade-EMS
10358929	DR	N-TS-DUFFERINTS-TF-T1	09/23/2009	DUFFERIN T1 OIL LEAK
10120066	DR	N-TS-DUFFERINTS-TF-T3	09/08/2008	T3 SECONDARY CONNECTION Y SIDE

4.0 ON-SITE STATION ASSESSMENT

Date of Assessment: 13 February 2015

Attendees:

Michael Xavier	Sr. Network Mgmt Eng/Off	Transmission Capital Investment Planning
Mark Truchanowicz	Network Mgmt Eng/Off	Transmission Capital Investment Planning
Kebede Asfaw	Asst. Network Mgmt Eng/Off	PCT Solutions
Sal Agusta	Stations Services Specialist	GTA Station Services
Tuyet Aiken	P&C Zone Senior	GTA Station Services

Context

- Investment planning focus has shifted toward station-centric (on a yard/by/yard basis) from the former asset-centric approach.
- Intent is to only visit each yard every 7-10 years
- Focus of this investment is the T1/T3 yard at Dufferin TS

Transformers

- All four banks are leaking oil at various degrees, most notably T1 and T4
- T1/T3 were installed in the mid-60s (identified for replacement) – THES has requested 100 MVA banks
    - Spill containment to be upgraded to current standards
- T2 installed in the mid-70s – Some oil leaks, review oil analysis.
- T4 was installed in the mid-80s – Extensive leaks, due to age may consider refurbishment of unit further oil analysis need to confirm transformer condition
- Concerns were previously identified with TOV levels at Dufferin on L13W, connected to T1/T2 – will investigate impact on design/transformer winding configuration/etc…
- High side rod gaps, and low-side surge arrestors to be replaced.

LV Switchgear

- THES metalclad at Dufferin TS is not currently identified for replacement.
- Project for LV switchgear to be released at a later date once THES is committed to upgrading their metalclad

Switches

- T1/T2/T3/T4 high side circuit switchers were replaced in the mid-80s, no current concerns
- L13W and L15W line disconnects look to be of the original vintage, candidates for replacement – no information available within SAP

Cables/Potheads

- Potheads for L13W/L15W appear to be in relatively good condition – will be reviewed by Lines Sustainment if there are any other concerns.
    - Historically, we haven't seen issues with indoor potheads, but will be reviewed for Dufferin

Protection & Control

- Due to recent revenue metering upgrades, panel space has freed up within the relay room, which will allow a staged approach to upgrading protections.
- Upgrade RTU – potential option is to install cabinet adjacent to existing RTU, cut over, remove legacy RTU and slide new RTU into place. Will need to be incorporated into staged approach.
- Upgrade all electromechanical and solid state protections – review use of RT and migrate to TT where possible.

Station Service

- Provided by THES – will need to ensure sufficient capacity to accommodate all P&C upgrades

Instrument Transformers

- Investigate possibility of high side CVTs

Insulators (General)

- All cap and pin insulators to be replaced as outages allow
- String type insulators to be replaced with equivalent glass type

General Comments

- Space will be a major risk for project execution – a detailed staging and execution plan will be need, especially for P&C work.

5.0 RECOMMENDATIONS

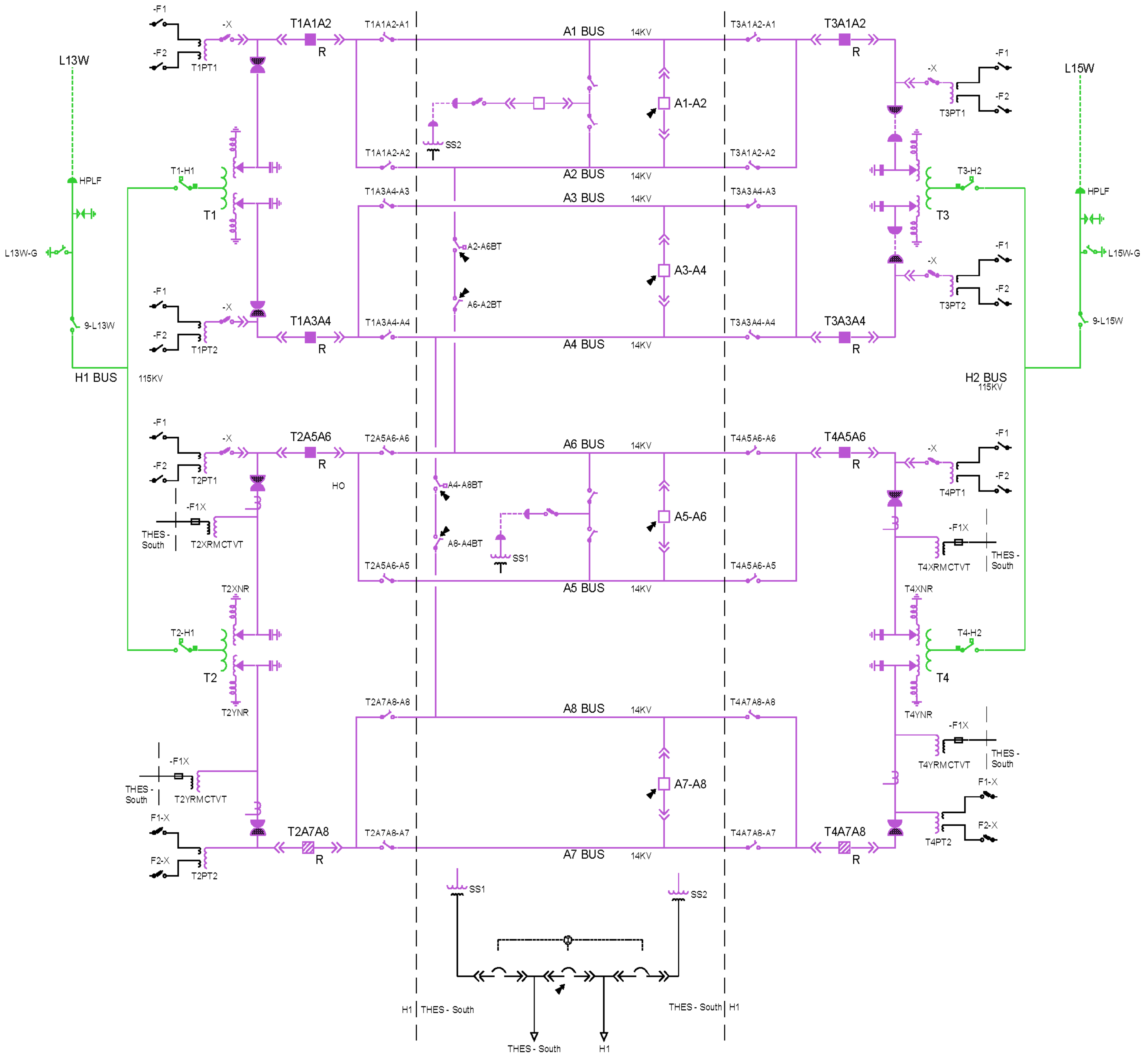
- Replace transformer T1 and T3 and spill containment as they have reached end-of-life and are heavily leaking oil.
  - Based on multiple oil analysis results these transformers have internal arcing and overheating , which indicates that there is higher probability of failure in the near future. Tap changer model requires frequent maintenance and faces obsolence issues.
  - Toronto Hydro has filed a CA requesting an upgrade to 100 MVA.
  - Review T2 & T4 deficiencies and monitor oil to determine replacement strategy.
- Replace L13W, L15W HV line disconnect switches due to condition they have reached end-of- life.
- Upgrade all remaining electromechanical and solid-state protections as they have reached end-of-life and are no longer supported.
  - Recent upgrades to revenue metering have made rack space available within the relay room.
  - This will facilitate staging of protection replacements.
  - Investigate possibility of HV ITs
- Replace cap and pin insulators, as they have been identified for removal due to high failure rates.
- Investigate options to mitigate TOV levels on L13W, potential options include;
  - Shunt reactor – would require 8-10MX, no space available at Dufferin TS – concerns with noise if it would be installed at Bridgman TS
  - HV breaker on L13W – no space available at Dufferin TS
  - Grounding Transformer on L13W (Preferred) – would require 1-5 MVA Ygnd-Delta, non-load serving transformer bank connected to L13W. Due to space constraints at Dufferin TS, could be installed at Bridgman TS.
    - Feasibility of acquiring the required grounding transformer is currently being investigated by Equipment Engineering

6.0 REFERENCE SOURCES

[1] Special Studies, "2014 Update of Short Circuit Survey and Breaker Ratings," [Online]. Available: https://teams.hydroone.com/sites/TPD/TPD/ss_pd/Short Circuit/Surveys/Breakers.

[2] Conestoga-Rogers & Associates, "Hydro One Station Spill Risk Model," Mississauga, 2011.

APPENDIX 1 – DUFFERIN TS OPERATING DIAGRAM



LEGEND					
500 KV	15.0	DEC 09 2014	Added demarcation to T2XRMCTVT, T4XRMCTVT, T2YRMCTVT, T4YRMCTVT.	BR	KL
345 KV	14.0	NOV 11 2014	Added cable termination HPLF to circuits L13W and L15W.	BR	DS
230 KV	13.0	JUN 19 2014	Added T4XRMCTVT and T4YRMCTVT. Added nomenclature to T4XNR and T4YNR.	MJ	DS
115 KV	12.0	JUN 12 2014	Added voltage devices T2XRMCTVT, T2YRMCTVT and associated equipment to the T2 transformer.	BR	DS
69 KV	11.0	FEB 14 2012	Changed references to THES to THES - South.	MJ	DS
35 to 44 KV	10.0	DEC 13 2011	Added deluge symbol to station title	BR	DS
22 to 28 KV	9.0	JAN 21 2010	Removed exclusion zone symbol.	MN	OT
14 KV	8.0	OCT 29 2009	Added exclusion zone symbol .	MN	OT
Auxiliary	7.0	FEB 10 2009	THEC ownership text changed to THES	JC	JS
	Rev. No.	Date	Revision	By	App'd

This legend is for local plotting purposes only. It serves as a reference for the local print only and may not necessarily match that of the Hydro One Operating Drawing Convention Standard.

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Dufferin TS
NT9

STATION OPERATING DIAGRAM

Hydro One Networks Inc.
Integrated Transmission Operating Facilities

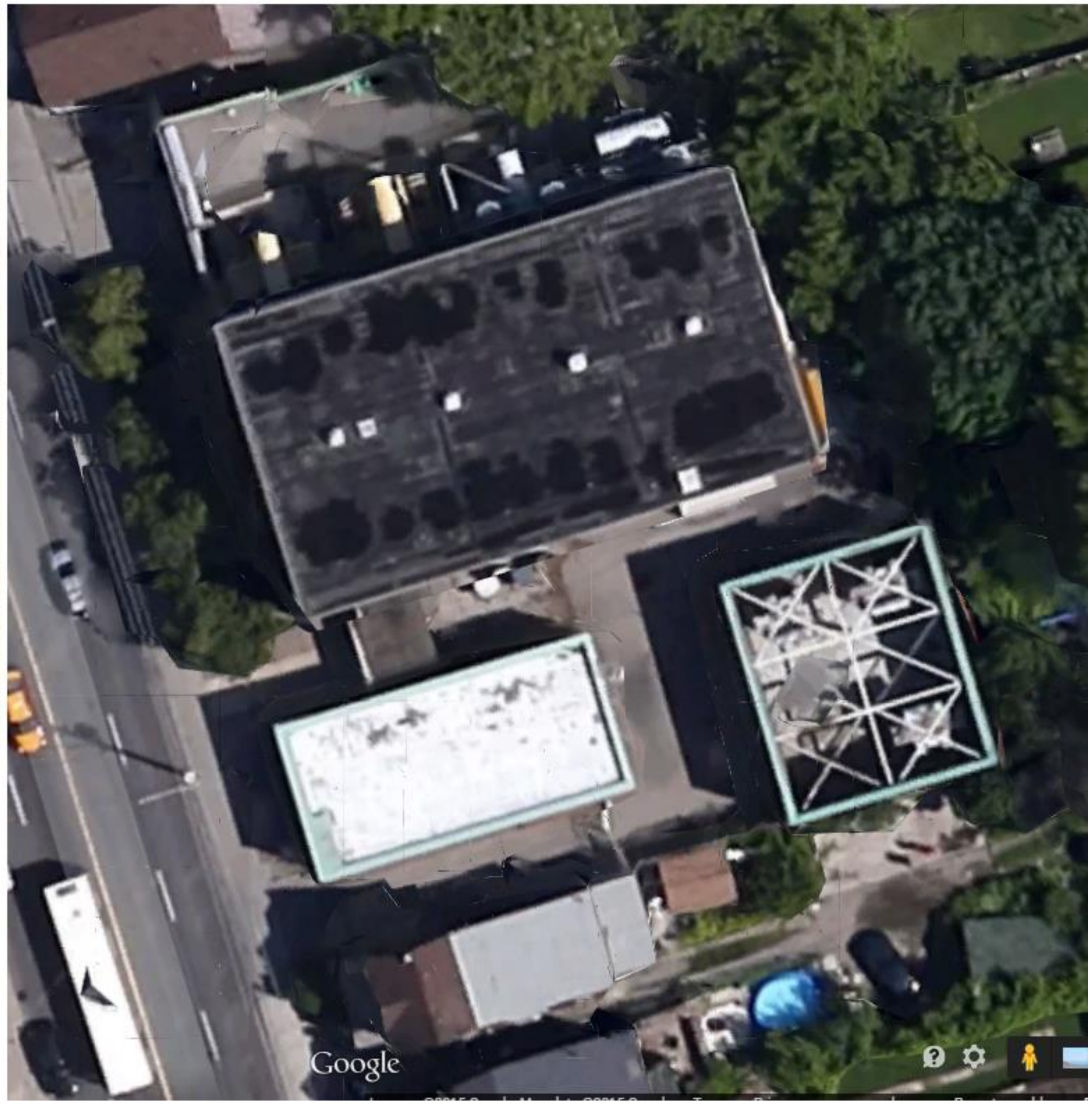
Date: DD/MM/YYYY 27/04/2004 | Drawn: | Checked:

Note:
All revisions to this diagram will require notification of the NMS Prints team, via email to NO Change Control Notification and followup with a field marked paper copy. Refer to:
OD-10-001: Operating Diagram Standard for Transmission
NMI-2020: Process for New and Revised Operating Diagrams

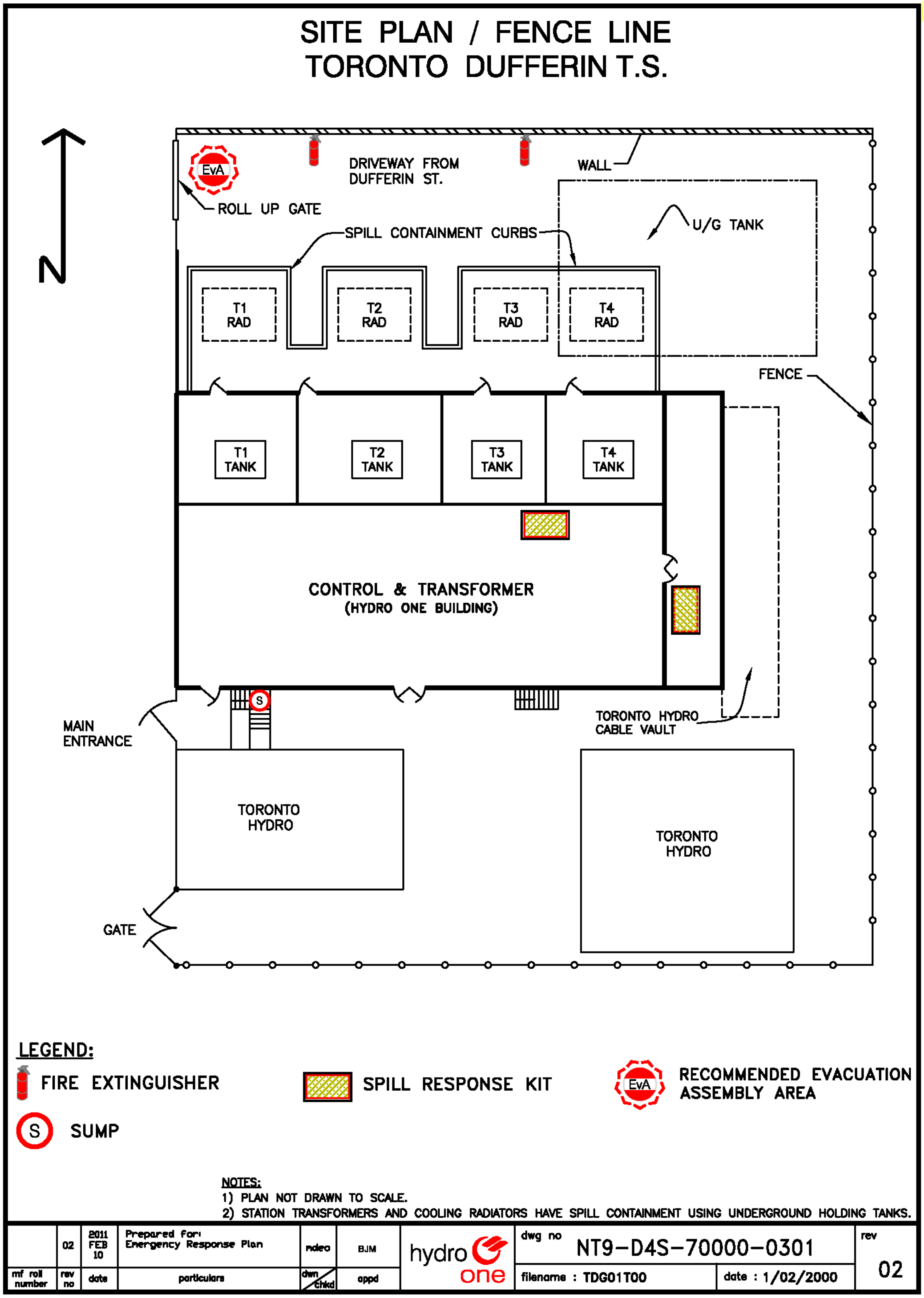
Paper Size: 22x16

DWG. NO. NT9 -1 | REV.NO. 15.0

APPENDIX 2 – AERIAL/SATELLITE VIEW



APPENDIX 3 – SITE PLAN / FENCE LINE



APPENDIX 4 – TRANSMISSION EQUIPMENT OUTAGE PERFORMANCE DATA

Dufferin TS T1/T3 DESN Station Equipment Sustained Outage Event Report

Period: From: 1/1/2010 To: 12/31/2014

#	Type	Op Des	Voltage	Date	Time	Duration (HR)	Cause Code	Cause Description	Outage Type	Urgency	Extent	Remark
1	Bus	NT9A1A2	LV	15-Apr-14	20:10	0.58	4FS	Power System Configuration-Series Connection	S	FA	CCT	L13W+L15W TRIP
2	Bus	NT9A3A4	LV	15-Apr-14	20:10	0.58	4FS	Power System Configuration-Series Connection	S	FA	CCT	L13W+L15W TRIP
3	Transformer	NT9T1	115	15-Apr-14	20:10	0.52	4FZ	Power System Configuration-Common Trip Zone	S	FA	CCT	L13W TRIP
4	Transformer	NT9T3	115	15-Apr-14	20:10	0.60	4FZ	Power System Configuration-Common Trip Zone	S	FA	CCT	L15W TRIP
5	Transformer	NT9T1	115	07-Feb-14	12:36	27.40	4FS	Power System Configuration-Series Connection	S	FM	CCT	L13W O/S @ NT9
6	Transformer	NT9T3	115	30-Nov-12	23:47	2.28	4FZ	Power System Configuration-Common Trip Zone	S	FA	CCT	L15W TRIP
7	Transformer	NT9T1	115	05-Nov-12	11:23	3.88	4FS	Power System Configuration-Series Connection	S	FM	CCT	L13W LINE TRIP-MANUALLY
8	Transformer	NT9T1	115	30-Jul-11	20:41	4.40	4FS	Power System Configuration-Series Connection	S	FM	CCT	L13W
9	Transformer	NT9T1	115	18-Sep-10	16:47	5.05	4FZ	Power System Configuration-Common Trip Zone	S	FA	CCT	NT9T1-H1 FALSHOVER WHEN CLOSIN
10	Transformer	NT9T1	115	17-Apr-10	04:00	17.48	7NPEC	Non Pwr Eqpt-Prot-DC Circuit-Cable/Wiring Defect	D	FA	CCT	TAPCHANGER WIRE GETS WET
11	Transformer	NT9T3	115	16-Apr-10	13:35	188.28	4FS	Power System Configuration-Series Connection	S	FM	CCT	LOSS OF SUPPLY CIRCUIT
12	Transformer	NT9T3	115	14-Apr-10	12:06	27.35	7NPSB	Non Pwr Eqpt-Prot-Gas Relay-Mechanical Defect	D	FM	CCT	REPLACE GAS RELAY

APPENDIX 5 – DELIVERY POINT INTERRUPTION DATA

Delivery Point Interruptions											
FORCED/PLANED: Forced; BLAME: Exclude CUSTOMER					From 1/1/2004		To 12/31/2013				
DPI_DATE	YEAR	DPNAME	BUS	DPDES	TXFMR	MW_INT	MW_MIN	BLAME	CAUSE	SUP1	SUP2
4/17/2010	2010	DUFFERIN	A1A2	NT9A1A2	T1/T3	13.0	195	EQUIPMENT	EQUIPMENT FAILURE TRANSFORMER OTHER	L13W	L15W
4/17/2010	2010	DUFFERIN	A3A4	NT9A3A4	T1/T3	8.0	120	EQUIPMENT	EQUIPMENT FAILURE TRANSFORMER OTHER	L15W	L13W
1/15/2009	2009	DUFFERIN	A1A2	NT9A1A2	T1/T3	26.0	13,806	EQUIPMENT	EQUIPMENT FAILURE NON_ELECTRIC	L13W	L15W
1/15/2009	2009	DUFFERIN	A3A4	NT9A3A4	T1/T3	14.0	13,020	EQUIPMENT	EQUIPMENT FAILURE NON_ELECTRIC	L15W	L13W

Dufferin TS
T2/T4 Yard

Station Assessment

Keywords: Dufferin, Transmission, Station, Assessment

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REVISION HISTORY

Date	Revision	Revision Comments
January 27, 2015	0	Initial Revision
February 20, 2015	1	Updated following on-site assessment

APPROVAL SIGNATURES

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Date:	January 27, 2015	January 27, 2015	January 27, 2015

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1.0 INTRODUCTION

This assessment provides an overview of the current state of the station. The recommendations offered in this document will allow Asset Management make well-informed capital investment decisions.

Integration of the replacement of multiple end of life components into a single investment allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work. A station assessment will ensure that all the replacement needs are captured and integrated into the investment before release.

2.0 STATION SUMMARY

Dufferin TS is a transmission station that provides transformation of 115 kV to 13.8 kV. Dufferin TS serves as the supply for Toronto Hydro customers in downtown Toronto via two (2) DESN units, T1/T3 and T2/T4.

The T2/T4 13.8 kV switchyard was originally placed in-service in 1974 and many assets are in degraded condition and are in need of replacement. Previous assessments have identified solid state PALC protection schemes that are in need of replacement.

3.0 DESKSIDE STATION ASSESSMENT

3.1 Station Fault Current Rating

Table 1: 2014 Station Fault Current Ratings for Dufferin TS [1]

T2/T4	Symmetrical		Asymmetrical		Symmetrical Rating		Asymmetrical Rating	
	3ph kA	LG kA	3ph kA	LG kA	3ph kA	LG kA	3ph kA	LG kA
A3/A4 @ 13.8 kV	16.846	10.499	18.866	13.231	36.00	36.00	38.80	38.80
A5/A6 @ 13.8 kV	16.832	10.489	18.831	13.21	25.00	25.00	26.90	26.90

3.2 Station 5 Year DESN Loading

Table 2: Transformer MVA Ratings, 5-Yr Avg, 5-Yr Peaks & Loading Deviation %'s

DESN	TF Max Rating (MVA)	StDev % of Max Avg	Max Avg (MVA) 2010-14	Max Avg % of TF Max Rtg	Max Peak vs Max Avg	StDev % of Max Peak	Max Peak (MVA) 2010-14	Max Peak % of TF Max Rtg	Max Peak MVA as % of LTR Avg	LTR Load Risk	LTR vs TF Max Rtg
T2/T4	75.0	4.3%	53.39	71.2%	183.7%	6.9%	98.07	130.8%	89.3%	Y	1.4

Table 3: Station LTR Ratings and Average and Peak Loading

DESN	LTR Rating		2010		2011		2012		2013		2014	
	Sum 10d LTR	Win 10d LTR	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]
T2/T4	95.80	109.80	53.39	98.07	50.24	93.54	52.80	90.79	48.46	97.07	51.10	79.35

3.2.1 Stranded Load

Station	Breakers	Connections	Stranded
Dufferin TS	ALL	Toronto Hydro	100%

3.3 Customer Information

Table 4: Customer Satisfaction Summary

Customer Name	Customer Satisfaction Rating					Trend
	2010	2011	2012	2013	2014	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

3.4 Outage Information

Dufferin TS T2/T4 has experienced few equipment outages and delivery point interruptions based on the analysis of Transmission Equipment Outage Performance Data and Delivery Point Interruptions as seen in Appendix 4 and Appendix 5.

In 2013, the 13.8 kV A5A6 and A7A8 delivery points saw better than standard performance in the frequency and duration of outages. This is a notable increase in performance with respect to the duration of outages from the 2009-2011 window, which had exceeded Delivery Point Performance Standards. All delivery points at Dufferin TS T2/T4 are **NOT** identified as Group or Individual Outliers. Data for 2014 is currently being prepared by the performance management group.

The Frequency and Duration of outages at the A5A6 and A7A8 Delivery Points at Dufferin TS are summarized in Table 5 and Table 6 below.

The 10 year and rolling 3 year averages highlight that overall delivery point performance at Dufferin TS is performing better than Delivery Point Performance Standards for the frequency of outages in the 40-80 MW load category. With respect to the duration of outages, the rolling 3 year average has shown significant improvement over past years; however the 10 year average still exceeds performance standards.

Table 5: Delivery Point Performance - Frequency

	Frequency>>>	10 yr avg	3 yr average										
NAME	OPDES	13-04	13-11	12-10	11-09	10-08	09-07	08-06	07-05	06-04	Indiv. Outlier Baseline (Freq)	Group Outlier Freq Target	Group Outlier Freq UB
DUFFERIN	A5A6	0.2	0.0	0.0	0.7	0.7	0.7	0.0	0.0	0.0	0.0	0.5	1.5
DUFFERIN	A7A8	0.2	0.0	0.0	0.7	0.7	0.7	0.0	0.0	0.0	0.0	0.5	1.5

Table 6: Delivery Point Performance – Duration

	Duration>>>	10 yr avg	3 yr average										
NAME	OPDES	13-04	13-11	12-10	11-09	10-08	09-07	08-06	07-05	06-04	Indiv. Outlier Baseline (Dur)	Group Outlier Duration Target	Group Outlier Duration UB
DUFFERIN	A5A6	154.3	0.0	0.0	514.3	514.3	514.3	0.0	0.0	0.0	0.0	11.0	55.0
DUFFERIN	A7A8	75.2	0.0	0.0	250.7	250.7	250.7	0.0	0.0	0.0	0.0	11.0	55.0

3.5 Station Spill Risk Ranking

Dufferin TS has four oil-filled power transformers as part of the T1/T3 and T2/T4 DESN stations. The station is ranked 147th out of 256 stations based on existing risk score from a 2011 spill risk report by Conestoga-Rogers & Associates [2] and is considered Low-Moderate risk.

3.6 Asset Analytics

Based off the Composite score in Asset Analytics, the following station equipment, not previously identified under the asset-centric work program, with a *Composite* score greater than 29 or a *Demographic* score greater than 74 should be considered for replacement.

Table 7: Summary of Assets Considered for Replacement Due to Demographic and Composite Score

Func. Location	Asset Class	Age	Condition	Demographics	Economics	Performance	Utilization	Criticality	Composite
N-TS-DUFFERINTS-BR-T2A7A8	Breaker: M/C SF6_< 69 kV	22	40	10	1	60	78	29	43
N-TS-DUFFERINTS-IT-T2PT1	IT: Instrument Transformer	36	1	100	1	1	0	22	15
N-TS-DUFFERINTS-IT-T2PT2	IT: Instrument Transformer	36	1	100	1	1	0	22	15
N-TS-DUFFERINTS-IT-T4PT1	IT: Instrument Transformer	26	1	100	1	1	0	22	15
N-TS-DUFFERINTS-IT-T4PT2	IT: Instrument Transformer	26	1	100	1	1	0	22	15
N-TS-DUFFERINTS-PR-L15W BU-T4	Protection: Electro Mechanical	29	0	25	1	80	0	1	45
N-TS-DUFFERINTS-PR-T2 A	Protection: Electro Mechanical	39	1	50	1	80	0	1	32
N-TS-DUFFERINTS-PR-T4 B	Protection: Solid State	29	1	75	1	1	0	1	10
N-TS-DUFFERINTS-TF-T2	Transformer: Step-dn_115 kV	40	15	100	12	1	39	21	24
N-TS-DUFFERINTS-TF-T4	Transformer: Step-dn_115 kV	31	54	55	100	50	39	21	53

3.7 Asset Centric Program Work

The following station equipment has been previously identified in Asset Centric Programs prior to the adoption of the Station Centric planning model:

Table 8: Summary of Assets Identified in Asset-Centric Work Programs

Func. Location	Asset Class	Age	Condition	Demographics	Economics	Performance	Utilization	Criticality	Composite
PALC Replacement Program									
N-TS-DUFFERINTS-PR-T2A7A8 BF	Protection: Solid State	23	1	50	1	1	0	10	8
N-TS-DUFFERINTS-PR-T4A7A8 BF	Protection: Solid State	23	1	50	1	1	0	10	8

3.8 Station Security

Dufferin TS is classified as ***Low Risk*** and as of November 2014 has experienced zero (0) break-ins since 2007.

Table 9: Count of Break-Ins by Year at Dufferin TS

2007	2008	2009	2010	2011	2012	2013	2014 (Nov)
0	0	0	0	0	0	0	0

As per ***SP-14000-002:*** *Functional Requirements for Preventing Copper Theft*, and ***SP-14000-001:*** *Functional Requirements for Transmission and Distribution Security Detection and Verification Systems*, all stolen/missing *below grade* fence grounding and power equipment grounding conductors are to be replaced with copper-clad steel conductors whenever safely possible and when the original copper conductor was 4/0# or smaller. In addition, all stolen/missing *above grade* fence grounding is to be replaced with aluminum grounding material.

Defined as a *Low Risk* station, Dufferin TS does not require any further security upgrades at this time.

For reference, criteria for station security risk classification are summarized in Table 10, below.

Table 10: Security Risk Classifications

Security Risk Level	Description
High	10+ break-ins from 2007- present
Medium	1-9 break-ins from 2007- present
Low	0 break-ins from 2007- present

3.9 Potential Need & Deficiency Report Notifications

Table 11 provides a summary of Deficiency Report (DR) notifications that have been issued by Field Staff and are currently outstanding. There are currently no outstanding Potential Needs (PN) notifications for Dufferin TS.

Table 11: Listing of Open and Outstanding Deficiency Report Notifications

Notification	Type	Functional Loc.	Notif.date	Description
13507367	DR	N-TS-DUFFERINTS-BR	01/21/2015	Dufferin TS Non Arc Proof Labels
13437947	DR	N-TS-DUFFERINTS	12/02/2014	AR22676 NT9 ARC FLASH LABELS EMD
13330457	DR	N-TS-DUFFERINTS-PR-L13W RT GBU	09/10/2014	LM1 RGBU Timer Relay to be replaced
12941152	DR	N-TS-DUFFERINTS-TF	04/30/2014	Dufferin Deluge monitoring
12768510	DR	N-TS-DUFFERINTS-SI-BLDG A	11/12/2013	BLDG - Doors Need Painting
12763961	DR	N-TS-DUFFERINTS-TF-T4	11/08/2013	Oil overflow drum needs emptying.
12492941	DR	N-TS-DUFFERINTS-SI-BLDG A	08/14/2013	Dufferin TS A/C Unit Replacement
12312619	DR	N-TS-DUFFERINTS-WM	06/12/2013	NT9 REV METERING CT LINK REPAIR
12144659	DR	N-TS-DUFFERINTS-TF-T4	04/12/2013	Dufferin T2Y Breather and Oil oil overfl
12046903	DR	N-TS-DUFFERINTS-SI-IF	01/08/2013	600 volt disconect rusted closed
11941419	DR	N-TS-DUFFERINTS-SI-BLDG A	11/12/2012	Roof Grounding Required
11144397	DR	N-TS-DUFFERINTS-TF-T2	04/25/2012	Dufferin TS Tap changer hot spot
10854678	DR	N-TS-DUFFERINTS-TF-T4	01/11/2012	Dufferin TS T4 (Y) ULTC UVT 2000A repair
10506145	DR	N-TS-DUFFERINTS-TF-T4	05/20/2010	Dufferin TS T4 hot spot
10506144	DR	N-TS-DUFFERINTS-TF-T4	05/20/2010	Dufferin TS T4 LTC hot spot
10439433	DR	N-TS-DUFFERINTS-SI	01/27/2010	AR#18743 NT9 Deluge upgrade-EMS
10343177	DR	N-TS-DUFFERINTS-TF-T4	08/11/2009	NT9T4 Y oil leak over flow container
10021618	DR	N-TS-DUFFERINTS-TF-T4	07/02/2008	MISSING BREATHER * INSTALL NEW UNIT
10019554	DR	N-TS-DUFFERINTS-TF-T2	06/26/2008	replace T2X tap reversing sw

4.0 ON-SITE STATION ASSESSMENT

Date of Assessment: 13 February 2015

Attendees:

Michael Xavier	Sr. Network Mgmt Eng/Off	Transmission Capital Investment Planning
Mark Truchanowicz	Network Mgmt Eng/Off	Transmission Capital Investment Planning
Kebede Asfaw	Asst. Network Mgmt Eng/Off	PCT Solutions
Sal Agusta	Stations Services Specialist	GTA Station Services
Tuyet Aiken	P&C Zone Senior	GTA Station Services

Context

- Investment planning focus has shifted toward station-centric (on a yard/by/yard basis) from the former asset-centric approach.
- Intent is to only visit each yard every 7-10 years
- Focus of this investment is the T2/T4 yards at Dufferin TS

Transformers

- All four banks are leaking oil at various degrees, most notably T1 and T4
- T1/T3 were installed in the mid-60s (identified for replacement) – THES has requested 100 MVA banks
  - Spill containment to be upgraded to current standards
- T2/T4 installed in the mid-80s – possible candidates for refurbishment or replacement further analysis is required.
- Concerns were previously identified with TOV levels at Dufferin on L13W, connected to T1/T2 – will investigate impact on design/transformer winding configuration/etc…

LV Switchgear

- THES metalclad at Dufferin TS is not currently identified for replacement.
- Project for LV switchgear to be released at a later date once THES is committed to upgrading their metalclad

Switches

- T1/T2/T3/T4 high side circuit switchers were replaced in the mid-80s, no current concerns
- L13W and L15W line disconnects look to be of the original vintage, candidates for replacement – no information available within SAP

Cables/Potheads

- Potheads for L13W/L15W appear to be in relatively good condition – will be reviewed by Lines Sustainment if there are any other concerns.
  - Historically, we haven't seen issues with indoor potheads, but will be reviewed for Dufferin

Protection & Control

- Due to recent revenue metering upgrades, panel space has freed up within the relay room, which will allow a staged approach to upgrading protections.
- Upgrade RTU – potential option is to install cabinet adjacent to existing RTU, cut over, remove legacy RTU and slide new RTU into place. Will need to be incorporated into staged approach.

- Upgrade all electromechanical and solid state protections – review use of RT and migrate to TT where possible.

Station Service

- Provided by THES – will need to ensure sufficient capacity to accommodate all P&C upgrades

Instrument Transformers

- Investigate possibility of high side CVTs

Insulators (General)

- All cap and pin insulators to be replaced as outages allow
- String type insulators to be replaced with equivalent glass type

General Comments

- Space will be a major risk for project execution – a detailed staging and execution plan will be need, especially for P&C work.

5.0 RECOMMENDATIONS

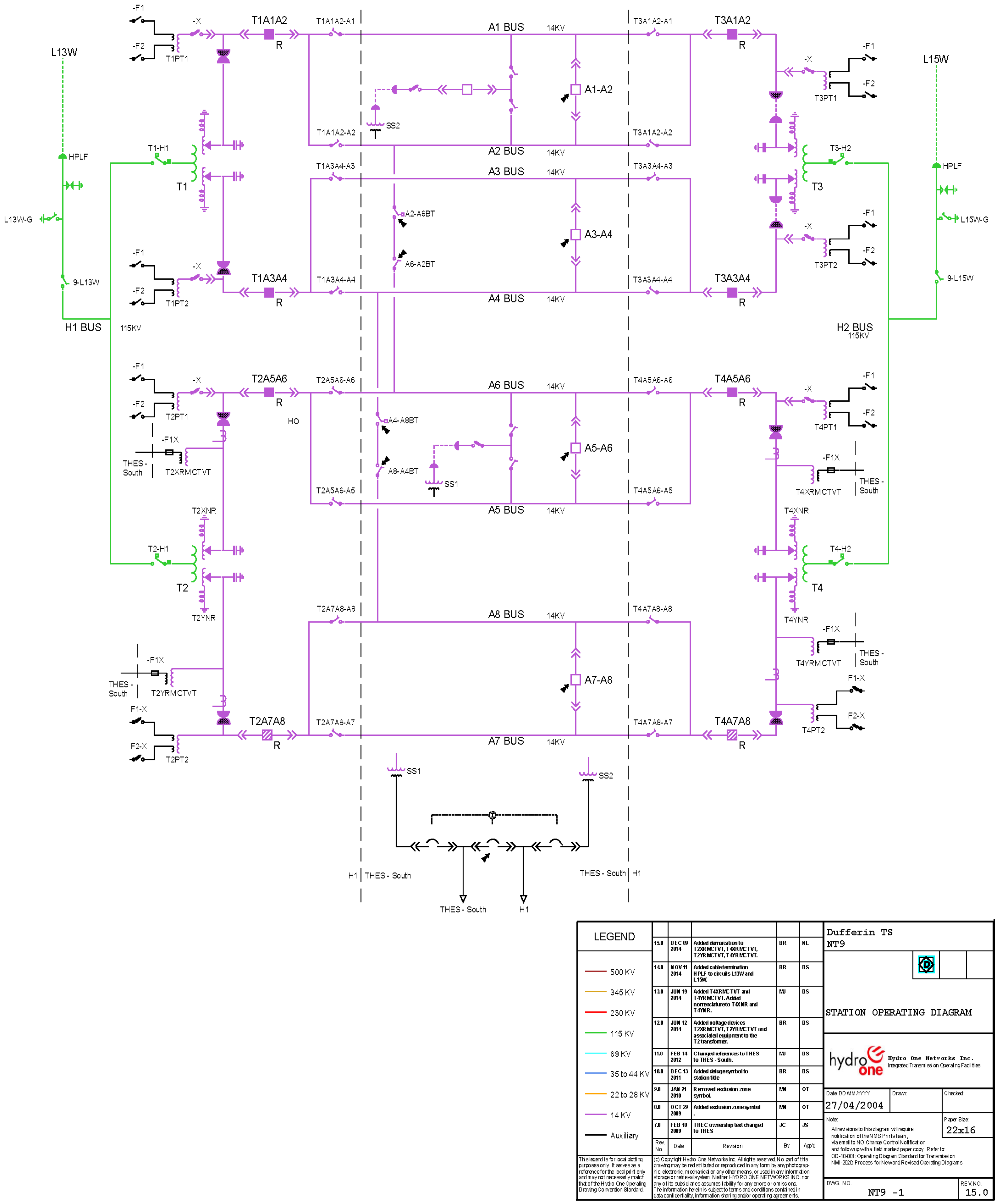
- Upgrade legacy RTU to current GE standard in advance of protection replacements.
  - Legacy RTU is no longer supported by the manufacturer and spare parts are limited.
  - Upgrading to current standards will maintain reliable operational control of the station and provide enhanced alarm monitoring
- Upgrade all remaining electromechanical and solid-state protections as they have reached end of life and are no longer supported.
  - Recent upgrades to revenue metering has made rack space available within the relay room.
  - This will facilitate staging of protection replacements.
- Replace cap and pin insulators, as they have been identified for removal due to high failure rates.

6.0 REFERENCE SOURCES

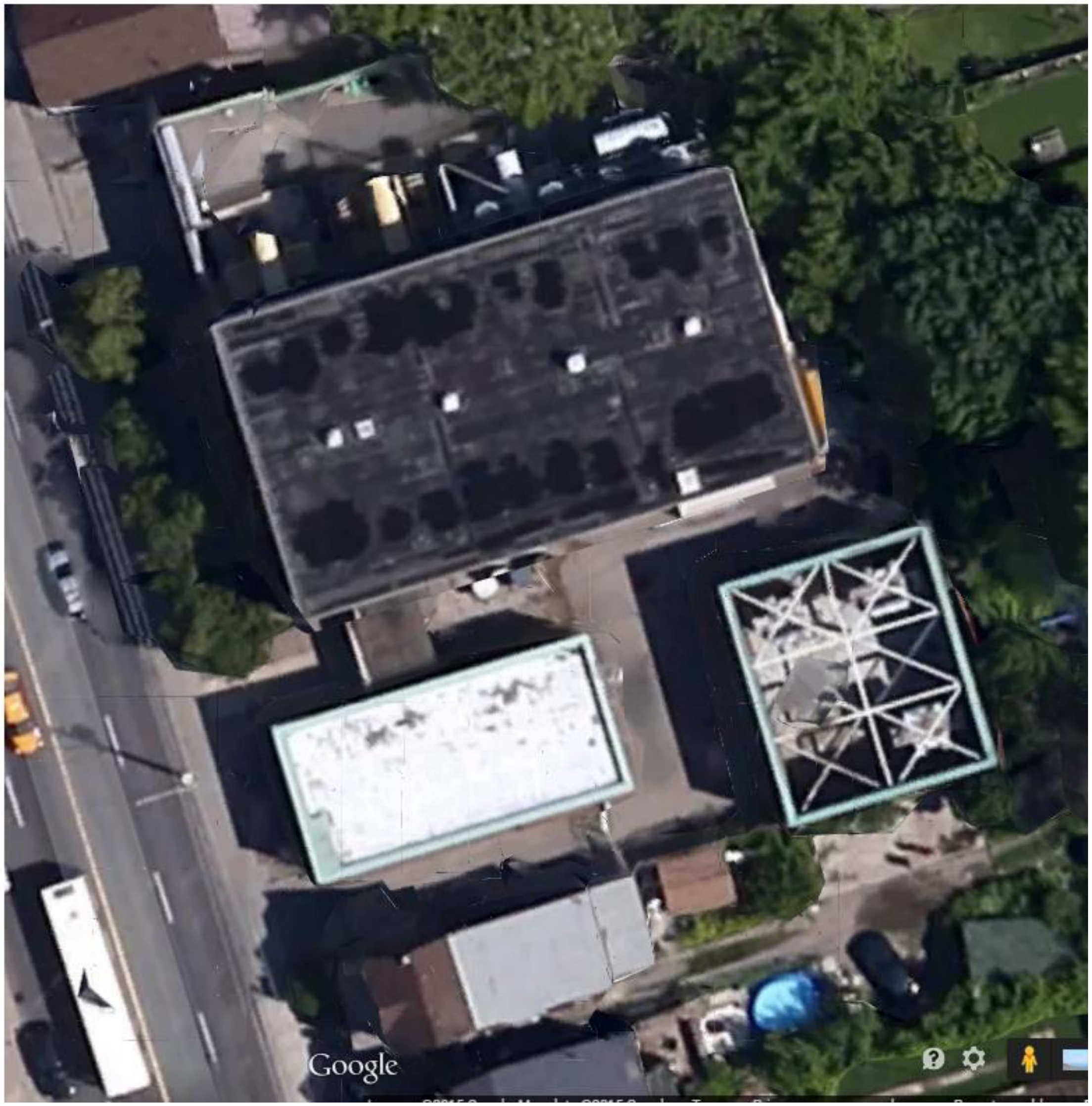
[1] Special Studies, "2014 Update of Short Circuit Survey and Breaker Ratings," [Online]. Available: https://teams.hydroone.com/sites/TPD/TPD/ss_pd/Short Circuit/Surveys/Breakers.

[2] Conestoga-Rogers & Associates, "Hydro One Station Spill Risk Model," Mississauga, 2011.

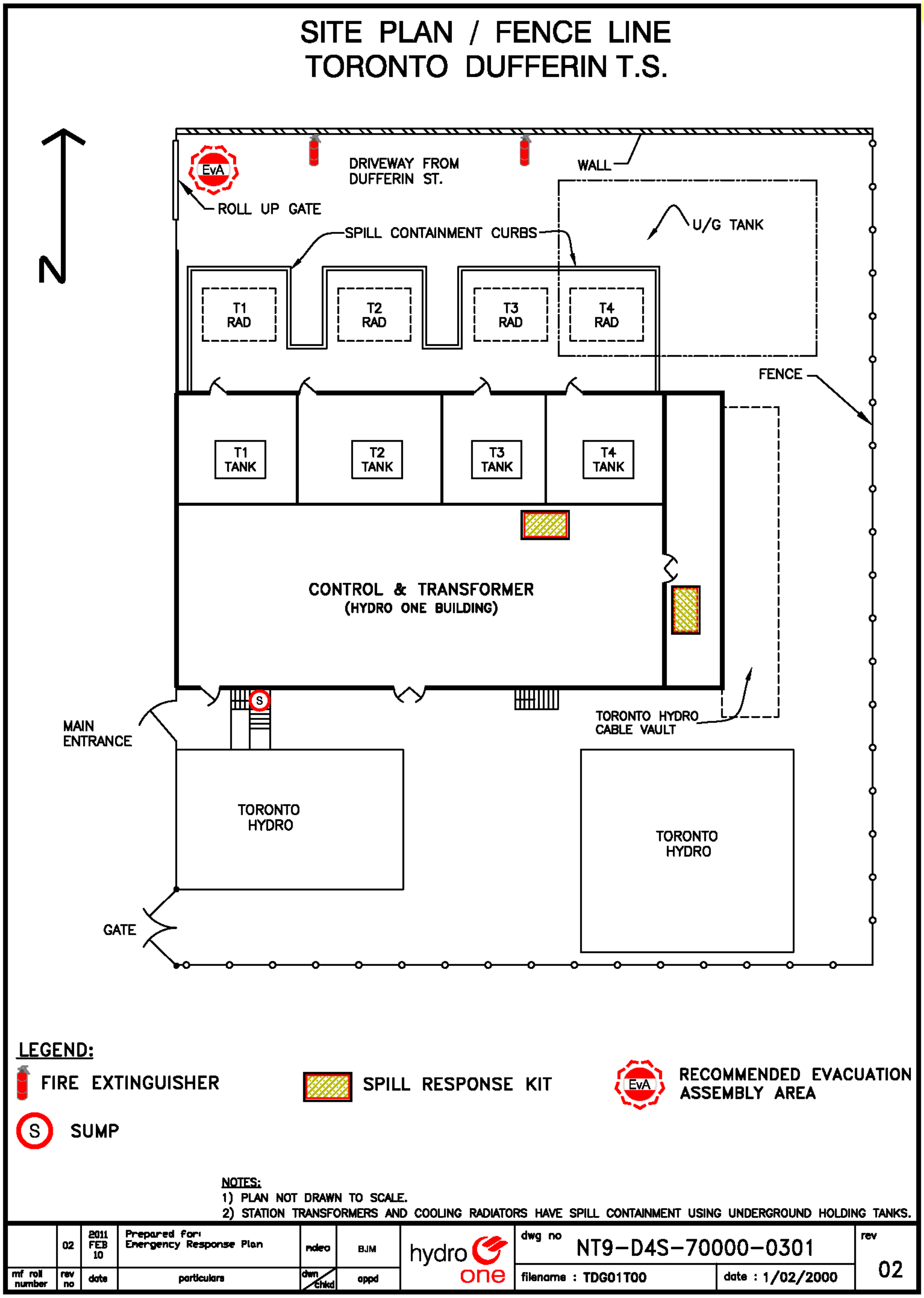
APPENDIX 1 – DUFFERIN TS OPERATING DIAGRAM



APPENDIX 2 – AERIAL/SATELLITE VIEW



APPENDIX 3 – SITE PLAN / FENCE LINE



APPENDIX 4 – TRANSMISSION EQUIPMENT OUTAGE PERFORMANCE DATA

Dufferin TS T2/T4 DESN Station Equipment Sustained Outage Event Report

Period: From: 1/1/2010 To: 12/31/2014

#	Type	Op Des	Voltage	Date	Time	Duration (HR)	Cause Code	Cause Description	Outage Type	Urgency	Extent	Remark
1	Bus	NT9A5A6	LV	15-Apr-14	20:10	0.65	4FS	Power System Configuration-Series Connection	S	FA	CCT	L13W+L15W TRIP
2	Bus	NT9A7A8	LV	15-Apr-14	20:10	0.65	4FS	Power System Configuration-Series Connection	S	FA	CCT	L13W+L15W TRIP
3	Transformer	NT9T2	115	15-Apr-14	20:10	0.65	4FZ	Power System Configuration-Common Trip Zone	S	FA	CCT	L13W TRIP
4	Transformer	NT9T4	115	15-Apr-14	20:10	0.65	4FZ	Power System Configuration-Common Trip Zone	S	FA	CCT	L15W TRIP
5	Breaker	NT9T2A7A8	LV	08-Feb-14	16:00	19.33	1MKBA	Main Pwr-Bkr Eqpt-Operating Mechanism Latch	D	FM	CC	FAILURE BKR MECHANISM
6	Transformer	NT9T2	115	07-Feb-14	12:36	27.40	4FS	Power System Configuration-Series Connection	S	FM	CCT	L13W O/S @ NT9
7	Transformer	NT9T4	115	30-Nov-12	23:47	2.28	4FZ	Power System Configuration-Common Trip Zone	S	FA	CCT	L15W TRIP
8	Transformer	NT9T2	115	05-Nov-12	11:23	3.88	4FS	Power System Configuration-Series Connection	S	FM	CCT	L13W LINE TRIP-MANUALLY
9	Transformer	NT9T4	115	09-Jun-12	14:06	513.90	1MTD	Main Pwr-Transformer Eqpt-Insulation System	D	FM	CCT	GAS ACCUMULATION
10	Transformer	NT9T4	115	29-May-12	14:08	176.82	1MTDD	Main Pwr-Transformer Eqpt-Insul-Gas Tested OK	D	FM	CCT	GAS ACCUMULATION
11	Transformer	NT9T2	115	30-Jul-11	20:41	4.40	4FS	Power System Configuration-Series Connection	S	FM	CCT	L13W
12	Transformer	NT9T2	115	18-Sep-10	16:47	5.05	4FZ	Power System Configuration-Common Trip Zone	S	FA	CCT	NT9T1-H1 FALSHOVER WHEN CLOSIN
13	Transformer	NT9T4	115	16-Apr-10	13:35	188.28	4FS	Power System Configuration-Series Connection	S	FM	CCT	LOSS OF SUPPLY CIRCUIT

APPENDIX 5 – DELIVERY POINT INTERRUPTION DATA

Delivery Point Interruptions											
FORCED/PLANED: Forced; BLAME: Exclude CUSTOMER					From 1/1/2004		To 12/31/2013				
DPI_DATE	YEAR	DPNAME	BUS	DPDES	TXFMR	MW_INT	MW_MIN	BLAME	CAUSE	SUP1	SUP2
5/8/2009	2009	DUFFERIN	A5A6	NT9A5A6	T2/T4	20.0	2,660	FOREIGN	FOREIGN RACCOONS,ETC TRANSFORMER BUSHING	L13W	L15W
5/8/2009	2009	DUFFERIN	A7A8	NT9A7A8	T2/T4	13.0	1,729	FOREIGN	FOREIGN RACCOONS,ETC TRANSFORMER BUSHING	L15W	L13W
1/15/2009	2009	DUFFERIN	A5A6	NT9A5A6	T2/T4	42.0	59,220	EQUIPMENT	EQUIPMENT FAILURE NON_ELECTRIC	L13W	L15W
1/15/2009	2009	DUFFERIN	A7A8	NT9A7A8	T2/T4	24.0	14,856	EQUIPMENT	EQUIPMENT FAILURE NON_ELECTRIC	L15W	L13W

DUFFERIN T1

Transformer Assessment

Keywords: Dufferin, T1, Transformer , Transmission, Station, Assessment

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APPROVAL SIGNATURES

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Date:			

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1. EXECUTIVE SUMMARY

- Built and in serviced 1964, Dufferin T1 is a 40/60/80 MVA, 110-14.2-14.2kV, 3 phase step down dual winding transformer with on load tap changers.
- The T1 Transformer at Dufferin TS has been reviewed and assessed based on 1) Demographics, 2) Equipment condition, 3) Potential or existing environmental/HSE hazards, 4) Loading and 5) Economics.
- The assessment concluded that T1 has shown signs of insulation degradation. Meanwhile T1's internal condition has shown fault conditions that are yet to confirm.
- T1 has been leaking badly since 2009. T1's tap changers also have not be able to perform reliably despite major upgrade in 2011.
- T1's tap changer vintage is approaching obsolesce with parts and service that can be expensive and inconvenient to access.
- 7 out of 11 T1's bushing cannot be sampled due to seal type design. It is unclear if they are PCB contaminated.
- Loading on T1 is stable and well below LTR limits in general.
- NPV analysis indicated a replacement starting 2016 is more economical compared to major refurbishment .
- Recommend for replacement within the next 5 years to mitigate reliability risk, to avoid potential PCB incompliance and lower overall lifecycle cost.

2. Equipment Summary

Built in 1964 by Westinghouse (CW), Dufferin T1 is a 40/60/80 MVA, 110-14.2-14.2kV, 3 phase, step down dual winding transformer with on load tap changers (model CI) built in 1963 by Maschinenfabrik Reinhausen (MR).

3. Demographics

T1 was in-serviced 1964 (52 years old). A total of 103 similar units are currently in service as of Dec 2015.

