Ontario Energy Board (Board Staff) INTERROGATORY #106

Reference:

Exhibit A/Tab 3/Sch1– Section 4: Transmission System Plan, pg. 13

Investment Category	EB-2014-0140		EB-2016-0160		Comparison between Filings	
	2017	2018	2017	2018	2017 Increase	2018 Increase
Sustaining	597.4	636.7	776.8	842.1	30.0%	32.3%
Development	148	116.4	196.4	170.2	32.7%	46.2%
Operations	44.4	25.2	25.4	30.8	-42.8%	22.2%
Common Corp Costs	58	60.4	77.6	79.1	33.8%	31.0%
Total Capital	**847.8**	**838.7**	**1076.1**	**1122.2**	**26.9%**	**33.8%**

Interrogatory:

a) Please confirm the following:

i) that the forecast sustaining capital expenditures in Test Years 2017 & 2018 are 30% and 32.3% higher than the corresponding Hydro One forecasts for sustaining capital expenditures in those years in the 2014 EB-2014-0140 filing.

ii) that the forecast development capital expenditures in Test Years 2017 & 2018 are 32.7% and 46.2% higher than the corresponding Hydro One forecasts for development capital expenditures in those years in the 2014 EB-2014-0140 filing.

iii) that the forecast operations capital expenditures in Test Years 2017 & 2018 are 42.8% lower and 32.3% higher respectively than the corresponding Hydro One forecasts for operations capital expenditures in those years in the 2014 EB-2014-0140 filing.

iv) that the forecast common corporate capital expenditures in Test Years 2017 & 2018 are 33.8% and 31% higher than the corresponding Hydro One forecasts for development capital expenditures in those years in the 2014 EB-2014-0140 filing.

b) Given the magnitude of these changes, please explain if Hydro One has obtained sources of material new information or changed evaluation methodologies between preparation of the 2014 application and this application.

Witness: Chong Kiat Ng/Glenn Scott

i) If a result of new information, please explain why this information was not available to Hydro One at its last application.

ii) If as a result of new methodology, please explain what benefits this new methodology will produce to justify the additional costs.

Response:

a) and b) See Hydro One's responses below.

i) The increases described above for Sustainment capital forecasts are confirmed. They reflect new information regarding customer needs and preferences, reliability risk, the schedule of nuclear generation retirement and refurbishment, and emerging asset condition data.

- Hydro One's extensive customer engagement exercise took place in early 2016, as described in Exhibit B1, Tab 2, Schedule 2. It was Hydro One's first systematic attempt to consult customers specifically on their needs and preferences in a manner that could inform Hydro One's investment plan. Accordingly, the results of that undertaking were not available at the time of Hydro One's last rate application. Based on customer feedback regarding the importance of system reliability and mitigating reliability risk, Hydro One has attempted to maintain an appropriate balance between system reliability and corresponding rate impact.

- Hydro One's reliability risk model was developed in early 2016 as a planning tool that helps assess future system reliability, so information regarding reliability risk was unavailable at the time of Hydro One's last rate application. It reflects Hydro One's attempt to develop a model that provides a directional indication on the level of capital investment needed to reduce risk to system reliability. The reliability risk model is developed as a leading indicator for system reliability performance. The typical duration needed to scope and execute a transmission investment is between three to five years. Therefore, the key to maintaining top quartile reliability performance is to remediate reliability risk before it manifests itself as deterioration in SAIDI and SAIFI. The model is also used to cross-check the bottom-up determination of Sustainment capital spending levels needed to address asset needs described in Exhibit B1, Tab 2, Schedule 5.

- The schedule for Bruce Power and Ontario Power Generation's nuclear generation refurbishment and retirement was unclear in 2014 and, therefore, unavailable at the time of Hydro One's last rate application. This will significantly reduce base load generation availability between 2022 and 2030. Accordingly, Hydro One is taking steps to ensure transmission assets connecting the other generation assets are available to support system requirements.

- The increases are also attributable to new information regarding asset needs. At the time of Hydro One's last rate application, the urgency to address CP/COB insulator condition was not clearly understood. A 2016 testing report by Electric Power Research Institute ("EPRI") on Hydro One's CP/COB insulators validated that they have deteriorated to the point that replacement program needs to be accelerated to ensure safety and reliability. Please refer to Exhibit B1, Tab 3, Schedule 11, Investment Summary Document #S79. A new structure coating product recently became available, enabling modifications to Hydro One's tower coating method, making it more efficient. Together with a new technical assessment conducted with EPRI, Hydro One was able to develop a coating program to extend life of transmission structures in high corrosive zones, which is reflected in the current application. Refer to Exhibit B1, Tab 3, Schedule 11, Investment Summary Document #S76 for more details.

ii) The increases described above for Development capital forecasts are confirmed. The increased capital expenditures in 2017 and 2018 are primarily due to unexpected delays in the Clarington TS and the Supply to Essex County Transmission Reinforcement projects, as well as the addition of two new load connection projects to the forecast (Hanmer TS and Runnymede TS). Details on these projects are available in Exhibit B1, Tab 3, Schedule 11, Investment Summary Documents #D01, D14, D18, and D19 respectively.

iii) Hydro One confirms that the Operations capital forecasts for 2017 and 2018 are 42.8% lower and 22.2% higher, respectively, than the forecasts provided in its EB-2014-0140 filing. (Note that the percentage change for 2018 is mistyped in the question.) The decrease in 2017 Operation capital expenditures can be attributed to reprioritization of the following investments that were referenced in the EB-2014-0140 application: mobile radio replacement, the telemetry expansion program, the distance to fault - fault locating program, wireless station cameras and the wide area network outreach program. The increase in 2018 Operations capital expenditures can be attributed to: (a) a shift in the work schedule and scope of the Integrated System Operations Centre project; and (b) the additional sustainment investment in station local control equipment. Details on these investments are provided in Exhibit B1, Tab 3, Schedule 11, Investment Summary Documents #O01 and #O02, respectively.

Witness: Chong Kiat Ng/Glenn Scott

iv) It is assumed that this question compares Common Corporate capital forecasts provided in the current application and in the EB-2014-0140 application. The increases described above are confirmed. The increases are largely attributable to changes in information technology ("IT") forecasts and transport, equipment and service equipment ("TWE") forecasts driven by new information.

- In the EB-2014-0140 application, IT estimates for 2017 and 2018 were based on class 'D' estimates (+50% accuracy) premised on a comparable business case for a medium size, complex SAP implementation of new functionality and enhancements. The estimates provided in the current application are based on more mature investment plans, meaning better defined requirements, proof-of-concept and/or actual vendor quotes. Also, emerging business needs to address process inefficiencies have driven additional investments not reflected in the 2014 application. For example, certain treasury, finance and human resource functions will be integrated into the existing enterprise SAP system to minimize manual tasks and promote a streamlined, more efficient enterprise environment. As part of Hydro One's "Security Event and Incident Management" upgrade and refresh initiative, a third-party assessment was commissioned in 2015 to review current design and practices, and make recommendations for improvements as needed. This resulted in a new investment in IT security as detailed in Exhibit B1, Tab 3, Schedule 6.

- For TWE, the cost increases are associated with a small increase in budget and an increase in costs allocated to the transmission business, reflecting the increased use of fleet assets for transmission work. Please refer to page 7 of Attachment 1 to Exhibit B1, Tab 3, Schedule 9 for a summary of the allocation approach for TWE.

Ontario Energy Board (Board Staff) INTERROGATORY #015

Reference:

Exhibit B1/Tab2/Sch 4/p. 8 - Section 3.2: Reliability Risk Modeling Approach, Table 1 – Relative Change in Reliability Risk]

"Table 1 below summarizes the expected relative decrease in risk, for each critical asset class and for the system as a whole, as a result of the 2017 and 2018 investment plan. For comparison the table also provides the relative increase in risk which will occur if no assets were replaced in the two year period."

Table 1: Relative Change in Reliability Risk

	Relative Change in Risk from Jan 1, 2017 to Dec 31, 2018, as per proposed investment	**Relative Change in Risk from Jan 1, 2017 to Dec 31, 2018, without investment**	**% of Interruption Duration***
Lines	-2%	11%	69%
Transformers	-9%	14%	9%
Breakers	1%	17%	6%
Other[1]	-	-	16%
Total*	**-2%**	**10%**	

* Total is calculated by weighting the change in risk by the asset class' contribution to interruption duration.

Interrogatory:

a) Please provide a description of the methodology, the detailed calculations and the supporting data used to populate Table 1 above.

b) Does Table 1 above show the overall probability of asset failures in each asset class contributing to SAIDI, CAIDI or some other metric?

c) Is the relationship between level of capital investment and the Relative Change in Risk values shown in Table 1 linear, or are there inflection points driven by different individual investments or overall levels of investment?

d) Did Hydro One evaluate any alternative investment plans other than the "proposed investment" and "without investment" cases shown in Table 1?
   i. If yes, please provide the investment level and projected reliability risk performance of these alternative investment portfolios.
   ii. If no, please explain how the proposed plan optimizes capital investment costs against reliability risk.

Witness: Mike Penstone

e) Has Hydro One ranked its capital investments to facilitate forced prioritization of the most effective reliability risk mitigation projects if the approved level of capital investment is less than Hydro One has requested?
   i. If yes, please provide the prioritized project list.
   ii. If no, please explain how the most effective risk mitigation projects will be prioritized if the approved capital investment level is less than requested.

Response:

a) The data in the table was summarized by running the risk model as described in Exhibit B1-02-04. The example of relative change in risk from Jan 1, 2017 to Dec 21, 2018 as per the proposed investment for lines (-2%) will be presented here.

Hazard curves that describe the asset survival risk by asset type are the basis for the risk model. Hydro One uses a report prepared by Foster Associates as basis for determining hazard curves, which is based on analysis of Hydro One's historical data (reference Exhibit I, Tab 1, Schedule 20, Part b).

Next, the demographic profile of the asset (for this example the asset type is lines) is multiplied by the age-specific hazard rate to obtain a risk profile for the assets as a function of their age. The overall probability is the sum of this profile. This operation is carried out for each asset type over the rate filing period for all replacements.

The asset risk calculation for lines with planned replacements until December 2018 is shown in the table below.

Total				
Age	**Circuit KM**	**Proportion of Total**	**Hazard Rate**	**1.053%**
0.00	14.87	0.05%	0.00%	0.000000%
1.00	34	0.11%	0.00%	0.000000%
2.00	101	0.34%	0.00%	0.000000%
3.00	122	0.41%	0.00%	0.000000%
4.00	445	1.51%	0.00%	0.000001%
5.00	93	0.31%	0.00%	0.000000%
6.00	160	0.54%	0.00%	0.000001%
7.00	117	0.40%	0.00%	0.000001%
8.00	269	0.91%	0.00%	0.000005%
9.00	28	0.10%	0.00%	0.000001%
10.00	34	0.11%	0.00%	0.000001%

Age	Total KM	Proportion of Total	Hazard Rate	1.053%
11.00	19	0.07%	0.00%	0.000001%
12.00	118	0.40%	0.00%	0.000009%
13.00	113	0.38%	0.00%	0.000012%
14.00	40	0.14%	0.00%	0.000006%
15.00	91	0.31%	0.01%	0.000016%
16.00	49	0.16%	0.01%	0.000011%
17.00	13	0.05%	0.01%	0.000004%
18.00	126	0.43%	0.01%	0.000044%
19.00	100	0.34%	0.01%	0.000043%
20.00	62	0.21%	0.02%	0.000032%
21.00	33	0.11%	0.02%	0.000020%
22.00	368	1.24%	0.02%	0.000270%
23.00	58	0.20%	0.03%	0.000050%
24.00	82	0.28%	0.03%	0.000083%
25.00	792	2.68%	0.03%	0.000929%
26.00	628	2.12%	0.04%	0.000851%
27.00	355	1.20%	0.05%	0.000552%
28.00	240	0.81%	0.05%	0.000427%
29.00	5	0.02%	0.06%	0.000010%
30.00	12	0.04%	0.07%	0.000028%
31.00	10	0.03%	0.08%	0.000026%
32.00	184	0.62%	0.09%	0.000535%
33.00	231	0.78%	0.10%	0.000748%
34.00	363	1.23%	0.11%	0.001316%
35.00	159	0.54%	0.12%	0.000642%
36.00	686	2.32%	0.13%	0.003062%
37.00	342	1.16%	0.15%	0.001690%
38.00	237	0.80%	0.16%	0.001288%
39.00	403	1.36%	0.18%	0.002412%
40.00	646	2.19%	0.19%	0.004248%
41.00	292	0.99%	0.21%	0.002099%
42.00	117	0.40%	0.23%	0.000917%
43.00	640	2.17%	0.25%	0.005482%
44.00	545	1.85%	0.28%	0.005084%
45.00	1,237	4.19%	0.30%	0.012517%
46.00	1,490	5.04%	0.32%	0.016342%
47.00	386	1.31%	0.35%	0.004585%
48.00	299	1.01%	0.38%	0.003827%

Age	Total KM	Proportion of Total	Hazard Rate	1.053%
49.00	176	0.60%	0.41%	0.002434%
50.00	150	0.51%	0.44%	0.002227%
51.00	609	2.06%	0.47%	0.009744%
52.00	629	2.13%	0.51%	0.010817%
53.00	90	0.30%	0.54%	0.001656%
54.00	117	0.40%	0.58%	0.002316%
55.00	313	1.06%	0.62%	0.006607%
56.00	300	1.02%	0.67%	0.006766%
57.00	512	1.73%	0.71%	0.012331%
58.00	630	2.13%	0.76%	0.016172%
59.00	493	1.67%	0.81%	0.013464%
60.00	192	0.65%	0.86%	0.005581%
61.00	645	2.18%	0.91%	0.019919%
62.00	568	1.92%	0.97%	0.018619%
63.00	206	0.70%	1.03%	0.007158%
64.00	474	1.60%	1.09%	0.017443%
65.00	1,838	6.22%	1.15%	0.071609%
66.00	1,639	5.55%	1.22%	0.067512%
67.00	345	1.17%	1.29%	0.014998%
68.00	382	1.29%	1.36%	0.017569%
69.00	286	0.97%	1.43%	0.013859%
70.00	177	0.60%	1.51%	0.009066%
71.00	102	0.35%	1.59%	0.005509%
72.00	33	0.11%	1.67%	0.001865%
73.00	0	0.00%	1.76%	0.000000%
74.00	44	0.15%	1.85%	0.002767%
75.00	506	1.71%	1.94%	0.033293%
76.00	198	0.67%	2.04%	0.013704%
77.00	248	0.84%	2.14%	0.018006%
78.00	0	0.00%	2.25%	0.000000%
79.00	392	1.33%	2.35%	0.031184%
80.00	19	0.06%	2.46%	0.001601%
81.00	198	0.67%	2.58%	0.017237%
82.00	529	1.79%	2.70%	0.048283%
83.00	700	2.37%	2.82%	0.066827%
84.00	791	2.68%	2.95%	0.078841%
85.00	12	0.04%	3.08%	0.001246%
86.00	284	0.96%	3.21%	0.030849%

Witness: Mike Penstone

Age	Total KM	Proportion of Total	Hazard Rate	1.053%
87.00	474	1.60%	3.35%	0.053732%
88.00	60	0.20%	3.49%	0.007119%
89.00	16	0.05%	3.64%	0.001948%
90.00	87	0.29%	3.79%	0.011134%
91.00	196	0.66%	3.95%	0.026156%
92.00	106	0.36%	4.11%	0.014700%
93.00	57	0.19%	4.28%	0.008272%
94.00	25	0.08%	4.45%	0.003765%
95.00	17	0.06%	4.63%	0.002735%
96.00	0	0.00%	4.81%	0.000000%
97.00	0	0.00%	4.99%	0.000000%
98.00	0	0.00%	5.18%	0.000000%
99.00	9	0.03%	5.38%	0.001548%
100.00	0	0.00%	5.58%	0.000000%
101.00	111	0.38%	5.79%	0.021760%
102.00	293	0.99%	6.00%	0.059607%
103.00	0	0.00%	6.22%	0.000000%
104.00	0	0.00%	6.45%	0.000000%
105.00	177	0.60%	6.68%	0.039984%
106.00	23	0.08%	6.91%	0.005381%
107.00	0	0.00%	7.15%	0.000000%
108.00	0	0.00%	7.40%	0.000000%
109.00	0	0.00%	7.66%	0.000000%
110.00	4	0.01%	7.92%	0.000938%
111.00	0	0.00%	8.18%	0.000000%
112.00	0	0.00%	8.46%	0.000000%
113.00	0	0.00%	8.74%	0.000000%
114.00	0	0.00%	9.02%	0.000000%
115.00	0	0.00%	9.32%	0.000000%
116.00	75	0.26%	9.62%	0.024549%
117.00	0	0.00%	9.93%	0.000000%
118.00	0	0.00%	10.24%	0.000000%
119.00	0	0.00%	10.56%	0.000000%
120.00	0	0.00%	10.89%	0.000000%
121.00	0	0.00%	11.23%	0.000000%
122.00	0	0.00%	11.57%	0.000000%
123.00	0	0.00%	11.92%	0.000000%
124.00	0	0.00%	12.28%	0.000000%
125.00	0	0.00%	12.65%	0.000000%

Witness: Mike Penstone

For example, there are 506 circuit-km of 75 year old lines making up about 1.7% of the population with an annual probability of failure of 1.94% given that these conductors survived previously to 74 years. Therefore the probability of failure of these 75 year old, 506 circuit-km is 0.0194 x 0.017. This calculation is performed for each age group over the entire demographic distribution and summed to produce the overall probability of failure.

This process is conducted for the present assets and after the planned replacements identified in this filing, representing a 1.056% and 1.031% probability of failure respectively. The ratio of these probabilities determines the relative risk as it appears in Table 1.

1.031%/1.056% - 1 = -2%.

As presented for lines, each asset type's demographic profile was multiplied by their age-specific hazard rates to obtain a risk profile for the assets as a function of their age. This was summed up as in the example for lines and these values are presented in Figure1 below under 'supporting data'. Future demographic asset distributions were used for the 'Proposed Investment' and 'Do Nothing' scenarios. For the 'proposed investment', the future demographics takes into account the aging of assets that are not replaced as well as those that are removed due to replacement. For the 'Do Nothing' scenario the presently installed assets are aged to the end of 2018.

Supporting Data				Calculations for Table 1				
Asset Type	Proposed Investment for 2017/18		"Do Nothing" After 2016	Relative Change in Risk from Jan 1, 2017 to Dec 31, 2018 as per proposed investment		Relative Change in Risk from Jan 1, 2017 to Dec 31, 2018 without investment		% of Interruption Duration *
	Jan. 1, 2017	End of Rate Filing Period	Jan. 2019					
Lines	1.056%	1.031%	1.17%	1.03 / 1.06 -1 =	-2%	1.17 / 1.06 - 1 =	11%	69%
Transformers	1.694%	1.535%	1.92%	1.54 / 1.69 -1 =	-9%	1.92 / 1.69 - 1 =	14%	9%
Breakers	2.610%	2.633%	3.05%	2.63 / 2.61 - 1 =	1%	3.05 / 2.61 - 1 =	17%	6%
				(-2% x 69%) + (-9% x 9%) + (1% x 6%) =	-2%	(-2% x 69%) + (-9% x 9%) + (1% x 6%) =	10%	

Figure 1

The totals in the bottom row as filed and presented in Table 1 utilize the SAIDI interruption data to weigh the overall probabilities of failure of each asset type as shown above. Figure 1 demonstrates the calculation of the total risk by weighing the relative risk of the asset type by the SAIDI interruption data and then summed up over all the assets.

b) As stated, the columns in Table 1 presenting the asset-specific relative risks are based on the computed overall probabilities of failure. It does not include outage interruption data (SAIDI) and is based on historical replacement rates. Note that in the case of multiple supply delivery points, an equipment failure will not result in SAIDI, CAIDI implications but will increase the risk of reliability while under the single supply condition.

c) The reliability risk is a function of asset demographics and hazard curves, which are non-linear. As such, the relationship between capital investment level and relative change in reliability risk is also non-linear. However, there is a positive correlation, a higher level of investment leads to more improvement in reliability risk.

d) Yes, Hydro One evaluated alternative investment scenarios, which were discussed as part of the customer engagement included in Exhibit B1, Tab 2, Schedule 2, Attachment 2, Transmission Customer Engagement: Investing for The Future, Page 23. Three indicative investment scenarios over a 5 year planning period were discussed. Respective reliability risk associated with Scenario 1, 2 and 3 are increased by 9%, increased by 2% and reduced by 10%.

e) Yes. Hydro One has prioritized its proposed investments at the corporate level. The prioritized project list takes the form of the optimized portfolio of investments filed in this application. In the event of a reduced approved level of capital investment, Hydro One will reduce its work program using the optimization criteria (Exhibit B1, Tab 2, Schedule 7).

The expected outcome is an increase in reliability risks and potential future deterioration in actual reliability performance. In this scenario, a load serving transformer in poor condition is ranked the lowest and may not get replaced, effective placing it under run to failure option, which is highly impactive to reliability.

Witness: Mike Penstone

Ontario Energy Board (Board Staff) INTERROGATORY #018

Reference:

Exhibit B1/Tab2/Sch 4/p. 15 – Section 6: Sustainment Forecast and External Constraints, Figure 5 – Anticipated Sustainment Work Volume

Interrogatory:

a) Please confirm that the anticipated sustainment work volume post-2016 shown in Figure 5 replicates Hydro One's original annual asset installation counts by asset class starting in 1949, effectively implying a fixed 68-year asset replacement cycle across all asset classes.

b) Please confirm that Hydro One is not proposing to follow the implied 68-year asset replacement cycle shown in Figure 5.

c) Please provide an updated Figure 5 with an asset replacement cycle that reflects the expected service lives of different asset classes and Hydro One's current asset base.

Response:

a) The anticipated sustainment work volume post-2016 shown in Figure 5 replicates Hydro One's original annual asset installation counts by asset class starting in 1949 of assets that are currently in service. This is not intended to imply a fixed 68-year replacement cycle across all asset classes, but demonstrates the number of assets that are presently operating at or beyond their expected service life ("ESL") that may require refurbishment or replacement post-2016.

b) Hydro One does not propose to follow a 68-year asset replacement cycle as shown in Figure 5. The proposed sustaining capital work volume to replace and/or refurbish assets is identified in Exhibit B1, Tab 3, Schedule 2.

c) An updated Figure 5 is provided below applying the expected service life, as documented in Exhibit B1, Tab 2, Schedule 6, of each asset class; transformers, breakers, and conductor. The quantity of assets operating beyond ESL is noted in the revised Figure 5 below.

Witness: Mike Penstone

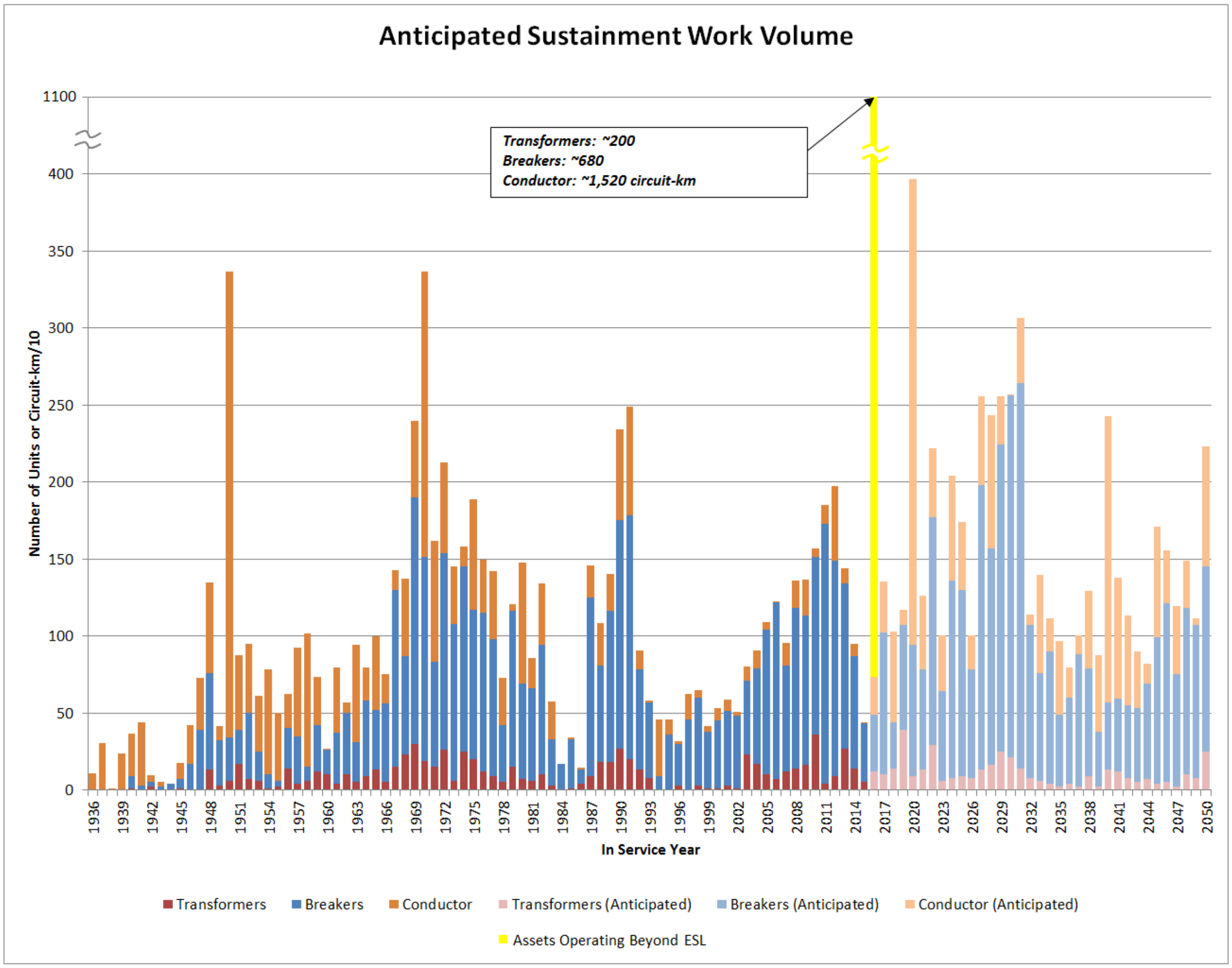


Figure 5: Anticipated Sustainment Work Volume

Ontario Energy Board (Board Staff) INTERROGATORY #060

Reference:

Exhibit B1/Tab2/Sch 7 – Section 6.2: Re-direction of Funds, pg. 17

"The re-direction of funds allows appropriate and prudent adjustments to be made to the work originally identified in the investment plan. As an example, the emergency restoration work needed to repair equipment failures or storm damage to a transmission line can be significant. Such events may necessitate the re-direction of funds and field resources from other investment areas."

Interrogatory:

a) What percentage of overall capital funds have been redirected from the investment plans in each year, from 2012 to 2015? Please identify the recipient and donor investment categories to and from which the funds were transferred, respectively, along with the rationale for the transfer.

b) For each project originally identified in the original investment plan but not executed as planned, please identify the rationale for re-directing funds to another project.

Response:

a) Between 2012 and 2015, redirection was not required to stay within the approved capital envelope as Hydro One underspent its capital budget.

b) Hydro One has project governance for variances that requires documentation and approval of material variances. The cost materiality threshold set by the governance structure is a forecasted cost increase of either: (a) more than 10% of currently approved funding and greater than $500,000; or (b) a variance greater than $2,000,000. There are also variances for scope changes or schedule changes, which are subject to the same governance structure, but with different thresholds. Below is a list of all projects, from 2012 to 2015 that met the materiality threshold in any combination of scope change, cost change or schedule change.

Project Name	Variance Type	Result of
Telematics	Schedule variance	Changing asset priorities based on new information
OMA Enterprise Content Management ECM	scope variance and Schedule variance	Changing customer needs and requirements

Witness: Mike Penstone

Project Name	Variance Type	Result of
Enhanced Asset Management Analytics (AA)	scope variance and cost increase	Changing asset priorities based on new information
IT Business Solutions Development SAP GIS Integration Project	Schedule variance and cost increase and scope variance	Changing asset priorities based on new information
customer Operations Mobile Phase 2B	Schedule variance and cost increase	Changing asset priorities based on new information
Domtar Green Transformation Generation Project (DC LINK)	Schedule variance and cost increase and scope variance	Changing external requirements
Terry Fox MTS Build New 230kV Line Tap	Schedule variance and cost increase	Changing customer needs and requirements
Lower Mattagami Generation Connections	Schedule variance and cost increase and scope variance	Undervalued estimate and scope increase
Leaside x Bridgman Transmission Expansion Project	Schedule variance and cost increase	Major unforeseen events
Lambton TS station Upgrade	Schedule variance and cost increase and scope variance	Changing customer needs and requirements
Port Arthur TS No 1 Install Series Reactors	Schedule variance and cost increase and scope variance	Unforeseen delay and cost increase in project component
H7L and H11L Mitigate 115kV Overvoltages Main TS Install 2 115kV Cct Breakers	Schedule variance and cost increase	Undervalued estimate
NetScaler Replacement Project	Schedule variance and cost increase and scope variance	Changing external requirements
H7L and H11L Mitigate 115kV Overvoltages	scope variance and cost increase	Undervalued estimate and scope increase
Uprate Short Circuit Capability of 15 115kV Breakers at Allanburg TS	Schedule variance and cost increase	Changing asset priorities based on new information
Manby TS Uprate 115 kV Station Short Circuit Capability	Schedule variance and cost increase	Undervalued estimate
Lambton TS Station Upgrade	Schedule variance and cost increase and scope variance	Changing asset priorities based on new information

Witness: Mike Penstone

Project Name	Variance Type	Result of
Basin TS 115kV Shunt Reactors and Arresters	Schedule variance and scope variance and cost increase	Undervalued estimate and scope increase, unforeseen delay in project component
Extreme Space Weather Readiness	Schedule variance and cost increase and scope variance	Changing customer needs and requirements
Crystal Falls SS Bulk	Schedule variance and cost increase and scope variance	Changing external requirements
D9H_D10S Line Refurbishment	Cost increase	Undervalued estimate
Kent TS DESN 1 Feeder M15 DG 274 Distance Limitation	Schedule variance and cost increase	Undervalued estimate
Orangeville TS Breaker Replacement	Schedule variance and cost increase	Undervalued estimate and scope increase
London Nelson TS EOL Replacement	Cost decrease and scope variance	Changing customer needs and requirements
Class EA Process Update	Cost decrease and schedule variance	Changing external requirements
Bridgman TS PCT Equipment Replacement	Scope variance and cost increase	Changing customer needs and requirements and changing external requirements
Hanmer TS Transmission Station Re Investment Project	Schedule variance and cost increase	Major unforeseen events
BSPS Replacement of End of Life Equipment Project	Schedule variance and cost increase and scope variance	Changing external requirements
Red Rock to Nipigon Hwy 11 17	Cost decrease and schedule variance	Scope decrease
2004 Monitoring Bruce GS add SER and Decommission (Bruce A and B RTUs)	Schedule variance and cost increase	Unforeseen delay and cost increase in project component
St Lawrence x Moses NYPA Tie Line Protection Replacement L33P and L34P	Schedule variance and cost increase and scope variance	Changing external requirements

Witness: Mike Penstone

today. Once we have undertaken the investment, when the risks go down, we are heading towards the right direction. That is the intended use of it.

MR. OAKLEY: Thank you. Again, when you are using reliability risk, I think as was just clarified, it's sort of an asset-focussed reliability risk; in other words, this is the likelihood of failure of assets, individual assets. But you have system redundancy, so is it doesn't necessarily project your expectation of the reliability risk to a system performance level -- or is that incorrect?

MR. PENSTONE: The model is not used to predict future SAIDI.

MR. OAKLEY: Right. Okay, thank you. I think that clarifies it.

I would like to discuss a little bit about Staff 20. I think it's on – well, you have a different PDF page than I do. I had 46, but --

I just wanted to confirm. Are the hazard curves based upon retirement for any cause at all, so that's whether it's a planned retirement, a storm retirement, you know, an explosion of a device or that sort of a thing. The hazard curves incorporate every time an asset is retired for whatever reason it goes out of service?

MR. NG: That is correct, yes.

MR. OAKLEY: And yes, so it doesn't -- so if there was a huge ice storm, let's say, that would all go into the hazard curves? It's just one of the ways assets fail is an ice storm will come through and asset wills fail because of while system renewal needs have increased to the point of creating risk to current reliability levels.

As described in Exhibit B1, Tab 2, Schedule 4, Hydro One has modified its asset management approach to include reliability risk as a leading indicator of future transmission system performance. Hydro One's approach has been informed by the development of this approach in other jurisdictions. This approach is new for Hydro One, and the company intends to develop the reliability risk approach and refine its application.

Reliability risk is a metric that is derived using a probabilistic calculation based on asset demographics and the historical relationship between asset age and the occurrence of failure or replacement. Reliability risk is used by Hydro One in its asset management process to gauge the impact of its investments on future transmission system reliability. It also provides a directional indicator to inform the appropriate level and pacing of sustainment investments. The reliability risk model is not used to identify specific asset needs and investments. Instead, these are determined by condition assessments and other asset-specific information, as described in Exhibit B1, Tab 2, Schedule 5.

Table 2 below reflects the relative change in risk for each critical asset class and for the system as a whole, as a result of 2017 and 2018 investments. With the planned investments, overall reliability risk would improve (i.e. decline) by 2% by 2019. Without the applied-for investments that are reflected in the 2017 and 2018 test years, overall reliability risk would deteriorate by 10%.

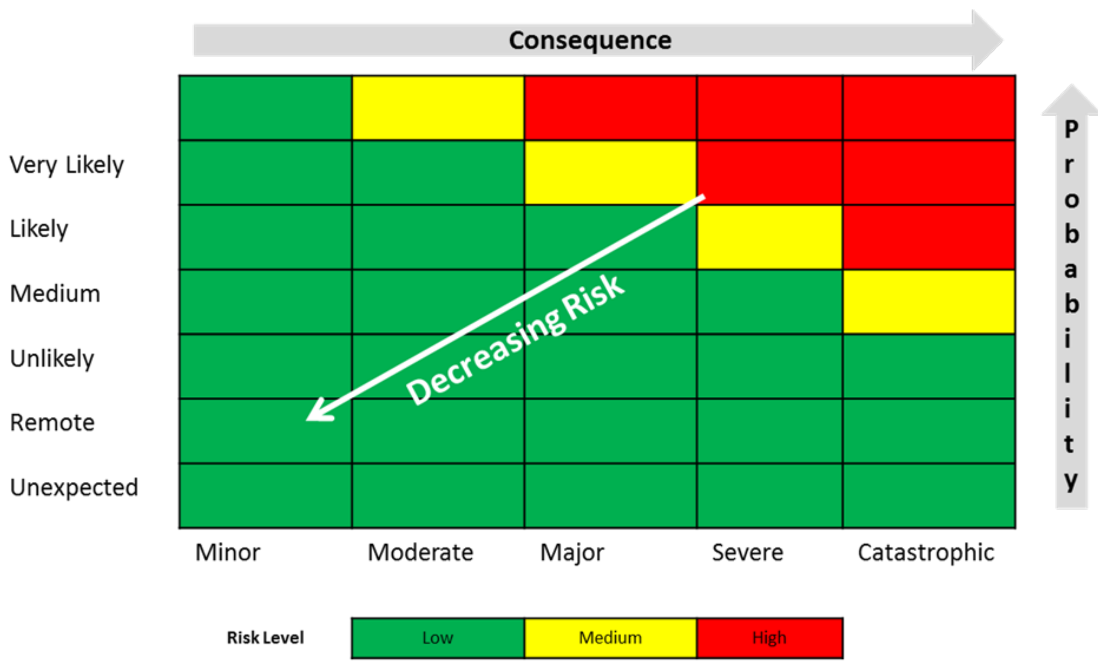


Figure 3: Business Driver Evaluation Matrix

4.4 Risk Treatment and Options Analysis

Following the identification and assessment of a given risk exposure, a decision is made to accept the risk or treat the risk. For risks identified for mitigation, risk treatment options, in the form of investment proposals, may be developed to address the risk. Risk mitigation occurs following investment implementation and may reduce the impact of the consequence or reduce the likelihood of the consequence occurring. The difference between the baseline risk and residual risk is the risk mitigation value created by the investment.

When developing the candidate investment, planners should consider multiple options that reflect different levels of funding, effort and outcomes to address the identified risk and investment need. Figure 4 illustrates the three funding levels (sometimes referred to as “accomplishment levels”) and their corresponding risk levels.

Witness: Michael Vels/Mike Penstone

Table 2: Relative Change in Reliability Risk

	Relative Change in Risk from Jan. 1, 2017 to Dec. 31, 2018, as per proposed investment	**Relative Change in Risk from Jan. 1, 2017 to Dec. 31, 2018, without investment**	**% of Interruption Duration***
Lines	-2%	11%	69%
Transformers	-9%	14%	9%
Breakers	1%	17%	6%
Other[1]	-	-	16%
Total*	**-2%**	**10%**	

* Total is calculated by weighting the change in risk by the asset class' contribution to interruption duration.

In addition to incorporating customer feedback and new information on system reliability risk, Hydro One also considered and incorporated the results of a total cost benchmarking study into the development of its Transmission System Plan (Exhibit B1, Tabs 1 to 4 of this Application). The study found that Hydro One's historical capital spending levels were significantly below median in its peer group. For the purposes of developing its investment plan, Hydro One used the total cost benchmarking study as a reference tool to further validate the proposed increases in spending associated with its Transmission System Plan. Based on the results of the report and Hydro One's investment proposal, the 2017 and 2018 total expenses (capital expenditures and OM&A) will still remain at or below median levels relative to the company's peer group.

[1] Represents all other assets; risk is assumed to be flat over the investment planning horizon for these assets

LIST OF CAPITAL INVESTMENT PROGRAMS OR PROJECTS REQUIRING IN EXCESS OF $3 MILLION IN TEST YEAR 2017 OR 2018

1. SUSTAINING CAPITAL (EXHIBIT B1, TAB 3, SCHEDULE 2)

1.1 Stations

		2017	2018
Air Blast Circuit Breaker Replacement Projects			
S01	Beck #1 SS	5.9	12.0
S02	Beck #2 TS	29.8	14.9
S03	Bruce A TS	13.8	19.7
S04	Bruce B SS	0.9	24.6
S05	Cherrywood TS	1.4	3.8
S06	Lennox TS	26.1	16.9
S07	Richview TS	16.9	13.5
Station Reinvestment Projects			
S08	Beach TS	16.5	15.9
S09	Centralia TS	12.5	6.2
S10	Dryden TS	16.2	0.1
S11	Elgin TS	22.6	17.8
S12	Espanola TS	3.0	0.0
S13	Gage TS	1.2	12.4
S14	Kenilworth TS	5.6	11.2
S15	Nelson TS	10.9	20.2
S16	Palmerston TS	8.8	11.6
S17	Wanstead TS	13.7	14.3
Integrated Station Component Replacement Projects			
S18	Alexander SS	14.4	8.8
S19	Allanburg TS	4.7	1.0
S20	Aylmer TS	3.5	0.0
S21	Barrett Chute SS	9.3	3.9
S22	Birch TS	12.1	13.8
S23	Bronte TS	3.7	17.1
S24	Bridgman TS	0.2	3.3
S25	Buchanan TS	4.2	0.0
S26	Cecil TS	9.6	0.0

		2017	2018
S27	Chenaux TS	7.5	2.1
S28	Crawford TS	4.2	0.0
S29	DeCew Falls SS	4.9	0.0
S30	Dufferin TS	6.5	7.4
S31	Ear Falls TS	10.9	0.0
S32	Frontenac TS	3.8	1.5
S33	Hanmer TS	24.4	11.0
S34	Hawthorne TS	1.6	4.3
S35	Horning TS	14.3	14.9
S36	Leaside TS Bulk	5.9	5.6
S37	Leaside TS 27.6 kV	6.3	6.5
S38	Main TS	5.4	8.4
S39	Manby TS	3.1	1.8
S40	Martindale TS	18.6	18.6
S41	Minden TS	4.2	7.0
S42	Mohawk TS	4.6	4.7
S43	N.R.C. TS	7.1	0.7
S44	Pine Portage SS	1.9	5.9
S45	Richview TS	7.3	0.0
S46	Sheppard TS	9.8	9.3
S47	St. Isidore TS	9.1	0.0
S48	Stanley TS	0.5	6.1
S49	Strachan TS	5.1	2.8
S50	Strathroy TS	5.3	0.0
Transmission Station Demand and Spares			
S51	Demand Capital – Power Transformers	8.0	8.2
S52	Minor Component Demand Capital	4.7	4.7
S53	Operating Spare Transformer Purchases	8.2	8.3
Protection, Control and Monitoring			
S54	Transformer Protection Replacement	4.6	4.6
S55	Replace Legacy SONET Systems	2.1	5.3
S56	Physical Security for Critical Stations (non CIP-014)	5.0	5.0
S57	CIP V6 Transient Cyber Assets & Removable Media	2.0	10.0
S58	PSIT Cyber Equipment EOL	5.0	6.0
S59	CIP-014 Physical Security Implementation	6.0	6.0
S60	NERC CIP V6 CAPEX - Low Impact Facilities	5.0	5.0
Transmission Site Facilities			
S61	Transmission Site Facilities	6.7	6.7

Witness: Multiple Witnesses

1 ## 1.2 Lines

		2017	2018
Transmission Line Refurbishment Projects			
S62	Line Refurbishment Project - C22J/C24Z/C21J/C23Z	18.5	2.5
S63	Line Refurbishment Project - D2L Dymond x Upper Notch	8.4	0.0
S64	Line Refurbishment Project - C1A/C2A/C3A	1.8	3.5
S65	Line Refurbishment Project - N21W/N22W	4.1	11.9
S66	Line Refurbishment Project - B5G/B6G	4.4	11.4
S67	Line Refurbishment Project - D2L Upper Notch x Martin River	18.3	21.1
S68	Line Refurbishment Project - B3/B4	0.9	6.4
S69	Line Refurbishment Project - A8K/A9K	0.4	6.6
S70	Line Refurbishment Project - A7L/R1LB and 57M1	0.9	20.5
S71	Line Refurbishment Project - K1/K2	0.9	7.4
S72	Line Refurbishment Project - E1C	0.9	12.8
S73	Line Refurbishment Project - D6V/D7V	2.6	5.7
S74	Line Refurbishment Project - D2H/D3H	0.9	12.5
Overhead Lines Component Replacement Programs			
S75	Wood Pole Replacements	35.3	35.3
S76	Steel Structure Coating	42.5	54.4
S77	Steel Structure Foundation Refurbishments	7.8	7.8
S78	Shieldwire Replacements	7.0	7.1
S79	Insulator Replacements	63.9	61.4
S80	Transmission Lines Emergency Restoration	8.7	8.8
Secondary Land Use and Recoverable Projects			
S81	Gordie Howe International Bridge (Recoverable)	12.7	12.5
S82	Manvers – Lafarge Aggregate Pit (Recoverable)	1.0	3.8
Underground Cable Projects			
S83	H7L/H11L Cable Replacement	1.3	21.1

Summary – Sustaining Capital		
Total Sustaining Capital Projects & Programs Listed Above	740.0	785.6
Sustaining Capital Projects & Programs Less than $3M	74.8	87.2
Total Gross Sustaining Capital	**814.8**	**872.8**
Less Capital Contribution	*(38.0)*	*(30.7)*
Total Net Sustaining Capital (per Exhibit B1-3-2)	**776.8**	**842.1**

Witness: Multiple Witnesses

2. DEVELOPMENT CAPITAL (EXHIBIT B1, TAB 3, SCHEDULE 3)

		2017	2018
2.1	**Inter-Area Network Transfer Capability**		
D01	Clarington TS: Build new 500/230kV Station	68.6	14.8
D02	Nanticoke TS: Connect HVDC Lake Erie Circuit	5.0	13.0
D03	Merivale TS to Hawthorne TS: 230 kV Conductor Upgrade	2.5	8.0
D04	East-West Tie Expansion: Station Work	3.0	30.0
D05	Milton SS: Station Expansion and Connect 230kV Circuits	2.0	5.0
2.2	**Local Area Supply Adequacy**		
D06	Galt Junction: Install In-Line Switches on M20D/M21D Circuits	3.6	0.1
D07	York Region: Increase Transmission Capability for B82V/B83V Circuits	22.6	0.2
D08	Hawthorne TS: Autotransformer Upgrades	8.0	5.8
D09	Brant TS: Install 115kV Switching Facilities	5.0	6.0
D10	Riverdale Junction to Overbrook TS: Reconfiguration of 115kV Circuits	2.4	4.2
D11	Southwest GTA Transmission Reinforcement	0.9	5.0
D12	Barrie TS: Upgrade Station and Reconductor E3B/E4B Circuits	4.0	20.0
2.3	**Load Customer Connection**		
D13	Ear Falls TS to Dryden TS: Upgrade 115kV Circuit E4D	10.0	5.9
D14	Supply to Essex County Transmission Reinforcement	33.0	31.4
D15	Horner TS: Build 230/27.6kV Transformer Station	16.0	13.0
D16	Lisgar TS: Transformer Upgrades	10.3	2.5
D17	Seaton MTS: Rebuild 230 kV Circuit	3.3	3.0
D18	Hanmer TS: Build 230/44kV Transformer Station	9.5	18.5
D19	Runnymede TS: Build 115/27.6kV Transformer Station and Reconductor 115kV Circuits	23.0	17.0
D20	Toyota Woodstock: Upgrade Station	3.0	2.5
D21	Enfield TS: Build 230/44kV Transformer Station	10.0	15.0
D22	TransCanada: Energy East Pipeline Conversion	1.9	10.2
2.4	**Protection and Control for Distributed Generation**		
D23	Protection and Control Modifications for Distributed Generation	6.0	5.5

		2017	2018
2.5	**Risk Mitigation**		
D24	Nanticoke TS: New Station Service Supply	10.0	0.0

Summary – Development	2017	2018
Total Development Projects & Programs Listed Above	**263.6**	**236.6**
Development Projects & Programs Less than $3 M	**27.4**	**33.3**
Total Gross Development Capital (per Exhibit B1-3-3)	**291.0**	**269.9**
Less Capital Contribution	*(94.7)*	*(99.7)*
Total Net Development Capital (per Exhibit B1-3-3)	**196.4**	**170.2**

3. OPERATIONS CAPITAL (EXHIBIT B1, TAB 3, SCHEDULE 4)

		2017	2018
3.1	**Grid Operations and Control Facilities**		
O01	Integrated System Operations Centre - New Facility Development	4.2	10.5
3.2	**Operating Infrastructure**		
O02	Station Local Control Equipment Sustainment	3.6	3.7
O03	Grid Control Network Sustainment	5.8	3.0

Summary – Operations	2017	2018
Total Operations Projects & Programs Listed Above	13.6	17.2
Operations Projects & Programs Less than $3 M	11.7	13.5
Total Operations Capital (per Exhibit B1-3-4)	**25.4**	**30.8**

4. COMMON CORPORATE CAPITAL AND OTHER COSTS (EXHIBIT B1, TAB 3, SCHEDULES 5-8)

Transmission Allocation of Capital Corporate Costs and Other Costs		2017	2018
4.1	**Information Technology**		
IT1	Hardware/Software Refresh and Maintenance	5.1	5.1
IT2	MFA Servers and Storage	4.2	2.8
IT3	Work Management and Mobility	5.0	3.0
4.2	**Other**		
CC1	Real Estate Field Facilities Capital	18.4	20.9
CC2	Transport & Work Equipment	20.9	21.8
CC3	Service Equipment	3.2	3.2

Summary - Capital Common Corporate Costs & Other Costs	2017	2018
Total Capital Common Corporate Costs Projects listed above	56.8	56.8
Capital Common Corporate Costs Projects less than $3 M	20.8	22.3
Transmission Allocation of Capital Common Corporate Costs & Other Costs (per Exhibit B1-3-5)	**77.6**	**79.1**

Witness: Multiple Witnesses

Ontario Energy Board (Board Staff) INTERROGATORY #022

Reference:

Exhibit B1/Tab2/Sch 4/ Attachment 1 – Section 5: Summary of Risk Model Assumptions, pg. 6

5. SUMMARY OF RISK MODEL ASSUMPTIONS

Asset	Critical Inputs and Assumptions		
	Demographics	**Hazard Curves**	**Units of activity under investment plan**
Conductors	All asset demographics in circuit kilometers Conductor asset demographics as of Jan 2016	• Hydro One's lines demographics extended beyond the age (90) at which the hazard curve for conductors reached a limit of 4.6%. • Assumption built into model of 1% increase in risk for every year of aging past 90 in order to more realistically represent the risk facing aging conductors	• Oldest conductors assumed to be replaced first

Interrogatory:

a) Has Hydro One quantified the relationship between conductor failures and asset age?

b) Does “risk" as used in the table above mean "annual probability of failure"?

c) Please show the calculations used by Hydro One to support the assumed 1% increase in "risk" (or annual probability of failure) for each year of aging past 90.

d) Please show the quantified relationship between Hydro One's conductor fleet demographics and annual conductor failures over the last 10 years.

e) Does Hydro One include failures caused by hardware such as sleeves, saddles, dead-ends and spacer-dampers in its count of conductor failures?

   i. If yes, is Hydro One able to separate hardware failures from actual conductor failures? Please provide the relevant data for the past 10 years.

   ii. Is conductor replacement the most economically efficient approach to reducing the frequency of hardware failures?

Witness: Mike Penstone

f) Please confirm that Hydro One's calculation of reliability risk change is based upon actual capital investment plans (for replacing conductors) rather than the assumption that the oldest conductors will be replaced. Please explain in detail.

g) Please confirm that the actual list of conductors being proposed for replacement comprises the oldest conductors, and if not, please identify how the actual list was developed.

Response:

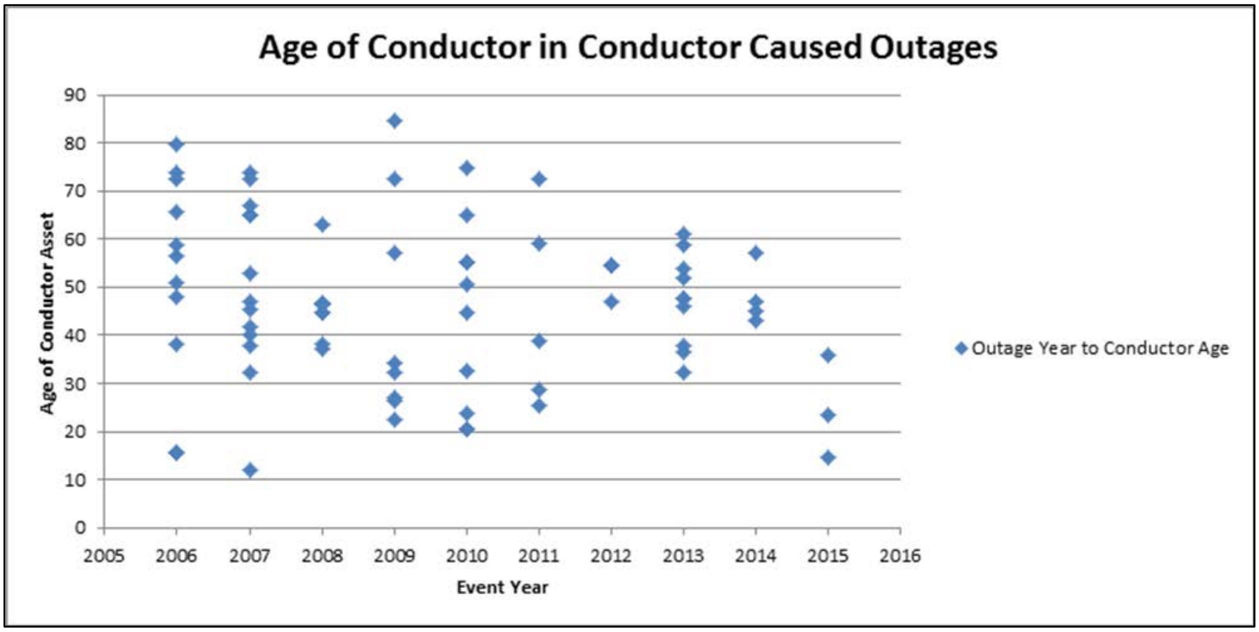
a) Yes, through hazard rate analysis, based on Hydro One historical data. Please refer to Exhibit I, Tab 1, Schedule 20, Part b).

b) The "risk" in the table above represents the annual probability of failure in the year, given that the asset has survived through the previous years.

c) The 1% increase in risk for every year of aging past 90 was considered and rejected during development of the reliability risk model. The reference in Attachment 1 – Section 5: Summary of Risk Model Assumptions was referenced in error. Instead the actual conductor hazard curve based on the 2014 Foster Associates Report was applied.

d) Within Ontario, the relationship between conductor failure and demographic is not linear because weather loading is a key contributing factor. An aged conductor will experience deterioration in strength and ductility, failure will occur when weather loading exceeds its remaining capability. Conductor failure is an adverse event that is dependent upon two factors, weather loading and integrity of asset. Weather events are unpredictable, hence the only controllable factor is to ensure asset integrity. Therefore, conductor fleet management approach is to replace aged and deteriorated conductor, verified by actual laboratory test results, to ensure safety and maintain reliability.

Witness: Mike Penstone



e) Yes, While Hydro One includes all failures that led to line drops as line failures, failure causes are tracked separately.

i) Sleeves and dead-end connectors are considered as part of conductor system; as such they are included in conductor failure statistics. Hardware such as u-bolts and suspension clamps are tracked separately. Please see the table below for hardware failures in the past 10 years.

