OEB Staff

CROSS-EXAMINATION COMPENDIUM

Panel 5

However, Hydro One also considered an option known as "Plan B – Modified." This option reduces the immediate impact on rates in 2018 to 5.4% while holding reliability performance constant over the planning period. The remainder of the DSP details the process followed to arrive at Hydro One's final investment plan, Plan B – Modified.

Section 1 of the DSP provides information on critical inputs into the formation of Hydro One's investment plan, specifically, customer engagement results, regional plans, internal productivity analyses and external benchmarking analyses.

Section 2 discusses the Investment and Asset strategies followed by Hydro One with respect to its asset base. The planning and optimization processes undertaken to determine the appropriate portfolio of investments and a detailed description of the system and its components are included here.

Section 3 describes the specifics about the selected investments including a set of Investment Summary Documents ("ISD") describing all investments over $1 million.

Reliability Performance Impact Estimation

Reliability impacts for the proposed scenarios were modelled using the effect of relative investment impacts for:

- Vegetation Management;
- Pole Replacement; and
- Distribution Stations.

Reliability performance is affected by other factors. Other Line Components are also included in the forecast. However, the three asset areas listed above contribute the majority of reliability impacts, and represent the most significant, predictable drivers of reliability for which Hydro One has meaningful statistical data. The data allowed Hydro One to understand each option before deciding on a solution that aligned customer preferences, asset needs and rate impacts.

Below is a summary of the forecast of the primary sources and impact on reliability of the Distribution system. The SAIDI and SAIFI impacts were calculated on a high level estimate basis, using simplified assumptions and are approximate. The methodology to determine the link between percent changes in SAIDI and SAIFI for poles, distribution station, other line components and vegetation under investment plans A, B, C, and B-Modified is briefly summarized below.

Pole Replacement

Hydro One has extensive condition data on its pole population. Assets in poor condition have a higher probability of failure than assets in good condition. Hydro One's change in asset condition profile for its fleet of wood poles at the end of the planning period was projected under the various proposed investment plans. Current SAIDI and SAIFI reliability contributions due to pole failure were assumed to be indicative of the current

Table 52 - SAIDI Projection for Investment Plan Scenarios

SAIDI[1]:	**Avg. 2013-15: 7.3 hours/year**	**Average Number of Hours that a Customer is Interrupted**					
	Assumptions			**Forecasted Impact on SAIDI by 2022[2]**			
	Failure Rate/Impact	**Contribution to SAIDI**	**SAIDI Contribution (based on 2013-15)**	**Plan A**	**Plan B**	**Plan C**	**Plan B-M[3]**
Poles	• 345 outages/year • 180 customers/outage • 10 hours/outage	3%	0.2	12%	10%	(18)%	7%
Stations	• 16 failures (outages) /year • 1200 customers/outage • 24 hours/outage	4%	0.2	14%	5%	(4)%	0%
Other Line Components	• 2070 outages/year • 180 customers/outage • 4 hours/outage	23%	1.5	10%	0%	(10)%	(5%)
Vegetation	• 15,530 outages/year	27%	1.8	8%	8%	4%	8%
Estimated Impact to SAIDI				**5%**	**2%**	**(2)%**	**0-1%**
Forecasted SAIDI (hours)				**7.0**	**7.1**	**7.4**	**7.3**

1-Excludes force majeure and loss of supply events
2 – These columns reflect the forecasted impact on SAIDI by then end of 2022. Estimated performance improvement is expressed as a positive value; performance deterioration is expressed as a negative value
3 – Impacts for "Plan B-M" refer to Plan "B-Modified" described earlier in this Section.