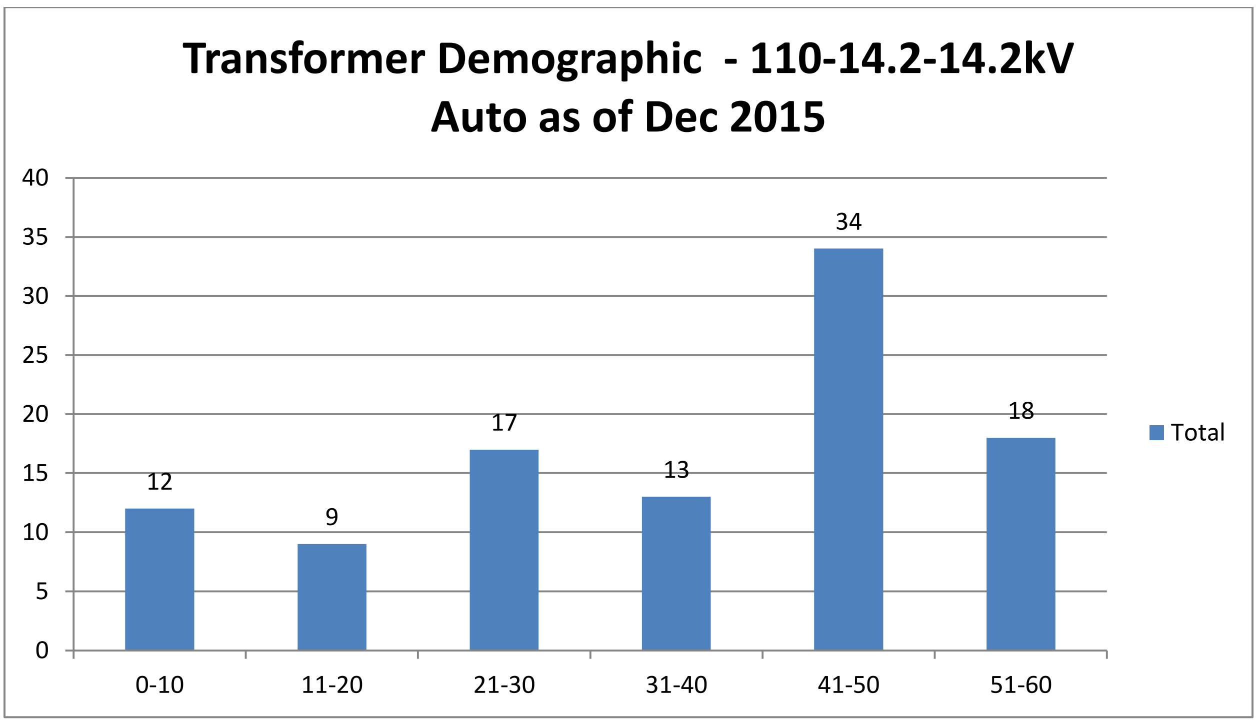


Chart 1 : Transformer Demographic - 110-14.2-14.2 kV Step down Transformer as of Dec 2015

4. Equipment Condition

Equipment condition is examined based on: 1) Dissolved Gas Analysis (DGA) and 2) Preventive Maintenance Result, Trouble Calls and Deficiency Report;

4.1 Oil analysis Data

Although acetylene (C_2H_2) and ethylene (C_2H_4) are presented in oil, these measurements have been fluctuating in narrow ranges, with only small amount of hydrogen detected, suggesting that that internal of the tank has been relatively stable. An increasing trend of C_2H_2, C_2H_4 and H_2 has been observed starting 2014, suggesting potential low energy discharges. However, due to the absence of other combustible hydrocarbon gases, it is also possible that this is contamination from tap-changer, but unfortunately no field inspections are available to confirm.

Signs of paper insulation deterioration observed as concentration of CO_2 remained high for a number of years.. Furan stable.

T1's oil quality is poor, where IFT measurements are at or near critical values as per PR1127. Oil colour is unacceptable. Oil's dielectric strength is normal. Overall, oil sample results suggested that T1's oil is aged.

Note: T1 has recorded bad oil leaks , DGA and oil quality result might not be indicative, see section 4.2

Date	C2H2	C2H4	C2H6	CH4	CO	CO2	H2	N2	O2	TDCG
06/25/2011	33	23	1.12	2.36	329	2710	15	68800	29800	10.17
05/30/2012	25	22	0	0	180	2450	0	67000	30500	9.97
01/07/2013	25	25	0	0	191	2720	0	71800	33200	10.75
02/07/2014	25	35	0	0	244	2370	15	63900	28700	9.48
04/19/2014	25	21	0	0	185	2570	0	64200	30400	9.7
01/07/2015	26	24	0	0	284	2710	15	65800	29700	9.82
02/08/2016	30	38	0	0	201	2500	10	66300	28600	9.73

Table 1 : DGA results for T1 from previous years

Date	Acidity	Colour	Furan	IFT	kV (ASTM D1816)	kV (ASTM D877)	Moisture	pf @ 25 °C
06/25/2011	0.06	3	41	24.4	56	48	9	0.22
05/30/2012	0.06	3	37	24.9	57	55	6	0.23
01/07/2013	0.05	3	40	24	60	53	4	0.13
02/07/2014	0.06	3	39	24.5	58	49	2	0.1
04/19/2014	0.06	3	44	24.7	38	53	6	0.15
01/07/2015	0.05	3	39	24.6	59	45	2	0.1
02/08/2016	0.06	3	45	25.1	67	49	2	0.12

Table 2: Dufferin T1 Oil quality from previous years

4.2 Maintenance History , Trouble Calls and Deficiency Report

Standard power transformer maintenance packages are applied on Dufferin T1 per Hydro One Work Standard Document SM-54-007 (main tank) and SM-54-014(ULTC) respectively.

Maintenance Item	2011	2012	2013	2014	2015	2016	2017
TF-GENERAL-D1 (4 year interval)	(CR01-2010)				CR01		
TF-GENERAL-D2[1] (8 year interval)							
TF-GENERAL-DBT (8 year interval)	CR01						
TF-GENERAL-GOT (Annual)	CR01	CR01	CR01	CR01	CR01	x	x
UT-MR-CI -UTOA (X) (Annual)	CR01	CR01	CR01	CR01	CR01	x	x
UT-MR-CI -UTOA (Y) (Annual)	CR01	CR01	CR01	CR01	CR01	x	x
UT- MR-CI -SI (X) (2 year interval)		CR01		CR01		CR01	
UT- MR-CI -SI (Y) (2 year interval)		CR01		CR01		CR01	

Table 3 : Preventive maintenance summary of T1 and future schedule (marked by x)

A list of all Preventive maintenance results are appended in Appendix I. It is concluded that preventive maintenance results are satisfactory.

<u>Equipment Obsolescence</u>

T1 is a Westinghouse Transformer that uses a 3 individual MR C-I tap changers. The original manufacturer still provides parts and services to this type of tap changer. Some parts are no longer available off-the-shelf. Depending on parts and maintenance required, it will require original manufacturer (MR) to fabricate on demand, with up to 10 weeks lead time. Hydro One Inc. will require technical assistance from MR to assign technicians with specialized skills set from Germany to support.

[1] D2 maintenance was only initiated in 2011 on an 8 year interval.

Trouble calls/deficiency report

Lists of trouble calls/deficiency report are reviewed appended in Appendix II. It is concluded that defects found are typical of its age, minor and manageable. Highlights include:

1. Numerous Tap changer problems : including Y- side tap changer lowered to tap 1 by itself a few times in 2010, required control relay contactor rebuilt. Tap changer gas trip device due to bad wiring. In 2016, X-side Tap changer reported stuck caused by defective components such as faulty mercury switch and damaged drive shaft. [SAP Ref. notification : 10467008, 10471137, 10471246, 10471218, 10473573, 10491429, 14630959, 14632008]
2. History of oil leaks from top of transformer since 2009. Despite repair attempts oil leaks from various parts continues to emerge. Inspection reported a pool of oil is accumulated on the ground in 2015 Q1, See Appendix III for picture. [SAP Ref. notification : 10358929, 10402089 , 10478549, 12867961]
3. Auxiliary devices including oil monitor and cooling becomes faulty, water ingress found in cables. [SAP Ref. notification : 10318872, 10470555, 10491251, 12051114]

5 Potential Environmental Risk/HSE

5.1 Spill Risk Assessment

Dufferin is ranked as low-moderate risk for spill containment (63) of 256 stations based on existing risk score from a 2011 spill risk report by Conestoga-Rogers & Associates [1]. Dufferin T1 is not equipped with containment according to Hydro One standards.

5.2 PCB content

Table below summarized the latest PCB content detected in various part of the equipment. Hydro One is obligated to remove or retrofit equipment with PCB contamination >50ppm per Environment Canada regulation by 2025. Currently 7/11 bushing PCB results are unavailable because these bushings are seal type design [SAP Ref. Notification: 12887821, 13944189, 13944200, 13944181, 13944187, 13944188, 13944182, 13944183, 13944184, 13944185, 13944180, 13944186]

Equipment	Description	Date	PCB (ppm)	Lab Reference
1188489	TF: Stepdn - 80MVA 110-14.2-14.2kV	02/08/2016	4	M304115A
1223879	(Y3) - BUSHING: 15 kV	n/a	[unknown]	
1223881	(Y2) - BUSHING: 15 kV	n/a	[unknown]	
1223883	(Y1) - BUSHING: 15 kV	n/a	[unknown]	
1223885	(Y0) - BUSHING: 15 kV	n/a	[unknown]	
1223886	(X3) - BUSHING: 15 kV	n/a	[unknown]	
1223888	(X2) - BUSHING: 15 kV	n/a	[unknown]	
1223890	(X1) - BUSHING: 15 kV	0	04/23/2013	#B357165
1223892	(X0) - BUSHING: 15 kV	0	04/23/2013	#B357165
1223894	(H1) - BUSHING: 115 kV	n/a	04/23/2013	#B357165
1223896	(H3) - BUSHING: 115 kV	n/a	04/23/2013	#B357165
1223898	(H2) - BUSHING: 115 kV	n/a	[unknown]	
1222512	(XB) TF: ULTC - 13 kV Div	06/15/2015	3	M288729A
1222514	(XR) TF: ULTC - 13 kV Div	06/15/2015	3	M288728A
1222516	(XW) TF: ULTC - 13 kV Div	06/15/2015	3	M263489A
1222518	(YB) TF: ULTC - 13 kV Div	06/15/2015	3	M288732A
1222520	(YR) TF: ULTC - 13 kV Div	06/15/2015	3	M288730A
1222522	(YW) TF: ULTC - 13 kV Div	06/15/2015	3	M263492A

6 Equipment Loading

Dufferin T1, is 40/60/80 MVA, dual secondary units (20/30/40) with summer and winter Limited Time Rating (LTR) are as follows:

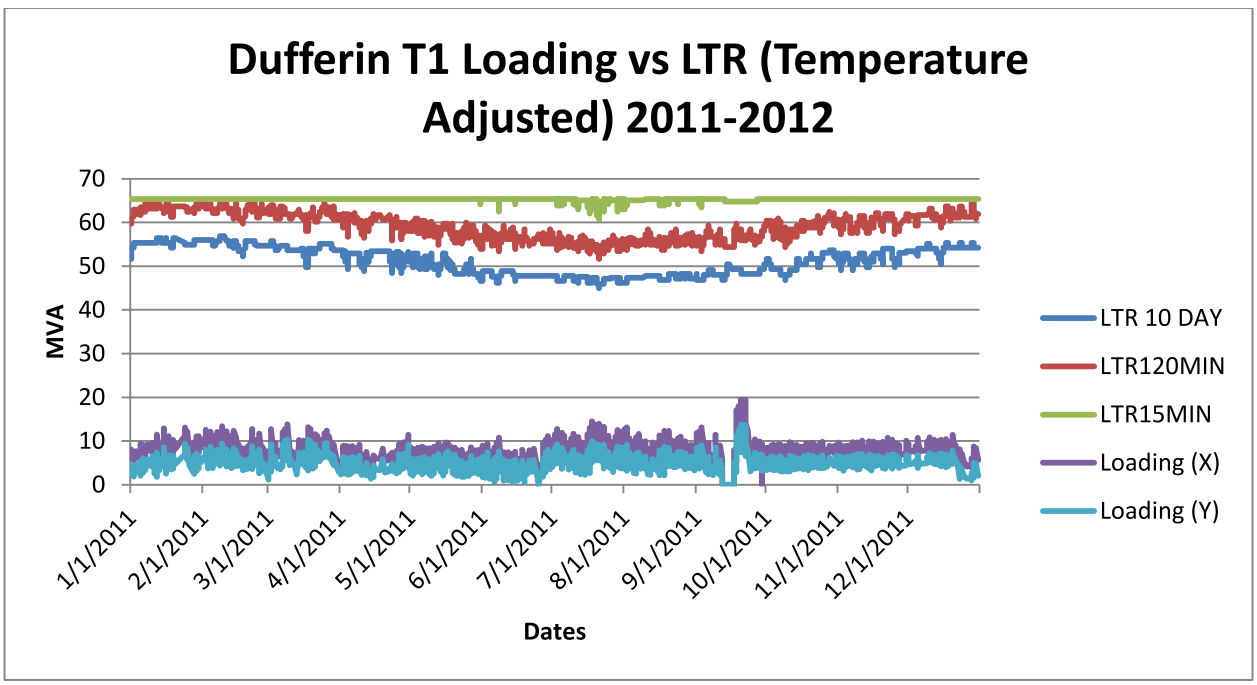
T1X:

Summer 10d LTR (31 ºC)	Winter 10d LTR (5ºC)
46MVA	54MVA

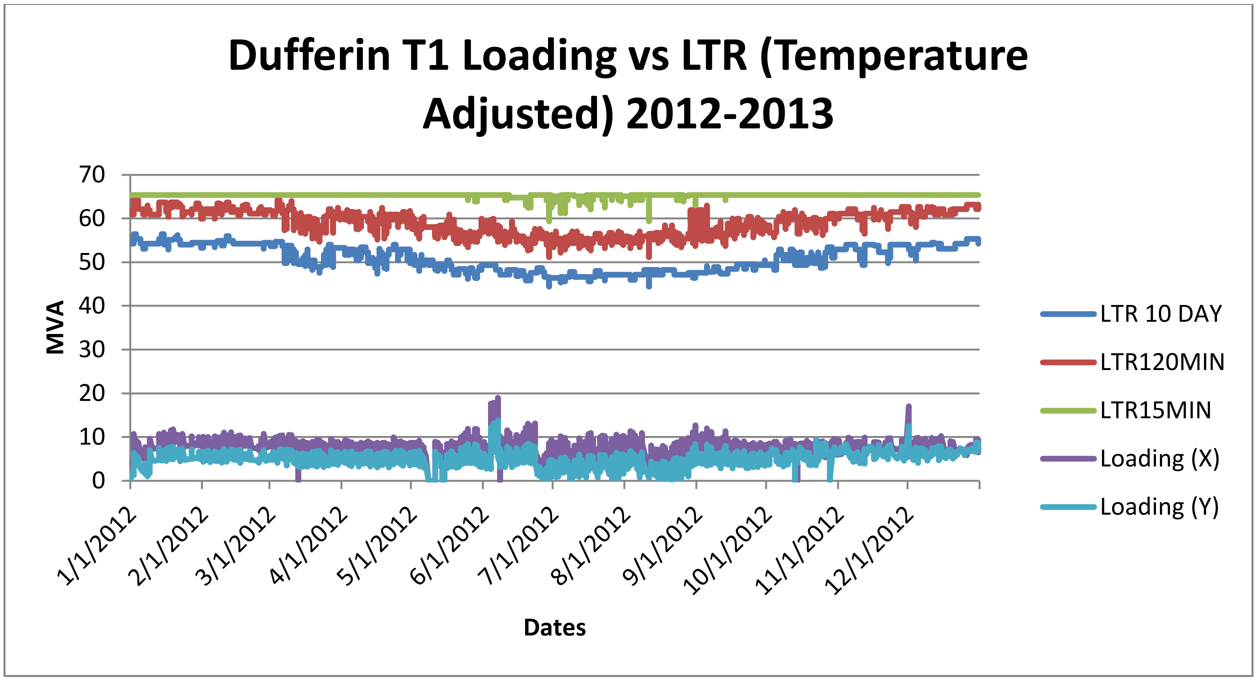
T1Y:

Summer 10d LTR (31 ºC)	Winter 10d LTR (5ºC)
46MVA	54MVA

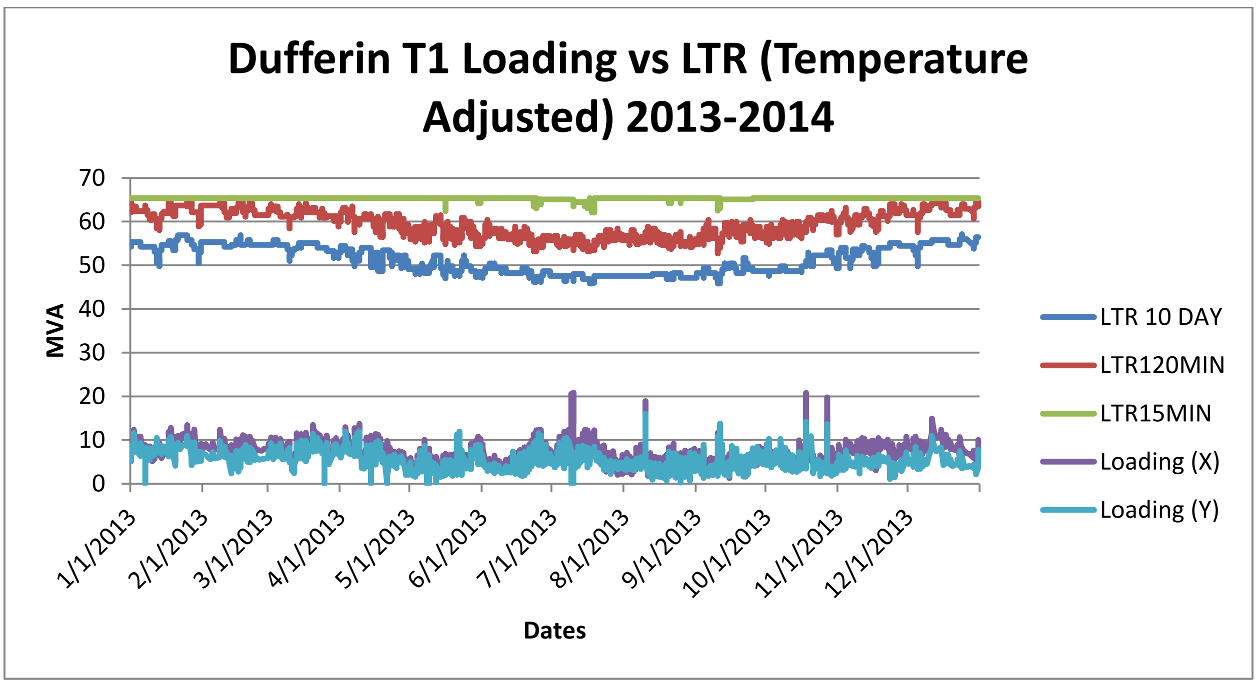
Dufferin T1's loading was reviewed with respect to its temperature adjusted LTR from 2011 -2015. It is observed T1's loading is positioned well below various loading limits. Loading surges were observed in occasionally but within acceptable limits.



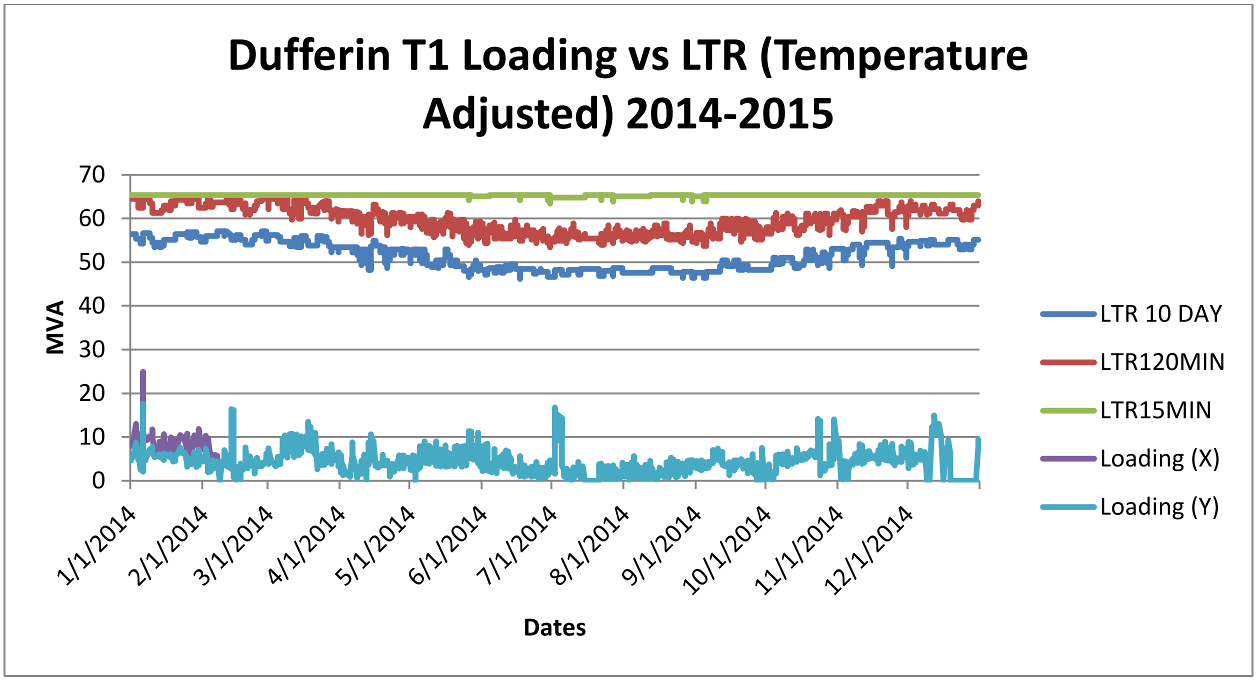
Graph 1: Dufferin T1Loading vs LTR (Temperature Adjusted) 2011-2012



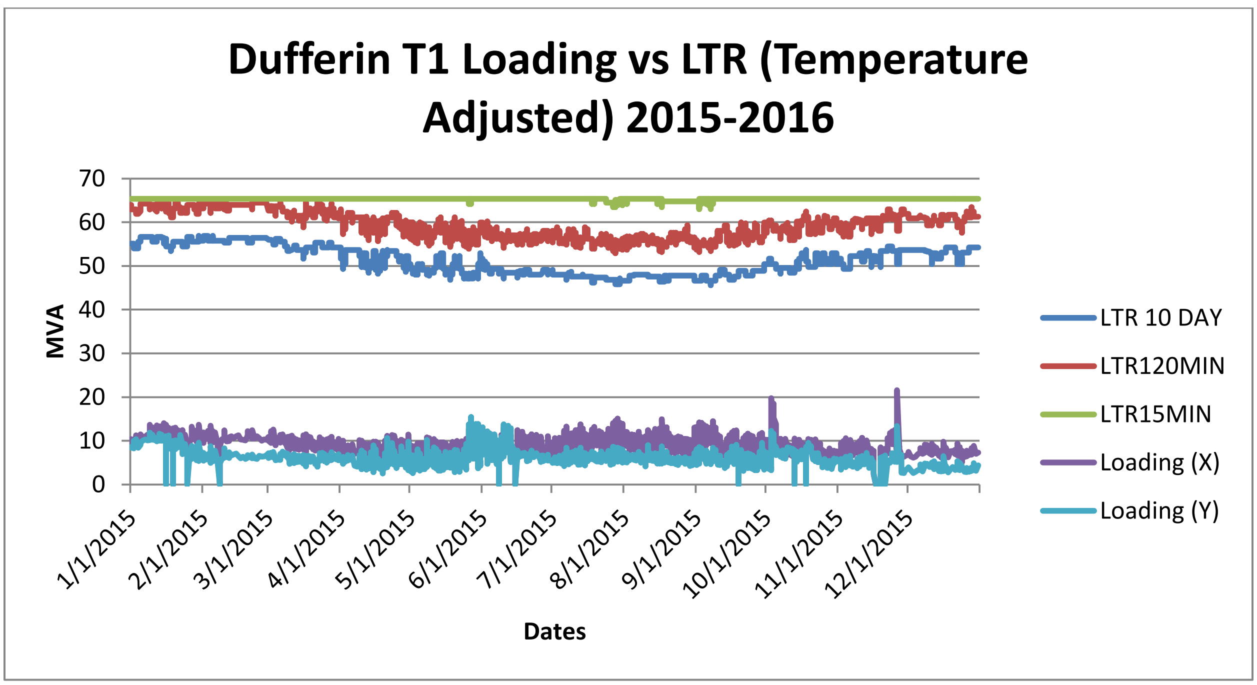
Graph 2: Dufferin T1 Loading vs LTR (Temperature Adjusted) 2012-2013



Graph 3: Dufferin T1 Loading vs LTR (Temperature Adjusted) 2013-2014



Graph 4: Dufferin T1 Loading vs LTR (Temperature Adjusted) 2014-2015



Graph 5: Dufferin T1 Loading vs LTR (Temperature Adjusted) 2015 Jan -2015 Dec

7 Economics

7.1 Recorded OM&A Spending.

Table 4 summarized OM&A incurred on Dufferin T1 since SAP inception in 2008. It is concluded that spending is higher than expected

Higher upgrade costs in 2013 were associated with LTC modifications on X & Y side and installation of UCL plates [Ref order: 60323756, 60062839]

Year	CORR	EMER	OPER	PREV	UPGR	Grand Total
2008				$23,480.40		$23,480.40
2009	$1,596.00	$421.00	$0.00	$236.00		$2,253.00
2010	$15,717.54	$6,966.81	$716.33	$33,123.68	$0.00	$56,524.36
2011			$925.07	$3,952.62	$157,323.23	$162,200.92
2012				$15,722.76		$15,722.76
2013	$2,000.09	$1,311.98		$1,514.00		$4,826.07
2014	$73.23			$17,322.25	$6,788.79	$24,184.27
2015			$302.51	$2,011.12		$2,313.63
2016	$7,188.05	$802.13	$0.00	$28,232.69		$36,222.87
Grand Total	**$26,574.91**	**$9,501.92**	**$1,943.91**	**$125,595.52**	**$164,112.02**	**$327,728.28**

Table 4 : Historical OM&A spending on T1

PREV Maintenance Activity	Average Actual Cost (2013 - 2015)	Applicable to unit under assessment
TAP CHANGER OIL SAMPLES	$ 370.51	✓
TAP CHANGER SI	$ 3380[2]	✓
TRANSFORMER DBT --General	$ 5,660.90	✓
TRANSFORMER D1 --General	$ 3,862.40	✓
TRANSFORMER D2 --General	$ 3,517.07	✓
TRANSFORMER OIL SAMPLES --General	$ 300.57	✓

Table 5: Unit cost of various Preventative Maintenance Activities. Based on actual unit cost from 2013-2015

[2] Due to number of tap changers (6) in service, unit cost adjusted utilizing actual cost data specific to Dufferin T1 since 2008 for higher accuracy in NPV calculation purpose. Normal unit price is $7019

7.2 Net Present Value Analysis

This session evaluates the cost benefit for various asset management options (sustain, repair , replacement) of T1 with Net Present Value Analysis(NPV)

The study makes the following assumptions:

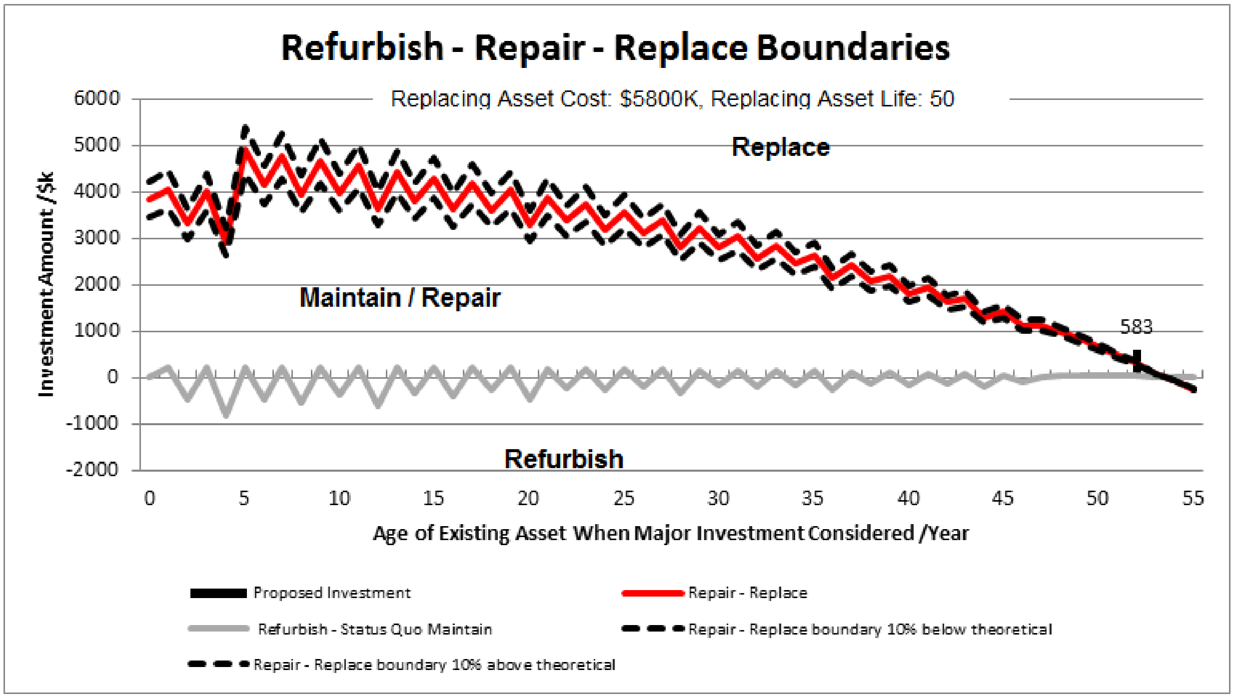
- Study period : 55 years[3]
- T1 will undergo refurbishment/ repair at 52 year old (2016), at approx. CAD$583.8k[4].
- Replacement cost is assumed to be CAD$5.8M[5] for a unit that matches purchasing standard S115-101
- The new unit will benefit from lower OM&A cost because it will be equipped with vacuum tap changer. Estimated interval for internal inspection is lengthen to 12 years. New unit will utilize Buchholz relay and eliminate D2 maintenance task.
- Inflation : 2%. [2]
- Cost of Capital: 5.78% [2]
- Corporate Tax rate : 26.5% [2]
- CCA rate for Transmission Asset : 8% [2]
- Disposal Value : $0
- Corrective cost not factored in.

NPV of 3 options (Status Quo Maintain, Repair and Replace) are evaluated under the aforementioned assumptions. In general, NPV calculation has preferred the option to maintain status quo and wait for replacement. Should a repair becomes necessary, the break-even point between Repair vs Replace options that results in NPV = $0, is the sum of the anticipated repair cost less the PV difference between repair vs replace option (CAD $583.8K - CAD $310.92K = CAD $272.08). The evaluation concludes that it is cheaper to advance replacement starting 2016 should a major repair becomes necessary. The result is within expectations as the new unit will have a much lower OM&A requirement compared to the existing unit.

Result Summary	Status Quo Maintain	Major Investment Maintain/Repair	Replace	Preferred Option
With CCA tax savings				
PV of Options, $k, with terminal value	4728.96	5299.85	4988.92	
PV of Options, $k, terminal value = 0	4751.21	5322.09	4988.92	
Investment Decision		NPV, $k		
Status Quo Maintain - Refurbish		-570.88		Maintain
Major Investment (Repair/Refurbish) - Replace		310.92		Replace
Repair - Replace boundary			272.08	
Repair - Replace boundary, upper bound			299.28	
Repair - Replace boundary, lower bound			244.87	

Table 4: Present Value comparison for different sustainment options

[3] Study period lengthen to 55 to accommodate the fact that the unit is already 52 years old. Normal study period is 50 years.
[4] $583.8 K is the 2010 – 2015 recorded average cost to refurbish transformer under AR 18335 (Transformer Oil Leak Reduction)
[5] Based on 2015 March, Average I/S Cost for Power Transformers in 115kV class.



Graph 6: Visual Representation of NPV analysis

8 Conclusion

The demographics data, condition data, environmental/HSE hazards, equipment loading and economics related to Dufferin T1 have been reviewed. T1 oil data showed no active fault on-going from 2011-2013, but an increasing trend of fault gases is observed since 2014. At present, it is inconclusive whether it is partial discharges or contamination from tap changers. T1's oil also shows signs of insulation aging and degradation. T1's overall maintenance history, reported deficiencies and spending has suggested that its tap changers have not be able to perform reliably despite major upgrade in 2011. Unfortunately, T1's tap changer vintage is approaching obsolesce with parts and service that can become expensive and inconvenient to access. A review of T1's loading has revealed that it is lightly loaded with respect to its various loading limits from 2011-2015. A NPV analysis has been performed and has concluded that while it is the cheapest to keep unit in service , a replacement is more economical to perform a repair when the unit reaches 52 years old (2016) due to lower maintenance requirement. In conclusion, a replacement of the unit within 5 years from 2016 would be considered prudent and economical as it can lower reliability risk , avoid potential PCB incompliance and lower future OM&A cost.

9 Reference

[1] Conestoga-Rogers & Associates. (2011). Hydro One Station Spill Risk Model. SIP-EnvMgmt-0100, Mississauga.

[2] Department of Economics and Load Forecasting, Hydro One Networks Inc. (2015), Hydro One Financial Evaluation Model, Toronto.

APPENDIX 1 – PREVENTIVE MAINTENANCE RESULT

Notifictn type	Notification	Functional Loc.	Notif.date	Coding	Description
PR	10002506	N-TS-DUFFERINTS-TF-T1	05/31/2008		UT-MR/BC-C-D-S
PR	10001439	N-TS-DUFFERINTS-TF-T1	05/31/2008	CR01	UT-MR/BC-C-D-SI
PR	10002507	N-TS-DUFFERINTS-TF-T1	05/31/2008		UT-MR/BC-C-D-SI
PR	10002509	N-TS-DUFFERINTS-TF-T1	05/31/2008		UT-MR/BC-C-D-SI
PR	10001440	N-TS-DUFFERINTS-TF-T1	05/31/2008		UT-MR/BC-C-D-SI
PR	10002510	N-TS-DUFFERINTS-TF-T1	05/31/2008		UT-MR/BC-C-D-SI
PR	10012643	N-TS-DUFFERINTS-TF-T1	06/11/2008		request oil for Dufferin T1 & T3
PR	10022837	N-TS-DUFFERINTS-TF-T1	07/04/2008		UT-MR/BC-C-D-D1
PR	10022838	N-TS-DUFFERINTS-TF-T1	07/04/2008		UT-MR/BC-C-D-D1
PR	10024449	N-TS-DUFFERINTS-TF-T1	07/09/2008		UT-MR/BC-C-D-D1
PR	10024450	N-TS-DUFFERINTS-TF-T1	07/09/2008		UT-MR/BC-C-D-D1
PR	10024451	N-TS-DUFFERINTS-TF-T1	07/09/2008		UT-MR/BC-C-D-D1
PR	10024452	N-TS-DUFFERINTS-TF-T1	07/09/2008		UT-MR/BC-C-D-D1
PR	10234362	N-TS-DUFFERINTS-TF-T1	12/12/2008	CR01	UT-MR/BC-C-D-UTOA
PR	10234331	N-TS-DUFFERINTS-TF-T1	12/12/2008	CR01	UT-MR/BC-C-D-UTOA
PR	10234363	N-TS-DUFFERINTS-TF-T1	12/12/2008	CR01	UT-MR/BC-C-D-UTOA
PR	10234364	N-TS-DUFFERINTS-TF-T1	12/12/2008		UT-MR/BC-C-D-UTOA
PR	10234332	N-TS-DUFFERINTS-TF-T1	12/12/2008	CR01	UT-MR/BC-C-D-UTOA
PR	10234365	N-TS-DUFFERINTS-TF-T1	12/12/2008	CR01	UT-MR/DM-1/12-1500/F-UTOA
PR	10237762	N-TS-DUFFERINTS-TF-T1	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI
PR	10237794	N-TS-DUFFERINTS-TF-T1	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI
PR	10237795	N-TS-DUFFERINTS-TF-T1	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI
PR	10237796	N-TS-DUFFERINTS-TF-T1	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI
PR	10237797	N-TS-DUFFERINTS-TF-T1	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI
PR	10237798	N-TS-DUFFERINTS-TF-T1	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI
PR	10237799	N-TS-DUFFERINTS-TF-T1	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI

PR	10237800	N-TS-DUFFERINTS-TF-T1	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI
PR	10237801	N-TS-DUFFERINTS-TF-T1	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI
PR	10237802	N-TS-DUFFERINTS-TF-T1	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI
PR	10237803	N-TS-DUFFERINTS-TF-T1	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI
PR	10237804	N-TS-DUFFERINTS-TF-T1	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI
PR	10246697	N-TS-DUFFERINTS-TF-T1	12/30/2008		UT-MR/BC-C-D-D1
PR	10246589	N-TS-DUFFERINTS-TF-T1	12/30/2008		UT-MR/BC-C-D-D1
PR	10246698	N-TS-DUFFERINTS-TF-T1	12/30/2008		UT-MR/BC-C-D-D1
PR	10246699	N-TS-DUFFERINTS-TF-T1	12/30/2008		UT-MR/BC-C-D-D1
PR	10246700	N-TS-DUFFERINTS-TF-T1	12/30/2008		UT-MR/BC-C-D-D1
PR	10267471	N-TS-DUFFERINTS-TF-T1	02/25/2009		UT-MR/BC-C-D-D1
PR	10319133	N-TS-DUFFERINTS-TF-T1	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10319165	N-TS-DUFFERINTS-TF-T1	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10319166	N-TS-DUFFERINTS-TF-T1	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10319167	N-TS-DUFFERINTS-TF-T1	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10319168	N-TS-DUFFERINTS-TF-T1	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10319169	N-TS-DUFFERINTS-TF-T1	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10319170	N-TS-DUFFERINTS-TF-T1	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10319171	N-TS-DUFFERINTS-TF-T1	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10319172	N-TS-DUFFERINTS-TF-T1	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10319173	N-TS-DUFFERINTS-TF-T1	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10319174	N-TS-DUFFERINTS-TF-T1	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10319175	N-TS-DUFFERINTS-TF-T1	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10391636	N-TS-DUFFERINTS-TF-T1	11/11/2009	CR01	TF-GENERAL-GOT
PR	10409775	N-TS-DUFFERINTS-TF-T1	12/11/2009		UT-MR/BC-C-D-UTOA
PR	10409766	N-TS-DUFFERINTS-TF-T1	12/11/2009		UT-MR/BC-C-D-UTOA
PR	10409783	N-TS-DUFFERINTS-TF-T1	12/11/2009		UT-MR/BC-C-D-UTOA
PR	10409776	N-TS-DUFFERINTS-TF-T1	12/11/2009		UT-MR/BC-C-D-UTOA
PR	10409772	N-TS-DUFFERINTS-TF-T1	12/11/2009		UT-MR/BC-C-D-UTOA
PR	10415063	N-TS-DUFFERINTS-TF-T1	12/26/2009		TF-GENERAL-M1

PR	10474931	N-TS-DUFFERINTS-TF-T1	03/10/2010	CR01	TF-GENERAL-DBT
PR	10474930	N-TS-DUFFERINTS-TF-T1	03/10/2010		TF-GENERAL-D1
PR	10474932	N-TS-DUFFERINTS-TF-T1	03/10/2010		UT-MR/BC-C-D-SI
PR	10474916	N-TS-DUFFERINTS-TF-T1	03/10/2010		UT-MR/BC-C-D-SI
PR	10474933	N-TS-DUFFERINTS-TF-T1	03/10/2010		UT-MR/BC-C-D-SI
PR	10474934	N-TS-DUFFERINTS-TF-T1	03/10/2010		UT-MR/BC-C-D-SI
PR	10474918	N-TS-DUFFERINTS-TF-T1	03/10/2010		UT-MR/BC-C-D-D1
PR	10474919	N-TS-DUFFERINTS-TF-T1	03/10/2010		UT-MR/BC-C-D-SI
PR	10474935	N-TS-DUFFERINTS-TF-T1	03/10/2010		UT-MR/BC-C-D-SI
PR	10508731	N-TS-DUFFERINTS-TF-T1	05/25/2010	CR02	STN 'A' PWR EQ INSP-SVI SPRING
PR	10508752	N-TS-DUFFERINTS-TF-T1	05/25/2010	CR01	STN 'A' PWR EQ INSP-SVI SPRING
PR	10508753	N-TS-DUFFERINTS-TF-T1	05/25/2010	CR01	STN 'A' PWR EQ INSP-SVI SPRING
PR	10508754	N-TS-DUFFERINTS-TF-T1	05/25/2010	CR01	STN 'A' PWR EQ INSP-SVI SPRING
PR	10508755	N-TS-DUFFERINTS-TF-T1	05/25/2010	CR01	STN 'A' PWR EQ INSP-SVI SPRING
PR	10508756	N-TS-DUFFERINTS-TF-T1	05/25/2010	CR01	STN 'A' PWR EQ INSP-SVI SPRING
PR	10508757	N-TS-DUFFERINTS-TF-T1	05/25/2010	CR01	STN 'A' PWR EQ INSP-SVI SPRING
PR	10525199	N-TS-DUFFERINTS-TF-T1	07/09/2010		UT-MR/BC-C-D-UTOA
PR	10559508	N-TS-DUFFERINTS-TF-T1	09/30/2010	CR01	STN 'A' PWR EQ INSP-SVI FALL
PR	10559529	N-TS-DUFFERINTS-TF-T1	09/30/2010	CR01	STN 'A' PWR EQ INSP-SVI FALL
PR	10559530	N-TS-DUFFERINTS-TF-T1	09/30/2010	CR01	STN 'A' PWR EQ INSP-SVI FALL
PR	10559531	N-TS-DUFFERINTS-TF-T1	09/30/2010	CR01	STN 'A' PWR EQ INSP-SVI FALL
PR	10559532	N-TS-DUFFERINTS-TF-T1	09/30/2010	CR01	STN 'A' PWR EQ INSP-SVI FALL
PR	10559533	N-TS-DUFFERINTS-TF-T1	09/30/2010	CR01	STN 'A' PWR EQ INSP-SVI FALL
PR	10559534	N-TS-DUFFERINTS-TF-T1	09/30/2010	CR01	STN 'A' PWR EQ INSP-SVI FALL
PR	10561189	N-TS-DUFFERINTS-TF-T1	10/04/2010	CR01	TF-GENERAL-GOT
PR	10561492	N-TS-DUFFERINTS-TF-T1	10/04/2010	CR01	UT-MR/BC-C-D-UTOA
PR	10561150	N-TS-DUFFERINTS-TF-T1	10/04/2010	CR01	UT-MR/BC-C-D-UTOA
PR	10561493	N-TS-DUFFERINTS-TF-T1	10/04/2010	CR01	UT-MR/BC-C-D-UTOA
PR	10561494	N-TS-DUFFERINTS-TF-T1	10/04/2010	CR01	UT-MR/BC-C-D-UTOA
PR	10561151	N-TS-DUFFERINTS-TF-T1	10/04/2010	CR01	UT-MR/BC-C-D-UTOA

PR	10561495	N-TS-DUFFERINTS-TF-T1	10/04/2010	CR01	UT-MR/BC-C-D-UTOA
PR	10663310	N-TS-DUFFERINTS-TF-T1	03/03/2011	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2011
PR	10663331	N-TS-DUFFERINTS-TF-T1	03/03/2011	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2011
PR	10663332	N-TS-DUFFERINTS-TF-T1	03/03/2011	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2011
PR	10663333	N-TS-DUFFERINTS-TF-T1	03/03/2011	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2011
PR	10663334	N-TS-DUFFERINTS-TF-T1	03/03/2011	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2011
PR	10663335	N-TS-DUFFERINTS-TF-T1	03/03/2011	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2011
PR	10663336	N-TS-DUFFERINTS-TF-T1	03/03/2011	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2011
PR	10687298	N-TS-DUFFERINTS-TF-T1	05/06/2011		20216 2011 TX PCB Reduction Oil Sample
PR	10731418	N-TS-DUFFERINTS-TF-T1	09/01/2011	CR01	STN 'A' PWR EQ INSP-SVI FALL 2011
PR	10731449	N-TS-DUFFERINTS-TF-T1	09/01/2011	CR01	STN 'A' PWR EQ INSP-SVI FALL 2011
PR	10731450	N-TS-DUFFERINTS-TF-T1	09/01/2011	CR01	STN 'A' PWR EQ INSP-SVI FALL 2011
PR	10731451	N-TS-DUFFERINTS-TF-T1	09/01/2011	CR01	STN 'A' PWR EQ INSP-SVI FALL 2011
PR	10731452	N-TS-DUFFERINTS-TF-T1	09/01/2011	CR01	STN 'A' PWR EQ INSP-SVI FALL 2011
PR	10731453	N-TS-DUFFERINTS-TF-T1	09/01/2011	CR01	STN 'A' PWR EQ INSP-SVI FALL 2011
PR	10731454	N-TS-DUFFERINTS-TF-T1	09/01/2011	CR01	STN 'A' PWR EQ INSP-SVI FALL 2011
PR	10763714	N-TS-DUFFERINTS-TF-T1	10/20/2011	CR01	UT-MR-CI-SI
PR	10762761	N-TS-DUFFERINTS-TF-T1	10/20/2011	CR01	UT-MR-CI-SI
PR	10763715	N-TS-DUFFERINTS-TF-T1	10/20/2011	CR01	UT-MR-CI-SI
PR	10763728	N-TS-DUFFERINTS-TF-T1	10/20/2011	CR01	UT-MR-CI-SI
PR	10762762	N-TS-DUFFERINTS-TF-T1	10/20/2011	CR01	UT-MR-CI-SI
PR	10763729	N-TS-DUFFERINTS-TF-T1	10/20/2011	CR01	UT-MR-CI-SI
PR	10771925	N-TS-DUFFERINTS-TF-T1	10/21/2011	CR01	TF-GENERAL-GOT
PR	10772449	N-TS-DUFFERINTS-TF-T1	10/21/2011	CR01	UT-MR-CI-UTOA
PR	10771835	N-TS-DUFFERINTS-TF-T1	10/21/2011	CR01	UT-MR-CI-UTOA
PR	10772450	N-TS-DUFFERINTS-TF-T1	10/21/2011	CR01	UT-MR-CI-UTOA
PR	10772451	N-TS-DUFFERINTS-TF-T1	10/21/2011	CR01	UT-MR-CI-UTOA
PR	10771836	N-TS-DUFFERINTS-TF-T1	10/21/2011	CR01	UT-MR-CI-UTOA
PR	10772452	N-TS-DUFFERINTS-TF-T1	10/21/2011	CR01	UT-MR-CI-UTOA

PR	10816131	N-TS-DUFFERINTS-TF-T1	12/13/2011	CR01	20216 Tx PCB sample 2012
PR	10884184	N-TS-DUFFERINTS-TF-T1	04/11/2012	CR02	STN 'A' PWR EQ INSP-SVI SPR 2012
PR	10884205	N-TS-DUFFERINTS-TF-T1	04/11/2012	CR01	STN 'A' PWR EQ INSP-SVI SPR 2012
PR	10884206	N-TS-DUFFERINTS-TF-T1	04/11/2012	CR01	STN 'A' PWR EQ INSP-SVI SPR 2012
PR	10884207	N-TS-DUFFERINTS-TF-T1	04/11/2012	CR01	STN 'A' PWR EQ INSP-SVI SPR 2012
PR	10884208	N-TS-DUFFERINTS-TF-T1	04/11/2012	CR01	STN 'A' PWR EQ INSP-SVI SPR 2012
PR	10884209	N-TS-DUFFERINTS-TF-T1	04/11/2012	CR01	STN 'A' PWR EQ INSP-SVI SPR 2012
PR	10884210	N-TS-DUFFERINTS-TF-T1	04/11/2012	CR01	STN 'A' PWR EQ INSP-SVI SPR 2012
PR	11678747	N-TS-DUFFERINTS-TF-T1	09/10/2012	CR01	20216 Tx PCB sample 2012
PR	11678744	N-TS-DUFFERINTS-TF-T1	09/10/2012	CR01	20216 Tx PCB sample 2012
PR	11678748	N-TS-DUFFERINTS-TF-T1	09/10/2012	CR01	20216 Tx PCB sample 2012
PR	11678749	N-TS-DUFFERINTS-TF-T1	09/10/2012	CR01	20216 Tx PCB sample 2012
PR	11678940	N-TS-DUFFERINTS-TF-T1	09/10/2012	CR01	20216 Tx PCB sample 2012
PR	11678745	N-TS-DUFFERINTS-TF-T1	09/10/2012	CR01	20216 Tx PCB sample 2012
PR	11678941	N-TS-DUFFERINTS-TF-T1	09/10/2012	CR01	20216 Tx PCB sample 2012
PR	11678942	N-TS-DUFFERINTS-TF-T1	09/10/2012	CR01	20216 Tx PCB sample 2012
PR	11678943	N-TS-DUFFERINTS-TF-T1	09/10/2012	CR01	20216 Tx PCB sample 2012
PR	11678746	N-TS-DUFFERINTS-TF-T1	09/10/2012	CR01	20216 Tx PCB sample 2012
PR	11678944	N-TS-DUFFERINTS-TF-T1	09/10/2012	CR01	20216 Tx PCB sample 2012
PR	11825198	N-TS-DUFFERINTS-TF-T1	10/13/2012	CR01	TF-GENERAL-GOT
PR	11825897	N-TS-DUFFERINTS-TF-T1	10/13/2012	CR01	UT-MR-CI-UTOA
PR	11825037	N-TS-DUFFERINTS-TF-T1	10/13/2012	CR01	UT-MR-CI-UTOA
PR	11825898	N-TS-DUFFERINTS-TF-T1	10/13/2012	CR01	UT-MR-CI-UTOA
PR	11825899	N-TS-DUFFERINTS-TF-T1	10/13/2012	CR01	UT-MR-CI-UTOA
PR	11825039	N-TS-DUFFERINTS-TF-T1	10/13/2012	CR01	UT-MR-CI-UTOA
PR	11825910	N-TS-DUFFERINTS-TF-T1	10/13/2012	CR01	UT-MR-CI-UTOA
PR	12144900	N-TS-DUFFERINTS-TF-T1	04/12/2013	CR02	STN 'A' PWR EQ INSP-SVI SPR 2013
PR	12144904	N-TS-DUFFERINTS-TF-T1	04/12/2013	CR01	STN 'A' PWR EQ INSP-SVI SPR 2013
PR	12144887	N-TS-DUFFERINTS-TF-T1	04/12/2013	CR01	STN 'A' PWR EQ INSP-SVI SPR 2013
PR	12144888	N-TS-DUFFERINTS-TF-T1	04/12/2013	CR01	STN 'A' PWR EQ INSP-SVI SPR 2013

PR	12144925	N-TS-DUFFERINTS-TF-T1	04/12/2013	CR01	STN 'A' PWR EQ INSP-SVI SPR 2013
PR	12144831	N-TS-DUFFERINTS-TF-T1	04/12/2013	CR01	STN 'A' PWR EQ INSP-SVI SPR 2013
PR	12144832	N-TS-DUFFERINTS-TF-T1	04/12/2013	CR01	STN 'A' PWR EQ INSP-SVI SPR 2013
PR	12644116	N-TS-DUFFERINTS-TF-T1	09/26/2013	CR01	TF-GENERAL-GOT
PR	12645201	N-TS-DUFFERINTS-TF-T1	09/26/2013	CR01	UT-MR-CI-UTOA
PR	12643957	N-TS-DUFFERINTS-TF-T1	09/26/2013	CR01	UT-MR-CI-UTOA
PR	12645202	N-TS-DUFFERINTS-TF-T1	09/26/2013	CR01	UT-MR-CI-UTOA
PR	12645204	N-TS-DUFFERINTS-TF-T1	09/26/2013	CR01	UT-MR-CI-UTOA
PR	12643959	N-TS-DUFFERINTS-TF-T1	09/26/2013	CR01	UT-MR-CI-UTOA
PR	12645206	N-TS-DUFFERINTS-TF-T1	09/26/2013	CR01	UT-MR-CI-UTOA
PR	12660647	N-TS-DUFFERINTS-TF-T1	09/27/2013	CR01	TF-GENERAL-D1
PR	12662190	N-TS-DUFFERINTS-TF-T1	09/27/2013	CR01	UT-MR-CI-SI
PR	12660446	N-TS-DUFFERINTS-TF-T1	09/27/2013	CR01	UT-MR-CI-SI
PR	12662191	N-TS-DUFFERINTS-TF-T1	09/27/2013	CR01	UT-MR-CI-SI
PR	12662194	N-TS-DUFFERINTS-TF-T1	09/27/2013	CR01	UT-MR-CI-SI
PR	12660447	N-TS-DUFFERINTS-TF-T1	09/27/2013	CR01	UT-MR-CI-SI
PR	12662195	N-TS-DUFFERINTS-TF-T1	09/27/2013	CR01	UT-MR-CI-SI
PR	12764011	N-TS-DUFFERINTS-TF-T1	11/08/2013	CR01	STN 'A' PWR EQ INSP-SVI FALL 2013
PR	12764034	N-TS-DUFFERINTS-TF-T1	11/08/2013	CR01	STN 'A' PWR EQ INSP-SVI FALL 2013
PR	12764035	N-TS-DUFFERINTS-TF-T1	11/08/2013	CR01	STN 'A' PWR EQ INSP-SVI FALL 2013
PR	12764036	N-TS-DUFFERINTS-TF-T1	11/08/2013	CR01	STN 'A' PWR EQ INSP-SVI FALL 2013
PR	12764037	N-TS-DUFFERINTS-TF-T1	11/08/2013	CR01	STN 'A' PWR EQ INSP-SVI FALL 2013
PR	12764038	N-TS-DUFFERINTS-TF-T1	11/08/2013	CR01	STN 'A' PWR EQ INSP-SVI FALL 2013
PR	12764039	N-TS-DUFFERINTS-TF-T1	11/08/2013	CR01	STN 'A' PWR EQ INSP-SVI FALL 2013
PR	12873313	N-TS-DUFFERINTS-TF-T1	02/28/2014	CR01	PREOUTAGE INSPECTION- CAT 1 - G&S
PR	12873312	N-TS-DUFFERINTS-TF-T1	02/28/2014	CR01	PREOUTAGE INSPECTION- CAT 1 - ELEC
PR	12887821	N-TS-DUFFERINTS-TF-T1	03/22/2014	CR03	Tx PCB Reduction Oil Sample
PR	13031753	N-TS-DUFFERINTS-TF-T1	06/10/2014	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2014
PR	13031787	N-TS-DUFFERINTS-TF-T1	06/10/2014	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2014
PR	13031785	N-TS-DUFFERINTS-TF-T1	06/10/2014	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2014