OUTDATE	AGE
5/21/2006	50
6/1/2006	73
6/15/2007	59
1/2/2009	57
3/29/2009	38
3/29/2009	75
3/29/2009	73
2/16/2011	35
2/29/2012	59
7/11/2012	66
7/11/2012	66
10/9/2012	40
1/23/2013	61

Witness: Mike Penstone

ii) Design life for conductor hardware (except u-bolt and dampers) meets or exceeds the life of a conductor. Therefore, there is no need to replace the conductor hardware prior to conductor replacement. All Hydro One line refurbishment projects are driven by deterioration of conductors and when this occurs all conductor hardware will be replaced.

U-bolts and dampers will wear out before conductors reach end of life. There are separate investments targeting line hardware component replacements prior to conductor reaching end of life.

In summary, for well designed and constructed lines, complete line refurbishment is the most economical approach to reduce the hardware failure frequency, restore asset integrity, mitigate safety hazard and maintain reliability.

f) Please refer to Staff IR 21.a and b. Similar to transformer reliability risk modeling, an assumption is made to simplify reliability risk calculation where oldest conductors are assumed to be the replacement candidates during planning stage. In practice, conductor replacement candidates are chosen based on laboratory verification of asset condition. Although there is a high degree of correlation between conductor age and condition, not all chosen replacement candidates are the oldest conductors.

g) The proposed conductor replacement candidates described in Investment Summary Document S63, S64, S66, S67, S68, S69, S70, S71, S72, S73 and S74, are based on actual conductor samples removed from the respective lines and end of life condition validated via laboratory testing.

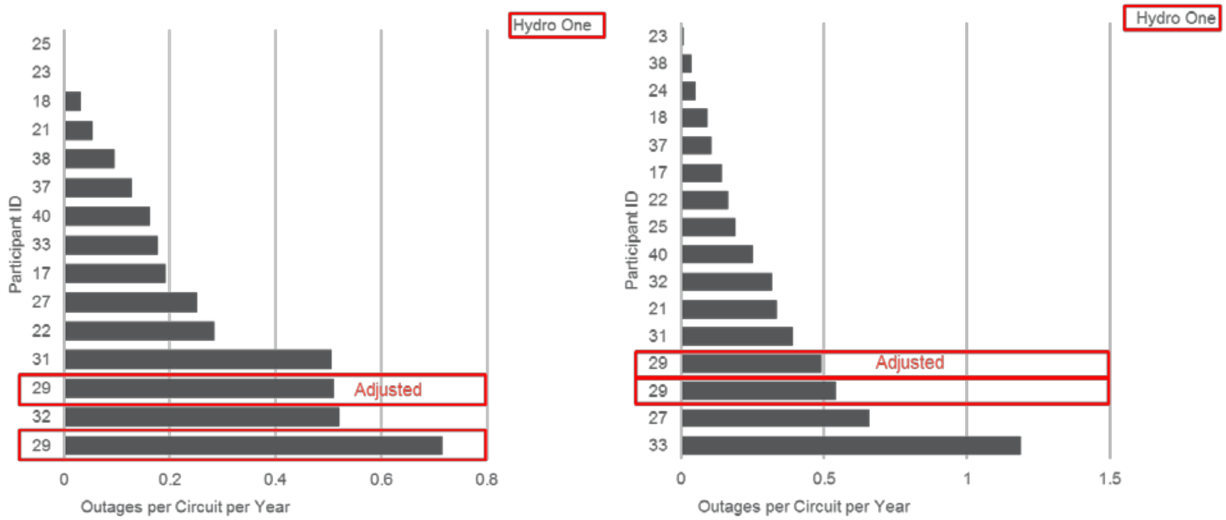
while system renewal needs have increased to the point of creating risk to current reliability levels.

As described in Exhibit B1, Tab 2, Schedule 4, Hydro One has modified its asset management approach to include reliability risk as a leading indicator of future transmission system performance. Hydro One's approach has been informed by the development of this approach in other jurisdictions. This approach is new for Hydro One, and the company intends to develop the reliability risk approach and refine its application.

Reliability risk is a metric that is derived using a probabilistic calculation based on asset demographics and the historical relationship between asset age and the occurrence of failure or replacement. Reliability risk is used by Hydro One in its asset management process to gauge the impact of its investments on future transmission system reliability. It also provides a directional indicator to inform the appropriate level and pacing of sustainment investments. The reliability risk model is not used to identify specific asset needs and investments. Instead, these are determined by condition assessments and other asset-specific information, as described in Exhibit B1, Tab 2, Schedule 5.

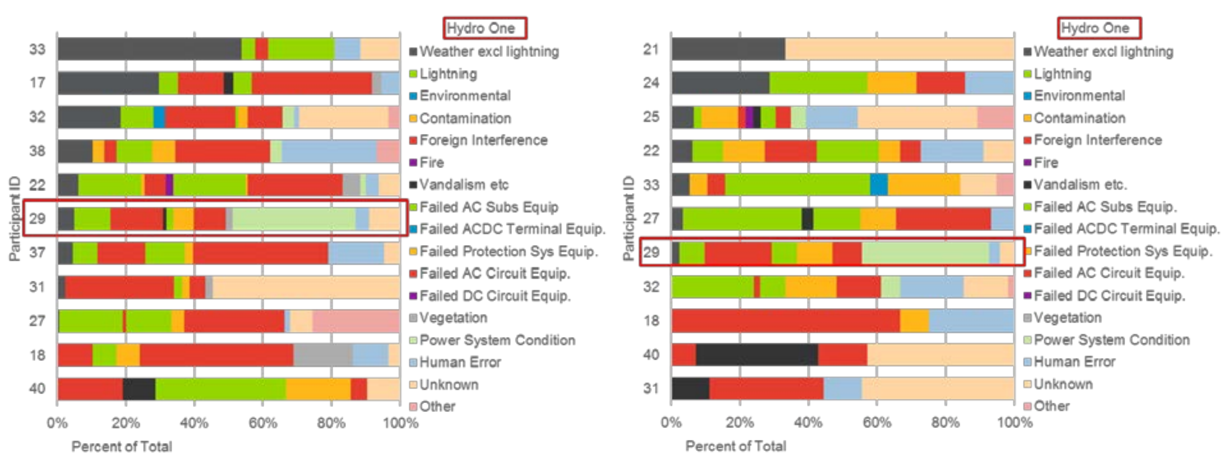
Table 2 below reflects the relative change in risk for each critical asset class and for the system as a whole, as a result of 2017 and 2018 investments. With the planned investments, overall reliability risk would improve (i.e. decline) by 2% by 2019. Without the applied-for investments that are reflected in the 2017 and 2018 test years, overall reliability risk would deteriorate by 10%.

Figure 18. Element Sustained Outage Frequency for <200 kV (left) and ≥200 kV (right), excluding Worst-Performing Circuits



Hydro One's momentary outage frequency was also among the highest in the peer group. "Power system condition" was the single largest cause of sustained transmission system outages. Power system condition causes include system instability, overload trip, out-of-step, abnormal voltage, abnormal frequency, or unique system configurations (e.g., an abnormal terminal configuration due to existing condition with one breaker already out of service).

Figure 19. Sustained Outage by Cause Code for <200 kV (left) and ≥200 kV (right)



A transmission outage can also affect the reliability that delivery customers experience, through delivery point interruptions. The level of impact attributable to transmission is measured in terms of both frequency (T-SAIFI-mc), as shown in Figure 20, and duration (T-SAIDI-mc), as shown in Figure 21. In a recent study by the CEA for multi-circuit supplied delivery points, Hydro One was shown to be performing well when compared to other Canadian companies when it comes to frequency and duration of actual interruptions. The following charts are for multi-circuit performance since 85% of Hydro One's throughput is supplied to multi-circuit delivery points. Note that the three colour in the figures indicate the leading, average, and lagging performance levels.

Figure 20. Sustained T-SAIFI-mc Comparison by the CEA

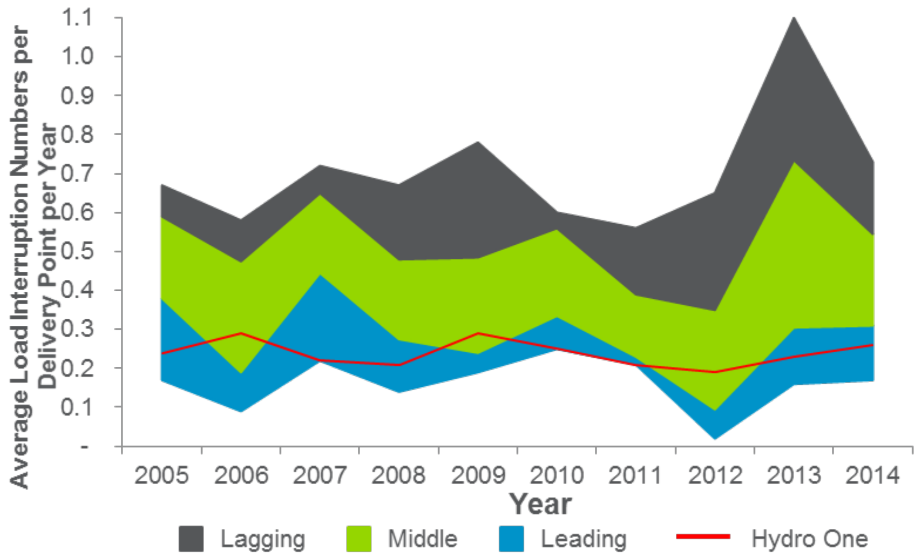
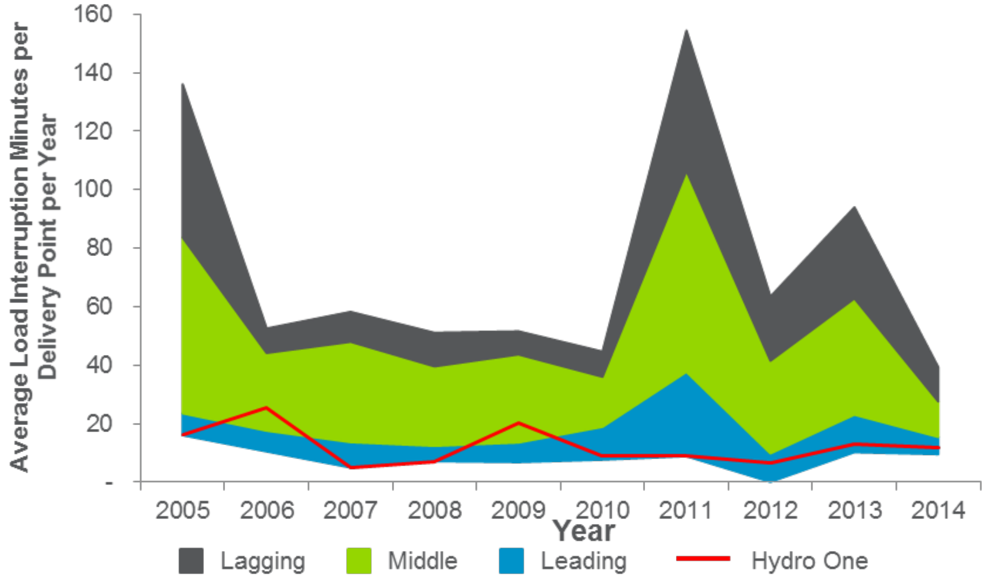


Figure 21. Sustained T-SAIDI-mc Comparison by the CEA



3. BENCHMARKING RESULTS

The five key elements of this section are:

1. **Overall Cost Performance:** Comparison of Hydro One's transmission lines and substations CAPEX, O&M, and OM&A costs relative to the peer group, broken out by asset type and activity.
2. **Reliability Performance:** Comparison of Hydro One's frequency and causes of sustained and momentary outages to the peer group.
3. **Project Management Performance:** Comparison of Hydro One's project budget and schedule management to the peer group.
4. **Safety:** Comparison of Hydro One's lost time and frequency of preventable vehicular accidents to the peer group.
5. **Staffing:** Comparison of Hydro One's wage rates and overtime to the peer group.

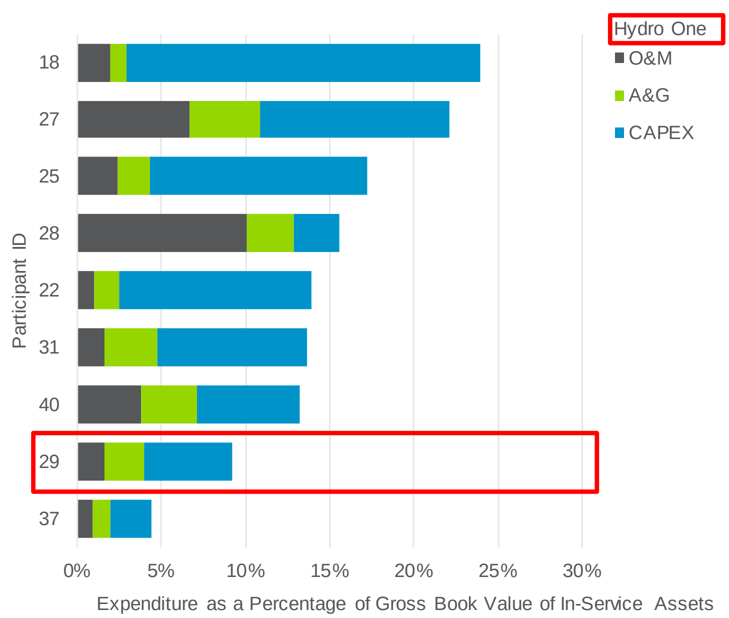
3.1 Overall Cost Performance

The cost analysis portion of the study was quantitative and dissected Hydro One's capital and operations, maintenance and administrative costs. Cost information was gathered for Hydro One as well as for the pool of companies included as comparators in the study directly using FERC accounting conventions and definitions. Costs were also gathered directly from each company based on specific activities as defined by First Quartile Consulting.

3.1.1 Transmission Lines and Substations

Hydro One's total expenditure for transmission lines and substations was amongst the lowest in the peer group in 2014, at 9.1% (Figure 3) of gross asset value. The peer group median was 13.9% of gross asset value. This measure includes administrative costs and corporate allocations.

Figure 3. Transmission Lines and Substations OM&A + CAPEX per Asset

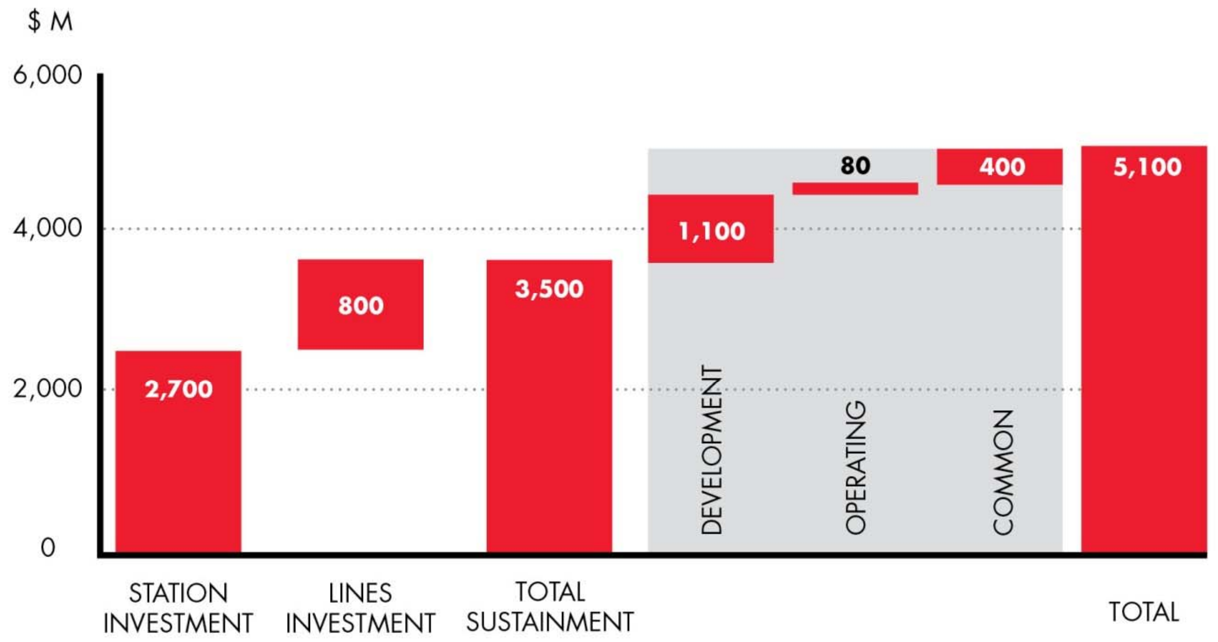


SCENARIO ONE

SCENARIO 1
~$5,100M (2016 – 2020)

KEY ELEMENTS OF SCENARIO 1

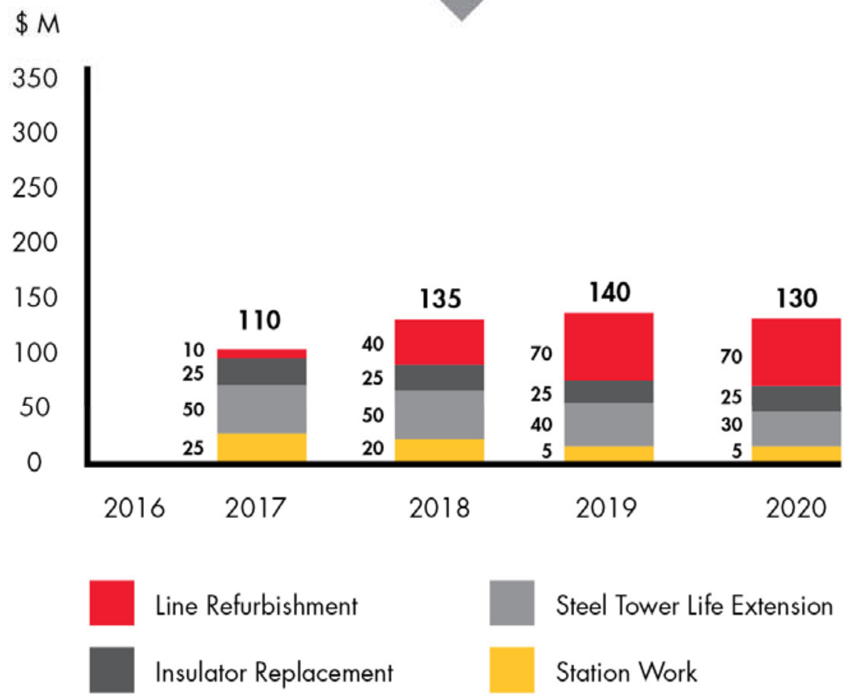
- Coordinated replacement of multiple elements at stations to reduce outages
- Investment to replace high risk air-blast circuit breakers
- Replacement of aging transformer population
- Does not fully address increasing risk due to line asset aging/conditions



Overall risk profile:
Reliability risk expected to increase

SCENARIOS TWO AND THREE

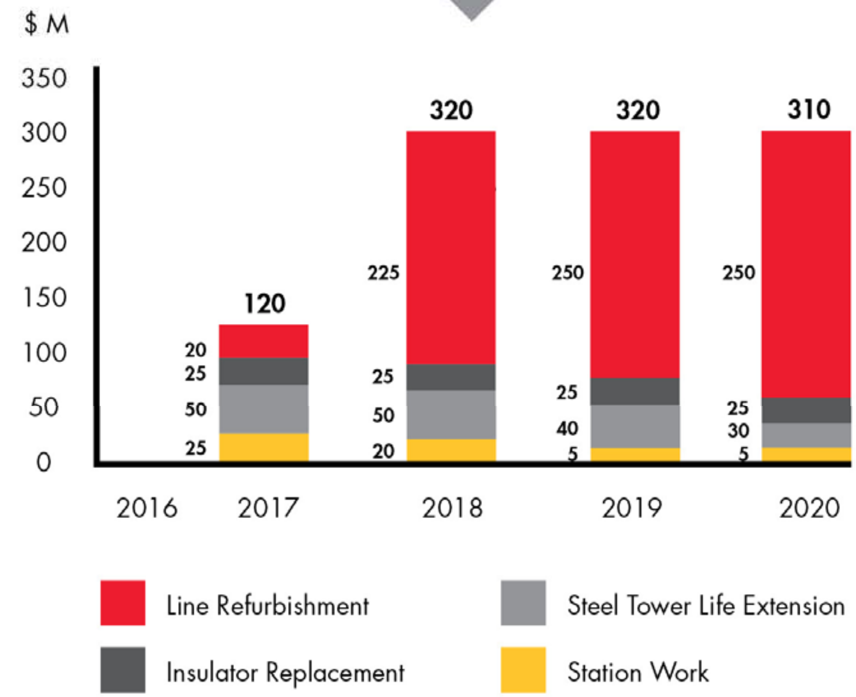
SCENARIO 2
~$520M in incremental CapEx from 2016 – 2020



- Scenario 1 and additional station work, insulator replacement, and steel tower life extension program
- Projected replacement of 1,200 cct-km of conductors, including all copper conductors at end of useful life

Overall risk profile:
Current reliability risk expected to remain unchanged

SCENARIO 3
~$1.1B in incremental CapEx from 2016 – 2020



- Scenario 1 and additional station work, insulator replacement, and steel tower life extension program
- Projected replacement of 2,300 cct-km of conductors, including all copper conductors at end of useful life

Overall risk profile:
Reliability risk expected to decrease

SCENARIOS BASED ON FOUR MAJOR ASSET REPLACEMENT PROGRAMS

hydro one

	DESCRIPTION	RATIONALE
STATION WORK	Additional replacement of air-blast circuit breakers (ABCB) with new SF6[1] breakers	• Air-blast circuit breakers known to have 5-7x higher likelihood of unplanned outage than new SF6 breakers • ABCB is an obsolete technology and manufacturers will cease support by 2020
LINE REFURBISHMENT	Accelerated replacement of lines, based on asset condition	• 20% of conductors beyond end of service life (70 years) will reach ~40% by 2024 under historic replacement rates • Historic average replacement rate of 60 cct-km lags rate required to maintain system age • Condition assessments of conductor fleet identified 2,300 cct-km conductors are either at or near end of useful life based on actual conductor sample testing
STEEL TOWER LIFE EXTENSION	Coating of select steel tower structures to extend useful life	• 25% of towers located in high-corrosion regions • Corrosion rate for high-corrosion regions is ~10x higher than in lower corrosion regions • 20% of towers in high-corrosion regions are > 80 years old • Coating extends tower life by 25 years, deferring the need for replacement, with a net present value of $100-200M
INSULATOR REPLACEMENT	Replacement of insulators with known increased risk of failure	• Insulators installed between 1965 and 1982 have a known increased risk of failure • The insulator failure in March 2015 in the GTA reinforces the need to accelerate replacement of insulators • Condition testing underway to better quantify increased risk

1. Sulfur hexafluoride breaker

the plan places a greater emphasis on lines-related investments while maintaining stations spending at a prudent level.

Hydro One Transmission's approximately 30,000 kilometres of transmission lines throughout the province require increased levels of refurbishment to ensure that electricity continues to be delivered in the safe, reliable manner that Hydro One's customers expect. The insulator replacement program is necessary to remove and replace faulty insulators for public safety reasons. Stations and related equipment continue to require refurbishment to address deteriorating asset conditions. Wherever possible, Hydro One looks for opportunities to extend the life of its assets in order to provide value to its customers. For example, Hydro One is increasing its zinc coating program for steel transmission towers in high corrosion areas, in an effort to maximize the life of its 52,000 towers and avoid costly replacements.

Hydro One anticipates that its work program will face outage constraints caused by the planned nuclear refurbishments at Darlington and Bruce in 2021 and beyond and the planned closure of Pickering generating station in 2025. Accordingly, Hydro One has paced Sustainment work over the next five years to ensure that assets are in-service before such constraints make work more difficult to complete. Beginning in 2017, Hydro One intends to replace deteriorating assets, before the next bow wave of Sustainment requirements surfaces in 2030, as explained in Exhibit B1, Tab 2, Schedule 4.

2.2 Development Capital

The Development capital expenditures are primarily driven by inter-area network transfer, local area supply, and load connection projects identified through regional planning. These projects include the Supply to Essex County Transmission Reinforcement in the Windsor-Essex area, and capacity increase at Lisgar TS in the

Ontario Energy Board (Board Staff) INTERROGATORY #062

Reference:

Exhibit B1/Tab3/Sch 1/ Attachment 1 – Comparison of Net Capital Expenditures by Major Category – Historic, Bridge and Test Years, pg. 1-3

Interrogatory:

a) What is the benefit to ratepayers of Hydro One's decision to change practice between 2012-2013 and 2017-2018 and group most substation spending into Integrated Station Investments? Please provide quantified evidence of the benefit to ratepayers.

b) Hydro One claims in Exhibit B1/Tab3/Sch2 – Section 3.3 that one of the benefits of Integrated Capital Investments is cost avoidance, thereby resulting in reduced overall capital expenditures. Please reconcile this claim with the forecast investment increase in Transmission Stations Capital from $322.5 million in 2012 to an annual average in excess of $500 million for the years 2014 to 2018.

c) What is the rationale for increasing the level of overhead lines investments by a factor of 5 from 2012 to 2018 despite acceptable line performance statistics? Please explain in detail.

d) What is the rationale for the order of magnitude step increase in underground cable refurbishment and replacement investment levels from 2017 to 2018?

e) Overall Sustaining Capital investments are forecast to increase from less than $400 million per year in 2012 to over $800 million per year in 2018. Please provide a cost-benefit analysis to justify more than doubling the level of Sustaining Capital Investments over this period.

Response:

a) Please refer to Exhibit B1, Tab 3, Schedule 2, Section 3.3 for details relating to the quantified benefits from Integrated Station Investments. This approach enables delivery of a large volume of investments driven by asset needs to maintain top quartile reliability and addresses customers' needs and preferences. A few examples of these are:

i) Wanstead TS (ISD-S17): Reduction of transformers from 3 to 2 units, standardization of design for operational efficiency, and reconfiguration to dual supply from 230kV connection to meet customer needs for improved reliability.

ii) Nelson TS (ISD-S15): Reduction of transformer from 4 to 2 units for operational efficiency, and upgrading of distribution voltage to 27.6kV to meet customer's needs.

iii) Aylmer TS (ISD-S20): Standardization of design to improve operation efficiency, replacing outdoor switchyard with medium voltage gas insulated switchgear to improve reliability and adding new feeder positions to meet customer's needs.

b) The saving from cost avoidance to reduce overall capital expenditure stems from reduction in asset footprint such as reducing 4 transformers to 2 transformers, or reconfiguring a switchyard to eliminate breakers. The increase in Transmission Station Capital is a result of undertaking a larger investment portfolio to maintain reliability performance. The level of investment is correlated to the large, aging and deteriorating asset fleet managed by Hydro One. Exhibit B2, Tab 2, Schedule 1 describes the Total Cost Benchmarking study that supports capital expenditure needs to increase to maintain reliability.

c) Due to historic low level of investment in this area, aging demographics and emerging information about asset conditions, such an increase in capital expenditure is needed to ensure safety, maintain reliability and extend asset life:

i) A sizeable subset of Hydro One's installed suspension insulators is deemed to be in poor condition due to a manufacturing defect. The urgency of this problem came to light upon completion of an Asset Event Investigation as a result of an impactive line drop incident in 2015. When these insulators fail and separate, the conductor will drop to ground, which is both a safety and reliability concern. An increase in investment to accelerate replacement program is a necessary step to ensure safety and reliability. ISD-S79 describes this investment in detail.

ii) Nineteen percent (19%) of Hydro One's conductor fleet is currently beyond ESL. Based on historic rate of replacement, by 2025 the subset of conductor operating beyond ESL will almost double. In order to maintain safety and reliability, minimize reliability risk and allow for a manageable execution pace, it is necessary to increase the conductor replacement rate. The conductors selected for line refurbishment investments are supported by actual conductor sample testing results to verify either at or near end of life conditions. When a conductor arrives at or is near end of life condition, it would have low remaining strength and low ductility, resulting in an increased probability of failure. ISD from S62 through S74 describe these investments.

iii) A subset of Hydro One transmission line structures requires application of zinc-based coating to extend life. A new steel structure comes with a layer of galvanized zinc to protect itself against corrosion. As this protective layer wears off over time, bare carbon steel is exposed to the atmosphere and corrodes at an increased rate. Corrosion erodes structural integrity, which leads to safety and reliability concerns. The eventual outcome of structure corrosion is costly structure replacement. Application of a zinc-based coating is an efficient and cost effective approach to extend asset life. (See Board Staff IR #55) ISD-S76 provides details of this investment.

Hydro One is observing a large portion of SAIDI that in recent years is attributed to line related failures. These failures contributed to 69% of Hydro One's total interruption minutes from 2011-2015 (see Exhibit B1, Tab 2, Schedule 2, Attachment 2, page 13). When a conductor has deteriorated to, or near end of life condition as verified by laboratory testing, it cannot be relied upon to operate in a safe and reliable manner. It will break under adverse weather loading conditions, which is a risk to safety and reliability. While historical performance has been acceptable, SAIDI and SAIFI or other lagging indicators are not indicative of future performance. In contrast, asset condition is indicating performance is likely to worsen in the future. Hydro One is therefore proposing to increase capital expenditure to maintain safety and reliability.

d) The reason for this step increase is H7L/H11L Cable Replacement project (ISD-S83). The project execution schedule requires $1.3M and $21.1M to be spent in 2017 and 2018 respectively.

e) The increase from $400 million per year in 2012 to over $800 million per year in 2018 is driven by asset needs to ensure safety and maintain reliability performance which is supported by Exhibit B2, Tab 2, Schedule 1, Total Cost Benchmarking Study. Cost benefit analysis is completed as part of the business case approval process of the individual projects which comprise the Sustainment capital investments.

Witness: Mike Penstone

that. My question was it is not standards driving this. You achieve standards when you are going to do it; that was really the point of the question.

MR. NG: Yes, it's secondary.

MR. OAKLEY: I would like to refer you to Staff 74 (a). Is the Lisgar TS still proceeding?

MR. YOUNG: No, it's not; it's been cancelled.

MR. OAKLEY: Okay, thanks. I guess then there is no follow up to that then, thanks.

There are two Staff IRs that are sort of intertwined on this one. I would like to refer you to -- I guess either of the charts would probably do as an example, but 52 (b). There is also 62 C2, but they have very similar graphs. Thanks.

I just wanted to confirm that the outages caused by conductor failures don't seem to be correlated with conductor age or corrosion environment. Is that what I should take from these graphs?

MR. NG: Yes.

MR. OAKLEY: Okay. Well, thanks. I was wondering if there shouldn't be an age relationship, but this clearly demonstrates that empirically, you are not seeing an age relationship with conductor failures -- or corrosion environment, it looks like.

MR. NG: Am I hearing a question to explain why is there no correlation between age and failure?

MR. OAKLEY: No, no, the question isn't why. It is just simply to confirm that, you know -- I wasn't exactly sure how the interpret these, what I would call scatter plots almost, and I just wanted to know if there was supposed to be a correlation because I don't see one and just wanted to confirm. It doesn't look like there is one.

MR. NG: On this chart, there is no correlation between age and failure.

MR. OAKLEY: Thank you. If I could move along to 62(c)(i), I just wanted to check. So there was the 2015 insulator failure which dropped the conductor in a parking lot, I think it was. Was there any indication prior to 2015 that this vintage of Ohio Brass insulators was problematic?

MR. NG: This particular vintage of insulator is known to have a cement expansion problem; it is well known by the industry.

Hydro One, we have been tracking the performance of this set of insulators since the '80s, with a testing program to monitor the performance of this insulator.

What we did not know until 2015 is the extent to which they have deteriorated, which adds to the urgency of the need to have them replaced.

MR. OAKLEY: Thanks, because that was again what I was wondering. We see just an immediate step increase in that and again, the industry sort of has been aware of this vintage of Ohio Brass, and I just wanted to wonder why that step increase was happening. And it looks like that particular incident was the alert or drove the concern, and then the testing followed that.

Ontario Energy Board (Board Staff) INTERROGATORY #052

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 3.1.3: Transmission Overhead Conductor and Hardware – Asset Assessment Details, Demographics, pg. 32

"Hydro One uses an expected service life ("ESL") of 70 years for conductors; although this can vary based on several factors, with environmental conditions being the primary factor."

Interrogatory:

a) Please quantify the relationship between the different environmental conditions evaluated by Hydro One and the impact on conductor ESL.

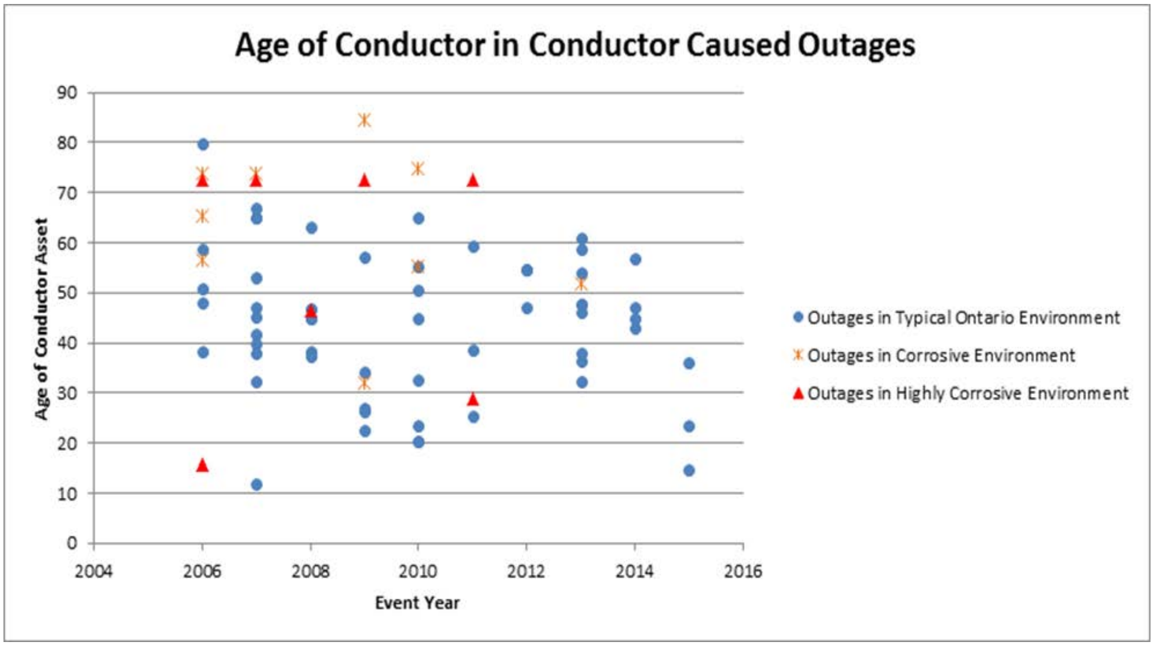
b) Please provide any analysis conducted by Hydro One that correlates conductor age in regions exhibiting these different environmental conditions with the frequency of outages caused by conductor failure.

Response:

a) Hydro One has recently conducted an environmental condition correlation study for conductor ESL. As part of this study end of life conductors verified by laboratory tests were mapped into various corrosion zones in Ontario. The result of the correlation study was not conclusive. As explained in Exhibit B1, Tab 2, Schedule 6, page 36, there are many influencing factors contributing to actual service life of a conductor.

Witness: Chong Kiat Ng

b)


Age of Conductor in Conductor Caused Outages
Age of Conductor Asset
Event Year
0
10
20
30
40
50
60
70
80
90
2004
2006
2008
2010
2012
2014
2016
Outages in Typical Ontario Environment
Outages in Corrosive Environment
Outages in Highly Corrosive Environment

Ontario Energy Board (Board Staff) INTERROGATORY #022

Reference:

Exhibit B1/Tab2/Sch 4/ Attachment 1 – Section 5: Summary of Risk Model Assumptions, pg. 6

5. SUMMARY OF RISK MODEL ASSUMPTIONS

Asset	Critical Inputs and Assumptions		
	Demographics	Hazard Curves	Units of activity under investment plan
Conductors	All asset demographics in circuit kilometers Conductor asset demographics as of Jan 2016	• Hydro One's lines demographics extended beyond the age (90) at which the hazard curve for conductors reached a limit of 4.6%. • Assumption built into model of 1% increase in risk for every year of aging past 90 in order to more realistically represent the risk facing aging conductors	• Oldest conductors assumed to be replaced first

Interrogatory:

a) Has Hydro One quantified the relationship between conductor failures and asset age?

b) Does "risk" as used in the table above mean "annual probability of failure"?

c) Please show the calculations used by Hydro One to support the assumed 1% increase in "risk" (or annual probability of failure) for each year of aging past 90.

d) Please show the quantified relationship between Hydro One's conductor fleet demographics and annual conductor failures over the last 10 years.

e) Does Hydro One include failures caused by hardware such as sleeves, saddles, dead-ends and spacer-dampers in its count of conductor failures?
   i. If yes, is Hydro One able to separate hardware failures from actual conductor failures? Please provide the relevant data for the past 10 years.
   ii. Is conductor replacement the most economically efficient approach to reducing the frequency of hardware failures?

Witness: Mike Penstone

f) Please confirm that Hydro One's calculation of reliability risk change is based upon actual capital investment plans (for replacing conductors) rather than the assumption that the oldest conductors will be replaced. Please explain in detail.

g) Please confirm that the actual list of conductors being proposed for replacement comprises the oldest conductors, and if not, please identify how the actual list was developed.

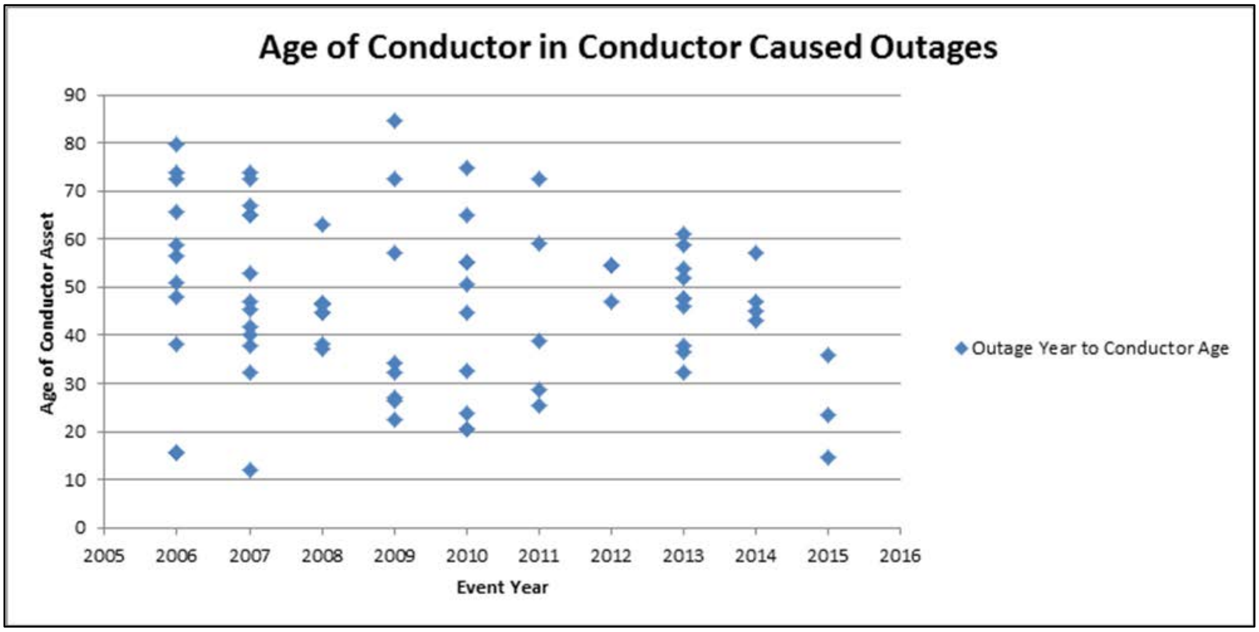
Response:

a) Yes, through hazard rate analysis, based on Hydro One historical data. Please refer to Exhibit I, Tab 1, Schedule 20, Part b).

b) The "risk" in the table above represents the annual probability of failure in the year, given that the asset has survived through the previous years.

c) The 1% increase in risk for every year of aging past 90 was considered and rejected during development of the reliability risk model. The reference in Attachment 1 – Section 5: Summary of Risk Model Assumptions was referenced in error. Instead the actual conductor hazard curve based on the 2014 Foster Associates Report was applied.

d) Within Ontario, the relationship between conductor failure and demographic is not linear because weather loading is a key contributing factor. An aged conductor will experience deterioration in strength and ductility, failure will occur when weather loading exceeds its remaining capability. Conductor failure is an adverse event that is dependent upon two factors, weather loading and integrity of asset. Weather events are unpredictable, hence the only controllable factor is to ensure asset integrity. Therefore, conductor fleet management approach is to replace aged and deteriorated conductor, verified by actual laboratory test results, to ensure safety and maintain reliability.



e) Yes, While Hydro One includes all failures that led to line drops as line failures, failure causes are tracked separately.

i) Sleeves and dead-end connectors are considered as part of conductor system; as such they are included in conductor failure statistics. Hardware such as u-bolts and suspension clamps are tracked separately. Please see the table below for hardware failures in the past 10 years.

OUTDATE	AGE
5/21/2006	50
6/1/2006	73
6/15/2007	59
1/2/2009	57
3/29/2009	38
3/29/2009	75
3/29/2009	73
2/16/2011	35
2/29/2012	59
7/11/2012	66
7/11/2012	66
10/9/2012	40
1/23/2013	61

Witness: Mike Penstone

ii) Design life for conductor hardware (except u-bolt and dampers) meets or exceeds the life of a conductor. Therefore, there is no need to replace the conductor hardware prior to conductor replacement. All Hydro One line refurbishment projects are driven by deterioration of conductors and when this occurs all conductor hardware will be replaced.

U-bolts and dampers will wear out before conductors reach end of life. There are separate investments targeting line hardware component replacements prior to conductor reaching end of life.

In summary, for well designed and constructed lines, complete line refurbishment is the most economical approach to reduce the hardware failure frequency, restore asset integrity, mitigate safety hazard and maintain reliability.

f) Please refer to Staff IR 21.a and b. Similar to transformer reliability risk modeling, an assumption is made to simplify reliability risk calculation where oldest conductors are assumed to be the replacement candidates during planning stage. In practice, conductor replacement candidates are chosen based on laboratory verification of asset condition. Although there is a high degree of correlation between conductor age and condition, not all chosen replacement candidates are the oldest conductors.

g) The proposed conductor replacement candidates described in Investment Summary Document S63, S64, S66, S67, S68, S69, S70, S71, S72, S73 and S74, are based on actual conductor samples removed from the respective lines and end of life condition validated via laboratory testing.

MR. NG: Transmission tower are not part of the consideration in the reliability risk model.

MR. OAKLEY: Okay. So this was more focused on exactly the asset condition assessment, and it's -- so your latest studies have shown you that these ones need to be recoated now or you are going to miss your opportunity.

MR. NG: Tower coating investment is based on spending some -- spending a dollar right now to save five bucks later on. So that is the justification for it.

MR. OAKLEY: So if -- so what you are saying, I guess, is that if you were to, say, reduce this program by half each year, you would actually lose towers that -- or a significant portion of towers that just couldn't be recoated later.

MR. NG: It is a question of timing. The later we can get to those tower, the less attractive it becomes for us to coat. There will be a point in time where we will not be able to do coating to arrest the deteriorations of the tower.

MR. OAKLEY: Yeah, thanks. I am still just trying to understand the rate of -- the pace of this. I just didn't understand from the evidence why this particular pace was required, and I am still not sure I do, but...

MR. NG: So it is a window of opportunity. We have identified in C4 and C5 area there are around 13,000 tower that require coating in the next...

Please bring up Exhibit B1-2-6, page 47.

So under sections 3.3.3, we laid out that there are approximately 13,000 tower that are located in the high corrosion zone. All these tower would need coating within the next ten years.

The pacing is designed in such a way that we have an ability to get through the entire coating program successfully. And that is why we propose to perform the coating in the -- we propose to go with the amount of coating investment that we -- they are in the ISD document.

MR. OAKLEY: Okay, thank you.

That's all my questions. Thank you very much, panel.

MS. HELT: Thank you very much.

It's now almost 12:30. We can take a break now if you'd like. Yes, everybody is shaking their head.

Okay. We will come back at 1:30 and we will carry on. Thank you.

--- Luncheon recess taken at 12:27 p.m.

--- On resuming at 1:33 p.m.

MS. HELT: All right, if we can get started. We have quite a lot to do this afternoon. There are a few intervenors who are coming back after the OPG matter finishes at 2:30, so hopefully we can get through who we have in the room by then, maybe not.

Mr. Elson, if you would like to proceed?

QUESTIONS BY MR. ELSON:

MR. ELSON: Thank you. For the record, my name is Kent Elson and I represent Environmental Defence.

Good afternoon, panel. I am going to be focussing most of my questions on the topic of transmission system

Ontario Energy Board (Board Staff) INTERROGATORY #055

Reference:

Exhibit B1/Tab2/Sch6/ and Exhibit B1/Tab3/Sch2
Section 3.1.3: Transmission Overhead Conductor and Hardware – Asset Assessment Details, Demographics, Figure 35 – Projection of Steel Structures Requiring Coating, pp. 49-50 and Section 5.2.2: Investment Plan, Table 16 – Overhead Lines Component Replacement Programs ($ Millions), pg. 35

"Based on the historical data, the average rate for structure renewal is about 200 towers per year. As outlined in Figure 35, at historic tower coating rates, the steel structures requiring coating in high corrosion zones will increase by 34% in 10 years. However, with planned coating plan, all structures requiring coating will be coated in the next 10 years."

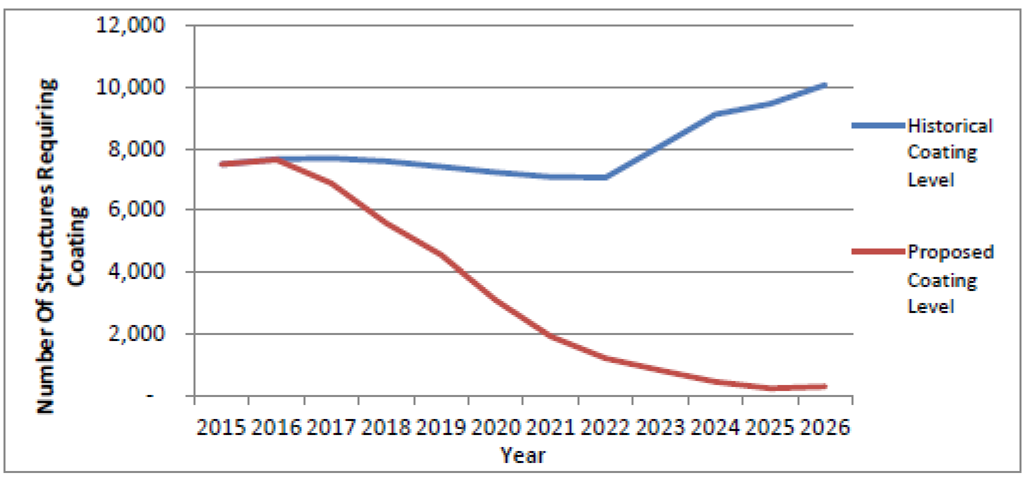


Figure 35: Projection of Steel Structures requiring Coating

Witness: Chong Kiat Ng

Table 16: Overhead Lines Component Replacement Programs ($ Millions)

Description	Historic Years				Bridge Year	Test Years	
	2012	2013	2014	2015	2016	2017	2018
Wood Pole Replacements	26.9	32.7	43.6	38.5	38.3	35.3	35.3
Steel Structure Coating	1.6	5.7	5.1	4.6	8.8	42.5	54.4
Steel Structure Foundation Refurbishments	3.3	4.5	3.6	1.6	3.9	7.8	7.8
Shieldwire Replacements	4.4	2.9	8.2	4.3	5.2	7.0	7.1
Insulator Replacements	3.3	6.9	3.8	2.8	26.1	63.9	61.4
Transmission Lines Emergency Restoration	8.0	8.2	8.7	8.8	8.3	8.7	8.8
Other Line Component Replacements	3.4	5.6	5.7	6.0	3.2	5.0	5.2
Total	**50.9**	**66.5**	**78.7**	**66.6**	**93.8**	**170.2**	**180.0**

Interrogatory:

a) Please show the expected rate of failure if the steel structure re-coating rate is maintained at the present rate rather than being increased by 34%.

b) Please provide a quantified rationale for the increase in Steel Structure Coating program investments in 2017 and 2018 relative to historic years. What, if any, change does this increased level of investment indicate in Hydro One's Steel Structure Coating sustaining capital investment philosophy?

c) Please provide a quantified rationale for doubling Steel Structure Foundation Refurbishment investments in 2017 and 2018 relative to historic years? What, if any, change does this increased level of investment indicate in Hydro One's Steel Structure Foundation sustaining capital investment philosophy?

d) Please provide a quantified rationale for the increased Insulator Replacements in 2017 and 2018 relative to historic years. What, if any, change does this increased level of investment indicate in Hydro One's Insulator Replacement sustaining capital investment philosophy?

e) Regarding "Other Line Component Replacements" investments, if the potential costs associated with emergency restoration are unpredictable, please explain how Hydro One selected investment values of $3.2M in 2016, $5.0M in 2017, and $5.2M in 2018?

Witness: Chong Kiat Ng

Response:

a) The main objective of structure coating program is to extend the life of steel structures in the most economical way. Structure coating program is not intended to prevent immediate structure failures. The rate of failure for structures is dependent on the condition of the structures and the impact of adverse environmental factors which is not predictable, such as wind and ice. If structures are not coated at the optimum time, they will require more expensive mitigation measures such as structure member replacement or even complete structure replacement. Therefore, structure coating is a cost effective alternative approach to replacement, as further explained in part (b) below.

b) In the past 10 years, Hydro One's structure coating program was significantly below the required levels to preserve the condition of these assets. Hydro One's structure coating philosophy has not changed. This was due to safety and work method constraints. The average recoating cost of the steel structures identified for the test years is approximately $34k per structure. The first structure coating typically needs to occur when the structure is approximately 60 years old and again every 30 to 40 years thereafter. However the cost of replacing a steel structure is approximately $250k to $350k, depending on the type of structure. Even with repeated coatings, the life of the steel structures can be extended indefinitely achieving a significant savings. Hydro One has estimated the present value savings of structure coating (over structure replacement) for 115 kV and 230 KV structures to be approximately $62K and $65K respectively.

c) The steel structure foundation refurbishment program is intended to assess, repair or replace the problematic steel structure foundations and mitigate the risk of foundation failure. Based on current available information, there are still approximately 16,000 steel structures requiring foundation assessment. The inspection reports from recent line refurbishment program show that the number of failed foundations is increasing and those failed foundations must be replaced with significantly higher cost than to inspect, clean and coat them in a timely manner. One example of excessive foundation deterioration is the D2L line refurbishment project. Hydro One anticipated approximately 20 to 30 of the foundations will require replacement, but the actual number exceeds 52 after inspecting the foundations. There is no change in Hydro One's Steel Structure Foundation sustaining capital investment philosophy, which is to arrest foundation deterioration before failure occurs.

d) Hydro One has asked Electrical Power Research Institute (EPRI) to conduct an independent evaluation of current condition of these defective insulators. The result of this investigation confirms that many tested insulators did not meet the standard electrical mechanical tests. In

March 2015, the centre phase insulator on V76R failed causing the conductor to fall to the ground in a commercial parking lot in Etobicoke. This type of failure represents a public safety risk. As a result, in 2016 Hydro One implemented an accelerated insulator replacement strategy which aims to address this public safety risk. Please refer to Exhibit I, Tab 1, Schedule 106, Part a), Subsection i) for more information.

e) "Other Line Component Replacements" and "Transmission Lines Emergency Restoration" are two separate line items in table 16. Hydro One selected investment values of $3.2M in 2016, $5.0M in 2017, and $5.2M in 2018 are for the other line component replacements, which are separate from emergency restoration. Other line component replacement are selected and forecasted based on condition assessments.

Witness: Chong Kiat Ng

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:

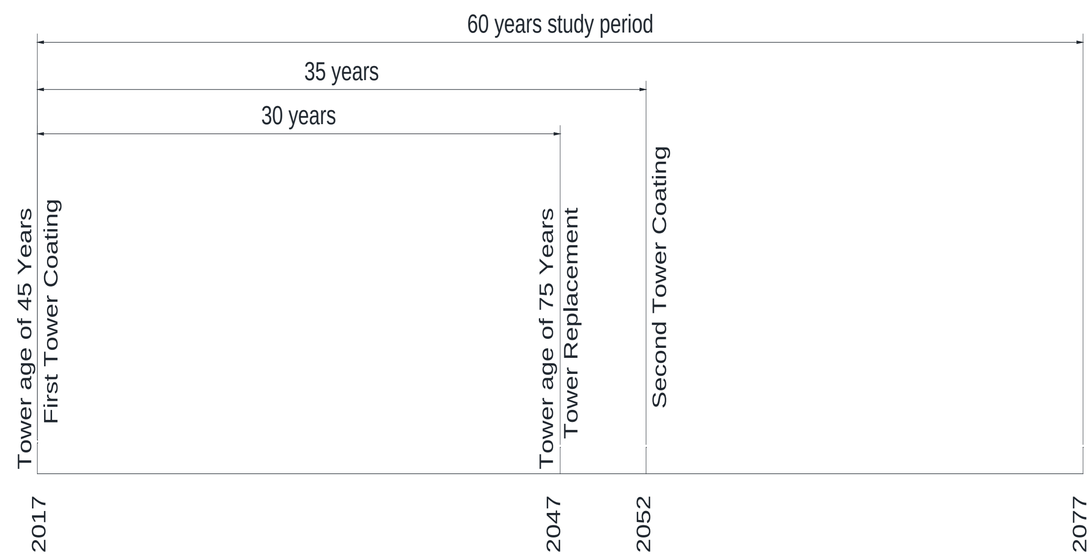
1. Tower replacement costs for replacing only one tower and a group of more than 20 towers in similar areas are presented. The lower unit cost for the latter case is due to economies of scale and savings from access, mobilization and demobilization.