Table 53 - SAIFI Projection for Investment Plan Scenarios

SAIFI [1]:	**Avg. 2013-15: 2.6 outages/year**	**Average Number of Times a Customer is Interrupted**					
	Assumptions			**Forecasted Impact on SAIFI by 2022[2]**			
	Failure Rate/Impact	**Contribution to SAIFI**	**SAIFI Contribution (based on 2013-15)**	**Plan A**	**Plan B**	**Plan C**	**Plan B-M[3]**
Poles	• 345 outages/year • 180 customers/outage • 10 hours/outage	2%	0.1	12%	10%	(18)%	7%
Stations	• 16 failures (outages) /year • 1200 customers/outage • 24 hours/outage	3%	0.1	14%	5%	(4)%	0%
Other Line Components	• 2070 outages/year • 180 customers/outage • 4 hours/outage	18%	0.5	10%	0%	(10)%	(5%)
Vegetation	• 15,530 outages/year	16%	0.4	8%	8%	4%	8%
Estimated Impact to SAIFI				**4%**	**2%**	**(2)%**	**0-1%**
Forecasted SAIFI (instances)				**2.5**	**2.6**	**2.7**	**2.6**

1-Excludes force majeure and loss of supply events
2 – These columns reflect the forecasted impact on SAIFI by then end of 2022. Estimated performance improvement is expressed as a positive value; performance deterioration is expressed as a negative value
3 – Impacts for "Plan B-M" refer to Plan "B-Modified" described earlier in this Section.

OEB Staff Interrogatory # 164

Issue:

Issue 29: Are the proposed capital expenditures resulting from the Distribution System Plan appropriate, and have they been adequately planned and paced?

Reference:

B1-01-01 Section 1.1 Page: 17 – 19

Distribution System Plan Overview, Section 1.1 (5.2.1) Distribution System Plan Overview

Interrogatory:

"Plan A resulted in a 7.1% Hydro One rate increase in 2018 (average of 3.8% over the five years), and forecasted improvement of approximately 6% in SAIDI and 4% in SAIFI related to the company's most significant areas of reliability risk over the five year period."

"Plan B was produced that reduces the rate impact in 2018 by 1%, to 6.2% (average of 3.5% over the five years), and also delivers a reliability improvement (approximately 3% SAIDI, 2% SAIFI)."

"Hydro One also considered what would be required to achieve the lowest 2018 rate increase without material disruption to its operations. Presented as the "Plan C" scenario, Hydro One's conclusion was that this option as a whole was not viable due to the estimated degradation of approximately 2% in both SAIDI and SAIFI that would result from such a reduced level of sustainment capital investment and reductions in work programs and the associated increased backlog of assets in poor condition."

"Plan B – Modified option reduces the immediate impact on rates in 2018 to 5.4% while holding reliability performance constant over the planning period."

a) What are Hydro One's most significant areas of reliability risk over the five-year forecast period?

b) Please explain in detail how Hydro One calculated the different SAIDI and SAIFI results that would result from implementing each of the plans.
    i. For each material capital project please provide the quantitative calculation used to calculate the expected improvement of SAIDI and SAIFI for each proposed

alternative. If a quantitative calculation was not used please discuss the analysis used to produce a quantitative result.

ii. Please confirm if the SAIDI and SAIFI metrics results associated with each plan exclude the impact of major weather-related outages and/or Loss of Supply events.

iii. What are the key asset failure modes under Plans B & C that cause the largest negative impacts on SAIDI and SAIFI results?

iv. Do all studied capital plans assume the same level of vegetation management expenditure? If not, please provide the different vegetation management assumptions associated with each plan.

c) Please explain how Hydro One determined which projects and programs would be included in the portfolios that comprise Plan A, Plan B and Plan C.

i. Have the projects in each plan been optimized to deliver the best possible SAIDI and SAIFI results within the overall capital expenditure envelope associated with each scenario? If yes, please explain the methodology used to determine the optimization.

ii. Hydro One stated that an Asset Investment Planning tool is used to optimize investment candidates during the optimization process. Please explain how SAIDI and SAIFI improvements are taken into consideration during this process.