PR	13031778	N-TS-DUFFERINTS-TF-T1	06/10/2014	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2014
PR	13031788	N-TS-DUFFERINTS-TF-T1	06/10/2014	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2014
PR	13031779	N-TS-DUFFERINTS-TF-T1	06/10/2014	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2014
PR	13031780	N-TS-DUFFERINTS-TF-T1	06/10/2014	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2014
PR	13369352	N-TS-DUFFERINTS-TF-T1	09/26/2014	CR01	TF-GENERAL-GOT
PR	13369932	N-TS-DUFFERINTS-TF-T1	09/26/2014	CR01	UT-MR-CI-UTOA
PR	13369252	N-TS-DUFFERINTS-TF-T1	09/26/2014	CR01	UT-MR-CI-UTOA
PR	13369934	N-TS-DUFFERINTS-TF-T1	09/26/2014	CR01	UT-MR-CI-UTOA
PR	13369936	N-TS-DUFFERINTS-TF-T1	09/26/2014	CR01	UT-MR-CI-UTOA
PR	13369253	N-TS-DUFFERINTS-TF-T1	09/26/2014	CR01	UT-MR-CI-UTOA
PR	13369938	N-TS-DUFFERINTS-TF-T1	09/26/2014	CR01	UT-MR-CI-UTOA
PR	13845810	N-TS-DUFFERINTS-TF-T1	06/03/2015	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2015
PR	13845856	N-TS-DUFFERINTS-TF-T1	06/03/2015	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2015
PR	13845892	N-TS-DUFFERINTS-TF-T1	06/03/2015	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2015
PR	13845859	N-TS-DUFFERINTS-TF-T1	06/03/2015	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2015
PR	13845871	N-TS-DUFFERINTS-TF-T1	06/03/2015	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2015
PR	13845873	N-TS-DUFFERINTS-TF-T1	06/03/2015	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2015
PR	13845876	N-TS-DUFFERINTS-TF-T1	06/03/2015	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2015
PR	13944189	N-TS-DUFFERINTS-TF-T1	06/29/2015	CR03	Tx PCB Reduction Oil Sample
PR	13944200	N-TS-DUFFERINTS-TF-T1	06/29/2015	CR03	Tx PCB Reduction Oil Sample
PR	13944181	N-TS-DUFFERINTS-TF-T1	06/29/2015	CR03	Tx PCB Reduction Oil Sample
PR	13944187	N-TS-DUFFERINTS-TF-T1	06/29/2015	CR03	Tx PCB Reduction Oil Sample
PR	13944188	N-TS-DUFFERINTS-TF-T1	06/29/2015	CR03	Tx PCB Reduction Oil Sample
PR	13944182	N-TS-DUFFERINTS-TF-T1	06/29/2015	CR03	Tx PCB Reduction Oil Sample
PR	13944183	N-TS-DUFFERINTS-TF-T1	06/29/2015	CR03	Tx PCB Reduction Oil Sample
PR	13944184	N-TS-DUFFERINTS-TF-T1	06/29/2015	CR03	Tx PCB Reduction Oil Sample
PR	13944185	N-TS-DUFFERINTS-TF-T1	06/29/2015	CR03	Tx PCB Reduction Oil Sample
PR	13944186	N-TS-DUFFERINTS-TF-T1	06/29/2015	CR03	Tx PCB Reduction Oil Sample
PR	13944180	N-TS-DUFFERINTS-TF-T1	06/29/2015	CR03	Tx PCB Reduction Oil Sample
PR	14042110	N-TS-DUFFERINTS-TF-T1	07/24/2015	CR01	TF-GENERAL-GOT

PR	14042407	N-TS-DUFFERINTS-TF-T1	07/24/2015		UT-MR-CI-UTOA
PR	14042059	N-TS-DUFFERINTS-TF-T1	07/24/2015	CR01	UT-MR-CI-UTOA
PR	14042408	N-TS-DUFFERINTS-TF-T1	07/24/2015		Dufferin T1 UTOA
PR	14042409	N-TS-DUFFERINTS-TF-T1	07/24/2015		UT-MR-CI-UTOA
PR	14042060	N-TS-DUFFERINTS-TF-T1	07/24/2015	CR01	UT-MR-CI-UTOA
PR	14042410	N-TS-DUFFERINTS-TF-T1	07/24/2015		UT-MR-CI-UTOA
PR	14055520	N-TS-DUFFERINTS-TF-T1	07/25/2015		UT-MR-CI-SI
PR	14054490	N-TS-DUFFERINTS-TF-T1	07/25/2015	CR01	UT-MR-CI-SI
PR	14055521	N-TS-DUFFERINTS-TF-T1	07/25/2015		UT-MR-CI-SI
PR	14055527	N-TS-DUFFERINTS-TF-T1	07/25/2015		UT-MR-CI-SI
PR	14054491	N-TS-DUFFERINTS-TF-T1	07/25/2015	CR01	UT-MR-CI-SI
PR	14055528	N-TS-DUFFERINTS-TF-T1	07/25/2015		UT-MR-CI-SI
PR	14490683	N-TS-DUFFERINTS-TF-T1	01/05/2016	CR01	STN 'A' PWR EQ INSP-SVI FALL 2015
PR	14490691	N-TS-DUFFERINTS-TF-T1	01/05/2016	CR01	STN 'A' PWR EQ INSP-SVI FALL 2015
PR	14490692	N-TS-DUFFERINTS-TF-T1	01/05/2016	CR01	STN 'A' PWR EQ INSP-SVI FALL 2015
PR	14490693	N-TS-DUFFERINTS-TF-T1	01/05/2016	CR01	STN 'A' PWR EQ INSP-SVI FALL 2015
PR	14490696	N-TS-DUFFERINTS-TF-T1	01/05/2016	CR01	STN 'A' PWR EQ INSP-SVI FALL 2015
PR	14490697	N-TS-DUFFERINTS-TF-T1	01/05/2016	CR01	STN 'A' PWR EQ INSP-SVI FALL 2015
PR	14490698	N-TS-DUFFERINTS-TF-T1	01/05/2016	CR01	STN 'A' PWR EQ INSP-SVI FALL 2015
PR	14538424	N-TS-DUFFERINTS-TF-T1	03/15/2016		PREOUTAGE INSPECTION- CAT 1 - ELEC
PR	14538425	N-TS-DUFFERINTS-TF-T1	03/15/2016	CR01	PREOUTAGE INSPECTION- CAT 1 - G&S
PR	14905851	N-TS-DUFFERINTS-TF-T1	07/16/2016		TF-GENERAL-GOT
PR	14912001	N-TS-DUFFERINTS-TF-T1	07/16/2016		UT-MR-CI-UTOA
PR	14904663	N-TS-DUFFERINTS-TF-T1	07/16/2016		UT-MR-CI-UTOA
PR	14912002	N-TS-DUFFERINTS-TF-T1	07/16/2016		UT-MR-CI-UTOA
PR	14912006	N-TS-DUFFERINTS-TF-T1	07/16/2016		UT-MR-CI-UTOA
PR	14904665	N-TS-DUFFERINTS-TF-T1	07/16/2016		UT-MR-CI-UTOA
PR	14912007	N-TS-DUFFERINTS-TF-T1	07/16/2016		UT-MR-CI-UTOA
PR	14967760	N-TS-DUFFERINTS-TF-T1	08/04/2016		PREOUTAGE INSPECTION- CAT 1 - G&S
PR	14967719	N-TS-DUFFERINTS-TF-T1	08/04/2016		PREOUTAGE INSPECTION- CAT 1 - ELEC

APPENDIX 2 – LIST OF DR AND TC NOTIFICATION

Notifictn type	Notification	Functional Loc.	Notif.date	Description
DR	10249589	N-TS-DUFFERINTS-TF-T1	01/06/2009	Dufferin TS T1 UCL install
TC	10258881	N-TS-DUFFERINTS-TF-T1	01/23/2009	Duffering TS - Leaside EMD AH
TC	10318872	N-TS-DUFFERINTS-TF-T1	06/22/2009	Dufferin T1 COOLING investigate
DR	10358929	N-TS-DUFFERINTS-TF-T1	09/23/2009	DUFFERIN T1 OIL LEAK
TC	10404276	N-TS-DUFFERINTS-TF-T1	11/30/2009	S3- DUFFERIN TS T1 T2 SWITCHING
DR	10414115	N-TS-DUFFERINTS-TF-T1	12/21/2009	Conduct Site Assessment at Dufferin TS
TC	10433372	N-TS-DUFFERINTS-TF-T1	01/11/2010	Sec 3 Dufferin TS T1
TC	10437770	N-TS-DUFFERINTS-TF-T1	01/21/2010	s3 dufferin ts T1
TC	10467008	N-TS-DUFFERINTS-TF-T1	02/06/2010	S3- DUFFERIN TS- T1 TAP CHANGER
TC	10470555	N-TS-DUFFERINTS-TF-T1	02/19/2010	S3 T1 Tap Changer Gas trip Blocking SW
DR	10471137	N-TS-DUFFERINTS-TF-T1	02/22/2010	Dufferin T1 tapchanger gas trip fail
TC	10471246	N-TS-DUFFERINTS-TF-T1	02/22/2010	SEC 3: DUFFERIN TS: T1 TAP CHANGER
TC	10471218	N-TS-DUFFERINTS-TF-T1	02/23/2010	SEC 3: DUFFERIN TS: T1 TAP CHANGER
DR	10473573	N-TS-DUFFERINTS-TF-T1	03/05/2010	DUFFERIN T1 Y T/C RUNAWAY
DR	10478549	N-TS-DUFFERINTS-TF-T1	03/22/2010	SMS to investigate T1 Dufferin oil leak
DR	10491429	N-TS-DUFFERINTS-TF-T1	04/17/2010	Water found in T1 X T/C RS1000 Gas relay
TC	10491250	N-TS-DUFFERINTS-TF-T1	04/17/2010	S3 T1tripped on Gas - investigate
TC	10491251	N-TS-DUFFERINTS-TF-T1	04/17/2010	S1 T1-RA
DR	12051114	N-TS-DUFFERINTS-TF-T1	01/17/2013	Dufferin T1 Calisto not functioning
DR	12867961	N-TS-DUFFERINTS-TF-T1	02/13/2014	NT9 Inspect transfrmer for oil leaks
DR	14511100	N-TS-DUFFERINTS-TF-T1	02/08/2016	Dufferin T1 fan wiring repairs
TC	14630959	N-TS-DUFFERINTS-TF-T1	05/03/2016	S3 RE: T1 TAP CHANGER STUCK
DR	14632008	N-TS-DUFFERINTS-TF-T1	05/04/2016	T1X drive shaft repair

APPENDIX 3 – PICTURE OF T1

Picture of T1’s bay showing puddles of oil accumulated on the ground (Picture taken 2015 Q1)

DUFFERIN T3

Transformer Assessment

Keywords: Dufferin, T3, Transformer , Transmission, Station, Assessment

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REVISION HISTORY

Date	Revision	Revision Comments
Sept 2016	**0**	**Initial draft**

APPROVAL SIGNATURES

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1. EXECUTIVE SUMMARY

- Built and in serviced 1964, Dufferin T3 is a 40/60/80 MVA, 110-14.2-14.2kV, 3 phase step down dual winding transformer with on load tap changers.
- The T3 Transformer at Dufferin TS has been reviewed and assessed based on 1) Demographics, 2) Equipment condition, 3) Potential or existing environmental/HSE hazards, 4) Loading and 5) Economics.
- The assessment concluded that T3 showed evident signs of insulation degradation, with suspected low energy discharge actives observed starting 2015.
- T3 has repeated tap changers issues and it has not be able to perform reliably despite major upgrade in 2011.
- T3's tap changer vintage is approaching obsolesce with parts and service that can become expensive and inconvenient to access.
- All of T3's bushing cannot be sampled due to their sealed design. It is unclear if they are PCB contaminated.
- Loading on T3 is stable and well below LTR limits in general.
- NPV analysis indicated a replacement starting 2016 is more economical compared to major refurbishment.
- Recommend for replacement within the next 5 years to mitigate reliability risk, to avoid potential PCB incompliance and lower overall lifecycle cost.

2. Equipment Summary

Built in 1964 by Westinghouse (CW), Dufferin T3 is a 40/60/80 MVA, 110-14.2-14.2kV, 3 phase, step down dual winding transformer with on load tap changers (model C-I) built in 1963 by Maschinenfabrik Reinhausen (MR).

3. Demographics

T3 was in-serviced 1964 (52 years old). A total of 103 similar units are currently in service as of Dec 2015.

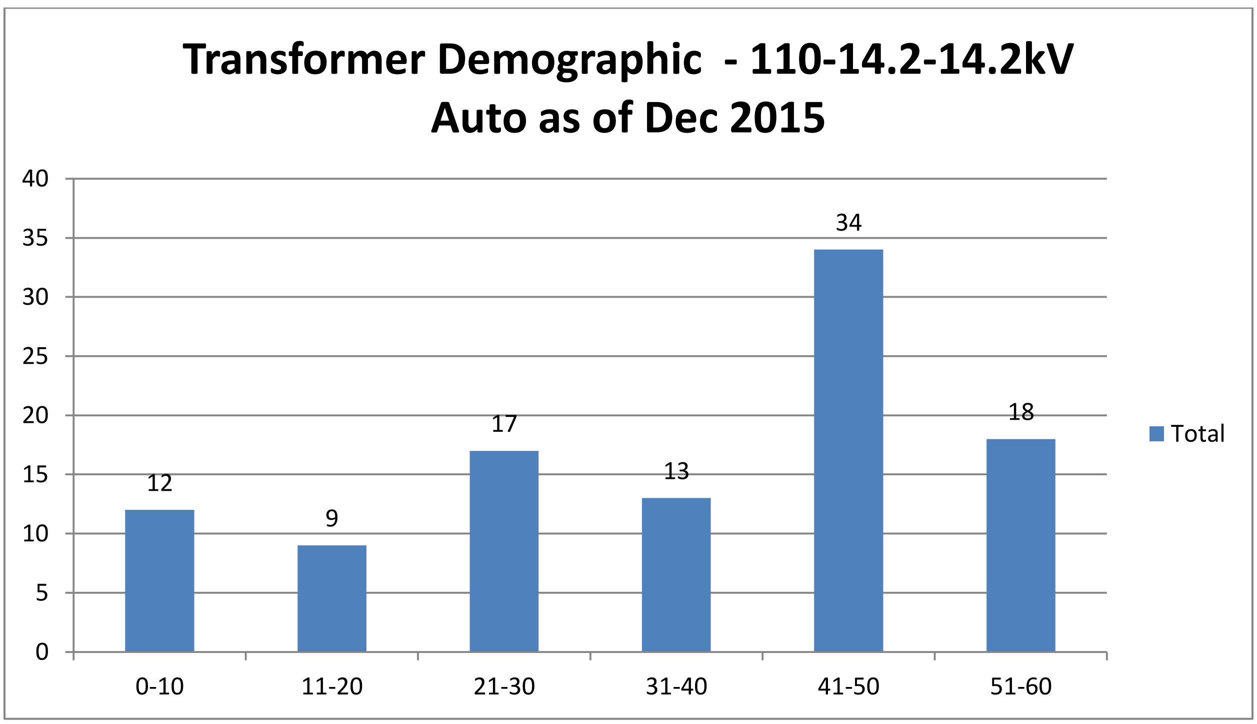


Chart 1 : Transformer Demographic - 110-14.2-14.2 kV Step down Transformer as of Dec 2015

4. Equipment Condition

Equipment condition is examined based on: 1) Dissolved Gas Analysis (DGA) and 2) Preventive Maintenance Result, Trouble Calls and Deficiency Report;

4.1 Oil analysis Data

DGA showed a clear signs paper insulation deterioration and strong oxidation reflected by T3's high concentration of CO,CO_2, and a continuous drop in oxygen level within its oil. While acetylene (C_2H_2) has been on an evaluated level and remained stable, an obvious jump in hydrogen (H_2), ethane (C_2H_6) and methane (CH_4) was observed in 2015's sample, suggesting a low energy partial discharge with possibility of thermal fault. It is noted that concentration of Ethane (C_2H_6) and Methane (CH_4) are still within threshold.

T3's oil quality is poor, Acidity of raising trend and IFT measurements are consistently below threshold as per PR1127, suggesting potential sludging in the oil. Oil colour is unacceptable. Oil's dielectric strength is normal. Overall, oil sample results suggested that T3's oil is very aged.

Date	C2H2	C2H4	C2H6	CH4	CO	CO2	H2	N2	O2	TG%
07/07/2010	30	16	8	19	795	4965	53	69712	855	7.64
06/07/2012	32	10	0	0	646	4790	40	70500	19900	9.55
01/07/2013	37	15	0	0	711	5510	45	64400	16500	8.68
02/07/2014	30	14	2	8	786	5490	50	63400	14000	8.34
01/07/2015	26	30	22	53	921	5600	90	64600	13500	8.44

Table 1 : DGA results for T3 from previous years

Date	Acidity	Colour	Furan	IFT	kV (ASTM D1816)	kV (ASTM D877)	Moisture	pf@ 25 °C
07/07/2010	0.07		110	22.7	52	21	32	0.17
06/07/2012	0.08	3.5	102	21.9	59	43	8	0.2
01/07/2013	0.08	3.5	102	21.7	46	47	5	0.16
02/07/2014	0.08	3.5	116	22.4	41	45	4	0.16
01/07/2015	0.09	3.5	100	22.5	55	44	3	0.15

Table 2: Dufferin T3 Oil quality from previous years

4.2 Maintenance History , Trouble Calls and Deficiency Report

Standard power transformer maintenance packages are applied on Dufferin T3 per Hydro One Work Standard Document SM-54-007 (main tank) and SM-54-014(ULTC) respectively.

Maintenance Item	2011	2012	2013	2014	2015	2016	2017
TF-GENERAL-D1 (4 year interval)	(CR01-2010)				CR01		
TF-GENERAL-D2[1] (8 year interval)							
TF-GENERAL-DBT (8 year interval)	CR01						
TF-GENERAL-GOT (Annual)	CR01	CR01	CR01	CR01	CR02	x	x
UT-MR-CI -UTOA (X) (Annual)	CR01	CR01	CR01	CR01	CR01	x	x
UT-MR-CI -UTOA (Y) (Annual)	CR01	CR01	CR01	CR01	CR01	x	x
UT- MR-CI -SI (X) (2 year interval)		CR01		CR01		CR01	
UT- MR-CI -SI (Y) (2 year interval)		CR01		CR01		CR01	

Table 3 : Preventive maintenance summary of T3 and future schedule (marked by x)

A list of all Preventive maintenance results are appended in Appendix I. It is concluded that preventive maintenance results are satisfactory.

Equipment Obsolescence

T3 is a Westinghouse Transformer that uses a 3 individual MR C-I tap changers. The original manufacturer still provides parts and services to this type of tap changer. Some parts are no longer available off-the-shelf. Depending on parts and maintenance required, it will require original manufacturer (MR) to fabricate on demand, with up to 10 weeks lead time. Hydro One Inc. will require technical assistance from MR to assign technicians with specialized skills set from Germany to support.

Trouble calls/deficiency report

Lists of trouble calls/deficiency report are reviewed appended in Appendix II. It is concluded that defects found are typical of its age, minor and manageable. Highlights include:

[1] D2 maintenance was only initiated in 2011 on an 8 year interval.

1. Unreliable tap changer with repeated "run-away" annunciation, where T3's tap changer automatically raised its tap in 2012 and 2016. Problem resolved itself when field personnel arrived at site and performed trouble-shooting [SAP Ref. notification : 11886034, 14541709]
2. Some oil leaks reported from top of transformer.[SAP Ref. notification : 12867963]
3. Gas accumulation relay operated 2016 May[2]. Pre-cautionary special oil samples taken with CR03 result. Resample pending. [SAP Ref. notification : 14652985]
4. Minor cooling and auxiliary devices defects including oil monitor and cooling [SAP Ref. notification : 12867963, 13536741, 10489522]

5 Potential Environmental Risk/HSE

5.1 Spill Risk Assessment

Dufferin is ranked as low-moderate risk for spill containment (63) of 256 stations based on existing risk score from a 2011 spill risk report by Conestoga-Rogers & Associates [1]. Dufferin T3 is equipped with containment/station catch basin.

5.2 PCB content

Table below summarized the latest PCB content detected in various part of the equipment. Hydro One is obligated to remove or retrofit equipment with PCB contamination >50ppm per Environment Canada regulation by 2025. Currently all 11 bushings have no PCB results because these bushings are sealed design [SAP Ref. Notification: 13944172, 139441723, 139441724, 13944175, 13944176, 13944177, 13944178, 13944179, 13944190, 13944191]

Equipment	Description	Date	PCB (ppm)	Lab Reference
1175626	TF: Stepdn - 80MVA 110-14.2-14.2kV	1/7/2015	10	M275350A
1222528	(XB) TF: ULTC - 13 kV Div	7/3/2014	11	M262711A
1222531	(XR) TF: ULTC - 13 kV Div	6/15/2015	12	M288733A
1222533	(XW) TF: ULTC - 13 kV Div	6/15/2015	11	M288734A
1222535	(YB) TF: ULTC - 13 kV Div	6/15/2015	11	M288738A
1222537	(YR) TF: ULTC - 13 kV Div	6/15/2015	11	M288736A
1222539	(YW) TF: ULTC - 13 kV Div	6/15/2015	11	M288737A
1223860	(Y2) - BUSHING: 15 kV	n/a	unknown	n/a
1223861	(Y1) - BUSHING: 15 kV	n/a	unknown	n/a
1223863	(Y0) - BUSHING: 15 kV	n/a	unknown	n/a
1223865	(X3) - BUSHING: 15 kV	n/a	unknown	n/a
1223867	(X2) - BUSHING: 15 kV	n/a	unknown	n/a
1223868	(X1) - BUSHING: 15 kV	n/a	unknown	n/a
1223870	(X0) - BUSHING: 15 kV	n/a	unknown	n/a
1223872	(H3) - BUSHING: 115 kV	n/a	unknown	n/a
1223874	(H1) - BUSHING: 115 kV	n/a	unknown	n/a
1223876	(H2) - BUSHING: 115 kV	n/a	unknown	n/a
1223877	(Y3) - BUSHING: 15 kV	n/a	unknown	n/a

[2] Gas accumulation relay is designed to detects incipient fault within the main tank.

6 Equipment Loading

Dufferin T3, is 40/60/80 MVA, dual secondary units (20/30/40) with summer and winter Limited Time Rating (LTR) are as follows:

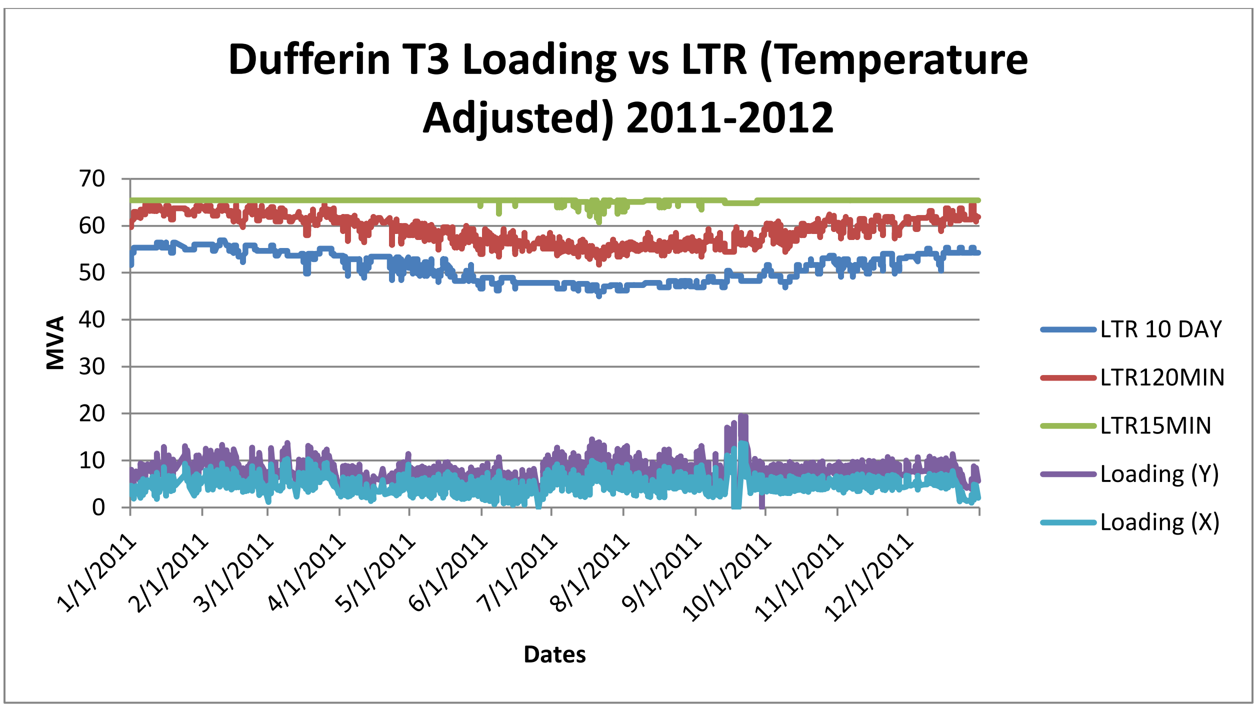
T3X:

Summer 10d LTR (31 ºC)	Winter 10d LTR (5ºC)
46MVA	54MVA

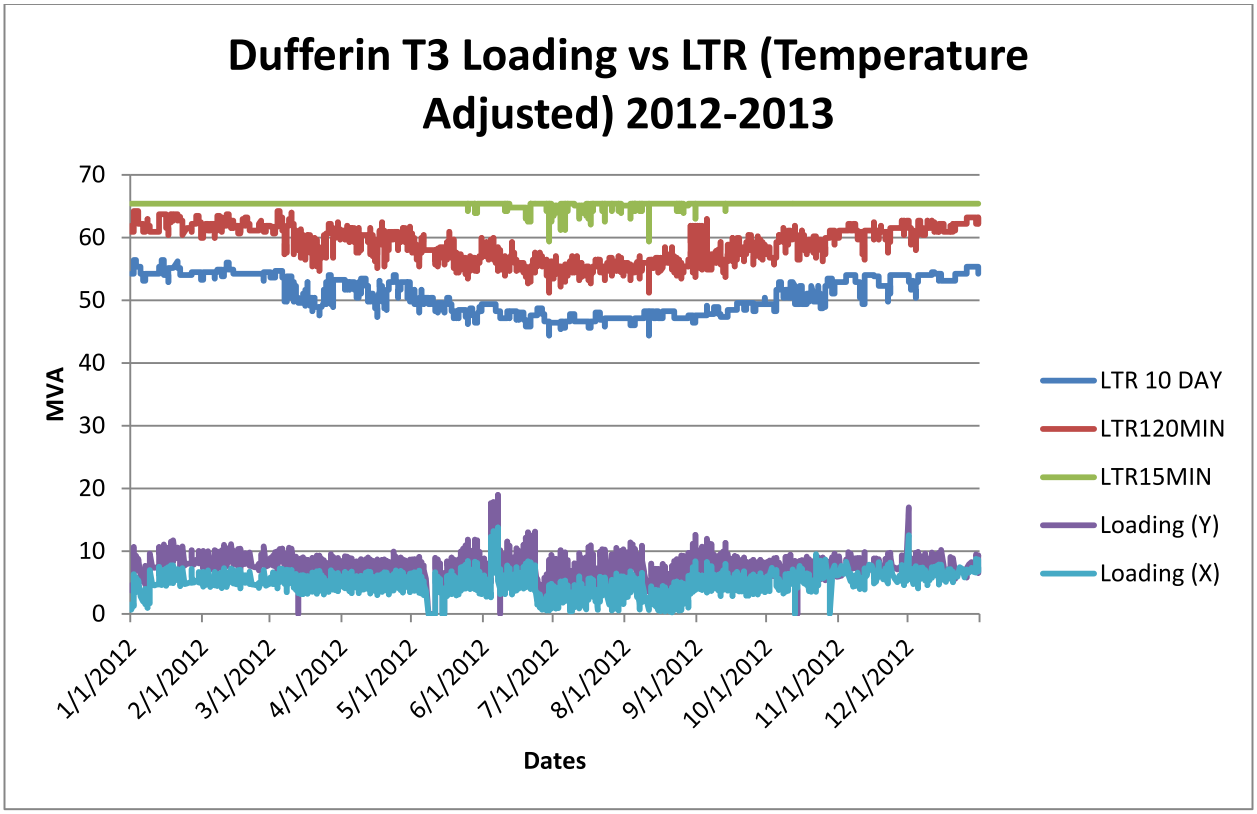
T3Y:

Summer 10d LTR (31 ºC)	Winter 10d LTR (5ºC)
46MVA	54MVA

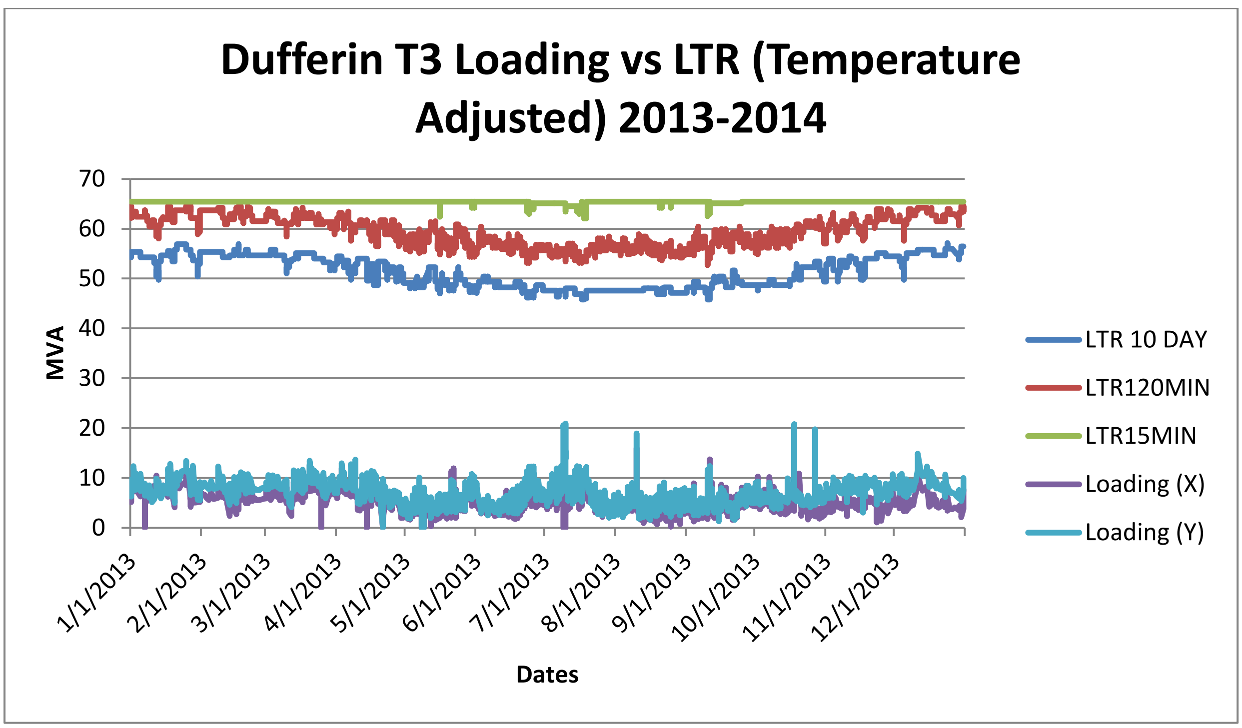
Dufferin T3's loading was reviewed with respect to its temperature adjusted LTR from 2011 -2015. It is observed T3's loading is positioned well below various loading limits. Loading surges were observed in occasionally but within acceptable limits.



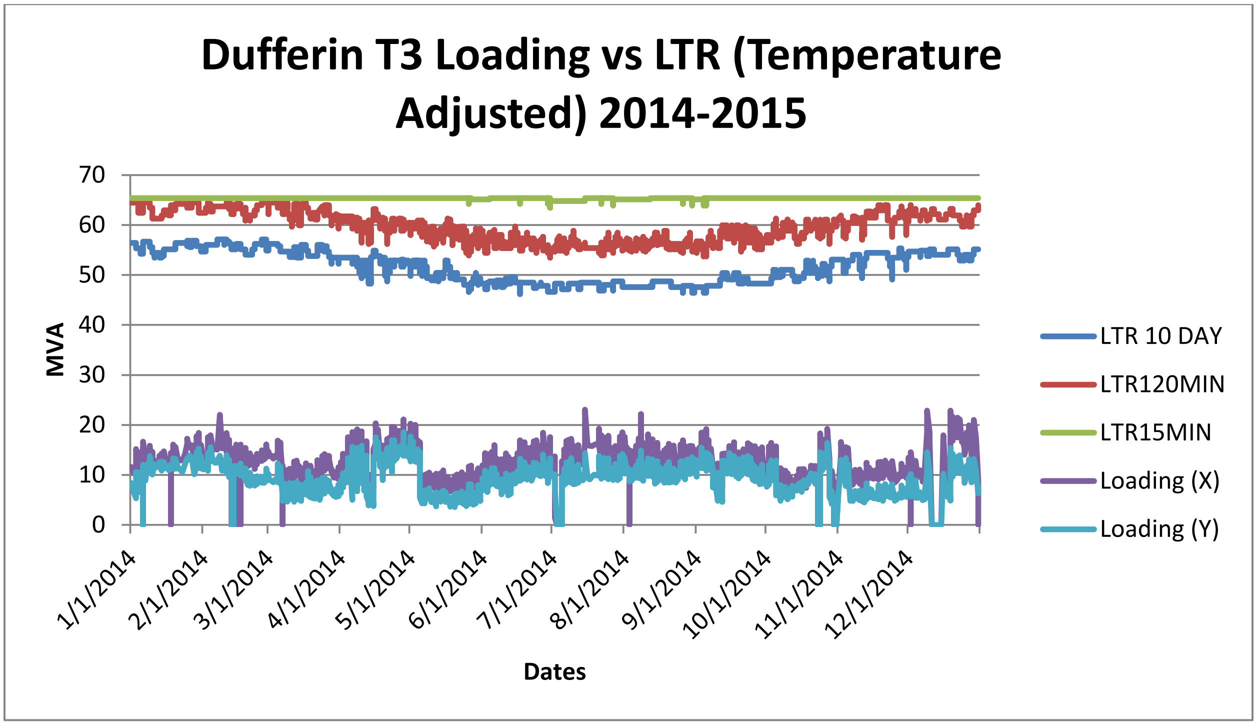
Graph 1: Dufferin T3Loading vs LTR (Temperature Adjusted) 2011-2012



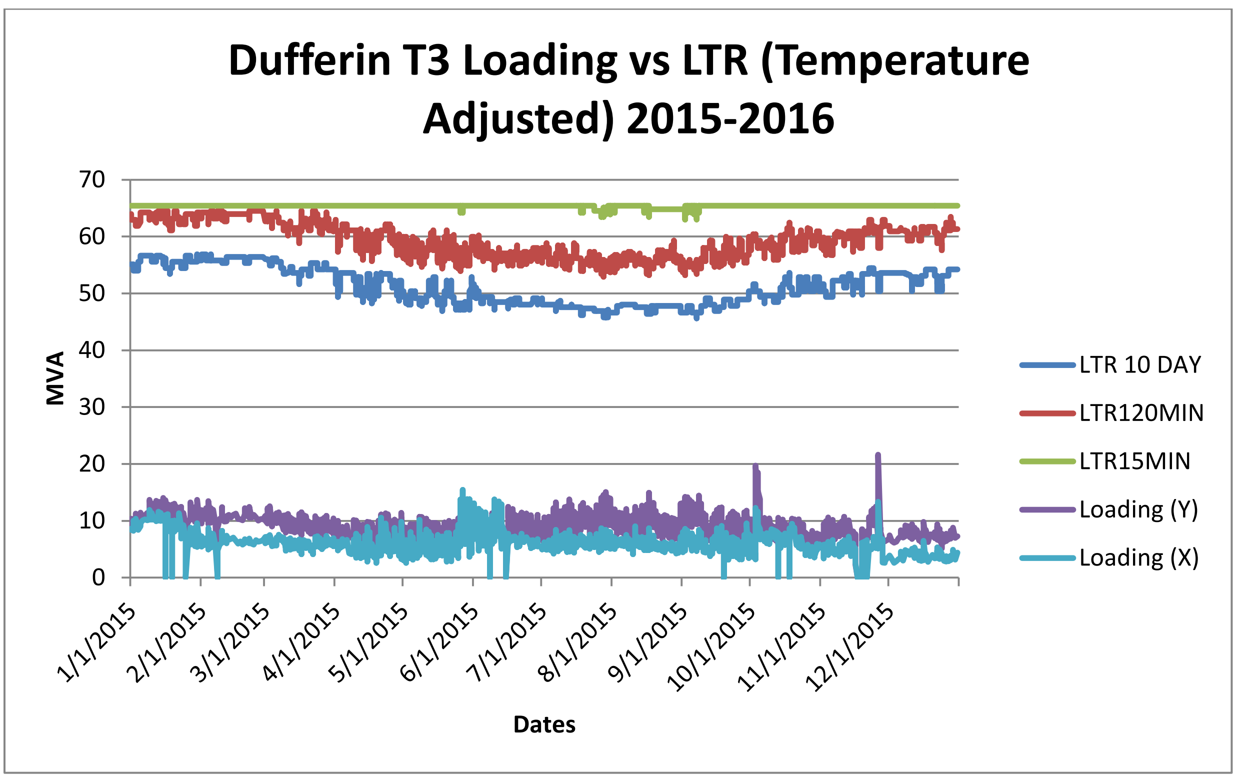
Graph 2: Dufferin T3 Loading vs LTR (Temperature Adjusted) 2012-2013



Graph 3: Dufferin T3 Loading vs LTR (Temperature Adjusted) 2013-2014



Graph 4: Dufferin T3 Loading vs LTR (Temperature Adjusted) 2014-2015



Graph 5: Dufferin T3 Loading vs LTR (Temperature Adjusted) 2015 Jan -2015 Dec

7 Economics

7.1 Recorded OM&A Spending.

Table 4 summarized OM&A incurred on Dufferin T3 since SAP inception in 2008. It is concluded that spending is higher than expected

Higher upgrade costs in 2013 was associated with LTC modifications on X & Y side where the energy accumulator was replaced [Ref order: 60323757, 60546316]

Year	CORR	EMER	OPER	PREV	UPGR	Grand Total
2008				$ 24,276.60		$ 24,276.60
2009			$ 432.50	$ 30,376.00		$ 30,808.50
2010	$ 6,427.53	$ 528.12	$ 1,733.95	$ 30,991.76		$ 39,681.36
2011	$ 2,601.67		$ -	$ 9,541.76	$ 117,044.21	$ 129,187.64
2012	$ 1,661.21			$ 14,845.36		$ 16,506.57
2013				$ 2,161.66		$ 2,161.66
2014	$ 73.23			$ 23,112.30		$ 23,185.53
2015			$ 852.08	$ 7,525.03		$ 8,377.11
Grand Total	**$ 10,763.64**	**$ 528.12**	**$ 3,018.53**	**$ 142,830.47**	**$ 117,044.21**	**$ 274,184.97**

Table 4 : Historical OM&A spending on T3

PREV Maintenance Activity	Average Actual Cost (2013 - 2015)	Applicable to unit under assessment
TAP CHANGER OIL SAMPLES	$ 370.51	✓
TAP CHANGER SI	$ 3373.57[3]	✓
TRANSFORMER DBT --General	$ 5,660.90	✓
TRANSFORMER D1 --General	$ 3,862.40	✓
TRANSFORMER D2 --General	$ 3,517.07	✓
TRANSFORMER OIL SAMPLES --General	$ 300.57	✓

Table 5: Unit cost of various Preventative Maintenance Activities. Based on actual unit cost from 2013-2015

[3] Due to number of tap changers (6) in service, unit cost adjusted utilizing actual cost data specific to Dufferin T3 since 2008 for higher accuracy in NPV calculation purpose. Normal unit price is $7019

7.2 Net Present Value Analysis

This session evaluates the cost benefit for various asset management options (sustain, repair , replacement) of T3 with Net Present Value Analysis(NPV)

The study makes the following assumptions:

- Study period : 55 years[4]
- T3 will undergo refurbishment/ repair at 52 year old (2016), at approx. CAD$583.8k[5].
- Replacement cost is assumed to be CAD$5.8M[6] for a unit that matches purchasing standard S115-101
- The new unit will benefit from lower OM&A cost because it will be equipped with vacuum tap changer. Estimated interval for internal inspection is lengthen to 12 years. New unit will utilize Buchholz relay and eliminate D2 maintenance task.
- Inflation : 2%. [2]
- Cost of Capital: 5.78% [2]
- Corporate Tax rate : 26.5% [2]
- CCA rate for Transmission Asset : 8% [2]
- Disposal Value : $0
- Corrective cost not factored in.

NPV of 3 options (Status Quo Maintain, Repair and Replace) are evaluated under the aforementioned assumptions. In general, NPV calculation has preferred the option to maintain status quo and wait for replacement. Should a repair becomes necessary, the break-even point between Repair vs Replace options that results in NPV = $0, is the sum of the anticipated repair cost less the PV difference between repair vs replace option (CAD $583.8K - CAD $310.92K = CAD $272.08). The evaluation concludes that it is cheaper to advance replacement starting 2016 should a major repair becomes necessary. The result is within expectations as the new unit will have a much lower OM&A requirement compared to the existing unit.

Result Summary	Status Quo Maintain	Major Investment Maintain/Repair	Replace	Preferred Option
With CCA tax savings				
PV of Options, $k, with terminal value	4728.96	5299.85	4988.92	
PV of Options, $k, terminal value = 0	4751.21	5322.09	4988.92	
Investment Decision		NPV, $k		
Status Quo Maintain - Refurbish		-570.88		Maintain
Major Investment (Repair/Refurbish) - Replace		310.92		Replace
Repair - Replace boundary			272.08	
Repair - Replace boundary, upper bound			299.28	
Repair - Replace boundary, lower bound			244.87	

Table 4: Present Value comparison for different sustainment options

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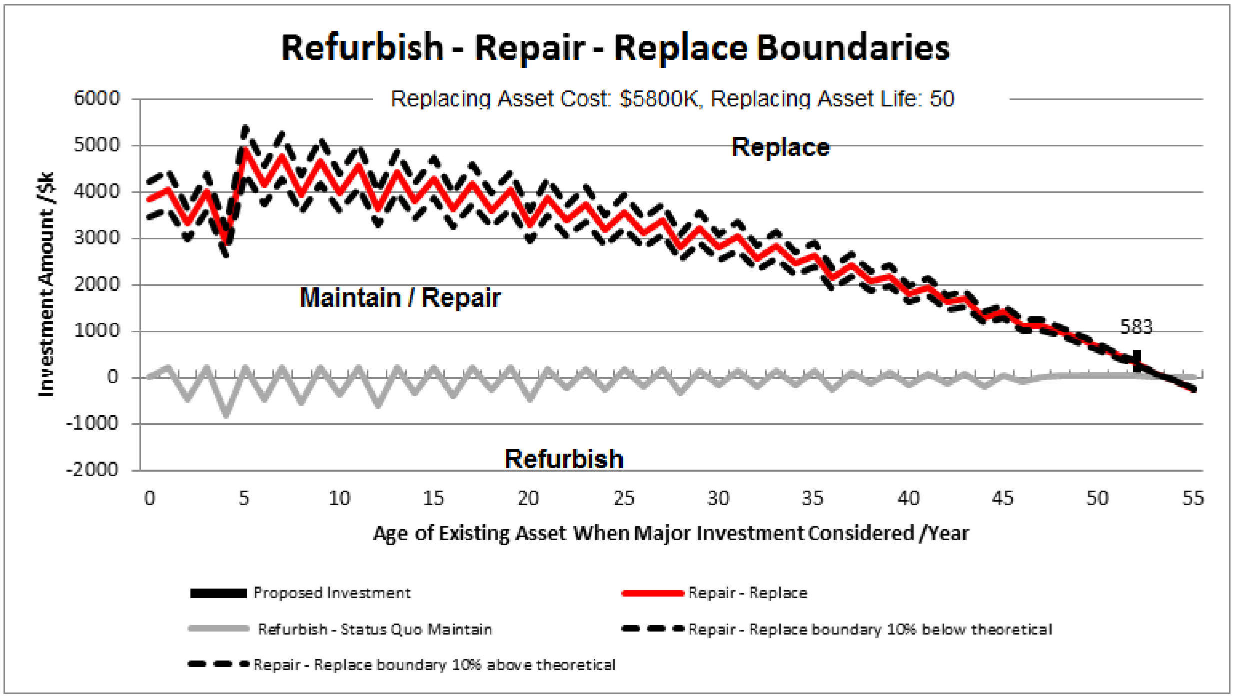
4 Study period lengthen to 55 to accommodate the fact that the unit is already 52 years old. Normal study period is 50 years.
5 $583.8 K is the 2010 – 2015 recorded average cost to refurbish transformer under AR 18335 (Transformer Oil Leak Reduction)
6 Based on 2015 March, Average I/S Cost for Power Transformers in 115kV class.



Graph 6: Visual Representation of NPV analysis

8 Conclusion

The demographics data, condition data, environmental/HSE hazards, equipment loading and economics related to Dufferin T3 have been reviewed. T3 oil data showed evident signs of insulation degradation, with suspected low energy discharge actives observed starting 2015. T3's tap changer vintage is approaching obsolesce with parts and service that can become expensive and inconvenient to access. T3's overall maintenance history, reported deficiencies and spending has suggested that its tap changer continue to experience deficiencies and required attention despite major upgrade in 2011. A review of T3's loading has revealed that it is lightly loaded with respect to its various loading limits from 2011-2015. A NPV analysis has been performed and has concluded that while it is the cheapest to keep unit in service, a replacement is more economical to perform a repair when the unit reaches 52 years old (2016) due to lower maintenance requirement. In conclusion, a replacement of the unit within 5 years from 2016 would be considered prudent and economical as it can lower reliability risk, avoid potential PCB incompliance and lower future OM&A cost.

9 Reference

[1] Conestoga-Rogers & Associates. (2011). Hydro One Station Spill Risk Model. SIP-EnvMgmt-0100, Mississauga.

[2] Department of Economics and Load Forecasting, Hydro One Networks Inc. (2015), Hydro One Financial Evaluation Model, Toronto.

APPENDIX 1 – PREVENTIVE MAINTENANCE RESULT

Notifictn type	Notification	Functional Loc.	Notif.date	Coding	Description
PR	10001524	N-TS-DUFFERINTS-TF-T3	05/31/2008		TF-GENERAL-M1
PR	10002637	N-TS-DUFFERINTS-TF-T3	05/31/2008		UT-MR/BC-C-D-SI
PR	10002636	N-TS-DUFFERINTS-TF-T3	05/31/2008		UT-MR/BC-C-D-D1
PR	10001442	N-TS-DUFFERINTS-TF-T3	05/31/2008		UT-MR/BC-C-D-SI
PR	10001441	N-TS-DUFFERINTS-TF-T3	05/31/2008		UT-MR/BC-C-D-D1
PR	10002640	N-TS-DUFFERINTS-TF-T3	05/31/2008		UT-MR/BC-C-D-SI
PR	10002639	N-TS-DUFFERINTS-TF-T3	05/31/2008		UT-MR/BC-C-D-D1
PR	10002629	N-TS-DUFFERINTS-TF-T3	05/31/2008	CR01	UT-MR/BC-C-D-D1
PR	10002630	N-TS-DUFFERINTS-TF-T3	05/31/2008	CR01	UT-MR/BC-C-D-SI
PR	10001446	N-TS-DUFFERINTS-TF-T3	05/31/2008		UT-MR/BC-C-D-SI
PR	10001444	N-TS-DUFFERINTS-TF-T3	05/31/2008		UT-MR/BC-C-D-D1
PR	10002634	N-TS-DUFFERINTS-TF-T3	05/31/2008		UT-MR/BC-C-D-SI
PR	10002632	N-TS-DUFFERINTS-TF-T3	05/31/2008	CR01	UT-MR/BC-C-D-D1
PR	10013003	N-TS-DUFFERINTS-TF-T3	06/12/2008		UT-MR/BC-C-D-UTOA
PR	10013005	N-TS-DUFFERINTS-TF-T3	06/12/2008	CR01	UT-MR/BC-C-D-UTOA
PR	10013008	N-TS-DUFFERINTS-TF-T3	06/12/2008		Dufferin TS - T3 XW - UTOA
PR	10013056	N-TS-DUFFERINTS-TF-T3	06/13/2008		UT-MR/BC-C-D-UTOA
PR	10013057	N-TS-DUFFERINTS-TF-T3	06/13/2008	CR01	UT-MR/BC-C-D-UTOA
PR	10237756	N-TS-DUFFERINTS-TF-T3	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI
PR	10237783	N-TS-DUFFERINTS-TF-T3	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI
PR	10237784	N-TS-DUFFERINTS-TF-T3	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI
PR	10237785	N-TS-DUFFERINTS-TF-T3	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI
PR	10237786	N-TS-DUFFERINTS-TF-T3	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI
PR	10237787	N-TS-DUFFERINTS-TF-T3	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI
PR	10237788	N-TS-DUFFERINTS-TF-T3	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI
PR	10237789	N-TS-DUFFERINTS-TF-T3	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI

PR	10237790	N-TS-DUFFERINTS-TF-T3	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI
PR	10237791	N-TS-DUFFERINTS-TF-T3	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI
PR	10237792	N-TS-DUFFERINTS-TF-T3	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI
PR	10237793	N-TS-DUFFERINTS-TF-T3	12/22/2008	CR01	STN 'A' PWR EQ INSP-SVI
PR	10256045	N-TS-DUFFERINTS-TF-T3	01/19/2009		UT-MR/BC-C-D-UTOA
PR	10256046	N-TS-DUFFERINTS-TF-T3	01/19/2009		UT-MR/BC-C-D-UTOA
PR	10256047	N-TS-DUFFERINTS-TF-T3	01/19/2009		UT-MR/BC-C-D-UTOA
PR	10256048	N-TS-DUFFERINTS-TF-T3	01/19/2009		UT-MR/BC-C-D-UTOA
PR	10256090	N-TS-DUFFERINTS-TF-T3	01/19/2009	CR01	UT-MR/BC-C-D-UTOA
PR	10256049	N-TS-DUFFERINTS-TF-T3	01/19/2009		UT-MR/BC-C-D-UTOA
PR	10289699	N-TS-DUFFERINTS-TF-T3	04/17/2009	CR01	UT-MR/BC-C-D-SI
PR	10289698	N-TS-DUFFERINTS-TF-T3	04/17/2009	CR01	UT-MR/BC-C-D-D1
PR	10289950	N-TS-DUFFERINTS-TF-T3	04/17/2009	CR01	UT-MR/BC-C-D-D1
PR	10289951	N-TS-DUFFERINTS-TF-T3	04/17/2009		UT-MR/BC-C-D-SI
PR	10289697	N-TS-DUFFERINTS-TF-T3	04/17/2009	CR01	UT-MR/BC-C-D-SI
PR	10319127	N-TS-DUFFERINTS-TF-T3	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10319154	N-TS-DUFFERINTS-TF-T3	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10319155	N-TS-DUFFERINTS-TF-T3	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10319156	N-TS-DUFFERINTS-TF-T3	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10319157	N-TS-DUFFERINTS-TF-T3	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10319158	N-TS-DUFFERINTS-TF-T3	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10319159	N-TS-DUFFERINTS-TF-T3	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10319160	N-TS-DUFFERINTS-TF-T3	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10319161	N-TS-DUFFERINTS-TF-T3	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10319162	N-TS-DUFFERINTS-TF-T3	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10319163	N-TS-DUFFERINTS-TF-T3	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10319164	N-TS-DUFFERINTS-TF-T3	06/22/2009	CR01	STN 'A' PWR EQ INSP-SVI
PR	10391637	N-TS-DUFFERINTS-TF-T3	11/11/2009	CR01	TF-GENERAL-GOT
PR	10462835	N-TS-DUFFERINTS-TF-T3	02/03/2010		TF-GENERAL-M1
PR	10462836	N-TS-DUFFERINTS-TF-T3	02/03/2010		TF-GENERAL-D1

PR	10462837	N-TS-DUFFERINTS-TF-T3	02/03/2010	CR01	TF-GENERAL-DBT
PR	10462777	N-TS-DUFFERINTS-TF-T3	02/03/2010		UT-MR/BC-C-D-D1
PR	10463170	N-TS-DUFFERINTS-TF-T3	02/03/2010		UT-MR/BC-C-D-D1
PR	10462778	N-TS-DUFFERINTS-TF-T3	02/03/2010		UT-MR/BC-C-D-D1
PR	10463171	N-TS-DUFFERINTS-TF-T3	02/03/2010		UT-MR/BC-C-D-D1
PR	10474943	N-TS-DUFFERINTS-TF-T3	03/10/2010		UT-MR/BC-C-D-UTOA
PR	10474941	N-TS-DUFFERINTS-TF-T3	03/10/2010		UT-MR/BC-C-D-D1
PR	10474942	N-TS-DUFFERINTS-TF-T3	03/10/2010		UT-MR/BC-C-D-SI
PR	10474936	N-TS-DUFFERINTS-TF-T3	03/10/2010		UT-MR/BC-C-D-SI
PR	10474947	N-TS-DUFFERINTS-TF-T3	03/10/2010	CR01	UT-MR/BC-C-D-UTOA
PR	10474946	N-TS-DUFFERINTS-TF-T3	03/10/2010		UT-MR/BC-C-D-SI
PR	10474945	N-TS-DUFFERINTS-TF-T3	03/10/2010		UT-MR/BC-C-D-D1
PR	10474938	N-TS-DUFFERINTS-TF-T3	03/10/2010		UT-MR/BC-C-D-SI
PR	10474937	N-TS-DUFFERINTS-TF-T3	03/10/2010		UT-MR/BC-C-D-SI
PR	10474939	N-TS-DUFFERINTS-TF-T3	03/10/2010		UT-MR/BC-C-D-SI
PR	10474940	N-TS-DUFFERINTS-TF-T3	03/10/2010		UT-MR/BC-C-D-UTOA
PR	10508725	N-TS-DUFFERINTS-TF-T3	05/25/2010	CR01	STN 'A' PWR EQ INSP-SVI SPRING
PR	10508758	N-TS-DUFFERINTS-TF-T3	05/25/2010	CR01	STN 'A' PWR EQ INSP-SVI SPRING
PR	10508759	N-TS-DUFFERINTS-TF-T3	05/25/2010	CR01	STN 'A' PWR EQ INSP-SVI SPRING
PR	10508760	N-TS-DUFFERINTS-TF-T3	05/25/2010	CR01	STN 'A' PWR EQ INSP-SVI SPRING
PR	10508761	N-TS-DUFFERINTS-TF-T3	05/25/2010	CR01	STN 'A' PWR EQ INSP-SVI SPRING
PR	10508762	N-TS-DUFFERINTS-TF-T3	05/25/2010	CR01	STN 'A' PWR EQ INSP-SVI SPRING
PR	10508763	N-TS-DUFFERINTS-TF-T3	05/25/2010	CR01	STN 'A' PWR EQ INSP-SVI SPRING
PR	10559502	N-TS-DUFFERINTS-TF-T3	09/30/2010	CR02	STN 'A' PWR EQ INSP-SVI FALL
PR	10559535	N-TS-DUFFERINTS-TF-T3	09/30/2010	CR01	STN 'A' PWR EQ INSP-SVI FALL
PR	10559536	N-TS-DUFFERINTS-TF-T3	09/30/2010	CR01	STN 'A' PWR EQ INSP-SVI FALL
PR	10559537	N-TS-DUFFERINTS-TF-T3	09/30/2010	CR01	STN 'A' PWR EQ INSP-SVI FALL
PR	10559538	N-TS-DUFFERINTS-TF-T3	09/30/2010	CR01	STN 'A' PWR EQ INSP-SVI FALL
PR	10559539	N-TS-DUFFERINTS-TF-T3	09/30/2010	CR01	STN 'A' PWR EQ INSP-SVI FALL
PR	10559540	N-TS-DUFFERINTS-TF-T3	09/30/2010	CR01	STN 'A' PWR EQ INSP-SVI FALL