Witness: Chong Kiat Ng

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

Witness: Chong Kiat Ng

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. Galvatech

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.

Witness: Chong Kiat Ng

Ontario Energy Board (Board Staff) INTERROGATORY #028

Reference:

Exhibit B1/Tab2/Sch 5/ – Section 2.1.6: Asset Economic Risk, pg. 4

"Asset economic risk is based on the economic evaluation of the ongoing costs associated with the operation of an asset. Depending on the asset type, this evaluation may be as simple as determining the replacement cost of the asset, or as complex as comparing the present value of ongoing maintenance to that of complete refurbishment or replacement.

While an economic evaluation can identify assets that are candidates for replacement, more typically, the evaluation assists in selecting the best form of remediation for assets already deemed to be candidates for refurbishment or replacement."

Interrogatory:

a) Does Hydro One develop business cases to evaluate the all-in economic risk of individual assets or groups of assets (such as integrated substation investment projects) when preparing its capital budgets, and when determining if the economic risk of an asset or group of assets would be most economically addressed by replacement or refurbishment?
   i. If yes, does the business case evaluation criteria change in accordance with a certain materiality threshold? Please provide details.
   ii. If yes, please provide the business cases for all projects listed in this filing with total costs of over $20M.
   iii. If no, please explain why Hydro One does not develop business cases to evaluate capital investments of this magnitude, and describe the cost materiality threshold at which developing a business case would be considered appropriate.
   iv. If no, please provide details of how the all-in economic risk is measured and analyzed.

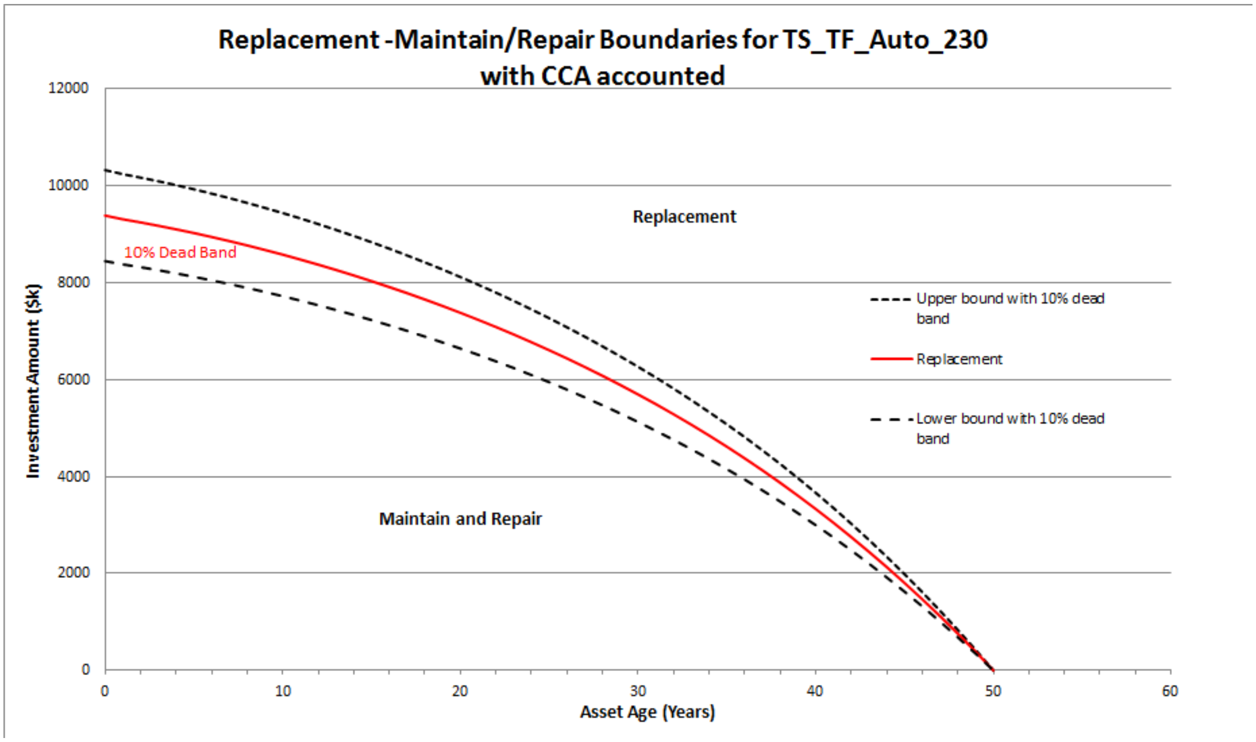
b) How does Hydro One evaluate the economic risk of a refurbished asset prematurely failing when deciding between replacement and refurbishment for a particular asset?

Response:

a) Yes, Hydro One evaluates the economic risk of replacing or refurbishing assets or groups of assets when developing business cases.

   i. Only major assets such as transformers, breakers and transmission lines are economically evaluated to determine if they should be replaced or refurbished. See the graph below for a sample economic analysis of a 230kV autotransformer.

Witness: Chong Kiat Ng



ii. Please see the requested information in the Investment Summary Documents in Exhibit B1, Tab 3, Schedule 11.

iii. Not applicable.

b) Please see the graph above. When deciding between refurbishing or replacing an asset, Hydro One will consider the life extension associated with refurbishment by performing an economic sensitivity analysis (i.e. net present value analysis) on the extension.

Table 4: Historical and Projected RCE Metrics

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Stations	Outages/Assets	117.0	105.7	103.9	85.6	98.0	87.7	80.8	74.8	70.0	63.7
	Assets/Maintenance	42.6	47.2	46.0	58.2	56.9	62.3	66.8	76.6	72.1	81.4
	RCE	**2.7**	**2.2**	**2.3**	**1.5**	**1.7**	**1.4**	**1.2**	**1.0**	**1.0**	**0.8**
	RCE (3 year average)			**2.4**	**2.0**	**1.8**	**1.5**	**1.4**	**1.2**	**1.0**	**0.9**
Lines & Forestry	Outages/Assets	132.4	139.5	132.3	115.8	120.2	78.8	88.8	108.4	101.0	94.7
	Assets/Maintenance	86.0	98.4	94.8	109.4	100.3	92.9	101.7	71.2	75.4	79.0
	RCE	**1.5**	**1.4**	**1.4**	**1.1**	**1.2**	**0.8**	**0.9**	**0.8**	**0.8**	**0.8**
	RCE (3 year average)			**1.5**	**1.3**	**1.2**	**1.0**	**1.0**	**0.8**	**0.8**	**0.8**

RCE trends have been favourable over time, particularly for lines and stations, and Hydro One expects the trend to continue as maintenance programs continue to contribute to improved reliability.

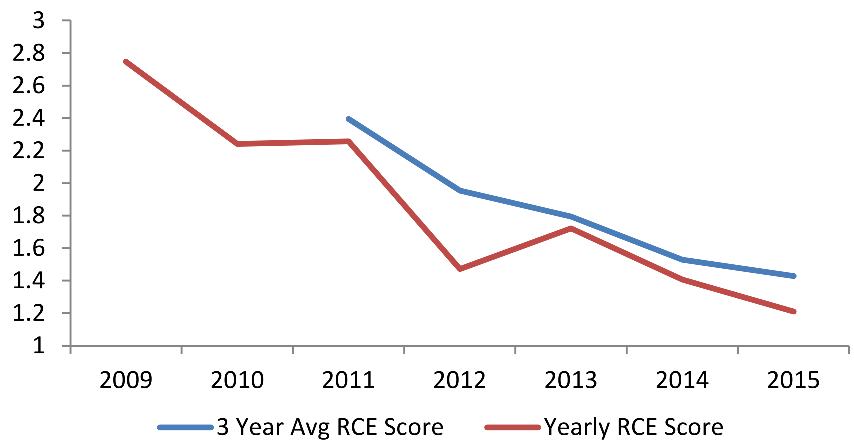


Figure 5: Stations RCE

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Station Reinvestment - Centralia TS
Targeted Start Date: Q3 2016
Targeted In-service Date: Q4 2018
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Centralia TS that are in need of replacement due to degraded condition that directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Built in the early 1950's, Centralia TS is a 64 year old transformer station that consists of a non-standard three transformer configuration, supplying load to Hydro One Distribution customers in the area. The oil analysis results of these transformers shows advanced signs of insulation degradation indicating that there is an increased probability of failure. In addition, two of the units have experienced multiple oil leaks posing a risk to the environment. All of the protection and control facilities have passed their expected service life and are obsolete. A majority of the circuit breakers are also obsolete and are beyond their end of life with operations exceeding manufacturer's design specification.

The project entails:

- Reconfiguration of Centralia TS by replacing and upgrading end of life facilities with new equipment built to current standards including: the 115-27.6 kV transformers, the existing air insulated 27.6kV switchyard (including eight circuit breakers) with a new medium voltage gas-insulated switchgear building installation, the existing protections, control and telecom ("PCT") equipment with a modern PCT solution, and the oil spill containment facilities in compliance with the Ministry and Environment and Climate Change ("MOECC") requirements; and
- Removal of one transformer, one breaker and associated systems that will no longer be required as a result of the reconfiguration to a standardized design.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:

Three alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo);
- Alternative 2: "Like-for-Like" replacement of the assets; and
- Alternative 3: Reconfiguration of the station.

Alternative 1 was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses. Both Alternatives 2 and 3 were considered further. Alternative 3 is the preferred and recommended alternative as it addresses all the needs of the station. Alternative 2 would not address the non-standard design configuration resulting in the need for an additional transformer; which would increase overall project costs as well as long term maintenance commitments.

Basis for Budget Estimate:

The project cost is based on budgetary cost estimates prepared by Hydro One.

Outcome:

To eliminate operational risks associated with operating end of life equipment, maintain system reliability, and reduce long term maintenance costs through the reconfiguration to a standardized design.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	12.5	6.2	20.7
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**12.5**	**6.2**	**20.7**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**12.5**	**6.2**	**20.7**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

IDENTIFYING ASSET NEEDS:
ASSET-SPECIFIC ASSESSMENTS

1. INTRODUCTION

This Exhibit describes how Hydro One determines its assets' needs, primarily focusing on Sustainment capital spending.

2. SUSTAINMENT NEEDS

Consistent with the asset management strategy described in Exhibit B1, Tab 2, Schedule 4, individual asset needs are determined using an asset risk assessment ("ARA") process, which relies on asset condition data, engineering analysis, and other information, including the input of experienced planning professionals. Exhibit B1, Tab 2, Schedule 6 contains a comprehensive overview of the condition of Hydro One's transmission assets and their needs, which supports proposed capital spending.

2.1 Asset Risk Assessment Methodology

The ARA methodology is an evolution of the asset condition assessment approach described in previous transmission rate filings (EB-2012-0031[1], EB-2010-0002[2]), extending the definition of asset risk to encompass risk factors other than asset condition.

[1] EB-2012-0031, Exhibit A, Tab 13, Schedule 2 "Transmission 10 Year Outlook".
[2] EB-2010-0002, Exhibit A, Tab 12, Schedule 4 "Investment Plan Development".

As illustrated in Figure 1, in the ARA methodology, different sources of risk are considered in developing a multi-faceted picture of asset risk.

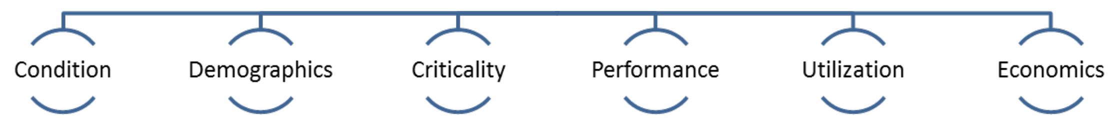


Figure 1: Factors used to evaluate asset risk

In assessing asset needs, planners also consider other factors such as environmental risks and requirements, compliance obligations, equipment defects, health and safety considerations and customer needs and preferences. Planners then make recommendations regarding what investments should be made within an identified timeframe. To clarify, the ARA is one step in the asset planning process; it does not replace decisions made by qualified engineers in conjunction with physical inspections.

2.1.1 Asset Condition Risk

Asset condition risk relates to the increased probability of failure that assets experience when their condition degrades over time, which is based on empirical data. Asset condition is defined using different criteria, depending on the asset. For example, the condition of a transmission station transformer is measured by visual inspections and analysis of the oil within the transformer. The condition of a wood pole is measured by a visual inspection, a sounding test, and if required, a boring test. While methods to evaluate condition vary from asset type to asset type, the condition of all assets of a given type is evaluated consistently. Assets of a given type that have a relatively high condition risk are candidates for refurbishment or replacement.

2.1.2 Asset Demographic Risk

Asset demographic risk relates to the increased probability of failure exhibited by assets of a particular make, manufacturer, and/or vintage, which is based on empirical data. Typically, the probability of asset failure increases with age. Thus, the asset demographic risk increases as an asset ages. Assets with relatively high demographic risk are candidates for refurbishment or replacement.

2.1.3 Asset Criticality

Asset criticality represents the impact that the failure of a specific asset would have on the transmission system. Primarily, it is used to show relative importance of an asset compared to other assets of the same type. Assets whose failure would result in an interruption to a larger amount of load would have an asset criticality that is higher than assets whose failure would have a smaller impact on the system load. Asset criticality is used to prioritize the refurbishment or replacement of assets whose condition, demographic, performance, utilization or economic risk has already resulted in the asset being considered a candidate for refurbishment or replacement.

2.1.4 Asset Performance Risk

Asset performance risk reflects the historical performance of an asset, which is based on empirical data. Performance is defined by any power interruptions that have been caused by failure of the asset. This risk factor considers the frequency and duration of these interruptions, as well as whether the interruptions are occurring more or less frequently over time. Past performance can be a good indicator of expected future performance.

Therefore, assets with a relatively high performance risk can be considered candidates for refurbishment or replacement.

2.1.5 Asset Utilization Risk

Asset utilization risk represents the increased rate of deterioration exhibited by an asset that is highly utilized, which is based on empirical data. The relative deterioration of some assets is highly dependent on the loading placed upon them or the number of operations they experience. For example, transformers that are heavily loaded relative to their nameplate rating deteriorate more quickly than those that are lightly loaded. Similarly, circuit breakers utilized for capacitor and reactor switching which are subject to significant operations experience accelerated mechanical and electrical wear-out of the breaker. Therefore, the asset utilization risk for transformers and circuit breakers attempts to consider their relative deterioration based on available loading and operation history, respectively.

Assets that exhibit a high utilization risk compared to other assets of the same type are considered candidates for upgrade, especially if they also carry a relatively high asset criticality or are deemed candidates for refurbishment or replacement based on other risk factors.

2.1.6 Asset Economic Risk

Asset economic risk is based on the economic evaluation of the ongoing costs associated with the operation of an asset. Depending on the asset type, this evaluation may be as simple as determining the replacement cost of the asset, or as complex as comparing the present value of ongoing maintenance to that of complete refurbishment or replacement.

While an economic evaluation can identify assets that are candidates for replacement, more typically, the evaluation assists in selecting the best form of remediation for assets already deemed to be candidates for refurbishment or replacement.

2.2 ARA Data

Asset condition data is collected during routine maintenance, inspections and testing. For each specific asset, information on condition, performance history, utilization, criticality and other non-condition characteristics is compiled into a database for planning purposes. Improving the quality and quantity of this data is an ongoing objective for Hydro One.

3. DEVELOPMENT, OPERATIONS, AND COMMON CORPORATE NEEDS

Development activities focus on customer-specific and system-level needs, which are discussed in Exhibit B1, Tab 2, Schedules 2 and 3. In Operations, asset needs are driven by the lifecycle of facilities and tools, which are primarily information technology ("IT") tools, as well as compliance requirements. Other determinants include the requirement to facilitate renewable generation and conservation initiatives.

Common Corporate asset needs are determined by organizational and compliance requirements. Fleet, real estate and facilities requirements are assessed annually between the relevant organizations within the company. There are compliance requirements that drive asset needs for fleet, real estate and facilities, but the primary determinants are the support requirements of the Sustainment, Development, and Operations workstreams. IT needs are driven by corporate requirements and compliance requirements, such as the NERC Critical Infrastructure Protection Standards.

Witness: Chong Kiat Ng

DEVELOPING THE INVESTMENT PLAN

1. INTRODUCTION

This Exhibit details the investment planning process that takes identified investment needs, turns them into candidate investments, and then inputs them into a prioritization process that yields an investment plan.

The investment planning process draws upon the previous year's efforts to identify investment needs, evaluating and prioritizing proposed individual investments that address these needs, based on the business objectives. The end product is a fully prioritized investment plan.

The key steps in developing the investment plan are shown in Figure 1 below.

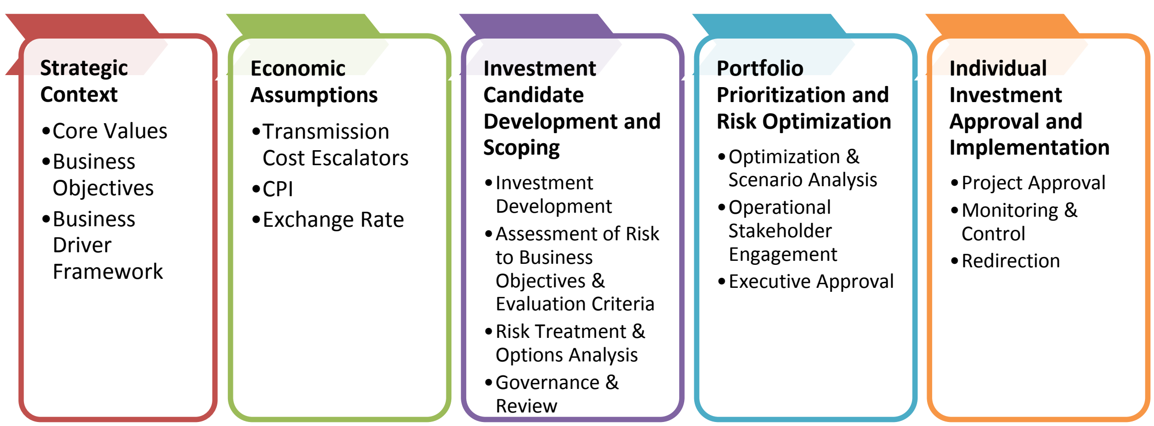


Figure 1: Investment Planning Process

Witness: Michael Vels/Mike Penstone

2. STRATEGIC CONTEXT

The annual investment planning process begins with a confirmation of core values and business objectives, which are described in Exhibit B1, Tab 1, Schedule 2. Hydro One's core values are translated into business objectives that inform a series of business drivers based upon which investment proposals are assessed. The business drivers are assigned weights by Hydro One's investment management group, based on their relative importance to the company. They are measured by a set of risk-based outcome-based factors which form the evaluation criteria against which candidate investments are developed, risks are managed, and trade-offs between investments are made in the prioritization process.

Table 1 illustrates the alignment of RRFE principles, business objectives, business drivers, and outcome factors.

Table 1

Customer Focus	**Customer Satisfaction**	• Improve current levels of customer satisfaction
	Customer Focus	• Engage with our customers consistently and proactively • Ensure our investment plan reflects our customers' needs and desired outcomes
Operational Effectiveness	**Cost Control**	• Actively control and lower costs through OM&A and capital efficiencies
	Safety	• Drive towards achieving an injury -free workplace
	Employee Engagement	• Achieve and maintain employee engagement
	System Reliability	• Maintain top quartile reliability relative to transmission peers
Public Policy Responsiveness	**Public Policy Responsiveness**	• Ensure compliance with all codes, standards, and regulations • Partner in the economic success of Ontario
	Environment	• Sustainably manage our environmental footprint
Financial Performance	**Financial Performance**	• Achieve the ROE allowed by the OEB

3. ECONOMIC ASSUMPTIONS

An economic outlook and customer load forecast are developed and used as basic assumptions in developing the investments. The load forecast is discussed in Exhibit E1, Tab 3, Schedule 1.

The investments reflected in this Application relied on the forecasts of key economic assumptions detailed in this section.

3.1 Transmission Cost Escalation for Construction, Operations and Maintenance

Hydro One used the "Transmission Cost Escalators for Construction, Operations & Maintenance" set out in Table 2 below as a planning tool to forecast expenditure level changes for transmission materials and services. These escalators are a broad average measure of the industry-wide yearly price changes, and track a representative basket of equipment and labour, comprised of the following types of equipment and labour: operation; supervision and engineering; load dispatching; station expenses; lines; meters; customer installations; maintenance; structures; station equipment; overhead lines; underground lines; line transformers; and miscellaneous.

Table 2: Global Insight's November 2015 forecast (%)

	Historical Years				Bridge Year	Test Years	
	2012	2013	2014	2015	2016	2017	2018
Transmission Cost Escalation for Construction	-0.1	2.0	2.2	1.3	1.8	2.3	2.5
Transmission Cost Escalation for Operations & Maintenance	2.1	0.9	0.4	-0.7	0.3	1.3	1.6

3.2 Consumer Price Index

Hydro One's operations are located only in the Province of Ontario. As a result, Hydro One has relied on the consumer price index ("CPI") for Ontario set out in Table 3, published by Statistics Canada, for its assumptions about inflation for other costs. The CPI provides a broad measure of the cost of living. Through the monthly CPI, Statistics Canada tracks the change in retail price of a representative shopping basket of about 600 goods and services from an average household's expenditure: food, housing, transportation, furniture, clothing, and recreation.

Table 3: Ontario CPI (%)*

	Historical Years				Bridge Year	Test Years	
	2012	2013	2014	2015	2016	2017	2018
CPI – Ontario	1.4	1.1	2.3	1.3	2.3	2.0	2.0

* Global Insight's February 2015 forecast.

Witness: Michael Vels/Michael Penstone

3.3 Exchange Rate (CDN:USD)

The historic rates in Table 4 are the average exchange rates for 2012, 2013 and 2014 from the Bank of Canada. The exchange rate forecasts for 2015 to 2018 are based on the November 2015 edition of the Global Insight Forecast.

Table 4: Exchange Rate (CDN:USD)

Description	Historical Years				Bridge Year	Test Years	
	2012	2013*	2014*	2015	2016	2017	2018
Exchange Rate	1.000	0.971	0.905	0.785	0.762	0.800	0.839

*The actual exchange rates were lower than forecasted due to unexpected decline in oil prices.

4. INVESTMENT CANDIDATE DEVELOPMENT AND SCOPING

As discussed in Exhibit B1, Tab 2, Schedules 2 to 6, throughout the year, Hydro One conducts needs assessments through its customer engagement activities, asset risk analyses, and regional and local supply planning. Using this information, planners identify potential investments that classified as “Sustainment”, “Development”, “Operations”, “Common Corporate”, and “Customer Care” to align with the company’s business activities. Exhibit B1, Tab 2, Schedules 3 to 6 discuss how Sustainment and Development investment candidates are identified. For completeness, this section provides information on how Operations and Common Corporate investment candidates are identified.

4.1 Operations

Operations investments are principally determined by control centre requirements, technology lifecycles and compliance requirements. Hydro One Transmission uses the following principles to define its Operations investment strategy:

- Use commercial-off-the-shelf software products that are best in class in the electrical utility industry;
- Enhance and extend existing applications, fully utilizing the existing tool set;
- Maximize asset utilization factors and useable lifespan;
- Maximize the use of operating data and increase data accuracy, improving business efficiency, safety, and the reporting of performance analysis and assessment of asset investment decisions; and
- Optimally replace and upgrade hardware and software according to industry best practice.

Assessments are conducted to determine the support requirements for existing operating facilities, including control facilities, infrastructure, telecommunications and administrative and engineering tools. Investment needs are prioritized based on compliance requirements and their impact on the electricity system and customers. Capital investments are typically driven by market rules and regulatory requirements and the need to replace end-of-life technology or implement major upgrades for existing operating tools and facilities. Since most technology investments are subject to contractual and interoperability restrictions, alternate solutions and investment pacing options may be limited.

4.2 Common Corporate Investments

In addition to the architectural principles described in Exhibit B1, Tab 3, Schedule 6, IT investment planning is guided by the following principles:

- Leverage enhanced capabilities already inherent in the existing tool set;
- Make better use of existing data;
- Adjust existing processes; and
- Upgrade hardware and software in anticipation of its end-of-life.

IT investments are typically subject to strict contractual limits. As a result, alternatives may be very limited; for example, specific investments must be made to maintain the necessary vendor support for a given IT solution.

Once real estate and facilities investment needs are identified, they are prioritized on the basis of legal requirements, operational requirements, and finally, the condition of the facilities. Where available, alternatives are considered, such as leasing additional or alternate space, making minor capital investments, and repurposing existing facilities. Candidate investment proposals are developed from conceptual plans; further detail is provided in Exhibit B1, Tab 3, Schedule 7.

Vehicles are considered for replacement on the basis of predetermined criteria including, but not limited to: manufacturer’s life expectancy, average cost per kilometer, regulated maintenance standards and safety/risk. Replacements are actually recommended if the existing assets cannot continue to meet operating requirements, are no longer safe to operate, or are no longer cost-effective to operate. Further detail is provided in Exhibit B1, Tab 3, Schedule 8.

4.3 Assessment of Risk to Business Objectives and Evaluation Criteria

Hydro One's risk-based investment planning process incorporates a risk definition that is consistent with the International Organization for Standardization (ISO) 31000 - 2009 Standard: "risk" is the effect of uncertainty on objectives. For clarity, in this Exhibit, "risk" refers to the risk of not achieving Hydro One's business objectives.

Once investment candidates are identified, they are assessed based on the value created by mitigating risks or their ability to enhance productivity. These assessments follow a structured process that includes the following key steps: (1) risk/hazard identification; (2) risk analysis and controls assessment; and (3) risk treatment.

4.3.1 Risk/Hazard Identification

The data collected as part of the needs assessment provides insight into potential hazards, vulnerabilities, threats or other risk sources that could present risks to achieving Hydro One's business objectives, such as asset condition, configuration or capacity.

4.3.2 Risk Analysis and Controls Assessment

Based on identified sources of risk, a three-stage risk analysis and controls assessment is conducted:

- an assessment of the worst credible consequence/impact of a given risk on a specific business objective, as measured on a five-point risk tolerance scale from "minor" to "catastrophic";
- an evaluation of the likelihood that a given consequence/impact will materialize, as measured on a six-point likelihood scale, from "unexpected" to "very likely"; and
- an evaluation of the effectiveness of existing controls.

A candidate investment may impact one or more business objectives. An asset investment may score high in the risk analysis because its deteriorated condition presents reliability and customer satisfaction risks stemming from probable equipment failure and a subsequent outage. In the risk analysis, a customer's capacity upgrade request may be rated highly because failing to fulfill it would pose significant risk to customer satisfaction, compliance with the Transmission System Code, and reliability.

The risk assessment process incorporates a probability and consequence-of-outcome "Business Driver Evaluation Matrix", which is illustrated in Figure 3, to determine the impact for each business driver. The risk assessment includes: (a) a baseline risk evaluation, representing the risk of not proceeding with the investment: and (b) a residual risk evaluation, representing the remaining risk after the investment is put into service.

The baseline risk assessment entails defining a credible risk scenario which may occur if an investment is not implemented. The baseline risk analysis involves the identification of the impact of the risk scenario, as measured by the outcome factors. The impact on the outcome factors may result in increased risk to achieving the company's business objectives as illustrated in Figure 2.

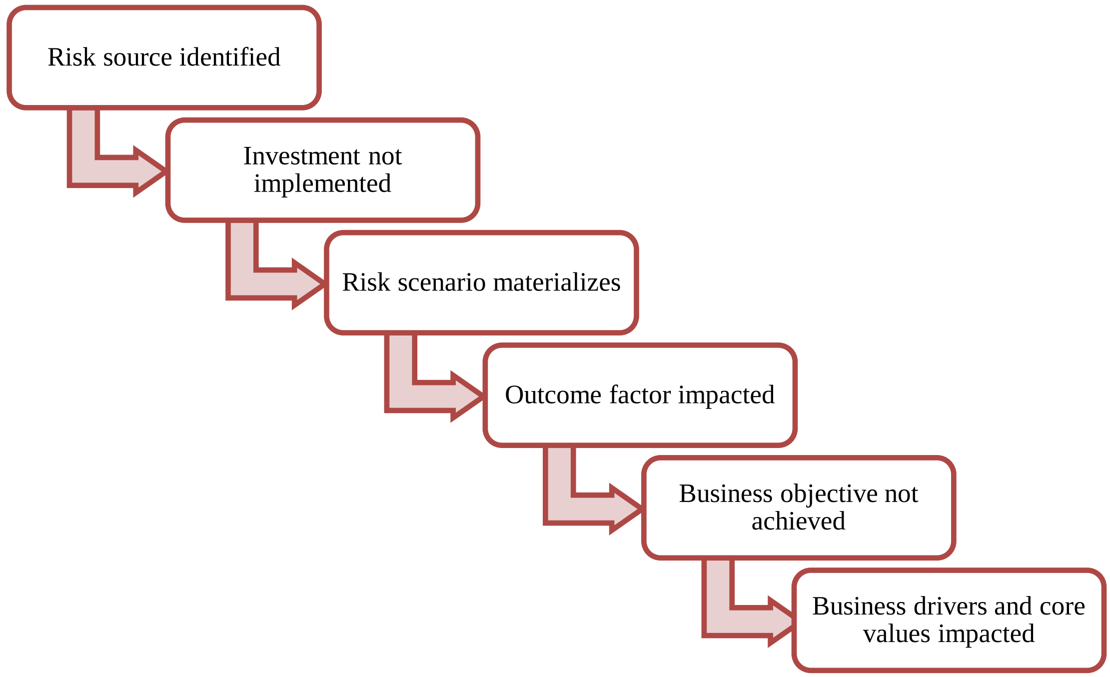


Figure 2: Baseline Risk Assessment Impact

A similar process is followed as part of the residual risk assessment, which identifies the impacts and residual risks following investment implementation. These risks assessments form a clear link between risks and the value of candidate investments.

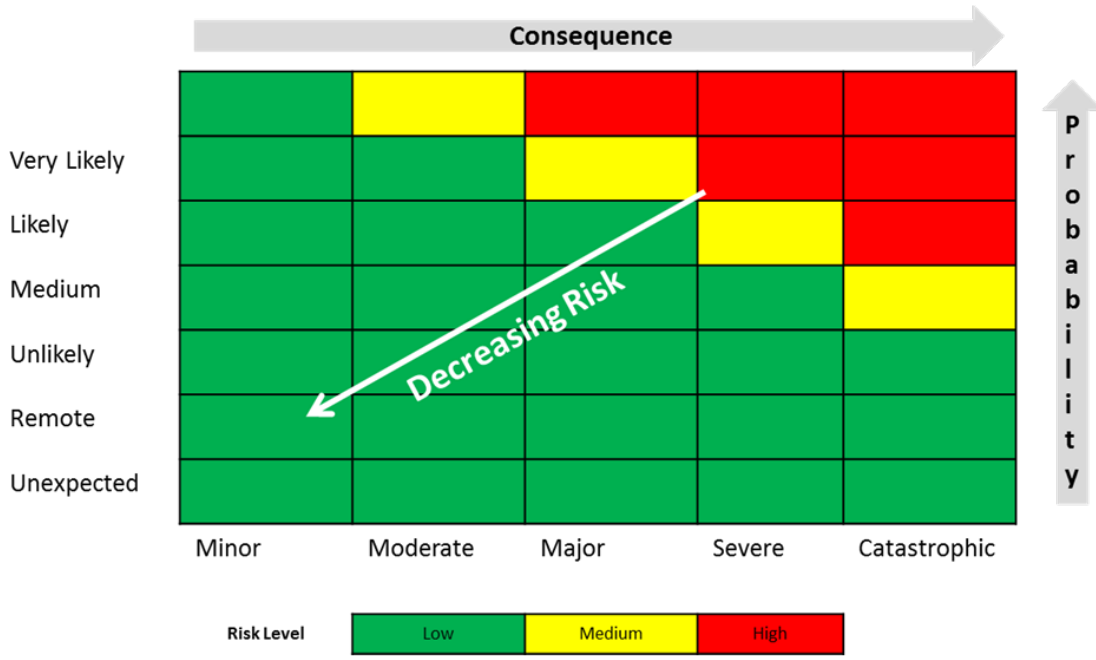


Figure 3: Business Driver Evaluation Matrix

4.4 Risk Treatment and Options Analysis

Following the identification and assessment of a given risk exposure, a decision is made to accept the risk or treat the risk. For risks identified for mitigation, risk treatment options, in the form of investment proposals, may be developed to address the risk. Risk mitigation occurs following investment implementation and may reduce the impact of the consequence or reduce the likelihood of the consequence occurring. The difference between the baseline risk and residual risk is the risk mitigation value created by the investment.

When developing the candidate investment, planners should consider multiple options that reflect different levels of funding, effort and outcomes to address the identified risk and investment need. Figure 4 illustrates the three funding levels (sometimes referred to as “accomplishment levels”) and their corresponding risk levels.

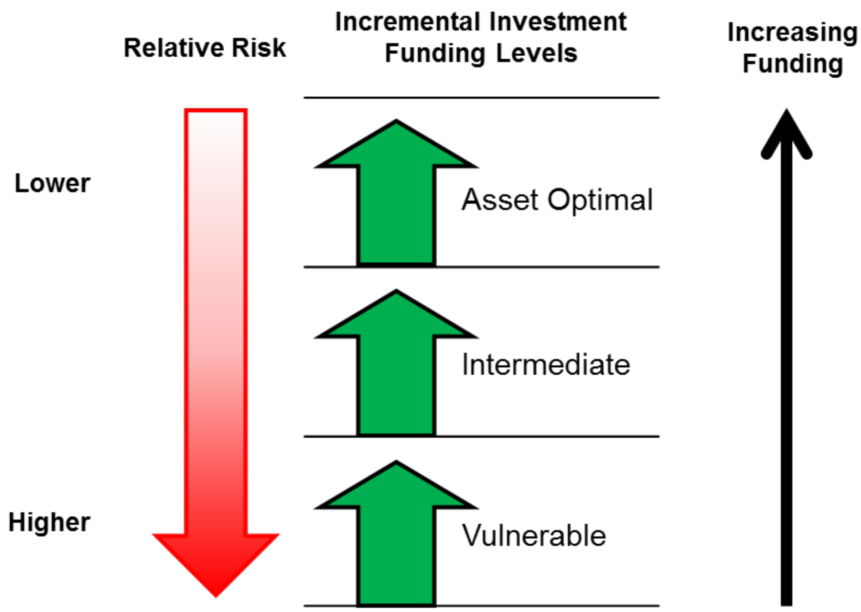


Figure 4: Accomplishment Levels versus Risk

The "vulnerable" investment level meets minimum compliance and health and safety requirements and is tolerable for only brief periods. At this level of funding, asset maintenance and/or replacement needs are not fully met, and asset failure is a possibility. The residual risk at the end of the five year planning period is just outside the "red zone" shown in Figure 3.

At the "intermediate" investment level, asset performance and risk are held at current levels. Where appropriate, there may be several intermediate investment levels to provide appropriate granularity between the "vulnerable" and "asset optimal" alternatives.

The "asset optimal" investment level represents the balancing point where total lifecycle costs of the asset are minimized and risk is low. This level of investment will ensure customer and asset needs are fully met, and there is a high degree of confidence that assets performance will align with the business objectives.

Further, select investments may have "start date flexibility". In these instances, an investment may functionally be allowed to shift during the optimization process by a specified period of time, typically a year or two. However, the risk exposure over the interim period may increase as a result of project deferral, as illustrated in Figure 5. This start date flexibility enables alternative investment pacing scenarios to be considered and assessed.

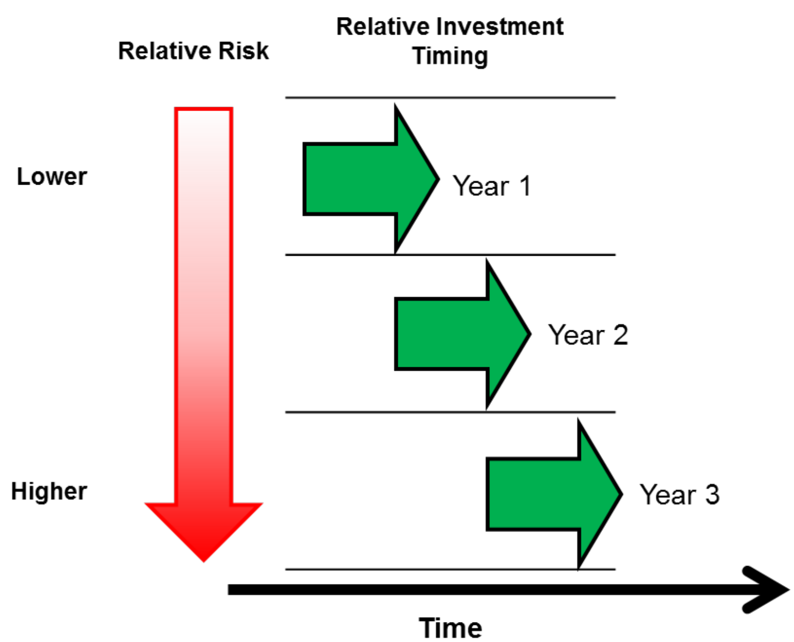


Figure 5: Start Date versus Risk

Across the investment portfolio, the risk assessments are then aggregated for each business driver in order to calculate the overall value of the investment to Hydro One. This overall value of the investment reflects the benefit of the investment through the investment's impact on evaluation criteria, risks mitigated and estimated costs.

These identified options and flexible timing arrangements are, at least in the short term, considered to be viable candidate investments, and are included in the optimization process for potential selection.

4.5 Line of Business Managerial Review

Once the investment plans have been consolidated into an investment portfolio, a structured, multi-level managerial review is conducted. In the AIP tool, investment candidates are routed for review by management of the relevant line of business. Managerial review of an investment is focused on the justification, the reasonableness of risk and investment value assessment, the appropriateness of the considered alternatives and recommended expenditure profiles, and the proposed investment schedule. If accepted, the candidate investment is included in the optimization process. Managers may reject an investment and send it back to the planner for edits and revisions. Multiple layers of review enable internal and cross-functional reviews and notional agreement on an investment candidate prior to its inclusion in the investment plan.

5. PRIORITIZATION AND RISK OPTIMIZATION: THE INVESTMENT PLAN PROPOSAL

All candidate investments (including alternatives) are then aggregated into a consolidated investment portfolio for optimization as illustrated in Figure 6. This investment optimization process occurs annually. The output of the process is a draft investment plan comprised of both capital and OM&A investments

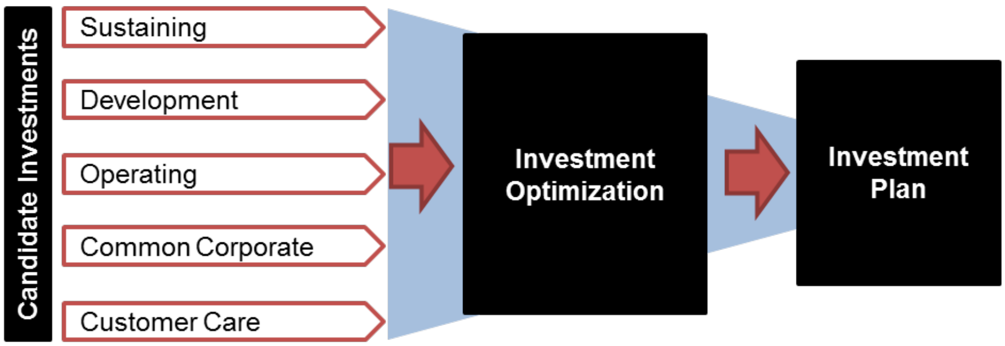


Figure 6: Candidate Investment Aggregation

At the core of the optimization process is the multi-variable framework based on the business drivers in Table 1, which helps decision-makers understand and quantify business risks and uncertainties so that objective decisions can be made, respecting investment priorities.

The optimization process attempts to find the combination of investment options and alternative start dates that maximizes investment value without exceeding the constraints that have been defined. This iterative process is intended to produce a portfolio of appropriately paced investments that achieves an optimal balance between cost effectiveness, timely responsiveness to customer needs, asset requirements and business needs.

5.1 Operational Stakeholder Engagement & Executive Approval

After the investment plan is optimized, cross-functional operational review meetings are held to review and discuss the draft investment plan. This review is meant to facilitate the consideration of additional operational and execution considerations such as resourcing and material and outage availability. Based on these discussions, adjustments may be made to reflect emerging execution risks and financial considerations. The end product is a revised investment plan proposal that represents an effective balance between these considerations.

Once the corporate support costs described in Exhibit C1, Tab 3, Schedules 3 and 4 are layered onto the investment plan, the end product is reviewed for approval by the executive team.

6. INDIVIDUAL INVESTMENT APPROVAL AND IMPLEMENTATION

Once the overall plan is approved, individual project proposals not already in execution are developed further for project-specific approvals. Factors considered in the assessment process include:

- the need for the investment;
- the implications of not doing the work and possible risk;
- the anticipated benefits (e.g., customer delivery point performance);
- the recommended solution; and
- estimated costs and in-service timing.

In determining the recommended solution, alternative approaches and project risks are considered. The proposals are then reviewed in a series of steps at the senior management and executive levels, depending on the dollar limit and the significance of the investment. The proposals are then approved, consistent with the provisions of the expenditure authority register, described in Exhibit A, Tab 5, Schedule 2.

6.1 Monitoring & Control

On a monthly basis, management monitors year-to-date expenditures and accomplishments as well as projected year-end expenditures. Variances from plan are identified and corrective action is taken. In the event that spending on a project is expected to be materially different from the amount originally approved, an interim review of variance ("IROV") is prepared. In effect, an IROV is an amended business case that is reviewed and approved based on the revised set of circumstances (such as revised cost, scope and/or schedule). The IROV is approved in accordance with the limits set out in the expenditure authority register. Projects that cannot be re-justified are reprioritized, cancelled or otherwise adjusted.

6.2 Re-direction of Funds

While the investment plan is the product of extensive planning and analysis, implementation of the plan must be done in a manner that is dynamic and flexible. Re-direction of approved funds may be required as new risks or opportunities emerge, including:

- changing customer needs and requirements (e.g., new regional plans, unexpected load growth, etc.);
- changing asset priorities based on new information;
- changing external requirements (such as changing industry, regulatory, technical standards and new policy initiatives); and
- major unforeseen events (e.g., extensive storms and equipment failures).

The re-direction of funds allows appropriate and prudent adjustments to be made to the work originally identified in the investment plan. As an example, the emergency restoration work needed to repair equipment failures or storm damage to a transmission line can be significant. Such events may necessitate the re-direction of funds and field resources from other investment areas.

cases; that's correct. But we have provided ISDs that describe those investments.

MR. OAKLEY: Okay, thanks.

If we could look up IR -- or this is IRR O-93, Staff O-93-B. I'm just trying to understand the sequencing of the process for optimizing the asset portfolio -- or the project portfolio.

Hydro One has advanced several activities to enter the project definition stage, including additional engineering, to minimize the need for assumptions during the estimating phase.

Could you describe the timing of that additional engineering in relation to specific steps in the asset risk assessment process, or if it's later in the investment selection process?

MR. PENSTONE: Within a business case, we identify the expected cost of the investment. Those costs are dependent on engineering to be done.

What we have undertaken is to do more engineering in the project definition stage, to enable us to come up with a better and more accurate estimate of the costs. That then gets reflected into our business case.

So, in essence, we have modified our processes to do a more in-depth examination through engineering studies to come up with more accurate cost estimates.

MR. OAKLEY: Thanks. So does that happen again as part of the ARA process, or does that happen -- is it variable?

Ontario Energy Board (Board Staff) INTERROGATORY #081

Reference:

Exhibit B1/Tab3/ Sch 11 – Hydro One Networks – Investment Summary Document, Reference #: S11 – Station Reinvestment – Elgin TS

*"**Need:** To address multiple assets at Elgin TS that are in need of replacement due to poor condition, obsolescence and high maintenance costs, which directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area."*

Interrogatory:

The statement: "are in need of replacement due to poor (or degraded) condition, obsolescence and high maintenance costs" or similar wording has been used in many of the integrated substation project need descriptions. Has Hydro One conducted business case evaluations or cost/benefit analyses for all of the integrated substation projects included in this filing?

a) If yes, please provide the business case evaluation or cost/benefit analysis conducted for each project

b) If no, please explain if the copied text (or similar wording) should be considered an appropriate level of business justification for such a diverse range of large investments.

Response:

a) No, a portion of the integrated substation projects are still awaiting business case evaluation before the projects are released for execution.

b) Hydro One's internal approval process requires business case evaluation be completed prior to the release of the integrated substation project for execution. All of the integrated substation projects included in the filing have gone through the Asset Risk Assessment process Exhibit B1, Tab 2, Schedule 5 to validate and justify asset need and the Investment Summary Documents submitted with this application provide a summary of that need.

Witness: Chong Kiat Ng

Table 2: Stations Sustaining Capital ($ Millions)

Description	Historic Years				Bridge Year	Test Years	
	2012	2013	2014	2015	2016	2017	2018
Circuit Breakers	11.2	23.4	25.0	7.1	2.4	1.1	0.0
Power Transformers	78.4	87.0	111.1	43.5	8.9	0.0	0.0
Other Power Equipment	28.3	26.5	27.5	12.5	4.5	0.0	0.0
Ancillary Systems	16.4	15.6	22.0	17.1	5.2	1.3	0.0
Station Environment	7.6	6.6	10.5	3.8	1.3	0.0	0.0
Integrated Station Investments	62.1	89.0	157.3	374.2	454.4	457.8	404.7
Transmission Transformer Demand and Spares	0.0	0.0	0.0	27.2	20.5	25.3	25.8
Protection and Automation	95.0	84.4	97.9	60.2	45.6	45.2	59.1
Site Facilities and Infrastructure	23.4	22.9	30.0	20.3	9.4	6.7	6.7
Total	**322.5**	**355.3**	**481.3**	**565.8**	**552.2**	**537.5**	**496.2**

The overall stations sustaining capital expenditures for the test year 2017 are approximately 2.7% less than the projected spending in 2016. The spending requirements for 2018 are also approximately 7.7% less than 2017 requirements. These expenditures reflect the asset needs and strategies detailed in the Asset Needs Overview, found in Exhibit B1, Tab 2, Schedule 6, which will meet customer needs and preferences, maintain Hydro One’s position in top quarter reliability among its transmission peers, and manage the business in an environmentally responsible manner. The variability observed year over year is directly associated with the timing of specific projects. These modest decreases in Station spending reflect the successful improvement of many stations as a result of completed projects eliminating some of riskiest stations and an increased need to refurbish Lines and associated assets.

Witness: Chong Kiat Ng

Ontario Energy Board (Board Staff) INTERROGATORY #064

Reference:

Exhibit B1/Tab3/Sch 2/ – Section 3.3: Benefits from Integrated Capital Investments, pg. 7

"Cost Avoidance – An integrated capital investment approach enables the system to be reconfigured and standardized, thereby reducing the number of assets within the system. For example, in the 2017 and 2018 test years, Hydro One plans to eliminate 10 transformers and 24 breakers from the system through reconfiguration. This results in avoided capital expenditures of $57 million during the test years."

Interrogatory:

a) Please reconcile the claim that the methodology described above avoided capital expenditures of $57 million in the Test Years when sustaining capital costs have more than doubled over the past 5 years.

b) Please provide detailed explanations of the $57 million savings and the base case against which those savings were calculated.

Response:

a) Integrated capital investment planning allows for holistic station planning as detailed in Exhibit B1, Tab 3, Schedule 2. Asset reduction achieved through design standardization and reconfiguration directly results in avoided capital cost, regardless of an increase in overall sustaining capital requirements that are driven by asset needs, as it results in a direct reduction of assets that would have otherwise been replaced under an asset-centric investment approach. For example, where condition and other risk factors described in Exhibit B1, Tab 2, Schedule 5, have identified a need to replace transformers at a station that presently operates in a non-standard configuration with three transformers, integrated capital planning facilitates the standardization of design in which the preferred alternative would be to replace three transformers with two units of a larger capacity. The reconfiguration of the station to reduce one transformer eliminates the need to replace each transformer individually resulting in avoided capital cost. Refer to Exhibit B1 Tab 3, Schedule 11, Investment Summary Documents S09, S11, S12, S13, S14, S16 and S17, etc.

b) The $57 million in avoided capital expenditure is directly related to the reduction of 10 power transformers and 24 breakers from the transmission system over the 2017 and 2018 test years. Historically, Hydro One has spent approximately $5 million for the planned capital replacement of a step-down transformer and approximately $300 thousand for the planned capital replacement of a low voltage circuit breaker. Through planned reconfiguration, the elimination of 10 step-down transformers and 24 low voltage circuit breakers translates to approximately $50 million in avoided capital expenditures for transformers and approximately $7 million in avoided capital expenditures for circuit breakers. The base case against which these savings were calculated was that in which each of the 10 transformers and 24 circuit breakers would have undergone a direct "like-for-like" replacement under an asset-centric investment approach.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated Station Component Replacement - Dufferin TS
Targeted Start Date: Q4 2016
Targeted In-Service Date: Q2 2019
Targeted Outcome: *Customer Focus, Operational Effectiveness*

Need:
To address multiple assets at Dufferin TS that are in need of replacement due to degraded condition, which directly impacts the operability and reliability of the transmission station. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to Toronto Hydro ("THESL") customers in the area.

Investment Summary:
Build 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 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.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Alternatives:

Two alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition and would result in increased maintenance expenses.

Basis for Budget Estimate:

The project cost is based on budgetary estimates prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:

To eliminate operational risks associated with operating end of life assets, and maintain system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	7.0	8.0	23.2
Operations, Maintenance & Administration and Removals	(0.5)	(0.6)	(1.5)
Gross Investment Cost	**6.5**	**7.4**	**21.7**
Capital Contribution	0.0	0.0	0.0
Net Capital Investment Cost	**6.5**	**7.4**	**21.7**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Chong Kiat (CK) Ng

Ontario Energy Board (Board Staff) INTERROGATORY #083

Reference:

Exhibit B1/Tab3/ Sch 11 – Hydro One Networks – Investment Summary Document, Reference #: S08 – Station Reinvestment – Beach TS; S11 – Station Reinvestment – Elgin TS; S13 – Station Reinvestment – Gage TS S14 – Station Reinvestment – Kenilworth TS

Project No.	*Station*	*Original ISD*	*Approximate Age*	*Need*
S08	*Beach TS*	*Late 1940's*	*65+ Years*	*Replacement due to poor condition, obsolescence and high maintenance costs*
S11	*Elgin TS*	*Late 1960's*	*48 Years*	*Replacement due to poor condition, obsolescence and high maintenance costs*
S13	*Gage TS*	*1940, with additional capacity in 1960's*	*75+ Years (from original ISD)*	*Replacement due to degraded condition and asset demographics*
S14	*Kenilworth TS*	*Early 1950's*	*65 Years*	*Replacement due to degraded condition and asset demographics*

Interrogatory:

a) Please explain why 4 critical transformer stations in the City of Hamilton (Beach TS, Elgin TS, Gage TS and Kenilworth TS) were allowed to fall into the described state of disrepair and obsolescence simultaneously.

b) Please explain how the 4 stations listed above have all reached end of life simultaneously despite having a wide range of station vintages and initial in-service dates.

Response:

a) Uncertainty in the Hamilton Steel industry over the last 10 years delayed Hydro One's investment in this area to manage investment risk associated with the unclear load supply requirements in this area. Hydro One's plan addresses the end of life asset needs at these stations while providing flexibility for future customer requirements. Exhibit B1, Tab 2, Schedule 4, Section 6, describes additional factors that have contributed to the delay in investment.

b) Investment at Gage, Kenilworth and Beach has been delayed as described in part (a) above. Investment at Elgin is aligned with the needs of the assets as determined through the Asset Risk Assessment process, detailed in Exhibit B1, Tab 2, Schedule 5.

Witness: Chong Kiat Ng

outside of asset analytics.

MR. OAKLEY: Yes, thank you.

I would like to refer to AMPCO number 10. And just, there are a lot of standards which Hydro One has changed, obviously, since, I think it's 2014, and there are a bunch more scheduled for the end of this year, I think it was 242 from Jan. 2014 to June 30th, 2016, and another 37 by the end of 2016.

And just given the pace of those standards changes, does that impact your decision to, you know, rebuild substations, as opposed to replace individual assets? It looks like it's a bit of chasing a moving target, because some of these substation builds that one of the justifications is we are trying to achieve, you know, modern standards, but it's pretty expensive to achieve a modern standard if a substation simply needs a transformer and a breaker.

MR. PENSTONE: When we undertake investments and we are refurbishing a station, we always apply the current standard to the new design of the new station. And the standard would reflect new requirements, for example, environmental standards would get reflected in the engineering design, new health and safety standards would get reflected in the design of the new station.

So our projects, when we describe the scope, the scope also always includes the requirement that the new facilities meet current standards.

MR. OAKLEY: Yeah, thanks, I appreciate that. I am thinking more of, if there are configuration standards that have changed and the decision is made with, you know, assets that are in good shape, that it's worth reconfiguring because it meets a modern standard or a template for what a station would be built like now. It's not -- I understand that when you replace a transformer you should use your standards, your protections should be put on with modern standards. Just trying to clarify, does the desire to achieve a standard become a driver in these rebuild projects?

MR. PENSTONE: So can I clarify, when you say "reconfigure", are you referring to, that the new station may have a different single-line description of it that you -- so for example, when we undertake investments, one of the considerations is, are there opportunities to manage the costs of the refurbishment and the subsequent ongoing costs by reconfiguring the station. There are examples where we have reduced the number of transformers. As an example, we have a station that may have had four transformers, the new station will be reduced down to two.