d) Please confirm if the reliability improvements expected for each Plan is calculated by a bottom-up method (i.e. The total reliability improvement is the summation of each expected reliability improvement for each project within the Plan)

Response:

a) Hydro One's most significant areas of reliability risk over the five year forecast period are related to vegetation management and defective equipment.

b)

i. The approach to identify forecasted SAIDI and SAIFI impacts of various scenarios is based upon the forecasted impact of different levels of asset replacement on overall fleet condition and professional judgment to account for potential mitigating factors. For example, an increased rate of replacement will increase the number of assets replaced, and reduce the number of assets in the fleet with deteriorated condition that require replacement. The net change in fleet level condition is then assumed to reflect a potential improvement or deterioration in reliability as shown in the table below for wood poles and used in Tables 52-53 in the DSP (Exhibit B1, Tab 1, Schedule 1).

	Wood Poles in need of replacement (k)	**Calculation**	**Change in Fleet Condition**	**Reliability Impact Shown (Tables 52-53)**
Current	106	-	-	-
Plan A	93	1 – (93/106)	12.3%	12%
Plan B	96	1 – (96/106)	9.4%	10%
Plan C	126	1 – (126/106)	(18.9)%	(18)%
Plan B-Modified	99	1 – (99/106)	6.6%	7%

For additional details on the accomplishment and condition assumptions for each of the scenarios, please refer to section 2.4 of the DSP “How the plan reflects investment planning and Asset Management’, “Reliability Performance Impact Estimation”, lines 15-20, page 2497 of 2930.

ii. Please refer to note “1” in Table 52 and 53.

iii. As Tables 52 and 53 of the DSP illustrate, for Plan B, both the SAIDI and SAIFI are most negatively impacted by "other line components” caused outages. With Plan C, both the SAIDI and SAIFI are most negatively impacted by "other line component” caused outages.

iv. No. The level of vegetation management expenditure for Plans A, B, and B-Modified are the same, however Plan C expenditure was assumed lower by approximately 1,000km/year. The different vegetation management assumptions associated with each plan are explained in Section 2.4 of the DSP under the “Vegetation Management” heading on page 2500. With the new vegetation management approach, Plan C would represent about 3000 km/year less.

c) Projects and programs levels included in Plan A and/or Plan B were assessed based on the risk mitigation or benefit to Business Objectives, as described in section 2.1 of the DSP. See DSP section 2.1.5.1 for more details (page 2385 of 2930). Plan C was not fully developed into specific programs and projects, as the option, as a whole, was deemed not viable due to a degradation of SAIDI and SAIFI that would result based on the Plan C funding level. See section 1.1 of the DSP (pages 17-19) and part c) of Exhibit I-35-BOMA-31.

i. SAIDI and SAIFI are not specifically used to optimize the overall capital portfolio. However, reliability is one of the prioritization criteria [Reference DSP Section 2.1.5.1 Table 34 (page 2386 of 2930)] used in the investment optimization process for Plans A and B. The optimization process is described in section 2.1 of the DSP. Prioritization criteria are determined based on the risk consequence table that planners used to assess candidate investments. Refer to Appendix A to Exhibit I-24-Staff-89 for the risk consequence table and a description of the risk assessment process. After optimization, outcomes (including SAIDI and SAIFI) are assessed based on the proposed portfolio of programs and projects.

ii. Please see the response to part c) i) above.

d) The reliability improvements expected for each Plan are not calculated using a bottom-up method. As described in section 2.4 of the DSP (page 2497 of 2930), the approach and results were calculated on a high level estimate basis, using simplified assumptions. The projected improvements are approximate and consider the impact of only select investments.

"Hydro One operates 1,005 stations, which 70 are in poor condition."

Do you see that?

MR. JESUS: Um-hmm.

MR. RUBENSTEIN: So if I was -- and then if you go to line 19, as an example, Plan A says:

"Process replace all stations deemed to be in poor condition in 70 by the end of the planning period 2020."