PR	10561191	N-TS-DUFFERINTS-TF-T3	10/04/2010		TF-GENERAL-GOT
PR	10663304	N-TS-DUFFERINTS-TF-T3	03/03/2011	CR03	STN 'A' PWR EQ INSP-SVI SPRING 2011
PR	10663339	N-TS-DUFFERINTS-TF-T3	03/03/2011	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2011
PR	10663340	N-TS-DUFFERINTS-TF-T3	03/03/2011	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2011
PR	10663341	N-TS-DUFFERINTS-TF-T3	03/03/2011	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2011
PR	10663346	N-TS-DUFFERINTS-TF-T3	03/03/2011	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2011
PR	10663342	N-TS-DUFFERINTS-TF-T3	03/03/2011	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2011
PR	10663343	N-TS-DUFFERINTS-TF-T3	03/03/2011	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2011
PR	10687300	N-TS-DUFFERINTS-TF-T3	05/06/2011		20216 2011 TX PCB Reduction Oil Sample
PR	10711012	N-TS-DUFFERINTS-TF-T3	06/30/2011	CR01	UT-MR-CI-UTOA
PR	10710969	N-TS-DUFFERINTS-TF-T3	06/30/2011	CR01	UT-MR-CI-UTOA
PR	10711010	N-TS-DUFFERINTS-TF-T3	06/30/2011	CR01	UT-MR-CI-UTOA
PR	10711011	N-TS-DUFFERINTS-TF-T3	06/30/2011	CR01	UT-MR-CI-UTOA
PR	10731412	N-TS-DUFFERINTS-TF-T3	09/01/2011	CR01	STN 'A' PWR EQ INSP-SVI FALL 2011
PR	10731457	N-TS-DUFFERINTS-TF-T3	09/01/2011	CR01	STN 'A' PWR EQ INSP-SVI FALL 2011
PR	10731458	N-TS-DUFFERINTS-TF-T3	09/01/2011	CR01	STN 'A' PWR EQ INSP-SVI FALL 2011
PR	10731459	N-TS-DUFFERINTS-TF-T3	09/01/2011	CR01	STN 'A' PWR EQ INSP-SVI FALL 2011
PR	10731460	N-TS-DUFFERINTS-TF-T3	09/01/2011	CR01	STN 'A' PWR EQ INSP-SVI FALL 2011
PR	10731461	N-TS-DUFFERINTS-TF-T3	09/01/2011	CR01	STN 'A' PWR EQ INSP-SVI FALL 2011
PR	10731462	N-TS-DUFFERINTS-TF-T3	09/01/2011	CR01	STN 'A' PWR EQ INSP-SVI FALL 2011
PR	10763842	N-TS-DUFFERINTS-TF-T3	10/20/2011	CR01	UT-MR-CI-SI
PR	10762764	N-TS-DUFFERINTS-TF-T3	10/20/2011	CR01	UT-MR-CI-SI
PR	10763843	N-TS-DUFFERINTS-TF-T3	10/20/2011	CR01	UT-MR-CI-SI
PR	10763837	N-TS-DUFFERINTS-TF-T3	10/20/2011	CR01	UT-MR-CI-SI
PR	10762767	N-TS-DUFFERINTS-TF-T3	10/20/2011	CR01	UT-MR-CI-SI
PR	10763841	N-TS-DUFFERINTS-TF-T3	10/20/2011	CR01	UT-MR-CI-SI
PR	10771927	N-TS-DUFFERINTS-TF-T3	10/21/2011	CR01	TF-GENERAL-GOT
PR	10772476	N-TS-DUFFERINTS-TF-T3	10/21/2011	CR01	UT-MR-CI-UTOA
PR	10771838	N-TS-DUFFERINTS-TF-T3	10/21/2011	CR01	UT-MR-CI-UTOA

PR	10772477	N-TS-DUFFERINTS-TF-T3	10/21/2011	CR01	UT-MR-CI-UTOA
PR	10772469	N-TS-DUFFERINTS-TF-T3	10/21/2011	CR01	UT-MR-CI-UTOA
PR	10771840	N-TS-DUFFERINTS-TF-T3	10/21/2011	CR01	UT-MR-CI-UTOA
PR	10772475	N-TS-DUFFERINTS-TF-T3	10/21/2011	CR01	UT-MR-CI-UTOA
PR	10816133	N-TS-DUFFERINTS-TF-T3	12/13/2011	CR01	20216 Tx PCB sample 2012
PR	10884178	N-TS-DUFFERINTS-TF-T3	04/11/2012	CR01	STN 'A' PWR EQ INSP-SVI SPR 2012
PR	10884213	N-TS-DUFFERINTS-TF-T3	04/11/2012	CR01	STN 'A' PWR EQ INSP-SVI SPR 2012
PR	10884214	N-TS-DUFFERINTS-TF-T3	04/11/2012	CR01	STN 'A' PWR EQ INSP-SVI SPR 2012
PR	10884215	N-TS-DUFFERINTS-TF-T3	04/11/2012	CR01	STN 'A' PWR EQ INSP-SVI SPR 2012
PR	10884216	N-TS-DUFFERINTS-TF-T3	04/11/2012	CR01	STN 'A' PWR EQ INSP-SVI SPR 2012
PR	10884217	N-TS-DUFFERINTS-TF-T3	04/11/2012	CR01	STN 'A' PWR EQ INSP-SVI SPR 2012
PR	10884218	N-TS-DUFFERINTS-TF-T3	04/11/2012	CR01	STN 'A' PWR EQ INSP-SVI SPR 2012
PR	11678965	N-TS-DUFFERINTS-TF-T3	09/10/2012	CR01	20216 Tx PCB sample 2012
PR	11678967	N-TS-DUFFERINTS-TF-T3	09/10/2012	CR01	20216 Tx PCB sample 2012
PR	11678982	N-TS-DUFFERINTS-TF-T3	09/10/2012	CR01	20216 Tx PCB sample 2012
PR	11678983	N-TS-DUFFERINTS-TF-T3	09/10/2012	CR01	20216 Tx PCB sample 2012
PR	11678984	N-TS-DUFFERINTS-TF-T3	09/10/2012	CR01	20216 Tx PCB sample 2012
PR	11678969	N-TS-DUFFERINTS-TF-T3	09/10/2012	CR01	20216 Tx PCB sample 2012
PR	11678985	N-TS-DUFFERINTS-TF-T3	09/10/2012	CR01	20216 Tx PCB sample 2012
PR	11678986	N-TS-DUFFERINTS-TF-T3	09/10/2012	CR01	20216 Tx PCB sample 2012
PR	11678987	N-TS-DUFFERINTS-TF-T3	09/10/2012	CR01	20216 Tx PCB sample 2012
PR	11678981	N-TS-DUFFERINTS-TF-T3	09/10/2012	CR01	20216 Tx PCB sample 2012
PR	11678988	N-TS-DUFFERINTS-TF-T3	09/10/2012	CR01	20216 Tx PCB sample 2012
PR	11825212	N-TS-DUFFERINTS-TF-T3	10/13/2012	CR01	TF-GENERAL-GOT
PR	11825957	N-TS-DUFFERINTS-TF-T3	10/13/2012	CR01	UT-MR-CI-UTOA
PR	11825042	N-TS-DUFFERINTS-TF-T3	10/13/2012	CR01	UT-MR-CI-UTOA
PR	11825959	N-TS-DUFFERINTS-TF-T3	10/13/2012	CR01	UT-MR-CI-UTOA
PR	11825952	N-TS-DUFFERINTS-TF-T3	10/13/2012	CR01	UT-MR-CI-UTOA
PR	11825046	N-TS-DUFFERINTS-TF-T3	10/13/2012	CR01	UT-MR-CI-UTOA
PR	11825955	N-TS-DUFFERINTS-TF-T3	10/13/2012	CR01	UT-MR-CI-UTOA

PR	12144853	N-TS-DUFFERINTS-TF-T3	04/12/2013	CR01	STN 'A' PWR EQ INSP-SVI SPR 2013
PR	12144906	N-TS-DUFFERINTS-TF-T3	04/12/2013	CR01	STN 'A' PWR EQ INSP-SVI SPR 2013
PR	12144833	N-TS-DUFFERINTS-TF-T3	04/12/2013	CR01	STN 'A' PWR EQ INSP-SVI SPR 2013
PR	12144834	N-TS-DUFFERINTS-TF-T3	04/12/2013	CR01	STN 'A' PWR EQ INSP-SVI SPR 2013
PR	12144903	N-TS-DUFFERINTS-TF-T3	04/12/2013	CR01	STN 'A' PWR EQ INSP-SVI SPR 2013
PR	12144835	N-TS-DUFFERINTS-TF-T3	04/12/2013	CR01	STN 'A' PWR EQ INSP-SVI SPR 2013
PR	12144836	N-TS-DUFFERINTS-TF-T3	04/12/2013	CR01	STN 'A' PWR EQ INSP-SVI SPR 2013
PR	12644130	N-TS-DUFFERINTS-TF-T3	09/26/2013	CR01	TF-GENERAL-GOT
PR	12645295	N-TS-DUFFERINTS-TF-T3	09/26/2013	CR01	UT-MR-CI-UTOA
PR	12643963	N-TS-DUFFERINTS-TF-T3	09/26/2013	CR01	UT-MR-CI-UTOA
PR	12645296	N-TS-DUFFERINTS-TF-T3	09/26/2013	CR01	UT-MR-CI-UTOA
PR	12645276	N-TS-DUFFERINTS-TF-T3	09/26/2013	CR01	UT-MR-CI-UTOA
PR	12643966	N-TS-DUFFERINTS-TF-T3	09/26/2013	CR01	UT-MR-CI-UTOA
PR	12645293	N-TS-DUFFERINTS-TF-T3	09/26/2013	CR01	UT-MR-CI-UTOA
PR	12660662	N-TS-DUFFERINTS-TF-T3	09/27/2013	CR01	TF-GENERAL-D1
PR	12662316	N-TS-DUFFERINTS-TF-T3	09/27/2013	CR01	UT-MR-CI-SI
PR	12660449	N-TS-DUFFERINTS-TF-T3	09/27/2013	CR01	UT-MR-CI-SI
PR	12662317	N-TS-DUFFERINTS-TF-T3	09/27/2013	CR01	UT-MR-CI-SI
PR	12662311	N-TS-DUFFERINTS-TF-T3	09/27/2013	CR01	UT-MR-CI-SI
PR	12660462	N-TS-DUFFERINTS-TF-T3	09/27/2013	CR01	UT-MR-CI-SI
PR	12662315	N-TS-DUFFERINTS-TF-T3	09/27/2013	CR01	UT-MR-CI-SI
PR	12764005	N-TS-DUFFERINTS-TF-T3	11/08/2013	CR01	STN 'A' PWR EQ INSP-SVI FALL 2013
PR	12764051	N-TS-DUFFERINTS-TF-T3	11/08/2013	CR01	STN 'A' PWR EQ INSP-SVI FALL 2013
PR	12764052	N-TS-DUFFERINTS-TF-T3	11/08/2013	CR01	STN 'A' PWR EQ INSP-SVI FALL 2013
PR	12764053	N-TS-DUFFERINTS-TF-T3	11/08/2013	CR01	STN 'A' PWR EQ INSP-SVI FALL 2013
PR	12764054	N-TS-DUFFERINTS-TF-T3	11/08/2013	CR01	STN 'A' PWR EQ INSP-SVI FALL 2013
PR	12764055	N-TS-DUFFERINTS-TF-T3	11/08/2013	CR01	STN 'A' PWR EQ INSP-SVI FALL 2013
PR	12764056	N-TS-DUFFERINTS-TF-T3	11/08/2013	CR01	STN 'A' PWR EQ INSP-SVI FALL 2013
PR	12888491	N-TS-DUFFERINTS-TF-T3	03/22/2014	CR03	Tx PCB Reduction Oil Sample
PR	13031746	N-TS-DUFFERINTS-TF-T3	06/10/2014	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2014

PR	13031784	N-TS-DUFFERINTS-TF-T3	06/10/2014	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2014
PR	13031789	N-TS-DUFFERINTS-TF-T3	06/10/2014	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2014
PR	13031792	N-TS-DUFFERINTS-TF-T3	06/10/2014	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2014
PR	13031793	N-TS-DUFFERINTS-TF-T3	06/10/2014	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2014
PR	13031794	N-TS-DUFFERINTS-TF-T3	06/10/2014	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2014
PR	13031795	N-TS-DUFFERINTS-TF-T3	06/10/2014	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2014
PR	13369355	N-TS-DUFFERINTS-TF-T3	09/26/2014	CR01	TF-GENERAL-GOT
PR	13369985	N-TS-DUFFERINTS-TF-T3	09/26/2014	CR01	UT-MR-CI-UTOA
PR	13369255	N-TS-DUFFERINTS-TF-T3	09/26/2014	CR01	UT-MR-CI-UTOA
PR	13369987	N-TS-DUFFERINTS-TF-T3	09/26/2014	CR01	UT-MR-CI-UTOA
PR	13369976	N-TS-DUFFERINTS-TF-T3	09/26/2014	CR01	UT-MR-CI-UTOA
PR	13369257	N-TS-DUFFERINTS-TF-T3	09/26/2014	CR01	UT-MR-CI-UTOA
PR	13369983	N-TS-DUFFERINTS-TF-T3	09/26/2014	CR01	UT-MR-CI-UTOA
PR	13845794	N-TS-DUFFERINTS-TF-T3	06/03/2015	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2015
PR	13845877	N-TS-DUFFERINTS-TF-T3	06/03/2015	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2015
PR	13845839	N-TS-DUFFERINTS-TF-T3	06/03/2015	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2015
PR	13845850	N-TS-DUFFERINTS-TF-T3	06/03/2015	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2015
PR	13845878	N-TS-DUFFERINTS-TF-T3	06/03/2015	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2015
PR	13845838	N-TS-DUFFERINTS-TF-T3	06/03/2015	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2015
PR	13845879	N-TS-DUFFERINTS-TF-T3	06/03/2015	CR01	STN 'A' PWR EQ INSP-SVI SPRING 2015
PR	13944172	N-TS-DUFFERINTS-TF-T3	06/29/2015	CR03	Tx PCB Reduction Oil Sample
PR	13944173	N-TS-DUFFERINTS-TF-T3	06/29/2015	CR03	Tx PCB Reduction Oil Sample
PR	13944174	N-TS-DUFFERINTS-TF-T3	06/29/2015	CR03	Tx PCB Reduction Oil Sample
PR	13944175	N-TS-DUFFERINTS-TF-T3	06/29/2015	CR03	Tx PCB Reduction Oil Sample
PR	13944176	N-TS-DUFFERINTS-TF-T3	06/29/2015	CR03	Tx PCB Reduction Oil Sample
PR	13944177	N-TS-DUFFERINTS-TF-T3	06/29/2015	CR03	Tx PCB Reduction Oil Sample
PR	13944178	N-TS-DUFFERINTS-TF-T3	06/29/2015	CR03	Tx PCB Reduction Oil Sample
PR	13944179	N-TS-DUFFERINTS-TF-T3	06/29/2015	CR03	Tx PCB Reduction Oil Sample
PR	13944190	N-TS-DUFFERINTS-TF-T3	06/29/2015	CR03	Tx PCB Reduction Oil Sample
PR	13944191	N-TS-DUFFERINTS-TF-T3	06/29/2015	CR03	Tx PCB Reduction Oil Sample

PR	14042112	N-TS-DUFFERINTS-TF-T3	07/24/2015		TF-GENERAL-GOT
PR	14042436	N-TS-DUFFERINTS-TF-T3	07/24/2015		UT-MR-CI-UTOA
PR	14042061	N-TS-DUFFERINTS-TF-T3	07/24/2015		UT-MR-CI-UTOA
PR	14042437	N-TS-DUFFERINTS-TF-T3	07/24/2015		UT-MR-CI-UTOA
PR	14042431	N-TS-DUFFERINTS-TF-T3	07/24/2015		UT-MR-CI-UTOA
PR	14042062	N-TS-DUFFERINTS-TF-T3	07/24/2015		UT-MR-CI-UTOA
PR	14042435	N-TS-DUFFERINTS-TF-T3	07/24/2015		UT-MR-CI-UTOA
PR	14055582	N-TS-DUFFERINTS-TF-T3	07/25/2015		UT-MR-CI-SI
PR	14054498	N-TS-DUFFERINTS-TF-T3	07/25/2015		UT-MR-CI-SI
PR	14055592	N-TS-DUFFERINTS-TF-T3	07/25/2015		UT-MR-CI-SI
PR	14055578	N-TS-DUFFERINTS-TF-T3	07/25/2015		UT-MR-CI-SI
PR	14054504	N-TS-DUFFERINTS-TF-T3	07/25/2015		UT-MR-CI-SI
PR	14055581	N-TS-DUFFERINTS-TF-T3	07/25/2015		UT-MR-CI-SI
PR	14490719	N-TS-DUFFERINTS-TF-T3	01/05/2016	CR01	STN 'A' PWR EQ INSP-SVI FALL 2015
PR	14490655	N-TS-DUFFERINTS-TF-T3	01/05/2016	CR01	STN 'A' PWR EQ INSP-SVI FALL 2015
PR	14490656	N-TS-DUFFERINTS-TF-T3	01/05/2016	CR01	STN 'A' PWR EQ INSP-SVI FALL 2015
PR	14490657	N-TS-DUFFERINTS-TF-T3	01/05/2016	CR01	STN 'A' PWR EQ INSP-SVI FALL 2015
PR	14490684	N-TS-DUFFERINTS-TF-T3	01/05/2016	CR01	STN 'A' PWR EQ INSP-SVI FALL 2015
PR	14490658	N-TS-DUFFERINTS-TF-T3	01/05/2016	CR01	STN 'A' PWR EQ INSP-SVI FALL 2015
PR	14490659	N-TS-DUFFERINTS-TF-T3	01/05/2016	CR01	STN 'A' PWR EQ INSP-SVI FALL 2015
PR	14668588	N-TS-DUFFERINTS-TF-T3	05/16/2016		TF-GENERAL-(SPECIAL)DGA -MAIN TANK
PR	14905857	N-TS-DUFFERINTS-TF-T3	07/16/2016		TF-GENERAL-GOT
PR	14912240	N-TS-DUFFERINTS-TF-T3	07/16/2016		UT-MR-CI-UTOA
PR	14904714	N-TS-DUFFERINTS-TF-T3	07/16/2016		UT-MR-CI-UTOA
PR	14912242	N-TS-DUFFERINTS-TF-T3	07/16/2016		UT-MR-CI-UTOA
PR	14912204	N-TS-DUFFERINTS-TF-T3	07/16/2016		UT-MR-CI-UTOA
PR	14904718	N-TS-DUFFERINTS-TF-T3	07/16/2016		UT-MR-CI-UTOA
PR	14912209	N-TS-DUFFERINTS-TF-T3	07/16/2016		UT-MR-CI-UTOA

APPENDIX 2 – LIST OF DR AND TC NOTIFICATION

Notifictn type	Notification	Order	Functional Loc.	Notif.date	Description
DR	10120066	60352973	N-TS-DUFFERINTS-TF-T3	09/08/2008	T3 SECONDARY CONNECTION Y SIDE
TC	10472381	60320823	N-TS-DUFFERINTS-TF-T3	02/26/2010	S3-DUFFERIN TS-T3 SWITCHING
DR	10489522	60334027	N-TS-DUFFERINTS-TF-T3	04/16/2010	Repair T3 Gas relay
DR	10538920	60492140	N-TS-DUFFERINTS-TF-T3	09/10/2010	fan not working on transformer T3
DR	11886034	60778650	N-TS-DUFFERINTS-TF-T3	10/24/2012	Dufferin T3 OUT OF STEP REPAIR
DR	12867963	60968321	N-TS-DUFFERINTS-TF-T3	02/13/2014	NT9 Inspect transfrmer for oil leaks
DR	13536741	61116987	N-TS-DUFFERINTS-TF-T3	02/24/2015	T3Y investigate SG contactor
TC	14541709	61272367	N-TS-DUFFERINTS-TF-T3	03/21/2016	SEC 3 - P&C - DUFFERIN TST3 RUNAWAY TAP
DR	14652985	61286326	N-TS-DUFFERINTS-TF-T3	05/11/2016	Dufferin T3 gas accumulation
TC	14943595	61352829	N-TS-DUFFERINTS-TF-T3	07/25/2016	S3 EMD RE: SET T3 COOLING TO MANUAL AT D

Dufferin T4

Transformer Assessment

Keywords: Dufferin, T4, Transformer , Transmission, Station, Assessment

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REVISION HISTORY

Date	Revision	Revision Comments
Feb 17th 2015	0	First draft
Dec 11, 2015	1	Department name and report format change ; updated 2015 PREV , DR/TC information and operating data
Feb 26th, 2016	2	Updated condition information and NPV analysis

APPROVAL SIGNATURES

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Date:	April 5th 2016	April 05, 2016	April 05/2016

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1. Executive Summary

- Built in 1983 and in-serviced 1985, Dufferin T4 is a 45/60/75 MVA, 115 – 14.2-14.2 kV, 3 phase transformer, equipped with CWC-UVT under load tap changer
- Dufferin T4 has been reviewed and assessed based on : 1) Demographics, 2) Equipment condition, 3) Potential or existing environmental/HSE hazards, 4) Equipment Loading , 5) Economics.
- Dufferin T4 has internal overheating , as reflected from DGA samples. Internal inspection has taken place in 2012 but result was inconclusive.
- Dufferin T4 has multiple leaks, with worst leak coming from headboard between main tank and tapchanger compartment
- Dufferin T4's tap changer had hot spot and repeated leaking reported though visual inspection and thermal vision.
- Loading on unit is normal with seasonal fluctuation and within loading limits. Occasionally over 10 day LTR.
- Currently no obsolesce foreseen on tap changer.
- Recommended for replacement within 5 years to lower reliability risk from overheating and maintenance cost.

2. Introduction

This document aims to provide a preliminary assessment of T4. The document will evaluate T4 based on: 1) Demographics, 2) Equipment condition, 3) Potential or existing environmental/HSE hazards, 4) Equipment Loading, 5) Economics

Dufferin T4 is a 45/60/75 MVA, 115 – 14.2-14.2 kV, 3 phase transformer, equipped with CWC-UVT under load tap changer and supplies Toronto Hydro Electric System exclusively. T4 is fed off of L15W circuit.

3. Demographics

Dufferin T4 was manufactured by CW in 1983 and in serviced July 25, 1985; 32 years old as of 2016, 31 years in service. Please refer to below graph for a summary of demographic 115 kV with dual secondary winding.

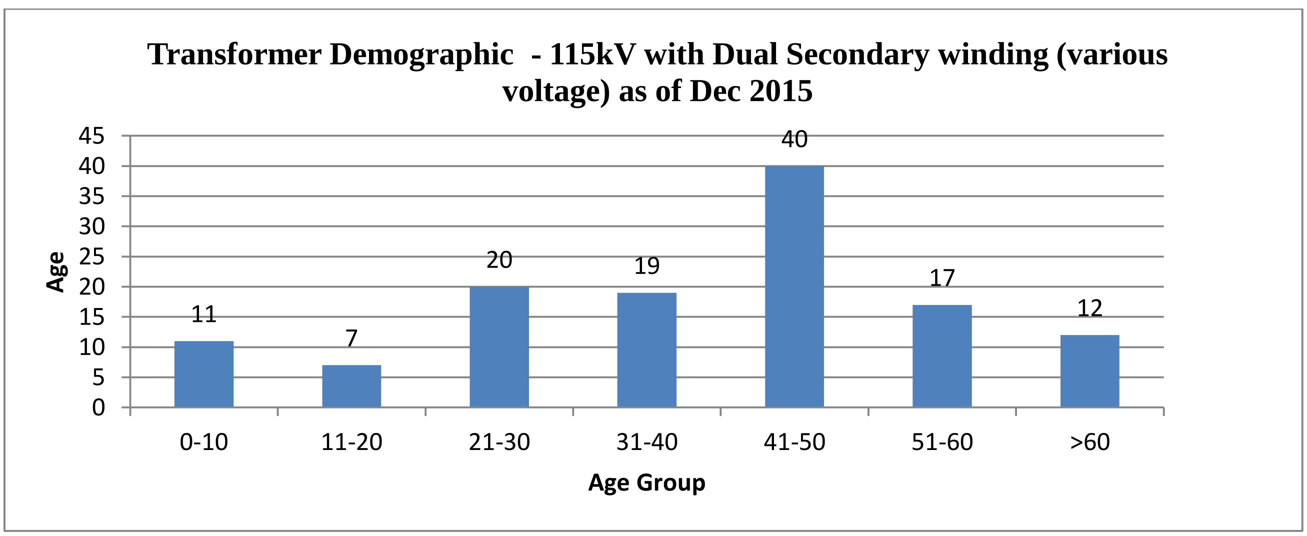


Chart 1: Transformer Demographic - 115kV with Dual Secondary winding (various voltage) as of Dec 2015

4. Equipment Condition

Equipment condition is examined based on: 1) Dissolved Gas Analysis; 2) Preventive Maintenance Result, Trouble Calls and Deficiency Report ;

4.1 Oil analysis Data

Based on oil sample data, it is evident the unit was gassing from thermal /overheating problem in 2011/2012. Increasing level of Ethylene (C2H4), carbon monoxide (CO) and carbon dioxide (CO_2) indicates a hot spot /overheating issue that involves paper insulation. The presence and concentration level of these 3 gases are also close to, or even exceeded warning limits as per PR1127 . Presence of hot spot within the unit was confirmed through thermal vision findings. See section 4.2 for details (Appendix III)

Based on oil sample history, the unit has its oil replaced/degassed in 2012. But it is observed that the combustion gas level within the tank quickly rebounded. It is also observed that that total volume of gas continues to increase year over year.

The colour of insulating oil indicates aged oil. Oil contamination/IFT values are marginally acceptable. See Table 2 Furan, acidity measures are stable.

A hydrogen gas monitor was installed at Dufferin T4 in 2013 due to its tendency to gas.

Note : Dufferin T4 is currently on reinforced dissolved gas analysis sampling cycle (every 3-6 months) by MTS to monitor condition.

Date	C2H2	C2H4	C2H6	CH4	CO	CO2	CO/CO2	H2	N2	O2	Total Vol %
1/31/2011	0	50	5	14	462	2110	0.22	0	65000	23100	18.12
8/24/2011	0	244	26	83	714	2950	0.24	60	68700	19400	9.18
2/10/2012	4	565	69	201	1195	4980	0.24	120	124000	37200	16.79
8/8/2012	0	9	0	0	60	658	0.09	0	46000	16600	6.3
1/7/2013	6	408	48	196	224	1758	0.13	110	105000	39000	14.62
3/25/2013	0	206	23	98	133	930	0.14	45	40000	17900	5.9
5/27/2013	3	202	26	93	187	996	0.19	50	37300	16500	5.51
7/29/2013	0	186	20	80	352	1550	0.23	35	47800	16500	6.63
9/13/2013	3	249	28	109	421	1870	0.23	60	46800	14800	6.42
10/23/2013	2	257	24	105	477	1960	0.24	55	50200	14200	6.7
1/8/2014	3	222	27	88	428	1600	0.27	50	54300	18500	7.48
2/7/2014	0	210	24	82	378	1590	0.24	40	51900	18400	7.24
5/27/2014	3	227	28	89	392	1550	0.25	50	52400	18500	7.29
7/14/2014	0	207	23	51	209	1650	0.13	10	66300	28500	9.65
10/24/2014	0	201	22	64	412	2020	0.20	20	61400	23900	8.77
1/7/2015	0	236	32	82	580	2200	0.26	40	60000	19200	8.19
4/23/2015	0	220	31	70	459	1930	0.24	20	62100	20400	8.48
10/16/2015	0	267	37	88	613	2630	0.23	35	63700	20200	8.71
10/25/2015	0	266	36	92	650	2550	0.25	40	69700	20600	9.37

Table 1 : Dufferin T4 dissolved gas history (in ppm)

Row Labels	Acidity	COLOUR OF INSULATING OIL	Furan	IFT	kV (ASTM D1816)	kV (ASTM D877)	Moisture	P/F @ 25 °C
01/31/2011	0.04	3	13	27.2	34	49	3	0.12
02/10/2012	0.04	3	14	24.7	49	45	6	0.13
01/07/2013	0.04	6	13	27	59	51	4	0.28
02/07/2014	0.03	3	16	27.2	57	48	1	0.09
01/07/2015	0.03	3	15	26.5	67	55	2	0.09

Table 2 : Dufferin T4 oil test result (blank means no data)

4.2 Preventive Maintenance History, Trouble Calls and Deficiency Report

Standard power transformer maintenance packages are applied on Dufferin T4 as per defined in Hydro One's Work Standard Document SM-54-003(Main tank) and SM-54-013 (Tap changer)

Main tank	**Frequency**
Visual-Inspection	6 mon
GOT	3-6 months[1]
DBT	8 yr
D1	4 yr
D2	8 yr

Table 3: Maintenance packages for Dufferin T4 main tank

Tap changer	**Frequency**
Visual inspection	6 mon
UTOA	6 mon
Selective Intrusive (SI)	10 yr

Table 4: Maintenance packages for DUFFERIN T4 Tap Changer

[1] Reinforced sampling cycle. Interval subject to Maintenance Technical Service's recommendation.

Preventive Maintenance schedule and results are summarized in Table 5.

MaintItem text	2011	2012	2013	2014	2015
TF-GENERAL-D1		CR01			
TF-GENERAL-D2		CR01			
TF-GENERAL-DBT		CR01			
TF-GENERAL-GOT	(1)	CR01	CR03	CR03	CR03
UT-CWC-UVT-SI (X)	CR01				
UT-CWC-UVT-SI (Y)	CR01				
UT-CWC-UVT-UTOA (X)	CR01	CR01	CR01	CR01	CR01
UT-CWC-UVT-UTOA (Y)	CR04	CR01	CR03	CR01	CR01

Table 5: Preventative maintenance summary of DUFFERIN T4

(1) Actual complete date Feb 2, 2011, but no CR rating available

It is concluded that maintenance is performed on a timely basis. Oil samples have been consistently rated CR03 on main tank. Refer Section 4.1 for details.

Condition of ULTC oil fluctuates. In 2011, the Y winding's under-load tap changer sample is rated CR04 due to high thermal gasses (order 60492703). Internal inspection found the tap changer has excessive burning on the moving and stationary selector switches on one of the phases. The same compartment's oil sample is rated CR03 due to moisture concerns. A 2nd sample was taken and result came back indicating CR01.

A list of all Preventive maintenance results are appended in Appendix 1.

Equipment Obsolescence

CWC UVT tapchanger is supported by MR. No obsolescence issue foreseen at this stage.

Trouble calls/deficiency report

A list of trouble calls/deficiency report is appended in Appendix 2. Highlights include:

1. Internal gassing problem on both main tank and tapchanger, which resulted in costly internal inspection and repair in 2009 (Order: 60155830) and 2012 (Order: 60695909) respectively. Internal inspection of the main tank was inconclusive.
2. Per SAP, tap changer hot spot detected through thermal vision in 2010 on east end at radiation symbol(Notification 10506145) . See Appendix III for thermo vision report.
3. Repeated oil leaks/oil overflow issue. Part of the leak can be captured with a barrel which requires periodic emptying/clean up. The worst leak comes from the headboard between main tank and tapchanger compartment, according to field assessment.

5 Potential Environmental Risk/HSE

Dufferin TS is ranked 63 (low-moderate risk) for spill containment based on existing risk score from a 2011 spill risk report by Conestoga-Rogers & Associates. [1]

Dufferin T1/T2/T3/T4 are equipped with spill containments. [Ref: NT9-79310-0001-D]

6 Equipment loading

Dufferin T4 is 45/60/75 MVA units with summer and winter LTR as of 2014 are as follows:

Summer 10 day LTR	Winter 10day LTR
95.80 MVA @ 30°C	109.80 MVA @ 5°C

OGCC data shows that Dufferin T4 exhibited annual loading profile from 2011 – 2015 as per Chart 2 to Chart 6. It is observed that loading remained below 10 Day LTR most of the time. However, there are more frequent loading surges that encroached on various LTR limits starting 2013.

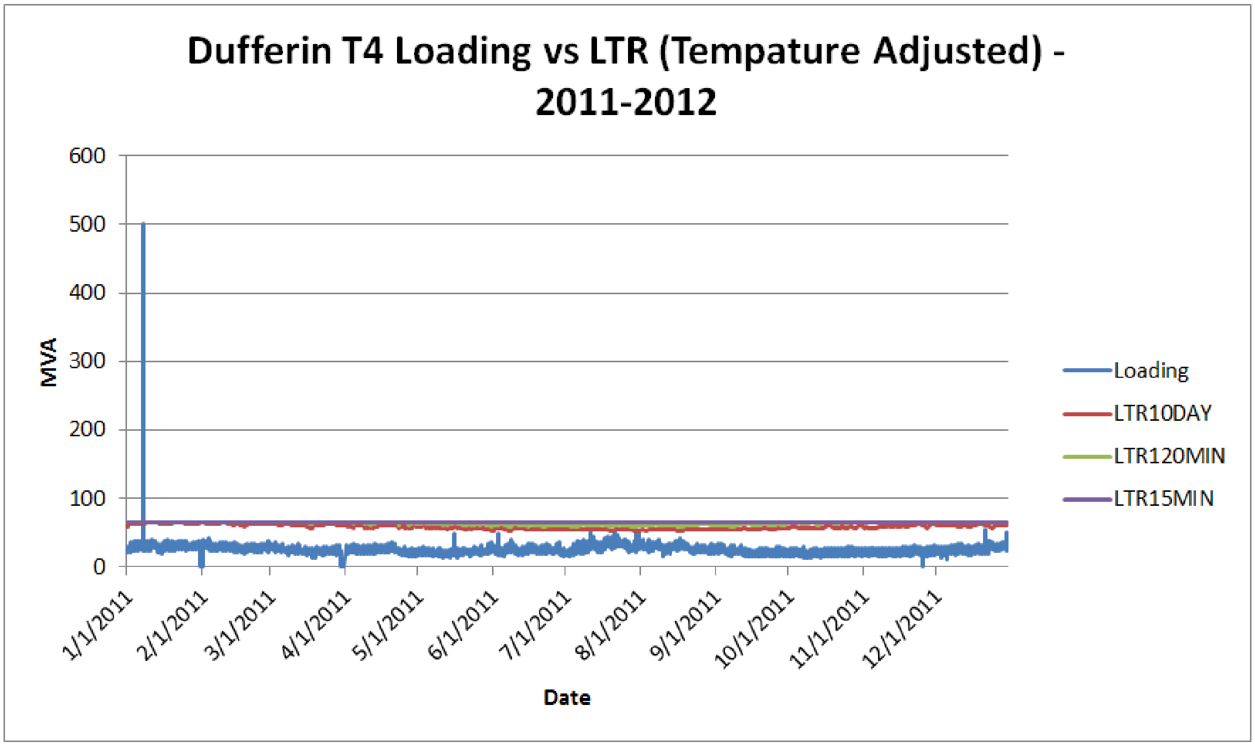


Chart 2 : Dufferin T4 loading vs Temperature Adjusted LTR – 2011

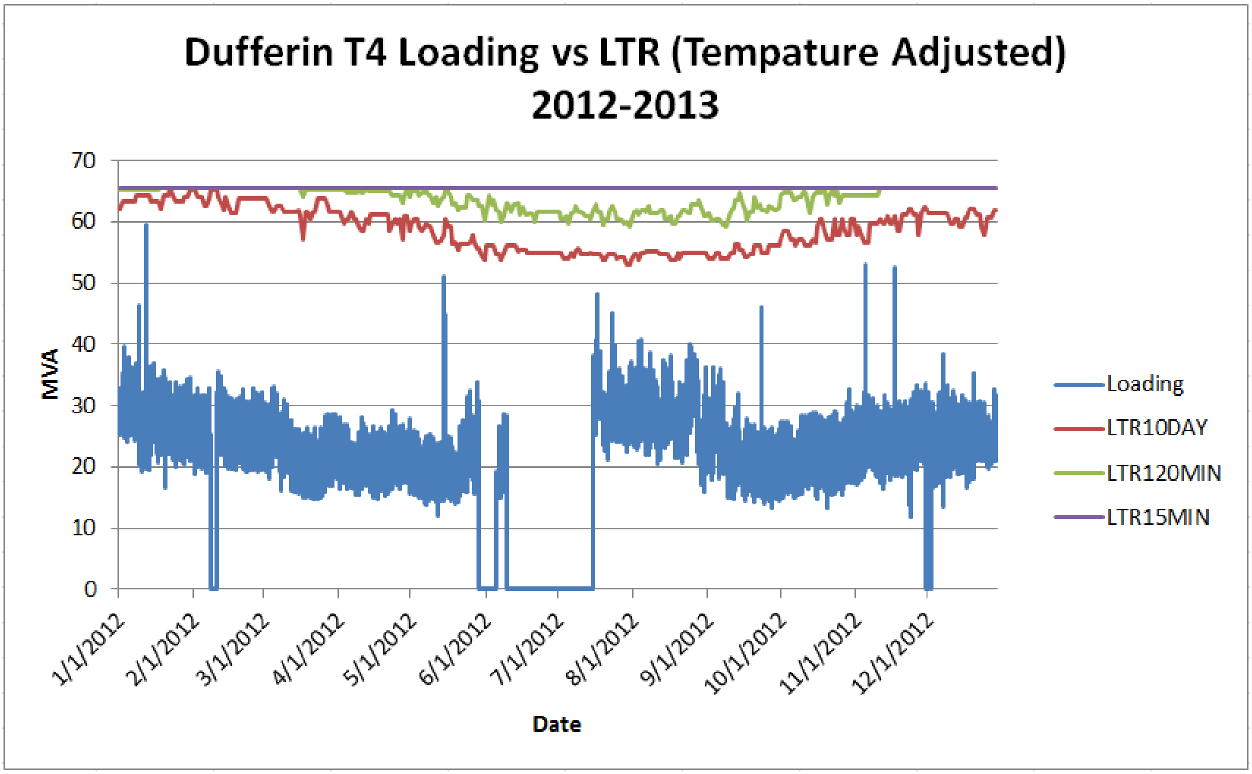


Chart 3 : Dufferin T4 loading vs Temperature Adjusted LTR – 2012

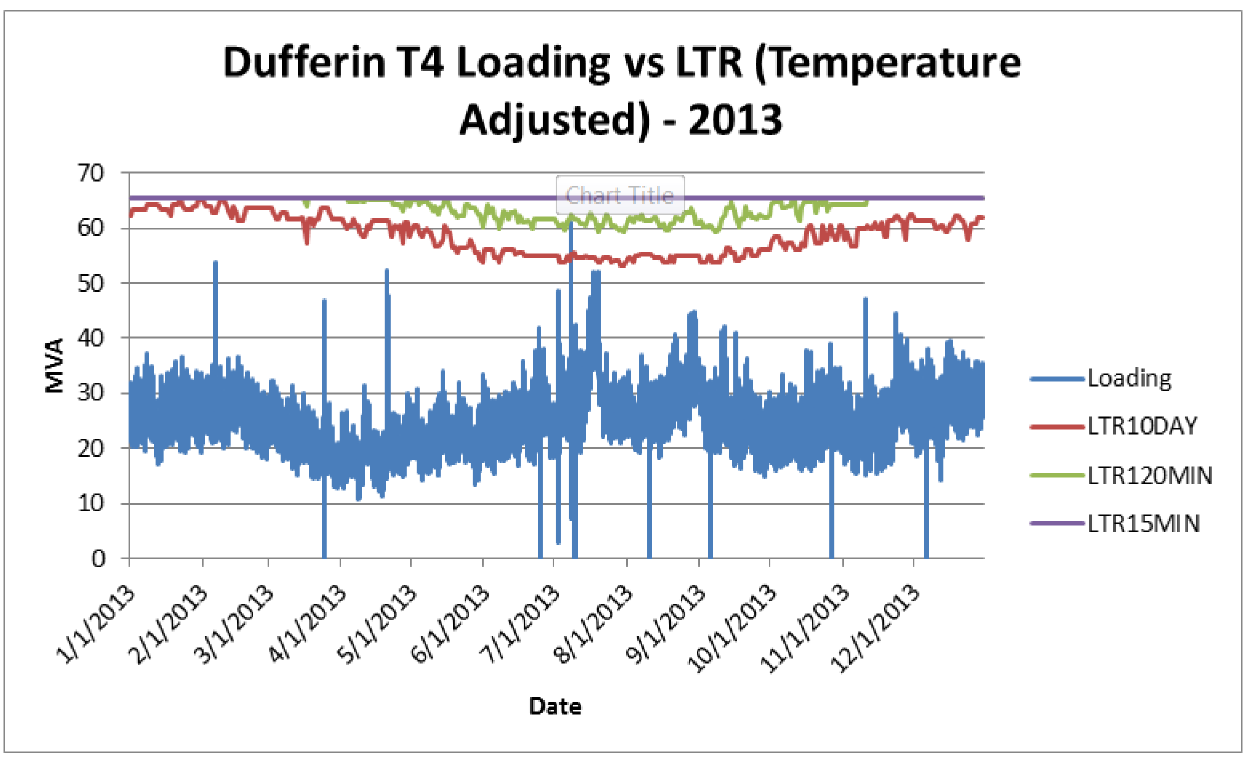


Chart 4 : Dufferin T4 loading vs Temperature Adjusted LTR – 2013

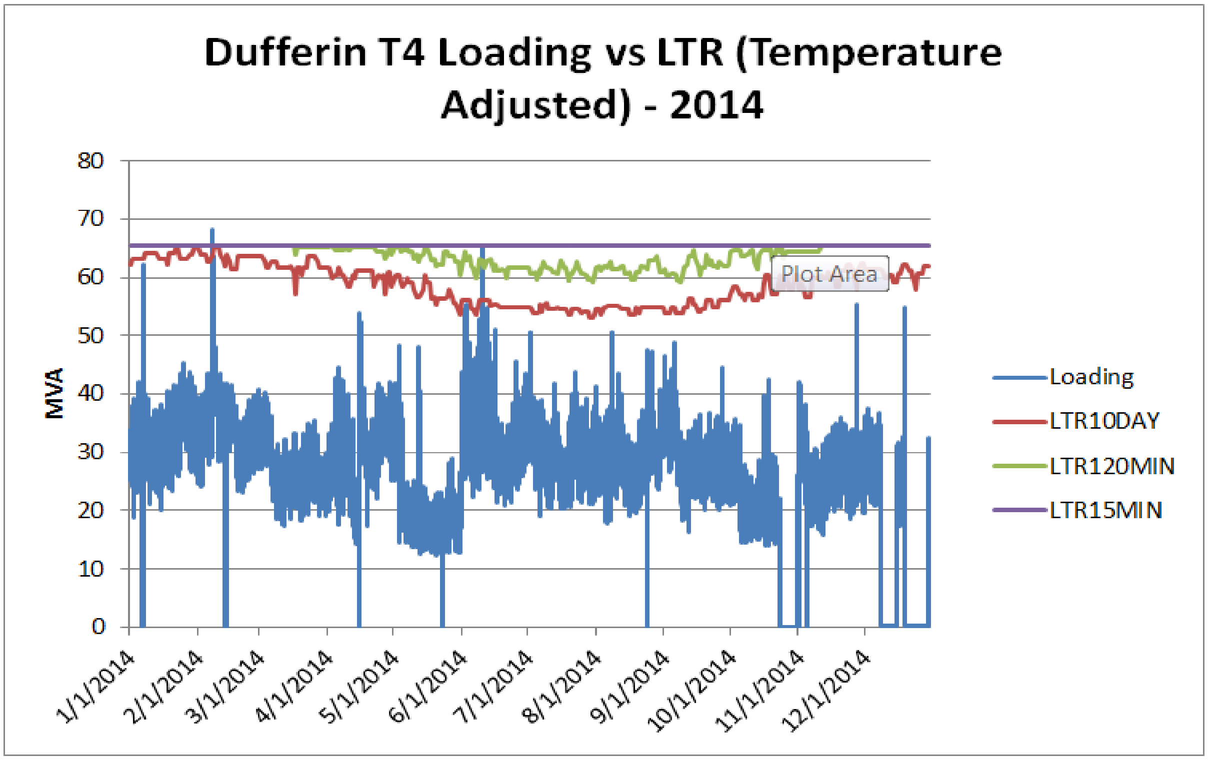


Chart 5 : Dufferin T4 loading vs Temperature Adjusted LTR – 2014

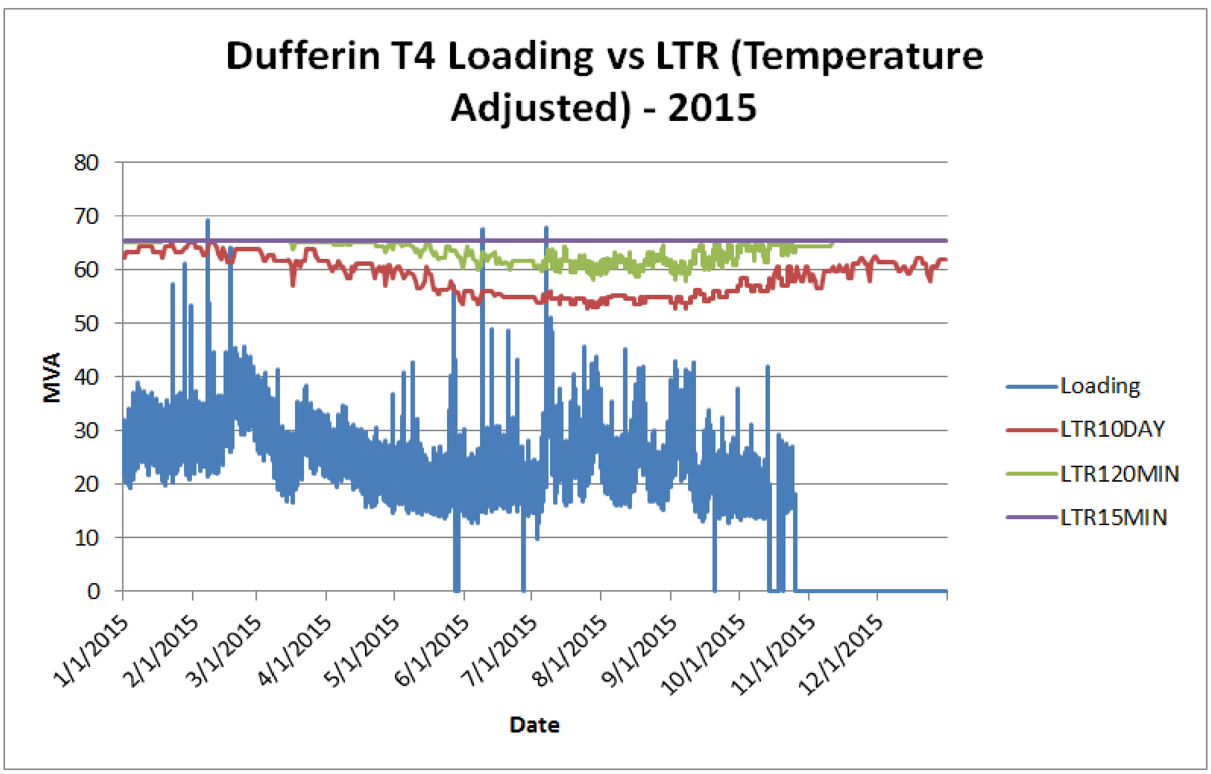


Chart 6 : Dufferin T4 loading vs Temperature Adjusted LTR – 2014

7 Economics

7.1 Net Present Value Analysis

This session evaluates the cost benefit for various asset management options (sustain, repair , replacement) of T4 with Net Present Value Analysis(NPV)

The study makes the following assumptions:

- Study period : 50 years
- T4 will required oil leak repair at 31 year old (2016), at approx. CAD$583.8k[2]. Repair will not be able to address gassing problem internal to the bank, hence unable to restore equipment condition to its original form.
- Annual cost to maintain T4 after refurbishment will decrease by $6000[3] a year due to elimination of oil leaks.
- Assumed reinforced sampling every 4 months. Replacement will eliminate need of reinforced oil sample for monitoring purpose, which is $2500 per year based on historical cost.
- Replacement cost is assumed to be CAD$5.8M[4] for a like-for-like replacement.
- Model did not account for any potential OM&A cost such as internal inspection(s) driven by oil sample.
- Inflation : 1.6%. [2]
- Cost of Capital: 5.78% [2]
- Corporate Tax rate : 26.5% [2]
- CCA rate for Transmission Asset : 8% [2]
- Disposal Value : $0

NPV of 3 options (Status Quo Maintain , Repair and Replace) were evaluated under the aforementioned assumptions. Calculations preferred the option to maintain status quo and avoid repair as it has the lowest present value.

Due to bad oil leaks, it would be beneficial to carry out minimal repair to reduce the amount of oil leak and future cash flow associated with oil leak clean up. Using discounted cash flow analysis, it can be calculated that the breakeven value between minor repair vs status quo option is CAD $52K[5] in net present value.

Result Summary	Status Quo Maintain	Major Investment Maintain/Repair	Replace	Preferred Option
Without CCA tax savings				
PV of Options, $k, with terminal value	2996.30	3430.74	5846.39	
PV of Options, $k, terminal value = 0	3189.69	3624.13	5846.39	
With CCA tax savings				
PV of Options, $k, with terminal value	2567.73	3002.17	4979.33	
PV of Options, $k, terminal value = 0	2761.12	3195.56	4979.33	
Investment Decision		NPV, $k		
Status Quo Maintain - Refurbish		-434.44		Maintain
Major Investment (Repair/Refurbish) - Replace		-1977.16		Repair/Refurbish
Repair - Replace boundary			2560.46	
Repair - Replace boundary, upper bound			2816.50	
Repair - Replace boundary, lower bound			2304.41	

2 $583.8 K is the 2010 – 2015 recorded average cost to refurbish transformer under AR 18335 (Transformer Oil Leak Reduction)
3 Estimated based on historical average on T4
4 Based on 2015 March, Average I/S Cost for Power Transformers in 230kV class.
5 Based on $6k per year for the remaining 19 years. Calculated using the Financial Evaluation Model, version 16A , by Decision Support

Table 6 : Present Value comparison for different sustainment options.

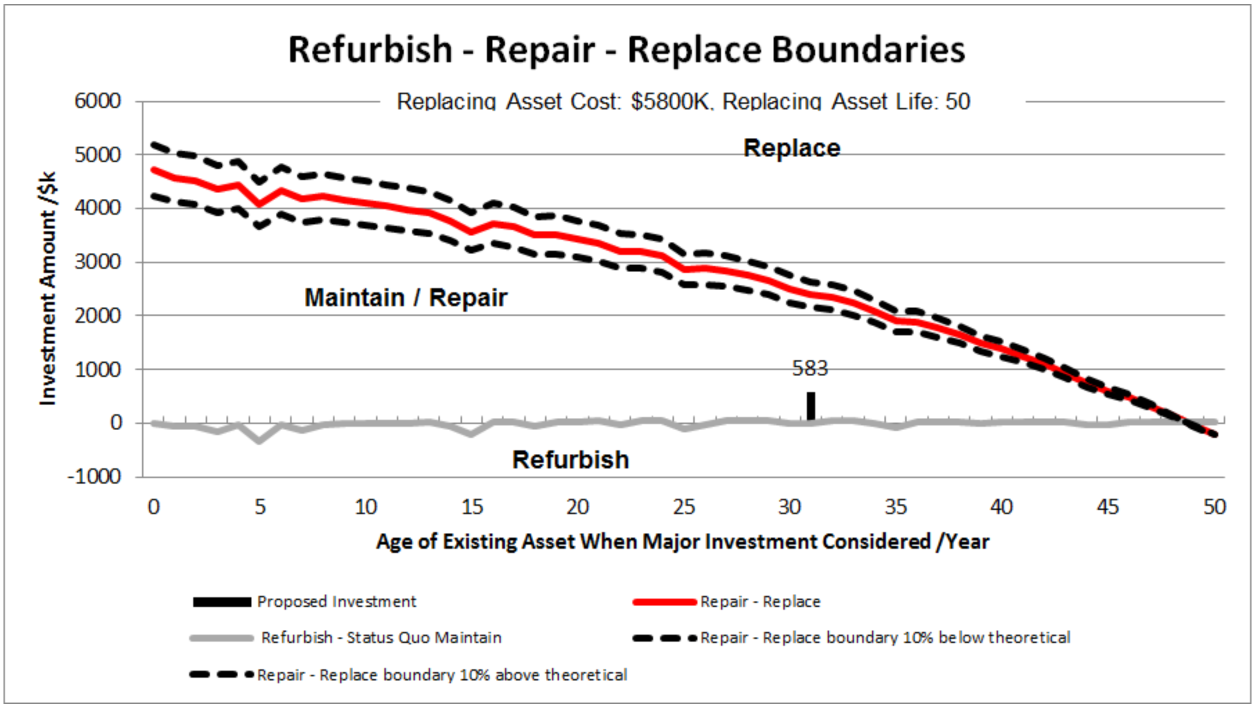


Chart 7 : Visual representation of NPV analysis

7.2 Recorded OM&A Spending

Maintenance Activity	Average Actual Cost (2013 - 2015)	Applicable to unit under assessment
TAP CHANGER OIL FILTER CHANGES	$ 1,115.05	
TAP CHANGER OIL SAMPLES	$ 370.51	✓
TAP CHANGER SI	$ 7019.4	✓
TRANSFORMER D1 --SS/Grounding	$ 1,293.68	
TRANSFORMER OIL SAMPLES --SS/Grounding	$ 258.23	
TRANSFORMER DBT --General	$ 5,660.90	✓
TRANSFORMER D1 --General	$ 3,862.40	✓
TRANSFORMER D2 --General	$ 3,517.07	✓
TRANSFORMER D1 --Critical	$ 5,086.62	
TRANSFORMER D2 --Critical	$ 3,572.14	
TRANSFORMER DBT --Critical	$ 7,597.20	
TRANSFORMER OIL SAMPLES --Critical	$ 270.16	
TRANSFORMER OIL SAMPLES --General	$ 300.57	✓

TRANSFORMER OIL TOP UP	$ 2710.74	

Table 7: Unit cost of various Preventative Maintenance Activities. Based on actual unit cost from 2013-2015

Table 8 summarized historical OM&A spending on T4 since 2008 from SAP . It is concluded that preventative spending are reasonable, with higher costs in 2013 and 2014 due to multiple special oil samples initiated by MTS for monitoring purposes. Higher corrective and emergency costs in year 2009 and 2012 are due to tapchanger repair and internal inspection described in section before. (highlighted in red)

OM&A cost summary

Year	CORR	EMER	OPER	PREV	UPGR	Grand Total
2008	$ 1,608.00	$ 986.20				$ 2,594.20
2009	$ 373,659.36	$ 3,270.50	$ 1,498.00	$ -	$ 3,620.94	$ 382,048.80
2010	$ 5,766.08			$ 532.22		$ 6,298.30
2011	$ 25,615.16		$ 741.70	$ 4,330.35		$ 30,687.21
2012	$ 373,074.42	$ 2,488.91		$ 12,853.28		$ 388,416.61
2013	$ 4,872.64			$ 8,412.23	$ 11,652.89	$ 24,937.76
2014	$ 1,527.85			$ 7,008.66		$ 8,536.51
2015	$ 17,478.47	$ 3,821.33		$ 2,463.71		$ 23,763.51

Table 8 : Historical OM&A spending on T4 since SAP inception in 2008

8 Conclusion

Data and information related to Dufferin T4's demographics, condition, environmental/HSE hazards, equipment loading and economics have been reviewed. It is evident from both oil sample and thermo visual report that T4 has internal overheating, which has led to expensive inspection and repair in the past. While oil samples reflect that the insulation integrity has not been jeopardized, it is expected that the insulation will deteriorate unevenly and quicker than normal due to localized overheating. Unfortunately, 2009's internal inspection was inconclusive and was unable to rectify the situation. At present, the unit is under reinforced sampling for monitoring purpose. It also has bad oil leaks which result in elevated OM&A expense. Therefore, despite NPV analysis indicates that it is more cost effective to keep the unit, an advance replacement is recommended in order to mitigate condition risk and avoid corrective expense in the future.