In essence that reconfigures the station, but we have good, valid reasons and justification for that reconfiguration and its purpose is, frankly, to minimize the long-term costs of the refurbished station.

MR. OAKLEY: Thanks. And just to clarify, what you are saying, I think, is that a decision has been made that a reconfiguration is required because the transformer station is doing something different, or its purpose is modified. And of course then you would use your modern standard when you are reconfiguring.

MR. PENSTONE: So I want to be very, very clear about standards because there's a million standards, right?

MR. OAKLEY: Yes.

MR. PENSTONE: So there is equipment standards, and we won't talk about equipment standards; we made the comment that they're to be up-to-date.

In terms of the actual configuration of the station, there is some latitude for the planners to change the configuration of the station -- in other words, the actual number of elements within a station -- and how are they connected to enable us to manage the long-term costs of the refurbished station. And we have taken advantage of the need to refurbish stations to, in a number of instances, reduce the number of elements in the new station.

MR. NG: I just want to add one clarification to Mr. Penstone's description.

We are there at the stations to deal with a certain asset need. In this example, we would have transformer in need of replacement, or two transformers in need of replacement. Then we will consider reconfiguration to make it more efficient.

So there has to be first an asset need reason. We do not go in to a station where assets are in good condition and start looking at changing the configuration to reduce the footprint.

MR. OAKLEY: Yes, thanks. I think you have clarified that. My question was it is not standards driving this. You achieve standards when you are going to do it; that was really the point of the question.

MR. NG: Yes, it's secondary.

MR. OAKLEY: I would like to refer you to Staff 74 (a). Is the Lisgar TS still proceeding?

MR. YOUNG: No, it's not; it's been cancelled.

MR. OAKLEY: Okay, thanks. I guess then there is no follow up to that then, thanks.

There are two Staff IRs that are sort of intertwined on this one. I would like to refer you to -- I guess either of the charts would probably do as an example, but 52 (b). There is also 62 C2, but they have very similar graphs. Thanks.

I just wanted to confirm that the outages caused by conductor failures don't seem to be correlated with conductor age or corrosion environment. Is that what I should take from these graphs?

MR. NG: Yes.

MR. OAKLEY: Okay. Well, thanks. I was wondering if there shouldn't be an age relationship, but this clearly demonstrates that empirically, you are not seeing an age relationship with conductor failures -- or corrosion environment, it looks like.

MR. NG: Am I hearing a question to explain why is there no correlation between age and failure?

MR. OAKLEY: No, no, the question isn't why. It is just simply to confirm that, you know -- I wasn't exactly

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #010

Reference:

Exhibit B1 Tab 1 Schedule 2

Interrogatory:

a) Please identify and explain any new or revised engineering design and construction standards and/or specifications implemented since Hydro One's last Cost of Service application.

b) Please discuss the cost impact of any new or changed engineering design and construction standards and/or specifications in the current application

Response:

a) Hydro One has an active program to create and maintain the standards that are used to execute the Transmission Capital work program in a safe, reliable and cost effective manner. Between January 1, 2014 and June 30, 2016, there were a total of 242 design standards and equipment and material standards published affecting the transmission system. Another 37 design standards are planned to be published by year-end 2016. See Attachment #1 for the list of standards. These standards cover all areas of the transmission system across transmission lines, substations, and the systems that provide protection and control functionality across the transmission system.

b) Standards drive consistency and repeatability across a portfolio of capital projects. This in turn controls costs associated with design, construction, commissioning and on-going operations & maintenance.

Witness: Brad Bowness

understand or I appreciate that the slides are being pulled up as questions are being asked, and even though they may not be the slides that are referred to by Mr. Oakley asking the questions, the purpose of pulling up the slides is to assist the witnesses in finding the evidence.

So if we are going do that, though, if the witnesses are going to refer to the actual slides to identify them for the purpose of the record -- I appreciate this slide wasn't referred to. But just going forward, I want to make sure that whatever we do have pulled up that the witness refers to, that the source is just on the record, just for assistance.

MR. NETTLETON: Ms. Helt, I think the slide that is currently on the projector right now was the slide that Mr. Penstone had referred to. This was his opening remarks.

MS. HELT: There was another slide then; she had changed, so that is all I am saying.

MR. OAKLEY: And I do appreciate this information being put in that context. It's helpful in your response, I do appreciate that.

If I can move along to some discussion of some of the substation integrated projects, these will be a bit more specific to the projects and programs as opposed to some of the process discussion.

If we could look at Staff 83 (a)? We are looking at the four Hamilton TS replacements that are rebuilds, or replacements in some cases. Are those stations projects being accelerated due to asset risk assessment results?

Did that process weigh heavily upon this?

MR. NG: These four projects would have gone through the ARA process to determine asset need.

MR. OAKLEY: Okay. So the ARA process would say, you know -- because I think they are largely driven by condition. I know there is some reconfiguration going on as well, but largely they are driven by need. So the ARA process would have put these forward as important candidate projects to go in the portfolio?

MR. NG: Correct.

MR. OAKLEY: All right. Could you confirm -- I think that it could be in this response, actually, that Beach TS and Elgin TS had begun -- there was -- the projects had started, I think, in Q2-2015 for Beach and Q3-2015 for Elgin. Would that be engineering work had started, I would assume, or...

MR. NG: Yes, for Beach and -- we have started construction activities. Elgin, we have released the project for executions, yes.

MR. OAKLEY: Okay, thanks.

Just a terminology clarification. Does Hydro One consider poor condition to be worse than degraded condition? Which of those is the ranking worst case?

MR. NG: We don't have a ranking between poor or degraded. In terms of calling it out as in degraded conditions, that means it require attention.

MR. OAKLEY: Thanks, but obviously, you know, certain levels of degradation require attention more promptly than other levels, and so I just wanted to see if -- you know, some things are replaced now because it's about to blow up or some things are -- you know, we have got some time, but we should really put this on our priority list to get around to replacing, so you are saying if it says poor or says degraded it's fine. It's more or less the same thing, which is saying replace now or...

MR. NG: So in terms of categorizing the state of degradation of an asset, we use a zero to 100 scale under asset analytic condition index. High score means it is in a poorer condition, low score means it is in a better condition. The definition of those are -- if the answer is in the high score between 80 to 100, we would describe it as very high-risk asset.

MR. OAKLEY: And the asset analytics scoring that you are talking about, that actually combines a variety of factors? That's not just an asset condition factor, that might be others as well, or is that purely asset condition that's driving the asset analytics number?

MR. NG: They are six risk factor in asset analytic, which are all described in Exhibit B1, Schedule 2, tab 5.

MR. OAKLEY: Right. And that includes age and the other parameters, yeah, okay. Thanks for that.

I guess given that -- so the work on Beach and Elgin started prior to Gage and Kenilworth, and I guess this is a poor and degraded question, so if it's answered by just saying, Look at the asset analytics score, or -- then that's fine.

Were those asset analytics scores provided with those projects in the ISDs, or...

MR. NG: No, those score are not provided in the ISD. But specific to Gage, in addition to asset analytic and the ARA assessment, there is also the question about the outlook of future load requirement in that area, which was uncertain until in recent months.

What happened there was, Gage had three -- still has three dozen in the stations, three load-serving stations in this one Gage station. Our plan in the past would have been going in to do like-for-like replacement, but due to the uncertainty in the steel industry we have taken the step to -- we have made the decision to wait and do a later evaluation to assess if it indeed do need to have three dozen at the same site.

The current investment plan is, no, we do not need to have three dozen at the site. We are reducing it from three to two. And that's part of the reason that we are doing the investment today, not last time.

MR. OAKLEY: Thanks.

MR. PENSTONE: Could I just clarify one point? And that is, I would like to ensure that the Board and other intervenors are aware that we don't undertake investments purely as a result of the output of asset analytics.

MR. OAKLEY: Thanks, yeah, I appreciate that. No, I understood the process is more complex than that, and it requires judgment, it looks like, on several stages.

MR. PENSTONE: Judgment and other factors that are

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Station Reinvestment - Beach TS
Targeted Start Date: Q2 2014
Targeted In-service Date: Q4 2019
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Beach TS that are in need of replacement due to poor condition, obsolescence, high maintenance costs, asset demographics and non-standard assets that directly impact the operability and system reliability. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the industrial customers within the City of Hamilton.

Investment Summary:
Built in the late 1940's, Beach TS is a network facility located within the industrial core in the City of Hamilton connecting to both the 230 kV and 115 kV transmission networks. Beach TS directly supplies the industrial customer ArcelorMittal Dofasco ("AMD"), local distribution company Horizon Utilities Corporation, and several Hydro One transformer stations within the industrial corridor and downtown core of the City of Hamilton.

The oil analysis results of two of the transformers at Beach TS show signs of insulation degradation indicating there is an increased probability of failure. In addition, these units are leaking oil from the voltage regulation component posing a risk to the environment. The proximity of these transformers to the station administrative buildings has also been identified as a safety concern and must be relocated to ensure sufficient separation.

The project entails:

- Extensive refurbishment and reconfiguration of Beach TS which will result in the replacement of two transformers, seven 230kV oil circuit breakers, one 115 kV oil circuit breaker, associated disconnect switches, and protection, control and telecom equipment;
- Upgrading of oil spill containment facilities to comply with the Ministry of Environment and Climate Change ("MOECC") requirements.

The new power transformers will be reconnected from the 115kV to the 230kV system to improve the reliability of supply to customers and reduce loading on the 115kV network in Hamilton/Niagara area. The upgrade of protection, control and telecom facilities will ensure compliance with the Northeast Power Coordinating Council ("NPCC") requirements.

Alternatives:
Three alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo);
- Alternative 2: In-Situ replacement of the assets; or
- Alternative 3: Relocated replacement of the assets.

Alternative 1 was considered and rejected as it does not address the risk of failure due to asset condition, safety concerns, and would result in increased maintenance expenses. Both Alternatives 2 and 3 were considered further. However Alternative 3 is the preferred and recommended alternative as it addresses all the needs of the station. Alternative 2 would not eliminate safety concerns regarding the proximity of the transformer to administrative buildings and would not allow for the reconnection of the transformers to the 230 kV network to alleviate congestions on the 115 kV system.

Basis for Budget Estimate:
The project cost is based on detailed cost estimates prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment, increase capacity on the 115 kV system, maintain system reliability, and ensure compliance with MOECC and NPCC requirements.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	16.7	15.9	77.3
Operations, Maintenance & Administration and Removals	(0.2)	0.0	(0.8)
Gross Investment Cost	**16.5**	**15.9**	**76.5**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**16.5**	**15.9**	**76.5**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Station Reinvestment - Elgin TS
Targeted Start Date: Q3 2015
Targeted In-Service Date: Q4 2019
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Elgin TS that are in need of replacement due to poor condition, obsolescence and high maintenance costs, which directly impact the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Built in the late 1960's, Elgin TS is a 48 year old transformer station that supplies load to Horizon Utilities Corporation which serves the downtown core of the City of Hamilton. The oil analysis results of all four transformers at Elgin TS show signs of internal arcing, overheating, and insulation degradation indicating that there is an increased probability of failure. The low voltage switching facilities have also been deemed end of life due to condition, performance, obsolescence and safety concerns over inadequate arc resistance.

The project entails:

- Reconfiguration of Elgin TS by replacing and upgrading existing facilities with new equipment built to current standards including: the 115/13.8kV transformers, the low voltage switching facilities (including thirty-eight low voltage breakers) with a new medium voltage gas-insulated switchgear building installation, protection and control facilities, and other associated ancillary equipment; as well as the oil spill containment facilities will be upgraded in compliance with the Ministry of Environment and Climate Change ("MOECC") requirements; and
- Replacement of four transformers with two standard units; the other two transformers will no longer be required as a result of the reconfiguration to a standardized design.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Witness: Chong Kiat (CK) Ng

Alternatives:
Three alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo);
- Alternative 2: "Like-for-Like" replacement of the assets; or
- Alternative 3: Reconfiguration of the station.

Alternative 1 was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses. Both Alternatives 2 and 3 were considered further. Alternative 3 is the preferred and recommended alternative as it addresses all the needs of the station. Alternative 2 would not address the non-standard design configuration resulting in the need for additional transformers; which would increase overall project costs as well as long term maintenance commitments.

Basis for Budget Estimate:
The project cost is based on detailed cost estimates prepared by Hydro One.

Outcome:
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, and reduce long term maintenance costs through the reconfiguration to a standardized design.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	22.6	17.8	58.2
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0
Gross Investment Cost	**22.6**	**17.8**	**58.2**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**22.6**	**17.8**	**58.2**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Chong Kiat (CK) Ng

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Station Reinvestment - Gage TS
Target Start Date: Q1 2017
Targeted In-service Date: Q4 2019
Targeted Outcome: *Operational Effectiveness*

Need:
To address multiple assets at Gage TS that are in need of replacement due to degraded condition and asset demographics that directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Gage TS is a transformer station that supplies load to Horizon Utilities Corporation in the city of Hamilton and other major industrial customers including: US Steel, Max Aicher North America, and ArcelorMittal Dofasco. The station was originally placed in-service in 1940 with additional capacity installed in the 1960s. Since Gage TS supplies critical industrial customer loads there have been no major refurbishments at the station since its inception due to the unavailability of outages to perform the work. The oil analysis results on four transformers at Gage TS have repeatedly shown advanced signs of insulation degradation, indicating that there is an increased probability of failure in the near term. In addition, several low voltage circuit breakers are in poor condition, are an obsolete design and spare part availability is limited.

The project entails a partial rebuild and reconfiguration of Gage TS, replacing existing aged and degraded infrastructure with new equipment built to current standards. The customer load at the station has reduced substantially over the years to about a third of the installed capacity. As a result, the station will be reconfigured from the existing three switchyards supplied by six transformers and consolidated to consist of two switchyards supplied by four transformers with increased ratings in order to maintain reliability and supply capability. Equipment to be replaced in this project includes: the 115/13.8kV transformers and associated spill containment systems in compliance with the Ministry of Environment and Climate Change ("MOECC") requirements, thirteen circuit breakers, disconnect switches, protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Witness: Chong Kiat (CK) Ng

Alternatives:

Three alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo);
- Alternative 2: "Like-for-Like" replacement of the assets; or
- Alternative 3: Reconfiguration of the station.

Alternative 1 was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses. Both Alternatives 2 and 3 were considered further. Alternative 3 is the preferred and recommended alternative as it addresses all the needs of the station. Alternative 2 would continue maintaining six transformers and the associated three switchyards; which was not deemed prudent given the reduction in loading.

Basis for Budget Estimate:

The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:

To eliminate operational risks associated with operating end of life equipment, maintain system reliability, and reduce long term maintenance costs through the consolidation of two switchyards.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	1.3	13.3	38.0
Operations, Maintenance & Administration and Removals	(0.1)	(0.9)	(2.0)
Gross Investment Cost	**1.2**	**12.4**	**36.0**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**1.2**	**12.4**	**36.0**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Chong Kiat (CK) Ng

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Station Reinvestment – Kenilworth TS
Targeted Start Date: Q3 2017
Targeted In-Service Date: Q4 2018
Targeted Outcome: *Operational Effectiveness*

Need:

To address multiple assets at Kenilworth TS that are in need of replacement due to degraded condition and asset demographics that directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining reliability to the major industrial customers located within the City of Hamilton.

Investment Summary:

Built in the early 1950's, Kenilworth TS is a 65 year old transformer station that supplies load to Horizon Utilities Corporation which serves the City of Hamilton. The oil analysis results for one of the transformers at Kenilworth TS has shown advanced signs of insulation degradation indicating there is an increased probability of failure in the near term and is consistently leaking oil. The low voltage metalclad switching facilities have also been deemed end of life due to condition, performance and safety concerns over inadequate arc flash resistance. All of the station protection, control and telecom facilities have reached end of life and are obsolete.

The scope of this project will entail the reconfiguration of Kenilworth TS, replacing existing facilities with new equipment built to current standards. The existing station configuration consists of three switchyards supplied by four transformers. However, one of the metalclad switchyards and two power transformers are presently out of service and are no longer required due to significant reduction in loading in the area. Therefore the station will be reconfigured and consolidated to consist of two switchyards supplied by two transformers with increased ratings in order to maintain reliability and supply capability. Equipment to be replaced within this project includes: one 115/13.8kV power transformer, fifteen low voltage breakers, all associated protection, control and telecom facilities, and other associated ancillary equipment; as well as the oil spill containment will be upgraded in compliance with the Ministry of Environment and Climate Change ("MOECC") requirements.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Witness: Chong Kiat (CK) Ng

Alternatives:
Three alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo).
- Alternative 2: “Like-for-Like” replacement of the assets.
- Alternative 3: Reconfiguration of the station.

Alternative 1 was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses. Both Alternatives 2 and 3 were considered further. Alternative 3 is the preferred and recommended alternative as it addresses all the needs of the station. Alternative 2 would continue maintaining four transformers and the associated switchyards; which was not deemed prudent given the reduction in loading.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, and reduce long term maintenance costs through the reconfiguration to a standardized design.

Costs:

($ Millions)	**2017**	**2018**	**Total**
Capital* and Minor Fixed Assets	6.0	12.0	20.0
Operations, Maintenance & Administration and Removals	(0.4)	(0.8)	(1.4)
Gross Investment Cost	**5.6**	**11.2**	**18.6**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**5.6**	**11.2**	**18.6**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Chong Kiat (CK) Ng

Ontario Energy Board (Board Staff) INTERROGATORY #034

Reference:

Exhibit B1/Tab2/Sch 6/ – Section 2.1.3: Transformers - Asset Assessment Details, Other Influencing Factors, p. 8

"Safety - Power transformers can experience catastrophic explosions and fire if their condition is deteriorated. Power transformer outages can represent a concern for employee and public safety as individuals may be exposed to unneeded risks and harmed from the results of transformer failure as well as through prolonged power outages."

Interrogatory:

a) Please provide the total number of Hydro One transformers that have failed catastrophically over the past 10 years, by voltage class.

b) Please provide the number of transformers in Hydro One's fleet that are materially susceptible to imminent catastrophic failure, and quantify the probability of catastrophic failure and the period of evaluation for each transformer identified in this response.

c) To which transformers does Hydro One apply real-time gas alarm monitoring to reduce the risk of catastrophic transformer

Response:

a) Please see the table below:

Transformers Failed Catastrophically Over the Past 10 Years 2006-2015

Voltage Class	Number of *Class 1 Failure Transformers
500kV	6
230kV	13
115kV	15

*Class 1 failure is irreparable transformer failure requiring replacement.

b) Hydro One does not knowingly operate transformers that are confirmed to be materially susceptible to imminent catastrophic failure. However, unpredictable transformer failures do occur and based on historical unpredictable failure rates, Hydro One anticipates 4 units per year will be class 1 failures.

c) Hydro One applies real-time gas alarm monitoring on all transformers.

Witness: Chong Kiat Ng

Ontario Energy Board (Board Staff) INTERROGATORY #069

Reference:

Exhibit B1/Tab3/Sch 2/ – Section 4.2.3: Investment Plan, pg. 19

"The purchase of operating spare transformers is in line with Hydro One's probabilistic approach to determine the number of spare requirements. The analysis considers performance trends and supply chain considerations of Hydro One's various power transformer types, and groups them into optimized spare cohorts to adequately cover the in-service population. The transmission operating spares requirement is intended to replenish inventory that is expected to be drawn down for future failures."

Interrogatory:

Please provide a table showing historic in-stock spares, annual draw-down and annual replenishment for 2012-2016, broken down into the following components:

- Autotransformers (>125 MVA);
- Large Transformers (>42MVA);
- Mid-size Transformers (15 to 42 MVA);
- 500 kV Breakers;
- 345 kV Breakers;
- 230 kV Breakers; and
- 115 kV Breakers.

Response:

The inventory of spare transformers and breakers specifying the draw-down and replenishment levels for each the years 2012 to 2016 is provided in the table below.

In Stock Spares as of Aug 18.	**2012**	**2013**	**2014**	**2015**	**2016**
Autotransformers (>125MVA)	9	10	10	7	6
Large Transformers (>42MVA)	31	26	23	23	24
Mid-size Transformers (15 to 42 MVA)	19	18	13	16	16
500kV Breakers	3	3	4	4	5
345kV Breakers	N/A	N/A	N/A	N/A	N/A
230kV Breakers	17	18	20	19	18
115kV Breakers	4	6	9	14	13

Witness: Mike Penstone

Annual Draw-Down	**2012**	**2013**	**2014**	**2015**	**2016**
Autotransformers (>125MVA)	1	0	1	1	2
Large Transformers (>42MVA)	0	3	2	3	1
Mid-size Transformers (15 to 42 MVA)	1	1	2	0	0
500kV Breakers	0	0	0	0	0
345kV Breakers	N/A	N/A	N/A	N/A	N/A
230kV Breakers	0	0	0	1	1
115kV Breakers	0	0	0	0	1

Annual Replenishment	**2012**	**2013**	**2014**	**2015**	**2016**
Autotransformers (>125MVA)	0	1	0	0	0
Large Transformers (>42MVA)	3	1	1	3	2
Mid-size Transformers (15 to 42 MVA)	0	1	0	1	0
500kV Breakers	0	0	1	0	1
345kV Breakers	N/A	N/A	N/A	N/A	N/A
230kV Breakers	8	1	2	0	0
115kV Breakers	0	2	3	5	0

> "Over the planning period, a number of foreseeable changes are expected to result in a power system that is increasingly variable and complex to operate on a day-to-day basis."

The IESO has successfully integrated over 6,000 MW of wind and solar PV into Ontario's electricity system. The IESO has made strides in integrating significant amounts of variable generation while maintaining reliable operations of the power system. This has been achieved through efforts such as the Renewable Integration Initiative (RII), which brought in centralized forecasting of variable generation and the capability to dispatch variable generators.

While the IESO is working on methods for improving short-term forecasting, measures are also being taken to maintain reliable and efficient operations in the face of an evolving power system. These measures include additional frequency regulation, flexibility, control devices, and system automation. Greater coordination between the grid operator and embedded resources, directly or through integrated operations with LDCs, could also improve visibility into the distribution system and reduce short-term forecast errors.

Load-following capability is primarily provided by peaking water-power resources, the Sir Adam Beck Pump Generating Station and natural gas-fired generation, and is sufficient in the near term. However, the need for flexibility will increase over time. In addition to existing mechanisms for acquiring ancillary services, consideration is being given to expanded markets that would allow for more dynamic real-time coordination.

Going forward, regulation and flexibility requirements will be assessed on an ongoing basis, along with the resource fleet available to provide these services. Electricity markets will play a stronger role in ensuring adequate supply of flexible resources through signals that price and dispatch these services. It is anticipated that many resource types will be able to compete to provide regulation and/or flexibility, including resources such as energy storage and aggregated loads. Some of these newer technologies can provide operability characteristics that are not achievable from some traditional resources, such as very fast ramp rates, which may allow efficiency improvements in how these services are currently dispatched.

3.5. Transmission and Distribution Outlook

Current transmission projects already at various stages of planning and implementation are outlined in Table 3.

No significant new transmission investments would be required in an outlook of flat electricity demand served by existing and currently planned resources. However, additional transmission or local resources to address specific regional needs may be identified in the future as regional planning continues across the province.

The need to replace aging transmission assets over coming years will also present opportunities to right-size investments in line with evolving circumstances. This could involve up-sizing equipment where needs exist such as in higher demand outlooks; downsizing, to reduce the risk of underutilizing or stranding assets; or even removing equipment that is no longer required, such as in the low demand outlook or in parts of the province that have seen reduced demand. Such instances may also present opportunities to enhance or reconfigure assets to improve system resilience and allow for the integration of variable and distributed energy resources.

In higher demand outlooks, investments in transmission will be required to accommodate new resources. Transmission to integrate those resources would have significant lead time requirements of up to 10 years. Much of Ontario's undeveloped renewable resource potential is located in areas with limited transmission capacity – new investments in Ontario's transmission system would be required to enable further resource developments in the province or significant imports into the province. For example, incorporation of renewable resources located in northern Ontario would require reinforcements to the major transmission pathway between northern and southern Ontario, the North-South Tie. A number of transmission upgrades within Northern Ontario would also be required to alleviate constraints within the region. To facilitate any potential large firm import capacity arrangement from Quebec/Newfoundland, major system reinforcements in eastern Ontario would be required – a new high-voltage direct current (HVDC) intertie to Lennox would be an example. The incorporation of new resources in Southwestern Ontario would require reinforcement of the transmission system, such as in the West of London area, as well as additional enabling facilities. Similarly, investments in new resources in the Greater Toronto Area might also trigger the need to reinforce the bulk transmission system.

In the near term, the system can manage increases in electricity demand driven by electrification. However, LDCs and transmitters may be more significantly impacted as local peak demands grow.

Table 3: Status and Drivers of Transmission Projects in Outlook B[10]

		Drivers			
Projects	Status	Maintaining Bulk System Reliability	Addressing Regional Reliability and Adequacy Needs	Achieving 2013 LTEP Policy Objectives	Facilitating Interconnections with Neighbouring Jurisdictions
East-West Tie Expansion	Expected to be in service in 2020.	●		●	
Line to Pickle Lake	Plan is complete; expected to be in service in early 2020.		●	●	
Remote Community Connection Plan	Draft technical report released; development work underway for connection of 16 communities; engagement with communities is ongoing.		●	●	
Northwest Bulk Transmission Line	Hydro One is carrying out early development work to maintain the viability of the option.	●		●	
Supply to Essex County Transmission Reinforcement	Expected in-service date of 2018.		●		
West GTA Bulk reinforcement	Plan is being finalized.	●			
Guelph Area Transmission Refurbishment	Expected to be in service in 2016.		●		
Remedial Action Scheme (RAS) in Bruce and Northwest	Under development. Northwest RAS targeted for late 2016 in-service; Bruce RAS early 2017.	●			
Clarington 500/230kV transformers	Expected to be in service in 2018.	●			
Ottawa Area Transmission Reinforcement	Project has been initiated; expected to be in service 2020.		●		●
Richview to Manby Transmission Reinforcement	Expected to be in service in 2020.		●		

[10] A merchant 1 GW bi-directional, high-voltage, direct current Lake Erie underwater transmission link is currently being proposed by ITC Holdings Corp. It would directly connect the Ontario transmission system at the Nanticoke Transformer Station with the PJM market in Pennsylvania. The proposed in-service date of the project is 2019. This is a merchant project that was not identified by the IESO as being needed to meet system requirements.

The extent to which the transmission and distribution system will be impacted will depend on the location of electrification driven demand growth. The low voltage distribution system is expected to be impacted to a much greater degree. For example, some distribution infrastructure is designed for a five kilowatt (kW) peak household load. On a cold day, one household equipped with an air-source heat pump could consume as much as 15 kW. Though the system as a whole could supply this need, transmission and distribution infrastructure in some regions would be challenged by rapid and widespread conversions from gas to electric heating. This could be compounded by the effect of home charging of EVs, whose impact on peak demand can also vary substantially with charging patterns. Some LDCs have already undertaken analysis of their systems to determine the potential impact that high saturation of EVs will have on their system and what measures could be taken to manage emerging needs in the most cost-effective manner. These measures include a focus on customer-based solutions such as the use of load control devices, DER and storage integrated with the local and provincial utility control systems. While the impact of electrification in space heating, water heating and transportation will increase electricity requirements across the province, the impact would be the most prominent in urban centres, with implications for regional transmission systems that will need to be considered as part of the regional planning processes.

The increased penetration of DERs will have implications for distribution and transmission systems. A number of facilities, tools and measures will be needed to ensure that the power system can continue to be reliably operated amid increasing amounts of DERs. In some cases, DER technologies themselves can help address some of these requirements. Pilot projects are building experience and capability with DERs within the sector. Strategies and options for using DERs to address local issues could be laid out in regional planning processes, working together with transmitters and LDCs.

> "In the near term, the system can manage increases in electricity demand driven by electrification. However, LDCs and transmitters may be more significantly impacted as local peak demands grow… The low voltage distribution system is expected to be impacted to a much greater degree."

3.6. Emissions Outlook

With the phase-out of coal-fired generation, the carbon emissions from Ontario's electricity fleet now come primarily from natural gas-fired generation.

Emissions are expected to continue to decline over the next five years as additional renewable generation enters service. Beyond this period, emissions will depend on the level of electricity demand and the extent to which energy production from the existing natural gas-fired fleet is displaced.

In the flat demand outlook, emissions would rise slightly following the retirement of the Pickering Nuclear Generating Station but would remain well below historical levels and stay relatively flat through to 2035 (Figure 18).

When Ontario's cap-and-trade system takes effect in 2017, the electricity sector will see the cost of carbon reflected in the wholesale electricity price when natural gas-fired resources are on the margin. The Ontario market price for carbon will also be applied to electricity imports. This will provide a level playing field for Ontario generators in the IESO market and reduce imports from higher-emitting sources. At the same time, imports to Ontario from non-emitting jurisdictions such as Quebec could increase, other things being equal.

On the other hand, the addition of a carbon price to emitting Ontario generators would reduce the amount of electricity exported from natural gas-fired generators and so reduce Ontario GHG emissions, with the impact depending on whether the receiving jurisdictions adopt similar carbon pricing as Ontario and Quebec.

Under the higher demand outlooks, the effects on carbon emissions will depend on the extent to which the existing natural gas-fired fleet is used to meet increases in demand. The existing natural gas-fired combined-cycle fleet has considerable capability to ramp up energy production should it be required. However, increased utilization of the existing combined-cycle fleet would increase emissions. Therefore, in this report, consideration of how to address the higher demand outlooks was based on keeping GHG emissions in the electricity sector low or declining.

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

Ref. A

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

Ref. B

Reference A: Undertaking TCJ1.33 Attachment 4, "Dufferin TS T1/T3 Yard Station Assessment", Revision 1, February 20, 2015, p. 7, Table 8

Reference B: Undertaking TCJ1.33 Attachment 5, "Dufferin TS T2/T4 Yard Station Assessment", Revision 1, February 20, 2015, p. 6, Table 7

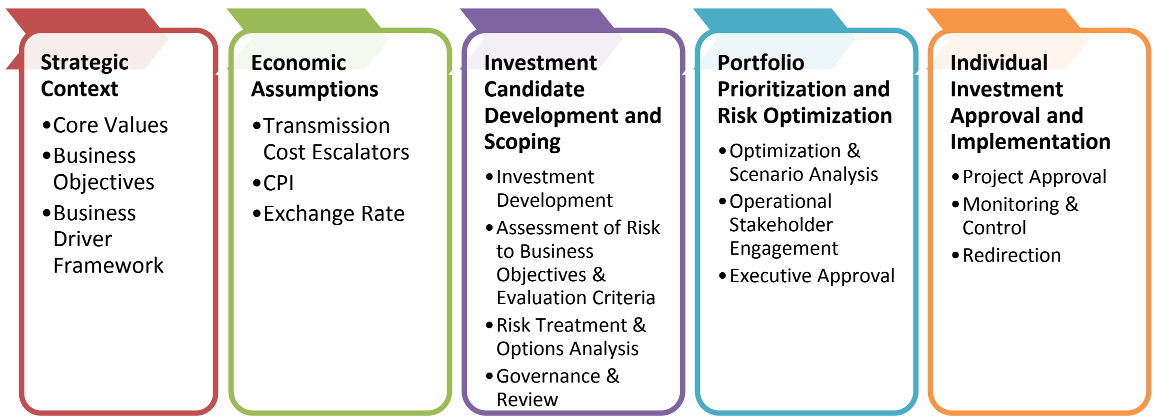
UNDERTAKING – TCJ1.33

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.

Witness: Chong Kiat Ng

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: 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.

Prepared by

Randy Tibben, P.Eng.
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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CONTACT/PUBLISHER

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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

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]
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

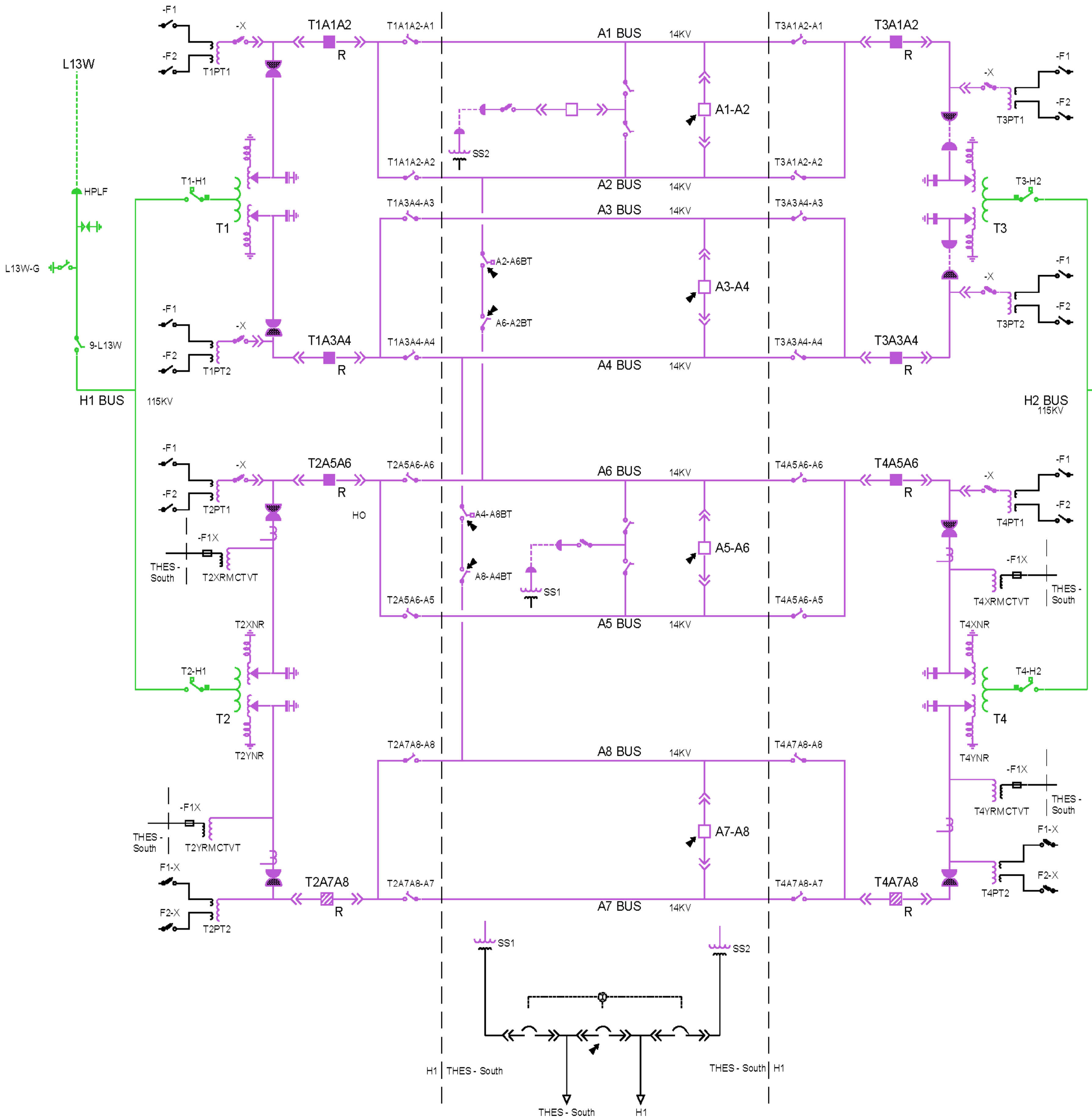
- Replace transformer T1 and T3 and spill containment as they have reached end-of-life and are heavily leaking oil.
  - Based on multiple oil analysis results these transformers have internal arcing and overheating , which indicates that there is higher probability of failure in the near future. Tap 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
345 KV
230 KV
115 KV
69 KV
35 to 44 KV
22 to 28 KV
14 KV
Auxiliary

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

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

Dufferin TS
NT9

STATION OPERATING DIAGRAM

Hydro One Networks Inc.
Integrated Transmission Operating Facilities

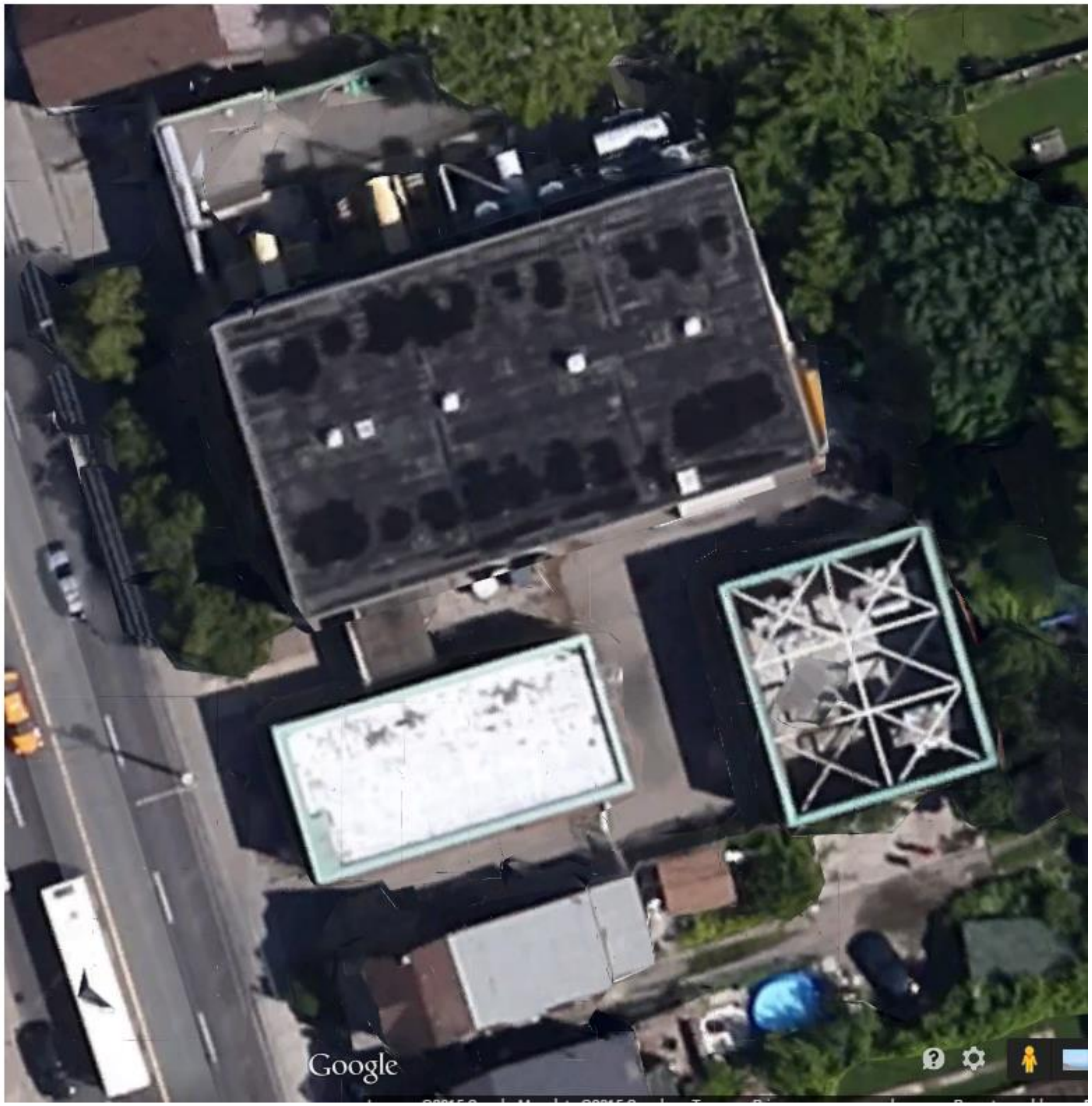
Date: DD/MM/YYYY	Drawn:	Checked:
27/04/2004		

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

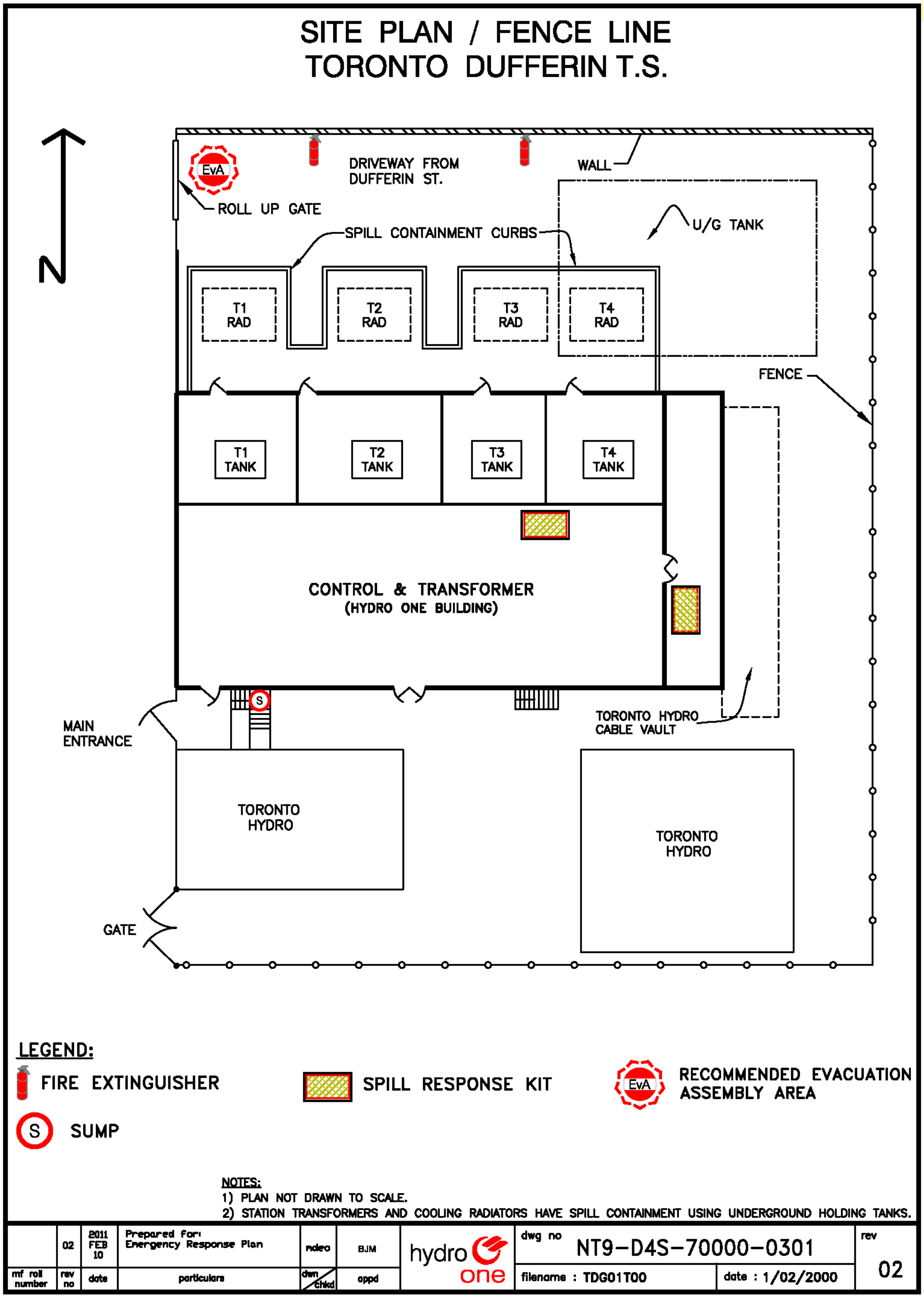
Paper Size: 22x16

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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Signature:			
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Title:	Network Mgmt Eng.	Sr. Network Mgmt Eng/Off	Manger, Transmission Capital Investment Planning
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

	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]
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

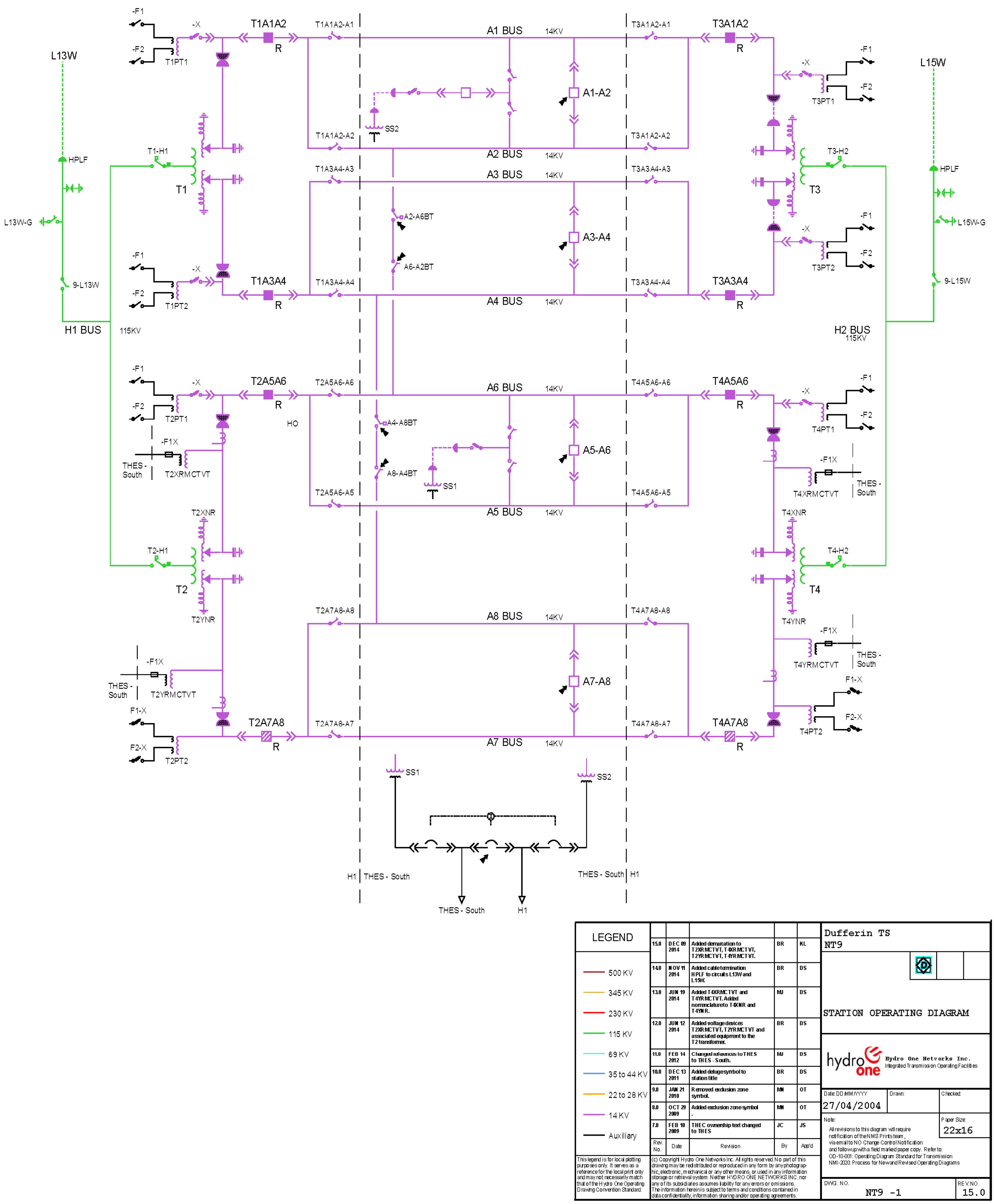
- Upgrade legacy RTU to current GE standard in advance of protection replacements.
    - Legacy RTU is no longer supported by the manufacturer and spare parts are limited.
    - Upgrading to current standards will maintain reliable operational control of the station and provide enhanced alarm monitoring
- 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

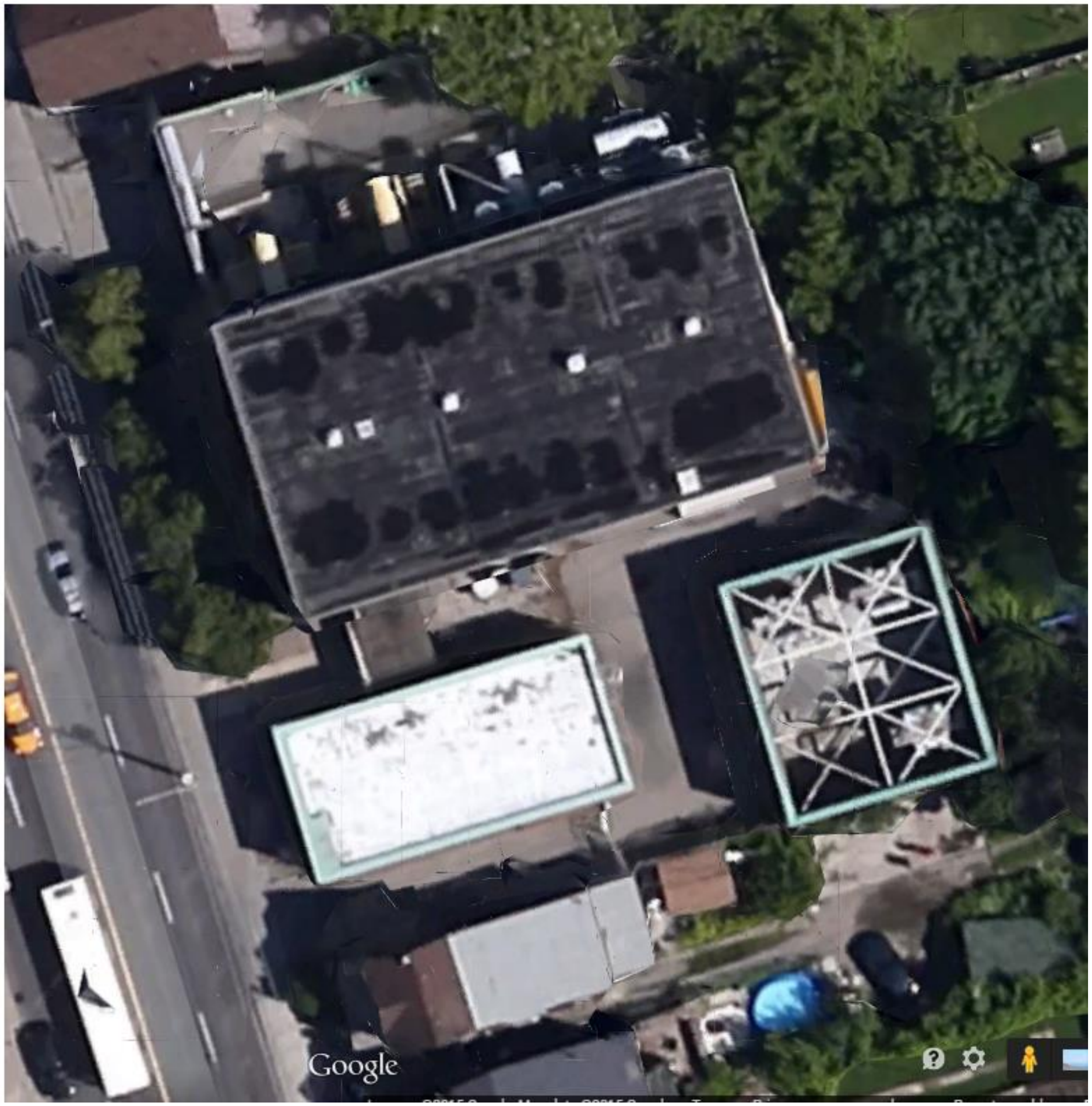
[1] Special Studies, "2014 Update of Short Circuit Survey and Breaker Ratings," [Online]. Available: https://teams.hydroone.com/sites/TPD/TPD/ss_pd/Short Circuit/Surveys/Breakers.

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

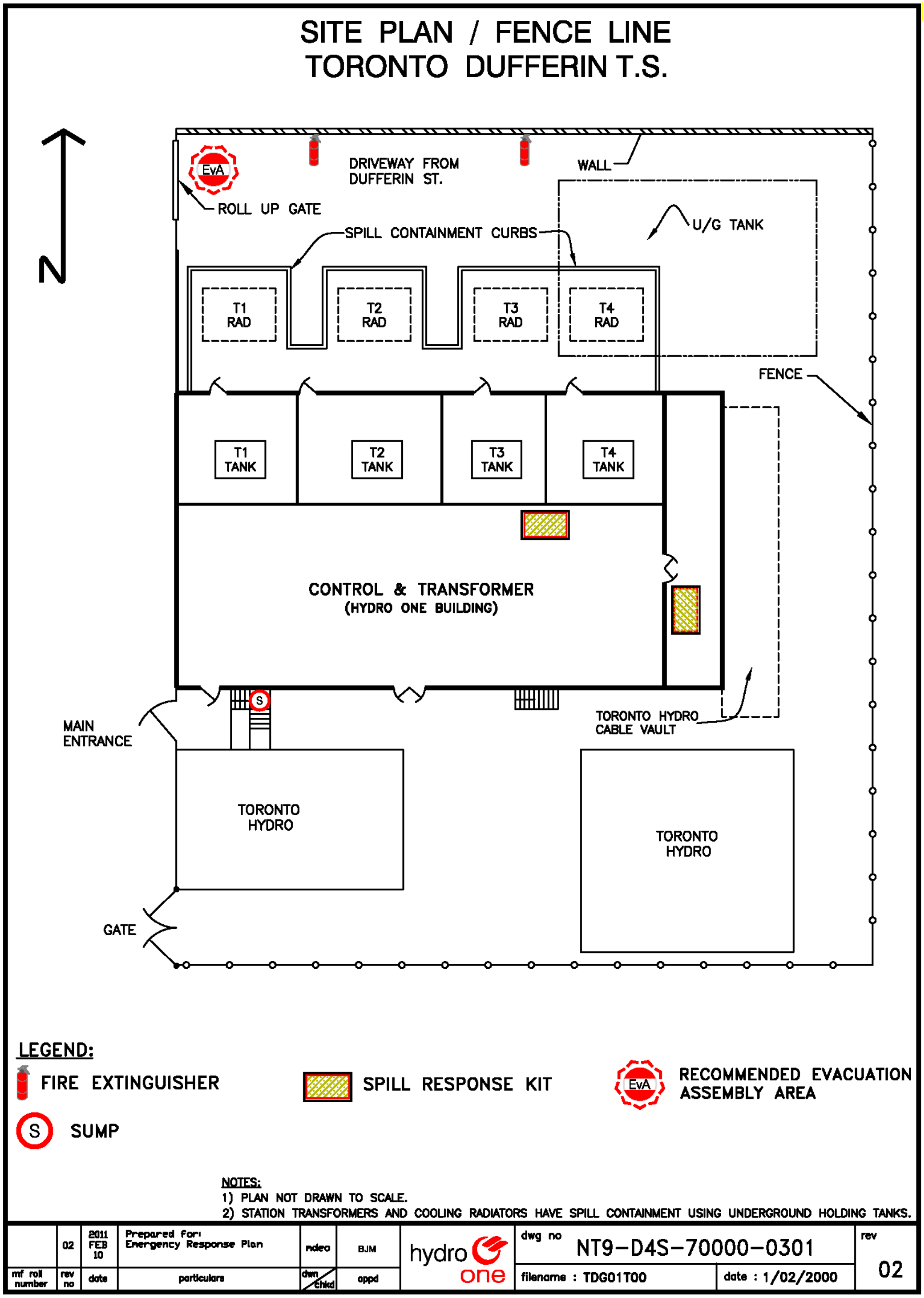
APPENDIX 1 – DUFFERIN TS OPERATING DIAGRAM



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

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.