If I was using the same logic as poles I'd have -- you would have solved that problem. It would be 100 percent. And yet here the SAIDI and SAIFI is forecast to improve only for 14 percent for that asset.

So I am trying to understand how you have come to your numbers.

MR. JESUS: Sure. So can I take you to I29-AMPCO-27. So the logic that we just followed for poles would be applied to the other components.

So if you go, scroll down, so there you can see -- in B you can see the differences in the poles being replaced in each of the years. If you scroll down again, you can see the stations that are being done, and effectively the same process would apply. So you'd look at the stations and the number of transformers that you're replacing with each one of the plans, and you determine what the reliability impact of that would be. Similarly for right-of-way.

So that was the process. The spreadsheets are there.

UNDERTAKING – JT 3.10

Undertaking

To provide the same table as provided for staff and for each category show the calculations.

Response

Here are the underlying calculations for stations, other station components and vegetation management impacts as reflected in Exhibit DSP Section 2.4.

Stations

Table 52 of DSP Section 2.4, Exhibit B1-1-1 assumes that eliminating all stations in poor condition stations will lead to a 14% improvement in station reliability. The updated assumption is that, by addressing all stations in poor condition, a 9% improvement in station-related reliability will be achieved based on the percentage of station outages that occurred at stations that are in poor condition. Station SAIDI and SAIFI impacts are assumed to be directly proportional to the number of stations that remain in poor condition as shown below.

	Stations in Poor Condition	**Calculation**	**Change in Fleet Condition**	**Reliability Impact**
Current	70	-	-	-
Plan A	0	1 – (0/70)	100%	9%
Plan B	40	1 – (40/70)	43%	4%
Plan C	90	1 – (90/70)	-29%	-3%
Plan B-Modified	70	1 – (70/70)	0%	0%

Other Components

The capital funding available to address other line components is covered under the Planned Component Replacement investment (see Investment Summary Document SR-10). This funding is required to address the replacement of other distribution lines components. The incremental funding available under each scenario relative to Plan B is assumed to address, proportionately, the number of outstanding line equipment defects of approximately 300,000 as shown in the table below.

	Incremental Line Defects Addressed Relative to Plan B (k)	**Calculation**	**Change in # of Defects (Reliability Impact**	**Reliability Impact Shown (Tables 52-53)**
Plan A	25	1 – (275/300)	8.3%	10%
Plan B	0	1 – (300/300)	0%	0%
Plan C	-34	1 – (334/300)	-11.3%	-10%
Plan B-Modified	-5	1 – (305/300)	-1.7%	-5%

Vegetation Management

Plans A, B and B-Modified, reduce the rights of way maintenance on medium or low-priority rights of way by 1,000 kilometers per year. This results in increasing the vegetation backlog by 8% and degrades SAIFI and SAIDI by 1%. These increases are offset by the 9% improvement expected in the high priority rights of way resulting in a total reliability improvement of 8% (i.e. 9% - 1%).

Plan C would reduce maintenance by an additional 1000 kilometers per year on the medium to low-priority rights of way. This is expected to further increase the backlog maintenance and degrade SAIFI and SAIDI by 5%. This is offset by the 9% improvement expected in the high priority rights of way resulting in a total reliability improvement of 4% (i.e. 9%-5%).