According to SAP, field staff makes monthly visit to Dufferin station to empty oil barrel that captures oil leak from T4. It will be advisable to perform small scale oil leak repair in order to slow the leak and reduce the frequency of visit. NPV analysis has shown that approximately CAD$149K is the break-even point.

9 Reference

[1] Conestoga-Rogers & Associates. (2011). Hydro One Station Spill Risk Model. SIP-EnvMgmt-0100, Mississauga.

[2] Department of Economics and Load Forecasting, Hydro One Networks Inc. (2015), Hydro One Financial Evaluation Model, Toronto.

APPENDIX 1 – PREVENTIVE MAINTENANCE LOG

type	Notification	Order	Description	Notif.date	System status	Code	FINISHDATE
PR	13505228	61106786	TF-GENERAL-(SPECIAL)MCT -MAIN TANK	01/16/2015	NOPR ORAS		
PR	13466327	61095434	TF-GENERAL-(SPECIAL)DGA -MAIN TANK	12/04/2014	NOCO ORAS	CR03	12/19/2014
PR	13388114	61065685	UT-CWC-UVT-UTOA	09/27/2014	NOPR ORAS		
PR	13388115	61065686	UT-CWC-UVT-UTOA	09/27/2014	NOPR ORAS		
PR	13388116	61065687	UT-CWC-UVT-UTOA	09/27/2014	NOPR ORAS		
PR	13388117	61065688	UT-CWC-UVT-UTOA	09/27/2014	NOPR ORAS		
PR	13369357	61046930	TF-GENERAL-GOT	09/26/2014	ATCONOCO ORAS	CR03	1/7/2015
PR	13153609	61012845	TF-GENERAL-(SPECIAL)DGA -MAIN TANK	07/18/2014	NOCO ORAS	CR03	10/24/2014
PR	13031750	60897698	STN 'A' PWR EQ INSP-SVI SPRING 2014	06/10/2014	NOCO ORAS	CR01	
PR	13031796	60897698	STN 'A' PWR EQ INSP-SVI SPRING 2014	06/10/2014	NOCO ORAS	CR01	
PR	13031791	60897698	STN 'A' PWR EQ INSP-SVI SPRING 2014	06/10/2014	NOCO ORAS	CR03	
PR	13025780	60999672	TF-GENERAL-(SPECIAL) DGA - MAIN UNIT	06/06/2014	NOCO ORAS	CR03	8/6/2014
PR	12887759	60978569	Tx PCB Reduction Oil Sample	03/22/2014	NOPR ORAS		
PR	12875835	60973510	TF-GENERAL-(SPECIAL) DGA	03/06/2014	NOCO ORAS	CR03	5/23/2014
PR	12858213	60959341	TF-GENERAL- (SPECIAL) DGA	01/17/2014	NOCO ORAS	CR03	3/25/2014
PR	12825080	60947108	TF-GENERAL-(SPECIAL) DGA	12/05/2013	NOCO ORAS	CR03	1/8/2014
PR	12764008	60766677	STN 'A' PWR EQ INSP-SVI FALL 2013	11/08/2013	NOCO ORAS	CR01	
PR	12764057	60766677	STN 'A' PWR EQ INSP-SVI FALL 2013	11/08/2013	NOCO ORAS	CR01	
PR	12764033	60766677	STN 'A' PWR EQ INSP-SVI FALL 2013	11/08/2013	ORAS OSNO OSTS	CR03	
PR	12702984	60927318	TF-GENERAL-(SPECIAL) DGA	10/09/2013	NOCO ORAS	CR03	10/23/2013
PR	12644132	60906045	TF-GENERAL-GOT	09/26/2013	ATCONOCO ORAS	CR03	2/19/2014
PR	12634408	60901184	UT-CWC-UVT-UTOA	09/25/2013	ATCONOCO ORAS	CR01	2/13/2014
PR	12634409	60901185	UT-CWC-UVT-UTOA	09/25/2013	NOPR ORAS		10/24/2014
PR	12634411	60901187	UT-CWC-UVT-UTOA	09/25/2013	NOPR ORAS		10/24/2014
PR	12634410	60901186	UT-CWC-UVT-UTOA	09/25/2013	ATCO NOPR ORAS	CR01	2/13/2014
PR	12589597	60876866	UT-CWC-UVT-(SPECIAL) MCDT - YLTC-DIV	09/18/2013	NOCO ORAS	CR01	12/6/2013
PR	12530102	60870723	TF-GENERAL-(SPECIAL) DGA	08/28/2013	ATCO NOCO ORAS	CR03	9/19/2013
PR	12316616	60847039	TF-GENERAL-(SPECIAL) DGA	06/13/2013	NOCO ORAS	CR03	7/29/2013

PR	12152505	60830123	TF-GENERAL-(SPECIAL) DGA --MAIN TANK	04/18/2013	NOCO ORAS	CR03	5/27/2013
PR	12144856	60766676	STN 'A' PWR EQ INSP-SVI SPR 2013	04/12/2013	NOCO ORAS	CR01	
PR	12144909	60766676	STN 'A' PWR EQ INSP-SVI SPR 2013	04/12/2013	NOCO ORAS	CR01	
PR	12144905	60766676	STN 'A' PWR EQ INSP-SVI SPR 2013	04/12/2013	ORAS OSNO OSTS	CR02	
PR	12055700	60809475	TF-GENERAL-(SPECIAL) DGA	01/24/2013	ATCO NOCO ORAS	CR03	3/25/2013
PR	11855873	60767054	UT-CWC-UVT-UTOA	10/14/2012	ATCO NOCO ORAS	CR01	3/25/2013
PR	11855875	60767057	UT-CWC-UVT-UTOA	10/14/2012	ATCO NOCO ORAS	CR01	3/25/2013
PR	11855877	60767058	UT-CWC-UVT-UTOA	10/14/2012	ATCO NOCO ORAS	CR03	9/5/2013
PR	11855874	60767055	UT-CWC-UVT-UTOA	10/14/2012	ATCO NOCO ORAS	CR01	9/5/2013
PR	11825214	60736382	TF-GENERAL-GOT	10/13/2012	ATCO NOCO ORAS	CR03	
PR	11562542	60711206	TF-GENERAL-(SPECIAL) DGA - RUSH	08/07/2012	NOCO ORAS	CR01	8/8/2012
PR	10884181	60589194	STN 'A' PWR EQ INSP-SVI SPR 2012	04/11/2012	NOCO ORAS	CR02	
PR	10884219	60589194	STN 'A' PWR EQ INSP-SVI SPR 2012	04/11/2012	NOCO ORAS	CR01	
PR	10884220	60589194	STN 'A' PWR EQ INSP-SVI SPR 2012	04/11/2012	NOCO ORAS	CR02	
PR	10876206	60669144	TF-GENERAL-(SPECIAL) DGA	03/21/2012	ATCO NOCO ORAS	CR01	7/19/2012
PR	10871537	60664723	TF-GENERAL-(SPECIAL) DGA	03/06/2012	NOCO ORAS	CR03	3/15/2012
PR	10866904	60615490	20216 Tx PCB sample 2012	02/17/2012	NOCO ORAS	CR01	2/28/2012
PR	10866905	60615490	20216 Tx PCB sample 2012	02/17/2012	NOCO ORAS	CR01	2/28/2012
PR	10866906	60615490	20216 Tx PCB sample 2012	02/17/2012	NOCO ORAS	CR01	2/28/2012
PR	10866907	60615490	20216 Tx PCB sample 2012	02/17/2012	NOCO ORAS	CR01	2/28/2012
PR	10866908	60615490	20216 Tx PCB sample 2012	02/17/2012	NOCO ORAS	CR01	2/28/2012
PR	10866909	60615490	20216 Tx PCB sample 2012	02/17/2012	NOCO ORAS	CR01	2/28/2012
PR	10866910	60615490	20216 Tx PCB sample 2012	02/17/2012	NOCO ORAS	CR01	2/28/2012
PR	10866911	60615490	20216 Tx PCB sample 2012	02/17/2012	NOCO ORAS	CR01	2/28/2012
PR	10866912	60615490	20216 Tx PCB sample 2012	02/17/2012	NOCO ORAS	CR01	2/28/2012
PR	10866913	60615490	20216 Tx PCB sample 2012	02/17/2012	NOCO ORAS	CR01	2/28/2012
PR	10866914	60615490	20216 Tx PCB sample 2012	02/17/2012	NOCO ORAS	CR01	2/28/2012
PR	10816134	60615490	20216 Tx PCB sample 2012	12/13/2011	NOPR ORAS	CR01	2/28/2012
PR	10794308	60601806	TF-GENERAL-(SPECIAL) DGA	11/11/2011	NOCO ORAS	CR03	2/28/2012
PR	10780049	60589463	UT-CWC-UVT-UTOA	10/22/2011	NOCO ORAS	CR01	2/28/2012

PR	10780051	60589465	UT-CWC-UVT-UTOA	10/22/2011	NOCO ORAS	CR01	2/28/2012
PR	10780050	60589464	UT-CWC-UVT-UTOA	10/22/2011	ATCO NOCO ORAS	CR01	
PR	10780052	60589466	UT-CWC-UVT-UTOA	10/22/2011	ATCO NOCO ORAS	CR01	
PR	10771928	60581418	TF-GENERAL-GOT	10/21/2011	NOCO ORAS	CR01	2/28/2012
PR	10762859	60572262	TF-GENERAL-DBT	10/20/2011	NOCO ORAS	CR01	2/28/2012
PR	10762858	60572261	TF-GENERAL-D1	10/20/2011	NOCO ORAS	CR01	2/28/2012
PR	10767767	60577176	TF-GENERAL-D2	10/20/2011	NOCO ORAS	CR01	2/28/2012
PR	10731415	60388328	STN 'A' PWR EQ INSP-SVI FALL 2011	09/01/2011	NOCO ORAS	CR01	
PR	10731463	60388328	STN 'A' PWR EQ INSP-SVI FALL 2011	09/01/2011	NOCO ORAS	CR01	
PR	10731464	60388328	STN 'A' PWR EQ INSP-SVI FALL 2011	09/01/2011	ORAS OSNO	CR03	
PR	10687301	60510224	20216 2011 TX PCB Reduction Oil Sample	05/06/2011	NOCO ORAS		1/4/2012
PR	10665499	60492702	UT-CWC/MR/UVT-(SPECIAL) DGA - RUSH	03/11/2011	NOCO ORAS	CR01	3/23/2011
PR	10665551	60492703	UT-CWC/MR/UVT-(SPECIAL) DGA - RUSH	03/11/2011	NOCO ORAS	CR04	3/23/2011
PR	10663307	60388327	STN 'A' PWR EQ INSP-SVI SPRING 2011	03/03/2011	NOCO ORAS	CR01	
PR	10663344	60388327	STN 'A' PWR EQ INSP-SVI SPRING 2011	03/03/2011	NOCO ORAS	CR02	
PR	10663345	60388327	STN 'A' PWR EQ INSP-SVI SPRING 2011	03/03/2011	NOCO ORAS	CR02	
PR	10662219	60488959	TF-GENERAL-(SPECIAL) DGA	02/25/2011	NOCO ORAS	CR03	8/24/2011
PR	10592260	60436354	TF-GENERAL-M1	10/15/2010	NOCO ORAS	CR03	2/1/2011
PR	10561192	60404535	TF-GENERAL-GOT	10/04/2010	NOPR ORAS		2/3/2011
PR	10559505		STN 'A' PWR EQ INSP-SVI FALL	09/30/2010	OSNO	CR02	
PR	10559830	60403193	UT-CWC/MR/UVT-D1	09/30/2010	NOCO ORAS	CR01	2/3/2011
PR	10559543		STN 'A' PWR EQ INSP-SVI FALL	09/30/2010	ATCO OSNO	CR03	
PR	10559544		STN 'A' PWR EQ INSP-SVI FALL	09/30/2010	OSNO	CR03	
PR	10559831	60403194	UT-CWC/MR/UVT-D1	09/30/2010	NOCO ORAS	CR01	2/3/2011
PR	10544052	60388445	UT-CWC/MR/UVT-UTOA	09/28/2010	NOCO ORAS	CR01	2/3/2011
PR	10544053	60388446	UT-CWC/MR/UVT-UTOA	09/28/2010	NOCO ORAS		
PR	10544054	60388447	UT-CWC/MR/UVT-UTOA	09/28/2010	NOCO ORAS	CR04	2/3/2011
PR	10544055	60388448	UT-CWC/MR/UVT-UTOA	09/28/2010	NOCO ORAS		
PR	10512578	60349554	TF-GENERAL-(SPECIAL) DGA - RUSH	06/03/2010	NOCO ORAS	CR01	6/8/2010
PR	10512579	60349555	UT-CWC/MR/UVT-(SPECIAL) DGA - RUSH	06/03/2010	NOCO ORAS	CR01	6/8/2010

PR	10512590	60349556	UT-CWC/MR/UVT-(SPECIAL) DGA - RUSH	06/03/2010	NOPR ORAS		6/8/2010
PR	10508728		STN 'A' PWR EQ INSP-SVI SPRING	05/25/2010	NOCO	CR01	
PR	10508766		STN 'A' PWR EQ INSP-SVI SPRING	05/25/2010	NOCO	CR01	
PR	10508767		STN 'A' PWR EQ INSP-SVI SPRING	05/25/2010	ATCO OSNO	CR03	
PR	10432307	60279598	TF-GENERAL-GOT	01/08/2010	NOCO ORAS	CR01	7/7/2010
PR	10319130		STN 'A' PWR EQ INSP-SVI	06/22/2009	OSNO	CR03	
PR	10319117		STN 'A' PWR EQ INSP-SVI	06/22/2009	NOCO	CR01	
PR	10319118		STN 'A' PWR EQ INSP-SVI	06/22/2009	NOCO	CR01	
PR	10319119		STN 'A' PWR EQ INSP-SVI	06/22/2009	NOCO	CR01	
PR	10319120		STN 'A' PWR EQ INSP-SVI	06/22/2009	NOCO	CR01	
PR	10319104		STN 'A' PWR EQ INSP-SVI	06/22/2009	NOCO	CR01	
PR	10319105		STN 'A' PWR EQ INSP-SVI	06/22/2009	NOCO	CR01	
PR	10319106		STN 'A' PWR EQ INSP-SVI	06/22/2009	NOCO	CR01	
PR	10319107		STN 'A' PWR EQ INSP-SVI	06/22/2009	NOCO	CR01	
PR	10319108		STN 'A' PWR EQ INSP-SVI	06/22/2009	NOCO	CR01	
PR	10319109		STN 'A' PWR EQ INSP-SVI	06/22/2009	NOCO	CR01	
PR	10319110		STN 'A' PWR EQ INSP-SVI	06/22/2009	NOCO	CR01	
PR	10296339	60154845	TF-GENERAL-M1	04/28/2009	NOCO ORAS		6/1/2009
PR	10248014	60107226	UT-CWC/MR/UVT-UTOA	01/01/2009	NOCO ORAS	CR04	
PR	10248015	60107227	UT-CWC/MR/UVT-UTOA	01/01/2009	NOCO ORAS	CR01	
PR	10237759		STN 'A' PWR EQ INSP-SVI	12/22/2008	OSNO	CR03	
PR	10237746		STN 'A' PWR EQ INSP-SVI	12/22/2008	NOCO	CR01	
PR	10237747		STN 'A' PWR EQ INSP-SVI	12/22/2008	NOCO	CR01	
PR	10237748		STN 'A' PWR EQ INSP-SVI	12/22/2008	NOCO	CR01	
PR	10237749		STN 'A' PWR EQ INSP-SVI	12/22/2008	NOCO	CR01	
PR	10237733		STN 'A' PWR EQ INSP-SVI	12/22/2008	NOCO	CR01	
PR	10237734		STN 'A' PWR EQ INSP-SVI	12/22/2008	NOCO	CR01	
PR	10237735		STN 'A' PWR EQ INSP-SVI	12/22/2008	NOCO	CR01	
PR	10237736		STN 'A' PWR EQ INSP-SVI	12/22/2008	NOCO	CR01	
PR	10237737		STN 'A' PWR EQ INSP-SVI	12/22/2008	NOCO	CR01	
PR	10237738		STN 'A' PWR EQ INSP-SVI	12/22/2008	NOCO	CR01	
PR	10237739		STN 'A' PWR EQ INSP-SVI	12/22/2008	NOCO	CR01	
PR	10237306	60103946	TF-GENERAL-GOT	12/21/2008	NOCO ORAS	CR01	

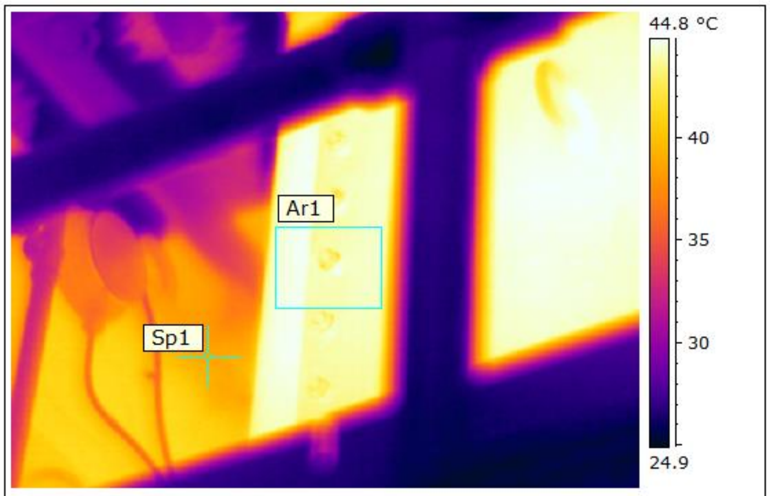
APPENDIX 2 – LIST OF DR AND TC NOTIFICATION

type	Notif	Order	Description	User status	Notif.date	System status	Code	FINISH DATE
DR	13510147	61111240	Dufferin TS empty oil barrel	VALD	01/28/2015	NOPR ORAS		
DR	12867964	60968322	NT9 Inspect transfrmer for oil leaks	INIT	02/13/2014	NOCO ORAS	9900	6/19/2014
DR	12763961	60957111	Oil overflow drum needs emptying.	VALD	11/08/2013	NOPR ORAS	0700	1/8/2014
DR	11366673	60704519	T4 contingency planning	INIT	07/13/2012	NOCO ORAS		8/1/2012
DR	11212038	60695909	Dufferin T4 repair gassing problem	VALD	06/13/2012	NOCO ORAS		8/8/2012
TC	11204879	60694874	S3 Dufferin T4 gas accumualtion	RECD	06/10/2012	NOCO ORAS		6/9/2012
TC	11192196	60693177	S3 RE:T4 TAP CHANGER LOCK OUT	RECD	06/04/2012	NOCO ORAS		6/4/2012
TC	11186099	60691743	S3 EMD SWITCHING T4	RECD	05/30/2012	NOCO ORAS		8/9/2012
TC	11182785	60691283	S3 EMD T4 GAS ACCUMULATION	RECD	05/29/2012	NOCO ORAS		5/29/2012
DR	11184330	60691126	T4 GAS ACCUMULATION investigation	VALD	05/29/2012	NOCO ORAS		6/5/2012
DR	10854678	60504083	Dufferin TS T4 (Y) ULTC UVT 2000A repair	INIT	01/11/2012	NOPR ORAS		1/6/2012
DR	10669811	60496849	Dufferin T4Y tapchanger gassing	VALD	03/25/2011	NOCO ORAS		4/1/2011
DR	10654654	60480794	Dufferin T4 low oil	VALD	02/01/2011	NOCO ORAS		2/1/2011
DR	10543639	60387987	Dufferin TS T4X Silica Gel Change	VALD	09/28/2010	NOCO ORAS		2/28/2012
DR	10508258	60346832	Dufferin T4Y Breather Missing etc.	VALD	05/25/2010	NOCO ORAS		2/28/2012
DR	10506144	60349033	Dufferin TS T4 LTC hot spot	VALD	05/20/2010	NOPR ORAS	3600	
DR	10506145	60349034	Dufferin TS T4 hot spot	VALD	05/20/2010	NOPR ORAS	3600	
DR	10343177	60206710	NT9T4 Y oil leak over flow container	VALD	08/11/2009	NOPR ORAS		11/24/2010
DR	10332290	60191548	Dufferin T4 install tapchanger shunts	VALD	07/23/2009	NOCO ORAS		8/4/2009
DR	10329004	60189433	Dufferin T4 bay clean up	VALD	07/17/2009	NOCO ORAS		7/17/2009
TC	10324336	60184688	S3 - Dufferin - T3 and T4	RECD	07/03/2009	NOCO ORAS		7/3/2009
DR	10298675	60156830	Dufferin T4 internal inspection	VALD	05/04/2009	NOCO ORAS	3600	11/24/2009
TC	10297447	60155618	P&C Secd Isol req'd - gas annun recv'd	RECD	04/29/2009	NOCO ORAS		4/29/2009
TC	10233035	60099662	S3 DUFERIN T4 VOTAGE READING	RECD DATA	12/09/2008	NOCO ORAS		12/10/2008
DR	10021618	929178	MISSING BREATHER * INSTALL NEW UNIT	VALD	07/02/2008	NOPR ORAS		8/18/2009
DR	10016440	929177	REPLACE SILICA GEL IN BREATHER	VALD	06/20/2008	NOCO ORAS		7/14/2008

APPENDIX 3 – THERMO VISISON REPORT

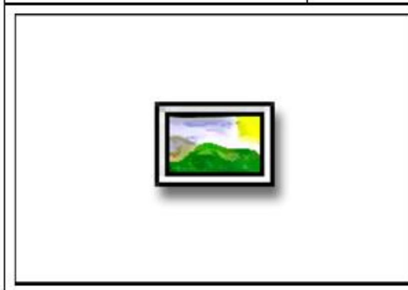
	Thermography Inspection At DUFFERIN TS	Date: MAY 19 2010

Recommendation	CR3-5.9 TEMPERATURE RISE
Nomenclature	T4
Phase	LTC 2
Component	TAP CHANGER
Location Description	TC COMPARTMENT
Equipment Type	TAP CHANGER EAST SIDE
Weather	INDOOR
Amb Temperature	20
Manufacturer	WESTINGHOUSE
Voltage	13.9
Rated Current (Amps)	1000
Actual Current (Amps)	500
Wind Speed (kph)	0



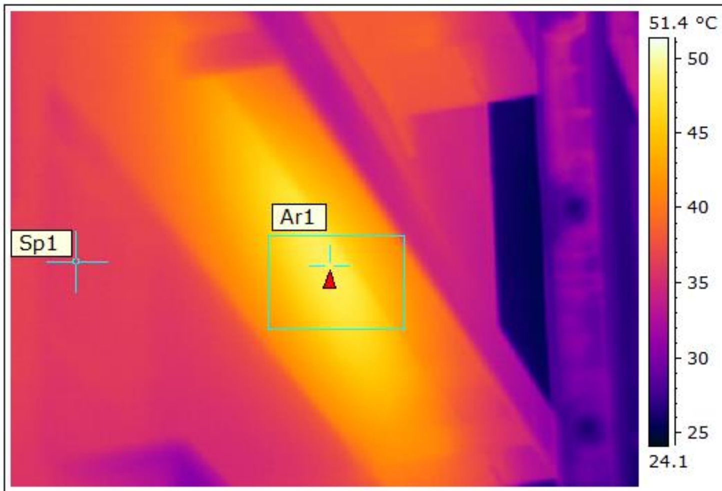
Ar1 Max. Temperature	44.8 °C
Sp1 Temperature	38.9 °C

Temperature Rise (Delta)	**5.9**
Load Corrected Temp Rise (Delta)	**17.7**



	Thermography Inspection At DUFFERIN TS	Date: MAY 19 2010

Recommendation	CR3-12.2 TEMPERATURE RISE]
Nomenclature	T4]
Phase	]
Component	TRANSFORMER]
Location Description	UNDER 3RD LATERAL SUPPORT BEAMON EAST SIDE OF TRANSFORMER]
Equipment Type	TRANSFORMER]
Weather	INDOOR]
Amb Temperature	20]
Manufacturer	WESTINGHOUSE]
Voltage	13.9]
Rated Current (Amps)	100]
Actual Current (Amps)	50]
Wind Speed (kph)	0]



Ar1 Max. Temperature	48.6 °C]
Sp1 Temperature	36.4 °C]

Temperature Rise (Delta)	**12.2**
Load Corrected Temp Rise (Delta)	**36.4**

Asset Risk Assessment Report

Project: Integrated Station Component Replacement - Pleasant TS

Recommendation

Defer – The investment is to be deferred as the condition of the station does not justify investment at this time.

Project Summary

Built in the mid 1950's Pleasant TS is a 62 year old transformer station that supplies load to mostly Hydro One Brampton customers in the Brampton area via three switchyards.

There are a number of low voltage oil circuit breakers at Pleasant TS which are approaching the end of their expected service life and will need to be replaced in the near future in order to maintain reliability of the supply. Also, two idle circuit breakers will need to be removed.

Most of the protections servicing the two older yards at the station have electromechanical or solid state relays. These relays are approaching the end of their service life and will need to be replaced with modern intelligent self-monitoring devices. There have been animal contact issues at the station which will need to be addressed through animal mitigation techniques to prevent further outages. Other station equipment such as oil filled bus potential transformers and porcelain surge arrestors should also be replaced to increase the station's supply reliability.

Proposed Investment

1. Replace 11 LV circuit breakers.
2. Remove 2 LV idle circuit breakers
3. Replace protection facilities.
4. Install animal mitigation at the station
5. Replace other minor station equipment such as surge arrestors and bus PTs.

Consideration is to be given to reconfiguring the station to eliminate the BY switchyard to meet current customer requirements.

Prepared by

Michael Xavier, P.Eng.
Sr. Network Management Engineer

Appendix 1 - Risk Assessment

Risk Factor	Risk Assessment*	Comments
Demographics	Fair	Transformers T1 & T2 are single secondary transformers that are each 41 years old which is approaching their expected service life. Two-thirds of the LV breakers in the station are KSO breakers currently averaging about 45 years old while the other third are MG FG4 breakers which are ~25 years old. Overall breakers are operating within their expected service life. A large portion of the protection equipment servicing the station is reaching or exceeding their expected service life and should be considered for replacement over the next 5-10 years.
Condition	Fair	The T2 transformer has had some oil leak issues but overall the T1 and T2 transformers condition is at the expected level for their age. The number of breaker notifications on average is less than 0.25 notifications per breaker per year. No. of Trouble Call (TC) & Corrective (DR) Notifications since 2009 – 2015 for T1, T2 and associated breakers and the T5/T6 yard breakers: 88 Annual TC & DR Frequency: 12.6
Economics	Fair	The O&M costs per breaker on average is less the $2k per year. O&M$ Spent since 2009: $407k Annual O&M$: $58k
Performance	Very Low	Not considering the capacitor breakers which have been recently replaced the station breakers have performed adequately. Number of direct breaker outages over last 5 years: 1 Duration of outages: 0.133 hours DP Performance: T1/T2 yard is performing better than target for frequency and duration over the last 10 years. The T5/T6 yard is generally performing at about target for frequency and duration over the last 10 years although the Y and Z buses have deteriorating performance over that last few years.
Utilization	Very Low	There are spare feeder positions available in the station. There is also a new DESN T7/T8 that was recently built which is not yet fully utilized.
Criticality	Fair	Pleasant supplies on average approximately 175MW of load in the Brampton area
Customer	Very Satisfied	[redacted]
Obsolescence	Fair	There are currently spare parts available to help service the existing population of breakers at Pleasant. The BY switchyard is an old 30C type structure with known maintainability concerns.
Health & Safety	Fair	The BY switchyard is an old 30C type structure having back-to-back switching hazard typical of this vintage of structure. This can only be addressed with a switchyard rebuild or reconfiguration to eliminate this legacy switchyard.
Environment	Low	Pleasant TS is 145th out of 256 stations in regards to Station Spill Risk Rankings.

**Available Selections: Very High, High, Fair, Low, Very Low, N/A*

Pleasant TS T1 /T2

Station Assessment

[Keyword]

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REVISION HISTORY

Date	Revision	Revision Comments
Jan 14, 2015	**0**	**First Draft**

APPROVAL SIGNATURES

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Date:			

TABLE OF CONTENTS

1.0 INTRODUCTION

This assessment provides an overview of the current state of the station. The recommendations offered in this document will allow Asset Management make well-informed capital investment decisions.

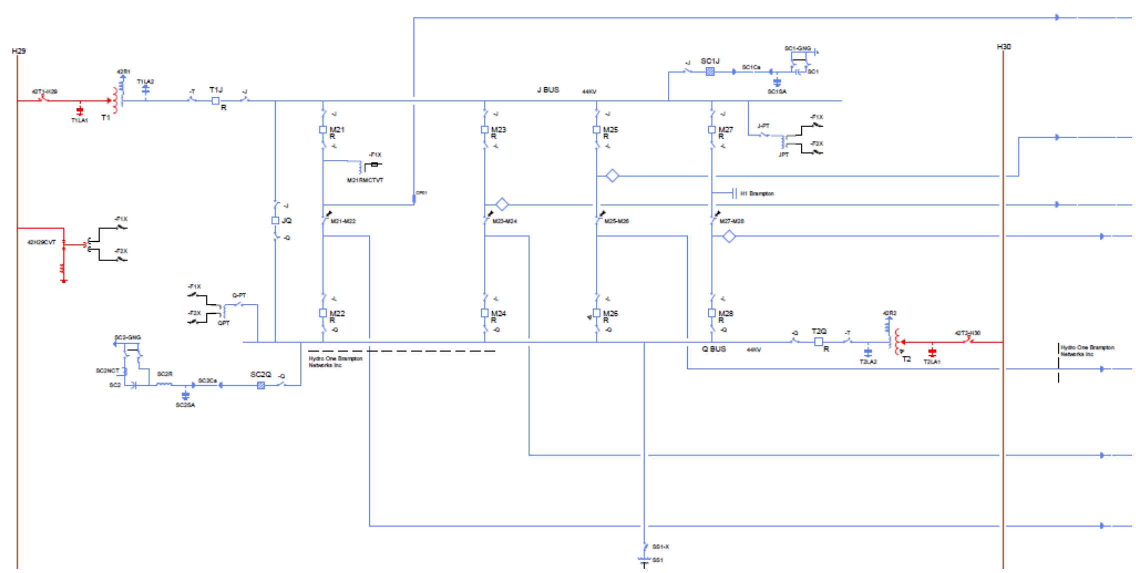
Integration of the replacement of multiple end of life components into a single investment allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work. A station assessment will ensure that all the replacement needs are captured and integrated into the investment before release.

2.0 STATION SUMMARY

Pleasant TS is a transmission station that provides transformation of 230 kV to 44kV and 27.6 kV. Pleasant TS serves as the supply to Hydro One Brampton, Halton Hills Hydro as well as directly connected Hydro One customers. This station is located in Brampton and supplies customers in the Brampton, Peel and Halton Hills area. Pleasant TS was originally placed i/s in 1954 and many assets are in degraded condition and are in need of replacement.

The Pleasant TS T1/T2 yard is DESN station supplied by 2-230kV LH3&LH4 lines. The 44kV secondary switchyard supplies eight feeders. There are also capacitor banks connected to each of the LV buses.

The project will result in the replacement of 2 LV breakers, security and grounding upgrades, nuisance wildlife control and the installation of an integrated PC&T box solution.



3.0 DESKSIDE STATION ASSESSMENT

3.1 Station Fault Current Rating

Table 1: 2014 Station Fault Current Rating for Pleasant TS [1].

Pleasant TS	Symmetrical		Asymmetrical		Symmetrical Rating		Asymmetrical Rating	
	3ph kA	LG kA	3ph kA	LG kA	3ph kA	LG kA	3ph kA	LG kA
JQ Bus @ 44kV	14.143	13.208	16.104	16.617	17.50	17.50	18.80	18.80

3.2 Station 5 Year DESN Loading (2008-2012)

Table 2: Transformer MVA Ratings, 5-Yr Avg, 5-Yr Peaks & Loading Deviation %'s

DESN	TF Max Rating (MVA)	StDev % of Max Avg	Max Avg (MVA) 2008-12	Max Avg % of TF Max Rtg	Max Peak vs Max Avg	StDev % of Max Peak	Max Peak (MVA) 2008-12	Max Peak % of TF Max Rtg	Max Peak MVA as % of LTR Avg	LTR Load Risk	LTR vs TF Max Rtg
T1/T2	125.0	44.7%	77.57	62.1%	178.1%	43.5%	138.15	110.5%	74.6%	N	1.4

Table 3: Station LTR Ratings and Average Peak Loading

	LTR Rating		2008		2009		2010		2011		2012	
DESN	Sum 10d LTR	Win 10d LTR	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]
T1/T2	164.50	185.20	77.57	128.41	82.57	131.72	77.57	124.77	70.78	138.15	73.83	137.40

- Adjusted, values were skewed by faults, transfers or anomalies

3.2.1 Stranded Load [2]

Station	Breakers	Connections	Stranded
Pleasant TS	M21,M22, M24,M26, M27		Yes (50%)

3.3 Customer Information

Table 4: Customer Satisfaction Summary

Customer Name	Customer Satisfaction Rating					Trend
	2009	2010	2011	2012	2013	
Hydro One Brampton Networks	Very Satisfied	Somewhat satisfied	Somewhat satisfied	Very Satisfied	Very Satisfied	Improving
Halton Hills Hydro Inc.	Not Disclosed	Not Disclosed	Not Disclosed	Neither satisfied nor dissatisfied	Somewhat satisfied	Improving

3.4 Outage Information

The Pleasant TS T1/T2 yard is not considered a Delivery Point (DP) group or individual outlier (Frequency or Duration). The 10 year average performance is very good.

Frequency>>>

			10 yr avg	3 yr average										
OPDES	Bus MW	DESN MW	12-03	12-10	11-09	10-08	09-07	08-06	07-05	06-04	05-03	Indiv. Outlier Baseline (Freq)	Group Outlier Freq Target	Group Outlier Freq UB
J	34.3	68.6	0.3	0.3	0.7	0.7	0.3	0.0	0.0	0.3	0.3	0.0	0.5	1.5
Q	34.3	68.6	0.3	0.7	0.7	0.7	0.3	0.0	0.0	0.0	0.0	0.6	0.5	1.5

Duration>>>

			10 yr avg	3 yr average										
OPDES	Bus MW	DESN MW	12-03	12-10	11-09	10-08	09-07	08-06	07-05	06-04	05-03	Indiv. Outlier Baseline (Dur.)	Group Outlier Dur. Target	Group Outlier Dur. UB
J	34.3	68.5	2.8	9.0	9.0	9.0	0.0	0.0	0.0	0.3	0.3	0.0	11.0	55.0
Q	34.3	68.5	3.4	11.3	9.0	9.0	0.0	0.0	0.0	0.0	0.0	35.9	11.0	55.0

3.5 Station Spill Risk Ranking

Pleasant TS has 6 oil-filled power transformers supplying 4 DESN switchyards. The overall station is ranked 145th out of 256 stations based on existing risk score from a 2011 spill risk report by Conestoga-Rogers & Associates [3].

3.6 Asset Analytics

Based off the Composite score in Asset Analytics, the following station equipment, not previously identified under the asset-centric work program, with a *Composite* score greater than 35 or a *Demographic* score greater than 74 should be considered for replacement.

Func. Location	Asset Class	Age	Condition	Demographics	Economics	Performance	Utilization	Criticality	Composite
N-TS-PLEASANTTS-SW-Q-PT	Switch: Air Break_< 69 kV	37	45	82	10	1	10	21	28
N-TS-PLEASANTTS-SW-T1J-J	Switch: Air Break_< 69 kV	37	45	82	10	1	10	21	28
N-TS-PLEASANTTS-BR-JQ	Breaker: Oil_< 69 kV	52	50	89	1	1	100	29	42
N-TS-PLEASANTTS-SW-T1J-T	Switch: Air Break_< 69 kV	37	45	82	10	1	10	21	28
N-TS-PLEASANTTS-SW-T2Q-Q	Switch: Air Break_< 69 kV	37	45	82	10	1	10	21	28
N-TS-PLEASANTTS-SW-T2Q-T	Switch: Air Break_< 69 kV	37	45	82	10	1	10	21	28
N-TS-PLEASANTTS-PR-42M27 MAIN	Protection: Solid State	38	1	100	1	1	0	10	14
N-TS-PLEASANTTS-PR-JQ BF	Protection: Solid State	37	1	100	1	1	0	1	14
N-TS-PLEASANTTS-PR-T1J BF	Protection: Solid State	37	1	100	1	1	0	1	14
N-TS-PLEASANTTS-SW-J-PT	Switch: Air Break_< 69 kV	37	45	82	10	1	10	21	28
N-TS-PLEASANTTS-PR-T2Q BF	Protection: Solid State	37	1	100	1	1	0	1	14
N-TS-PLEASANTTS-BR-M23	Breaker: Oil_< 69 kV	44	43	60	5	42	82	23	45
N-TS-PLEASANTTS-BR-M27	Breaker: Oil_< 69 kV	38	23	38	100	8	92	23	37
N-TS-PLEASANTTS-BR-M22	Breaker: Oil_< 69 kV	44	50	60	1	1	96	23	38
N-TS-PLEASANTTS-BR-T2Q	Breaker: Oil_< 69 kV	44	16	60	49	20	100	31	37
N-TS-PLEASANTTS-BR-M28	Breaker: Oil_< 69 kV	38	55	38	8	42	93	23	48
N-TS-PLEASANTTS-BR-M25	Breaker: Oil_< 69 kV	38	63	38	1	100	86	23	65
N-TS-PLEASANTTS-BR-JQ	Breaker: Oil_< 69 kV	52	50	89	1	1	100	29	42
N-TS-PLEASANTTS-PR-42M21 MAIN	Protection: Electro Mechanical	37	1	50	100	100	0	1	48
N-TS-PLEASANTTS-PR-42M22 MAIN	Protection: Electro Mechanical	37	1	50	1	100	0	10	39
N-TS-PLEASANTTS-SC-SC2	Capacitor: Shunt_< 69 kV	21	20	40	85	10	95	28	36
N-TS-PLEASANTTS-SC-SC1	Capacitor: Shunt_< 69 kV	21	20	40	16	70	100	28	46
N-TS-PLEASANTTS-BU-Q	Bus: Air Insulated_< 69 kV	0	1	1	100	100	0	30	44
N-TS-PLEASANTTS-BR-SC2Q	Breaker: SF6_< 69 kV	22	51	10	41	82	93	27	58

3.7 Station Security

*Pleasant TS T1/T2 is classified as **High Risk** and as of July 2014 has experienced fourteen (14) break-ins since 2007. The history of break-ins at Pleasant TS is shown in Table 1.*

Table 1: Count of Break-Ins by Year at Pleasant TS

2007	2008	2009	2010	2011	2012	2013	2014
2	0	0	0	7	0	3	2

As per ***SP-14-001-R1:*** *Functional Requirements for Preventing Copper Theft*, and ***SP-14000-001-R0:*** *Functional Requirements for Transmission and Distribution Security Detection and Verification Systems*, all stolen/missing *below grade* fence grounding and power equipment grounding conductors are to be replaced with copper-clad steel conductors whenever safely possible and when the original copper conductor was 4/0# or smaller. In addition, all stolen/missing *above grade* fence grounding is to be replaced with aluminum grounding material.

Defined as a Medium Risk station, current functional requirements dictate that the station be enclosed by a standard 8' (2.44 m) chain link perimeter fence.

For reference, criteria for station security risk classification are summarized in Table 2, below.

Table 2: Security Risk Classifications

Security Risk Level	Description
High	10+ break-ins from 2007- present
Medium	1-9 break-ins from 2007- present
Low	0 break-ins from 2007- present

3.8 Potential Need & Deficiency Report Notifications

Below is a summary of Potential Needs (PN) and Deficiency Report (DR) notification that have been issued by Field Staff and currently outstanding.

Table 3: Listing of Open and Outstanding Potential Needs (PN) Notifications

Notification		Functional Loc.	Notif.date	Description
13222093	08/11/2014	N-TS-PLEASANTTS	08/11/2014	Wood Pole/Structure Repl Candidates
13222092	08/11/2014	N-TS-PLEASANTTS	08/11/2014	Wood Pole/Structure Repl Candidates
13222099	08/11/2014	N-TS-PLEASANTTS	08/11/2014	Wood Pole/Structure Repl Candidates
13222098	08/11/2014	N-TS-PLEASANTTS	08/11/2014	Wood Pole/Structure Repl Candidates
13222097	08/11/2014	N-TS-PLEASANTTS	08/11/2014	Wood Pole/Structure Repl Candidates
13222096	08/11/2014	N-TS-PLEASANTTS	08/11/2014	Wood Pole/Structure Repl Candidates
13222094	08/11/2014	N-TS-PLEASANTTS	08/11/2014	Wood Pole/Structure Repl Candidates
13222095	08/11/2014	N-TS-PLEASANTTS	08/11/2014	Wood Pole/Structure Repl Candidates
11153587	05/04/2012	N-TS-PLEASANTTS-CN	05/04/2012	Pleasant RTU Bell circuit
10348780	08/26/2009	N-TS-PLEASANTTS-PR	08/26/2009	Relays upgrade plan status (ZFB)

Table 4: Listing of Open and Outstanding Deficiency Report Notifications for the LV yard

Notification			
13500986	N-TS-PLEASANTTS-BR-SC5E	01/12/2015	Pleasant TS - SC5E Htr issue.
13497489	N-TS-PLEASANTTS-SI-BLDG A	01/06/2015	Place Salt Bins-BJCC
13497620	N-TS-PLEASANTTS-SI-BLDG B	01/06/2015	Re-fill Salt Bin-BJCC
13497623	N-TS-PLEASANTTS-SI-BLDG C	01/06/2015	Check Heater-BJCC
13497621	N-TS-PLEASANTTS-SI	01/06/2015	Place Snow Shovel
13497622	N-TS-PLEASANTTS-SI-FG	01/06/2015	Install Gate Stop
13265567	N-TS-PLEASANTTS-SI-IF	08/22/2014	Pleasant trip hazard -BJCC
13326438	N-TS-PLEASANTTS-BR-M28	09/09/2014	Pleasant M28 Leaking Drain Valve
13326506	N-TS-PLEASANTTS-BR-M25	09/09/2014	Pleasant M25 Htr Repair
13432916	N-TS-PLEASANTTS-SC-SC2	11/11/2014	Pleasant TS - SC2 Repair

13436665	N-TS-PLEASANTTS-SI-BLDG C	11/14/2014	Pleasant Hvac
12716747	N-TS-PLEASANTTS-SI-EN	10/17/2013	ENV- Multipal containment wall cracks
13192096	N-TS-PLEASANTTS-BR-M23	07/30/2014	Pleasant M23 Open/Close indicator
13326780	N-TS-PLEASANTTS	09/09/2014	Pleasant Leaking Pot Head - T6Yca
13326597	N-TS-PLEASANTTS-BR-JQ	09/09/2014	Pleasant JQ - Heater Fail and Oil Lvl
13265580	N-TS-PLEASANTTS-SW	08/22/2014	Pleasant 44kv bus switch mtnce.
13265569	N-TS-PLEASANTTS-SW-T2Q-Q	08/22/2014	Pleasant T2Q-Q repair
13265568	N-TS-PLEASANTTS-SW-JQ-J	08/22/2014	Pleasant JQ-J repair
13229563	N-TS-PLEASANTTS-SW-T1J-J	08/13/2014	Pleasant TS T1J-J switch
13009844	N-TS-PLEASANTTS-BU	05/30/2014	live bus not indicated on print
12896304	N-TS-PLEASANTTS-SI-BLDG A	04/03/2014	BLDG. FLOOR TILES -BJCC
12896082	N-TS-PLEASANTTS-SI	04/03/2014	COPPER GROUND THEFT
12904485	N-TS-PLEASANTTS-DC-CH125A	04/09/2014	Faulty charger timer
12777086	N-TS-PLEASANTTS-TF-T2	11/15/2013	Pleasant TS T2 conservator oil top up
12637415	N-TS-PLEASANTTS-SI-BLDG B	09/25/2013	AR#19275 NA42 TX BLDG Bsmnt Survey
12431026	N-TS-PLEASANTTS-SI	07/22/2013	sump electrical fault
12569428	N-TS-PLEASANTTS-SI-BLDG A	09/11/2013	ELIGHTS- Emergency light not working
12489074	N-TS-PLEASANTTS-TF-T2	08/13/2013	Pleasant TS T2 Oil Leak
12371115	N-TS-PLEASANTTS-TF-T2	06/29/2013	Pleasant T2 differential
12267853	N-TS-PLEASANTTS-SI-IF	05/29/2013	Pleasant Sump Alarm
12258779	N-TS-PLEASANTTS-SI-BLDG C	05/27/2013	HVAC Pleasant PCT Building
11157144	N-TS-PLEASANTTS-SI-BLDG B	05/10/2012	BLDG-Bricks Spalling South Side-BJCC
12034579	N-TS-PLEASANTTS-AC-FSB SS1/5/6	12/14/2012	PLEASANT SS5-SS6 TIE
12041293	N-TS-PLEASANTTS-IT-QPT	12/26/2012	Low Oil
11951637	N-TS-PLEASANTTS-BR-M27	11/16/2012	Pleasant M27 Breaker - 52Y Relay
12034578	N-TS-PLEASANTTS-AC-FSB SS1/5/6	12/14/2012	PLEASANT SS5 SEC FUSE BLOCK
12034577	N-TS-PLEASANTTS-AC-FSB SS1/5/6	12/14/2012	Pleasnt SS6 Sec Fuse block
11561940	N-TS-PLEASANTTS-IT-QPT	08/07/2012	Pleasant QPT red phase low oil
11561881	N-TS-PLEASANTTS-SW-M23-M24	08/07/2012	Pleasant M23-M24
11895367	N-TS-PLEASANTTS-SI-IF	10/28/2012	SSFF-Ground Scaffold Stairs
11366665	N-TS-PLEASANTTS-SI	07/13/2012	Pleasant Q/J bus install phase markings
11780435	N-TS-PLEASANTTS-SI-IF	09/27/2012	SSFF-Scope Out Line To Tile Bed -BJCC
11157142	N-TS-PLEASANTTS-SI-IF	05/10/2012	TRENCH - Cracked & Broken Covers -BJCC
10872041	N-TS-PLEASANTTS-TF-T2	03/07/2012	PLEASANT T2 OIL LEAKS
10720626	N-TS-PLEASANTTS-AC	07/27/2011	Pleasant AC Cabinet Missing Nomenclature
10728323	N-TS-PLEASANTTS-BU-B	08/23/2011	Pleasant B-bus insulator repair
10726266	N-TS-PLEASANTTS-SI-IF	08/17/2011	Pleasant Grounding Replacements
10720067	N-TS-PLEASANTTS-IT-QPT	07/26/2011	PLeasant TS QPT Low Oil
10720630	N-TS-PLEASANTTS-BR-M24	07/27/2011	Pleasant M24 RMCVT Low Oil
10691566	N-TS-PLEASANTTS-BR-SC2Q	05/16/2011	Pleasant SC2Q Trip Coil
10371072	N-TS-PLEASANTTS-BR	10/09/2009	Missing Nomenclature
10371076	N-TS-PLEASANTTS-SW-M25-M26	10/09/2009	Pleasant M25-M26 Broken Shunts
10371077	N-TS-PLEASANTTS-SW-M27-M28	10/09/2009	Pleasant M27-M28 Broken Shunts

10348090	N-TS-PLEASANTTS-BR-M25	08/24/2009	Pleasant TS M45-LL01 hot spot
10231800	N-TS-PLEASANTTS-SI-BLDG B	12/05/2008	BLDG-Walls Need Repairs & Painting-BJCC
10231745	N-TS-PLEASANTTS-SI-BLDG B	12/05/2008	BLDG - Door Frame Rusting Away
10017903	N-TS-PLEASANTTS-BR-M27	06/25/2008	Repair htr wiring.

3.9 Asset Centric Program Work

The following station equipment has been previously identified in Asset Centric Programs prior to the adoption of the Station Centric planning model:

Func. Location	Asset Class	Age	Condition	Demographics	Economics	Performance	Utilization	Criticality	Composite
N-TS-PLEASANTTS-PR-T1J BF	Protection: Solid State	37	1	100	1	1	0	1	14
N-TS-PLEASANTTS-PR-T2Q BF	Protection: Solid State	37	1	100	1	1	0	1	14
N-TS-PLEASANTTS-PR-42M24 MA	Protection: Electro Mechanical	37	1	50	64	80	0	10	39
N-TS-PLEASANTTS-PR-42M25 MA	Protection: Electro Mechanical	37	1	50	1	84	0	1	33
N-TS-PLEASANTTS-PR-42M26 MA	Protection: Electro Mechanical	38	1	50	1	1	0	1	7
N-TS-PLEASANTTS-PR-42M27 MA	Protection: Solid State	38	1	100	1	1	0	10	14
N-TS-PLEASANTTS-PR-42M28 MA	Protection: Electro Mechanical	38	1	50	1	1	0	1	7
N-TS-PLEASANTTS-BR-SC1J	Breaker: SF6_< 69 kV	0	13	1	1	1	100	27	20
N-TS-PLEASANTTS-BR-SC2Q	Breaker: SF6_< 69 kV	0	13	1	1	1	100	27	20
N-TS-PLEASANTTS-PR-J BU	Protection: Electro Mechanical	38	1	50	1	1	0	1	7
N-TS-PLEASANTTS-PR-J MAIN	Protection: Electro Mechanical	38	1	50	1	1	0	1	7
N-TS-PLEASANTTS-PR-JQ BF	Protection: Solid State	37	1	100	1	5	0	1	15
N-TS-PLEASANTTS-PR-MG MAIN	Protection: Electro Mechanical	38	1	50	1	1	0	1	7
N-TS-PLEASANTTS-PR-Q BU	Protection: Electro Mechanical	38	1	50	1	84	0	1	33
N-TS-PLEASANTTS-PR-42M22 MA	Protection: Electro Mechanical	37	1	50	1	100	0	10	39
N-TS-PLEASANTTS-PR-42M23 MA	Protection: Electro Mechanical	36	1	50	1	1	0	1	7
N-TS-PLEASANTTS-PR-Q MAIN	Protection: Electro Mechanical	38	1	50	1	1	0	1	7
N-TS-PLEASANTTS-PR-SC1 MAIN	Protection: Solid State	21	1	50	1	1	0	1	7
N-TS-PLEASANTTS-PR-SC2 MAIN	Protection: Solid State	21	1	50	1	1	0	1	7
N-TS-PLEASANTTS-BR-SC1J	Breaker: SF6_< 69 kV	22	40	10	100	33	85	27	45
N-TS-PLEASANTTS-BR-SC2Q	Breaker: SF6_< 69 kV	22	51	10	41	82	93	27	58

4.0 RECOMMENDATIONS

There are two general sustainment approaches to consider depending on the asset age distribution & condition and vintage & condition of the existing structure.

Option #1 – In-Situ Piecemeal Component Replacement

With this option, individual components can be replaced at any time. However, as more individual components are replaced, the more the organization is commiting to continued use of the existing older structure. Some older structures are not ideal in terms of maintainability, clearances, and constructability. As well, in-situ replacements could be more costly to account for constructability & outage challenges and the underlying structural infrastructure (footings, steel struture) would not be renewed.

Option #2 – Postpone major capital expenditure now to allow future full rebuild (if the existing older structure is mediocre for reasons noted above)

If the major components of the switchyard (breakers, switches) are all approximately the same age and vintage, consider postponing major capital investment (and maintain) until all major assets begin to show generally declining condition and performance. At this optimal point, consider completely rebuilding switchyard if constraints allow for it. Benefits would be fully renewed infrastructure and improved structure design.

Considering the above, with most 44kV T1/T2 switchyard assets between 40-46yo located in a non-ideal 47A structure and no major urgent condtion or performance concerns, the ideal approach may be to postpone major capital investment in the switchyard for approximately 8-10y, maintain, and reconsider for full rebuild in 8-10y. However, a PCT box could be installed at an earlier date to replace poor PCT equipment.

Equipment	Observation/Recommendation	Reason/Rationale
Insulators	- cap&pin and porcelain strain insulators.	- cap&pin insulators can experience cement growth leading to faileading to failure. -defects are difficult to detect in porcelain strain insulators and they lose mechanical strength when insulator sheds fail.
Yard Lighting	-upgrade fixtures	-existing yard lighting is inadequate.
Cable Trench	- trench and covers degrading in select locations.	
Surge Arresters	-replace porcelain SA's	-porcelain surge arresters have poor pressure venting which may weaken arrester and result in failure.
QPT & JPT	-Replace	-Older oil-filled PT's are likely have high PCB levels.
PCT	-consider replacement of all T1/T2 PCT equipment.	- all protections advanced in age, declining in condition, and older technology is becoming obsolete.
48VDC plant	-remove	- remove 48VDC plant from control building once no longer required.
Revenue Metering	-upgrade	- upgrade revenue metering equipment to comply with latest standard.