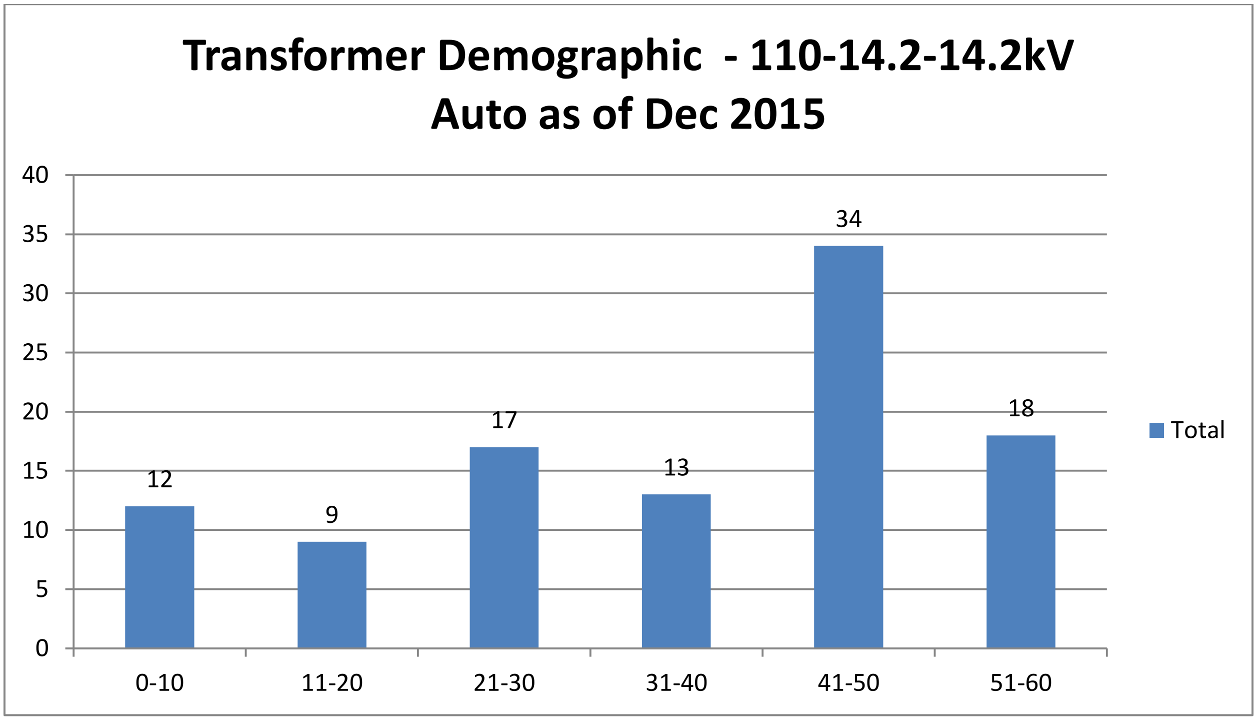


Chart 1 : Transformer Demographic - 110-14.2-14.2 kV Step down Transformer as of Dec 2015

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:

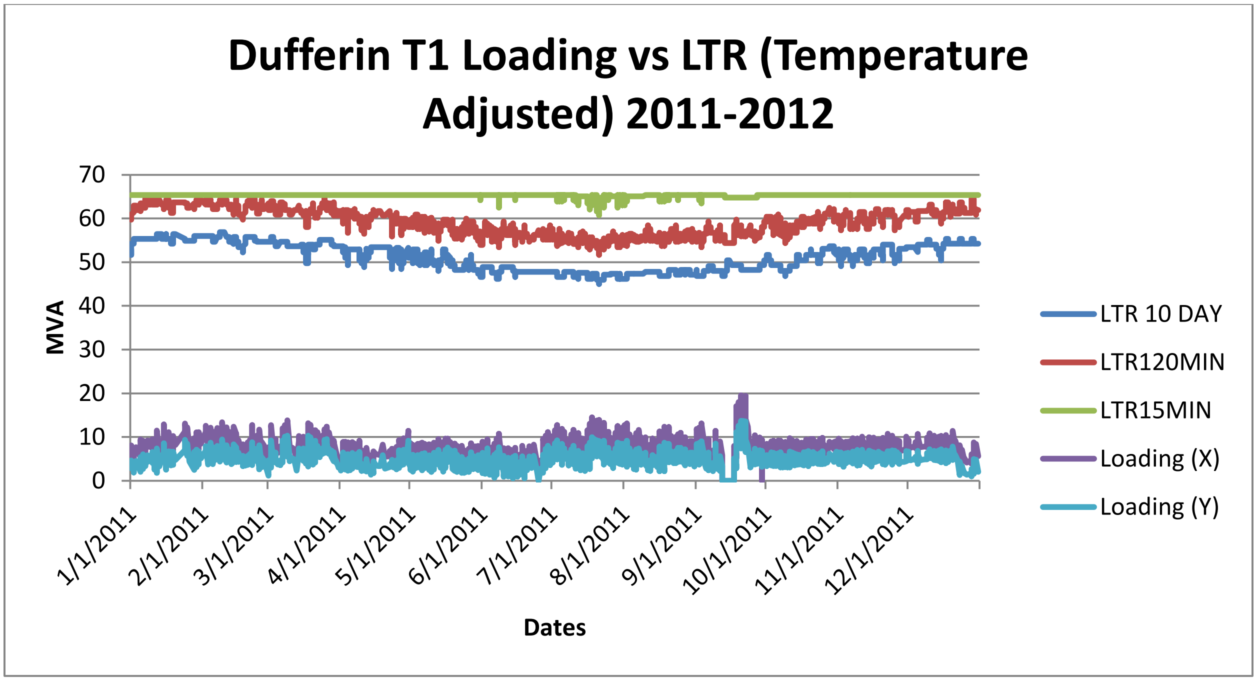
T1X:

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

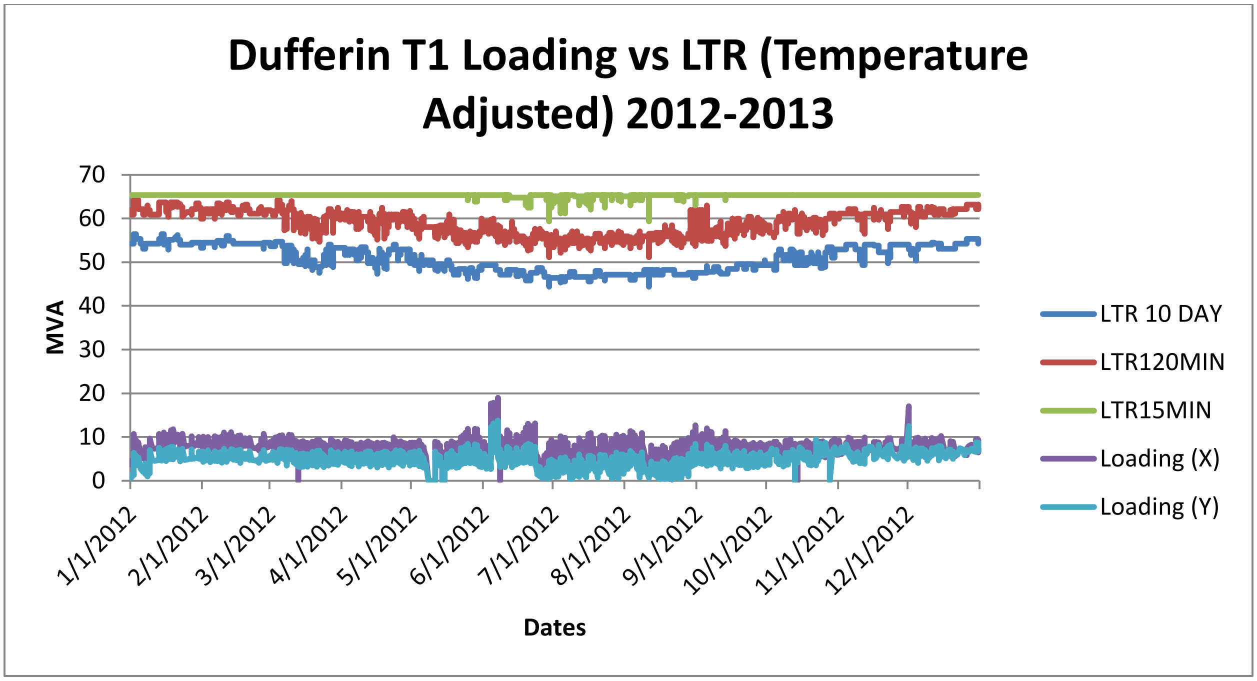
T1Y:

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

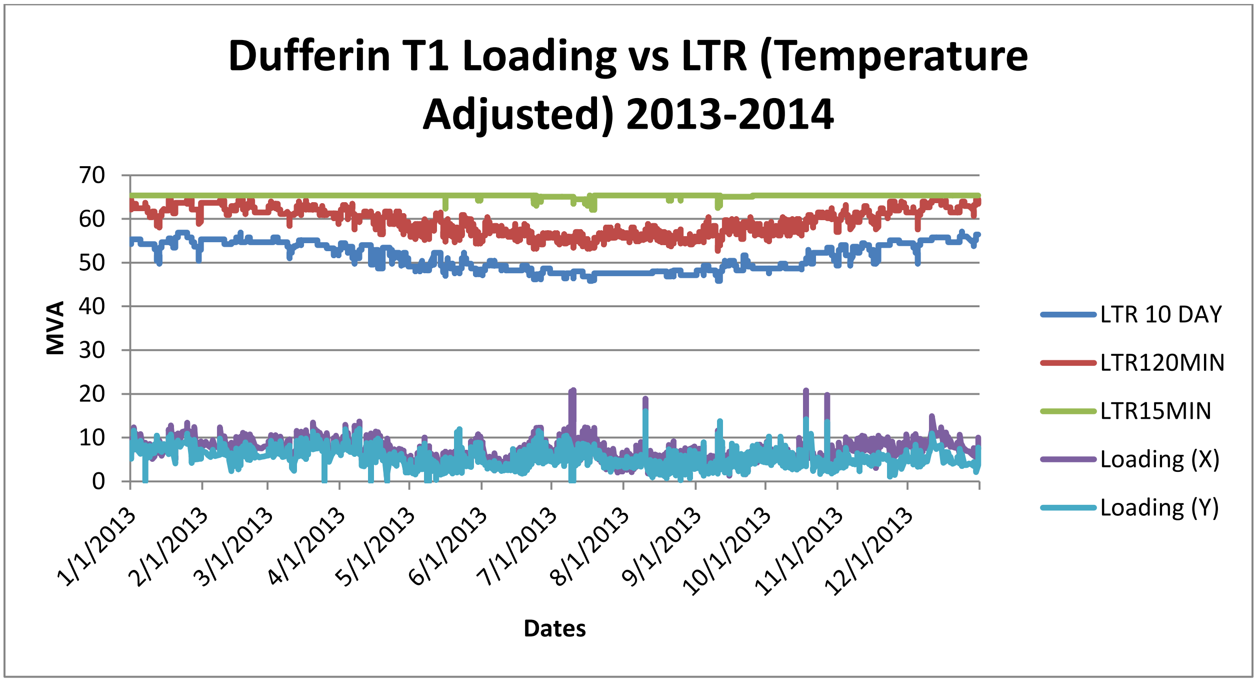
Dufferin T1's loading was reviewed with respect to its temperature adjusted LTR from 2011 -2015. It is observed T1's loading is positioned well below various loading limits. Loading surges were observed in occasionally but within acceptable limits.



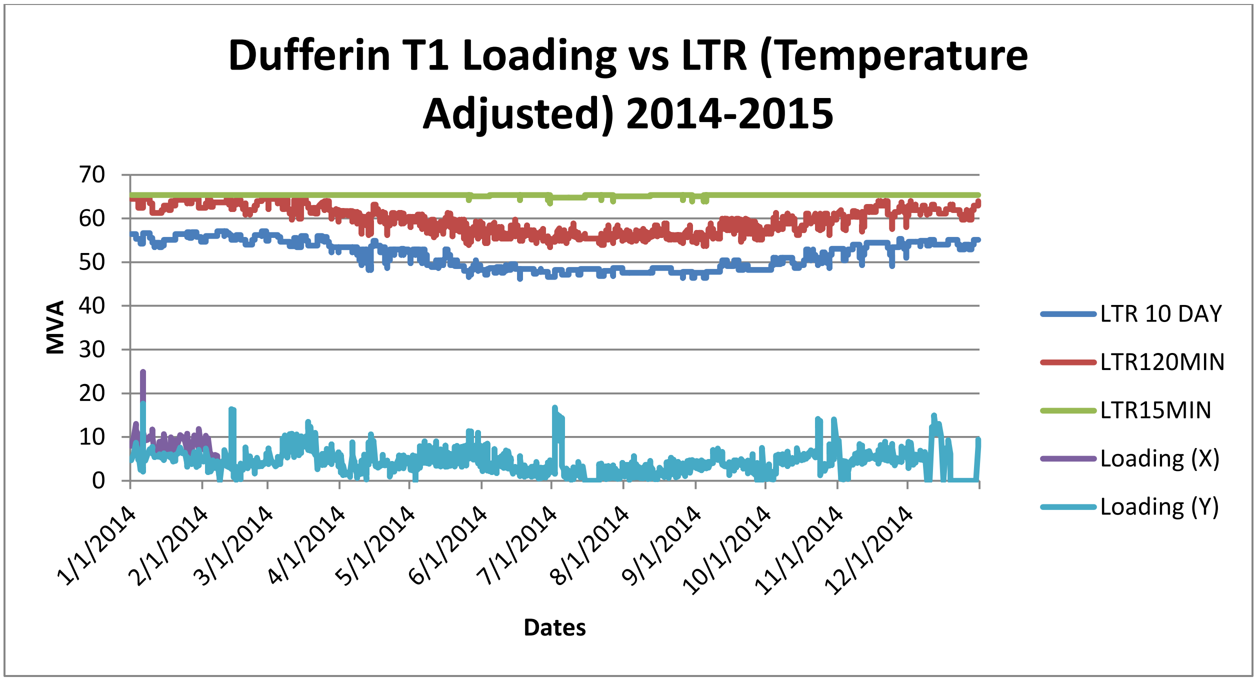
Graph 1: Dufferin T1Loading vs LTR (Temperature Adjusted) 2011-2012



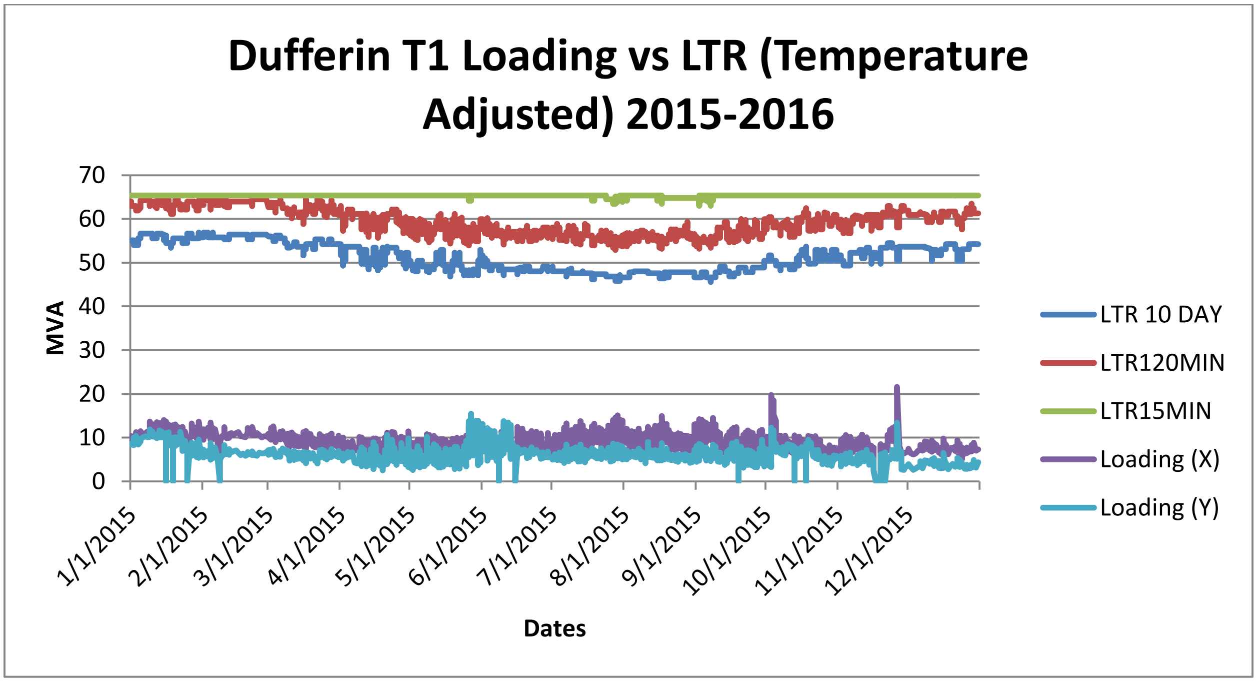
Graph 2: Dufferin T1 Loading vs LTR (Temperature Adjusted) 2012-2013



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:

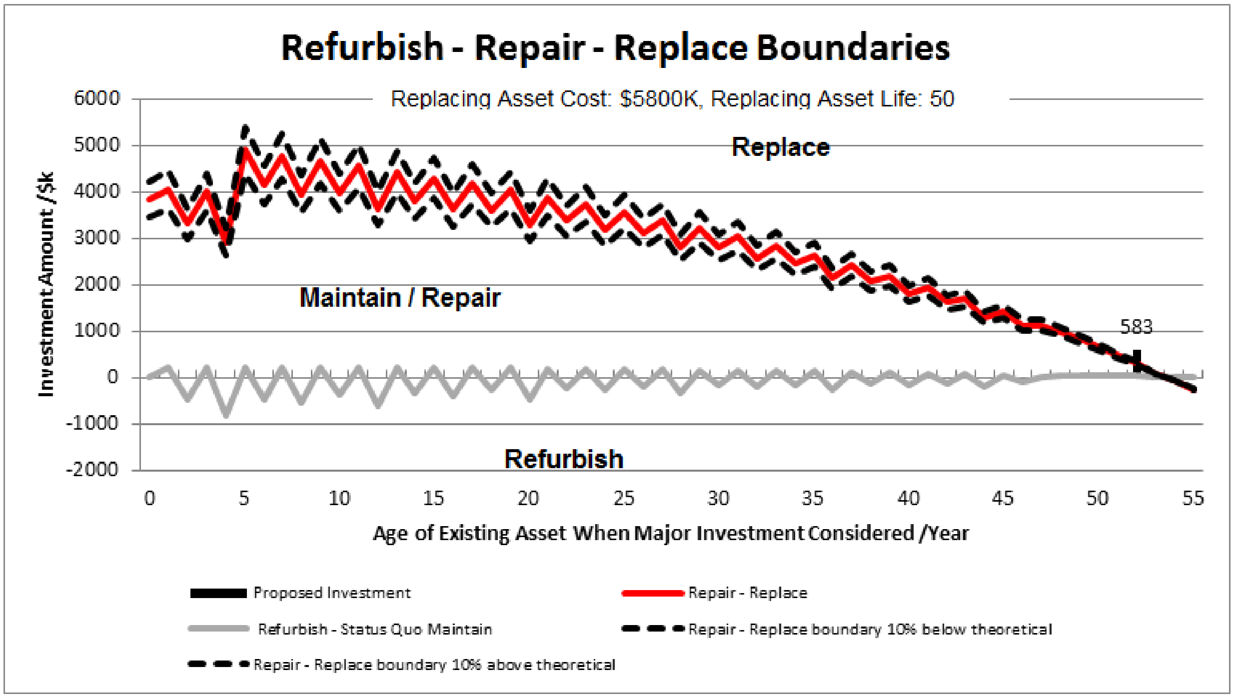
- Study period : 55 years[3]
- T1 will undergo refurbishment/ repair at 52 year old (2016), at approx. CAD$583.8k[4].
- Replacement cost is assumed to be CAD$5.8M[5] for a unit that matches purchasing standard S115-101
- The new unit will benefit from lower OM&A cost because it will be equipped with 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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TABLE OF CONTENTS

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.

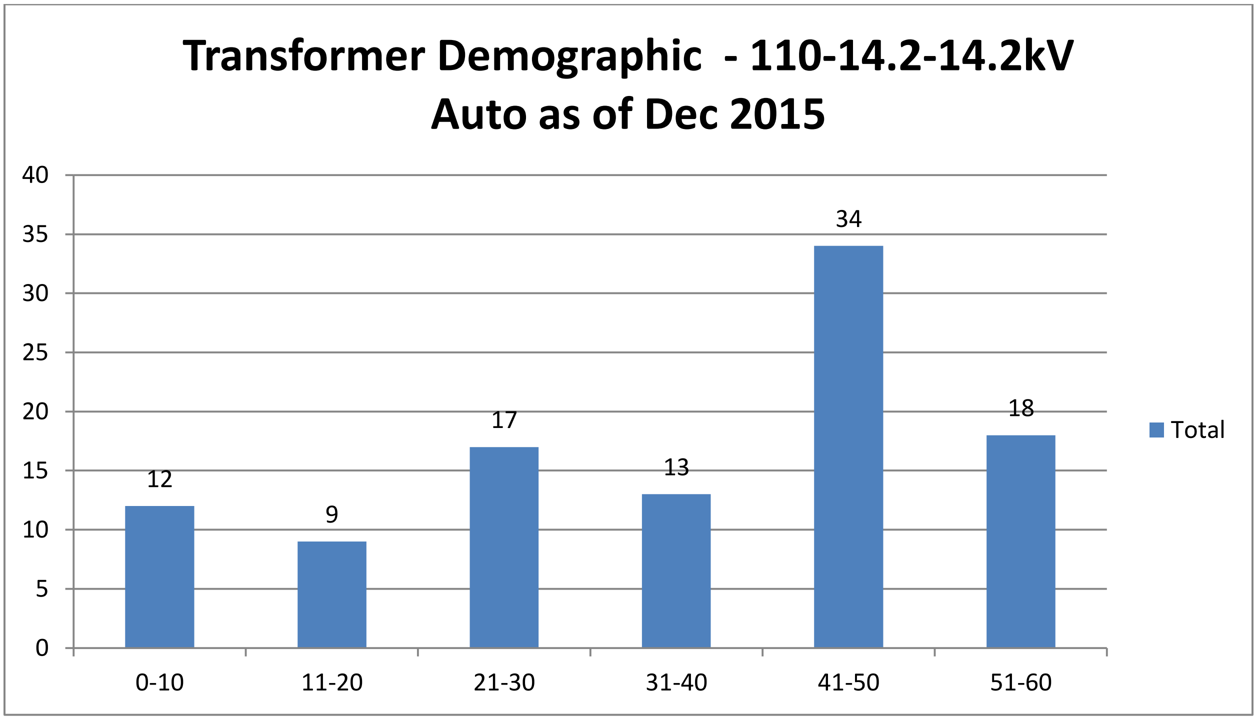


Chart 1 : Transformer Demographic - 110-14.2-14.2 kV Step down Transformer as of Dec 2015

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:

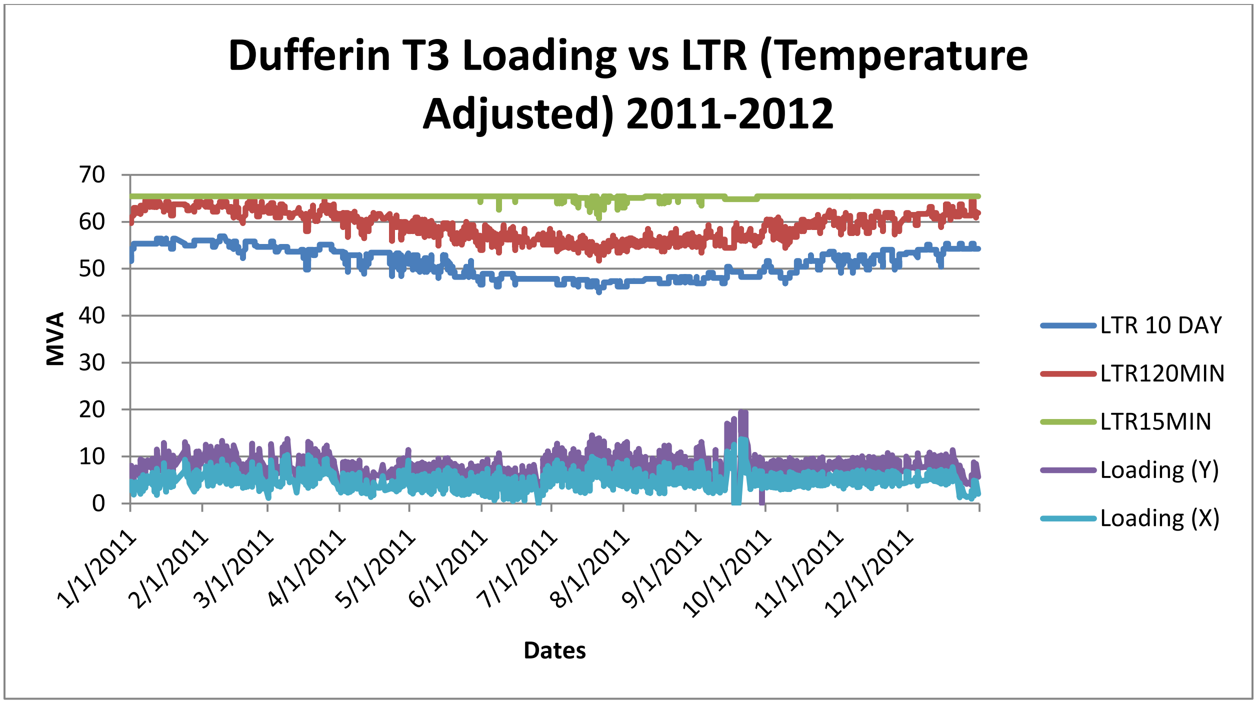
T3X:

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

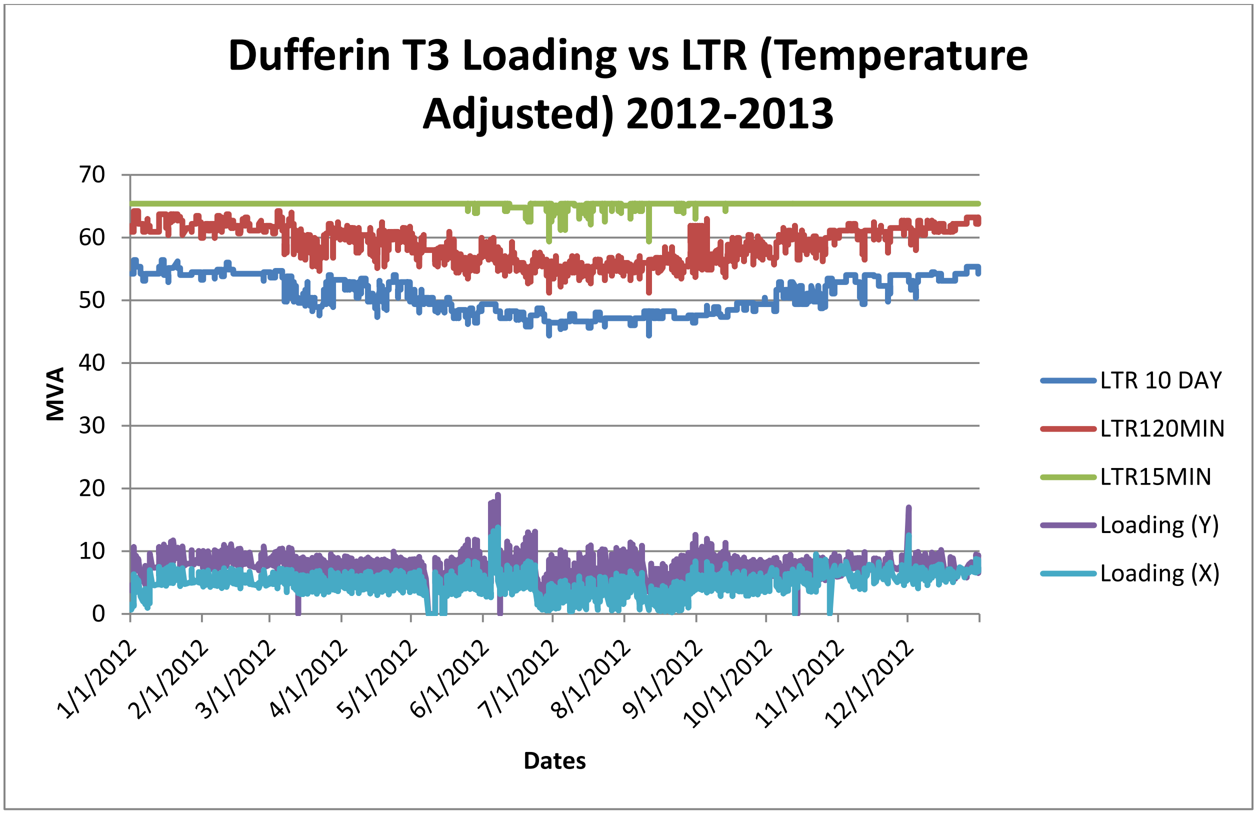
T3Y:

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

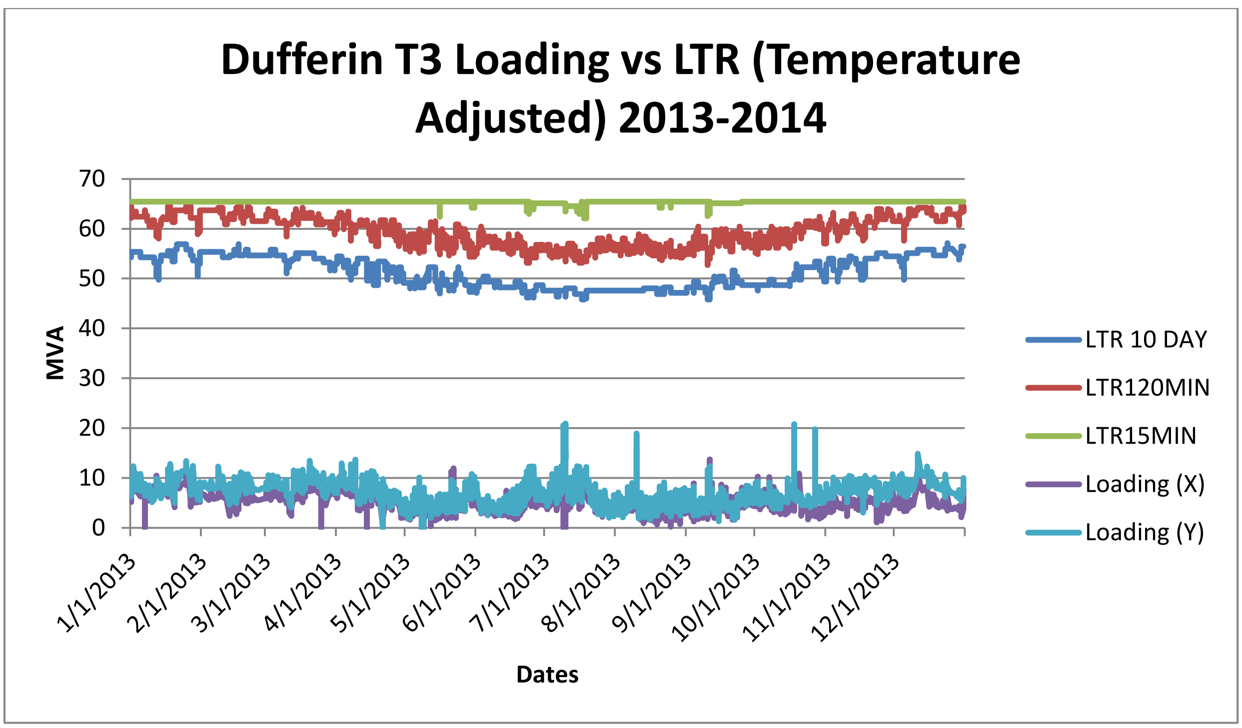
Dufferin T3's loading was reviewed with respect to its temperature adjusted LTR from 2011 -2015. It is observed T3's loading is positioned well below various loading limits. Loading surges were observed in occasionally but within acceptable limits.



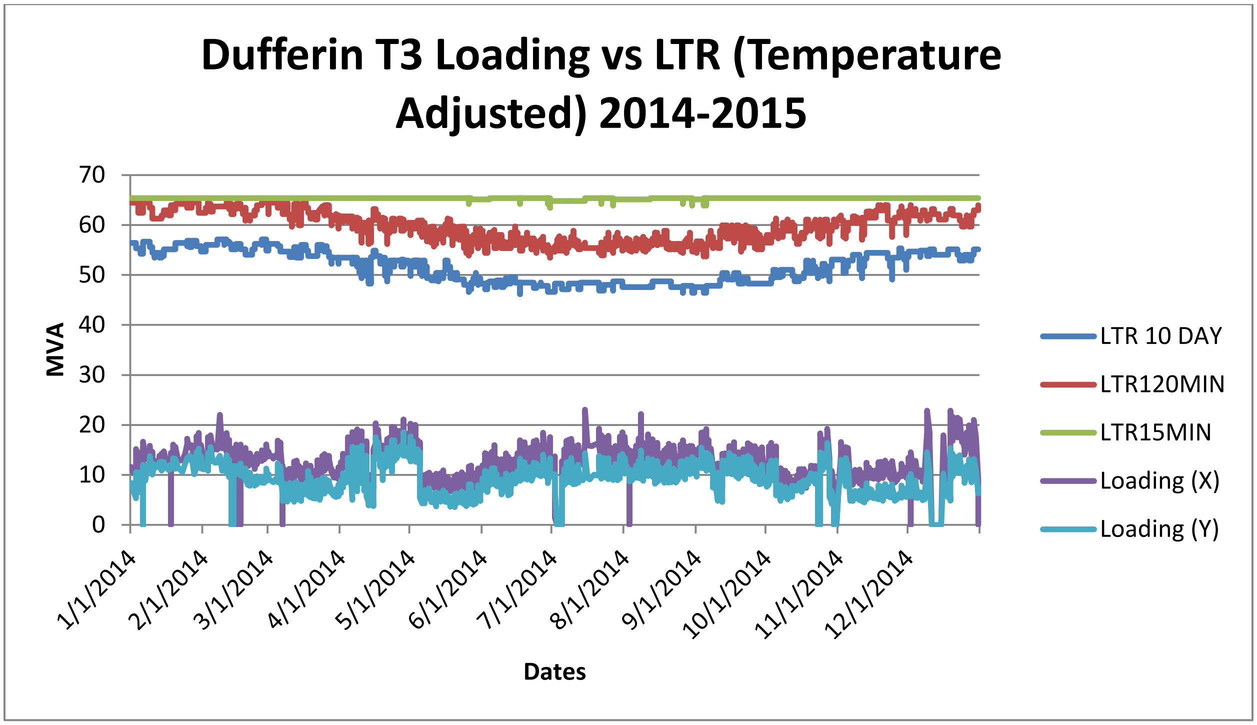
Graph 1: Dufferin T3Loading vs LTR (Temperature Adjusted) 2011-2012



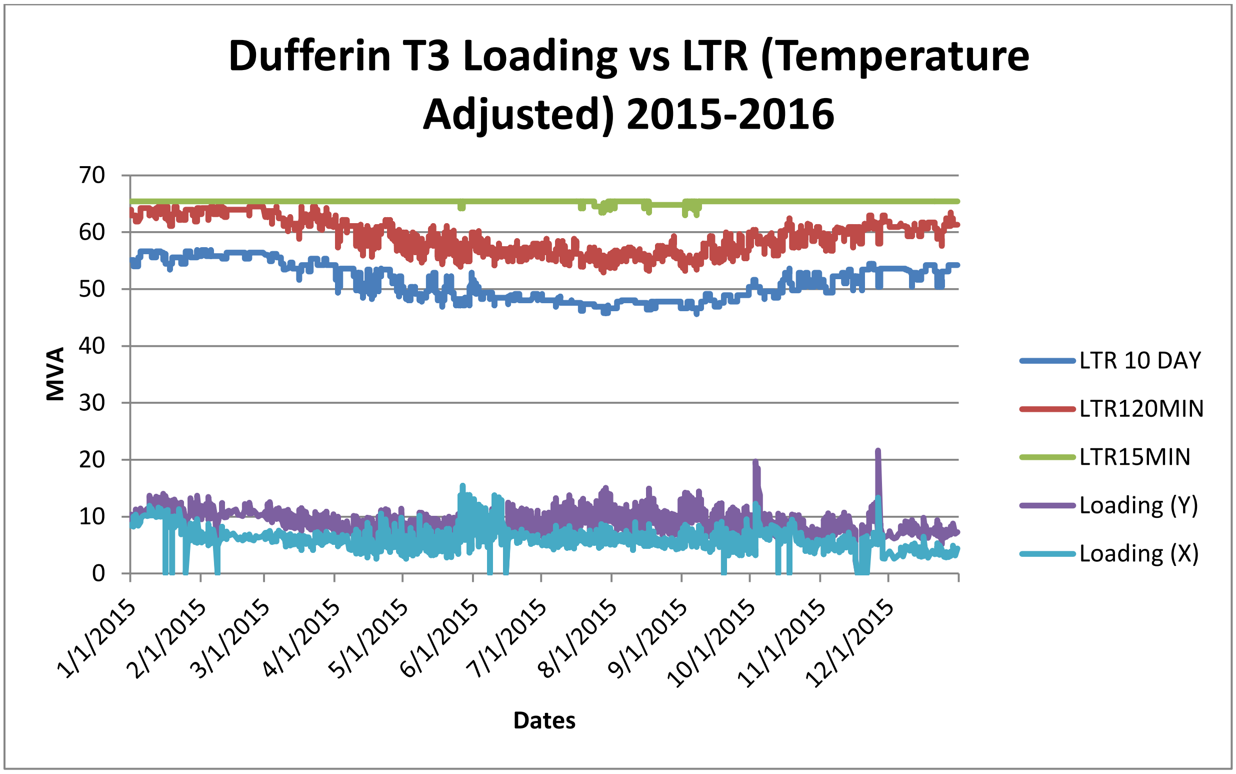
Graph 2: Dufferin T3 Loading vs LTR (Temperature Adjusted) 2012-2013



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:

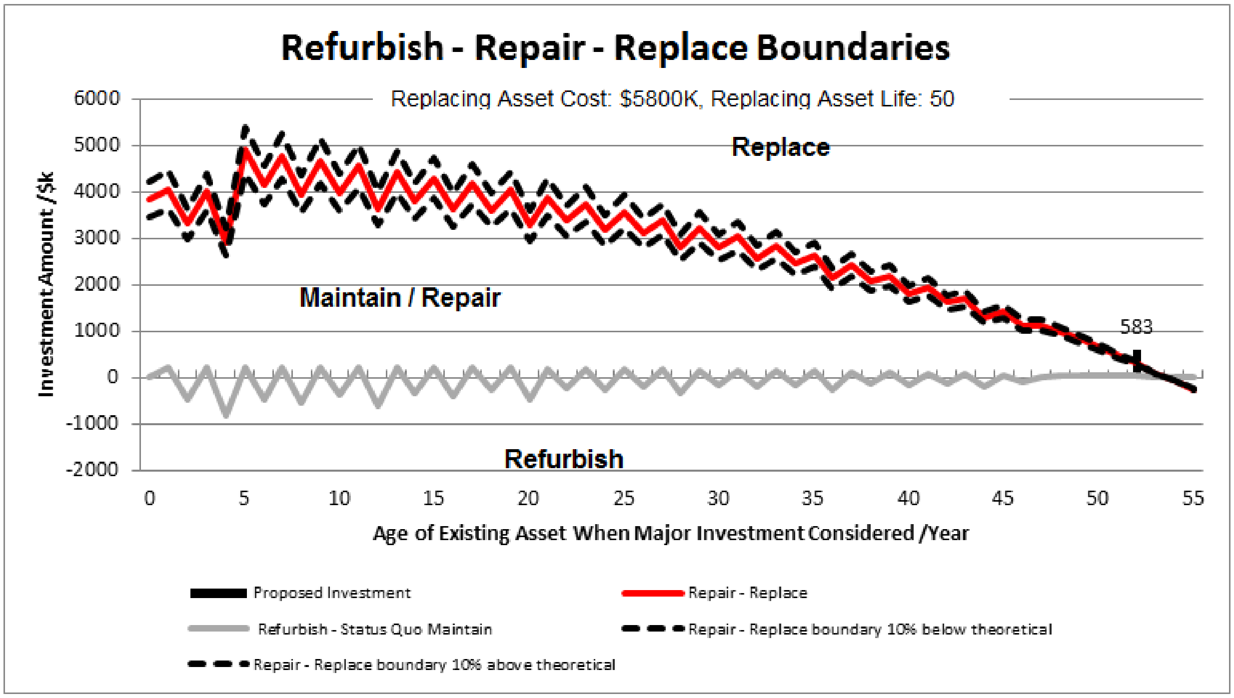
- Study period : 55 years[4]
- T3 will undergo refurbishment/ repair at 52 year old (2016), at approx. CAD$583.8k[5].
- Replacement cost is assumed to be CAD$5.8M[6] for a unit that matches purchasing standard S115-101
- The new unit will benefit from lower OM&A cost because it will be equipped with 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

[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
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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.

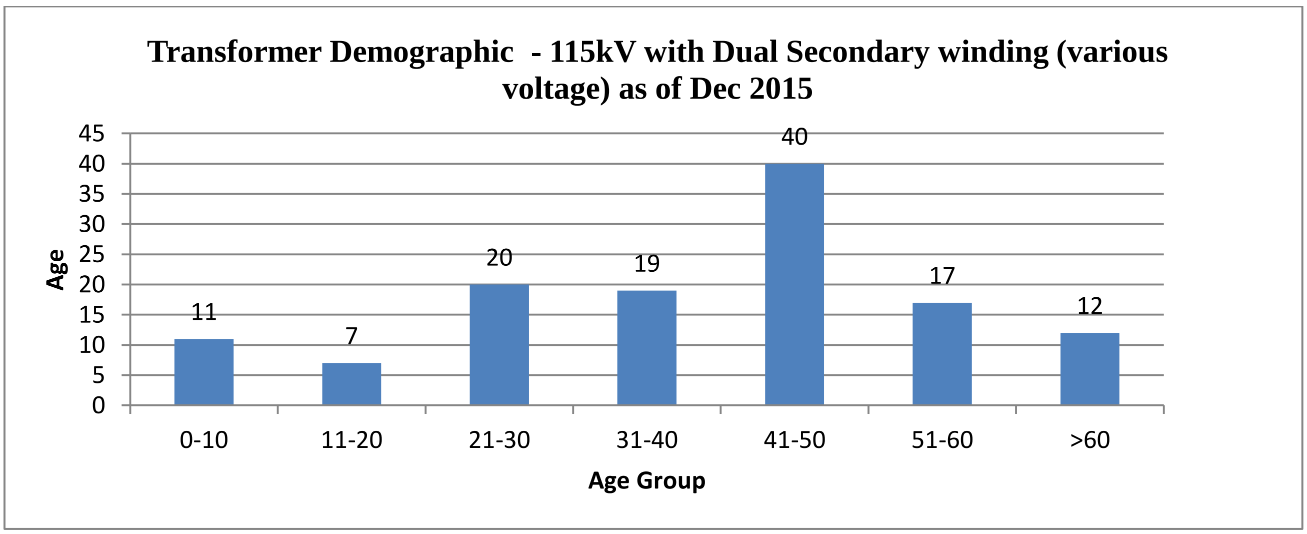


Chart 1: Transformer Demographic - 115kV with Dual Secondary winding (various voltage) as of Dec 2015

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.

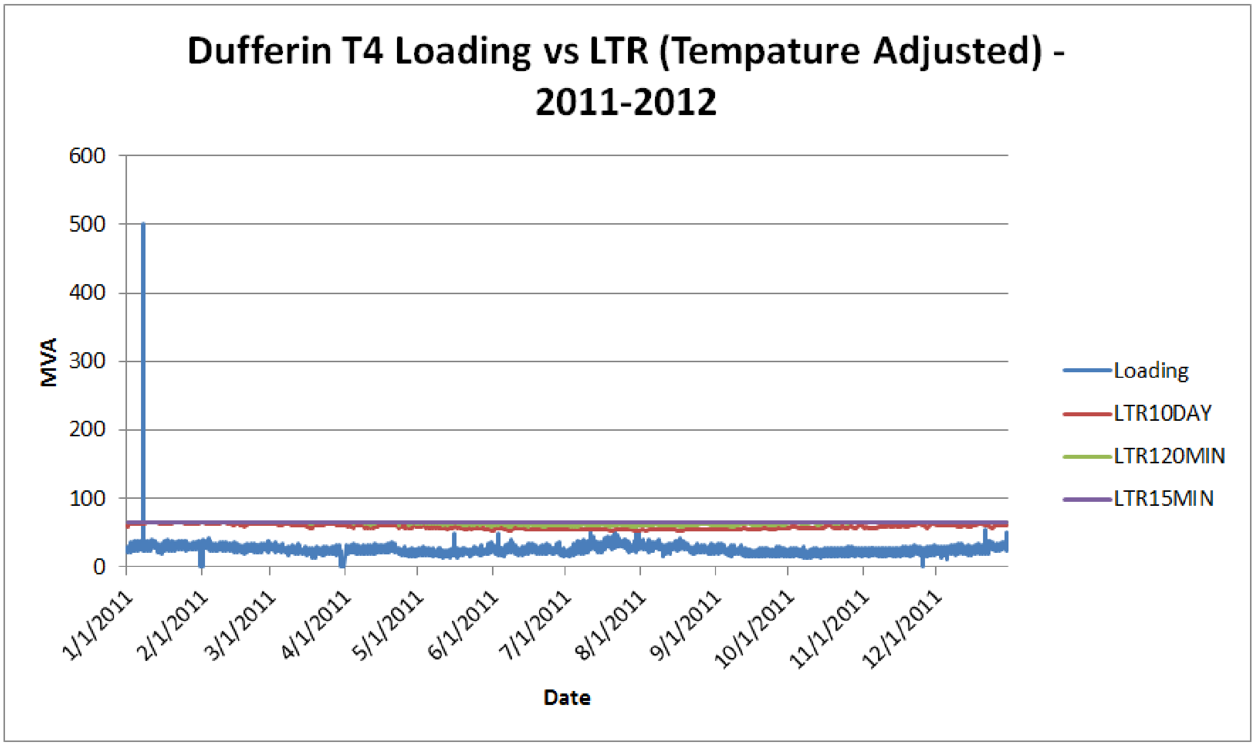


Chart 2 : Dufferin T4 loading vs Temperature Adjusted LTR – 2011

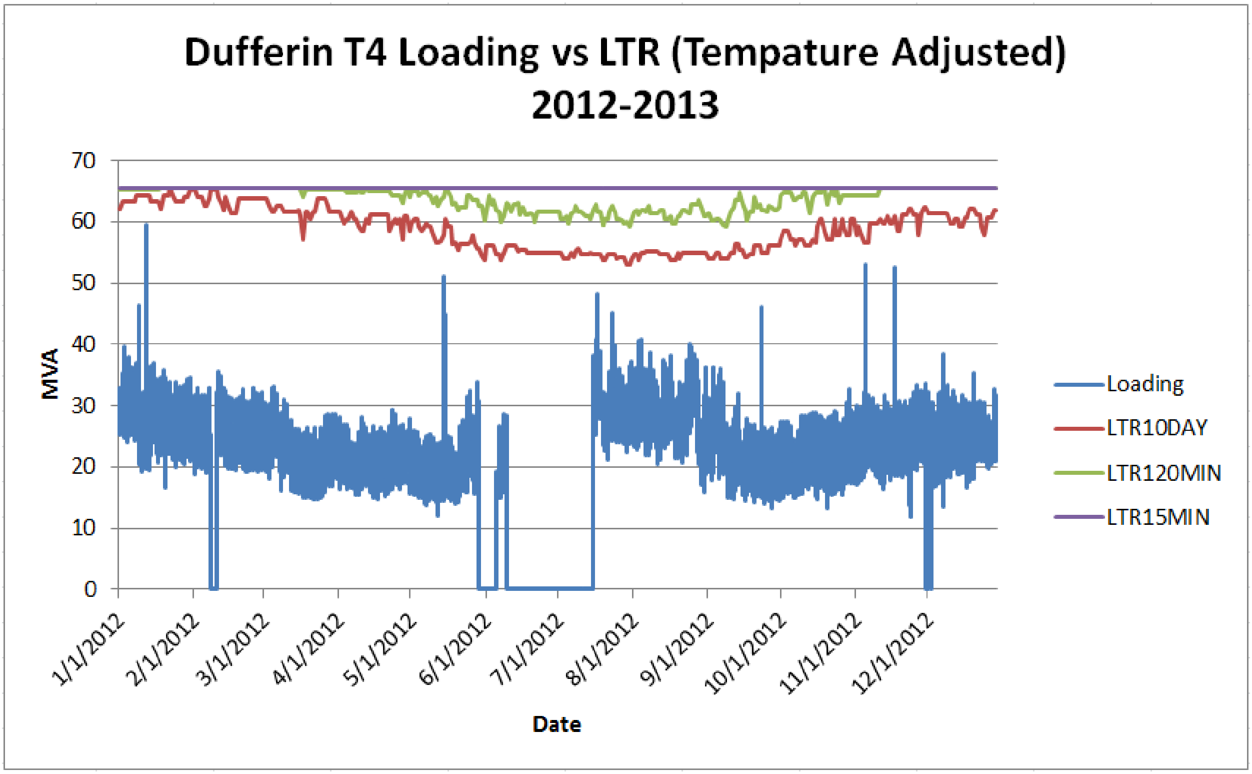


Chart 3 : Dufferin T4 loading vs Temperature Adjusted LTR – 2012

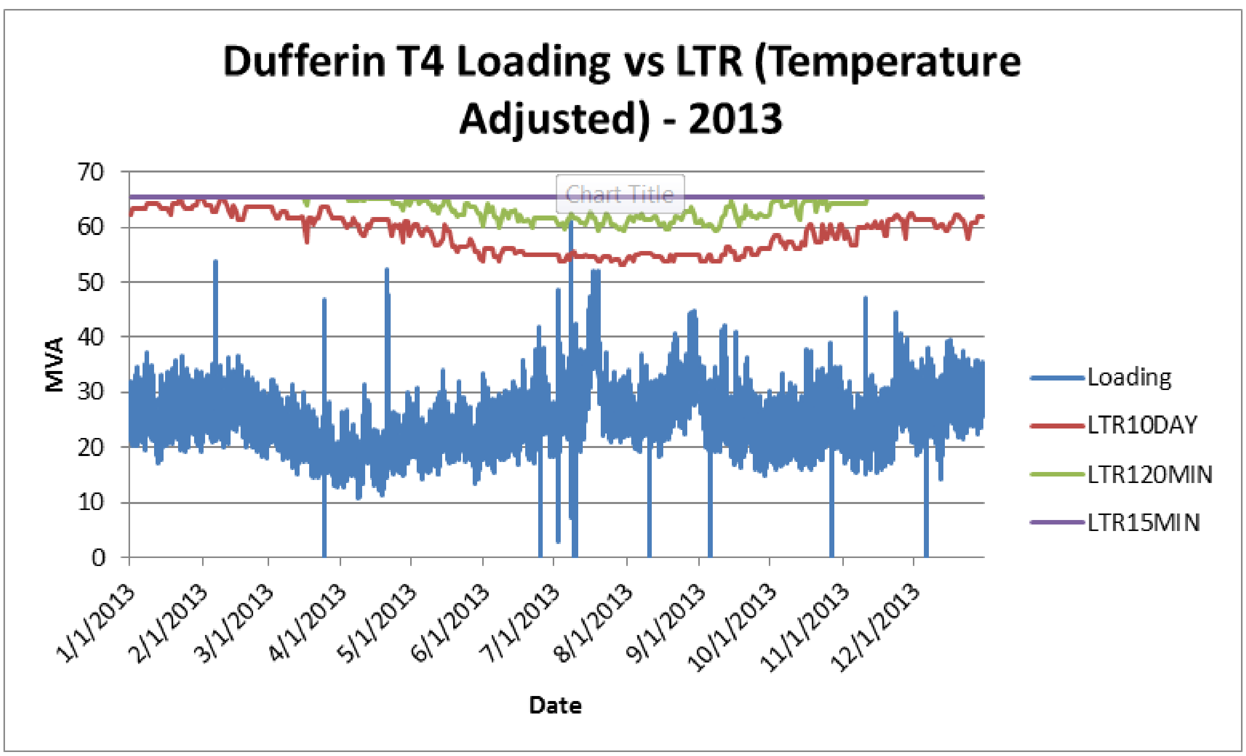


Chart 4 : Dufferin T4 loading vs Temperature Adjusted LTR – 2013

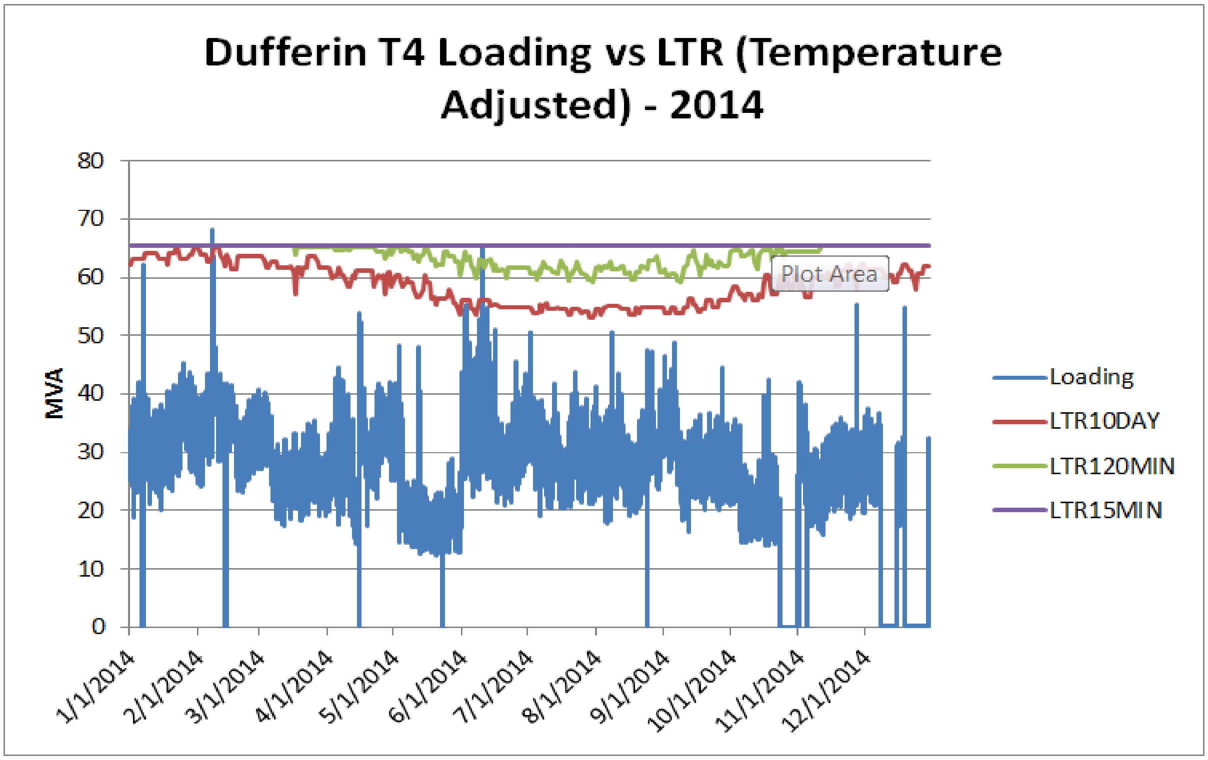


Chart 5 : Dufferin T4 loading vs Temperature Adjusted LTR – 2014

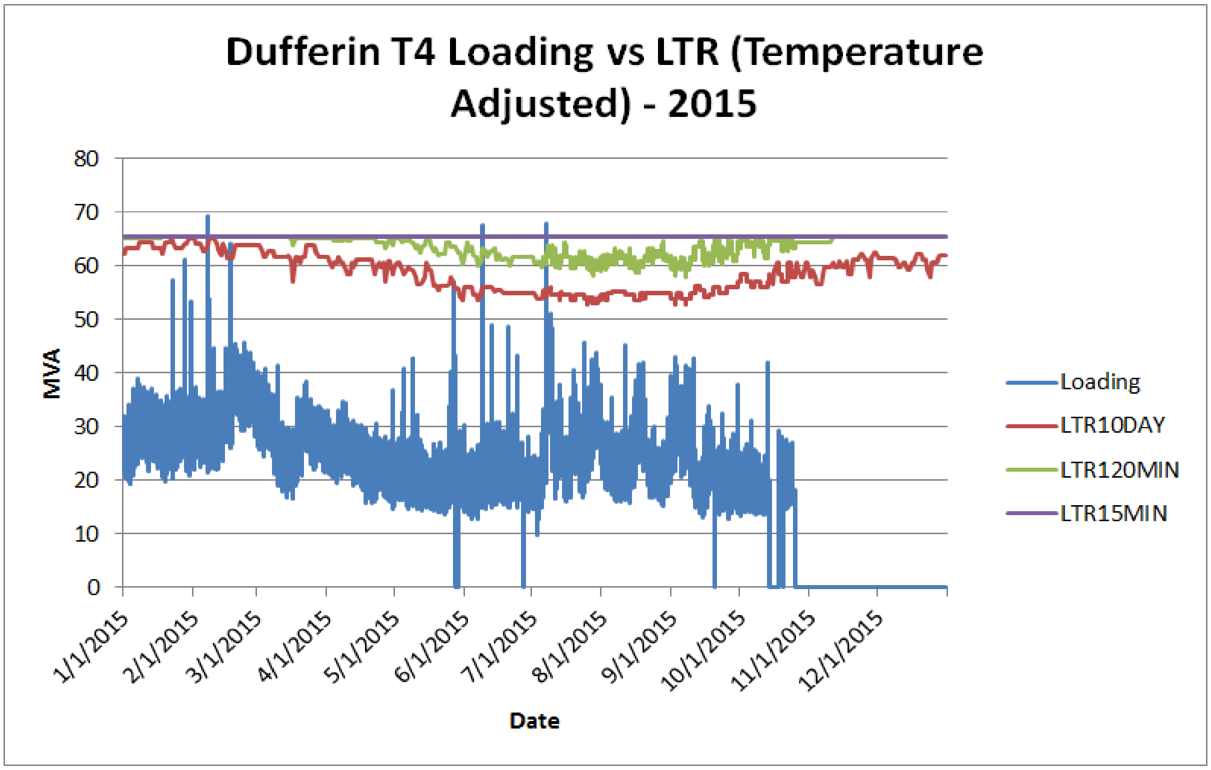


Chart 6 : Dufferin T4 loading vs Temperature Adjusted LTR – 2014

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.