1.6 Key Findings

- **Maintenance Cycle –** The increase in the number of defects per km based on years since last worked found in the survey confirms a direct relationship between cycle intervals, defects, and reliability performance. Based on the survey data a 3 -year maintenance cycle is the optimal period before defects increase significantly which causes cost escalation and reduced reliability performance.
- **Work Scope** – The number of Off-ROW defects found in the survey confirms that the current work scope, in combination with the extended cycle, is the biggest contributor to less than desired reliability performance. It was evident that maintenance activities have been largely focused on areas within the ROW, leaving behind Off-ROW vegetation which is the major contributor to poor reliability performance.
- **Reliability Modeling** –By implementing an optimal maintenance cycle, modified work scope and an analytics based hazard tree program, it is reasonable to expect a 20% to 40% plus improvement in reliability by the end of 2020. An analytics based hazard tree program requires funding beyond the baseline maintenance levels.
- **Cost Modeling –** There is a reasonable probability, assuming that work scope is managed through a quality control effort, that the first 3-year maintenance cycle can be performed within existing funding levels. Cost for subsequent cycles may be significantly less as hazard trees and contact defects are controlled.
- **Feeder Prioritization –** The survey provides the data necessary to begin the transition to a shorter cycle interval with feeder prioritization based on voltage, defect volume, forecast cost and historical reliability results.

1.7 Recommendations

- Adopt an initial 3-year maintenance cycle first time through the system and re-evaluate prior to start of the second cycle. Alternative cycle intervals (2-5 years) may be introduced based on actual field conditions (3 years of data) matched to the desired outcome based on the intersection between defect, reliability, and cost.
- Revise work scope to focus on defects first (on and off ROW).
- Implement a Quality Control (QC) process to control scope and monitor work performance.
- Finalize and fully implement an outage investigation process to develop analytics for system awareness and continuous improvement.
- Implement a formal hazard tree program, part of which is incorporated into baseline cycle work and part of which is targeted work based on analytics.
- Implement work management and project management tools.
- Continue with workforce and work methods strategy.

Important Safety Observation

Recommendations contained in this report suggest a renewed emphasis on the identification and mitigation of hazard trees, with an estimated 1.1m trees needing work over the first cycle. Hazard trees, by definition, pose a risk not only to electric facilities but also to workers. Exposure to the dangers associated with climbing and/or felling hazard trees is likely to be greater than previously experienced. Additional precautions are advised.

including major events. It's representing 20 percent on the bottom end.

MR. SIDLOFSKY: So that's the -- and that's -- that's figure 11 that's showing the 20 percent at the end of the three-year cycle, correct?

MR. TANKERSLEY: Correct.

MR. SIDLOFSKY: So that would be on the low end. Would that mean that in order to achieve that, Hydro One wouldn't necessarily have to take all of those steps in the recommendation?

MR. TANKERSLEY: So there are three key steps in that. It is the shortened cycle, the modified work scope, and then the third one is the analytics-based program. So the first two will get you to a 20 percent, I believe, or greater. And then the third one is something that over time, as you learn more about your system through analytics of what's causing your outages, those that are easiest to prevent through a modified cycle and scope come right off the top.

The others become more difficult, but not that achievable as you are able to apply better practices across your system. That would come at a longer timeframe.

MR. SIDLOFSKY: So that may actually help me understand -- or help me get to the next question here.

I take it the bulk of the projected outage reduction is expected to be achieved at the end of the first three-year cycle.

MR. TANKERSLEY: Which would be the start of the

3.7 (5.4.5.1) LIST OF MATERIAL CAPITAL INVESTMENTS PROPOSED

Below is a list of the Investment Summary Documents (“ISD”).

Each ISD includes a priority.

- “**Demand**” Priority refers to those projects that are part of Demand Work and are effectively non-discretionary in nature. Not completing these projects is likely to cause or extend failures on the system. Completion of these activities may be necessary to satisfy legislative or regulatory directives.
- **“High”** Priority projects ranked highest in the risk matrix. Failure to complete is expected to have significant impacts on the risk profile of the system in the short term.
- **“Medium”** Priority projects represent the largest group of projects. If reductions are required and sufficient savings are not available from the Low priority group, the Medium items would be reviewed as well for possible decreases in spending.
- **“Low”** Priority is for those projects ranking among the lowest group in the risk prioritization methodology. These projects are important to Hydro One but should a reduction in spending be necessary, Hydro One would look at these projects first for cost savings. Failure to complete Low Priority projects is not expected to have significant detrimental effects on the system in the near term.