5.0 REFERENCE SOURCES

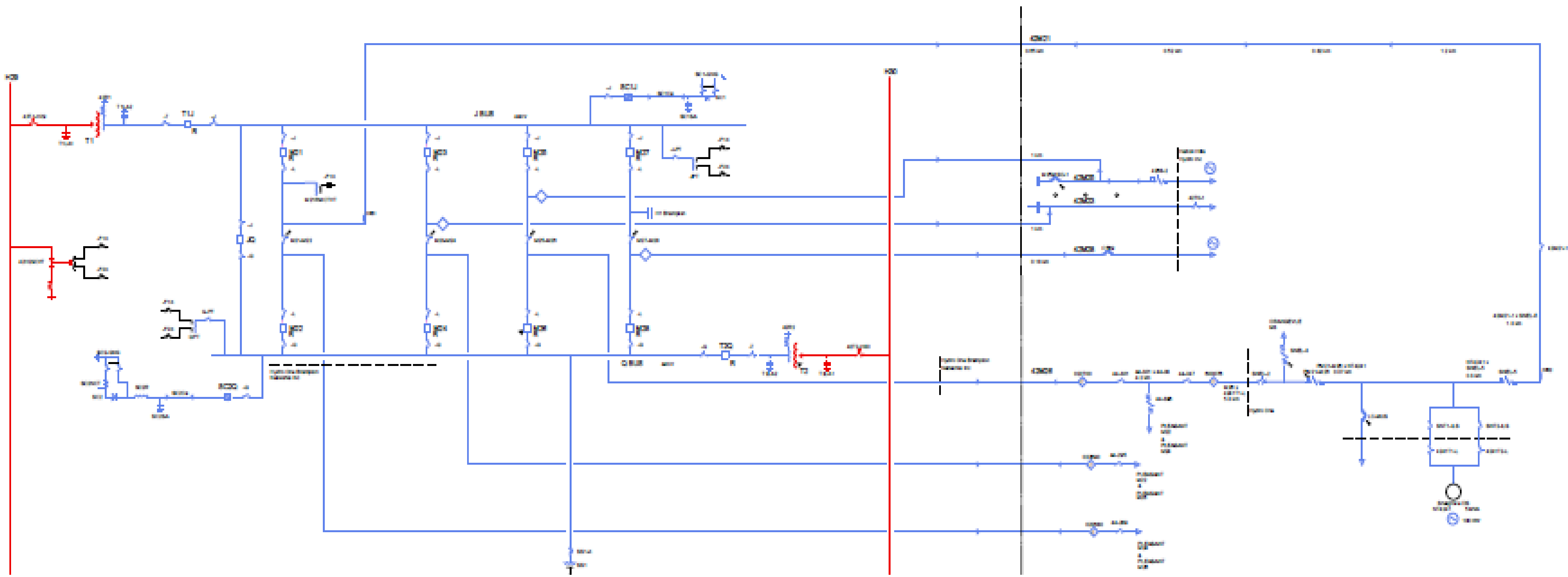
Bibliography

[1] Hydro One Networks Inc., "Station Fault Current Ratings," 2014. [Online]. Available: https://teams.hydroone.com/sites/TPD/TPD/ss_pd/Short Circuit/Surveys/Breakers.

[2] "Hydro One Networks; Stranded Load May 2013," [Online]. Available: https://teams.hydroone.com/sites/gridops/NOD/OP/Shared Documents.

[3] Conestoga-Rogers & Associates, "Hydro One Station Spill Risk Model," Mississauga, 2011.

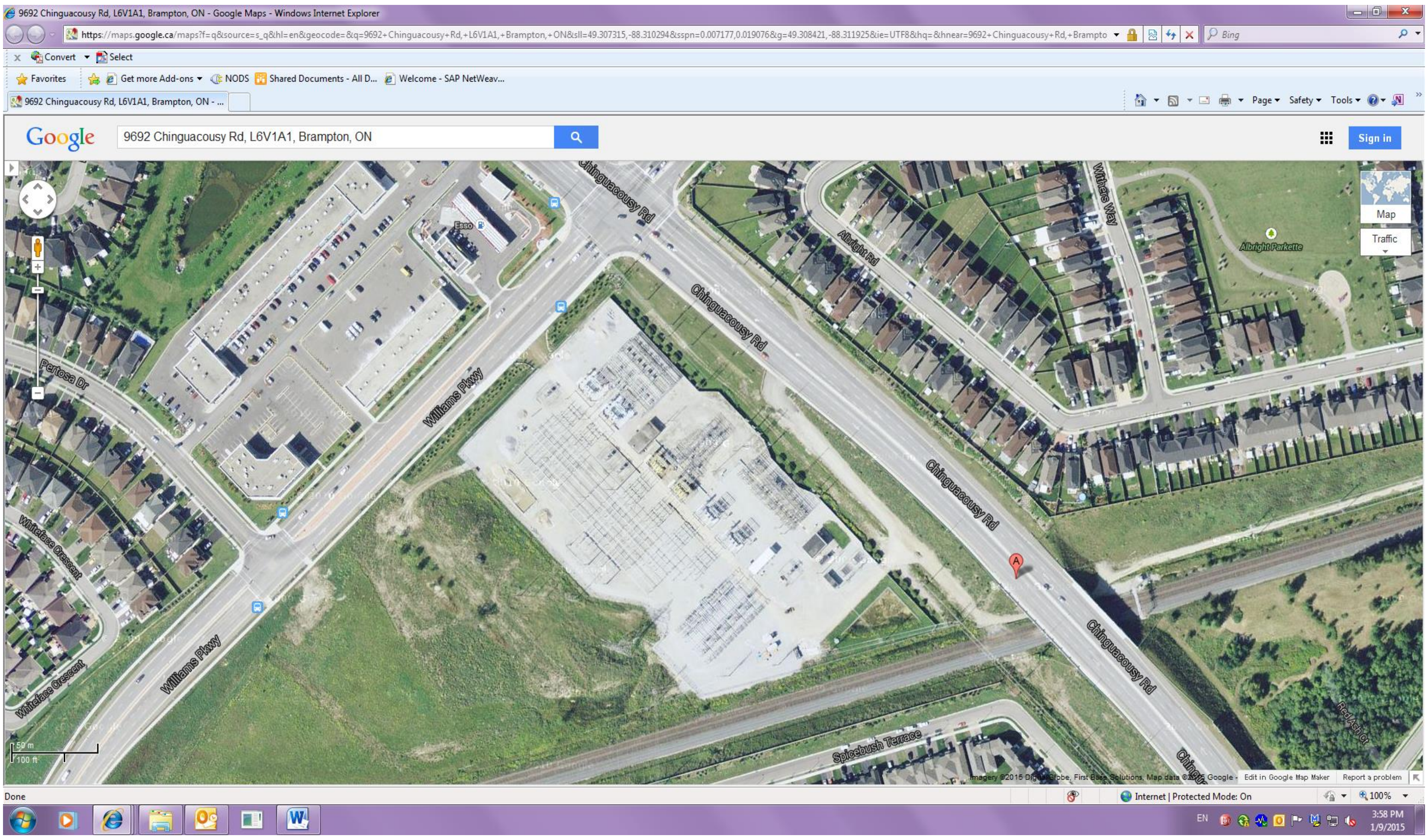
APPENDIX 1 - PLEASANT TS OPERATING DIAGRAM (CENTERED ON T1/T2 DESN)

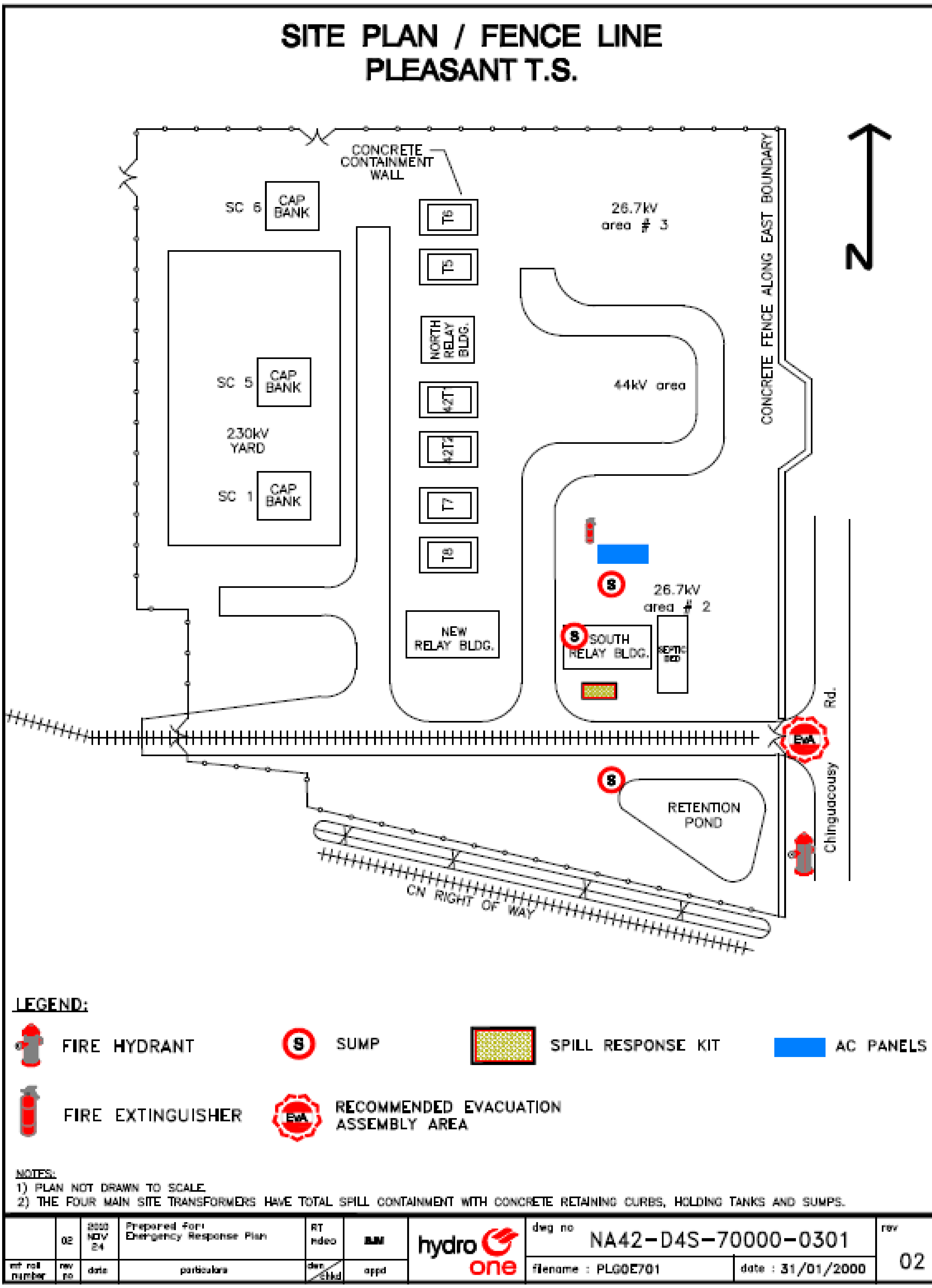


APPENDIX 2 TRANSMISSION EQUIPMENT OUTAGE PERFORMANCE DATA

Pleasant
T1/T2

TEST	1/1/2009	*42013*	11/30/2014							
MCTYPE	MCID	OUTDATE	OUTIME	ODURALL_HR	PCAUSE	DESCRIPT	OUTURG	OUTEXT	STANAME	REMARK
Breaker	NA42SC1J	22-Jun-11	06:30	507.58	7NCKC	Non Pwr Eqpt-Control-Breaker-Cable/Wiring Defect	FM	CC	PLEASANT TS	CANNOT CLOSE FROM CONTROL
Breaker	NA42SC2Q	30-Jan-12	14:06	744.23	1MKG	Main Pwr-Bkr Eqpt-Auxiliary Equipment	FM	CC	PLEASANT TS	REPLACE RECEIVER TANK-RUSTED
Bus	NA42J	23-Feb-10	13:54	0.45	4FS	Power System Configuration-Series Connection	FA	CCT	PLEASANT TS	H30 TRIP-R19T WAS O/S
Bus	NA42Q	09-Mar-12	07:13	0.12	6B	Foreign Interference-Birds	FA	CCT	PLEASANT TS	GOOSE CONTACTED M22-Q SWITCH
Bus	NA42Q	23-Feb-10	13:54	0.45	4FS	Power System Configuration-Series Connection	FA	CCT	PLEASANT TS	H30 TRIP
Capacitor	NA42SC1	29-Jun-14	15:50	69.25	6B	Foreign Interference-Birds	FA	CCT	PLEASANT TS	BIRD CONTACT
Capacitor	NA42SC1	22-Jun-11	06:30	507.58	4FKB	Power System Config.-Breaker Unavailable/Failure	FM	CCT	PLEASANT TS	SC1J BKR
Capacitor	NA42SC2	30-Jan-12	14:06	744.23	4FS	Power System Configuration-Series Connection	FM	CCT	PLEASANT TS	SC2Q BREAKER
Capacitor	NA42SC2	29-Jun-11	10:17	25.40	1MCBA	Main Pwr-Cap Eqpt-Unit Failure	FA	CCT	PLEASANT TS	ONE CAN DEFECTIVE
Capacitor	NA42SC2	03-Jun-10	16:52	16.00	1MCBB	Main Pwr-Cap Eqpt-Unit Blown Fuse	FA	CCT	PLEASANT TS	FUSES BLOWN-REPLACED
Transformer	NA42T1	05-Jun-14	11:04	0.07	4FZ	Power System Configuration-Common Trip Zone	FA	CCT	PLEASANT TS	H29 TRIP
Transformer	NA42T2	28-Jun-13	14:06	28.17	6A	Foreign Interference-Animals	FA	CCT	PLEASANT TS	SQUIRREL CONTACT WITH BUSHING
Transformer	NA42T2	23-Feb-10	13:54	0.45	4FZ	Power System Configuration-Common Trip Zone	FA	CCT	PLEASANT TS	H30 TRIP


9692 Chinguacousy Rd, L6V1A1, Brampton, ON - Google Maps - Windows Internet Explorer
9692 Chinguacousy Rd, L6V1A1, Brampton, ON
Chinguacousy Rd
Williams Pkwy
Map
Traffic
Done
Internet | Protected Mode: On


SITE PLAN / FENCE LINE
PLEASANT T.S.
CONCRETE CONTAINMENT WALL
SC 6 CAP BANK
T6
T5
26.7kV area # 3
CONCRETE FENCE ALONG EAST BOUNDARY
N
NORTH RELAY BLDG.
SC 5 CAP BANK
44kV area
42T1
42T2
230kV YARD
SC 1 CAP BANK
T7
T8
26.7kV area # 2
NEW RELAY BLDG.
SOUTH RELAY BLDG.
SEPTIC BED
EvA
Chinguacousy Rd.
RETENTION POND
CN RIGHT OF WAY
LEGEND:
FIRE HYDRANT
SUMP
SPILL RESPONSE KIT
AC PANELS
FIRE EXTINGUISHER
RECOMMENDED EVACUATION ASSEMBLY AREA
NOTES:
1) PLAN NOT DRAWN TO SCALE.
2) THE FOUR MAIN SITE TRANSFORMERS HAVE TOTAL SPILL CONTAINMENT WITH CONCRETE RETAINING CURBS, HOLDING TANKS AND SUMPS.
02
2000 NOV 24
Prepared for: Emergency Response Plan
RT
mt roll number
rev no
date
particulars
dsn chkd
appd
hydro one
dwg no NA42-D4S-70000-0301
filename : PLG0E701
date : 31/01/2000
rev 02

Pleasant TS T5 /T6

Station Assessment

[Keyword]

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REVISION HISTORY

Date	Revision	Revision Comments
Jan 14, 2015	0	First Draft

APPROVAL SIGNATURES

	Prepared By	Reviewed By:	Approved By:
Signature:			
Name:	Tanya Ryzhova	Michael Xavier	
Title:	Network Mgmt Engineer	Sr. Network Mgmt Engineer	
Date:			

TABLE OF CONTENTS

1.0 INTRODUCTION

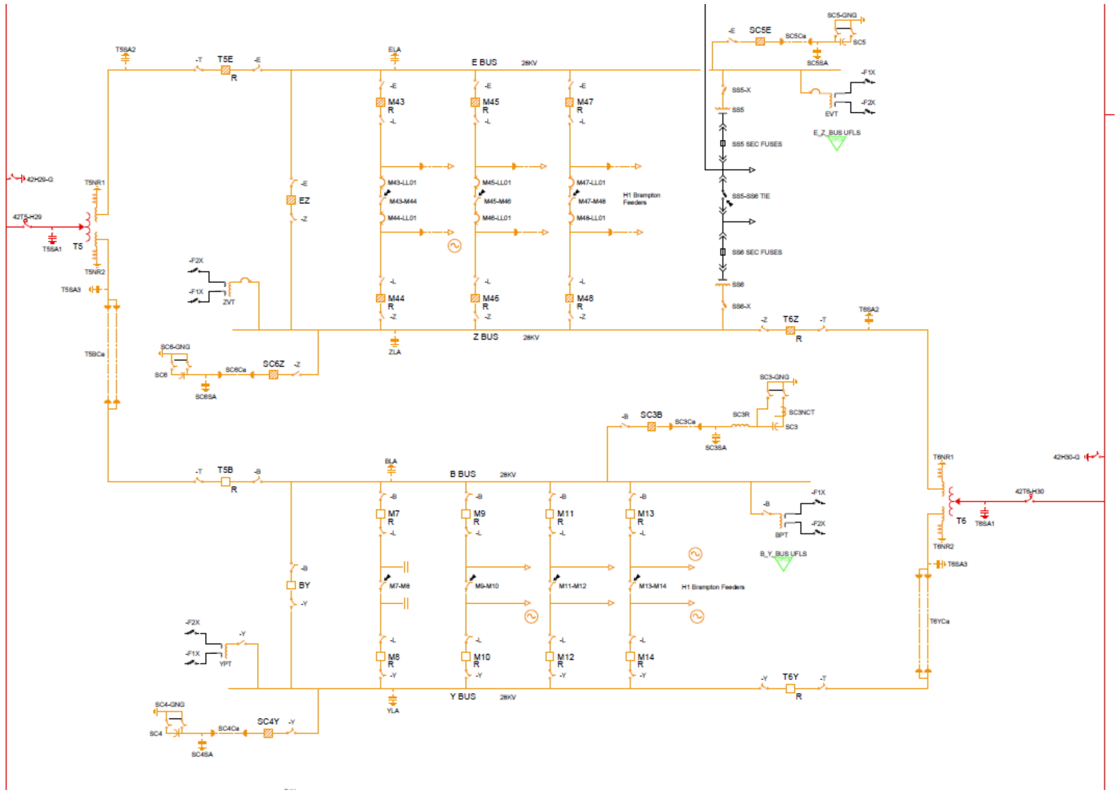
This assessment provides an overview of the current state of the station. The recommendations offered in this document will allow Asset Management make well-informed capital investment decisions.

Integration of the replacement of multiple end of life components into a single investment allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work. A station assessment will ensure that all the replacement needs are captured and integrated into the investment before release.

2.0 STATION SUMMARY

Pleasant TS is a transmission station that provides transformation of 230 kV to 44kV and 27.6 kV. Pleasant TS serves as the supply to Hydro One Brampton, Halton Hills Hydro as well as directly connected Hydro One customers. This station is located in Brampton and supplies customers in the Brampton, Peel and Halton Hills area. Pleasant TS was originally placed i/s in 1954 and many assets are in degraded condition and are in need of replacement.

The Pleasant TS is supplied by 2-230kV LH3&LH4 lines. T5/T6 Double Secondaries Transformers provide power to two 27.6kV switchyards with six and eight feeders.



3.0 DESKSIDE STATION ASSESSMENT

3.1 Station Fault Current Rating

Table 1: 2014 Station Fault Current Rating for Pleasant TS [1].

Pleasant TS	Symmetrical		Asymmetrical		Symmetrical Rating		Asymmetrical Rating	
	3ph kA	LG kA	3ph kA	LG kA	3ph	LG	3ph	LG
BY Bus @ 27.6kV	13.095	10.178	16.053	13.402	18.50	18.50	19.90	19.90
EZ Bus @ 27.6kV	12.944	10.148	15.881	13.38	30.00	30.00	32.30	32.30

3.2 Station 5 Year DESN Loading (2008-2012)

Table 2: Transformer MVA Ratings, 5-Yr Avg, 5-Yr Peaks & Loading Deviation %'s

DESN	TF Max Rating (MVA)	StDev % of Max Avg	Max Avg (MVA) 2008-12	Max Avg % of TF Max Rtg	Max Peak vs Max Avg	StDev % of Max Peak	Max Peak (MVA) 2008-12	Max Peak % of TF Max Rtg	Max Peak MVA as % of LTR Avg	LTR Load Risk	LTR vs TF Max Rtg
T5/T6	125.0	10.6%	106.56	85.2%	186.4%	6.1%	198.65	158.9%	89.8%	Y	1.7

Table 3: Station LTR Ratings and Average Peak Loading

DESN	LTR Rating		2008		2009		2010		2011		2012	
DESN	Sum 10d LTR	Win 10d LTR	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]
T5/T6	201.60	221.20	94.73	182.32	106.56	182.22	98.95	198.65	88.90	174.32	92.55	198.61

- Adjusted, values were skewed by faults, transfers or anomalies

3.2.1 Stranded Load [2]

Station	Breakers	Connections	Stranded
Pleasant TS	M7TOM14, M43TOM48		Yes (50%)

3.3 Customer Information

Table 4: Customer Satisfaction Summary

Customer Name	Customer Satisfaction Rating					Trend
	2009	2010	2011	2012	2013	
Hydro One Brampton Networks	Very Satisfied	Somewhat satisfied	Somewhat satisfied	Very Satisfied	Very Satisfied	Improving

3.4 Outage Information

The Pleasant TS T5/T6 yard is not considered a Delivery Point (DP) group or individual outlier (Frequency or Duration). The 10 year average performance is below the group outlier.

Frequency>>>

			10 yr avg	3 yr average										
OPD ES	Bus MW	DESN MW	12-03	12-10	11-09	10-08	09-07	08-06	07-05	06-04	05-03	Indiv. Outlier Baseline (Freq)	Group Outlier Freq Target	Group Outlier Freq UB
B	21.6	86.6	0.8	0.7	1.0	0.7	1.0	0.3	0.7	1.0	1.0	1.0	0.3	1.0
Y	21.6	86.6	0.6	0.7	1.0	1.0	0.7	0.0	0.0	0.3	0.7	0.6	0.3	1.0
E	21.6	86.6	0.1	0.0	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.4	0.3	1.0
Z	21.6	86.6	0.2	0.3	0.7	0.7	0.3	0.0	0.0	0.0	0.0	0.4	0.3	1.0

Duration>>>

			10 yr avg	3 yr average										
OPDES	Bus MW	DESN MW	12-03	12-10	11-09	10-08	09-07	08-06	07-05	06-04	05-03	Indiv. Outlier Baseline (Dur.)	Group Outlier Dur. Target	Group Outlier Dur. UB
B	21.6	86.6	7.3	5.6	6.3	3.3	10.2	6.9	10.9	8.3	8.3	23.6	5.0	25.0
Y	21.6	86.6	5.3	11.7	12.3	12.3	3.3	0.0	0.0	0.3	2.5	6.8	5.0	25.0
E	21.6	86.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.0	25.0
Z	21.6	86.6	2.7	9.0	9.0	9.0	0.0	0.0	0.0	0.0	0.0	0.0	5.0	25.0

3.5 Station Spill Risk Ranking

Pleasant TS has 6 oil-filled power transformers supplying 4 DESN switchyards. The overall station is ranked 145th out of 256 stations based on existing risk score from a 2011 spill risk report by Conestoga-Rogers & Associates [3].

3.6 Asset Analytics

Based off the Composite score in Asset Analytics, the following station equipment, not previously identified under the asset-centric work program, with a *Composite* score greater than 35 or a *Demographic* score greater than 74 should be considered for replacement.

Func. Location	Asset Class	Age	Condition	Demographics	Economics	Performance	Utilization	Criticality	Composite
N-TS-PLEASANTTS-SW-M11-B	Switch: Air Break_< 69 kV	47	45	94	10	1	10	21	29
N-TS-PLEASANTTS-SW-M13-B	Switch: Air Break_< 69 kV	47	45	94	10	1	10	21	29
N-TS-PLEASANTTS-SW-M13-L	Switch: Air Break_< 69 kV	47	45	94	10	1	10	21	29
N-TS-PLEASANTTS-BR-T5B	Breaker: Oil_< 69 kV	50	23	82	1	1	68	31	28
N-TS-PLEASANTTS-BR-T6Y	Breaker: Oil_< 69 kV	50	63	82	9	1	90	31	45
N-TS-PLEASANTTS-BR-M11	Breaker: Oil_< 69 kV	49	50	78	1	38	45	23	43
N-TS-PLEASANTTS-SW-M14-L	Switch: Air Break_< 69 kV	47	45	94	10	1	10	21	29
N-TS-PLEASANTTS-SW-M14-Y	Switch: Air Break_< 69 kV	47	45	94	10	1	10	21	29
N-TS-PLEASANTTS-PR-42M14 MAIN	Protection: Solid State	26	1	75	1	1	0	10	11

N-TS-PLEASANTTS-PR-B MAIN	Protection: Solid State	37	1	100	4	1	0	1	14
N-TS-PLEASANTTS-PR-BY BF	Protection: Solid State	44	1	100	1	1	0	1	14
N-TS-PLEASANTTS-SW-T5B-B	Switch: Air Break_< 69 kV	47	45	94	10	1	10	21	29
N-TS-PLEASANTTS-SW-BY-B	Switch: Air Break_< 69 kV	47	45	94	10	1	10	21	29
N-TS-PLEASANTTS-SW-BY-Y	Switch: Air Break_< 69 kV	47	45	94	10	1	10	21	29
N-TS-PLEASANTTS-SW-YPT-Y	Switch: Air Break_< 69 kV	47	45	94	10	1	10	21	29
N-TS-PLEASANTTS-SW-T5B-T	Switch: Air Break_< 69 kV	47	45	94	10	1	10	21	29
N-TS-PLEASANTTS-SW-T6Y-T	Switch: Air Break_< 69 kV	47	45	94	10	1	10	21	29
N-TS-PLEASANTTS-SW-T6Y-Y	Switch: Air Break_< 69 kV	47	45	94	10	1	10	21	29
N-TS-PLEASANTTS-BR-M9	Breaker: Oil_< 69 kV	50	37	82	1	1	32	23	27
N-TS-PLEASANTTS-BR-BY	Breaker: Oil_< 69 kV	50	23	82	100	60	71	29	53
N-TS-PLEASANTTS-BR-M12	Breaker: Oil_< 69 kV	49	42	78	1	1	31	23	28
N-TS-PLEASANTTS-PR-T5B BF	Protection: Solid State	44	1	100	1	1	0	1	14
N-TS-PLEASANTTS-PR-T6Y BF	Protection: Solid State	44	1	100	1	1	0	1	14
N-TS-PLEASANTTS-PR-Y MAIN	Protection: Solid State	37	1	100	1	1	0	1	14

N-TS-PLEASANTTS-BR-T6Y	Breaker: Oil_< 69 kV	50	63	82	9	1	90	31	45
N-TS-PLEASANTTS-BR-M11	Breaker: Oil_< 69 kV	49	50	78	1	38	45	23	43
N-TS-PLEASANTTS-BR-M13	Breaker: Oil_< 69 kV	39	70	42	1	38	92	23	52
N-TS-PLEASANTTS-SC-SC3	Capacitor: Shunt_< 69 kV	21	20	40	4	90	100	28	51
N-TS-PLEASANTTS-BU-B	Bus: Air Insulated_< 69 kV	0	1	1	45	100	0	30	39
N-TS-PLEASANTTS-BU-Z	Bus: Air Insulated_< 69 kV	23	1	58	1	100	0	30	41
N-TS-PLEASANTTS-PR-SC3 MAIN	Protection: Solid State	21	1	50	100	100	0	1	48
N-TS-PLEASANTTS-BR-BY	Breaker: Oil_< 69 kV	50	23	82	100	60	71	29	53
N-TS-PLEASANTTS-TC-LEASED_PSTS	Telecom: Leased Circuit	0	33	0	30	100	0	1	54
N-TS-PLEASANTTS-TC-NT0001M	Telecom: Neutralising Transfomers	6	1	1	76	93	0	1	37

3.7 Station Security

*Pleasant TS T1/T2 is classified as **High Risk** and as of July 2014 has experienced fourteen (14) break-ins since 2007. The history of break-ins at Pleasant TS is shown in Table 1.*

Table 1: Count of Break-Ins by Year at Richview TS

2007	2008	2009	2010	2011	2012	2013	2014
2	0	0	0	7	0	3	2

As per ***SP-14-001-R1:*** *Functional Requirements for Preventing Copper Theft*, and ***SP-14000-001-R0:*** *Functional Requirements for Transmission and Distribution Security Detection and Verification Systems*, all stolen/missing *below grade* fence grounding and power equipment grounding conductors are to be replaced with copper-clad steel conductors whenever safely possible and when the original copper conductor was 4/0# or smaller. In addition, all stolen/missing *above grade* fence grounding is to be replaced with aluminum grounding material.

Defined as a Medium Risk station, current functional requirements dictate that the station be enclosed by a standard 8' (2.44 m) chain link perimeter fence.

For reference, criteria for station security risk classification are summarized in Table 2, below.

Table 2: Security Risk Classifications

Security Risk Level	Description
High	10+ break-ins from 2007- present
Medium	1-9 break-ins from 2007- present
Low	0 break-ins from 2007- present

3.8 Potential Need & Deficiency Report Notifications

Below is a summary of Potential Needs (PN) and Deficiency Report (DR) notification that have been issued by Field Staff and currently outstanding.

Table 3: Listing of Open and Outstanding Potential Needs (PN) Notifications

Notification	Functional Loc.	Notif.date	Description
13222093	N-TS-PLEASANTTS	08/11/2014	Wood Pole/Structure Repl Candidates
13222092	N-TS-PLEASANTTS	08/11/2014	Wood Pole/Structure Repl Candidates
13222099	N-TS-PLEASANTTS	08/11/2014	Wood Pole/Structure Repl Candidates
13222098	N-TS-PLEASANTTS	08/11/2014	Wood Pole/Structure Repl Candidates
13222097	N-TS-PLEASANTTS	08/11/2014	Wood Pole/Structure Repl Candidates
13222096	N-TS-PLEASANTTS	08/11/2014	Wood Pole/Structure Repl Candidates
13222094	N-TS-PLEASANTTS	08/11/2014	Wood Pole/Structure Repl Candidates
13222095	N-TS-PLEASANTTS	08/11/2014	Wood Pole/Structure Repl Candidates
11153587	N-TS-PLEASANTTS-CN	05/04/2012	Pleasant RTU Bell circuit
10351559	N-TS-PLEASANTTS-SI	09/01/2009	Multi Station Security Upgrades SIP
10348780	N-TS-PLEASANTTS-PR	08/26/2009	Relays upgrade plan status (ZFB)

Table 4: Listing of Open and Outstanding Deficiency Report Notifications for the LV yard

Notification			
13500986	N-TS-PLEASANTTS-BR-SC5E	01/12/2015	Pleasant TS - SC5E Htr issue.
13497489	N-TS-PLEASANTTS-SI-BLDG A	01/06/2015	Place Salt Bins-BJCC
13497620	N-TS-PLEASANTTS-SI-BLDG B	01/06/2015	Re-fill Salt Bin-BJCC
13497623	N-TS-PLEASANTTS-SI-BLDG C	01/06/2015	Check Heater-BJCC
13497621	N-TS-PLEASANTTS-SI	01/06/2015	Place Snow Shovel

13497622	N-TS-PLEASANTTS-SI-FG	01/06/2015	Install Gate Stop
13265567	N-TS-PLEASANTTS-SI-IF	08/22/2014	Pleasant trip hazard -BJCC
13326630	N-TS-PLEASANTTS-BR-M11	09/09/2014	Pleasant M11 Oil Leaks
13326439	N-TS-PLEASANTTS-TF-T5	09/09/2014	Pleasant T5 Hads
13436665	N-TS-PLEASANTTS-SI-BLDG C	11/14/2014	Pleasant Hvac
12716747	N-TS-PLEASANTTS-SI-EN	10/17/2013	ENV- Multipal containment wall cracks
13326780	N-TS-PLEASANTTS	09/09/2014	Pleasant Leaking Pot Head - T6Yca
13326629	N-TS-PLEASANTTS-BR-T6Y	09/09/2014	Pleasant T6Y Local Indication faded
13265580	N-TS-PLEASANTTS-SW	08/22/2014	Pleasant 44kv bus switch mtnce.
13208597	N-TS-PLEASANTTS-BR-M13	08/06/2014	Pleasant M13 Open/Close Indicator Broken
13009844	N-TS-PLEASANTTS-BU	05/30/2014	live bus not indicated on print
12889645	N-TS-PLEASANTTS-TF-T6	03/25/2014	Pleasant T6 TAP CHANGER ISSUES
12896304	N-TS-PLEASANTTS-SI-BLDG A	04/03/2014	BLDG. FLOOR TILES -BJCC
12896082	N-TS-PLEASANTTS-SI	04/03/2014	COPPER GROUND THEFT
12904485	N-TS-PLEASANTTS-DC-CH125A	04/09/2014	Faulty charger timer
12431026	N-TS-PLEASANTTS-SI	07/22/2013	sump electrical fault
12569428	N-TS-PLEASANTTS-SI-BLDG A	09/11/2013	ELIGHTS- Emergency light not working
12267853	N-TS-PLEASANTTS-SI-IF	05/29/2013	Pleasant Sump Alarm
12258779	N-TS-PLEASANTTS-SI-BLDG C	05/27/2013	HVAC Pleasant PCT Building
11157144	N-TS-PLEASANTTS-SI-BLDG B	05/10/2012	BLDG-Bricks Spalling South Side-BJCC
12034578	N-TS-PLEASANTTS-AC-FSB SS1/5/6	12/14/2012	PLEASANT SS5 SEC FUSE BLOCK
12034577	N-TS-PLEASANTTS-AC-FSB SS1/5/6	12/14/2012	Pleasnt SS6 Sec Fuse block
11895367	N-TS-PLEASANTTS-SI-IF	10/28/2012	SSFF-Ground Scaffold Stairs
11780435	N-TS-PLEASANTTS-SI-IF	09/27/2012	SSFF-Scope Out Line To Tile Bed -BJCC
11605808	N-TS-PLEASANTTS-TF-T6	08/17/2012	Pleasant T6 DC GROUND REPAIR
11273173	N-TS-PLEASANTTS-TF-T6	07/05/2012	Pleasant T6 test operate level guage
11157142	N-TS-PLEASANTTS-SI-IF	05/10/2012	TRENCH - Cracked & Broken Covers -BJCC
10756170	N-TS-PLEASANTTS-SC-SC5	10/07/2011	Pleasant SC5 blown fuses
10756428	N-TS-PLEASANTTS-IT-ZVT	10/07/2011	Pleasant ZVT broken insulator
10755104	N-TS-PLEASANTTS-TF-T6	10/06/2011	Pleasant T6 gas relay drain repairs.
10720626	N-TS-PLEASANTTS-AC	07/27/2011	Pleasant AC Cabinet Missing Nomenclature
10728323	N-TS-PLEASANTTS-BU-B	08/23/2011	Pleasant B-bus insulator repair
10726266	N-TS-PLEASANTTS-SI-IF	08/17/2011	Pleasant Grounding Replacements
10621074	N-TS-PLEASANTTS-SW-T5B-T	11/30/2010	T5B-T REQUIRES ADJUSTMENT
10621073	N-TS-PLEASANTTS-SW-T5B-B	11/30/2010	T5B-B REQUIRES ADJUSTMENT

10371072	N-TS-PLEASANTTS-BR	10/09/2009	Missing Nomenclature
10371073	N-TS-PLEASANTTS-SW-M45-M46	10/09/2009	Pleasant M45-M46 Broken Nomenclature
10371074	N-TS-PLEASANTTS-SW-M47-M48	10/09/2009	Pleasant M47-M48 Broken Nomenclature
10231800	N-TS-PLEASANTTS-SI-BLDG B	12/05/2008	BLDG-Walls Need Repairs & Painting-BJCC
10231745	N-TS-PLEASANTTS-SI-BLDG B	12/05/2008	BLDG - Door Frame Rusting Away
10016506	N-TS-PLEASANTTS-SW-T5B-B	06/20/2008	HOT JAW PAD CONNECTION

3.9 Asset Centric Program Work

The following station equipment has been previously identified in Asset Centric Programs prior to the adoption of the Station Centric planning model:

Func. Location	Asset Class	Age	Condition	Demographics	Economics	Performance	Utilization	Criticality	Composite
N-TS-PLEASANTTS-BR-SC6Z	Breaker: SF6_< 69 kV	25	13	25	3	7	49	27	17
N-TS-PLEASANTTS-BR-T5E	Breaker: SF6_< 69 kV	25	13	25	1	1	87	31	21
N-TS-PLEASANTTS-PR-42M7 MAIN	Protection: Electro Mechanical	37	1	50	1	1	0	10	8
N-TS-PLEASANTTS-PR-42M8 MAIN	Protection: Electro Mechanical	37	1	50	1	1	0	10	8
N-TS-PLEASANTTS-PR-42M9 MAIN	Protection: Electro Mechanical	37	1	50	1	1	0	10	8
N-TS-PLEASANTTS-PR-B BU	Protection: Electro Mechanical	37	1	50	1	1	0	1	7
N-TS-PLEASANTTS-PR-B MAIN	Protection: Solid State	37	1	100	4	1	0	1	14
N-TS-PLEASANTTS-PR-BY BF	Protection: Solid State	44	1	100	1	1	0	1	14
N-TS-PLEASANTTS-PR-E BU	Protection: Electro Mechanical	23	1	25	1	1	0	1	4
N-TS-PLEASANTTS-PR-E MAIN	Protection: Electro Mechanical	23	1	25	1	1	0	1	4
N-TS-PLEASANTTS-PR-EZ BF	Protection: Solid State	23	1	50	1	1	0	1	7
N-TS-PLEASANTTS-PR-42M43 MAIN	Protection: Solid State	23	1	50	1	1	0	10	8
N-TS-PLEASANTTS-PR-42M44 MAIN	Protection: Solid State	23	1	50	1	1	0	10	8
N-TS-PLEASANTTS-PR-42M45 MAIN	Protection: Solid State	23	1	50	1	1	0	10	8
N-TS-PLEASANTTS-PR-42M46 MAIN	Protection: Solid State	23	1	50	1	1	0	10	8
N-TS-PLEASANTTS-PR-42M47 MAIN	Protection: Solid State	23	1	50	1	1	0	10	8
N-TS-PLEASANTTS-PR-42M48 MAIN	Protection: Solid State	23	1	50	1	1	0	10	8
N-TS-PLEASANTTS-PR-SC3 MAIN	Protection: Solid State	21	1	50	100	100	0	1	48
N-TS-PLEASANTTS-PR-SC4 MAIN	Protection: Solid State	21	1	50	1	1	0	1	7
N-TS-PLEASANTTS-PR-SC5 MAIN	Protection: Solid State	21	1	50	61	50	0	1	29
N-TS-PLEASANTTS-PR-SC6 MAIN	Protection: Solid State	21	1	50	1	1	0	1	7
N-TS-PLEASANTTS-BR-T6Z	Breaker: SF6_< 69 kV	26	11	30	1	1	37	31	14
N-TS-PLEASANTTS-BR-SC5E	Breaker: SF6_< 69 kV	25	13	25	1	7	50	27	17

N-TS-PLEASANTTS-PR-T5B BF	Protection: Solid State	44	1	100	1	1	0	1	14
N-TS-PLEASANTTS-PR-T5E BF	Protection: Solid State	23	1	50	1	1	0	1	7
N-TS-PLEASANTTS-PR-T6Y BF	Protection: Solid State	44	1	100	1	1	0	1	14
N-TS-PLEASANTTS-PR-T6Z BF	Protection: Solid State	23	1	50	1	1	0	1	7
N-TS-PLEASANTTS-PR-Y BU	Protection: Electro Mechanical	37	1	50	1	84	0	1	33
N-TS-PLEASANTTS-PR-Y MAIN	Protection: Solid State	37	1	100	1	1	0	1	14
N-TS-PLEASANTTS-PR-Z BU	Protection: Electro Mechanical	23	1	25	1	1	0	1	4
N-TS-PLEASANTTS-PR-Z MAIN	Protection: Electro Mechanical	23	1	25	4	4	0	1	5
N-TS-PLEASANTTS-BR-SC3B	Breaker: SF6_< 69 kV	0	13	1	1	1	1	27	7
N-TS-PLEASANTTS-BR-SC4Y	Breaker: SF6_< 69 kV	0	13	1	1	1	100	27	20

4.0 RECOMMENDATIONS

There are two general sustainment approaches to consider depending on the asset age distribution & condition and vintage & condition of the existing structure.

Option #1 – In-Situ Piecemeal Component Replacement

With this option, individual components can be replaced at any time. However, as more individual components are replaced, the more the organization is commiting to continued use of the existing older structure. Some older structures are not ideal in terms of maintainability, clearances, and constructability. As well, in-situ replacements could be more costly to account for constructability & outage challenges and the underlying structural infrastructure (footings, steel struture) would not be renewed.

Option #2 – Postpone major capital expenditure now to allow future full rebuild (if the existing older structure is mediocre for reasons noted above)

If the major components of the switchyard (breakers, switches) are all approximately the same age and vintage, consider postponing major capital investment (and maintain) until all major assets begin to show generally declining condition and performance. At this optimal point, consider completely rebuilding switchyard if constraints allow for it. Benefits would be fully renewed infrastructure and improved structure design.

Considering the above, with most BY switchyard assets approximately 50yo located in a non-ideal 30C structure and no major urgent condtion or performance concerns, the ideal approach may be to postpone major capital investment in the switchyard for a few years, maintain, and reconsider for full rebuild in 5-10y. However, a PCT box could be installed at an earlier date to replace poor PCT equipment.

Equipment	Observation/Recommendation	Reason/Rationale
T5B, BY, T6Y, M9, M11, M12	- consider replacement of oil-filled circuit breakers	-oil breakers are obsolete technology. These breakers are showing declining condition and performance.
T5E, EZ, SC6Z, SC5E, T6Z	-consider replacement of early vintage SF6 breakers.	- early vintage SF6 breakers that experience leaks and performance issues.
M7&M8	-remove	- M7 & M8 no longer dead-ended and not utilized.
Insulators	- cap&pin and porcelain strain insulators.	- cap&pin insulators can experience cement growth leading to faileading to failure. -defects are difficult to detect in porcelain strain insulators and they lose mechanical strength when insulator sheds fail.
Yard Lighting	-upgrade fixtures	-existing yard lighting is inadequate.
Cable Trench	- trench and covers degrading in select locations.	
Surge Arresters	-replace porcelain SA’s	-porcelain surge arresters have poor pressure venting which may

		weaken arrester and result in failure.
ZVT, EVT, BPT and YPT	-Replace	-Older oil-filled PT's are likely have high PCB levels.
PCT	-consider replacement of all T5/T6 PCT equipment.	- all protections advanced in age, declining in condition, and older technology is becoming obsolete.

5.0 REFERENCE SOURCES

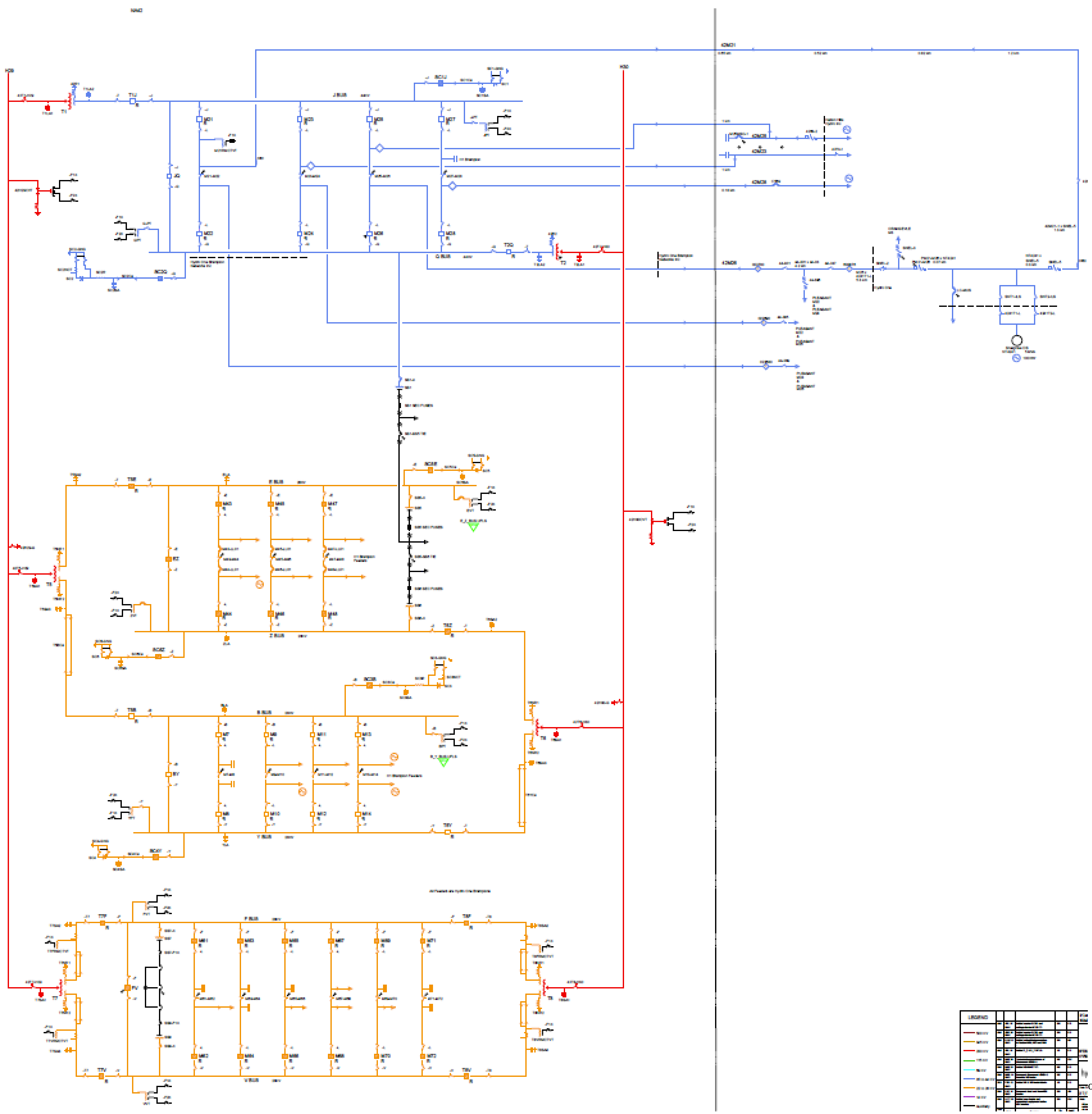
Bibliography

[1] Hydro One Networks Inc., "Station Fault Current Ratings," 2014. [Online]. Available: https://teams.hydroone.com/sites/TPD/TPD/ss_pd/Short Circuit/Surveys/Breakers.

[2] "Hydro One Networks; Stranded Load May 2013," [Online]. Available: https://teams.hydroone.com/sites/gridops/NOD/OP/Shared Documents.

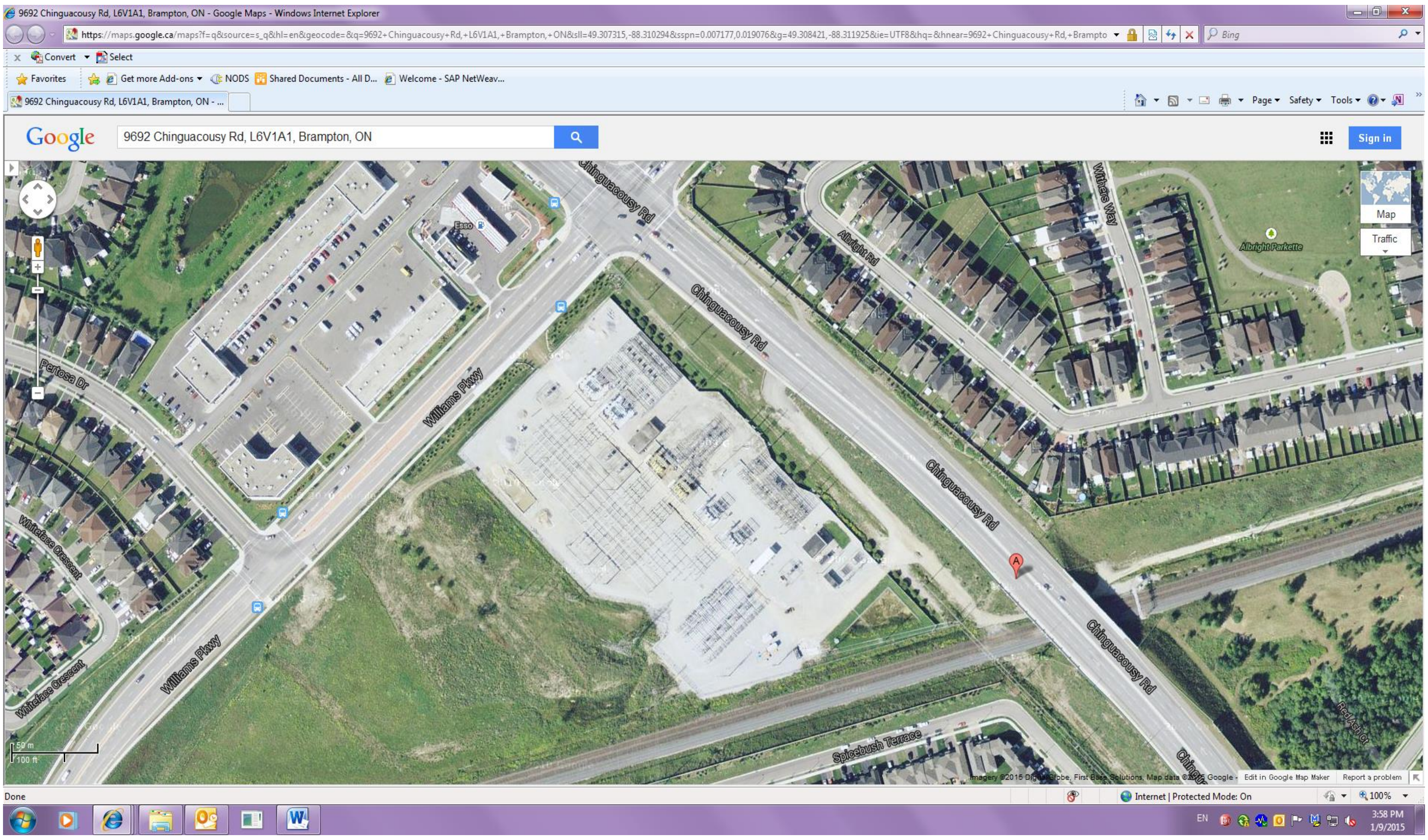
[3] Conestoga-Rogers & Associates, "Hydro One Station Spill Risk Model," Mississauga, 2011.