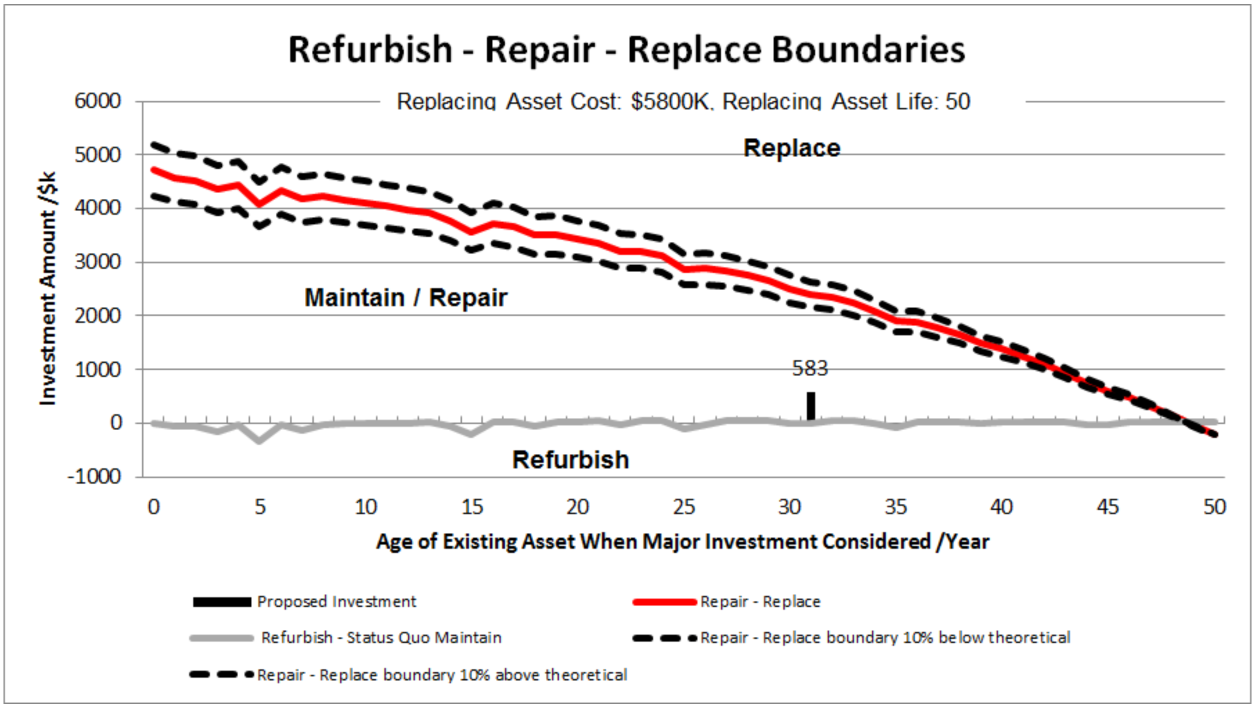


Chart 7 : Visual representation of NPV analysis

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	

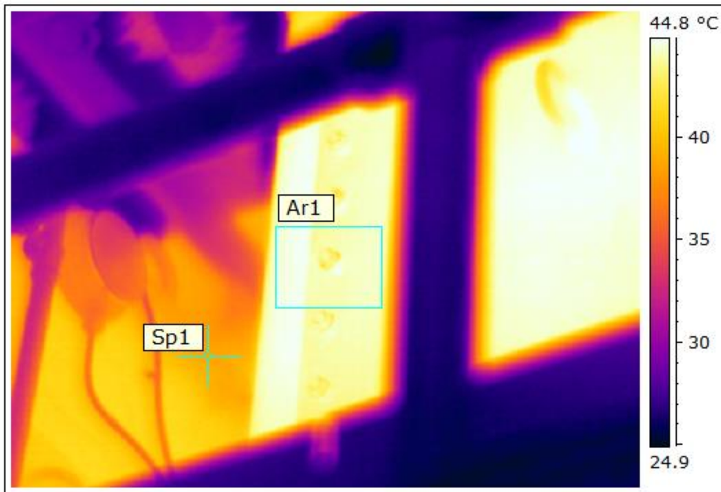
APPENDIX 2 – LIST OF DR AND TC NOTIFICATION

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

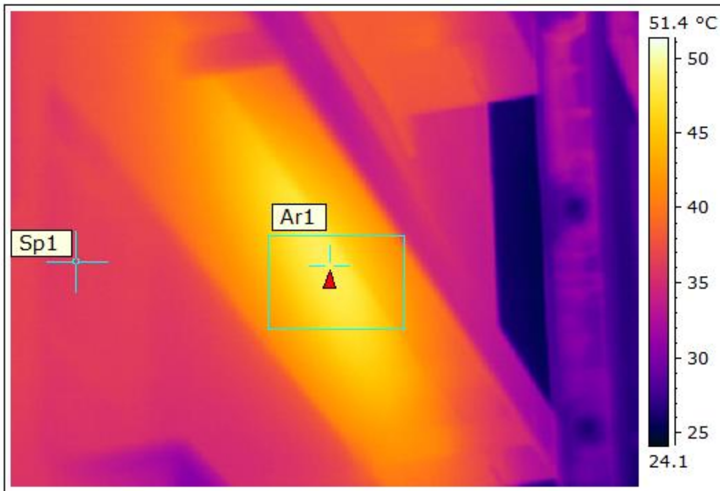


Ar1 Max. Temperature	44.8 °C
Sp1 Temperature	38.9 °C

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**

INTERNAL AUDIT REPORT

INVESTMENT PLANNING

To:

Mike Penstone
Vice President, Planning

Distribution:

Carm Marcello	President and Chief Executive Officer
Sandy Struthers	Chief Operating Officer & EVP Strategic Planning
Ali Suleman	Acting Chief Financial Officer
Paul Brown	Director, Distribution Asset Management
Randy Church	Director, Network Connections & Development
Kathleen McCorriston	Manager, Investment Planning and Prioritization
Scott McLachlan	Director, Transmission Asset Management
Bing Young	Director, System Planning
Brad Bowness	Director, Project Management, E&CS
Mike Boland	Director, Station Services, Stations & Operating

Final Report Issued: January, 30, 2015　　Auditor: Atul A. Solanki
Draft Report Issued: December 31, 2014
Report Number: 2014-29

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GLOSSARY:

AA	Asset Analytics – A support tool that focuses on asset risk prioritization to enable planners to make optimal asset decisions at any point in time (30+ year timeline)
AIP	Asset Investment Planning – A support tool that evaluates investment alternatives based on corporate risks and financial objectives to produce an optimized investment plan
BCS	Business Case Summary (used for Project approval)
BPC	Business Planning and Consolidation – A support tool that delivers an integrated financial model to support business planning, budgeting, and forecasting
BV	Business Values – These are the values that enable the achievement of the Company's strategic goals by forming the criteria against which investments are developed, risks are managed, and trade-offs are facilitated between investments.
IPP	Investment Plan Proposal – The output of the prioritization process that feeds into the Corporate Business Plan
OAR	Organizational Authority Register
PN	Potential Need notification (as documented in SAP against a specific asset)
SICA	Station Investment Capital Approval (used for "station centric" bundled program approval)
UPC	Unit Price Catalogue / Unit Price Cost

EXECUTIVE SUMMARY

Hydro One has adopted an Asset Management model since its inception to separate accountability for asset and system investment decision making from the execution of work. The Planning Organization is accountable to produce an annual Investment Plan Proposal (IPP) detailing investments (and resulting work) required to develop and sustain asset and system capabilities over the next five years. The IPP is a major input to the Hydro One's Corporate Business Plan that is approved annually by its Board of Directors. The IPP also forms a basis for the Transmission and Distribution rate filing with the Ontario Energy Board. The IPP is put together based on the results of customer, asset and system need evaluation using criticality, performance, and condition as key factors. The plan goes through a risk-based optimization to ensure the maximization of corporate business values[1] (such as safety, reliability, customer satisfaction, shareholder value, etc.). The plan is further adjusted by Management to ensure that it is executable, meets financial objectives, and reduces plan risks to an acceptable level.

We are pleased to observe that the Planning organization is able to deliver an annual IPP on schedule. The introduction of support tools such as Asset Analytics (AA) and Asset Investment Planning (AIP) has resulted in timely availability of asset information for analysis as well as optimization of investment selection based on specified constraints. The Planning organization has a good mix of experienced and new planners, as well as managers, who bring varied perspectives. A recent move towards "station centric" sustainment investment planning is expected to improve planning and execution efficiencies. However, several key challenges remain to consistently determine, develop, optimize and release investments required to meet customer, asset and system needs.

Based on the specific areas reviewed, we conclude that controls are often ineffective and significant improvements are needed to ensure that a consistent investment planning process is used to produce a risk-based Investment Plan Proposal to address customer, asset and system needs.

Our conclusion is based on the following key observations:
- Ineffective governance and controls over the investment planning end-to-end process.
- Inconsistent identification, assessment, prioritization and action on asset and system needs.
- Lack of risk-based alternatives with a thorough cost-benefit analysis for most plans.
- Inefficient investment plan prioritization process that is not well-understood by the planners and service providers.
- Lengthy approval process that delays release of major investments.

Action plans have been developed by management to address the areas noted above and are summarized in the Summary of Actions (Appendix H). We would like to thank the management and staff in Planning, Engineering & Construction, and Stations for their assistance and open discussions during this review.

Atul A. Solanki, Audit Associate

[1] "Corporate business values" is the term used in the Asset Investment Planning (AIP) optimization process. These are actually the Corporate Strategic Objectives.

OBSERVATIONS AND RECOMMENDATIONS

The Investment Planning audit focused on the following five areas:

1. Effective governance structure and control environment over the "end-to-end" Investment Planning process
2. Appropriate identification and assessment of customer, asset and system needs requiring investment
3. Development of risk-based investment alternatives to meet the identified needs
4. Optimization of investment plans selecting alternatives that maximize corporate business values.
5. Timely release of sufficiently detailed investment plans for execution by the Service Providers.

A sample of 16 investments from the 2015-2019 Investment Plan Proposal (IPP) were selected for review during this audit.

The following are our observations and recommendations related to the above five areas.

1. Ineffective governance and controls

Background:

An effective governance structure and adequate control activities are a must for an organization to achieve its stated objectives while managing the risks it faces to a level that it is willing to accept. The governance and controls set the tone at the top regarding management's expectation of how its business activities are to be performed and an expected standard of conduct for the employees performing those activities. Management sets the control environment by developing, reviewing, approving and communicating appropriate policies, standards, processes, procedures and guidelines in sufficient details. Management ensures that appropriately qualified and trained employees are equipped with adequate tools to perform the tasks assigned to them. An effective governance structure and control environment also requires that adequate supervision, monitoring and quality assurance are in place to meet the organization's key deliverables.

Observations:

We are pleased to observe the following:

1.1 The Planning organization has been developed and released an increasing work program in recent years with a largest work program release of $2.8 billion (gross) for 2015. The 2015-2019 IPP was approved as part of the Hydro One Business Plan at the November 2014 Board meeting.

1.2 A recent reorganization combining the asset management and system development divisions into a single business unit has resulted in a management team of varied experience and background.

1.3 Monthly management reports are being put together to communicate work progress in each department and division.

1.4 An Approvals, Customers, Estimates, and Releases (ACER) review process has been put in place where executive, director and manager level monthly reviews occur between planning and executing lines of businesses to discuss and resolve issues related to large and complex plans (>$1 Million and/or customer impact) prior to their full release.

1.5 The majority of planners are experienced and knowledgeable about the customer, asset and system needs. In most cases, junior planners are teamed with senior planners for mentoring and knowledge transfer. The planners have tools such as Asset Analytics (AA), Asset Investment Planning (AIP), SAP and other databases to perform their assigned tasks.

1.6 AIP training is provided prior to start of the annual investment planning cycle. Detailed PowerPoint training presentations and job aids are posted on the SharePoint site.

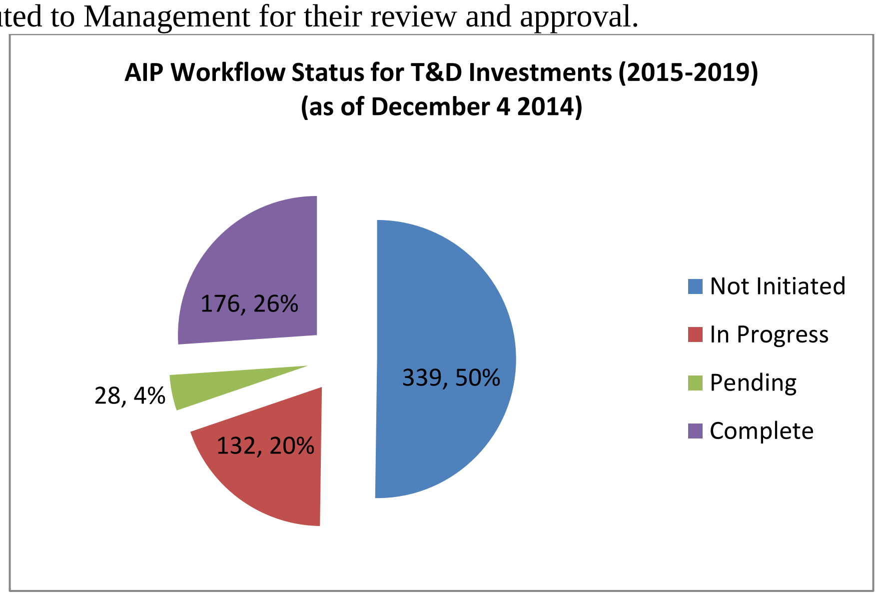
We also observed the following opportunities for improving controls:

1.7 There has been no recent and formal business risk assessment of the overall Planning business unit's objectives completed as per the Enterprise Risk Management Policy (SP0736).

1.8 Approximately 44 approved policies and directives are in place for planning and asset management. However, most of these documents are over 3 years old and do not have a review date. It is unclear if these policies are being followed by the planners as there were no references to any of these policies in the 16 investment planning documents that were reviewed during this audit. A key policy titled "*Asset Investment Planning Risk Assessment Corporate Operational Policy*" was developed in 2013 but was never approved by Management.

1.9 Approximately 363 business process models related to managing asset information and investments are documented in the ARIS Business Process modelling and management software, which is the official source of record for Hydro One business processes. The majority of these were developed during Cornerstone Phase 1 and 2 and have never been incorporated in the Hydro One Business Process Modelling Notation (H-BPMN). Only 42 process models have been mapped to process area "*01.02 Manage Asset Investments*" and "*01.03 Manage Asset Information*", which are the focus of this audit. Most of these process models are in "draft" form, have references to outdated process steps and work groups and have missing integration points with other business processes. Most planners are not aware of these process models and seldom follow them. Some departments have simplified versions of these processes in PowerPoint format for training and discussion purposes. Process clarification and guidelines are often communicated via e-mail or in training presentations.

1.10 There is no formally documented Quality Assurance process with related measures to assess the effectiveness of the "end-to-end" planning process. The "Investment Approval Process" within the training presentation indicated that all Investment plans (or ISR) prepared by an Investment Owner (Planner) were to be sent to the Driver Owner (Manager) for review and approval. All programs greater than $15M and all projects > $10M required additional review and approval by the Portfolio Owner (Director). These reviews and approvals were to occur through AIP workflows. The following is a summary of the AIP Workflow status for T&D investments where the Investment Summary Report (ISR) produced for each investment plan was to be routed to Management for their review and approval.



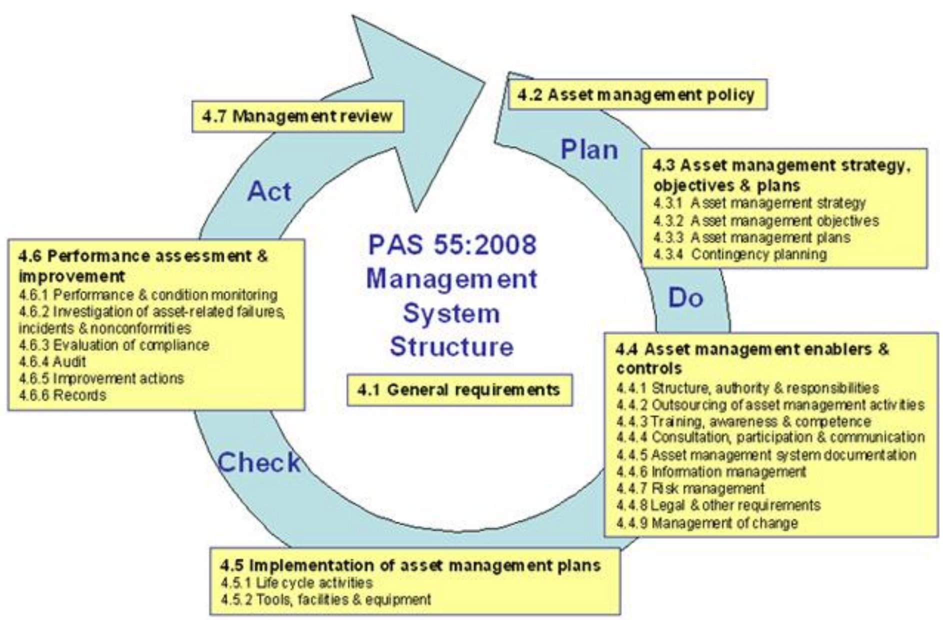
The above results show that half of the investments were never sent by planners to Management for review and approval. About 20% were sent for approval but were neither approved nor rejected by Management. Only the remaining 30% of the plans were either formally approved or rejected. Management has indicated that verbal reviews and approval did occur for all investments but the statuses were not updated in AIP due to time constraints. It was not possible to validate the quality of management reviews in the absence of appropriate documentation.

1.11 There is a lack of a clearly defined process and guidelines for the level of input to be sought by the planners and to be provided by the service providers during the investment plan development. For some plans, service provider input is only sought after an Investment Plan Proposal (IPP) has been put together. For other plans, service provider input is sought and incorporated during the early stages of plan development. Service providers have indicated a preference to be involved as early as possible during the plan development but this could lead to plans being influenced by the service providers' capability to execute rather than risk based customer, asset and system needs.

1.12 There is no formal training for the overall "end to end" planning process. However, there is informal training on use of tools. None of the training is tracked and refreshed as the process and tools evolve.

1.13 There is no formal lessons learned documentation for continuous process improvement. A Lessons Learned presentation was put together for discussion following completion of the 2013 planning cycle. However, it is unclear if any of these lessons were incorporated in the process that was followed during 2014 planning cycle.

1.14 At a high-level, the overall Investment planning process does seem to be aligned with the PAS55:2008 specification for the optimized management of physical assets with its "plan, do, check and act" phases as detailed below. However, significant opportunities exist to define an appropriate asset management strategy & objectives, implement appropriate enablers and controls, monitor performance and practice continuous improvement.



Source: Key Features of PAS55:2008, http://pas55.net/features.asp

Risks: R

- Lack of well-defined, communicated and understood policies, standards, processes, procedures and guidelines could lead to inconsistent decision making leading to poorly defined investment plans that are unable to adequately address the asset and system risks and needs.
- Inadequate specification of accountabilities, training and suitable tools would lead to staff performing their assigned duties on a best effort basis leading to poor quality output and resulting rework.
- Insufficient monitoring of process effectiveness and quality assurance of process outputs would lead to an increased risk of errors and degradation of output quality.
- Lack of continuous improvement through lessons learned would lead to inefficient processes that will have a lower chance of being adopted by the users.

Recommendations:
We recommend that Management:

1.1 Perform a formal risk assessment as per ERM Policy (SP0736) on an annual basis to ensure that business risks facing the planning organization are identified and mitigating actions are developed and tracked. (related to Observation 1.7)

1.2 Develop, review and approve sufficiently detailed policies, standards, procedures and guidelines to ensure a consistent risk-based approach to planning and decision making. This would require a review of the existing governance documents and ARIS process models for their accuracy and validity. Management has informed us that a Policy Review project is currently underway to consolidate policy and directive documents. (related to Observations 1.8 and 1.9)

1.3 Clarify the timing and level of input to be sought by the planners from the service providers as they develop their plans. (related to Observation 1.11)

1.4 Implement a formalized Quality Assurance process and related performance measures to assess the effectiveness of the end-to-end planning process. This would include quality expectations for plans being prepared by the planners and the quality of reviews and feedback being given by management prior to approving those plans. (related to Observation 1.10)

1.5 Formalize and track all process and tool related training being given to planners in their Learning Management System. Establish refresher training requirements whenever there are significant changes in process and tools. (related to Observation 1.12)

1.6 Document and communicate lessons learned after each planning cycle and use them for continuous improvement of the planning process. (related to Observation 1.13)

Management Response:
All recommendations have been agreed to by Mike Penstone, VP Planning. They are assigned for action as follows:

1.1 Randy Church, Director, Network Connections and Development
1.2 Luis Marti, Director, Reliability Studies, Strategies and Compliance
1.3 Kathleen McCorriston, Manager, AM Processes & Tools
1.4 Scott McLachlan, Director, Transmission Asset Management
1.5 Mike Penstone, VP Planning
1.6 Kathleen McCorriston, Manager, AM Processes & Tools

Proposed Action Plan: *(Accountable Manager, above in Management Response)*

1.1 Planning will work with ERM Group to conduct a risk workshop to identify risks in achieving the planning business objectives.

1.2 Conduct a review of processes, procedures, standards and guidelines to determine the need, effectiveness, currency and to ensure they are aligned with and support the Corporate Operational Policies. Establish a review cycle for these documents.

1.3 At the annual LOB kick off, AM Processes and Tools will identify and seek input from the service providers to obtain their feedback on ideal timing and level of input required. Planning will also be in attendance to ensure agreement and consistency in approach.

1.4 Quality expectations and the required metrics for the end-to-end process will be established and communicated by the Planning Organization.

1.5 The Planning Organization will assess all training requirements including the frequency of refresher training and mechanism for tracking training completion. We will develop an implementation plan that defines the accountabilities for creation and delivery of training material.

1.6 AM Processes & Tools will document and communicate lessons learned after the 2016-2020 planning cycle.

Completion Dates:

1.1 Q4, 2015
1.2 Q4, 2015
1.3 Q1, 2015
1.4 Q3, 2015
1.5 Q4, 2015
1.6 Q3, 2015

2. Inconsistent Customer, Asset & System Need Assessment

Background:

Hydro One's Transmission and Distribution (T&D) investment plans consist of four major categories of investments related to sustainment (maintain existing capability), development (add new capability to ensure secure and reliable supply), operation (operate and monitor assets and systems) and common corporate investments. For this audit, the focus was on T&D Station sustainment and development investments.

Key steps in investment planning process include:

i. the determination of investment needs from various stakeholders (including customers),
ii. collection and analysis of supporting data (e.g. asset data), and
iii. assessment of needs.

Sustainment investment needs are primarily identified using asset condition data collected during routine maintenance, inspections and testing, performance history, asset utilization, age, and criticality. Asset Analytics (AA) is a new tool available to planners to collect and analyze this data. An Overview of AA is provided in Appendix F. Development investment needs are primarily identified by system changes that include demand, performance, and configuration as well as changes to standards, codes and market rules. New customer connection requests as well as changes in Local Area Supplies and network transfer capabilities also result in development investment needs.

Both sustainment and development investment needs are assessed by focusing on mitigating risks associated with the likelihood and consequences of asset failures as well as maintaining T&D system performance and satisfying customer expectations.

Observations:
We are pleased to observe the following:

2.1 There has been a recent move towards "station centric" sustainment investments with a goal of bundling sustainment investments at a given transmission station every seven years.

2.2 The Potential Need (PN) notifications in SAP are being used by field staff to alert the planners of future asset sustainment needs. This requirement and related process is formally documented in HODS as "Potential Need (PN) Notification Administration Guide (SP1546)".

2.3 For transmission station refurbishment, a detailed "desk-side station assessment" listing all asset conditions and needs is being documented by the planner and discussed with the field staff.

We also observed the following opportunities for improving controls:

2.4 There is inconsistent documentation and tracking of asset and system needs for later follow-up. Most planners have their own spreadsheets in which they capture needs discovered during field visits, e-mail discussions with field service specialists or recommendations from maintenance technical services. Customer needs and manufacturers' recommendations are also tracked in various e-mails and documents. For most investments, there is no tie back of earlier identified needs to the investments being made. There is no consistent documentation showing which customer, asset and system needs were received, reviewed, accepted/rejected and actioned.

2.5 The PN Notification process outlined in SP1546 is not being consistently followed. In 2014, 307 PN notifications for TS assets were created and 273 (89%) of these have not yet been reviewed by the planners, while only 10 PN notifications were created for DS assets and none of them have been reviewed by the planners. According to the SP1546, "*Asset Management is responsible for assigning a PN notification to every planned replacement and refurbishment candidate in the current business plan*". There is no evidence to support that this has consistently occurred in 2014.

2.6 There is inconsistent use of AA data to assess individual asset needs. There are no documented procedures or guidelines on how to validate AA Risk Index data and translate them into asset needs. Most planners use the AA data as a starting point for further discussion with the service providers to confirm asset needs.

2.7 The AA data quality remains a concern. The quality of underlying data (accuracy, completeness and timely availability of recent data) being used from SAP and other databases for risk index calculations is unknown. It was noted that:

- Only 44% of DS and 51% of TS Supporting Factor data used for risk index calculation is considered "Normal". The remaining data are statistical calculations or default values.
- Percentage of assets with missing Asset Risk Index data (ARI = 0) is as follows:

AA Data Quality – Missing ARI						
ARI	**Condition**	**Demographics**	**Criticality**	**Economics**	**Utilization**	**Composite**
Distribution Station	54%	54%	10%	54%	70%	10%
Transmission	8%	8%	0%	7%	63%	0%

AA Data Quality – Missing ARI						
ARI	**Condition**	**Demographics**	**Criticality**	**Economics**	**Utilization**	**Composite**
Station						

- Gage TS, where major refurbishment is planned, currently shows a composite station level risk index as 27. According to the Risk Index guide, a risk index between 15 to 30 is considered "Good" condition. Dunneville TS, the reputedly the worst ranked station in the province, has a composite station level risk index of 36, which is on the better end of "Fair" condition scale of between 30 to 50.
- Breaker counter reading is one of the supporting factors used for the Utilization ARI calculation. The counter reading is supposed to be recorded twice a year during station inspections but the Aguasabon SS T1L1 breaker last had a counter reading of 292 recorded on August 7, 2012 in SAP. This data is obviously outdated and as a result the Utilization ARI for this breaker is suspect.

2.8 System development projects are based on area supply studies requiring power system historical data related to load flows, voltages, asset connectivity and statuses. These data are not available in AA.

2.9 There are no clearly documented asset strategies against which individual asset needs are assessed. However, work has recently started on developing Asset Strategy Documents for 30 key asset groups. These documents will detail key strategies in managing risks of a given asset group against which the individual asset needs will be assessed by the planners.

Risks: R Y

- Absence of a well-managed process to capture, review, assess, prioritize and action needs increases the risk of critical needs not being addressed in a timely fashion
- Absence of well-understood and quality asset information increases the risk of inadequate need assessment resulting in a less than optimal investment decision.
- Absence of clearly documented asset strategies increases the risk of inconsistent need assessment and investment decision.

Recommendations:

We recommend that Management:

2.1 Develop, implement and monitor an effective Need Identification Process. This may require review and enhancement of SP1546 to include both sustainment and development needs. This process should address a consistent mechanism for tracking details related to need identification, acceptance, review, prioritization, action as well as investment that has been made to meet the need. (related to Observations 2.4 and 2.5)

2.2 Develop detailed guidelines about how the planners should validate and use AA Risk Factors for the need assessment. (related to Observation 2.6)

2.3 Request an audit of Asset Analytics data sources and algorithms to confirm that quality data and appropriate calculation methods are used for calculating the six Asset Risk Indexes for individual assets as well as asset groups. (related to Observation 2.7)

2.4 Consider expanding the scope of the Asset Analytics tool to include up-to-date power system historical data such as load flows, connectivity, voltages, statuses, etc. (related to Observation 2.8)

2.5 Continue to develop sufficiently detailed Asset Strategy Documents for all asset groups and ensure that all future asset needs are assessed against these documented strategies. (related to Observation 2.9)

Management Response:
All recommendations have been agreed to by Mike Penstone, VP Planning. They are assigned for action as follows:

2.1 Scott McLachlan, Director, Transmission Asset Management
2.2 Scott McLachlan, Director, Transmission Asset Management
2.3 Randy Church, Director, Network Connections and Development
2.4 Bing Young, Director, System Planning
2.5 Scott McLachlan, Director, Transmission Asset Management

Proposed Action Plans: *(Accountable Manager, Title above in Management Response)*

2.1 This recommendation will be addressed as part of the overall Quality Assurance Process and metrics as outlined in Proposed Action Plan 1.4.
2.2 This recommendation will be addressed as part of the overall Quality Assurance Process and metrics as outlined in Proposed Action Plan 1.4.
2.3 SAP Data Audit on Asset and Maintenance data is already underway. The results of these audits will be used to address the underlying data issues in AA. Workshops with respective LOBs will be held regarding usability of existing algorithms.
2.4 AM Process and Tools will request ISD to add audit recommendation to corporate application roadmap. Key requirement is to have access to NMS information.
2.5 We will continue to develop Asset Strategy Documents.

Completion Dates:

2.1 Q3, 2015
2.2 Q3, 2015
2.3 Q4, 2015
2.4 Q1, 2015
2.5 Q4, 2015

3. Lack of Investment Alternatives

Background:
Developing investment alternatives is the next step required in the Investment Planning process and it is guided by the results from the need assessment. Work bundling opportunities among several programs are also explored while developing alternatives. Some programs are demand driven (such as service upgrades, trouble calls, studies, storm damage, etc.) and have only one alternative that is included in the plan based on historical averages of funding. Projects that are already under execution also have only one alternative. Most other projects and programs should have more than one alternative with varying risks and benefits to allow selection of the best alternative during optimization process. Project alternatives can shift in time, while program alternatives can have varying levels of accomplishments.

For program work, four levels of alternatives are considered as follows:

1. Vulnerable – Minimal short-term funding to meet regulatory and safety risks
2. Intermediate (1..n) – Varying levels of risk exposures with increased funding above vulnerable level
3. Asset Optimal – Balancing point where asset lifecycle costs are minimized. This would be an ideal level of funding.

4. Accelerated – Exceeds asset optimal funding in order to mitigate an oncoming “bow wave” of asset needs.

Further detail on these alternatives is included in Appendix F.

Program work cost is unit priced while project work cost is based on the planner’s estimate based on similar projects, budgetary estimate or detailed estimate from the service provider (where available).

The need, objectives, accomplishments, costs and risk assessment for each alternative is documented in the AIP tool by the planners and an Investment Summary Report (ISR) is produced for each investment. Management performs a quality assurance review of the ISR to ensure that a clear and compelling justification is made for each alternative along with uniform use of the risk assessment model.

Observation:

We are pleased to observe the following:

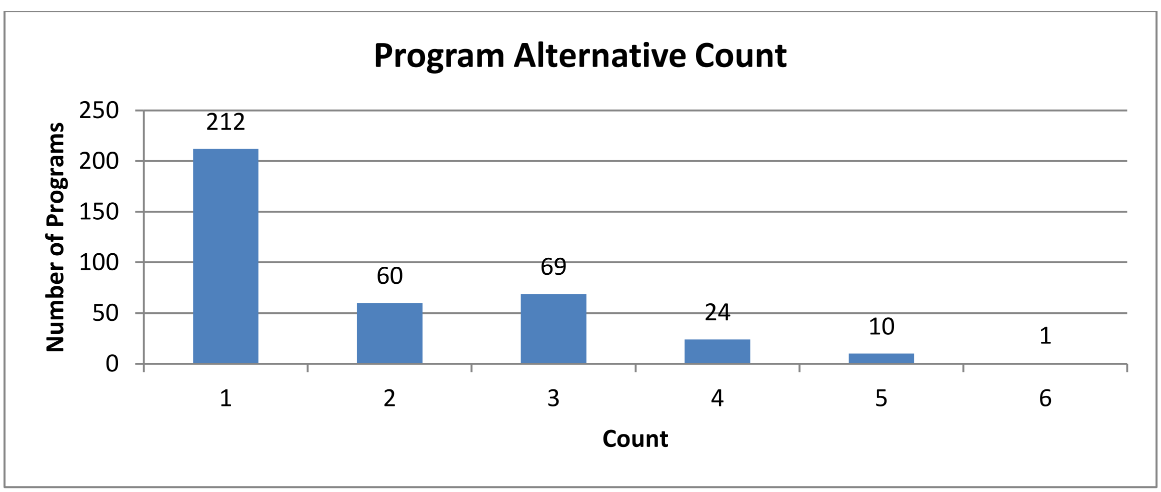
3.1 Investment values were calculated based on a weighted average of 8 corporate business values as follows: Safety (17%), Reliability (17%), Customer Satisfaction (13%), Productivity (13%), Financial Benefit (13%), Employees (9%), Environment (9%) and Shareholder value (9%).

3.2 Baseline and alternative risks for each investment are being evaluated using a sufficiently detailed and a standardized risk matrix based on 6 levels of probability and 9 levels of consequence.

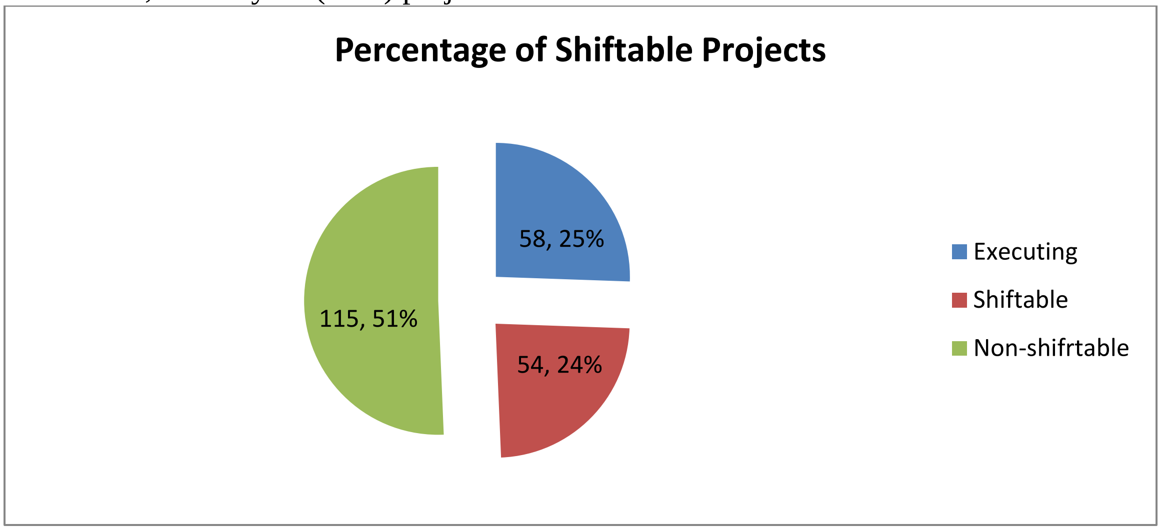
3.3 A risk consequence table was provided to the planners to guide their selection of the appropriate consequence for each corporate business value. A spreadsheet based tool was also developed to guide the planners in determining consequence ratings through a series of questions. Job aids related to risk assessment for each corporate value were also provided and posted on the SharePoint site for planners’ use.

We also observed the following opportunities for improving controls:

3.4 For the AIP optimization to be effective, projects should be shiftable in time and programs should have more than one alternative. There are 675 plans for Transmission and Distribution drivers in the 2015-2019 IPP with 448 Programs and 227 Projects. Of the 448 programs, 50 programs are demand driven and 22 programs are already under execution so these are required to have only a single alternative. The remaining 376 are under short term planning and should have had more than one alternative specified. However, 212 (56%) have only one alternative specified. The following is the alternative count for these programs.



Of the 227 projects, 58 are under execution and are not shiftable. The remaining 169 should all be shiftable, but only 54 (24%) projects were identified as shiftable in time.



From the above analysis, it can be concluded that projects and programs do not have sufficient alternatives defined to allow optimal selection of best available alternative.

3.5 Baseline and alternative risks assessed for most investments are mostly subjective with no (or very little) quantitative data to support the assigned probability and consequence for the risks. Although informal guidelines were provided on how to translate AA risk factors into corporate risks, this was not done for most investments. Most planners have indicated that the current risk matrix is confusing and that the provided guidelines are subjective. The provided training and job aid explained the risk matrix but it did not specify how the planners should rank risks (i.e. pick a specific box in the risk matrix). It was left up to the management reviews of risk assessment to ensure that risk ranking is consistent across all investments.

3.6 There was no risk assessment done for transmission system development plans as all of these plans are non-discretionary.

3.7 Sample investments having single alternatives lack appropriate justification documented in the Investment Summary Report.

3.8 There is very little documentation of management quality assurance review of investment plans (including risk assessments). Management has indicated that these type of reviews have occurred with verbal feedback being provided to planners in most cases. Please refer to related observation 1.10.

3.9 Some of the unit prices being used for program work are outdated or incorrect. As an example, unit prices for TS maintenance work do not include material cost while the unit prices for DS maintenance work do include material cost. The 2015 PCB Retro fill program is considered "underfunded" by the service provider because the outdated 2013 unit prices were used in determining the funding level.

3.10 There is inconsistent engagement with internal service providers during the development of alternatives. Some investment plans have significant engagement with service providers to confirm start date, in-service date, accomplishment levels, resources or cash flow based on sufficiently detailed estimates provided by the service provider. Most other plans are based on planner's estimates and desired schedule. The service providers have indicated a preference to be involved much earlier during the investment plan development. Please refer to related observation 1.11.

3.11 There are insufficient documented details on coordination of plans among sustainment and development groups as well as identification of any bundling opportunities between transmission and distribution work.

3.12 There are insufficient details on how the individual plans align with the regulatory filing.

3.13 There is a lack of details for placeholder investments having significant value. The placeholder investments are used for projects that are expected but have very little scope defined. The value of these placeholder investments is based on historical trends and future forecasts. There are 37 placeholder investments in the IPP totalling $914M (Gross) over the 2015-2019 planning period. Service providers are concerned about providing accurate forecasts for these placeholder investments that have no or very little defined scope.

Risks: R Y

- Lack of available alternatives increases the risk of less than optimal investment plans.
- Inadequate assessment of baseline and alternative risk could result in incorrect risk values being assigned to the alternative.
- Incorrect assumptions related to the timing and costs of investment could result in less than optimal cash flow requirements.
- Undue influence by the service provider during the planning process increases the risk of plans being made based on the service provider’s ability to execute rather than on asset needs.

Recommendations:

We recommend that Management:

3.1 Require the planners to define more than one alternative for non-demand driven programs and time shift-able projects. Management should also ensure that appropriate justification is documented and reviewed for plans having only a single alternative. (related to Observation 3.4)

3.2 Simplify the risk assessment matrix and provide suitable training and guideline to planners to perform an effective risk assessment. Specific focus should be on using quantative data from AA and other systems to determine/support appropriate probability and consequence on the established risk matrix. (related to Observations 3.5, 3.6 and 3.7)

3.3 Increase quality assurance reviews and feedback to planners on the quality of their alternatives and risk assessment to ensure uniformity of plans and related risk assessment. (related to Observation 3.8)

3.4 Review and confirm the Unit Price Catalog with the service providers prior to the start of each planning cycle to ensure that the most current unit prices are being used to determine the funding level for the program work. (related to Observation 3.9)

3.5 Define and communicate the required level of engagement with the service provider when investment plans are being developed to ensure that plans are based on asset needs rather than executability by the service providers. Please refer to related Recommendation 1.3. (related to Observation 3.10)

3.6 Require the planners to electronically attach/link supporting data (such as those from AA) and related documentation for each alternative risks assessment to their ISR in AIP. (related to Observations 3.11, 3,12 and 3.13)

Management Response:
All recommendations have been agreed to by Mike Penstone, VP Planning. They are assigned for action as follows:

3.1 Scott McLachlan, Director, Transmission Asset Management
3.2 Scott McLachlan, Director, Transmission Asset Management
3.3 Scott McLachlan, Director, Transmission Asset Management
3.4 Chong Ng, Project Development
3.5 Kathleen McCorriston, AM Processes & Tools
3.6 Scott McLachlan, Director, Transmission Asset Management

Proposed Action Plans: *(Accountable Manager, Title above in Management Response)*

3.1 We will define the framework for investments including the expectations outlining the definition and governance of programs and projects and requirements for program alternatives and time shift-able projects. Document and communicate these requirements.
3.2 We will improve the guidance on the use of the risk assessment matrix through the provision of practical examples.
3.3 This recommendation will be addressed as part of the overall Quality Assurance Process and metrics as outlined in Proposed Action Plan 1.4.
3.4 We will establish a process to ensure costs included in the investment plans are agreed upon between Planning and Operations (executing LOBs).
3.5 This recommendation will be addressed as part of the Proposed Action Plan 1.3 related to the timing and level of input to be sought from LOBs.
3.6 This recommendation will be addressed as part of the overall Quality Assurance Process and metrics as outlined in Proposed Action Plan 1.4.

Completion Dates:

3.1 Q3, 2015
3.2 Q4, 2016
3.3 Q3, 2015
3.4 Q4, 2015
3.5 Q1, 2015
3.6 Q3, 2015

4. Inefficient Investment Plan Optimization

Background:
Hydro One uses an Asset Investment Planning (AIP) tool for risk-based optimization to ensure that selected investments will result in the maximization of corporate business values. During each planning cycle, the AIP tool is set up with appropriate investment master data from SAP (such as driver, LOB, Appropriation Request Number, etc.), historical and forecast finance data, corporate value function and other constraints. The risk assessment, costs, schedule and accomplishments for each investment alternative is then input by the planners in to the AIP tool. Once all input is completed, the optimization process starts during which the AIP tool selects the best of the several alternatives of each investment based on the timing of investments that will maximize risk mitigation and financial benefits while satisfying pre-determined constraints and dependencies. The aggregation of work programs and projects selected from available alternatives during the optimization process yields the preliminary Investment Plan Proposal (IPP).

An enterprise engagement takes place whereby each line of business (planning, executing and finance) is represented at review meetings to discuss the preliminary IPP. Management discretion is used to adjust the IPP to ensure that appropriate resources are available to execute the plan, financial and regulatory objectives are met, and the level of risk imposed by the plan is acceptable.

Observations:

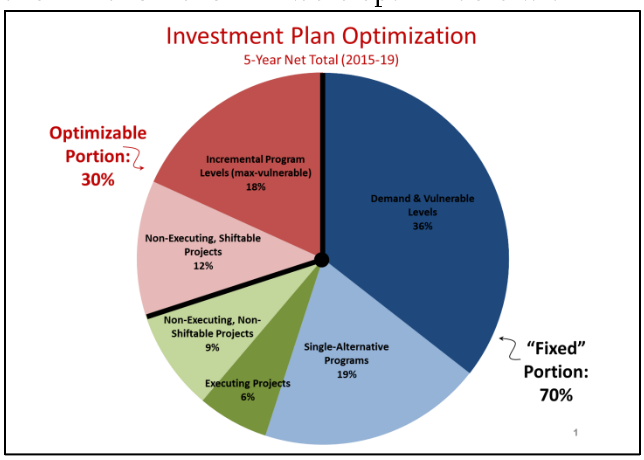
We are pleased to observe the following:

4.1 For the 2015-2019 Investment planning, a detailed schedule was developed and communicated to ensure that the optimization process and IPP review was completed by end of June 2014. The planned tasks on this schedule were completed on time and a weekly workflow status report was issued to management to indicate progress.

4.2 A detailed procedure exists for set up of the AIP tool at the start of the prioritization process.

We also observed the following opportunities for improving controls:

4.3 Only 30% of the plans in 2015-2019 IPP were optimizable within AIP.



Source: Director Review June 2 v2.pptx from Kathleen Kerr

4.4 The AIP tool was only available for a limited time resulting in planners having insufficient time for thorough documentation of their plans and management having insufficient time to review those plans in detail. The planned and actual schedule dates for the 2015-2019 planning cycle were as follows:

Event	Planned	Actual
LOB approval of Unit Price Catalog	April 11	No official signoff was received
Setup of AIP Tool Complete	April 11	April 11
AIP open for Planner Input	April 14	April 14
Investment Approval Workflow Submission deadline	May 9	May 9 – Workflow status reports were issued weekly to Management
Investment approval deadline	May 16	May 20 – Extra weekend was given for management review and approval
Start of Optimization	May 20	May 20
Optimization results review (Prelim. IPP)	June 2	June 2
LOB and Stakeholder review and input	June 13	June 13
IPP adjustments complete	June 30	July 4

Planners were given 4 weeks to complete their input into AIP and management was given 1 week to review it. As of May 15, one day before the plan approval deadline, only 49% of the plans had workflow initiated for review and approval by management. Please refer to related observation 1.10.

4.5 Manual workarounds are in place to update AIP data from SAP and other systems. Spreadsheet based tools are being used for data uploads. These uploads are based on a snapshot of available data from the originating system (such as SAP) and they became stale as soon as the snapshot is taken since the originating system is continually updated. As an example, forecast costs and in-service date changes are continually being updated in SAP by the service providers, but these changes are not reflected in AIP once the snapshot of data is taken from SAP and uploaded to AIP.

4.6 Enterprise engagement is occurring at the director level and above with a focus on comparison with previous year's plan to identify what has changed and discuss why. A line by line review is only occurring for major / complex plans. The LOB engagement for 2015-2019 IPP occurred over a four day period from June 9 to 13, but the service providers have indicated that they need more time to review each investment line item in IPP in sufficient detail with their project and program managers to ensure that the IPP can be executed as planned.

4.7 Adjustments and changes to the optimized IPP are logged in a spreadsheet based change log. This change log does not seem to capture all changes. As an example, total gross funding has significantly changed for DS preventive and corrective maintenance, TS preventive maintenance, P&C Maintenance and P&C NOEA support, but these changes are not logged in the change log. Service providers have also indicated that some of their project and program specific input was incorporated while others was not. They have also indicated that there was a lack of communication about why some input related to in-service date and cash flow changes was not accepted.

4.8 It is unclear what changes to the optimized plan would require the plan to be run through the optimization process again. The IPP, once optimized, is simply adjusted based on changes recommended during the enterprise engagement reviews. The resulting adjusted IPP may not be a fully optimized plan. It was noted that the preliminary IPP was adjusted and re-issued to LOBs approximately 10 times before being finalized.

4.9 It is unclear how multi-year in-service additions are being treated in the IPP. In all cases, the "station centric" multi-year programs are being shown as in-serviced in the final year of the program. The reality is that these programs are in-serviced each year as the work progresses.

Risks: R Y

- An insufficient number of optimizable plans defeat the benefits of overall plan optimization.
- Insufficient time to provide quality input to the optimization process and to review the results of the optimization process increases the risk of having less than optimal plan.
- Inadequate communication around changes to the optimized plan increases the risk of diminishing the plan's credibility and less acceptance of the plan by its users.

Recommendations:

We recommend that Management:

4.1 Increase the number of investments that are optimizable. (related to Observation 4.3) Please refer to related Recommendation 3.1.