Ref #	Investment Name	Total Cost ($M)				
		2018	2019	2020	2021	2022
System Access						
SA-01	Joint Use and Line Relocations Program	21.7	22.0	22.2	22.6	22.8
SA-02	Meter Infrastructure Sustainment	14.3	14.8	15.1	15.6	16.1
SA-03	AMI Network Expansion	3.0	2.9	2.9	2.7	2.8
SA-04	New Load Connections, Service Upgrades, Cancellations and Metering	109.9	112.9	115.7	120.0	123.2

Ref #	Investment Name	Total Cost ($M)				
		2018	**2019**	**2020**	**2021**	**2022**
SA-05	Generation Connections	4.1	3.4	3.3	2.9	3.0
Projects Under $1M		1.6	1.6	1.7	2.1	2.1
Subtotal – System Access		**154.6**	**157.6**	**160.9**	**165.9**	**170.0**
System Renewal						
SR-01	Distribution Station Demand Program	2.3	2.3	2.4	2.6	2.7
SR-02	Mobile Unit Substations Program	3.5	5.7	5.8	5.9	6.0
SR-03	Station Spare Transformer Purchases	2.6	3.4	4.1	4.2	4.3
SR-04	Distribution Station Component Planned Replacement Program	1.9	2.0	2.0	2.5	2.6
SR-05	Distribution Station Reclosers Upgrade	2.3	2.3	2.4	2.5	2.5
SR-06	Distribution Station Refurbishments	15.0	29.6	33.8	34.5	35.2
SR-07*	Distribution Lines Trouble Call and Storm Damage Response Program	75.6	77.1	78.5	80.5	82.0
SR-08	Distribution Lines PCB Equipment Replacement Program	11.6	11.8	12.1	18.5	18.9
SR-09	Pole Replacement Program	73.8	112.1	127.9	131.3	133.9
SR-10	Distribution Lines Planned Component Replacement	9.1	6.0	6.1	7.1	7.0
SR-11	Component Replacement Submarine Cable	7.5	7.7	7.8	8.0	8.2

Ref #	Investment Name	Total Cost ($M)				
		2018	**2019**	**2020**	**2021**	**2022**
SR-12	Distribution Lines Sustainment Initiatives	22.3	31.1	30.9	33.8	33.7
SR-13	Life Cycle Optimization and Operational Efficiency Projects	20.5	27.1	22.4	29.0	34.9
SR-14	AMI Hardware Refresh	0.0	0.0	0.0	1.4	78.5
Projects Under $1M		0.6	0.5	0.5	0.7	0.7
Subtotal – System Renewal		**248.6**	**318.7**	**336.7**	**362.5**	**451.1**
** A portion of SR-07 funding is reported in System Service.*						
System Service						
SS-01	Remote Disconnection Reconnection Program	5.8	5.8	5.7	5.6	5.6
SS-02	System Upgrades Driven by Load Growth	40.4	51.4	42.9	32.7	22.6
SS-03	Reliability Improvements	4.6	7.0	6.3	7.2	8.1
SS-04	Demand Investments	3.6	3.7	3.8	4.3	4.4
SS-05	Distribution System Modifications	7.3	7.2	8.0	8.8	8.8
SS-06	Worst Performing Feeders Program	7.1	10.1	10.5	10.9	11.3
SS-07	Advanced Distribution System	5.0	0.0	0.0	0.0	0.0
SR-07*	Distribution Lines Trouble Call and Storm Damage Response Program	7.1	7.3	7.4	7.7	7.8
Projects Under $1M		0.9	0.9	1.0	1.6	0.9