APPENDIX 1 - PLEASANT TS OPERATING DIAGRAM (CENTERED ON T5/T6 DESN)



APPENDIX 2 TRANSMISSION EQUIPMENT OUTAGE PERFORMANCE DATA

TEST	1/1/2009	*	42018	11/30/2014							
MCTYPE	MCID	VOLT	OUTDATE	OUTIME	ODURALL_HR	PCAUSE	DESCRIPT	OUTURG	OUTEXT	STANAME	CMODI
Breaker	NA42BY	Low Voltage	28-Jul-12	02:59	0.13	6A	Foreign Interference-Animals	FA	CC	PLEASANT TS	
Breaker	NA42SC3B	Low Voltage	31-Jul-13	23:31	11.07	1MKBA	Main Pwr-Bkr Eqpt-Operating Mechanism Latch	FM	CC	PLEASANT TS	
Breaker	NA42SC3B	Low Voltage	19-Apr-13	14:35	835.73	1MKFA	Main Pwr-Bkr Eqpt-Interrupting Medium Air Problem	FM	CC	PLEASANT TS	
Breaker	NA42SC4Y	Low Voltage	24-Aug-10	10:40	1.58	7NA	Non Pwr Eqpt-Annunciation/Alarm Circuit	FM	CC	PLEASANT TS	
Breaker	NA42SC4Y	Low Voltage	05-Dec-09	22:21	303.98	1MKG	Main Pwr-Bkr Eqpt-Auxiliary Equipment	FM	CC	PLEASANT TS	
Breaker	NA42SC5E	Low Voltage	09-Dec-10	10:48	0.95	1MKA	Main Pwr-Bkr Eqpt-Bushing (General)	FM	CC	PLEASANT TS	
Breaker	NA42SC6Z	Low Voltage	09-Dec-10	10:48	0.95	1MKA	Main Pwr-Bkr Eqpt-Bushing (General)	FM	CC	PLEASANT TS	
Bus	NA42B	Low Voltage	03-Dec-13	13:01	0.08	8	Unknown	FA	CCT	PLEASANT TS	
Bus	NA42B	Low Voltage	26-Sep-13	13:32	0.77	8	Unknown	FA	CCT	PLEASANT TS	
Bus	NA42B	Low Voltage	28-Jul-12	02:59	0.13	4FP	Power System Config.-(Overlapping) Protection Zones	FA	CCT	PLEASANT TS	
Bus	NA42B	Low Voltage	21-Aug-11	20:55	0.12	8	Unknown	FA	CCT	PLEASANT TS	
Bus	NA42B	Low Voltage	08-Sep-09	22:38	0.17	4FS	Power System Configuration-Series Connection	FA	CCT	PLEASANT TS	
Bus	NA42Y	Low Voltage	28-Jul-12	02:59	0.13	4FP	Power System Config.-(Overlapping) Protection Zones	FA	CCT	PLEASANT TS	
Bus	NA42Y	Low Voltage	23-Feb-10	13:54	0.45	4FS	Power System Configuration-Series Connection	FA	CCT	PLEASANT TS	
Bus	NA42Y	Low Voltage	08-Sep-09	22:38	0.17	6A	Foreign Interference-Animals	FA	CCT	PLEASANT TS	
Bus	NA42Z	Low Voltage	23-Feb-10	13:54	0.45	4FS	Power System Configuration-Series Connection	FA	CCT	PLEASANT TS	
Capacitor	NA42SC3	Low Voltage	06-Oct-14	13:06	25.00	6A	Foreign Interference-Animals	FA	CCT	PLEASANT TS	
Capacitor	NA42SC3	Low Voltage	26-Sep-13	13:32	0.77	4FZ	Power System Configuration-Common Trip Zone	FA	CCT	PLEASANT TS	
Capacitor	NA42SC3	Low Voltage	31-Jul-13	23:31	11.07	4FZ	Power System Configuration-Common Trip Zone	FM	CCT	PLEASANT TS	
Capacitor	NA42SC3	Low Voltage	19-Apr-13	14:35	835.73	4FKB	Power System Config.-Breaker Unavailable/Failure	FM	CCT	PLEASANT TS	
Capacitor	NA42SC3	Low Voltage	22-Feb-10	13:27	50.05	7NPR	Non Pwr Eqpt-Prot-Relay (General)	FA	CCT	PLEASANT TS	
Capacitor	NA42SC3	Low Voltage	07-Dec-09	21:38	21.10	1MCBB	Main Pwr-Cap Eqpt-Unit Blown Fuse	FA	CCT	PLEASANT TS	
Capacitor	NA42SC4	Low Voltage	24-Aug-10	10:40	1.58	4FKB	Power System Config.-Breaker Unavailable/Failure	FM	CCT	PLEASANT TS	
Capacitor	NA42SC4	Low Voltage	05-Dec-09	22:21	303.98	4FKB	Power System Config.-Breaker Unavailable/Failure	FM	CCT	PLEASANT TS	
Capacitor	NA42SC5	Low Voltage	13-Dec-11	06:24	5.85	1MCBC	Main Pwr-Cap Eqpt-Unit Neutral Unbal.	FA	CCT	PLEASANT TS	
Capacitor	NA42SC5	Low Voltage	09-Dec-10	10:48	0.95	4FKB	Power System Config.-Breaker Unavailable/Failure	FM	CCT	PLEASANT TS	
Capacitor	NA42SC6	Low Voltage	09-Dec-10	10:48	0.95	4FKB	Power System Config.-Breaker Unavailable/Failure	FM	CCT	PLEASANT TS	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Google
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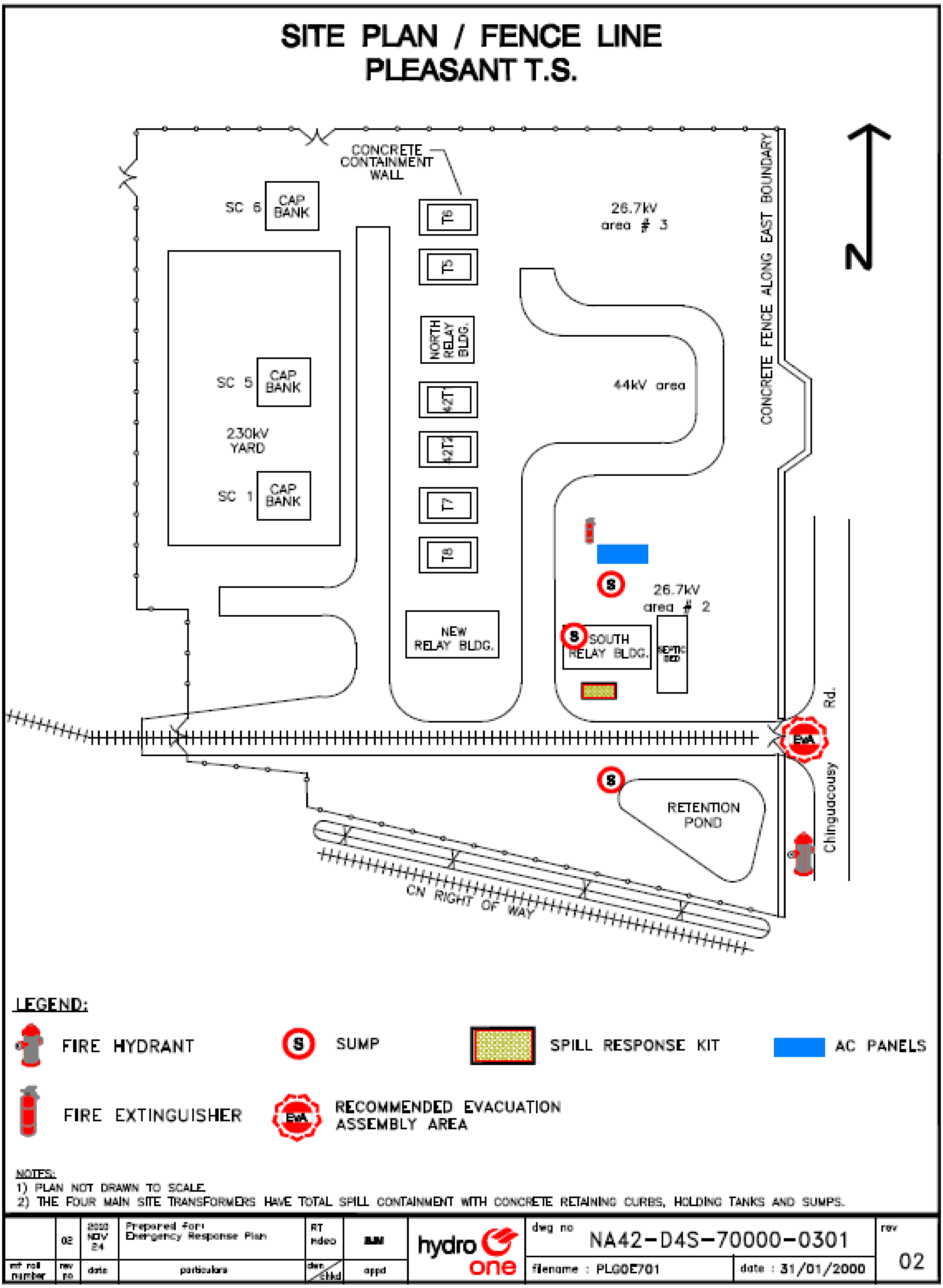
Sign in
Chinguacousy Rd
Williams Pkwy
Albright Rd
Map
Traffic
Albright Parkette
Spicebush Terrace
Done
Internet | Protected Mode: On
100%
3:58 PM
1/9/2015


SITE PLAN / FENCE LINE
PLEASANT T.S.
CONCRETE CONTAINMENT WALL
SC 6
CAP BANK
SC 5
CAP BANK
230kV YARD
SC 1
CAP BANK
T6
T5
NORTH RELAY BLDG.
42T1
42T2
T7
T8
NEW RELAY BLDG.
26.7kV area # 3
44kV area
26.7kV area # 2
SOUTH RELAY BLDG.
SEPTIC BED
CONCRETE FENCE ALONG EAST BOUNDARY
N
EvA
RETENTION POND
CN RIGHT OF WAY
Chinguacousy Rd.
LEGEND:
FIRE HYDRANT
SUMP
SPILL RESPONSE KIT
AC PANELS
FIRE EXTINGUISHER
RECOMMENDED EVACUATION ASSEMBLY AREA
NOTES:
1) PLAN NOT DRAWN TO SCALE.
2) THE FOUR MAIN SITE TRANSFORMERS HAVE TOTAL SPILL CONTAINMENT WITH CONCRETE RETAINING CURBS, HOLDING TANKS AND SUMPS.
02
2000 NOV 24
Prepared for: Emergency Response Plan
RT Hdeo
mf roll number
rev no
date
particulars
dsn chkd
appd
dwg no NA42-D4S-70000-0301
filename : PLG0E701
date : 31/01/2000
rev 02

UNDERTAKING – TCJ2.1

Undertaking

To provide a percentage increase in total compensation for PWU and Society staff, including base rate increase, as well as the increase in the share grants.

Response

The PWU Shares are not issued to eligible PWU members until 2017. On April 1, 2017, there is a 1% base wage adjustment and eligible PWU employees will receive their 1st installment of Hydro One Limited shares equal to 2.7% of their April 1, 2015 base rate/ by IPO share price. An increase to pension contributions of on average 0.7% will also be implemented, which brings the total pension contribution increase on average to 2.7% since April 1 2015.

The Society Shares are not issued to eligible Society members until 2018. On April 1, 2018, there is a 0.5% base wage adjustment and eligible Society employees will receive their 1st installment of Hydro One Limited shares equal to 2.0% of their September 1, 2015 base rate/ by IPO share price. An increase to pension contributions of 0.5% will also be implemented, which brings the total pension contribution increase to 1.75% above the contribution rate in effect on September 1, 2015.

UNDERTAKING – TCJ2.2

Undertaking

To clarify the response to Board Staff Interrogatory 116 in terms of the potential for double counting in the forecast period.

Response

The savings found in Board Staff interrogatory 116 and Consumers Council of Canada interrogatory 9 are unrelated. The savings in Board Staff interrogatory 116 are calculated/estimated on a per year average against the historical cost prior to the implementation of the initiative.

UNDERTAKING – TCJ2.3

Undertaking

To provide calculations behind the tower coating evaluations.

Response

Part 1: Net Present Value Calculation

The Net Present Value (NPV) of a tower coating investment for 2 scenarios is presented below. The first scenario assumes an individual tower needs replacement and the second scenario assumes a group of more than 20 towers located in close vicinity needs replacement.

Information and Assumptions

a. Tower replacement age: 75 year-old
b. Average age of eligible towers is 45 year-old
c. Expected new coating life: 35 years
d. Straight line depreciation with ½ year rule in the first year
e. Inflation rate equal to 2%.
f. Study period of 60 years.
g. Start time for the study is 2017.
h. Unit costs for tower coating and replacement as provided below.

Table 1: Tower Coating and Replacement Costs

Single Tower Replacement		**Multiple Towers Replacement**	
115 kV Tower		**115 kV Tower**	
Replacement Cost ($k)	400	Replacement Cost ($k)	250
Coating Cost ($k)	30	Coating Cost ($k)	30
230 kV Tower		**230 kV Tower**	
Replacement Cost ($k)	450	Replacement Cost ($k)	350
Coating Cost ($k)	37	Coating Cost ($k)	37

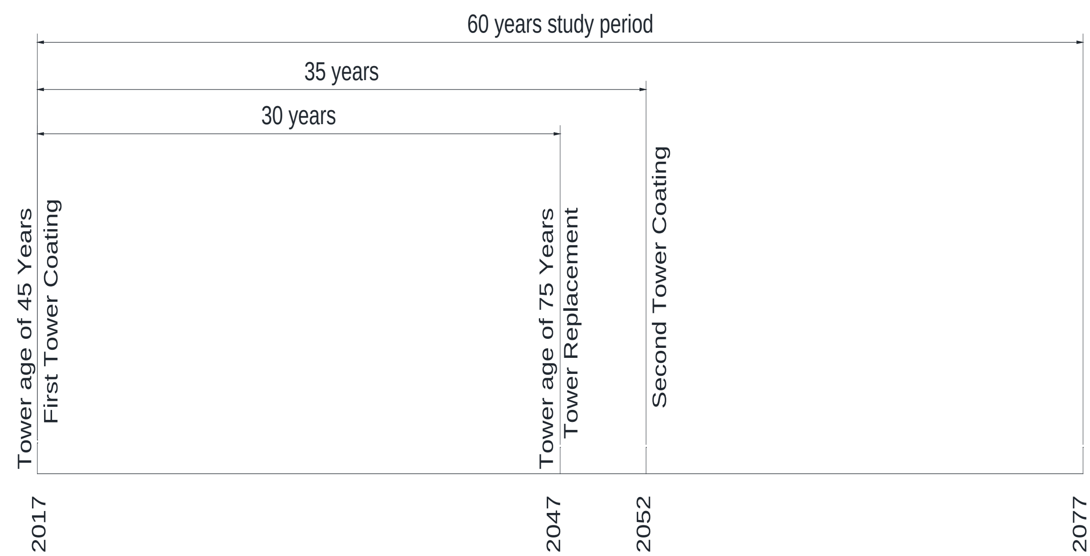
Notes:

1. Tower replacement costs for replacing only one tower and a group of more than 20 towers in similar areas are presented. The lower unit cost for the latter case is due to economies of scale and savings from access, mobilization and demobilization.

2. Tower coating unit costs remain the same for single or multiple towers coating.

3. The unit cost for tower replacement considers materials, labour and equipment cost. Revenue loss, customer and reliability impact due to a lengthy outage to replace the towers is not considered.

The first application of the tower coating is expected to take place in 2017 (tower at 45 year-old), the second application of coating is 35 years later in 2052 (tower at 80 year-old). Without the application of the coating, the tower will continue to deteriorate starting in 2017 and reaches end of life in 2047(tower at 75 year-old), which will require replacement.



NPV calculation result is summarized in Table 1 below.

Table 2: Summary Results of Calculations

Single Tower Replacement		**Multiple Towers Replacement**	
115 kV Tower		**115 kV Tower**	
PV for Coating Cost ($k)	30	PV for Coating Cost ($k)	30
PV for Replacement ($k)	92	PV for Replacement ($k)	57
Unit Capital Cost Saving ($k)	62	Unit Capital Cost Saving ($k)	27
230 kV Tower		**230 kV Tower**	
PV for Coating Cost ($k)	38	PV for Coating ($k)	38
PV for Replacement ($k)	103	PV for Replacement ($k)	80
Unit Capital Cost Saving ($K)	65	Unit Capital Cost Saving ($)	42

Total capital cost saving resulted from 2017 and 2018 tower coating investment is shown below. Total towers expected to be coated in 2017 and 2018 is 2850. Fifteen percent of coating candidates are 115kV and 85% are 230kV towers.

Table 3: Unit and Total Cost Savings

Single Tower Replacement		**Multiple Towers Replacement**	
115 kV Tower		**115 kV Tower**	
Unit Cost Saving	$62k	Unit Cost Saving	$27k
Total Cost Saving: $62K*2850*0.15	$26.50M	Total Cost Saving: $27K*2850*0.15	$11.54M
230 kV Tower		**230 kV Tower**	
Unit Cost Saving	$65k	Unit Cost Saving	$42k
Total Cost Saving: $65K*2850*0.85	$157.46M	Total Cost Saving: $42K*2850*0.85	$101.75M
Total NPV Capital Cost Saving Resulted from Test Years Tower Coating	**$184.0M**	**Total NPV Capital Cost Saving Resulted from Test Years Tower Coating**	**$113.3M**

Additional Information

There are 2 new developments since 2014 that have significantly improved the NPV analysis of this investment, which is the basis to support increasing investment for tower coating.

A. <u>Engineering Study to Determine Corrosion Zones, Corrosion Rates, Tower Condition Assessment; and End of Life Criteria and Coating Opportunity</u>

i) Corrosion Zones, Corrosion Rates and Tower Condition Assessment:
Hydro One and Electric Power Research Institute (EPRI) conducted an engineering study to define corrosion zones and corrosion rates in the province of Ontario and assess impact of corrosion to Hydro One's transmission tower. The study includes condition assessment of towers located in various corrosion zones. The study concludes that a significant portion of towers located in high corrosive zones are in need of coating to arrest further deterioration and prevent eventual replacements. Refer to Exhibit B1, Tab 2, Schedule 6, Section 3.3 and Exhibit I, Tab 9, Schedule 6, Attachment 2.

ii) Tower End of Life Criteria and Coating Opportunity:
A transmission tower is deemed to have reached end of life when it has lost 10% of steel thickness, rendering it incapable to withstand design load. A new

tower comes with a layer of protective zinc applied over bare steel via hot-dip galvanizing process. This layer varies in thickness. The American Society of Testing and Materials (ASTM) specifies a minimum thickness of 100 microns for tower steel. It is common for fabricator to deliver steels with an average zinc thickness of 150 microns.

The most common steel member thickness for 115 and 230kV towers is 8mm ie, 8000 microns. In high corrosive areas, the average annual zinc corrosion rate is 3.3 microns and bare steel is 27.5 microns.

- Most common steel member thickness = 8mm.
- End of Life Criteria = 10% loss of steel thickness, 800 microns
- Opportunity to coat = in the time interval between when the zinc layer is nearly depleted and before end of life.

New steel members come with 150 microns zinc layer and the annual zinc corrosion rate is 3.3 microns. Hence, it takes 45 years (150/3.3=45) to deplete the zinc layer.

Once zinc layer is depleted, the exposed bare steel will corrode at an annual rate of 27.5 microns. Hence, it takes 29 years (800/27.5=29) to lose 800 microns of thickness.

A tower in high corrosive area will reach end of life in 74 years (45+29)

Therefore, the opportunity to economically extend life of towers located in high corrosive area via coating is around 45 year-old and before 74 year-old. As the towers exceed 75 year-old, various level of refurbishment effort will be required to restore strength before coating can be applied. Eventually, costly tower replacement becomes the only feasible option.

B. <u>Galvatech</u>

Galvatech is a zinc rich coating product manufactured by Rust-Anode. Hydro One became aware of this product in recent years and completed a detailed assessment of its performance. Refer to Exhibit I, Tab 9, Schedule 6, Attachment 3. The unique and desirable performance characteristics of this product are:

i) Does not require extensive surface preparation;
ii) Rapid curing, approximately 2 hours as opposed to 24 hours;

iii) Less dripping, less likely to contaminate other line components such as insulators, which enables live-working technique;

iv) High performance, quality of coating comparable to hot-dip galvanizing process; and

v) Durability, coating is expected to last 30 to 35 years in the high corrosive zones.

These 2 new developments described in (A) and (B) have improved significantly the productivity and efficiency of tower coating investment, which makes it an attractive and prudence asset management undertaking as discussed in Part 1.

Tower Coating Investment Pacing

The Hydro One transmission system consists almost exclusively of overhead transmission lines and owns approximately 52,000 steel structures. Hydro One is planning to coat 1,250 and 1,600 towers in 2017 and 2018 respectively. The total count of 2,850 towers eligible for coating in the test years represents approximately 5.5% of the tower population.

There are approximately 13,000 towers located within high corrosive zones, which is the focal point of the tower coating investment. Currently 7,550 of these 13,000 towers have met coating criteria and are within the window of opportunity for coating. Sixty percent of these 7,550 towers are currently experiencing corrosion and metal loss. As these towers approach 75 years old, the ability to extend their service life by coating diminishes.

Hydro One intends to complete coating these 7,550 towers between 2017 and 2021 to extend the service life of these towers and maximize capital cost savings by minimizing tower replacements. 2017 is intended to be a ramp up year operations with 1,250 towers. Subsequent years from 2018 to 2021 will see an average of 1,600 towers coated per year. The tower coating program will be adjusted after 2021 based on the condition of the remaining towers in high corrosive zones that meet the tower coating criteria and lessons learned from the test years.

UNDERTAKING – TCJ2.4

Undertaking

To explain why Hydro One does not have a Board Committee separate from Health, Safety and the Environment specifically for First Nations matters rather than the answer given here.

Response

Hydro One has four standing committees of its Board of Directors, which is a common number of committees for publicly traded companies. Matters pertaining to First Nations are covered in the mandate for its Health, Safety, Environment, First Nations & Métis Committee.

UNDERTAKING – TCJ2.5

Undertaking

To update the number once the report is available. Also to update the table when the report becomes available.

Response

This undertaking was to provide two updates, as follows:

Response Part 1: Updating of 2015 CDPP Outliers numbers

In response to interrogatory #I-10-003, part vii) CDPP outliers, to update the chart at the bottom of page 3 with the number of Outliers in the 2015 CDPP report, and to update the list at the top of page 6 of which First Nations delivery points are identified as Outliers in the 2015 CDPP report, when available. The report has now been finalized and the chart and list are updated below with this information.

CDPP Outliers:

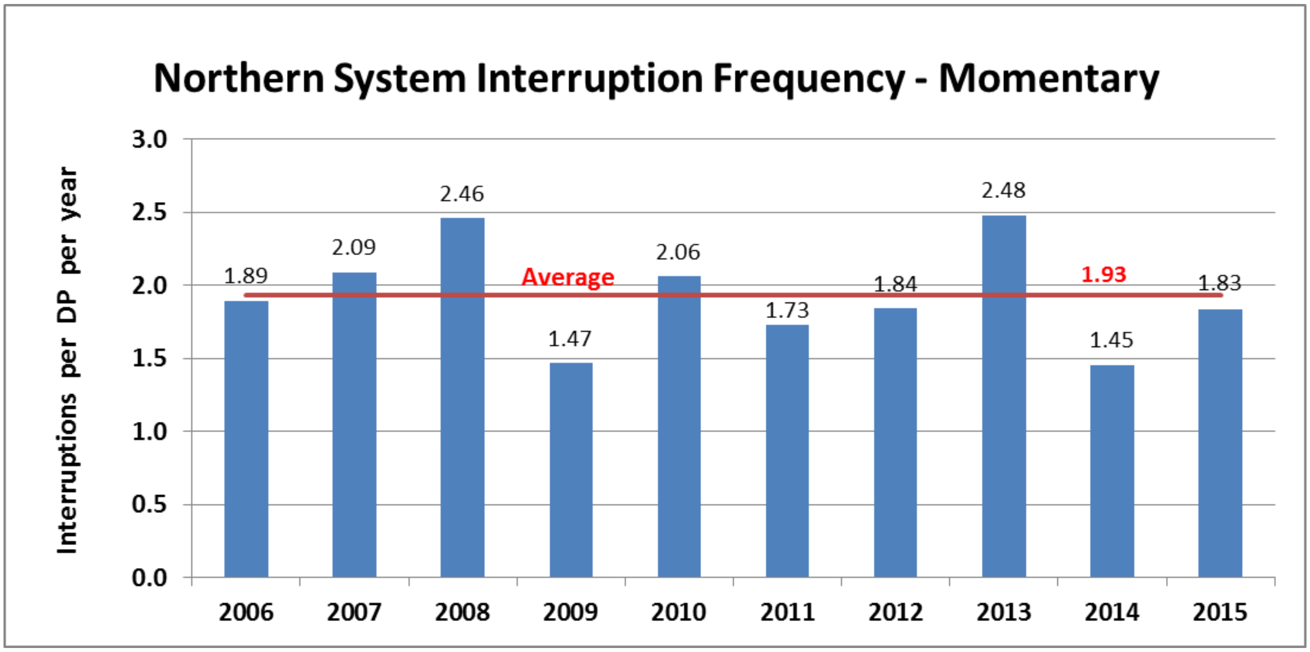
NE115,NE230,NW115,NW230	2010	2011	2012	2013	2014	2015
Total # of DPs in Northern Region	148	149	149	150	152	149
# of Outliers	64	56	53	53	65	54

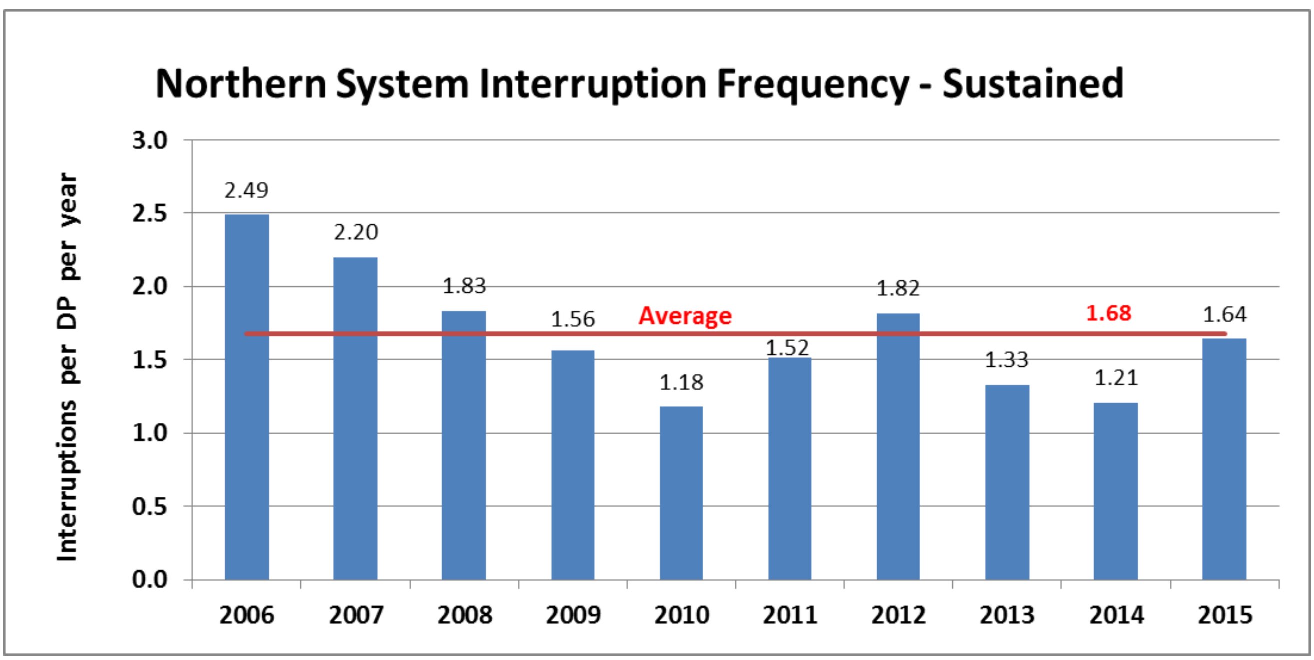
CDPP Outliers:

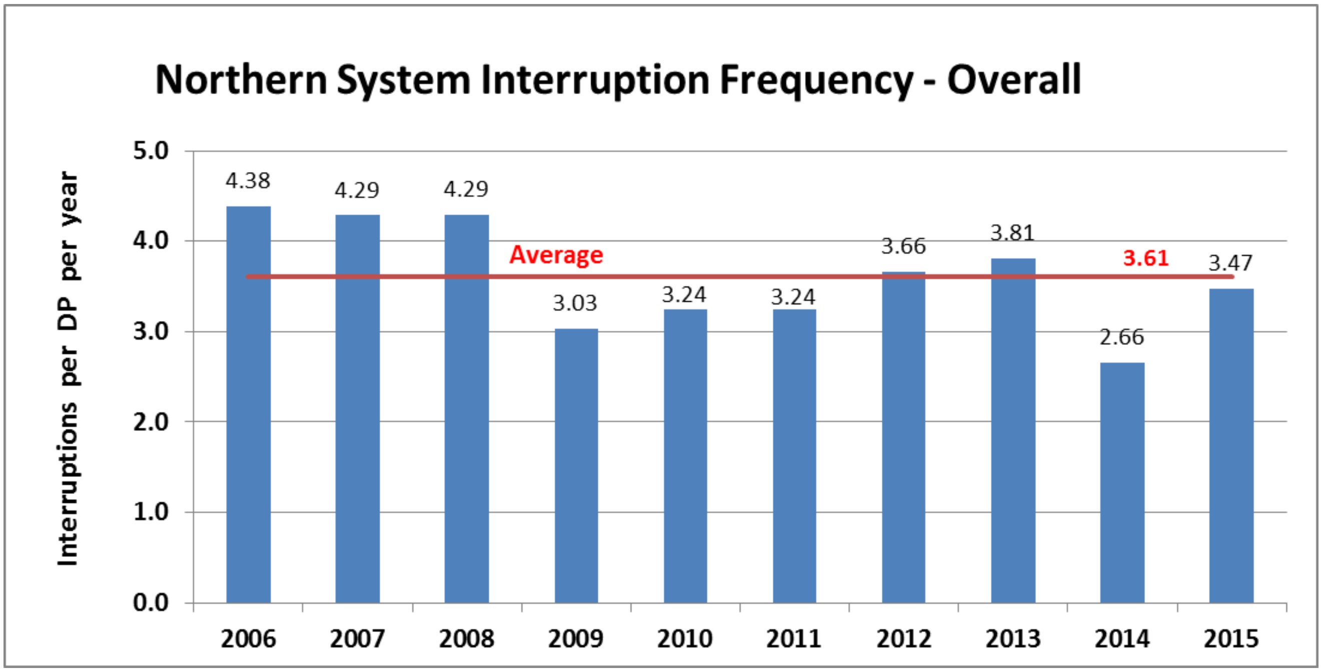
2010	LONGLAC TS, MOOSONEE DS
2011	LONGLAC TS, MOOSONEE DS
2012	LONGLAC TS, MOOSONEE DS
2013	MOOSONEE DS
2014	LONGLAC TS, MOOSONEE DS, BEARDMORE #2 DS
2015	LONGLAC TS, MOOSONEE DS, BEARDMORE #2 DS

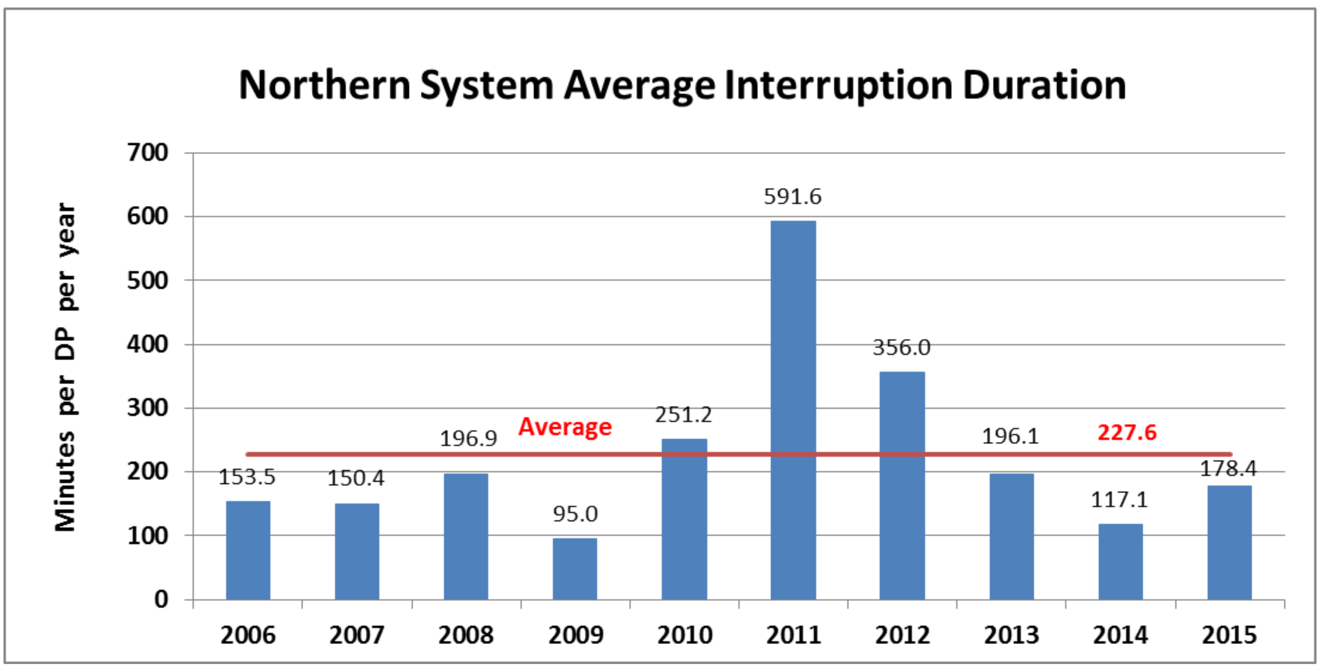
Response Part 2: Provide the Northern Transmission System Performance and Transmission System Performance supplying First Nations Communities in a Chart format similar to Exhibit B1, Tab 1, Schedule 3. These charts are provided below, with the 10-year average line included, as requested.

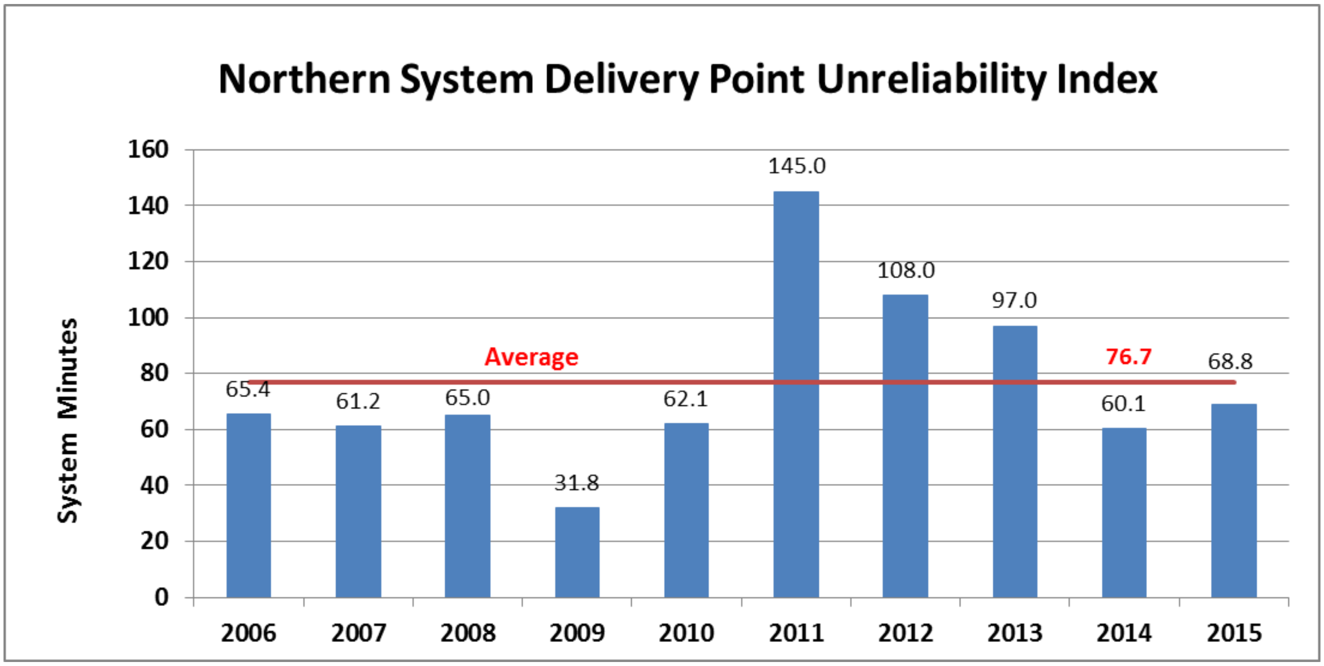
a) Northern Transmission System Performance



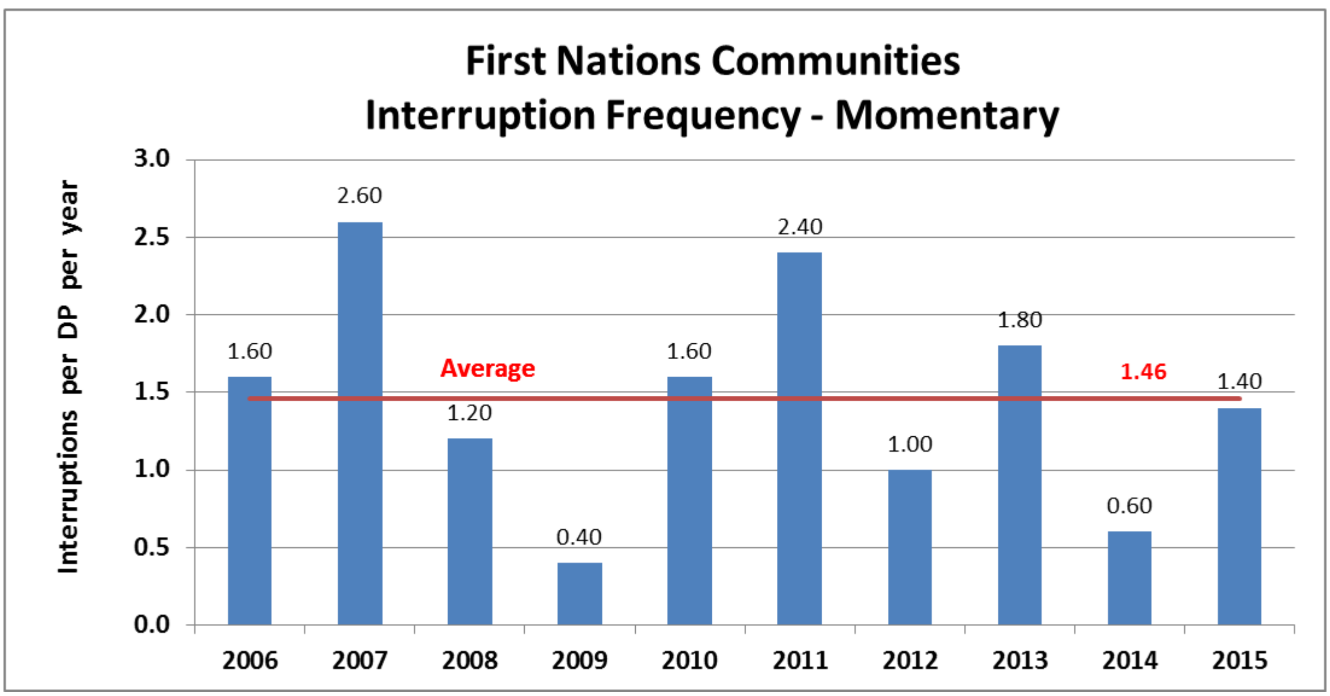


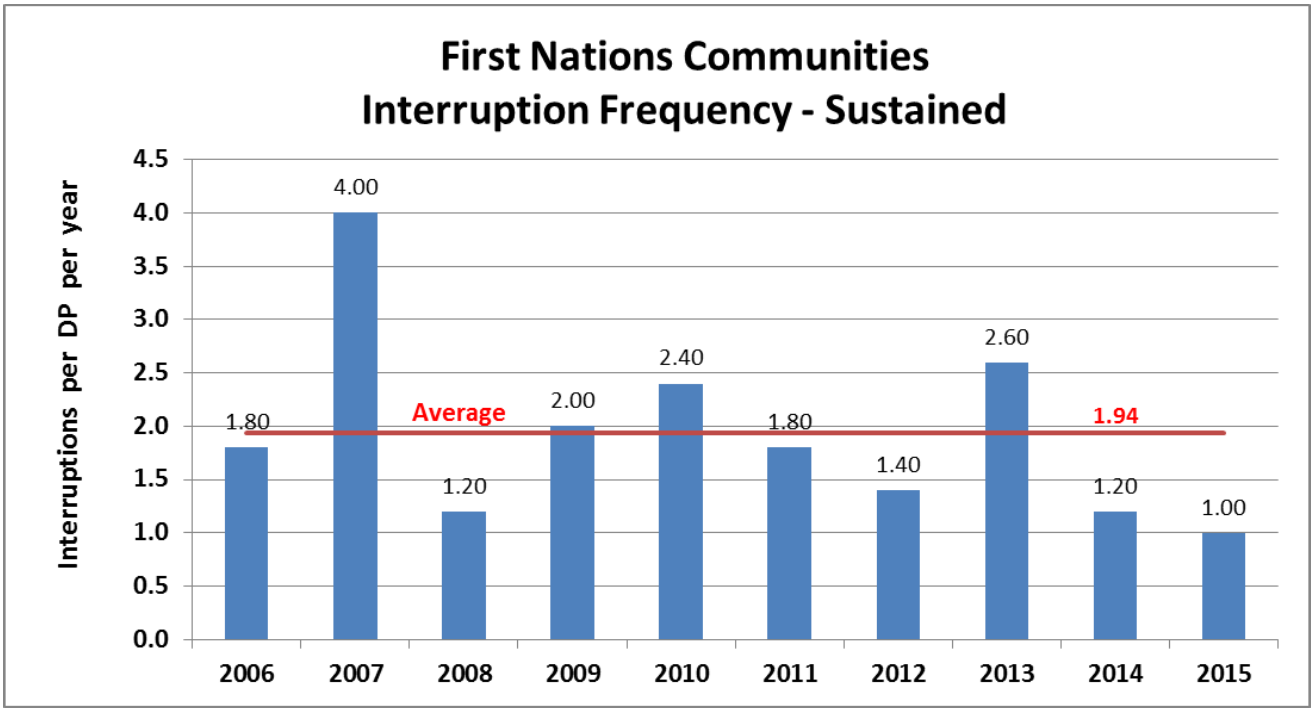

Northern System Interruption Frequency - Overall
Interruptions per DP per year
5.0
4.0
3.0
2.0
1.0
0.0
4.38
4.29
4.29
3.03
3.24
3.24
3.66
3.81
2.66
3.47
Average
3.61
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015

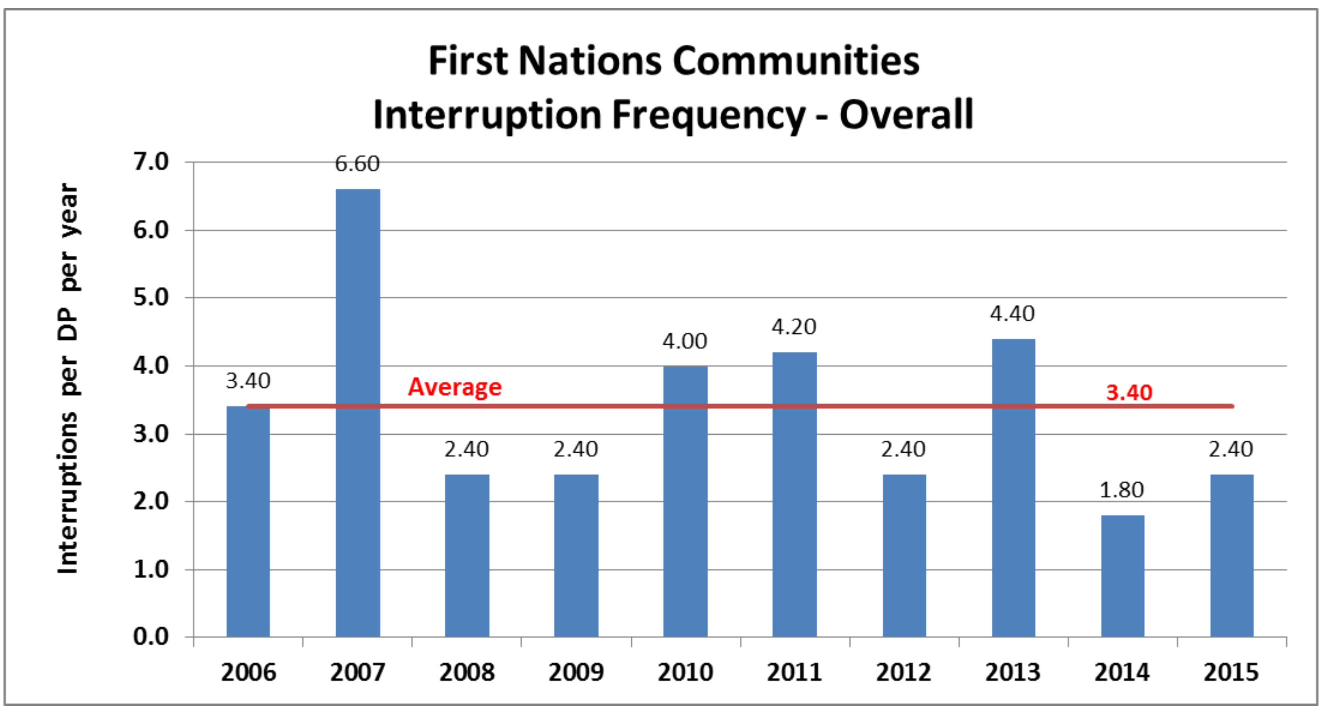

Northern System Average Interruption Duration
Minutes per DP per year
700
600
500
400
300
200
100
0
153.5
150.4
196.9
95.0
251.2
591.6
356.0
196.1
117.1
178.4
Average
227.6
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015

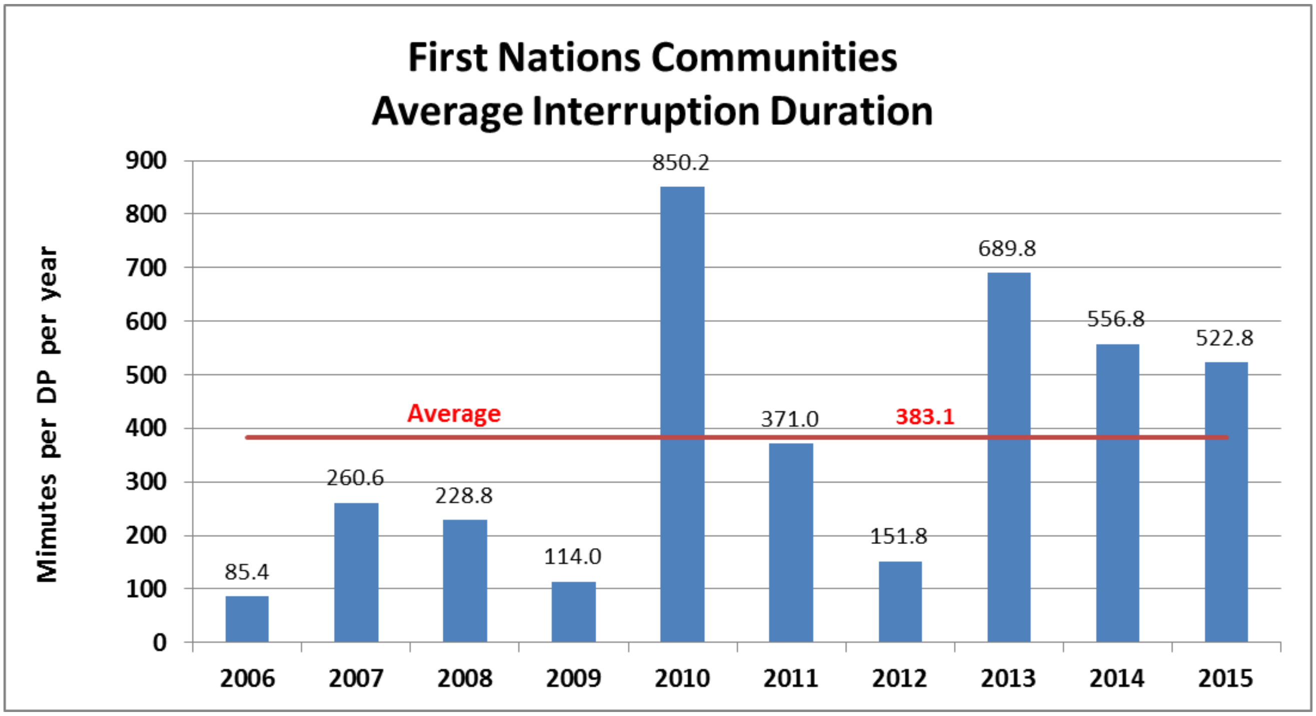


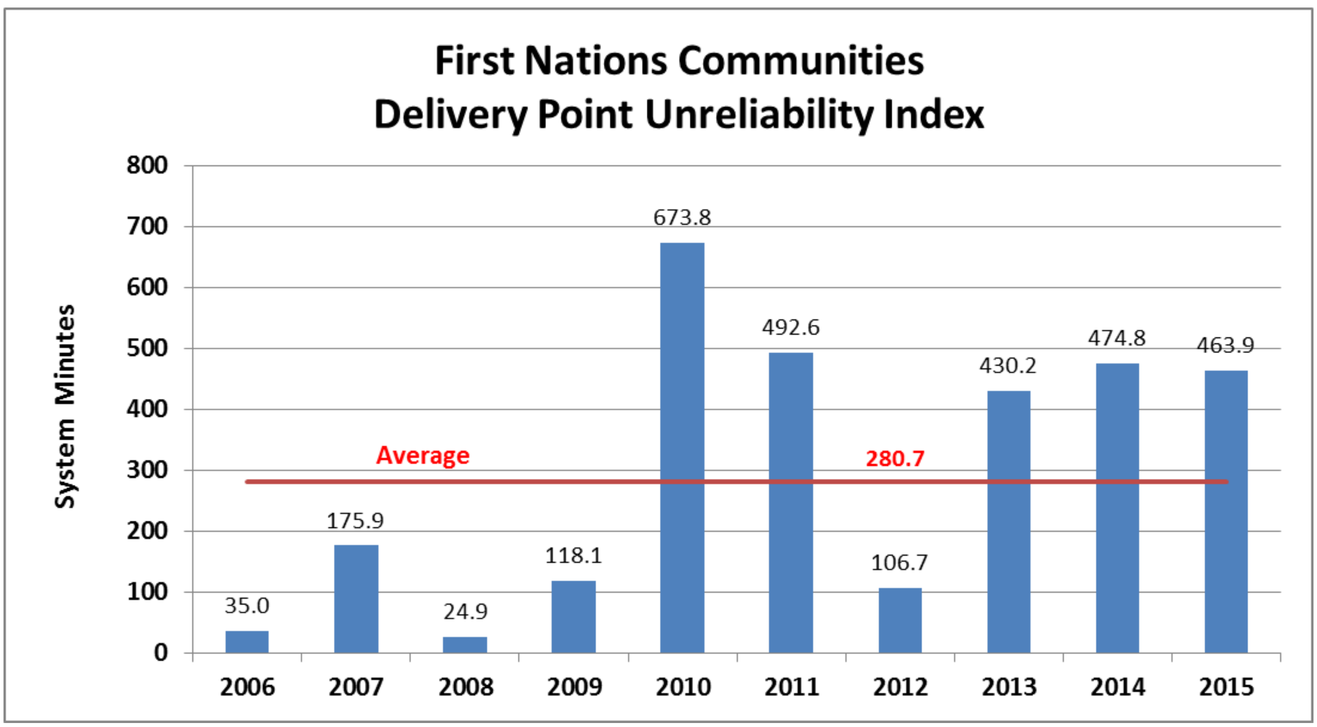
b) Transmission System Performance supplying First Nations Communities



1 
First Nations Communities
Interruption Frequency - Sustained
Interruptions per DP per year
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.80
4.00
1.20
2.00
2.40
1.80
1.40
2.60
1.20
1.00
Average
1.94
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015

2 
First Nations Communities
Interruption Frequency - Overall
Interruptions per DP per year
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
3.40
6.60
2.40
2.40
4.00
4.20
2.40
4.40
1.80
2.40
Average
3.40
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015

1 
First Nations Communities
Average Interruption Duration
Mimutes per DP per year
900
800
700
600
500
400
300
200
100
0
850.2
689.8
556.8
522.8
Average
371.0
383.1
260.6
228.8
114.0
151.8
85.4
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015

2 
First Nations Communities
Delivery Point Unreliability Index
System Minutes
800
700
600
500
400
300
200
100
0
673.8
492.6
474.8
463.9
430.2
Average
280.7
175.9
118.1
106.7
35.0
24.9
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015

UNDERTAKING – TCJ2.6

Undertaking

No undertaking assigned.

Response

N/A

Witness: N/A

UNDERTAKING – TCJ2.7

Undertaking

With reference to Anwaatin IR 3, Page 4, Line 4, to explain the large increase in the duration of the sustained delivery point interruptions, and for the table labelled "Delivery Point Unreliability Index".

Response

In response to this undertaking, Hydro One believes the correct interrogatory referenced should be Anwaatin interrogatory 5. Anwaatin interrogatory 5, page 4, contains the charts indicating the “Duration of Delivery Point Interruptions” and “Delivery Point Unreliability Index”.

The major contributing events to the large increase over the 2010 to 2015 period are identified in the summary below.

Major Events Impacting First Nations Delivery Point Performance – Interruption Duration (2010 to 2015)

1. Major events and delivery point interruptions in 2010

- On April 14, 2010 at 06:41 EST, 115/44 kV Longlac transformer T1 was forced from service due to arcing on the secondary bushings. The total interruption duration to Longlac TS was about 393 minutes or 6 hours 33 minutes.

- On May 20, 2010 at 05:51 EST, 115 kV Circuit A4L (Alexander x Longlac) was removed from service due to a flashed insulator at Longlac TS between the transformer and the secondary breaker. The total interruption duration to Longlac TS and Beardmore DS #2 was about 251 minutes or 4 hours 11 minutes each.

- On May 24, 2010 at 20:19 EST, 115 kV Circuit T7M (Otter Rapids x Moosonee) was removed from service due to a pole (structure #487) damage caused by lightning during electrical storms. The total interruption duration to Moosonee DS was about 982 minutes or 16 hours 22 minutes.

- On May 26, 2010, there were two sustained outages on 115 kV Circuit T7M (Otter Rapids x Moosonee), starting from 15:50 EST. The cause of the outages was a damaged tower and defective insulator string approximately 9 km from Otter Rapids Switching Station, and a defective sky wire at tower 971. The total duration for two sustained interruptions to Moosonee DS was about 1,411 minutes or 23 hours 31 minutes.

- On July 27, 2010 at 14:57 EST, 115 kV Circuit A4L (Alexander x Longlac) was removed from service due to three broken crossarms on the line. The total interruption duration to Longlac TS and Beardmore DS #2 was about 407 minutes or 6 hours 47 minutes each.

2. Major events and delivery point interruptions in 2011

- On January 22, 2011 at 03:21 EST, 115 kV Breaker L6L7 at Otter Rapids station tripped due to defective equipment (low SF6). The total interruption duration to Moosonee DS was about 433 minutes or 7 hours 13 minutes.

- On April 11, 2011 at 00:42 EST, 115 kV Circuit T7M (Otter Rapids x Moosonee) and other 115 kV circuits in the area were removed from service due to a line insulator failure. The total interruption duration to Moosonee DS was about 953 minutes or 15 hours and 53 minutes.

- On May 5, 2011 at 16:22 EST, 115 kV Circuit A6P (Alexander x Port Arthur) was removed from service due to defective equipment. 115 kV Circuit A7L (Lakehead x Alexander) was recalled from a planned outage to restore supply to the interrupted delivery points. The total interruption duration to Nipigon DS and Red Rock DS was about 192 minutes or 3 hours and 12 minutes each.

3. No major event or delivery point interruption in 2012

4. Major events and delivery point interruptions in 2013

- On June 26, 2013 at 21:41 EST, 115 kV Circuit A4L (Alexander x Longlac) was removed from service due to electrical storms in the area. Defective insulators between Jellicoe DS #3 Junction & Beardmore DS #2 Junction at structure #733 were found and repaired the next day. The total interruption duration to Longlac TS and Beardmore DS #2 was about 826 minutes or 13 hours 46 minutes each.

- On September 10, 2013 at 11:02 EST, 115 kV Circuit T7M (Otter Rapids x Moosonee) was removed from service due to adverse weather in the area. The total interruption duration to Moosonee DS was about 456 minutes or 7 hours and 36 minutes.

- On November 18, 2013 at 11:14 EST, 115 kV Circuit T7M (Otter Rapids x Moosonee) was removed from service due to damaged customer-owned equipment due to high winds and snow. Moosonee DS was restored temporarily and then was interrupted again. The total duration to Moosonee DS for the two sustained interruptions was about 690 minutes or 11 hours and 30 minutes.

- From December 5 to 10 in 2013, multiple outages happened on 115 kV Circuits T7M (Otter Rapids x Moosonee) and M9K (Moosonee x Five Nations System). The cause was adverse weather in the area. The total duration to Moosonee DS for five sustained interruptions was approximately 636 minutes or 10 hours and 36 minutes.