4.2 Make the AIP tool available year around to allow the planners to input and update their plans and risk assessments throughout the year. Management has indicated that plans are already underway to upgrade the AIP tool to allow this to occur in 2015. (related to Observation 4.4)

4.3 Consider AIP tool integration with other systems and tools such as AA (for asset risk factors), SAP (for AR and driver related data), BPC (Business Process Consolidation, for LOB forecast and accomplishment data) and UPC (Unit price catalog, for unit price data) to ensure that information in AIP is kept up-to-date with other systems. (related to Observation 4.5)

4.4 Increase the enterprise engagement period to allow a detailed line by line review of unreleased work in the IPP by the project and program managers who will be executing the plan. This will allow better feedback on cash flows and in-service dates from the service providers based on the established scope. (related to Observation 4.6)

4.5 Implement a formal change log to document all recommended changes. This should also include appropriate review, approval and incorporation of changes with appropriate communication back to the requestor of the change. (related to Observation 4.7)

4.6 Determine and document which types of changes to the individual plans require the IPP to be run through the optimization process again to ensure that the resulting plan remains optimal. (related to Observation 4.8)

Management Response:

All recommendations have been agreed to by Mike Penstone, VP Planning. They are assigned for action as follows:

4.1 Scott McLachlan, Director, Asset Management)
4.2 Kathleen McCorriston, Manager, AM Processes and Tools
4.3 Kathleen McCorriston, Manager, AM Processes and Tools
4.4 Kathleen McCorriston, Manager, AM Processes and Tools
4.5 Kathleen McCorriston, Manager, AM Processes and Tools
4.6 Kathleen McCorriston, Manager, AM Processes and Tools

Proposed Action Plans: *(Accountable Manager, Title above in Management Response)*

4.1 This recommendation will be addressed as part of the action plan for recommendation 3.1.
4.2 This recommendation will be addressed upon implementation of AIP tool upgrade.
4.3 AM Process and Tools will request ISD to add audit recommendation to corporate application roadmap.
4.4 Enterprise Engagement period will be revised and incorporated into the revised schedule for the 2016-2020 planning cycle.
4.5 All changes will be recorded in the accomplishment file change log and/or documented in the meeting minutes.
4.6 AM Process & Tools will document conditions and requirement for the IPP to be run through the optimization process again into the Investment Optimization Management Procedure.

Completion Dates:

4.1 Q3, 2015
4.2 Q3, 2015
4.3 Q3, 2015
4.4 Q3, 2015
4.5 Q1, 2015 – COMPLETED
4.6 Q2, 2015

5. Lengthy Investment Plan Approval and Release Process

Background:
After the completion of IPP prioritization and review/adjustment by Senior Management, the adjusted IPP is included in the Corporate Business Plan for approval by the Hydro One Board of Directors. Subsequently, individual investments are then released to the service provider for execution. Programs work is approved at Board level and released annually while project work is released after a review and approval of Business Case Summary (BCS) by the appropriate Organization Authority Register (OAR) authorities.

The planners ensure that BCS showing cash flow based on detailed estimates, start date and in-service date as agreed with the service providers and customers (if required) is prepared and approved by appropriate OAR authorities prior to releasing funds to the service provider through SAP.

In May 2013, changes to the project/program definition and approval limits were implemented as per recommendations by Finance and approval of the Executive Committee (EC). A key change was to apply the interpretation of "program" to include component replacement/refurbishment, including bundling of such work. This resulted in a number of "station centric" bundled programs (often referred to as "projam" because they have a scope and schedule similar to project work but are funded through approved programs using unit pricing) of significant value being approved at a director level using Station Investment Capital Approval (SICA) even though the value of the "projam" exceeded the director level OAR authority.

Observation:
We are pleased to observe the following:

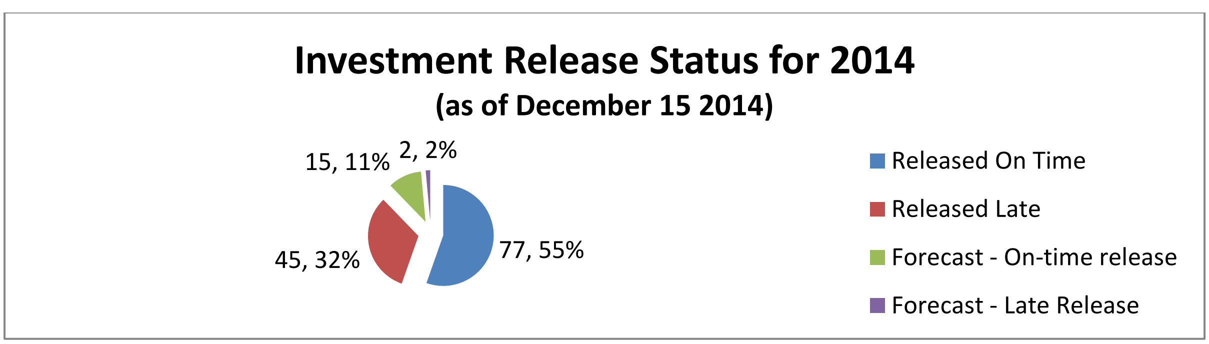
5.1 The approval and release process has not changed over the last several years. Appropriate training presentations, templates and job aids are available to planners for development of the BCS and directing it to the appropriate OAR authority.

5.2 87% of 2015 and 46% of 2016 transmission capital work program have already been released to Engineering and Construction.

We also observed the following opportunities for improving controls:

5.3 A requirement has been put in place recently to treat all "projam" greater than \$20M as projects requiring an approved BCS by the appropriate OAR authority prior to release. However, it is unclear how the remaining "projam" investments will be approved and progress will be monitored.

5.4 100 projects and 39 "station centric" programs were scheduled to be released in 2014 using a BCS or SICA. The following is a summary of their release statuses as of December 15 2014.



From the above analysis, we conclude that release dates are often optimistic.

5.5 Of the 45 projects that were released late in 2014, only one had its in-service date pushed back due to late release. The service providers are concerned about the timing of work release as they can't execute the work without a release. They have requested that changes in the release date need to be tied to changes in the in-service date to ensure that it will be met.

5.6 The primary cause for a delayed release is a delay in availability of detailed estimates.

5.7 A BCS requiring board approval goes through a series of reviews at director, VP, SVP/COO/CFO, President/EC and BT Committee of the Board. All these reviews require timely submission of information and if there are any questions or concerns raised during the review, the process is delayed. A detailed "Investment Review Schedule" showing earliest and latest submission dates for approval at specific committee or board meeting date is available to planners. It shows that, in most cases, the review and approval process needs to start a minimum of 6 to 8 weeks ahead of the Board meeting date.

Risks: R Y

- Delayed release of investments increases the risk of not meeting the approved in-service date.
- Lengthy review and approval process of BCS requiring Board Approval increases the risk of delayed release.

Recommendations:
We recommend that Management:

5.1 Clarify the approval requirement and progress monitoring for "projam" investments. Review the project and program approval process with specific focus on shortening the approval timeline. This may include appropriate escalation triggers as well as clarification of requirement for timely review / approval. (related to Observation 5.7)

5.2 Ensure that realistic release dates are considered by the planners as they develop their plans. (related to Observation 5.4, 5.5 and 5.6)

Management Response:
All recommendations have been agreed to by Mike Penstone, VP Planning. They are assigned for action as follows:

5.1 Mike Penstone, VP Planning
5.2 Scott McLachlan, Director, Transmission Asset Management

Proposed Action Plans: *(Accountable Manager, Title above in Management Response)*

5.1 This will be incorporated into annual review of OAR.
5.2 This recommendation will be addressed as part of the action plan for recommendation 1.4.

Completion Dates:

5.1 Q3, 2015
5.2 Q3, 2015

BACKGROUND

Hydro One has adopted an Asset Management model, since its inception, to plan, approve and implement work related to customers, assets and system needs. The Asset Management function is responsible for defining and planning work, while the Work Execution function is responsible for delivering asset and customer based services in accordance with work defined and planned by Asset Management. The primary responsibility for identifying needs, decision making, planning and defining work related to transmission and distribution assets lies with Asset Management, while the primary responsibility for design & engineering, construction, operation & maintenance and customer care services lies with the Work Execution function.

The Planning Organization, reporting to the Chief Operating Officer, has accountability for all planning activities related to programs and projects, including: Asset Management, Project Development, Network Development, Regional Planning, as well as accountability for reliability strategies, initiatives and compliance with electricity regulatrions. A key part of the Asset Management is the Investment Planning process, which is the focus of this audit. This process has never been audited before and the objective and scope of this audit is included in Appendix B.

The output of the investment planning process is the Investment Plan Proposal (IPP) which details the work plan, funding levels and accomplishments for a five year period. This plan is determined based on the assessment of identified needs using an iterative risk-based prioritization and optimization process that takes into account corporate business values (such as safety, reliability, customer satisfaction, shareholder value, etc.), investment strategies, financial constraints and resource/outage availability. The IPP is a major input to the Hydro One's Corporate Business Plan that is approved annually by its Board of Directors. The IPP also forms a basis for the Transmission and Distribution rate filings with the Ontario Energy Board. Although the IPP includes all investments related to the development and sustainment of transmission and distribution assets, operating assets and common corporate assets (such as IT, fleet, facilities, etc.), this audit specifically focuses on the development and sustaining investments being made at the transmission and distribution stations only.

A high-level Investment Planning process is summarized in Appendix D. Key steps of the process are as follows:

1. Identification of customer, asset and system needs
2. Data collection and assessment of needs
3. Development of risk-based Investment alternatives
4. Selection of Investments using an optimization process to maximize corporate business values within identified constraints
5. Approval and release of investments to Work Execution function

The above process steps result in an IPP showing the best portfolio of investments that achieve the optimal balance of cost effectiveness, customer expectations, asset and system needs within the financial, material, resource, outage availability as well as customer rate impact constraints. A thorough management review and appropriate adjustment of the optimized IPP ensures that the IPP is executable, financial objectives are met and the risks that the plan imposes are acceptable.

AUDIT OBJECTIVES & SCOPE

Audit Objective:
The primary objective of this audit was to provide management with assurances that processes and controls for investment planning within Hydro One Networks are effective. This was a high-level "end to end" process audit with future audits being recommended in specific areas of concern.

Scope of the Audit:
The scope of this audit was limited to the following areas related to development of the Investment Plan Proposal (IPP) with focus on the Transmission and Distribution stations assets only:

- Determine asset needs
- Develop Investment Plans
- Prioritize Investment Plans
- Approval and release of Investment Plans

Redirection and Change Control processes were out of scope as these processes are applied after IPP is approved and implemented. This review included work related to the development of the 2015-2019 Investment Plan Proposal and related documentation produced as of November 30, 2014.

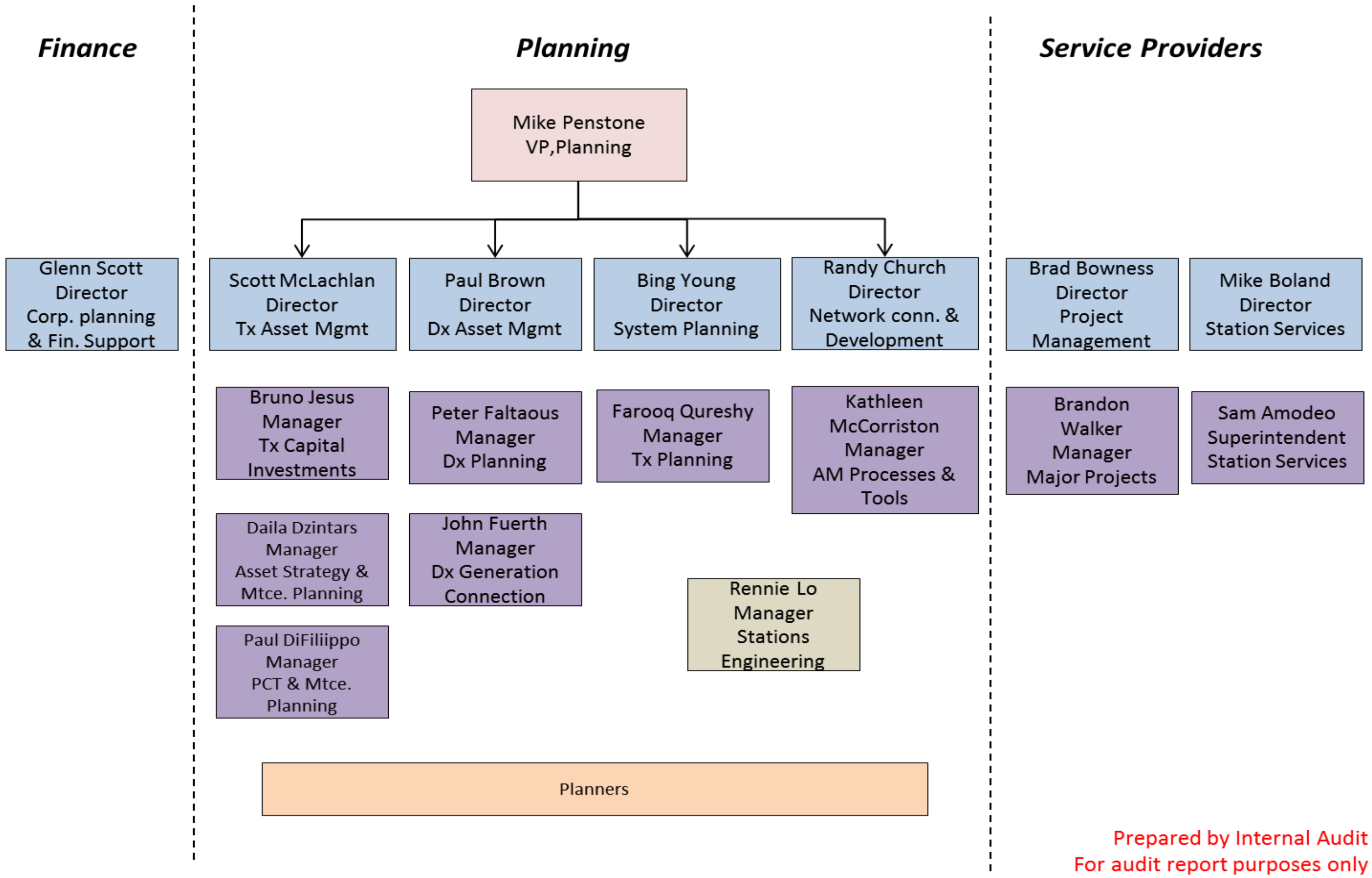
Approach:
This audit involved the following activities:

1. Review the existing investment planning process documents and examples of current investment plans.
2. Confirm and update our understanding of the investment planning processes and tools by having discussions with management and staff.
3. Document the process for audit purposes.
4. Update our understanding of the key controls that provide assurance relative to the audit objectives.
5. Interview and discuss with the accountable management, staff and stakeholders regarding control effectiveness.
6. Test a sample of investments and records related to the scope for control effectiveness.
7. Brief management on any control issues throughout the review.
8. Recommend improvements, where appropriate.

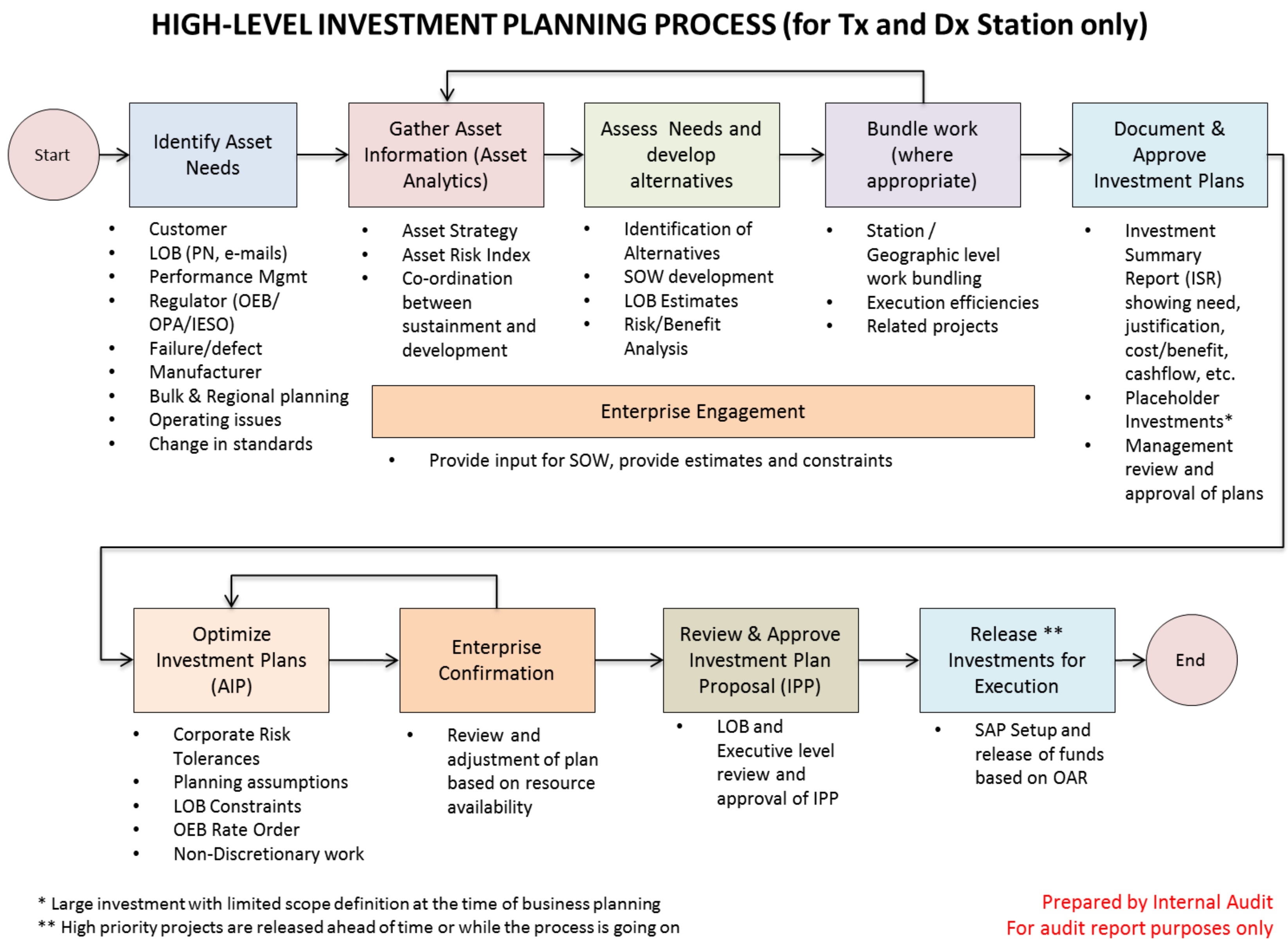
Disclaimer
In this report, we provide suggestions for improving controls to mitigate the risks identified. These recommendations may not be the only solution, nor are they intended to be prescriptive as to management's action. It is management's responsibility to ensure that they develop and implement action plans that are both cost-effective and address the risks identified in the report.

AUDIT CONTACTS

INVESTMENT PLANNING PROCESS AUDIT CONTACTS (for Tx and Dx Station only)

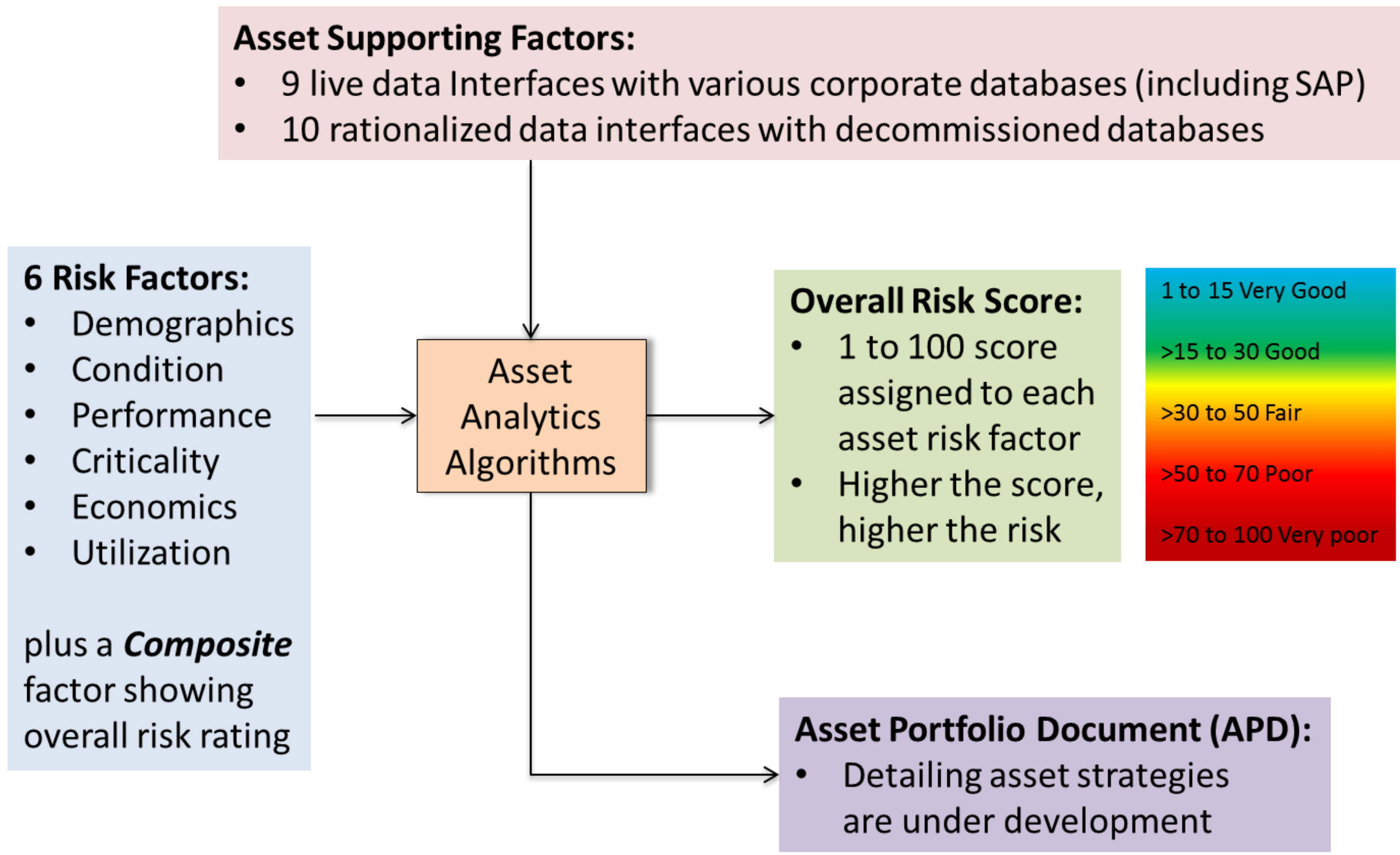


INVESTMENT PLANNING PROCESS (HIGH LEVEL)



ASSET ANALYTICS (AA) OVERVIEW

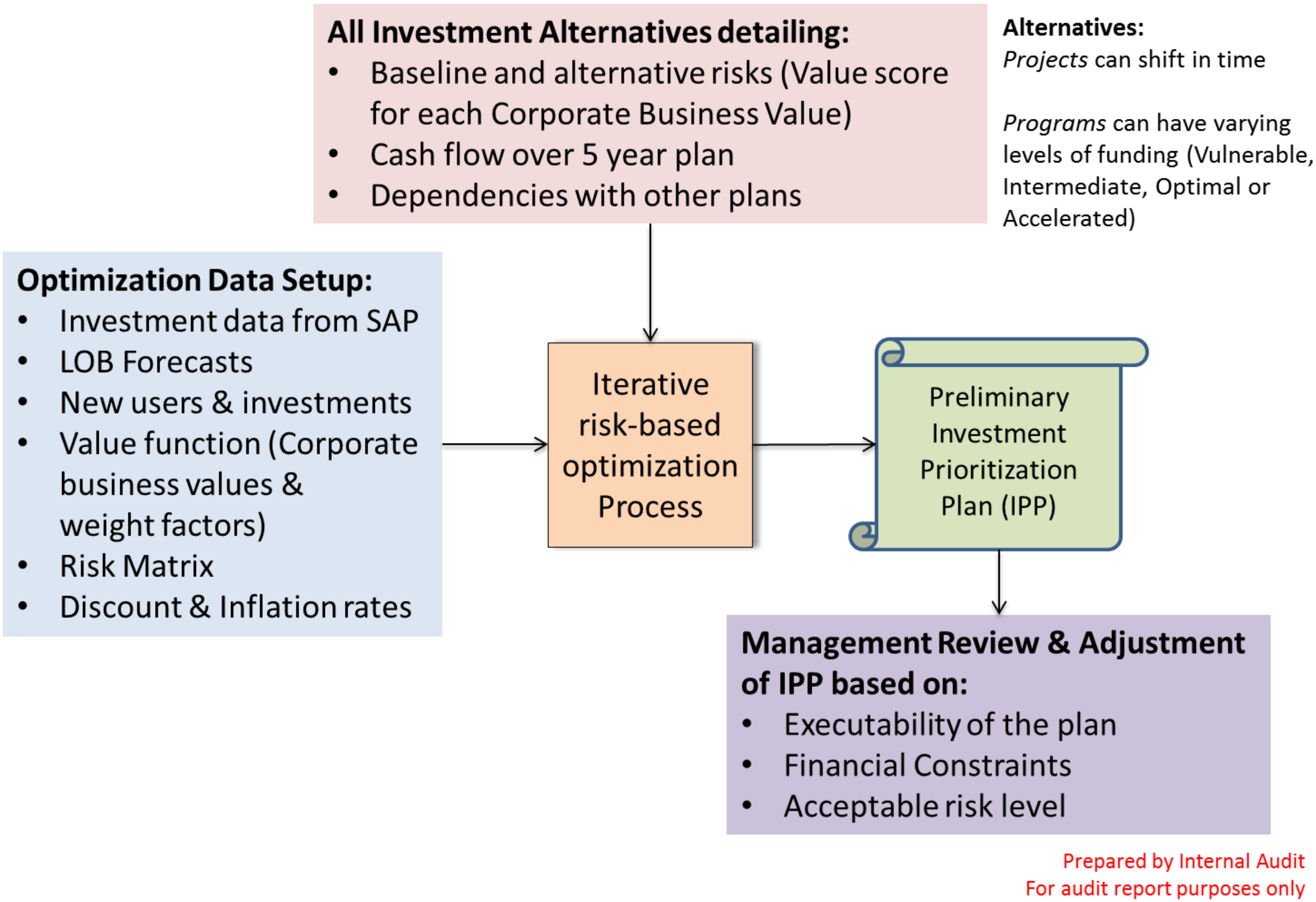
Asset Analytics (AA) Overview



Prepared by Internal Audit
For audit report purposes only

ASSET INVESTMENT PLANNING (AIP) OVERVIEW

Asset Investment Planning (AIP) Overview



INVESTMENT ALTERNATIVES OVERVIEW

Concepts and Definitions

Investment Alternative Names (for Programs)

Alternative	Definition
Accelerated	▪ This investment alternative exceeds "Asset Optimal" in order to mitigate a coming "bow wave" of asset needs. ▪ It is normally only applied where in a future year there will be a jump in required investment beyond what can be resourced or reasonably executed, so a 'head start' is necessary to ensure that the "Asset Optimal" investment level is achievable in future years
Asset Optimal	• This investment alternative represents the ideal balance point, where <u>total lifecycle costs</u> (not unit cost) of the asset are minimized and risk is low • Asset needs are fully met and there is a high degree of confidence that the assets will perform as aligned with the Asset Strategy which in turn aligns with the Corporate Strategy
Intermediate (1..n)	• These investment alternatives represent materially less risk exposure and materially more cost than "Vulnerable" but remain below "Asset Optimal" and therefore are less than ideal • All intermediate levels lie between "Vulnerable" and "Asset Optimal" in terms of cost and risk
Vulnerable	▪ This investment alternative is tolerable for only brief periods and exposes the company to significant risk of the asset not performing. ▪ Asset maintenance and/or replacement needs are not fully met. Future performance of the asset is uncertain, and is almost certain to drop below acceptable levels beyond 5 years if the level of investment is not increased. ▪ Short-term, strict regulatory compliance and safety is reasonably assured, but little else; the level of residual risk at the end of the 5 year planning period is just outside the "red zone" which is tolerable only in the near term and is not sustainable

Note: Projects will only have one alternative (which can be named the same as the project name)

Source: Business Concepts
2015-19 Investment Planning, April 2014, PPT Presentation

SUMMARY OF ACTIONS

(R) #	Observations	Risk	Recommendations (R)	Action Plan	Accountability	Completion Date
1. Governance and Controls						
1.1	There has been no recent and formal business risk assessment of the overall Planning business unit's objectives completed as per the Enterprise Risk Management Policy (SP0736).	M	Perform a formal risk assessment as per ERM Policy (SP0736) on an annual basis to ensure that business risks facing the planning organization are identified and mitigating actions are developed and tracked.	Planning will work with ERM Group to conduct a risk workshop to identify risks in achieving the planning business objectives.	Randy Church, Director, Network Connections and Development	Q4, 2015
1.2	Policies, processes, procedures, standards and guidelines are missing, incomplete, outdated or not being used consistently	H	Develop, review and approve sufficiently detailed policies, standards, procedures and guidelines to ensure a consistent risk-based approach to planning and decision making. This would require a review of the existing governance documents and ARIS process models for their accuracy and validity. Management has informed us that a Policy Review project is currently underway to consolidate policy and directive documents.	Conduct a review of processes, procedures, standards and guidelines to determine the need, effectiveness, currency and to ensure they are aligned with and support the Corporate Operational Policies. Establish a review cycle for these documents.	Luis Marti, Director, Reliability Studies, Strategies and Compliance	Q4, 2015
1.3 3.5	There is a lack of a clearly defined process and guidelines for the level of input to be sought by the planners and to be provided by the service providers during the	M	Clarify the timing and level of input to be sought by the planners from the service providers as they develop their plans.	At the annual LOB kick off, AM Processes and Tools will identify and seek input from the service providers to obtain their feedback on ideal timing and level of input required.	Kathleen McCorriston, Manager, AM Process & Tools	Q1, 2015

	Observations	Risk	Recommendations	Action Plan	Accountability	Completion Date
	investment plan development. There is inconsistent engagement with internal service providers during the development of alternatives.		Define and communicate the required level of engagement with the service provider when investment plans are being developed to ensure that plans are based on asset needs rather than executability by the service providers.	Planning will also be in attendance to ensure agreement and consistency in approach.		
1.4 2.1 2.2 3.3 3.6 5.2	There is no formally documented Quality Assurance process with related measures to assess the effectiveness of the "end-to-end" planning process.	H	Implement a formalized Quality Assurance process and related performance measures to assess the effectiveness of the "end-to-end" planning process. This would include: • a Need identification and tracking process • guidelines on use and validation of AA data to assess needs and risks • QA reviews of Investment Summary Reports and feedback to planners • Supporting document availability and review, and • realistic investment release dates	Quality expectations and the required metrics for the end-to-end process will be established and communicated by the Planning Organization.	Scott McLachlan, Director, Transmission Asset Management	Q3, 2015
1.5	There is no formal training for the overall "end to end" planning process. However, there is informal training on use of tools. None of the training is tracked and refreshed as the process and tools evolve.	M	Formalize and track all process and tool related training being given to planners in their Learning Management System. Establish refresher training requirements whenever there are significant changes in process and tools.	The Planning Organization will assess all training requirements including the frequency of refresher training and mechanism for tracking training completion. We will develop an implementation plan that defines the accountabilities	Mike Penstone, VP Planning	Q4, 2015

	Observations	Risk	Recommendations	Action Plan	Accountability	Completion Date
				for creation and delivery of training material.		
1.6	There is no formal lessons learned documentation for continuous process improvement.	M	Document and communicate lessons learned after each planning cycle and use them for continuous improvement of the planning process.	AM Processes & Tools will document and communicate lessons learned after the 2016-2020 planning cycle.	Kathleen McCorriston, Manager, AM Process & Tools	Q3, 2015
2. Customer, Asset and System Need Assessment						
2.3	The AA data quality remains a concern. The quality of underlying data (accuracy, completeness and timely availability of recent data) being used from SAP and other databases for risk index calculations is unknown.	H	Request an audit of Asset Analytics data sources and algorithms to confirm that quality data and appropriate calculation methods are used for calculating the six Asset Risk Indexes for individual assets as well as asset groups.	SAP Data Audit on Asset and Maintenance data is already underway. The results of these audits will be used to address the underlying data issues in AA. Workshops with respective LOBs will be held regarding usability of existing algorithms.	Randy Church, Director, Network Connections and Development	Q4, 2015
2.4	System development projects are based on area supply studies requiring power system historical data related to load flows, voltages, asset connectivity and statuses. These data are not available in AA.	M	Consider expanding the scope of the Asset Analytics tool to include up-to-date power system historical data such as load flows, connectivity, voltages, statuses, etc.	AM Process and Tools will request ISD to add audit recommendation to corporate application roadmap. Key requirement is to have access to NMS information.	Bing Young, Director, System Planning	Q1, 2015

	Observations	Risk	Recommendations	Action Plan	Accountability	Completion Date
2.5	There are no clearly documented asset strategies against which individual asset needs are assessed. However, work has recently started on developing Asset Strategy Documents for 30 key asset groups.	M	Continue to develop sufficiently detailed Asset Strategy Documents for all asset groups and ensure that all future asset needs are assessed against these documented strategies.	We will continue to develop Asset Strategy Documents.	Scott McLachlan, Director, Transmission Asset Management	Q4, 2016
3. Investment Alternatives						
3.1 4.1	For the AIP optimization to be effective, projects should be shiftable in time and programs should have more than one alternative. Only 30% of the plans in 2015-2019 IPP were optimizable within AIP.	H	Increase the numbers of investments that are optimizable by requiring the planners to define more than one alternative for non-demand driven programs and time shift-able projects. Management should also ensure that appropriate justification is documented and reviewed for plans having only a single alternative.	We will define the framework for investments including the expectations outlining the definition and governance of programs and projects and requirements for program alternatives and time shift-able projects. Document and communicate these requirements.	Scott McLachlan, Director, Transmission Asset Management	Q3, 2015
3.2	The current risk matrix is confusing and that the provided guidelines are subjective.	M	Simplify the risk assessment matrix and provide suitable training and guideline to planners to perform an effective risk assessment. Specific focus should be on using quantative data from AA and other systems to determine/support appropriate probability and consequence on the established risk matrix.	We will improve the guidance on the use of the risk assessment matrix through the provision of practical examples.	Scott McLachlan, Director, Transmission Asset Management	Q4, 2016

	Observations	Risk	Recommendations	Action Plan	Accountability	Completion Date
3.4	Some of the unit prices being used for program work are outdated or incorrect.	M	Review and confirm the Unit Price Catalog with the service providers prior to the start of each planning cycle to ensure that the most current unit prices are being used to determine the funding level for the program work.	We will establish a process to ensure costs included in the investment plans are agreed upon between Planning and Operations (executing LOBs).	Chong Ng, Director, Project Development	Q4, 2015
4. Investment Plan Optimization						
4.2	The AIP tool was only available for a limited time resulting in planners having insufficient time for thorough documentation of their plans and management having insufficient time to review those plans in detail.	M	Make the AIP tool available year around to allow the planners to input and update their plans and risk assessments throughout the year. Management has indicated that plans are already underway to upgrade the AIP tool to allow this to occur in 2015.	This recommendation will be addressed upon implementation of AIP tool upgrade.	Kathleen McCorriston, Manager, AM Process & Tools	Q3, 2015
4.3	Manual workarounds are in place to update AIP data from SAP and other systems.	L	Consider AIP tool integration with other systems and tools such as AA (for asset risk factors), SAP (for AR and driver related data), BPC (Business Process Consolidation, for LOB forecast and accomplishment data) and UPC (Unit price catalog, for unit price data) to ensure that information in AIP is kept up-to-date with other systems.	AM Process and Tools will request ISD to add audit recommendation to corporate application roadmap.	Kathleen McCorriston, Manager, AM Process & Tools	Q3, 2015

	Observations	Risk	Recommendations	Action Plan	Accountability	Completion Date
4.4	Enterprise engagement is occurring at the director level and above with a focus on comparison with previous year's plan to identify what has changed and discuss why. A line by line review is only occurring for major / complex plans. The LOB engagement for 2015-2019 IPP occurred over a four day period from June 9 to 13, but the service providers have indicated that	H	Increase the enterprise engagement period to allow a detailed line by line review of unreleased work in the IPP by the project and program managers who will be executing the plan. This will allow better feedback on cash flows and in-service dates from the service providers based on the established scope.	Enterprise Engagement period will be revised and incorporated into the revised schedule for the 2016-2020 planning cycle.	Kathleen McCorriston, Manager, AM Process & Tools	Q3, 2015
	they need more time to review each investment line item in IPP in sufficient detail with their project and program managers to ensure that the IPP can be executed as planned.					
4.5	Adjustments and changes to the optimized IPP are logged in a spreadsheet based change log. This change log does not seem to capture all changes.	M	Implement a formal change log to document all recommended changes. This should also include appropriate review, approval and incorporation of changes with appropriate communication back to the requestor of the change.	All changes will be recorded in the accomplishment file change log and/or documented in the meeting minutes.	Kathleen McCorriston, Manager, AM Process & Tools	Q1, 2015 Complete

	Observations	Risk	Recommendations	Action Plan	Accountability	Completion Date
4.6	It is unclear what changes to the optimized plan would require the plan to be run through the optimization process again. The IPP, once optimized, is simply adjusted based on changes recommended during the enterprise engagement reviews. The resulting adjusted IPP may not be a fully optimized plan. It was noted that the preliminary IPP was adjusted and re-issued to LOBs approximately 10 times before being finalized.	M	Determine and document which types of changes to the individual plans require the IPP to be run through the optimization process again to ensure that the resulting plan remains optimal.	AM Process & Tools will document conditions and requirement for the IPP to be run through the optimization process again into the Investment Optimization Management Procedure.	Kathleen McCorriston, Manager, AM Process & Tools	Q2, 2015
5. Investment Plan Approval and Release						
5.1	A requirement has been put in place recently to treat all “projam” greater than $20M as projects requiring an approved BCS by the appropriate OAR authority prior to release. However, it is unclear how the remaining “projam” investments will be approved and progress will be monitored.	H	Clarify the approval requirement and progress monitoring for “projam” investments. Review the project and program approval process with specific focus on shortening the approval timeline. This may include appropriate escalation triggers as well as clarification of requirement for timely review / approval.	This will be incorporated into annual review of OAR.	Mike Penstone, VP Planning	Q3, 2015

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November 25, 2016

VIA RESS AND COURIER

Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, Ontario M4P 1E4

Dear Ms. Walli:

RE: EB-2016-0160 Hydro One Networks Inc. ("Hydro One") Transmission Rates Application – Response to OEB Staff Pre-Hearing Undertakings

Hydro One's response to Board Staff Pre-hearing Undertakings 1-3 is enclosed.

Yours truly,

McCarthy Tétrault LLP
Per:

For: Gordon M. Nettleton

GMN

Ontario Energy Board (Board Staff) Pre-Hearing UNDERTAKING #1

Undertaking

The attached document, “Table A - 2016 HONI Projects” lists the capital projects filed in EB-2016-0160 with budgeted expenditures in 2017 & 2018 above $3 million.

a) For each capital project for which the currently budgeted 2017 & 2018 expenditures are significantly different than the forecast 2017 & 2018 expenditures for that project in EB-2014-0140 (e.g.: new project, cost change, scope change or schedule change), identify, as applicable:

   i. 2017 & 2018 forecast expenditures from EB-2014-0140
   ii. which of the four reasons for the increased capital expenditures provided in HONI’s response to Staff IR 106 (Exhibit I-1-106) by four factors: Reliability Risk Analysis Results, Customer Preference, System needs arising from OPG’s planned nuclear refurbishments and retirements, New information that has arisen since the last filing regarding specific asset class needs; is the primary driver of the proposed change, or indicate if the change is driven by a factor other than the four identified.

b) The attached document “Table B - 2014 HONI Projects” lists the capital projects filed in EB-2014-0140 with budgeted expenditures in 2015 & 2016 above $3 million. For each listed project, identify, as applicable:

   i. the 2017 & 2018 capital expenditure forecast for that project that was included in the overall 2017 & 2018 forecasts in Table 1: Transmission Capital Expenditures (EB-2014-0140, Exhibit A, Tab 16, Schedule 8, Page 3-4)
   ii. The ISD Reference Number from EB-2016-0160 for that project if it still exists in the 2016 filing, or alternatively, the reason the project was cut since 2014.

Response

In response to Pre-Hearing Undertaking No.1, (part a, ii) the references to reliability risk analysis results and system needs arising from OPG's planned nuclear refurbishments and retirements require clarification.

The reliability risk is an outcome measure to gauge the impact of Hydro One's investment plan on future system reliability performance. It does not determine individual investment, which is determined by asset needs and other factors as described in Exhibit B1, Tab 2, Schedule 5. Therefore, reliability risk analysis is not used as a primary reason to explain the changes between EB-2014-0140 and EB-2016-0160 investments.

The notion behind Bruce Power and OPG nuclear refurbishments and retirements affecting Hydro One's investments is that it is not prudent to carry a backlog of sustainment investments into 2022, when a large reduction of based load generation will become unavailable. No investment has been advanced from beyond 2022. The objective is not to further defer sustainment investments and enter 2022 with a backlog. Therefore, nuclear refurbishment is not used as a primary reason to explain the changes between EB-2014-0140 and EB-2016-0160 investments.

Please refer to Attachment 1 (Table A - 2016 HONI Projects) and Attachment 2 (Table B - 2014 HONI Projects) for the completed tables.

Ontario Energy Board (Board Staff) Pre-Hearing Undertaking 1 Attachment 1

Table A: EB-2016-0160: List of Capital Investment Programs or Projects Requiring in Excess of $3 Million in Test Year 2017 or 2018[1]

Sustaining Capital Projects						
ID	**Project**	**EB-2016-0160**		**If included in EB-2014-0140:**		**If project is new, or if planned expenditures in 2017 or 2018 have increased since 2014 application, identify which of the four cited reasons drives the change.**
		2017 Budget	**2018 Budget**	**2017 Forecast**	**2018 Forecast**	
S01	Beck #1 SS	$5.9	$12.0	**35.00**	**13.00**	Scope Change
S02	Beck #2 TS	$29.8	$14.9	**0.00**	**0.00**	Scope Change
S03	Bruce A TS	$13.8	$19.7	**17.39**	**0.00**	Scope Change / Schedule Change
S04	Bruce B SS	$0.9	$24.6			New Project
S05	Cherrywood TS	$1.4	$3.8	**0.00**	**20.68**	Schedule Change
S06	Lennox TS	$26.1	$16.9	**0.16**	**10.56**	Schedule Change
S07	Richview TS	$16.9	$13.5	**18.80**	**0.00**	Scope Change / Schedule Change
S08	Beach TS	$16.5	$15.9	**0.00**	**0.49**	Scope Change
S09	Centralia TS	$12.5	$6.2	**0.94**	**17.86**	Schedule Change
S10	Dryden TS	$16.2	$0.1	**0.19**	**14.10**	Schedule Change
S11	Elgin TS	$22.6	$17.8	**0.00**	**0.00**	Scope Change / Schedule Change
S12	Espanola TS	$3.0	$0.0	**0.00**	**0.00**	Scope Change
S13	Gage TS	$1.2	$12.4	**15.59**	**0.00**	Scope Change
S14	Kenilworth TS	$5.6	$11.2	**3.29**	**22.56**	Scope Change
S15	Nelson TS	$10.9	$20.2	**4.40**	**12.56**	Customer Preference
S16	Palmerston TS	$8.8	$11.6			New Project

[1] EB-2016-0160, Exhibit B1, Tab 3, Schedule 11

Sustaining Capital Projects						
ID	**Project**	**EB-2016-0160**		**If included in EB-2014-0140:**		**If project is new, or if planned expenditures in 2017 or 2018 have increased since 2014 application, identify which of the four cited reasons drives the change.**
		2017 Budget	**2018 Budget**	**2017 Forecast**	**2018 Forecast**	
S17	Wanstead TS	$13.7	$14.3	**17.86**	**0.00**	Customer Preference
S18	Alexander SS	$14.4	$8.8			New Project
S19	Allanburg TS	$4.7	$1.0	**0.00**	**0.65**	Scope Change
S20	Aylmer TS	$3.5	$0.0	**1.99**	**9.03**	Schedule Change
S21	Barrett Chute SS	$9.3	$3.9			New Project
S22	Birch TS	$12.1	$13.8			New Project
S23	Bronte TS	$3.7	$17.1			New Project
S24	Bridgman TS	$0.2	$3.3	**0.00**	**1.32**	Scope Change
S25	Buchanan TS	$4.2	$0.0	**0.19**	**4.70**	Scope Change
S26	Cecil TS	$9.6	$0.0			New Project
S27	Chenaux TS	$7.5	$2.1	**0.00**	**0.00**	Schedule Change
S28	Crawford TS	$4.2	$0.0			New Project
S29	DeCew Falls SS	$4.9	$0.0			New Project
S30	Dufferin TS	$6.5	$7.4			New Project
S31	Ear Falls TS	$10.9	$0.0	**0.00**	**0.00**	Scope Change / Schedule Change
S32	Frontenac TS	$3.8	$1.5			New Project
S33	Hanmer TS	$24.4	$11.0			New Project
S34	Hawthorne TS	$1.6	$4.3	**0.14**	**0.00**	Scope Change / Schedule Change
S35	Horning TS	$14.3	$14.9			New Project
S36	Leaside TS Bulk	$5.9	$5.6			New Project
S37	Leaside TS 27.6 kV	$6.3	$6.5	**5.45**	**0.00**	Scope Change
S38	Main TS	$5.4	$8.4			New Project

Sustaining Capital Projects						
ID	**Project**	**EB-2016-0160**		**If included in EB-2014-0140:**		**If project is new, or if planned expenditures in 2017 or 2018 have increased since 2014 application, identify which of the four cited reasons drives the change.**
		2017 Budget	**2018 Budget**	**2017 Forecast**	**2018 Forecast**	
S39	Manby TS	$3.1	$1.8	**0.80**	**0.60**	Scope Change
S40	Martindale TS	$18.6	$18.6			New Project
S41	Minden TS	$4.2	$7.0			New Project
S42	Mohawk TS	$4.6	$4.7	**0.00**	**0.96**	Scope Change
S43	N.R.C. TS	$7.1	$0.7	**0.00**	**0.00**	Scope Change / Schedule Change
S44	Pine Portage SS	$1.9	$5.9			New Project
S45	Richview TS	$7.3	$0.0			New Project
S46	Sheppard TS	$9.8	$9.3	**5.38**	**1.90**	Scope Change
S47	St. Isidore TS	$9.1	$0.0	**0.00**	**0.00**	Scope Change
S48	Stanley TS	$0.5	$6.1			New Project
S49	Strachan TS	$5.1	$2.8			New Project
S50	Strathroy TS	$5.3	$0.0	**18.80**	**0.00**	Schedule Change
S51	Demand Capital – Power Transformers	$8.0	$8.2	**6.54**	**6.68**	Ongoing Program
S52	Minor Component Demand Capital	$4.7	$4.7			New Ongoing Program
S53	Operating Spare Transformer Purchases	$8.2	$8.3	**8.56**	**8.73**	Ongoing Program
S54	Transformer Protection Replacement	$4.6	$4.6			New Project
S55	Replace Legacy SONET Systems	$2.1	$5.3	**6.14**	**7.22**	Scope Change
S56	Physical Security for Critical Stations (non CIP-014)	$5.0	$5.0	**4.50**	**2.00**	Scope Change
S57	CIP V6 Transient Cyber Assets & Removable Media	$2.0	$10.0			New Project
S58	PSIT Cyber Equipment EOL	$5.0	$6.0			New Ongoing Program
S59	CIP-014 Physical Security Implementation	$6.0	$6.0			New Project

Sustaining Capital Projects						
ID	**Project**	**EB-2016-0160**		**If included in EB-2014-0140:**		**If project is new, or if planned expenditures in 2017 or 2018 have increased since 2014 application, identify which of the four cited reasons drives the change.**
		2017 Budget	**2018 Budget**	**2017 Forecast**	**2018 Forecast**	
S60	NERC CIP V6 CAPEX - Low Impact Facilities	$5.0	$5.0			New Project
S61	Transmission Site Facilities	$6.7	$6.7	**8.60**	**8.60**	Scope Change
S62	Line Refurbishment Project - C22J/C24Z/C21J/C23Z	$18.5	$2.5			New Project
S63	Line Refurbishment Project - D2L Dymond x Upper Notch	$8.4	$0.0			New Project
S64	Line Refurbishment Project - C1A/C2A/C3A	$1.8	$3.5			New Project
S65	Line Refurbishment Project - N21W/N22W	$4.1	$11.9			New Project
S66	Line Refurbishment Project - B5G/B6G	$4.4	$11.4			New Project
S67	Line Refurbishment Project - D2L Upper Notch x Martin River	$18.3	$21.1			New Project
S68	Line Refurbishment Project - B3/B4	$0.9	$6.4			New Project
S69	Line Refurbishment Project - A8K/A9K	$0.4	$6.6			New Project
S70	Line Refurbishment Project - A7L/R1LB and 57M1	$0.9	$20.5			New Project
S71	Line Refurbishment Project - K1/K2	$0.9	$7.4			New Project
S72	Line Refurbishment Project - E1C	$0.9	$12.8			New Project
S73	Line Refurbishment Project - D6V/D7V	$2.6	$5.7			New Project
S74	Line Refurbishment Project - D2H/D3H	$0.9	$12.5			New Project
S75	Wood Pole Replacements	$35.3	$35.3	**28.81**	**29.38**	Improved Forecast

Sustaining Capital Projects						
ID	**Project**	**EB-2016-0160**		**If included in EB-2014-0140:**		**If project is new, or if planned expenditures in 2017 or 2018 have increased since 2014 application, identify which of the four cited reasons drives the change.**
		2017 Budget	**2018 Budget**	**2017 Forecast**	**2018 Forecast**	
S76	Steel Structure Coating	$42.5	$54.4	**11.79**	**13.37**	New Information
S77	Steel Structure Foundation Refurbishments	$7.8	$7.8	**5.55**	**5.74**	Scope Change
S78	Shieldwire Replacements	$7.0	$7.1	**4.52**	**4.61**	Scope Change
S79	Insulator Replacements	$63.9	$61.4	**3.76**	**3.84**	New Information
S80	Transmission Lines Emergency Restoration	$8.7	$8.8	**11.35**	**11.58**	Improved Forecast
S81	Gordie Howe International Bridge (Recoverable)	$12.7	$12.5	**0.00**	**0.00**	Customer Preference
S82	Manvers – Lafarge Aggregate Pit (Recoverable)	$1.0	$3.8	**0.00**	**0.00**	Customer Preference
S83	H7L/H11L Cable Replacement	$1.3	$21.1	**14.83**	**15.12**	Schedule Change

Development Capital Projects						
ID	**Project**	**EB-2016-0160**		**If included in EB-2014-0140:**		**If project is new, or if planned expenditures in 2017 or 2018 have increased since 2014 application, identify which of the four cited reasons drives the change.**
		2017 Budget	**2018 Budget**	**2017 Budget (Gross $M)**	**2018 Budget (Gross $M)**	
D01	Clarington TS: Build new 500/230kV Station	$68.6	$14.8	53.2	0.0	Project schedule delayed to Q4 2018 as described in ISD Ref # D01.
D02	Nanticoke TS: Connect HVDC Lake Erie Circuit	$5.0	$13.0	N/A	N/A	New project initiated by customer request.
D03	Merivale TS to Hawthorne TS: 230 kV Conductor Upgrade	$2.5	$8.0	N/A	N/A	New project required to address inter-area network transfer capability need.
D04	East-West Tie Expansion: Station Work	$3.0	$30.0	N/A	N/A	New project required to address inter-area network transfer capability need. However, was referenced in EB-2014-0140, Exhibit D1, Tab 3, Schedule 3, page 33 as a major project with limited scope definition and no cash flow projections were provided at the time.
D05	Milton SS: Station Expansion and Connect 230kV Circuits	$2.0	$5.0	N/A	N/A	New project per the regional planning report, "Northwest Greater Toronto Area Integrated Regional Resource Plan."
D06	Galt Junction: Install In-Line Switches on M20D/M21D Circuits	$3.6	$0.1	N/A	N/A	Alternative project to defer the Preston TS Transformation project (ISD Ref # D06 in EB-2014-0140) at a reduced cost from $24.9M to $4.5M.
D07	York Region: Increase Transmission Capability for B82V/B83V Circuits	$22.6	$0.2	7.0	0.0	Original cash flows were based on a preliminary cost estimate. The current cash flows are based on a detailed cost estimate. The project schedule was delayed by 6 months.