Ref #	Investment Name	Total Cost ($M)				
		2018	**2019**	**2020**	**2021**	**2022**
Subtotal – System Service		**81.8**	**93.4**	**85.6**	**78.8**	**69.5**
** A portion of SR-07 funding is reported in System Renewal.*						
General Plant						
GP-01	Transport and Work Equipment	35.0	39.5	40.4	42.0	44.1
GP-02	Real Estate Facilities Capital	35.4	42.9	36.9	36.9	33.9
GP-03	MFA Servers and Storage	3.2	3.2	3.2	3.2	3.2
GP-04	MFA PC and Printer Hardware	2.1	1.9	1.9	1.9	1.9
GP-05	Hardware/Software Refresh and Maintenance	3.9	4.1	4.1	4.1	4.1
GP-06	MFA Telecom Infrastructure	1.3	1.4	1.4	1.4	1.4
GP-07	Corporate Performance Reporting	1.5	2.0	0.0	0.0	0.0
GP-08	PCMIS Modernization and Optimization	0.0	1.6	0.0	0.0	0.0
GP-09	ECM - Phase C	0.0	0.0	0.2	0.9	1.0
GP-10	Work Management & Mobility	4.0	4.6	0.0	1.4	0.6
GP-11	Enterprise Geographical Information System	2.0	1.9	0.9	0.9	0.9
GP-12	Business Process Consolidation	0.0	0.0	1.5	1.2	0.0
GP-13	HR and Pay Related Technology Investments	0.5	2.9	1.6	0.0	0.0

Ref #	Investment Name	Total Cost ($M)				
		2018	2019	2020	2021	2022
GP-14	Warehouse Scanning Device Replacement	0.7	1.1	0.0	0.0	0.0
GP-15	SAP Treasury	0.0	1.5	1.2	0.0	0.0
GP-16	Customer Self Service Technology	0.0	2.3	1.4	2.3	6.9
GP-17	S4 HANA for Finance and Enterprise Asset Management	0.0	0.0	1.2	1.7	3.6
GP-18	Integrated System Operating Centre - New Facility Development	10.5	42.6	3.3	0.0	0.0
GP-19	Operating Common Information Technology Infrastructure	2.7	1.4	0.8	2.1	4.1
GP-20	Network Outage Management System (NOMS) Refresh	1.1	0.0	0.0	0.0	0.0
GP-21	Ontario Grid Control Centre Data Centre Remediation	2.4	1.6	0.6	0.0	0.0
GP-22	Ontario Grid Control Centre Office Remediation	0.0	0.0	0.0	0.5	1.1
GP-23	Integrated Voice Communications and Telephony System Refresh	0.0	0.0	0.0	3.0	3.5
GP-24	Station Security Upgrades	1.1	1.1	1.1	1.2	1.2
GP-25	Leamington TS Capital Contribution	2.2	0.0	0.0	0.0	0.0
GP-26	Hanmer TS Capital Contribution	3.4	0.3	0.0	0.0	0.0

Ref #	**Investment Name**	**Total Cost ($M)**				
		2018	**2019**	**2020**	**2021**	**2022**
GP-27	Enfield TS - Capital Contribution	2.0	1.0	0.0	0.0	0.0
GP-28	Call Centre Technology	7.5	0.0	7.2	2.9	0.0
GP-29	Customer Service Billing Investments	0.0	0.0	0.0	4.5	5.9
GP-30	Customer Service Regulatory Changes and Pricing Options	3.4	5.6	3.9	1.0	0.0
GP-31	Collection Enhancements	0.0	0.0	0.0	0.0	6.1
GP-32	Customer Data and Analytics	1.8	0.0	2.6	5.5	0.0
GP-33	Customer Service Complaint Management Tool	3.0	0.3	0.0	0.0	0.0
GP-34	Smart Meter Network Investments	2.5	6.9	4.0	1.4	0.0
GP-35	Asset Analytics Risk Factor	0.0	0.0	2.0	0.0	0.0
Projects Under $1M and Other Capital		15.8	15.4	14.4	13.4	13.1
Subtotal – General Plant		**149.0**	**187.1**	**135.8**	**133.4**	**136.6**