5. Major events and delivery point interruptions in 2014

- On June 7, 2014 at 15:11 EST, 115 KV Circuit T7M (Otter Rapids x Moosonee) was removed from service due to a failed line insulator. Due to unsettled weather in the area, and approaching nightfall, the helicopter patrol was deferred until daybreak. This delay contributed to the interruption duration. The total interruption duration to Moosonee DS was approximately 1,402 minutes or 23 hours and 22 minutes.

- On July 21, 2014 at 18:14 EST, 115 kV Circuits A4L (Alexander x Longlac) was removed from service caused by a blown surge arrestor on a 115/44 kV transformer at Longlac TS. Circuit A4L was sectionalized to restore the supply to Beardmore DS #2 before the restoration of the line. The total interruption duration was about 1,019 minutes or 17 hours to Longlac TS and 281 minutes or 4 hours and 41 minutes to Beardmore DS #2.

6. Major events and delivery point interruptions in 2015

- On March 29, 2015 at 19:47 EST, 115 kV Circuit A4L (Alexander x Lakehead) was removed from service due to a truck collision with a line pole. A4L was sectionalized allowing restoration of supply to the majority of the load before the repairs were made. The total interruption duration was approximately 596 minutes or 9 hours and 56 minutes to Longlac TS and 454 minutes or 7 hours 34 minutes to Beardmore DS #2.

- On May 3, 2015 at 15:14 EST, 115 KV Circuit T7M (Otter Rapids x Moosonee) was removed from service due to a broken conductor. The total interruption duration to Moosonee DS was about 1,365 minutes or 22 hours and 45 minutes.

UNDERTAKING – TCJ2.08

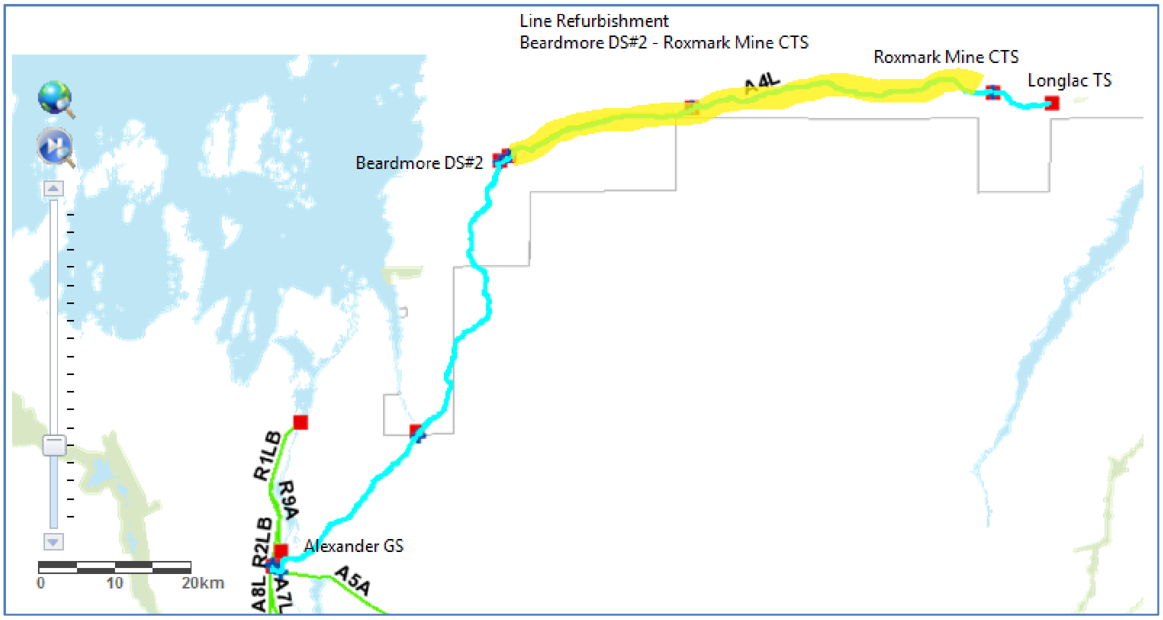
Undertaking

To provide a description of where the 70 kilometers of line is located.

Response

The A4L circuit is about 153 km in length. The 70 km section selected for line refurbishment is highlighted in yellow on the second map below and runs between Beardmore DS#2 and Roxmark Mine CTS.

Witness: Chong Kiat Ng


Line Refurbishment
Beardmore DS#2 - Roxmark Mine CTS
Roxmark Mine CTS
Longlac TS
A4L
Beardmore DS#2
R1LB
R9A
R2LB
Alexander GS
A5A
A8L
A7L
0
10
20km

UNDERTAKING – TCJ2.9

Undertaking

To check the numbers associated with Hydro One's transmission assets associated with the various transmission stations and SS's in Exhibit I, Tab 10, Schedule 5, page 6 of 8.

Response

Please see response TCJ 2.10.

UNDERTAKING – TCJ2.10

Undertaking

To fill out this table to give an indicator of the anticipated date for asset replacement in the future. Also, to include the expected service life of those assets in that table.

Response

The table below provides a list of all of Hydro One's transmission assets, their age, their originally-anticipated replacement date and their actual or anticipated replacement date.

In responding to Anwaatin IR#5, Hydro One provided info on "Original/Anticipated Replacement Date" and "Actual/Plan Replacement Date". The "Original/Anticipated Replacement Date" is referring to previously planned replacement dates. The "Actual/Plan Replacement Date" is referring to actual date when the replacement took place. The table below consolidates the info and simplifies the presentation.

Hydro One's Transmission Asset	Age (Year)	Expected Service life	Recent Replacement Or Planned Replacement Date
Longlac TS			
Power Transformer -T2	5	50	2011
Power Transformer - T3	5	50	2011
Breaker -116M1	5	40	2011
Breaker -116M2	5	40	2011
Breaker - SC1Z	5	40	2011
Breaker - SC2Z	5	40	2011
M2 feeder protection	5	20	2011
Moosonee SS			
M9K A protection	9	20	No near term plan to replace
M9K B protection	9	20	No near term plan to replace
OtterRapid SS			
Breaker -L6L7	9	40	2007
Breaker -L6L8	6	40	2010
Alexander SS			
A4L A protection	24	20	2018
A4L B protection	15	20	2018

Witness: Chong Kiat Ng

Hydro One's Transmission Asset	Age (Year)	Expected Service life	Recent Replacement Or Planned Replacement Date
A6P A protection	15	20	2018
A6P B protection	14	20	2018
HL6 BF protection	19	20	2018
L5L6 BF protection	19	20	2018
Port Arthur TS			
Power Transformer -T1	42	60	2021
Power Transformer - T2	42	60	2021
Breaker -2A6P	62	55	2021
Breaker -2L3P	70	55	2021
Breaker -2L4P	70	55	2021
Breaker -2P1P	66	55	2021
Breaker -2P1T	68	55	2021
Breaker -2P3B	63	55	2021
Breaker -2P5M	64	55	2021
Breaker -2P7B	64	55	2021
Breaker -BY	65	55	2021
Breaker -M1-27	67	55	2021
Breaker -M2	64	55	2021
Breaker -M3	64	55	2021
Breaker -M4	68	55	2021
Breaker -M5	67	55	2021
Breaker -M6	68	55	2021
Breaker -T1B	59	55	2021
Breaker -T2B	59	55	2021
A6P A protection	16	25	2021
A6P B protection	18	25	2021
2A6P BF protection	47	45	2021
Elliot Lake TS			
Power Transformer -T1	59	40	2024
Power Transformer - T2	68	40	2024
Power Transformer - T3	20	40	2024
Breaker -M1	61	55	2024
Breaker -M2	66	55	2024
Breaker -M3	35	55	2024

Hydro One's Transmission Asset	Average Age (Year)	Expected Service life	Recent Replacement Or Planned Replacement Date
M9K circuit/conductor (Less than 1 km)	41	70	No near term plan to replace
M3K circuit/conductor (Recently was bought by First Nation)	12	70	No near term plan to replace
A4L circuit/conductor (153 km)	74	70	70 km in 2021*
T1B circuit/conductor (65 km)	63	70	Requires assessment
56M1 circuit/conductor (8 km)	19	70	No near term plan to replace
57M1 circuit/conductor (5 km)	19	70	No near term plan to replace

*A4L circuit is about 153 km. 70 km of this circuit is secluded for a complete line refurbishment in 2021. 55 km of the circuit has been assessed and no line refurbishment is required in the foreseeable future. The remaining 28 km of the circuit requires assessment.

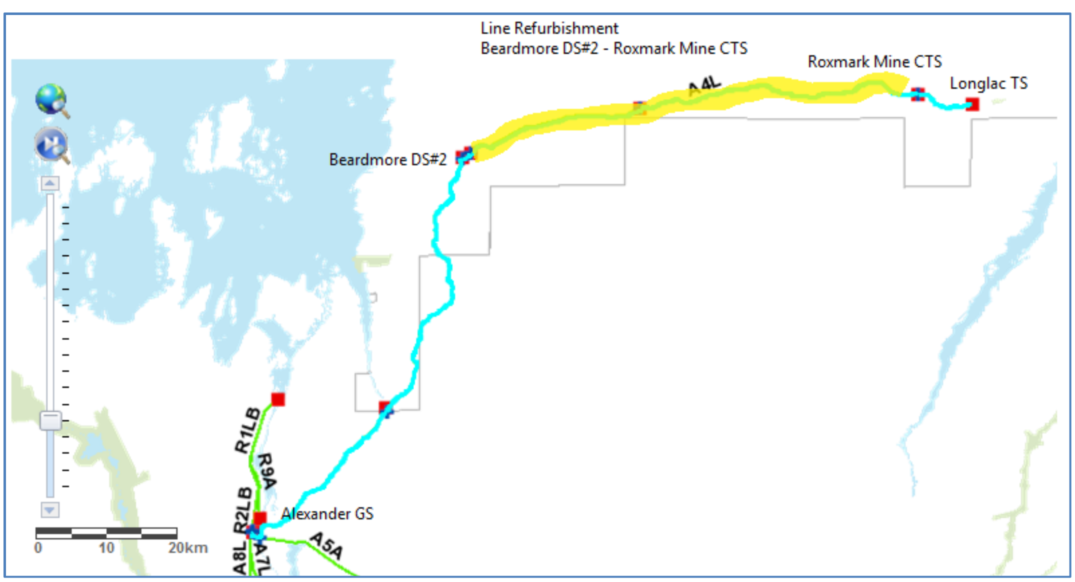
UNDERTAKING – TCJ2.11

Undertaking

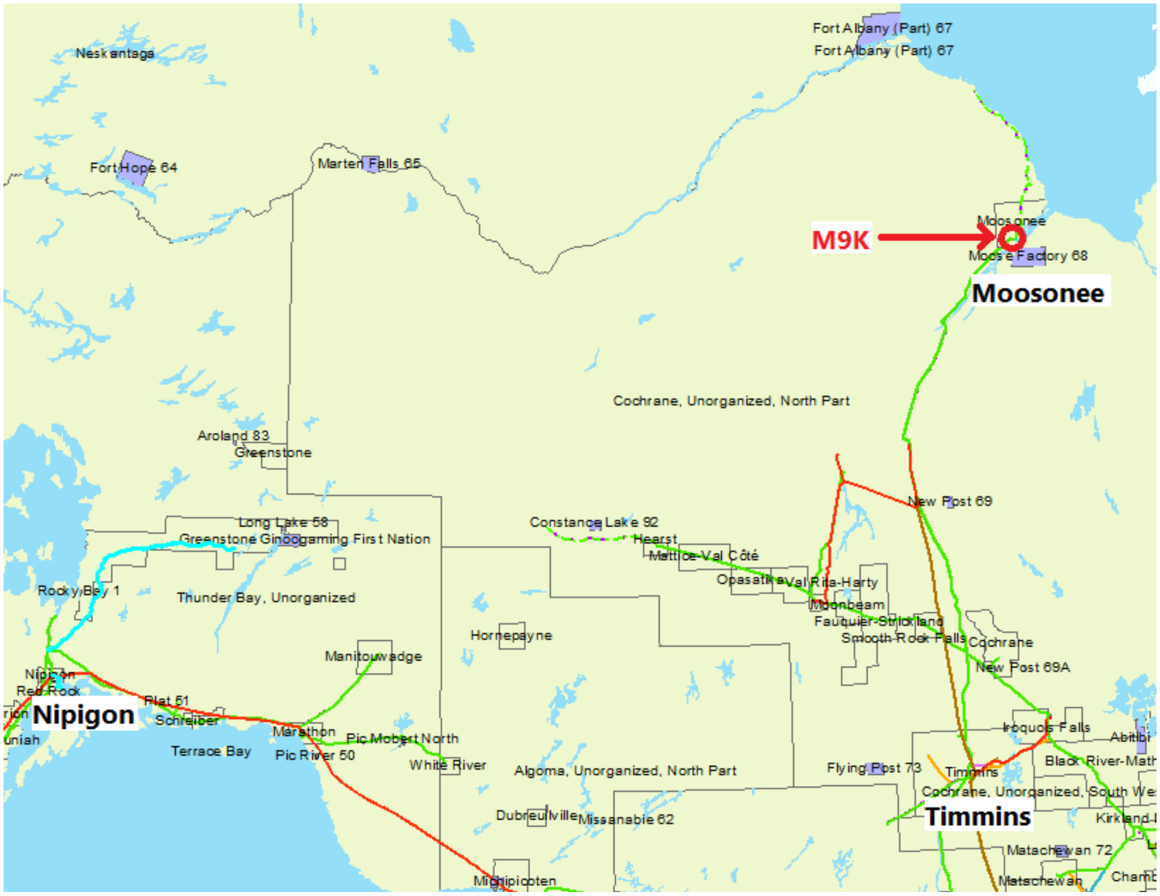
To provide which portions of the line, how long, where they run.

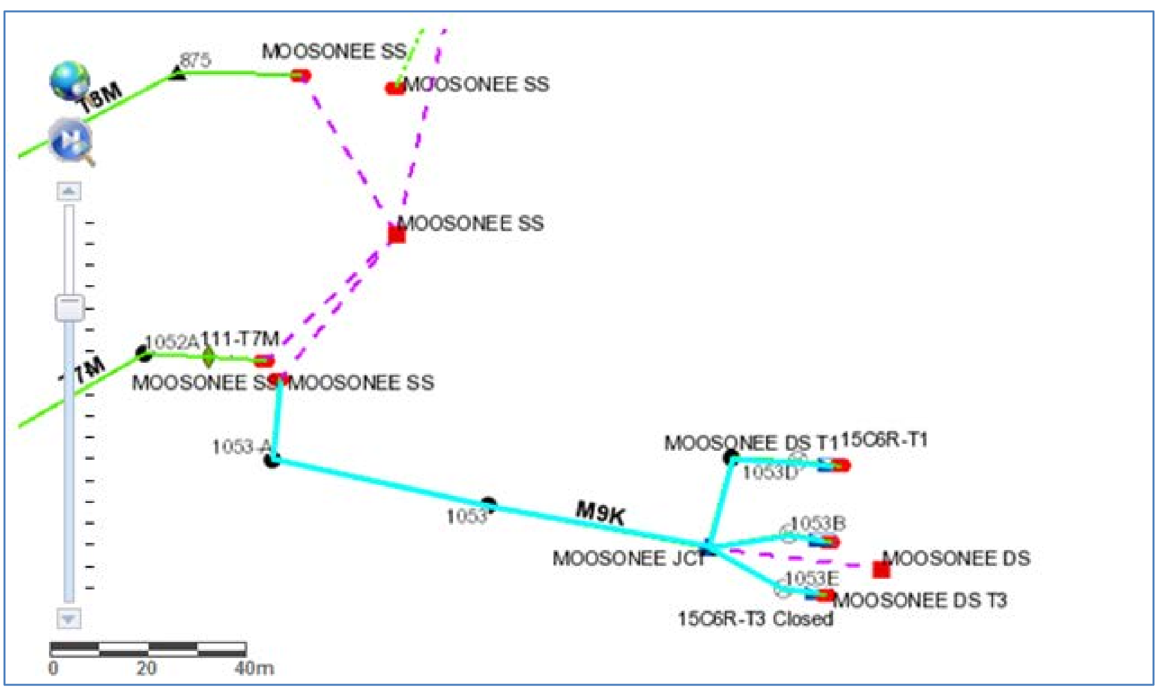
Response

A4L: Alexander SS – Longlac TS (153 km)



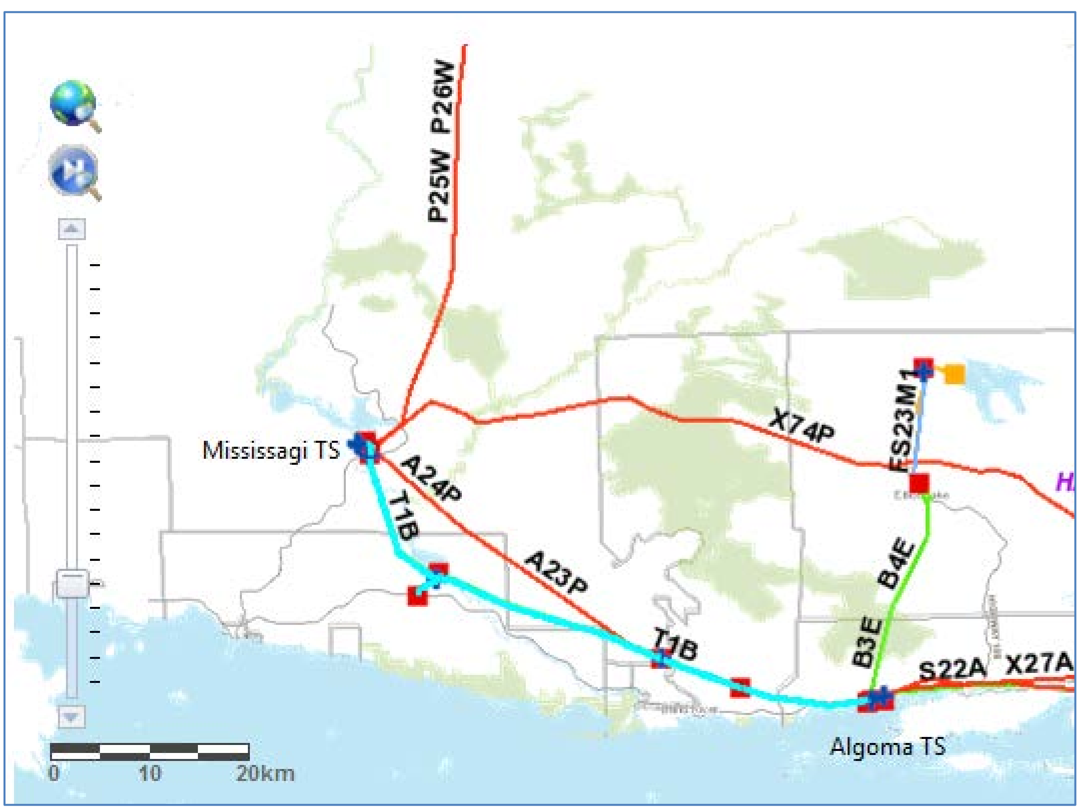
M9K: Moosonee DS - Moosonee SS (Less than 1 km)



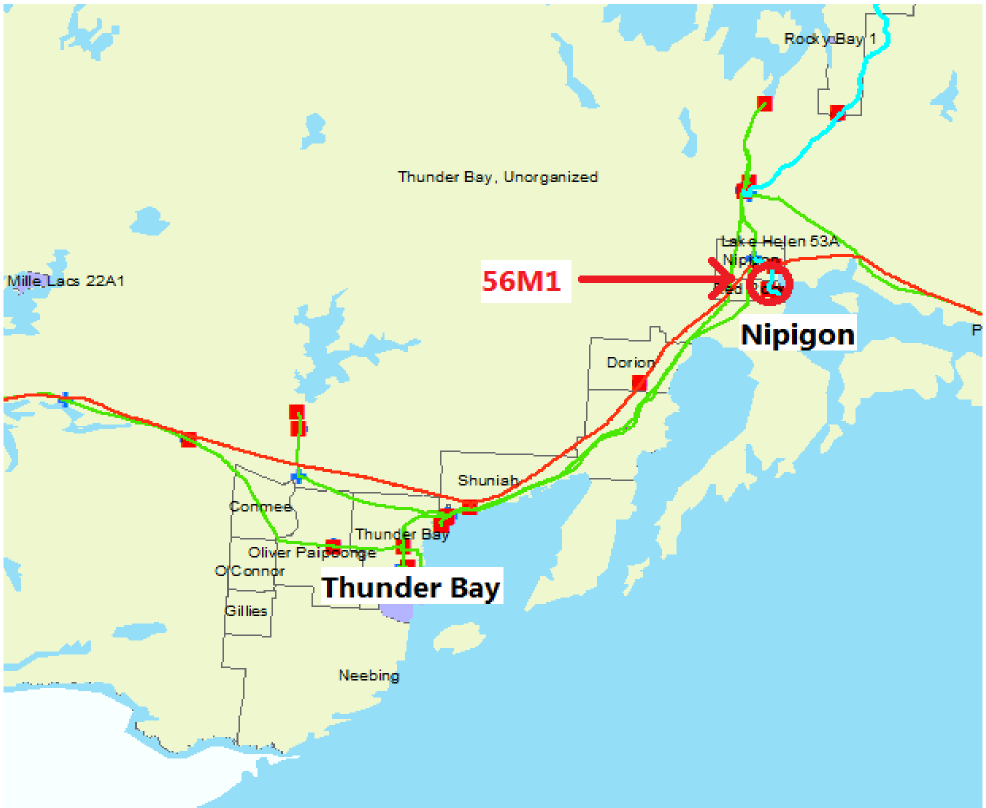


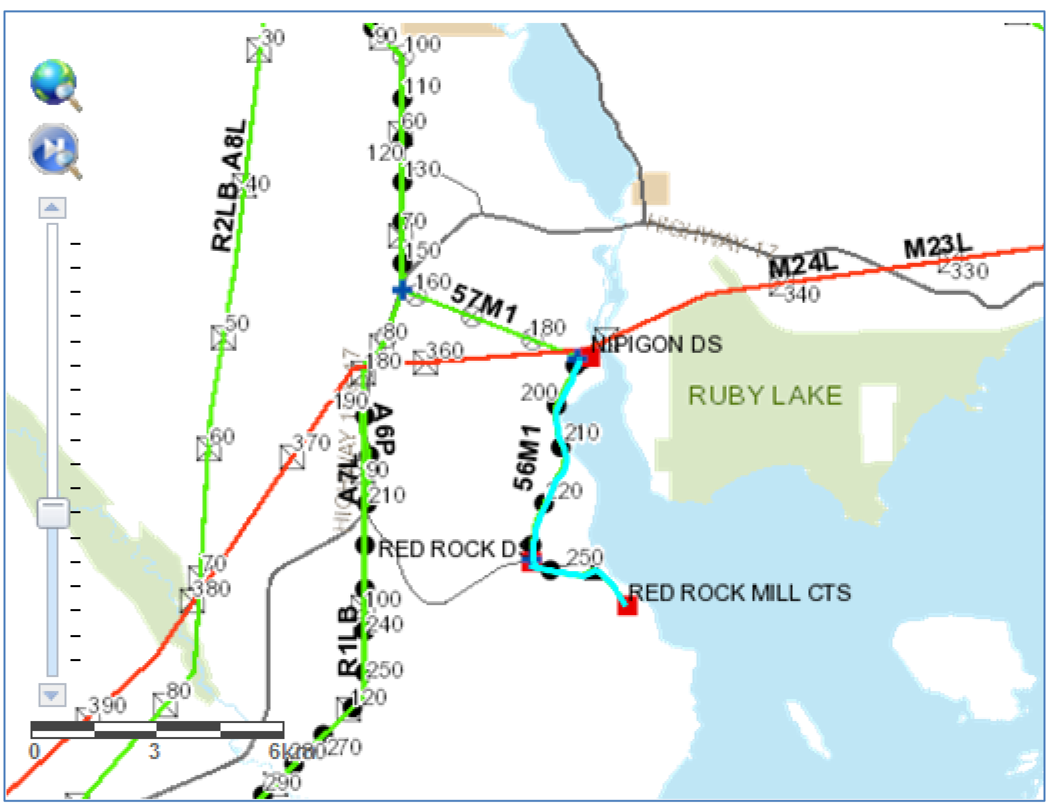
Witness: Chong Kiat Ng

<u>T1B: Rayner CGS –Algoma TS (65 km)</u>

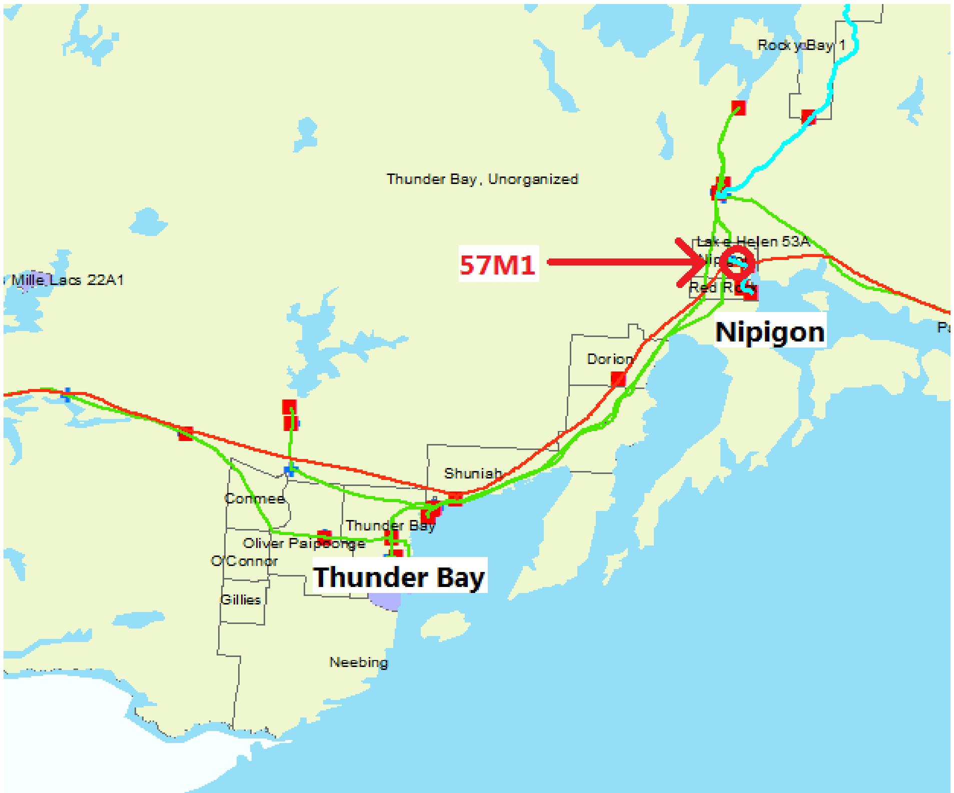


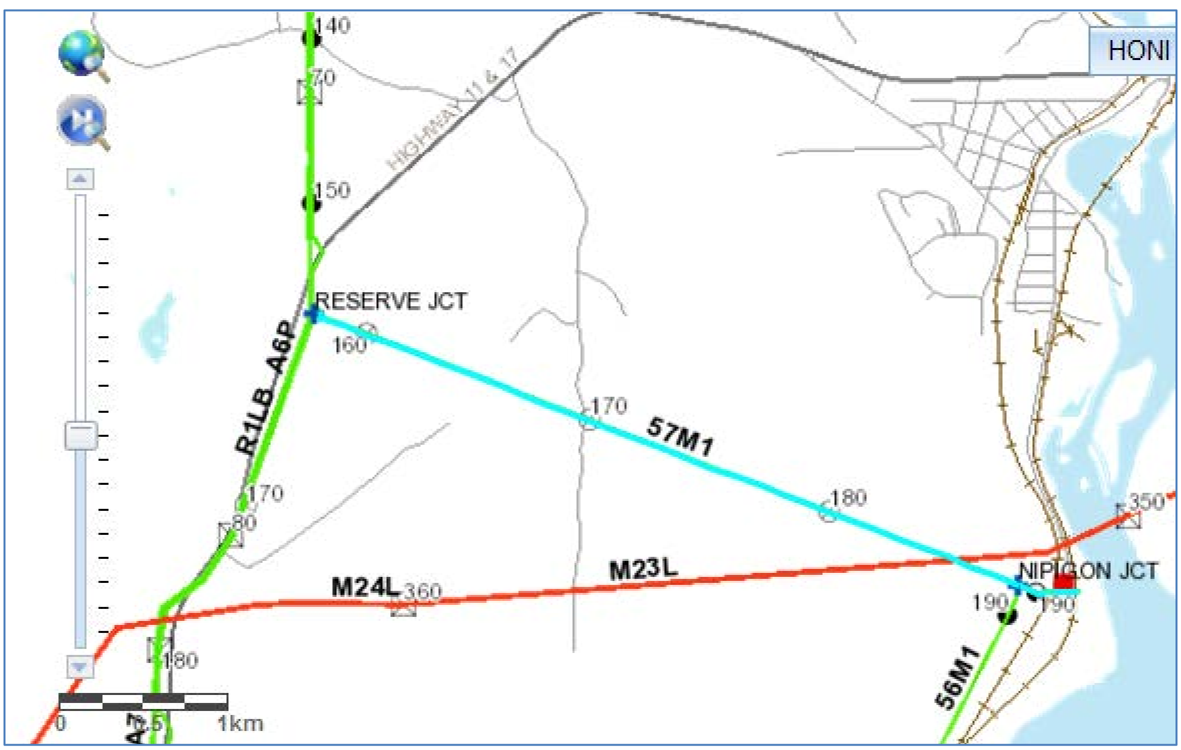
56M1: Nipigon Jct – Red Rock Mill CTS (8 km)





57M1: Reserve Jct – Nipigon DS (5 km)





UNDERTAKING – TCJ2.12

Undertaking

To provide a response to three recommendations of the Auditor General's Report on page 251.

Response

The undertaking was to provide a summary of how three additional areas of concern cited by the Auditor General were addressed in this application. The additional areas are:

- Spare Transformers in Storage Not Aligned with Hydro One's Needs
- Data from Power Quality Meters Not Used to Help Customers Avoid Disruptions
- Weak Management Oversight Processes over Capital Project Costs

Spare Transformers in Storage Not Aligned with Hydro One's Needs

A comprehensive review of the transformer spares inventory at Hydro One's Central Maintenance Shop in Pickering has been completed. Our system of record (i.e. SAP) has been updated to reflect the outcome of review. Hydro One spare inventory management is described in to Exhibit B1, Tab 3, Schedule 2, Section 4.2.2, Spare Transformers.

Hydro One also reviewed its suite of power transformers to determine whether opportunities existed to further consolidate design and procurement standards. The review concluded that there are limited efficiencies to be gained from further standardization.

Data from Power Quality Meters Not Used to Help Customers Avoid Disruptions

Frequency and voltage fluctuations on the transmission system become a power quality event only if customers' equipment or processes are adversely affected. It is not technically possible for a utility to predict or determine whether a voltage sag event caused a PQ disruption to a customer,

The most common power quality problem that can lead to disruption of large industrial customer processes is temporary voltage sags. The impact of voltage sag depends on their magnitude and duration and the resilience of customers' equipment.

Hydro One has completed system studies to estimate the magnitude, frequency and duration of power quality voltage sag events at the specific point of connection of large transmission-connected end users. The results of these system studies provide an indication of the number, severity and duration of voltage sag events that a customer may experience and should be able to withstand according to the IEEE Standard 1668.

Customers will be able to use these studies to inform their decisions regarding investments to improve the resilience of their facilities and decrease their susceptibility to low-to-moderate voltage sag events as suggested in IEEE Standard 1668.

Hydro One is also in the process of working with its customers to enable their revenue meters to serve as PQ meters. This will allow for more effective assessment of PQ events.

Moreover, Hydro One has offered the services of 3rd party experts to assess customers' facilities and recommend measures to mitigate events.

Weak Management Oversight Processes over Capital Project Costs

Hydro One has taken significant steps to improve in the areas of benchmarking, estimating and tracking to ensure that projects are completed on time and on budget.

The Navigant Total Cost Benchmarking study (Exhibit B2, Tab 2, Schedule 2, Attachment 1, section 3.3) has been completed noting a number of benchmarks for project management performance. In support of furthering our benchmarking capabilities, Hydro One is refining the internal work breakdown structure to enable a more efficient, consistent and accurate cost collection process for capturing project actual costs which will aid in cost comparisons. In addition, Hydro One is currently working to develop relationships with peer Canadian utilities to develop a consistent approach to benchmarking capital project work with early focus on transmission lines projects with subsequent focus to be on substation projects.

Contingency and escalation allowances have been reviewed and redefined. As a first step, Hydro One has reduced contingency percentage allocation on projects to a maximum of 10% of overall project budget, with exceptions requiring upper management approval. Escalation rates are also now in line and consistent with our corporate business plan (approx. 2%/year). In addition, Hydro One has implemented a quantitative project risk management methodology. Contingencies for major capital projects going forward will be based on an assessment of potential risks with a projected cost impact value and assigned probability weighting. Exceptions to contingency amounts that are greater than 10% are reviewed and approved at the Director and or VP level where these exceptions are justified. This approach is in line with industry best practices. In addition, estimates are also now reviewed by all applicable Lines of Business, to ensure alignment and add rigor.

A formalized project closure report process (including all project stakeholders) has been implemented to analyze the project plan and the effectiveness of its execution. Findings and feedback will be incorporated into future project estimates. This will help ensure major project work (projects >$5 million) is completed as planned and that project estimates are compared against actuals, with variances explained and lessons learned incorporated into future projects. On a regular basis a list is prepared to capture projects that have/are planned to be completed in a calendar year. On time / on-budget analysis is conducted.

UNDERTAKING – TCJ2.13

Undertaking

To explain why there is no spending in 2012, 2013, and 2014 under transmission, transformers, demand and spares at Exhibit B1, Tab 3, Schedule 1, Attachment 1, page 1.

Response

No historical spending is captured under "Tx Transformers, Demand, and Spares" in 2012, 2013, and 2014 as this is a new category of expenditures introduced in 2015.

Historical spending in 2012, 2013, and 2014 associated with spare transformer procurements was captured within the "Power Transformers" capital expenditure category.

UNDERTAKING – TCJ2.14

Undertaking

To provide the number of transformers that have been included in the forecast for the test years for spares and for power.

Response

Hydro One has currently purchased the following spare units in 2016:

- 1 unit of 125 MVA, 230kV/28-28kV, step-down transformer
- 1 units of 83MVA, 230kV/44kV, step-down transformer
- 1 unit of 150MVAr, 27.6kV, dry type reactor
- 1 unit of 50MVAr, 13.8kV, dry type rector

Hydro One anticipates purchasing four (4) spare transformers in each of 2017 and 2018 to account for an average of four (4) demand failures per year as outlined in Exhibit I, Tab 1, Schedule 31. The specific type of transformers is dependent upon the actual failures.

The list of transformers identified for procurement to meet planned replacement requirements in 2017 and 2018 are outlined in Exhibit I, Tab 1, Schedule 31.

UNDERTAKING – TCJ2.15

Undertaking

To describe the accounting for engineering portfolio completed externally as described in AMPCO 51.

Response

When developing estimates for transmission capital projects where the engineering is executed internally, Hydro One utilizes an average hourly rate for all engineering labour based on standard costing methodologies as per Exhibit C1, Tab 5, Schedule 1 - Costing of Work. Historically during estimate development, there was not a specific distinction made between internal and external engineering rates. An average hourly rate based on internal labour is used across all of the different resource types typically used in the delivery of engineering services (i.e. engineers, designers, and drafting resources) and the different experience levels of the staff (i.e. junior, intermediate, senior).

Since early 2016, cost estimates used for project approval have taken into account whether the engineering work is to be executed internally or externally. If executed externally, engineering estimated costs are based on a fixed price quote using the contracted external rates. If executed internally, the aforementioned average hourly rate is used.

Costs incurred on projects are always based on the costs of the actual resource performing the work, and are reflected in the project totals which are ultimately additions to rate base.

UNDERTAKING – TCJ2.16

Undertaking

To describe to what effect being an outlier has on the capital budget and specifically in this application for the two-year period which projects are being initiated because of being outliers on the project.

Response

See AMPCO IR# I-03-014 for initial response to this undertaking.

For this application, the latest annual report on the Customer Delivery Point Performance (CDPP) Standard was for calendar year 2014. This report identified 105 delivery points having a status of "outlier", supplied from 53 circuits in total, and was analyzed for primary cause and performance trends. As stated in IR # I-003-14, many of these supply circuits (and therefore the supplied delivery points) have capital program investments identified in the submitted business plan. In particular, in the test years of 2017 and 2018, work is planned on seventeen (17) circuits containing 40 delivery points that were identified as outliers in the latest CDPP report. These capital investments are initiated through the Asset Risk Assessment process outlined within this application and they will improve the performance of the supply circuits, and consequently they will positively impact the performance of the supplied delivery points.

Some examples include:

- A4L – Wood poles and conductor replacements
- E1C – Wood poles, conductor and insulator replacements
- B3 – Conductor and insulators replacements

There is no direct capital funding attributed to improvements of specific delivery points in the test years, however, the analysis of the CDPP outliers indicated that the predominant cause exists at the transmission circuit level. The outliers will be monitored for material performance outcomes and possible subsequent remediation investments execution.

UNDERTAKING – TCJ2.17

Undertaking

To provide the various details listed in the past several questions re: the table found at Exhibit I, Tab 8, Schedule 7, page 2 of 2.

Response

The following table addresses parts a) and b) of the interrogatory:

		Actual $M				Forecast $M		
		2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Stations Assets	**Corrective Maintenance**	43.6	49.6	49.9	47.8	36.5	51.9	51.7
	Preventative Maintenance	73.4	77.4	76.5	78.5	79.6	82.0	77.5
	Total	*117.0*	*127.0*	*126.4*	*126.3*	*116.1*	*133.9*	*129.1*
	Corrective % of Total	**37%**	**39%**	**39%**	**38%**	**31%**	**39%**	**40%**

		Actual $M				Forecast $M		
		2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Lines Assets	**Corrective Maintenance**	13.1	11.5	13.0	13.8	12.6	13.2	12.9
	Preventative Maintenance	35.5	38.9	44.1	38.8	46.2	46.6	47.9
	Total	*48.6*	*50.4*	*57.1*	*52.6*	*58.8*	*59.8*	*60.8*
	Corrective % or Total	**27%**	**23%**	**23%**	**26%**	**21%**	**22%**	**21%**

		Actual $M				Forecast $M		
		2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Total	**Corrective Maintenance**	56.7	61.1	62.9	61.6	49.1	65.1	64.6
	Preventative Maintenance	108.9	116.3	120.6	117.3	125.8	128.6	125.4
	Total	*165.6*	*177.4*	*183.5*	*178.9*	*174.9*	*193.7*	*190*
	Corrective % or Total	**34%**	**34%**	**34%**	**34%**	**28%**	**34%**	**34%**

*Support programs not included as they are not directly tied to preventative and corrective maintenance program.

Witness: Chong Kiat Ng

c) The ratio of corrective maintenance work to total maintenance work is relatively constant over historic, bridge and test years. The lower percentage for stations in 2016 is due to restricted funding envelope and cuts being made to some of the immediate corrective work which will need to be addressed in future.

d) Hydro One is aware of the Transmission Total Cost Benchmarking Study recommendation with respect to ratio of corrective maintenance to total maintenance and is reviewing the appropriateness of the recommended target, considering the system design philosophy and requirements of the asset base.

UNDERTAKING – TCJ2.18

Undertaking

To review questions prepared by counsel for the SEP with respect to Society IR No. 5, in particular the response to part (f), and if possible to respond.

The follow-up questions provided by counsel for the Society of Energy Professionals were as follows:

With reference to I-8-5 part f) which provides a comparison to fully burdened External and Internal Engineering Labour rates. The Society seeks clarification that the External engineering rates provided reflect the full cost to Hydro One of employing these resources and the comparator roles are the same, specifically:

a) With regard to the comparator role, in its response Hydro One states it is "an Intermediate Engineer, which is functionally a Society MP4". Within Hydro One, a job requirement is that all MP4 journeypersons in engineering stream jobs are required to have their Professional Engineering license prior to starting in the MP4 engineering stream position. Please confirm whether the Request For Proposal process Hydro One utilizes for external engineering resources specifies that such resources must have their Professional Engineering license and that this is also confirmed when these resources are engaged. If this is not done please explain why not & why Hydro One would consider these positions comparable if the external engineers do not necessarily have their Professional Engineering license.

b) With regards to whether the External engineering rates provided reflect the full cost to Hydro One of employing these resources, please confirm that these rates include the following. If they do not include any of these please explain why they do not.
    i. The gross margin which the external engineering company earns.
    ii. All the administrative and supply chain costs incurred by Hydro One to use these external resources e.g. contract management costs including invoice payment, contract management etc.
    iii. The cost of office space, supplies & services if these are provided by Hydro One.
    iv. All the elements that are added onto internal Labour cost in C1-T5-S1 Costing of Work i.e. "Field Supervision & Technical Support" and "Support Activity" [as per part g) of the IR response].

v. The full cost for contract product review by internal staff as outlined in I-8-15 part c) p2 lns 13-20

Response

a) Hydro One does not specifically require that all external engineering resources be licensed engineers. We do specify what engineering deliverables from the external companies are required to be sealed by their own Professional Engineers, as is done consistently within Hydro One. The external companies maintain their own Certificate of Authorization from the Professional Engineers of Ontario ("PEO") and managed systems around quality management as well as staff hiring and retention. It is Hydro One's experience in working with these qualified companies that the vast majority of the staff working on our projects are in fact licensed engineers.

It should be noted that not all Hydro One MP4s in the engineering stream jobs are licensed engineers. The related Letter of Understanding executed with the Society of Energy Professionals in July 2014 states that all incumbents in the role who are not licensed will be have their job titles updated to remove the specific word "engineer", and all other requirements will be grandfathered. This change is consistent with requirements defined by the PEO.

Future hires into the MP4, MP5 and MP6 roles within the engineering stream are in fact required to be licensed, and the company has agreed to reimburse the associated annual dues on the practicing engineer's behalf.

b)

i. Yes, these costs are included in the external rates provided in Exhibit I, Tab 8, Schedule 5, part f).

ii. These costs are borne by Hydro One and recovered through a material surcharge, consistent with all purchased materials and contracted services as outlined in Exhibit C1, Tab 5, Schedule 1, page 7.

iii. These costs are entirely paid by the external engineering companies.

iv. For the 2016 labour rate, 81% of the costs are combined payroll obligations, contractual time away from work (i.e. vacation, sick time, etc.), and time not directly benefiting a specific program or project (i.e. safety meetings, training, downtime).

The remaining 19% is for supervision and support staff, administrative expenses, and workgroups such as Work Methods & Training, Health Safety & Environment.

v. Hydro One currently does not discretely collect these costs for product reviews, commonly referred to as Owner's Engineer reviews. All actual costs incurred by internal engineers in support or during these reviews are charged into the capital program or project at standard labour rates.

In developing estimates for projects and programs, 20% of the estimated hours are planned for Owner's Engineer reviews by Hydro One. That is, in addition to 100 hours of planned external engineering, the project will include 20 hours of planned internal engineering to review external deliverables for quality and completeness, adherence to Hydro One's standards, and answer any questions that may come up during the execution of the work by the external partner.

UNDERTAKING – TCJ2.19

Undertaking

To provide an estimate of the cost savings achieved by the percentages shown in AMPCO 52 (A) in 2018 and 2017.

Response

There is no significant cost savings from the outsourcing of Hydro One's construction work. Hydro One's construction force is mainly a casual labour force hired through EPSCA, CUSW and seventeen other building trades unions. Hydro One negotiates directly with CUSW and through EPSCA, and is bound to collective agreements negotiated for the other seventeen Building Trade Unions. The construction workforce fully burdened hourly labour rate is an industry standard rate.

The goal of outsourcing construction is to respond to the growing work program while maintaining the current level of Hydro One's construction labour (casual trades) workforce. The assumption is that any savings associated with contractors' construction efficiencies would be offset by the profit margin in their contracts. All construction labour (casual trades) is unionized in the province and regardless of whether the work is managed internally or externally, the same unionized labour rates apply. In addition, external vendors apply a profit margin on top of labour rates which Hydro One does not. Engineering is currently the only area where savings are expected. Please refer to The Society of Energy Professionals (SEP) Interrogatory #5 response (f) for details on internal vs. external engineering comparisons.

Any cost savings associated with outsourcing would be correlated to the delivery model used. Contracts have not yet been secured for all of the work planned to be outsourced in 2017/18. Through the Enhanced Delivery Initiative, Hydro One is working toward greater visibility to the contractor's cost breakdown to facilitate benchmarking and to determine if evolution in the contract/delivery models may result in increased cost savings.

UNDERTAKING – TCJ2.20

Undertaking

To respond in writing to the follow-up questions that Ms. Grice asked about the Reliability Model, the consultation, and how that has affected the overall plan re Exhibit I, Tab 11, Schedule 2; Exhibit A, Tab 3, Schedule 1, Table 2, page 7; Exhibit B1, Tab 3, Schedule 1, page 1, Table 2; and Exhibit B1, Tab 2, Schedule 2, Attachment 2.

Response

Part 1:

What does the Risk Reliability Model cover, just Sustainment Capital as indicated in response to part a) or any other classes of Capital Investment as well e.g. Control Centre?

The reliability risk model is an outcome measure to gauge the impact of investments on future transmission reliability performance. It is based on asset hazard functions, demographic profiles, proposed investment plan and three asset classes that are most impactive to SAIDI performance. Please refer to Exhibit B1, Tab 2, Schedule 2, Attachment 2, Page 13. These three classes of assets are currently in-service, and hence the outcome measure is affected by Sustainment Capital investment. Investments in these three asset classes will help Hydro One to maintain its system reliability performance; hence, the reliability risk model is focusing in on these three asset classes.

Part 2:

Of the three Investment Scenarios Attachment 2, Ipsos Report page 24 presented to the Consultation Exhibit B1, Tab 2, Schedule 2, it says on Page 14

> "the majority of participants would be willing to support the investment required to at least maintain the current level of reliability risk. The general sentiment, overall, was that the right balance between reliability risk and rates is somewhere between Illustrative Scenario 2 (6.3% rate increase for an essentially unchanged reliability risk) and Scenario 3 (6.8%rate increase for approximately 10% improvement in reliability risk)."

1. Which (Sustaining?) Investment Scenario and Rate Increase presented in the Consultation is closest to
    a) the participants expressed preference and
    b) Hydro One proposal Preferred Scenario as shown Table 2

Include Investment amount 2016-2020 and associated average “Rate Increase”.

a) As described above, the majority of the participants would be willing to support the investment required to at least maintain the current level of reliability risk, and the general sentiment was the right balance is between Scenario 2 and Scenario 3. It is not possible to assess whether the participants preference is closer to Scenario 2 or Scenario 3.

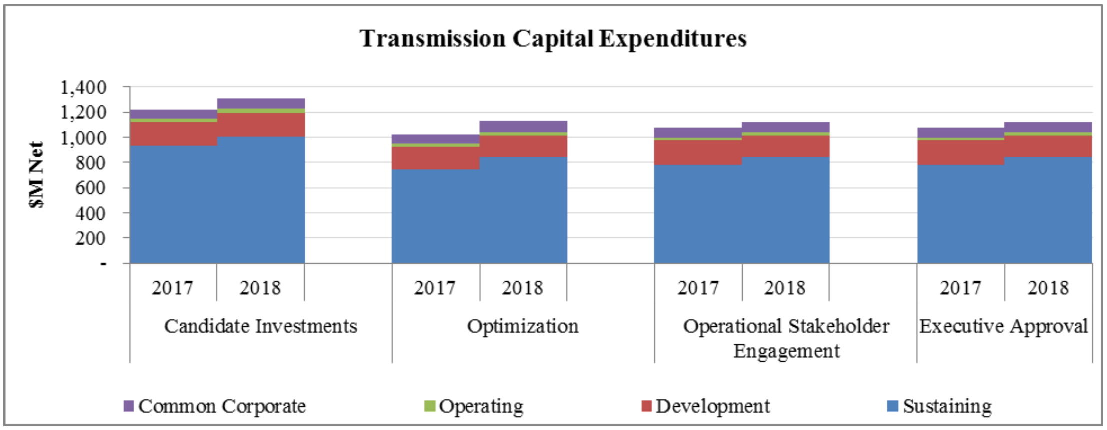
b) Hydro One did not have a preferred Scenario while conducting its customer consultation. The feedback from customer consultation process influenced Hydro One’s investment plan, which underpins its 2017 and 2018 Tx rate application. Information regarding investment level and rate increases presented to the customers can be found in Exhibit B1, Tab 2, Schedule 2, Attachment 2, Page 23.

Part 3

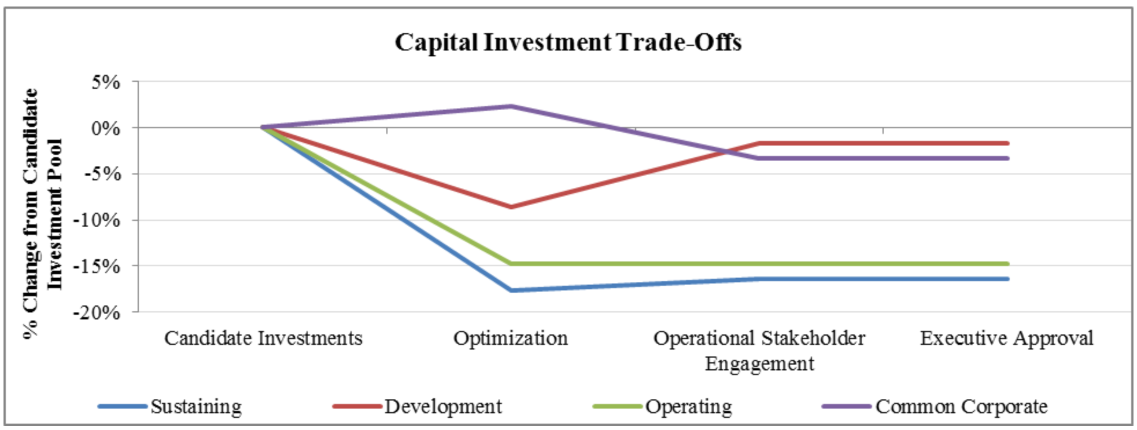
Each of the major investment categories are developed from individual candidate investments, each of which is assessed based on the potential value created by the candidate investment through risk mitigation or its ability to enhance productivity.

All candidate investments are aggregated into a consolidated investment portfolio for optimization. Through the optimization process, trade-offs between investments were made within the financial parameters.

The graphs below show the 2017/18 transmission capital work program through the different stages of the planning process, as well as the trade-offs between the different investment categories of sustaining, development, operating and common corporate costs, (based on the cumulative 2017/18 expenditures), relative to the initial candidate investment portfolio.

1 
Transmission Capital Expenditures
1,400
1,200
1,000
800
600
400
200
-
$M Net
2017
2018
Candidate Investments
2017
2018
Optimization
2017
2018
Operational Stakeholder Engagement
2017
2018
Executive Approval
Common Corporate
Operating
Development
Sustaining

2

3 
Capital Investment Trade-Offs
5%
0%
-5%
-10%
-15%
-20%
% Change from Candidate Investment Pool
Candidate Investments
Optimization
Operational Stakeholder Engagement
Executive Approval
Sustaining
Development
Operating
Common Corporate

UNDERTAKING – TCJ2.21

Undertaking

With respect to Exhibit I, Tab 1, Schedule 118, to clarify the performance of Inergi.

Response

References: Exhibit C1Tab 3 Schedule 2 Pages 3 and 12 and Appendix B Table 1
Energy Probe IRR Exhibit I Tab 11Schedule 18
OEB IRR Exhibit I Tab 1 Schedule 118 Attachment 1

Hydro One has filed in confidence with the OEB a summary of Inergi LP's actual performance of the PIs (monthly, quarterly, and yearly measures) for the period March 2015 to February 2016. The summary categorizes the PIs and provides the following information: the number of PIs in each category; the number and percentage of PIs for which Inergi met performance expectations; and the number of PIs for which Inergi missed target or minimum performance levels. As an explanatory note in the summary, Hydro One indicates how many PIs were adjusted upward to achieve continuous improvement as per the Inergi Agreement, effective as of January 1, 2016.

1. Please provide more details on the derivation and specifics of the 5 performance metrics that underlie the performance figures shown in the Table provided in the Response to OEB Staff Interrogatory 118.

Hydro One worked with its external advisor to determine commercially relevant PIs that leveraged market best practices while aligning to business objectives, which were identified in its Request for Proposal. The specifics of the negotiated list of PIs can be found within Hydro One's confidential response to BOMA IRR Exhibit I Tab 2 Schedule 11 in Exhibit 2 of each statement of work.

2. Please indicate how performance is judged for each Metric relative to 100% (e.g. individually or in aggregate.

For the five statements of work, there are collectively 136 performance indicators ("PIs") measured on a monthly, quarterly and yearly basis, for which achievement or failure is determined on an individual PI basis. Relative to 100%, each PI sets two thresholds for service performance: a minimum service level and a target service level. The former is the minimum level of performance at which Inergi must perform, while the latter is a higher contracted level of performance. Inergi is required to meet both thresholds for the PI to be considered met.

3. Please indicate how performance is linked to the rewards/ penalties for Inergie, using 2015 as an example.

There are no rewards owing to Inergi for achieving PIs. There are only remedies owing to Hydro One in the event a PI is not achieved, which is determined on an individual PI basis. For each PI failure, Hydro One may be entitled to a remedy from Inergi in the form of a credit, a plan for remediation action, or both. The methodology for how remedies are applied in the event of a PI failure, and for which PIs remedies apply to, can be found within Hydro One's confidential response to BOMA IRR Exhibit I Tab 2 Schedule 11 in *Schedule 5.1 - Service Level Methodology*.

4. Please Provide YTD performance for 2016.

The table below includes actual results for Inergi's performance for the period from March to August 2016. As indicated in cell E6, Inergi met or exceeded 92% of all PIs for all statements of work during the period.

		A	B	C	D	E = B / A
	Statement of Work	**Performance Indicators Measured for period March through August 2016**	**Performance MET**	**PI Target NOT MET**	**PI Minimum NOT MET**	**% Met**
1	**Information Technology Services**	289	**266**	**13**	**10**	**92%**
2	**Finance and Accounting Services**	105	**97**	**7**	**1**	**92%**
3	**Payroll Services**	78	**62**	**10**	**6**	**79%**
4	**Supply Chain Services**	183	**175**	**2**	**6**	**96%**
5	**Settlement Services**	69	**68**	**1**	0	**99%**
6	**Total**	**724**	**668**	**33**	**23**	**92%**