Development Capital Projects						
ID	**Project**	**EB-2016-0160**		**If included in EB-2014-0140:**		**If project is new, or if planned expenditures in 2017 or 2018 have increased since 2014 application, identify which of the four cited reasons drives the change.**
		2017 Budget	**2018 Budget**	**2017 Budget (Gross $M)**	**2018 Budget (Gross $M)**	
D08	Hawthorne TS: Autotransformer Upgrades	$8.0	$5.8	4.5	0.0	Original cash flows were based on a preliminary cost estimate. The current cash flows are based on a detailed cost estimate. The project schedule was delayed by 1 year.
D09	Brant TS: Install 115kV Switching Facilities	$5.0	$6.0	N/A	N/A	New project per the regional planning report, “Brant Area Integrated Regional Resource Plan.”
D10	Riverdale Junction to Overbrook TS: Reconfiguration of 115kV Circuits	$2.4	$4.2	N/A	N/A	New project per the regional planning report, “Greater Ottawa Area Regional Infrastructure Plan.”
D11	Southwest GTA Transmission Reinforcement	$0.9	$5.0	N/A	N/A	New project per the regional planning report, “Metro Toronto Regional Infrastructure Plan.”
D12	Barrie TS: Upgrade Station and Reconductor E3B/E4B Circuits	$4.0	$20.0	N/A	N/A	New project per the IESO regional planning letter. (Refer to Exhibit B1, Tab 2, Schedule 3, Attachment 11.)
D13	Ear Falls TS to Dryden TS: Upgrade 115kV Circuit E4D	$10.0	$5.9	N/A	N/A	New project requested by the customer and also per the regional planning report, “North of Dryden Integrated Regional Resource Plan.”
D14	Supply to Essex County Transmission Reinforcement	$33.0	$31.4	10.0	0.0	Project schedule was delayed by 15 months due to delays in major project approvals.
D15	Horner TS: Build 230/27.6kV Transformer Station	$16.0	$13.0	N/A	N/A	New project requested by the customer and also per the regional planning report, “Metro Toronto Regional Infrastructure Plan.”
D16	Lisgar TS: Transformer Upgrades	$10.3	$2.5	N/A	N/A	New project requested by the customer and also per the regional planning report, “Greater Ottawa Regional

Development Capital Projects						
ID	**Project**	**EB-2016-0160**		**If included in EB-2014-0140:**		**If project is new, or if planned expenditures in 2017 or 2018 have increased since 2014 application, identify which of the four cited reasons drives the change.**
		2017 Budget	**2018 Budget**	**2017 Budget (Gross $M)**	**2018 Budget (Gross $M)**	
						Infrastructure Plan." This project was cancelled by the customer on August 16, 2016.
D17	Seaton MTS: Rebuild 230 kV Circuit (Provide 230kV Line Connection)	$3.3	$3.0	8.0	0.0	Scope change from building the transformer station and line connection work to only the line connection work.
D18	Hanmer TS: Build 230/44kV Transformer Station	$9.5	$18.5	N/A	N/A	New project requested by the customer and also per the regional planning report, "Sudbury Algoma Needs Assessment."
D19	Runnymede TS: Build 115/27.6kV Transformer Station and Reconductor 115kV Circuits	$23.0	$17.0	N/A	N/A	New project requested by the customer and also per the regional planning report, "Metro Toronto Regional Infrastructure Plan."
D20	Toyota Woodstock: Upgrade Station	$3.0	$2.5	N/A	N/A	New project requested by the customer.
D21	Enfield TS: Build 230/44kV Transformer Station	$10.0	$15.0	N/A	N/A	New project requested by the customer and also per the regional planning report, "Oshawa-Clarington Sub-Region Local Plan."
D22	TransCanada: Energy East Pipeline Conversion	$1.9	$10.2	N/A	N/A	New project requested by the customer. This project was cancelled by the customer in July 2016.
D23	Protection and Control Modifications for Distributed Generation	$6.0	$5.5	6.7	0.1	All 2017/2018 expenditures are recoverable.
D24	Nanticoke TS: New Station Service Supply	$10.0	$0.0	N/A	N/A	New project initiated for risk mitigation as a result of OPGI decommissioning the existing Nanticoke station service supply.

Operations Capital						
ID	**Project**	**EB-2016-0160**		**If included in EB-2014-0140:**		**If project is new, or if planned expenditures in 2017 or 2018 have increased since 2014 application, identify which of the four cited reasons drives the change.**
		2017 Budget	**2018 Budget**	**2017 Budget**	**2018 Budget**	
O01	Integrated System Operations Centre - New Facility Development	$4.2	$10.5	$6.0	$3.3	New information on asset / facility deficiencies within the Network Operating Backup Control Centre, Security Operations Centre and the Backup Integrated Telecommunication Management Centre.
O02	Station Local Control Equipment Sustainment	$3.6	$3.7	$0.0	$0.0	New Information
O03	Grid Control Network Sustainment	$5.8	$3.0	$2.0	$2.0	New Information

Capital Common Corporate Costs And Other Costs						
ID	**Project**	**EB-2016-0160**		**If included in EB-2014-0140:**		**If project is new, or if planned expenditures in 2017 or 2018 have increased since 2014 application, identify which of the four cited reasons drives the change.**
		2017 Budget	**2018 Budget**	**2017 Budget**	**2018 Budget**	
IT1	Hardware/Software Refresh and Maintenance	$5.1	$5.1	$5.4	$5.4	This is an ongoing program.
IT2	MFA Servers and Storage	$4.2	$2.8	$4.4	$2.9	This is an ongoing program.
IT3	Work Management and Mobility	$5.0	$3.0	$4.3	$1.1	Scope expanded beyond provincial lines organization to now include provincial lines, stations, and forestry organizations.

Capital Common Corporate Costs And Other Costs						
ID	**Project**	**EB-2016-0160**		**If included in EB-2014-0140:**		**If project is new, or if planned expenditures in 2017 or 2018 have increased since 2014 application, identify which of the four cited reasons drives the change.**
		2017 Budget	**2018 Budget**	**2017 Budget**	**2018 Budget**	
CC1	Real Estate Field Facilities Capital	$18.4	$20.9	$17.2	$19.9	No material net change.
CC2	Transport & Work Equipment	$20.9	$21.8	$15.5	$17.2	New information that contributed to an increased transmission work program. This increased the requirement for fleet assets.
CC3	Service Equipment	$3.2	$3.2	$4.2	$3.8	No material net change.

Ontario Energy Board (Board Staff) Pre-Hearing Undertaking 1 Attachment 2

Table B: EB-2014-0140 - List of Capital Investment Programs or Projects Requiring in Excess of $3 Million in Test Year 2015 or 2016[1]

Sustaining Capital Projects				
ID	**Project**	**EB-2014-0140**		**ISD Reference Number from EB-2016-0160 if project is included in 2016 filing, or reason for deletion**
		2017 Forecast	**2018 Forecast**	
S01	Oil Circuit Breaker Replacements	10.27	10.48	Consolidated into Station-Centric Investments
S02	SF6 Circuit Breaker Replacements	8.43	11.05	Consolidated into Station-Centric Investments
S03	GTA Metalclad Switchgear Replacements	6.38	5.28	Consolidated into Station-Centric Investments
S04	Air Blast Circuit Breaker Replacement - Richview TS	18.80	0.00	S07
S05	Air Blast Circuit Breaker Replacement - Beck #2 TS	0.00	0.00	S02
S06	Air Blast Circuit Breaker Replacement - Bruce A TS	17.39	0.00	S03
S07	Air Blast Circuit Breaker Replacement - Burlington TS	0.00	0.00	Project is scheduled to be completed by year-end 2016
S08	End of Life Station Reconfiguration - Gage TS	15.59	0.00	S13

[1] EB-2014-0140, Exhibit I, Tab 10, Schedule 14

Sustaining Capital Projects				
ID	Project	EB-2014-0140		ISD Reference Number from EB-2016-0160 if project is included in 2016 filing, or reason for deletion
		2017 Forecast	2018 Forecast	
S09	End of Life Station Reconfiguration – Timmins TS	0.00	0.00	Project Completed
S10	End of Life Station Reconfiguration - Hanmer TS	0.00	0.00	Project Completed
S11	Integrated DESN Replacement - Dunnville TS	0.00	0.00	Project Completed
S12	Integrated DESN Replacement – National Research Council TS	0.00	0.00	S43
S13	Integrated DESN Replacement - Espanola TS	0.00	0.00	S12
S14	Integrated DESN Replacement - Strathroy TS	18.80	0.00	S50
S15	Integrated DESN Replacement - Elgin TS	0.00	0.00	S11
S16	Integrated DESN Replacement - Gerrard TS	0.00	0.00	Project Completed
S17	Integrated DESN Replacement – Chenaux TS	0.00	0.00	S27
S18	Integrated DESN Replacement - Overbrook TS	0.00	0.00	Project Completed
S19	Integrated DESN Replacement – Ear Falls TS	0.00	0.00	S31
S20	Integrated DESN Replacement - Wiltshire TS	0.00	0.00	Project Completed
S21	Integrated DESN Replacement - Bridgman TS	0.00	0.00	Project Completed
S22	Integrated DESN Replacement – Dundas TS	0.00	0.00	Project Completed
S23	Integrated DESN Replacement - Goderich TS	6.58	0.00	Project is scheduled to be completed by year-end 2017
S24	Integrated DESN Replacement - Leaside TS	5.45	0.00	S37

Sustaining Capital Projects				
ID	**Project**	**EB-2014-0140**		**ISD Reference Number from EB-2016-0160 if project is included in 2016 filing, or reason for deletion**
		2017 Forecast	**2018 Forecast**	
S25	Integrated Station Component Replacements	1.84	16.27	Consolidated into Station-Centric Investments
S26	Power Transformer Replacements	21.47	37.12	Consolidated into Station-Centric Investments
S27	Operating Spare Transformer Purchases	8.56	8.73	S53
S28	Disconnect Switch Replacements	8.69	8.86	Consolidated into Station-Centric Investments
S29	Capacitor Bank Replacements	6.62	6.69	Consolidated into Station-Centric Investments
S30	Instrument Transformer Replacements	3.28	3.35	Consolidated into Station-Centric Investments
S31	Insulator Replacements	4.61	4.73	Consolidated into Station-Centric Investments
S32	Station Service Replacements	12.61	12.61	Consolidated into Station-Centric Investments
S33	Spill Containment	10.98	11.20	Consolidated into Station-Centric Investments
S34	Integrated Station P&C Replacements	32.02	18.61	Consolidated into Station-Centric Investments

Sustaining Capital Projects				
ID	**Project**	**EB-2014-0140**		**ISD Reference Number from EB-2016-0160 if project is included in 2016 filing, or reason for deletion**
		2017 Forecast	**2018 Forecast**	
S35	Protection Replacements	22.08	21.24	Consolidated into Station-Centric Investments
S36	RTU and SER Replacements	8.34	8.51	Consolidated into Station-Centric Investments
S37	DC Signaling (Remote Trip) Replacements	1.02	0.00	Consolidated into Station-Centric Investments
S38	Protection Tone Channel Replacements	4.32	4.41	Consolidated into Station-Centric Investments
S39	PLC Device Replacements	4.83	4.92	Consolidated into Station-Centric Investments
S40	Cyber Security NERC CIP V5 Readiness	0.25	0.00	Project Completed
S41	Cyber Security of Load Stations	4.50	2.00	S56
S42	Station Building Infrastructure	8.60	8.60	Consolidated into Station-Centric Investments
S43	Station Civil Infrastructure	12.53	12.77	Consolidated into Station-Centric Investments
S44	Wood Pole Replacements	28.81	29.38	S75
S45	Steel Structure Coating	11.79	13.37	S76
S46	Steel Structure Replacements	5.78	5.89	Consolidated into Line

Sustaining Capital Projects				
ID	Project	EB-2014-0140		ISD Reference Number from EB-2016-0160 if project is included in 2016 filing, or reason for deletion
		2017 Forecast	2018 Forecast	
				Refurbishment projects
S47	Steel Structure Foundation Refurbishments	5.55	5.74	S77
S48	Shieldwire Replacements	4.52	4.61	S78
S49	Insulator Replacements	3.76	3.84	S79
S50	Transmission Lines Emergency Restoration	11.35	11.58	S80
S51	C25H Line Refurbishment	0.00	0.00	Project Completed
S52	H24C Line Refurbishment	0.00	0.00	Project is scheduled to be completed by year-end 2016
S53	D10S/D9HS Line Refurbishment	0.00	0.00	Project Completed
S54	Q11S/Q12S Line Refurbishment	0.00	0.00	Project Completed
S55	Secondary Land Use and Recoverable Projects	0.00	0.00	S81, S82
S56	H2JK/K6J Cable Replacement	0.00	0.00	Project Completed
S57	H7L/H11L Cable Replacement	14.83	15.12	S83

Development Capital Projects[2]				
ID	**Project**	**EB-2014-0140**		**ISD Reference Number from EB-2016-0160 if project is included in 2016 filing, or reason for deletion**
		2017 Budget ($M)	**2018 Budget ($M)**	
D01	New 500 kV Bruce to Milton Double Circuit Transmission Line	6.5	0.0	Other Projects <$3M
D02	Clarington TS: Build new 500/230kV Station	53.2	0.0	ISD Ref # D01
D03	Installation of Shunt Capacitor Banks at Cherrywood TS	7.0	3.5	Other Projects <$3M
D04	Midtown Transmission Reinforcement Plan	0.0	0.0	Project in-service November 2016
D05	Guelph Area Transmission Reinforcement	0.0	0.0	Project in-service November 2016
D06	Preston TS Transformation	10.0	0.0	Project deferred and replaced by Galt Jct. switches. Refer to ISD Ref # D06
D07	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate	0.0	0.0	Expected in-service December 2016.
D08	Hawthorne TS: Replace two existing Transformers	4.5	0.0	ISD Ref # D08
D09	York Region – Increase Transmission Capability for B82V/B83V Circuits	7.0	0.0	ISD Ref # D07
D10	Copeland MTS: Build line connection for Toronto	0.0	0.0	In-service date delayed to Q1 2018 by

[2] Some forecast costs were provided in EB-2014-0140 Exhibit 1, Tab 4, Schedule 20, Page 2 of 4

Development Capital Projects[2]				
ID	**Project**	**EB-2014-0140**		**ISD Reference Number from EB-2016-0160 if project is included in 2016 filing, or reason for deletion**
		2017 Budget ($M)	**2018 Budget ($M)**	
	Hydro			customer in August 2016. Project is expected to be fully recoverable.
D11	Seaton TS: Build New 230-28kV Transformer Station	8.0	0.0	ISD Ref # D17
D12	Supply to Essex County Transmission Reinforcement	10.0	0.0	ISD Ref # D14
D13	Napanee Gas Generation Connection	0.5	0.0	Other Projects <$3M
D14	Transmission Station P&C Upgrades for DG	6.7	0.1	ISD Ref # D23

Operations Capital				
ID	**Project**	**EB-2014-0140**		**ISD Reference Number from EB-2016-0160 if project is included in 2016 filing, or reason for deletion**
		2017 Budget	**2018 Budget**	
O1	NMS Capital Sustainment	0.0	0.0	In-serviced in February 2016. Investment Complete.
O2	BUCC New Facility Development	6.0	3.3.	ISD Ref # O01 – Investment name changed from BUCC New Facility Development to Integrated System Operations Centre – New Facility Development (ISD-O01)
O3	Wide Area Network Outreach Program	5.0	1.0	Cancelled due to negative test results. No cash flow greater than $3M in test years
O4	Station LAN Infrastructure Program	5.9	6.0	Majority of the work has been combined with integrated station investment projects. No cash flow greater than $3M in test years
O5	Fault Locating Program	3.0	0.0	The plan is being re-evaluated and combined with other control infrastructure

Operations Capital				
ID	**Project**	**EB-2014-0140**		**ISD Reference Number from EB-2016-0160 if project is included in 2016 filing, or reason for deletion**
		2017 Budget	**2018 Budget**	
				initiatives. No cash flow greater than $3M in test years.
O6	Grid Control Network Sustainment	2.0	2.0	ISD Ref# O02
O7	Hub Site Management Program	3.9	3.3	No cash flow greater than $3M in test years.

Capital Common Corporate Costs And Other Costs				
ID	**Project**	**EB-2014-0140**		**ISD Reference Number from EB-2016-0160 if project is included in 2016 filing, or reason for deletion**
		2017 Budget	**2018 Budget**	
IT1	Hardware/Software Refresh and Maintenance	$5.4	$5.4	ISD Ref #IT1 - Ongoing Capital Program.
IT2	MFA Servers and Storage	$4.4	$2.9	ISD Ref #IT2 - Ongoing Capital Program.
IT3	MFA PC and Printer Hardware	$2.9	$2.5	No cash flow in excess of $3M in

Capital Common Corporate Costs And Other Costs				
ID	**Project**	**EB-2014-0140**		**ISD Reference Number from EB-2016-0160 if project is included in 2016 filing, or reason for deletion**
		2017 Budget	**2018 Budget**	
				2017 or 2018. Ongoing Capital Program.
IT4	Field Workforce Optimization and Mobile IT	$4.3	$1.1	ISD Ref #IT3
IT5	Customer Experience	$0.0	$0.0	Entire associated costs are allocated to Distribution.
IT6	Corporate Support Optimization	$0.0	$1.6M	No cash flow in excess of $3M in 2017 or 2018. In proceeding EB-2016-0160, this investment is described as specific human resource, environment health and safety functions associated projects.
C1	Real Estate Head Office & GTA Facilities Capital for 2015	0	0	Project completed.
C2	Real Estate Field Facilities Capital	$17.2	$19.9	ISD Ref #CC1 - Ongoing program.
C3	Transport & Work Equipment	$15.5	$17.2	ISD Ref #C3
C4	Service Equipment	$4.2	$3.8	ISD Ref #C4

Ontario Energy Board (Board Staff) Pre-Hearing UNDERTAKING #2

Undertaking

Please provide the most current business cases supporting the complete rebuild of the following four substations in the Hamilton area as listed in **Exhibit B1, Tab 3, Schedule 11**

- #S08 – Station Reinvestment – Beach TS;
- #S11 – Station Reinvestment – Elgin TS;
- #S13 – Station Reinvestment – Gage TS;
- #S14 – Station Reinvestment – Kenilworth TS.

Response

Attached are business case summary approval documents for Elgin TS(S11) and Beach TS (S08).

Kenilworth TS (S14) and Gage TS (S13) are under detailed estimating. As such, business case summary documents are not available at this time. Business case summary documents are produced upon finalizing the cost estimate as the vehicle for seeking authorization to proceed with expenditure.

In recent discussions with the IESO, Hydro One agreed that there is merit in looking at Gage and Kenilworth from a broader coordinated regional perspective as these projects have not been committed. We will be reviewing them with the IESO and LDC's as part of the Burlington to Nanticoke Regional Infrastructure Plan. The review will shape their final business case documents to achieve the best overall solution for the system and rate payers. Conducting regional planning review for these and other future major investments will ensure full coordination with the planning activities of the IESO and the regional planning partners to optimize ratepayer value.

hydro one

Investment Driver: N.T.C.1.08 Date: July 27, 2015

AR Number: 17148 Title: Elgin TS: EOL Replacement Project

Hydro One Networks - Business Case Summary - 50004070

Elgin TS: End of Life (EOL) Replacement Project

Investment Driver: **In-Service date:** November 2, 2019

N.T.C.1.08: System Re-investments (2015 - $226M, 2016 - $180M, 2017 - $153M, 2018 - $154M, 2019 - $106M) are intended to integrate the replacement of multiple station assets that are approaching end of life.

This Approval: $58.2M **Previous Approval:** $0.2M **Project Total:** $58.4M

Need:

To replace assets at Elgin TS that are at end of life (EOL) due to their deteriorated condition, obsolescence and high maintenance costs. Not proceeding with this work will increase the risk of further equipment deterioration and result in reduced reliability to Horizon Utilities' customers in downtown City of Hamilton. There is an increased level of urgency to address the risk of equipment failure due to the fact that the station is adjacent to a school and daycare centre.

Investment Summary:

Elgin TS is a transmission station that transforms 115 kV into 13.8 kV, supplying load delivery to customer Horizon Utilities in the downtown core of the City of Hamilton.

The Elgin TS T1/T2 and T3/T4 transformer switchyards were built in 1968. These assets are in degraded condition as verified through visual inspection and diagnostic testing. Further, the equipment within these two switchyards are obsolete and some of the parts are no longer supported by the manufacturer.

This investment will result in the complete rebuild and reconfiguration of the T1/T2 and T3/T4 switchyards, replacing existing EOL and degraded infrastructure, including the T1/T2 and T3/T4 transformers and associated switchgear, with new Medium Voltage Gas Insulated Switchgear (MVGIS) equipment built to current HONI standards. These two existing switchyards will be reconfigured into a single switchyard and avoid the need to procure additional land to expand the station.

Reconfiguration of the station into a single facility will minimize ongoing lifecycle cost and integration of the replacement of multiple end-of-life components into a single station project, allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Results:

Improved reliability, standardized design and reduced ongoing lifecycle costs.

Costs:

	2015 M	2016 M	2017 M	2018 M	2019 M	Total M
Capital* and MFA	0.9	7.1	13.4	22.5	13.5	57.4
OM&A and Removals	0.1	0.7	0.0	0.0	0.0	0.8
Gross Investment Cost*	1.0	7.8	13.4	22.5	13.5	58.2
Recoverable	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	1.0	7.8	13.4	22.5	13.5	58.2

Cost includes interest and overhead at current rates

Alternatives

ALTERNATIVES CONSIDERED AND REJECTED

Status Quo or Do nothing Alternative

The existing Pioneer Electric, Ferranti Packard and English Electric transformers and associated equipment at Elgin TS are EOL, in deteriorated condition and are in need of replacement to maintain the reliability of supply to Horizon Utilities downtown City of Hamilton loads. This status quo option is rejected because it does not address the condition of the assets, reliability of the station and risk of equipment failure which is magnified by the fact that the station is adjacent to a school and daycare centre.

Alternative One

This alternative maintains the existing two switchyard arrangement by replacing like-for-like four transformers and associated low voltage facilities in two switchyards. This alternative was rejected because the existing station property footprint does not provide the necessary space required to meet current HONI switchyard requirements e.g. holding tanks and spill containment facilities required for four transformers.

Alternative Two

Due to the lack of additional space available within the existing station footprint this alternative purchases additional property and reroutes underground 115kV power supply cables. It would also require extensive rerouting and re-termination of the distribution system cables. This alternative was rejected because of the high cost of rebuilding and rerouting the underground cables through City of Hamilton streets and the increased time required for approvals including real estate, environmental and OEB Section 92.

RECOMMENDED ALTERNATIVE AND RATIONALE

Alternative Three

This alternative consists of reconfiguring the station's two switchyards to a single switchyard with MVGIS to reduce station switchgear assemblies supplying Horizon Utilities. Along with the transformer and switchgear upgrades, spill containment, protection, control and telecommunication equipment would also be upgraded to meet current HONI standards. Proceeding with this option consolidates the station facilities into one switchyard within the existing station footprint and improves the reliability of supply to Horizon Utilities in the City of Hamilton.

Alternative three is the recommended alternative because it addresses all deteriorated equipment at Elgin TS, improves the reliability of supply to the customer, addresses the safety concerns and minimizes OM&A costs by reducing the number of DESN's from two to one.

Alternatives Compared

	Project Level Risk		
Business Value	**Current Risk**	**Alt3**	**Comparison**
Reliability	HIGH	LOW	Alternative three will increase reliability of supply by providing MVGIS switchgear facilities to meet customer requirements and HONI standards. This station refurbishment will also aim to reduce the 20 delivery point interruptions since 2005 and improve the 174 deficiency reports related to the station over the last 7 years.
Customer	HIGH	LOW	Alternative three will ensure a robust and reliable supply to Horizon Utilities by consolidating station facilities into one switchyard within the existing station footprint. This avoids the need to expand the station and minimizes the impact to the customer during construction.
Competitiveness	HIGH	LOW	Alternative three will minimize ongoing lifecycle costs by consolidating and reconfiguring the station into one DESN station.
Safety and environment	MED	LOW	The existing transformers T1/T2 have no spill containment facilities, while transformers T3/T4 spill containment facilities are not up to current HONI standard. No noise mitigation or fire barrier facilities exist for T1 and T2.Spill containment, noise mitigation and fire separation for new transformers will mitigate environmental risks and comply with MOE requirements. There is an increased level of urgency to address the risk of equipment failure due to the fact that the station is adjacent to a school and daycare centre.
Regulatory / Legal	MED	LOW	Replacement of EOL facilities will ensure that Hydro One continues to meets its license obligations under the Transmission System Code.
Reputation	N/A	N/A	Not influential in the investment decision.
Initial Cost ($M)		58.4	
Financial: PV Cost / NPV ($M)			NPV costs were not calculated as there is only one viable alternative and the decision was not primarily based on financial factors

Project Risk and Mitigation:

Cost:

Project costs of $58.4M are based on estimates which have an accuracy of +/- 20% and include interest charges, overheads and an allowance of $3.9M for contingency.

Investment Driver: N.T.C.1.08 | Date: July 27, 2015
AR Number: 17148 | Title: Elgin TS: EOL Replacement Project

Business Planning:

This investment was included in the 2015-2019 Business Plan at a cost of $42.2M. Current estimated costs are $58.4M. This increase is due to improved project definition as a result of detailed estimate and a site assessment with engineering and field personnel. Additional required funding will be provided through the reprioritization of projects within the Tx capital envelope.

Execution Risks:

Approvals - Low
S.92 - N/A
EA - N/A
Outages - Medium (due to coordination with Horizon Utilities required)
Resourcing - Low
First Nations - N/A
Real Estate - Medium (construction staging area requires City of Hamilton approval to use nearby parking lot)
Agreements - N/A
Technology - N/A

Regulatory Considerations:

This investment was included in Hydro One's 2015/2016 Transmission Rate Filing at a total cost of $33M (to be spent by 2016) and with an in-service date in 2017. Funding for the additional proposed TX capital expenditures will be redirected from projects that are delayed or through the reprioritization of work within the Transmission capital envelope. Any impact to the total transmission 2015 and 2016 capital in-service additions target, as a result of reprioritization of projects, will be coordinated and managed.

The current capital project's expenditures forecast of $13.4M, $22.5M and $13.5M planned to be spent in 2017, 2018 and 2019 respectively, will be included in HONI's next transmission rates application, as it was outside the window of the previous Transmission rate filing.

No other significant regulatory issues are anticipated other than the standard need and prudence justification.

Funds Included in Business Plan: N	**Director:** Chong Kiat Ng	**Planner:** Fred Kouhdani
This Approval($M): 58.2	**Previous Approval($M):** 0.2	**Current Est. of Total Cost($M):** 58.4
Signature Block:		
Submitted by: Sandy Struthers	**Title:** COO & EVP Strategic Planning	**Date:** Ag 24/15
Reviewed by: Michael Vels	**Title:** Chief Financial Officer	**Date:** 8/25/15
Recommended by: Carmine Marcello	**Title:** President and CEO	**Date:** Aug. 31/15
Approved by:	**Title:** Board of Directors Advice	**Date:** Aug 31/15

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? N
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? N

Hydro One Limited / Hydro One Inc.
ADVICE OF DECISION OF BOARD OF DIRECTORS
(excerpt from minutes of Board of Directors)

to____________________ date of meeting February 2, 2016

copies to: File agenda number 7.2

subject: Capital Projects

Beach Transformer Station Upgrade

After consideration, upon motion duly made, seconded, and unanimously carried, it was RESOLVED:

THAT the Board of Directors approve the investment of $77.7 million for the Beach Transformer Station Upgrade.

M Vaughan

SECRETARY
Issued on February 4, 2016

Hydro One Limited/ Hydro One Inc.
Submission to the Board of Directors

Date: February 2, 2016

Re: Approval for Beach Transformer Station Integrated Station Upgrade

At the board meeting, I will present a proposal to spend $77.7 million to replace end of life equipment at Beach Transformer Station. The station serves Hamilton's industrial centre and part of its downtown core. The completed planned in-service date is December 2019.

We are asking for approval of the project, as per the attached board resolution.

Yours sincerely,

Sandy Struthers
Chief Operating Officer and
Executive Vice President, Strategic Planning

Beach Transformer Station Upgrade

Resolution:

After consideration, upon motion duly made, seconded, and unanimously carried, be it RESOLVED:

THAT the Board of Directors of Hydro One Inc. approve the investment of $77.7 million for the Beach Transformer Station Upgrade.

Hydro One Inc.

Hydro One Board of Directors

Approval – Beach Transformer Station Integrated Station Upgrade

February 2, 2016

Hydro One Inc.

Overview

We are requesting approval for $77.7 million to replace end of life equipment by rebuilding the Beach Transformer Station 230 kV switchyard in a greenfield location, on the existing property, consistent with current Hydro One design standards and Northeast Power Coordinating Council requirements. The station has deteriorated assets and conditions that are negatively impacting the reliability of supply to local distribution companies and direct industrial customers in the Hamilton/Niagara and Burlington areas.

The planned completed in-service date is December 2019.

Investment Details

Built in the late 1940's, Beach Transformer Station is located within Hamilton's industrial core. It is connected to Hydro One's networks in the area. Beach Transformer Station directly supplies two major industrial customer stations owned by ArcelorMittal Dofasco and a local distribution company (Horizon Utilities). The station also serves as a primary supply point for twenty other transformer stations within Hamilton-Niagara Region.

Due to the condition of the assets at Beach, since 2008, there have been 20 cooling or oil level/temperature related issues on transformers T3 and T4 and a total of over 280 corrective and emergency work orders. These transformers are located adjacent to administrative buildings and lack the necessary fire protection and separation, resulting in increased safety risk.

Oil Circuit Breaker in poor condition

T3/T4 in close proximity to building

Furthermore, spill containment, drainage and oil/water separator facilities currently do not meet current Ministry of Environment and Climate Change requirements and are assessed to be the second greatest spill risk of the 291 Hydro One stations. Separate investments are already underway to correct the deficiency at the highest (Wanstead) and third highest risk (Birch) transformer stations.

We had initially approved the investment in 2014 with an estimated total cost of $25.4 million based on using a brownfield, like-for-like, in-situ asset replacement, and using unit cost estimates.

Subsequent engineering revealed that the station layout makes in-situ asset replacement unfeasible and confirmed that the only viable approach would be to rebuild the existing 230kV switchyard in a greenfield location, replace and relocate transformers T3 and T4, install spill containment to meet regulatory requirements and upgrade the protection, control and telecommunication facilities.

We have undertaken significant work to date, including the refurbishment of the existing protection, control and telecommunication building, construction of AC/DC station service, and construction of the new switchyard ground grid, foundations, steel structures, and associated buses. These past expenditures were required to support the increased scope of the project and will form part of the useful in-service additions starting in 2016. This approval seeks the remaining funds required to upgrade the station to required standards.

Benefits

Beach Transformer Station is key to the reliable supply to a major distributor and a large industrial customer, and to twenty customer owned and Hydro One stations. As such, any improvements in reliability and reduced interruption cost impact a large number of our customers. The investment will provide the following benefits:
(a) Reduce the risk of customer interruptions and improve reliability of supply by 30%
(b) Reduce outage constraints for improved work execution efficiency and minimize the risk of interruptions to Horizon Utilities and ArcelorMittal Dofasco
(c) Increase station short circuit capability to enable future integration of generation
(d) Address an ongoing safety concern
(e) Reduce loading on the 115kV network in Hamilton and Burlington
(f) Meet current Hydro One design standards and Northeast Power Coordinating Council requirements.

Cost Summary

This is a multi-year project, with expenditures planned over four years. However, we are able to segregate and measure discrete elements of the project to enable capital to be placed into service during the project duration, thus limiting the lag between capital spending and inclusion of the investment in the Company's rate base. The following is the planned schedule of placing asset in-service:

	2016($M)	2017($M)	2018 ($M)	2019 ($M)	Total ($M)
In-Service $ Additions	19.1	13.2	38.2	5.5	76.0

The cost breakdown is as follows:

Category	Cost ($M)
Material	24.3
Construction	24.0
Project Management, Engineering & Commissioning	11.0
Contingency	2.0
Interest & Overhead	16.4
Total	**77.7**

* $1.7 million of construction expenditures is OM&A for removal of old assets

Contingency represents only 2.6% of the total project cost as a majority of the materials have already been procured, significant engineering and make ready construction work has been completed and dedicated resources have been allocated to manage outage requirements.

Alternatives Considered

Due to asset condition, performance and safety concerns; there is no other viable alternative.

Regulatory Impacts

The 2015 and 2016 capital spend for this project were not included in Hydro One's approved 2015/16 Transmission Rate Filing. The funding for the project will require redirection from other projects which will be delayed or deferred without impacting committed in-service capital amounts.

The total planned project expenditures and related in-service commitments will be included in the 2017/2018 rate application that will be filed with the Ontario Energy Board in May 2016. We consider the risk of non-recovery of these amounts to be low as this investment is required to address equipment risks that exist at the station, potential significant impact to customers in the network and the clear and supportable benefits to the system of proceeding.

No other significant regulatory issues are anticipated other than the standard need and prudence justification.

Risks and Mitigation

Outages

Obtaining the necessary outages at this station will require outage coordination with ArcelorMittal Dofasco and Horizon Utilities. ArcelorMittal Dofasco has two customer owned stations which are supplied directly from Beach Transformer Station and have limited acceptable outage windows and durations. The customer outage windows are also constrained by distribution system outages that may be required by Horizon Utilities. The risk is considered to be medium. Unforeseen delays in securing the required outages will directly impact the project cost and schedule, until the next outage opportunity becomes available.

These risks are being mitigated by Horizon Utilities cooperating to facilitate load transfers to adjacent stations and working with the two customers to agree upon and complete a detailed outage staging plan

First Nations

The work to be completed will take place within the existing station footprint and a Class Environmental Assessment is not required. However, Hydro One will notify the surrounding First Nations to maintain its ongoing positive relationship. We do not consider this element to be a high risk for this project.

SAP Information & Signature Sheet

Annual Expenditures:

	2015($M)	2016($M)	2017($M)	2018 ($M)	2019 ($M)	Total ($M)
Capital*	28.2	9.7	14.3	18.3	5.5	76.0
OM&A and Removals	-	0.9	0.8	-	-	1.7
Gross Investment Cost	28.2	10.6	15.1	18.3	5.5	77.7

* Includes capitalized interest and overheads

Investment Name:	**Beach Transformer Station Integrated Station Upgrade**	
Final In-service Date:	**December 31, 2019**	
Business Case Summary #: 50004331	**Acquisition Request (AR) #:** 23020	**Investment Driver:** N.T.C.1.10
Funds Included in Business Plan: Yes	**Director:** Chong Kiat Ng	**Planner:** Nimesh Mistry
This Approval ($): $52.3M	**Previous Approval ($):** $25.4M	**Current est. of Total Cost ($):** $77.7M
Signature Block:		
Submitted by: Sandy Struthers	**Title:** COO & EVP Strategic Planning	**Date:**
Reviewed by: Michael Vels	**Title:** Chief Financial Officer	**Date:**
Recommended by: Mayo Schmidt	**Title:** President and CEO	**Date:**
Approved by:	**Title:** Board of Directors Advice	**Date:**

***Scientific Research & Experimental Development Tax Credits (SR&ED):* _CONFIRM WITH TAX IF REQUIRED**

- Do you anticipate that an initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? No

- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? No

Ontario Energy Board (Board Staff) Pre-Hearing UNDERTAKING #3

Undertaking

OEB staff has compiled the following tables using information in the current EB-2016-0160 application as well as the previous EB-2014-0140 application. Staff requests that Hydro One confirm the calculations, totals and percentages in the tables.

Table 1- Average Capital Expenditure and Investment Percentage by Category 2012 – 2021 ($ Million)

Category	Historic and Bridge Year Expenditures (2012 – 2016)		Test Year and Forecast Expenditures (2017 – 2021)		Forecast Increase in Average Annual Expenditures vs. Historical Spend by Cost Category
	Average Expenditures	% of Total Expenditure	Average Expenditures	% of Total Expenditure	
Sustaining	581.84	68%	895.58	73%	54%
Development	192.94	23%	224.58	18%	16%
Operations	21.4	2%	32.16	3%	50%
Common Corp Costs	61.04	7%	77.56	6%	27%
Total Capital	**857.2**	**100%**	**1,229.86**	**100%**	**43%**

Table 2- Forecast Expenditure Increases Compared to 2015/16 COS Filing in 2014 (EB-2014-0140) ($ Million)

Investment Category	EB-2014-0140[1]			EB-2016-0160			Comparison between Filings		
	Forecast Years			Test Year 1	Test Year 2	Forecast Year	2017 Increase	2018 Increase	2019 Increase
	2017	2018	2019	2017	2018	2019			
Sustaining	597.4	636.7	600.1	776.8	842.1	825.7	30.0%	32.3%	37.6%
Development	148.0	116.4	155.5	196.4	170.2	244.0	32.7%	46.2%	56.9%
Operations	44.4	25.2	18.8	25.4	30.8	58.8	-42.8%	22.2%	212.8%
Common Corp Costs	58.0	60.4	57.0	77.6	79.1	79.1	33.8%	31.0%	38.8%
Total Capital	**847.8**	**838.7**	**831.4**	**1,076.1**	**1,122.2**	**1,207.5**	**26.9%**	**33.8%**	**45.2%**

[1] *EB-2014-0140, Exhibit A, Tab 16, Schedule 8, Page 3-4: Table 1: Transmission Capital Expenditures*

Response

Hydro One has reviewed Table 1 and 2 as provided by the OEB staff and confirms the calculations, totals and percentages in the table are correct.

Ontario Energy Board (Board Staff) INTERROGATORY #002

Reference:

Exhibit A and Auditor General's Report, Fall 2015

Interrogatory:

The 2015 Ontario Auditor General's report identified a number of areas of concern for Hydro One and in particular, the transmission system. The most significant concerns cited by the auditor general were:

- Deterioration of system reliability
- Backlogs of preventative maintenance
- High risk assets not being replaced
- Significant assets beyond expected life still in use
- Asset analytics not considering all factors for asset replacement decisions.
- Inaccurate data in OEB funding requests
- Limited security for electronic devices.

Please provide a summary of how the areas of concern cited by the Auditor General were addressed in this application.

Response:

Deterioration of System Reliability

The Auditor General evaluated the reliability trend based upon two distinct data points; 2010 and 2014. Due to annual variations caused by weather and major or force majeure events, determination of trends in reliability is meaningful using 3 or 5 year rolling averages, which normalize these variations. Based on this industry accepted approach, Hydro One's transmission reliability has remained relatively constant as indicated by the reliability performance metrics provided in Exhibit B1, Tab 1, Schedule 3 of the application.

To improve its ability to more accurately measure the effect of system investment on reliability Hydro One has done the following:

- Supplemented its existing analysis with an additional model to quantify reliability risk which provides a directional indication of the effect of system investment on future transmission system reliability.

Witness: Mike Penstone

- Continued initiatives to reduce the number of planned outages by combining, and better scheduling, capital and maintenance activities undertaken during outages.
- Improved the performance of single circuit delivery points, which by design are not as reliable as delivery points served by multiple circuits. Single-circuit delivery point reliability has increased over the 2010 to 2014 period, as shown by the improved SAIDI and SAIFI results and lower planned outages.

Backlogs of Preventative Maintenance

In regard to backlogs of preventative maintenance, Hydro One's practice is to release more maintenance orders than available execution resources. This strategy provides execution scheduling flexibility and enables work bundling and crew redeployment in the event of outage cancellations. In addition, in 2014, a large amount of work orders for PCB testing, needed to ensure compliance with federal regulations, was released to enable efficient scheduling and bundling of this work. Hydro One expected this volume of PCB related work orders to be completed by 2020, and does not consider these to be a backlog of incomplete work due to poor planning, rather a conscious decision to add these work orders to improve the visibility of this long-term initiative.

Although Hydro One does not believe this practice has negatively affected system reliability, it has addressed this issue by recently developing a process to help asset planners better monitor the status of preventative maintenance orders and maintenance spending to aid them in identifying and prioritizing equipment that should be replaced due to poor performance or excessive maintenance costs.

High Risk Assets

The Auditor General made conclusions regarding the deferral or delay in replacing transformers. This conclusion was solely based on asset condition information but without the benefit of the full information that Hydro One uses in determining asset replacement. Overall fleet condition informs the capital spending level but cannot be used to determine the specific asset replacements. Asset Condition is not the sole consideration in determining the need to replace an asset. These replacement decisions take into account other factors as described in Exhibit B1, Tab 2, Schedule 5. Conversely, assets in good condition may need replacement based on other factors such as environmental, health and safety, inadequate capacity and customer needs and preferences, while assets that are deteriorated may be deprioritized due to their having a less material impact on the system.

Hydro One has addressed these concerns by ensuring all transformers selected for replacement in 2017 and 2018 are supported by detailed assessments based on the factors described in Exhibit B1, Tab 2, Schedule 5. As part of the process Hydro One also engaged a reputable third party, Electric Power Research Institute (EPRI) to assess overall transformer fleet health based on dissolved gas analysis.

Significant assets beyond Expected Useful Life still in use

As defined in Exhibit B1, Tab 3, Schedule 2, the expected service life is the average time in years that an asset can be expected to operate under normal system conditions. It does not imply the asset will need immediate replacement beyond this period of time. Hydro One operates a fleet of transmission assets that are beyond expected service life. However, Hydro One's asset management objective is to maintain asset performance while minimizing full life cycle costs. This is accomplished through proper maintenance and timely replacement which are detailed in our application. This approach benefits ratepayers by minimizing rate increases.

Asset Analytics not considering all factors for asset replacement decisions

Hydro One acknowledges Asset Analytics' data and algorithms require refinement, and Hydro One continues to take steps to implement such improvements. The purpose of Asset Analytics is to provide asset planners with convenient access to asset data and assess emerging risk factors in an efficient manner. Decisions to replace assets are made by the asset planners in part based on Asset Analytics output and also based on other factors fully described in Exhibit B1, Tab 2, Schedule 5. Asset Analytics is one tool to aid in decision making, but it is not the only factor considered.

To address this issue, Hydro One intends to continue improving Asset Analytics, including addressing data gaps, improving functionality and refining the algorithms used. However Hydro One does not intend that it become the sole source of decision making for asset replacement.

Inaccurate Data in OEB Funding Requests

Hydro One endeavors to ensure all data submitted to the OEB for rate setting purposes accurately reflects its forward test year plans. In making this statement, the Auditor General appears to have focused on investments that appeared in successive applications. In practice, investments are sometimes delayed due to work execution delays or other factors including changes in priority due to changing circumstances since the last rate application. In such cases a project may be delayed in favor of completing another with a more urgent need. Hydro One believes this practice is appropriate and is consistent with its asset management responsibility. To address this concern Hydro One has provided evidence supporting the 2017 and 2018 capital spending plans. These plans are based on the best information available at the time of filing the application. Hydro One is also prepared to explain variations from its previous plans and/or OEB approved spending amounts, compared to actual work completed.

Limited Security of Electronic Devices

Hydro One has been improving electronic security concerns through its Security Code of Practice and by increasing security practices in order to be NERC compliant, and by applying security measures that are commensurate with regulatory requirements and the risk to the power system.

- Hydro One has completed the development of a comprehensive security framework. This framework is called the Hydro One Security Code of Practice which includes the Security Policy and Security Operating Standards for the organization. The Code of Practice was completed in November 2015, but was recently modified to include minor revisions required by NERC CIP v5 Standards.

- Hydro One has developed NERC Critical Infrastructure Protection (CIP) compliant Engineering Standards and Build Documentation for all power system electronic devices. It is Hydro One's policy that all devices deployed will be compliant with these standards. This will ensure standard and consistent security hardening of the devices across all stations. Only a subset of Hydro One's transmission stations is required to fully comply with all NERC CIP requirements (electronic and physical). Other stations are less impactive to grid reliability and require less stringent security measures. These non-NERC impactive stations are protected based on good utility practice. From a cost prudency perspective, different levels of security measures are deployed to stations based on their criticality to grid reliability.

A reduction in this program will result in an increase in the length of time required to address degrading performance of air blast circuit breakers at critical network stations, and the integrated rebuild of these stations delivering load to customers. Negative impacts to both system and customer reliability would be a result.

4.2 Transmission Station Demand and Spares

4.2.1 Introduction

Hydro One strives to maximize the useful asset life of all stations equipment and to prudently refurbish or replace assets as required to ensure that assets remain in good working order and maintain a safe and reliable transmission system. However, equipment failures can occur and must be addressed quickly to minimize customer impacts and reduce the risk to overall system reliability. Hydro One plans for reactive maintenance or asset replacements to address equipment failures. Hydro One therefore maintains a sufficient level of spare power equipment to ensure that failed equipment can be replaced and return the system to normal operating conditions quickly and efficiently.

4.2.2 Spare Transformers

Hydro One's transmission system was developed over a time span exceeding 100 years. The evolution of design standards and operating principles over time, coupled with construction and material availability constraints have led to the deployment of a mixture of various types of asset within an asset class.

The diversity of the assets within Hydro One's system is the key factor in establishing spare equipment requirements. The primary objective is to ensure that Hydro One has the ability to recover from major power equipment catastrophic failure events and restore supply reliability in a timely and safe manner. As such, the minimum level of spare transformers is correlated to the types of transformers deployed in Hydro One's system. In 2009 Hydro One consolidated 30 types of transformers to 14 standards. These 14 standards include mid-size (15 to 42 MVA ratings) and large-size transformers (greater than 42 MVA ratings), and auto-transformers (larger than 125MVA).

Over time, as Hydro One rebuilds and replaces deteriorating assets, focus will be placed on ensuring that a high degree of standardization is adhered to. In 2009, approximately 80% of Hydro One's transformer fleet were standard units. In 2016, 84% of Hydro One's transformers are standard units, while 16% are non-standard transformers. It is anticipated that over the next 15 years, standardization will trend toward 90%.

Spare transformer requirements will decline as Hydro One continues to achieve higher levels of standardization. Today, inventory includes 48 operating spare transformers; 36 of these are standard units and 12 are non-standard.

While Hydro One has taken steps to institute standardization, adequate inventory to address the failure of non-standard transformers must continue until station reinvestment and new customer requirements allow for transformer standardization across Hydro One's entire fleet.

4.2.3 Investment Plan

This program funds the demand replacement of transmission system assets, resulting from unplanned or premature equipment failure, as well as the procurement of operating spare equipment, including power transformers and circuit breakers. This program ensures that a sufficient level of inventory of critical and ancillary power equipment is available as operational spares or for emergency replacement in the event of equipment failure.

The purchase of operating spare transformers is in line with Hydro One's probabilistic approach to determine the number of spare requirements. The analysis considers performance trends and supply chain considerations of Hydro One's various power transformer types, and groups them into optimized spare cohorts to adequately cover the in-service population. The transmission operating spares requirement is intended to replenish inventory that is expected to be drawn down for future failures.

This program also covers the purchase of mobile transformers to facilitate planned outages, as well as spare breakers, and bushings that are required as operating spares in case of equipment failure.

Table 7 outlines the proposed funding for test years 2017 and 2018, along with the spending levels for the bridge and historic years.

Table 7: Transmission Station Demand and Spares ($ Millions)

Description	Historic Years				Bridge Year	Test Years	
	2012	2013	2014	2015	2016	2017	2018
Transmission Station Demand and Spares*	-	-	-	27.2	20.5	25.3	25.8

**Previously these amounts were recorded as Power Transformers and Circuit Breakers.*

Hydro One manages the Transmission Station and Demand Spares category by grouping investments for demand work execution and the purchase of spare power equipment. Details of specific programs are outlined in Table 8.

Witness: Chong Kiat Ng

Table 8: Transmission Station Demand and Spares ($ Millions)

Ref #	Description	Test Years	
		2017	**2018**
S51	Demand Capital – Power Transformers	8.0	8.2
S52	Minor Component Demand Capital	4.7	4.7
S53	Operating Spare Transformer Purchases	8.2	8.3
	Other Demand and Spares Programs	4.5	4.7
	Total	**25.3**	**25.8**

Additional details for these investments are provided in the Investment Summary Documents S51 to S53 in Exhibit B1, Tab 3, Schedule 11.

4.2.4 Summary of Expenditures

The planned Transmission Station Demand and Spares expenditures for 2017 and 2018 are $25.3 million and $25.8 million respectively. The test year expenditures for the overall Transmission Station Demand and Spares program are based on historic spending required for emergency replacement of major power equipment and required equipment spare levels to effectively and prudently manage equipment failures. A reduction in this program will delay the replacement of failed equipment and will lead to maintaining a less than optimal spares inventory, resulting in increased risk exposure to reliability at both system stations and customer load delivery stations.

Witness: Chong Kiat Ng

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Demand Capital - Power Transformers
Targeted Start Date: Ongoing Program
Targeted In-service Date: Ongoing Program
Targeted Outcome: Operational Effectiveness

Need:
To address the failure of power transformers and station service transformers throughout the province, in order to maintain reliability. Not proceeding with this investment will result in declining reliability.

Investment Summary:
Hydro One Transmission owns and operates a fleet of 721 power transformers and a fleet and approximately 580 station service transformers across the province.

This program is supported by the *Operating Spare Transformer Purchases* program (ISD S53). In the unlikely event of a transformer failure, Hydro One Transmission will utilize operating spares to replace failed units. This plan is derived from historical data and performance trends. This investment funds the design, construction and commissioning resources required to the expediently replace failed transformers.

Alternatives:
This program is in response to emergency outages and no alternatives were considered as failure to respond to service interruptions or other emergency situations would result in unacceptable reliability and safety risks

Basis for Budget Estimate:
The program cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of program of similar scope.

Outcome:
Maintain system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	8.2	8.3	16.5
Operations, Maintenance & Administration and Removals	0.2	0.2	0.3
Gross Investment Cost	**8.0**	**8.2**	**16.2**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**8.0**	**8.2**	**16.2**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

Witness: Chong Kiat (CK) Ng

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Minor Component Demand Capital
Targeted Start Date: Ongoing Program
Targeted In-Service Date: Ongoing Program
Targeted Outcome: *Operational Effectiveness*

Need:
To address the failure of ancillary station equipment throughout the province, in order to maintain reliability. Not proceeding with this investment will result in declining reliability.

Investment Summary:
Hydro One Transmission owns and operates 292 transmission stations across the province of Ontario.

This program funds the replacement of ancillary station equipment, including but not limited to batteries, switches, and instrument transformers. In the event of equipment failure, Hydro One Transmission will utilize available spares or source new stock to replace failed equipment in a timely manner in order to restore the system to normal operation.

Alternatives:
- Alternative 1: Reactive Replacement (No Inventory); or
- Alternative 2: Status Quo – Replenish inventory.

Alternative 1 was considered and rejected because it does not address the transformer failure in a timely manner and will reduce system reliability. Alternative 2 is the preferred alternative as it addresses equipment failure in a timely manner to maintain system reliability.

Basis for Budget Estimate:
The program cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of programs of similar scope.

Outcome:
Maintain system reliability.

Witness: Chong Kiat (CK) Ng

Costs:

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	5.0	5.0	10.0
Operations, Maintenance & Administration and Removals	(0.3)	(0.3)	(0.7)
Gross Investment Cost	**4.7**	**4.7**	**9.3**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**4.7**	**4.7**	**9.3**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

Witness: Chong Kiat (CK) Ng

Hydro One Networks – Investment Summary Document

Sustaining Capital - Stations

Investment Name: Operating Spare Transformer Purchases
Targeted Start Date: Ongoing Program
Targeted In-Service Date: Ongoing Program
Targeted Outcome: Operational Effectiveness

Need:
To address the failure of power transformers and station service transformers throughout the province, in order to maintain reliability. Not proceeding with this investment will result in declining reliability.

Investment Summary:
Hydro One Transmission currently owns and operates a fleet of 721 power transformers and a fleet of approximately 580 station service transformers across the province.

In order to ensure timely response in the event of a failure, spare transformers are required. The number of spares Hydro One Transmission maintains is based on a probabilistic cost/risk analysis model, consistent with industry standards. The model determines the optimum number of spares required for each group of transformers by taking into consideration several factors: demographics, failure rates, repair/replacement time, internal performance trends and national performance levels supplied by the Canadian Electricity Association. Delivery lead time is also considered in the analysis. This program is supported by the *Demand Capital – Power Transformers* investment (S51) which funds resources to replace failed transformers.

The transformers scheduled for procurement in the test years for use as operating spares will replenish transformers used from system reserves to support failure replacements. Transformers purchased under this program will vary in size and type in order to support the sizes and types of the in-service transformer fleet.

Alternatives:

- Alternative 1: Reactive Replacement (No Inventory); or
- Alternative 2: Status Quo – Replenish inventory.

Alternative 1 was considered and rejected because it does not address the transformer failure in a timely manner and will reduce system reliability. Alternative 2 is the preferred alternative as it addresses equipment failure in a timely manner to maintain system reliability.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
Maintain system reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	8.3	8.4	16.7
Operations, Maintenance & Administration and Removals	(0.1)	(0.1)	(0.2)
Gross Investment Cost	**8.2**	**8.3**	**16.5**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**8.2**	**8.3**	**16.5**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

Witness: Chong Kiat (CK) Ng

Aid to Cross #004

Ref: Ontario Energy Board Staff INTERROGATORY #069

Exhibit: I-1-69

	Claimed Stores					Calculated Stores				Delta				
In Stock Spares as of Aug18	2012	2013	2014	2015	2016	2013	2014	2015	2016	2013	2014	2015	2016	Total
Autotransformers (>125MVA)	9	10	10	7	6	10	9	9	5	0	1	-2	1	0
Large Transformers (>42MVA)	31	26	23	23	24	29	25	23	24	-3	-2	0	0	-5
Mid-size Transformers (15 to 42 MVA)	19	18	13	16	16	19	16	14	16	-1	-3	2	0	-2
500kV Breakers	3	3	4	4	5	3	4	4	5	0	0	0	0	0
230kV Breakers	17	18	20	19	18	18	20	19	18	0	0	0	0	0
115kV Breakers	4	6	9	14	13	6	9	14	13	0	0	0	0	0

Annual Draw-Down					
Autotransformers (>125MVA)	1	0	1	1	2
Large Transformers (>42MVA)	0	3	2	3	1
Mid-size Transformers (15 to 42 MVA)	1	1	2	0	0
500kV Breakers	0	0	0	0	0
230kV Breakers	0	0	0	1	1
115kV Breakers	0	0	0	0	1

Annual Replenishment					
Autotransformers (>125MVA)	0	1	0	0	0
Large Transformers (>42MVA)	3	1	1	3	2
Mid-size Transformers (15 to 42 MVA)	0	1	0	1	0
500kV Breakers	0	0	1	0	1
230kV Breakers	8	1	2	0	0
115kV Breakers	0	2	3	5	0