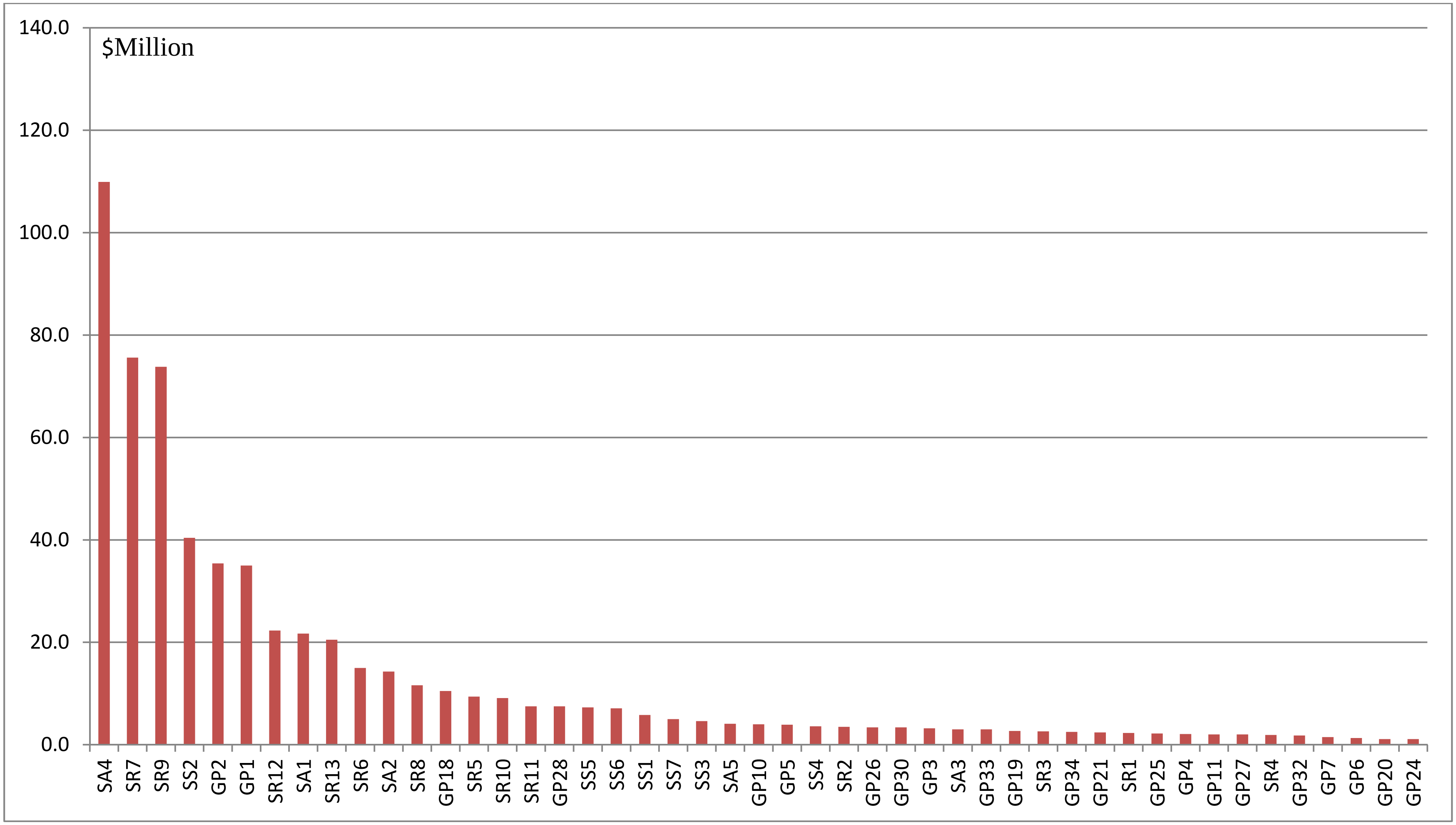


Figure 45 - Investments greater than $1 Million – 2018

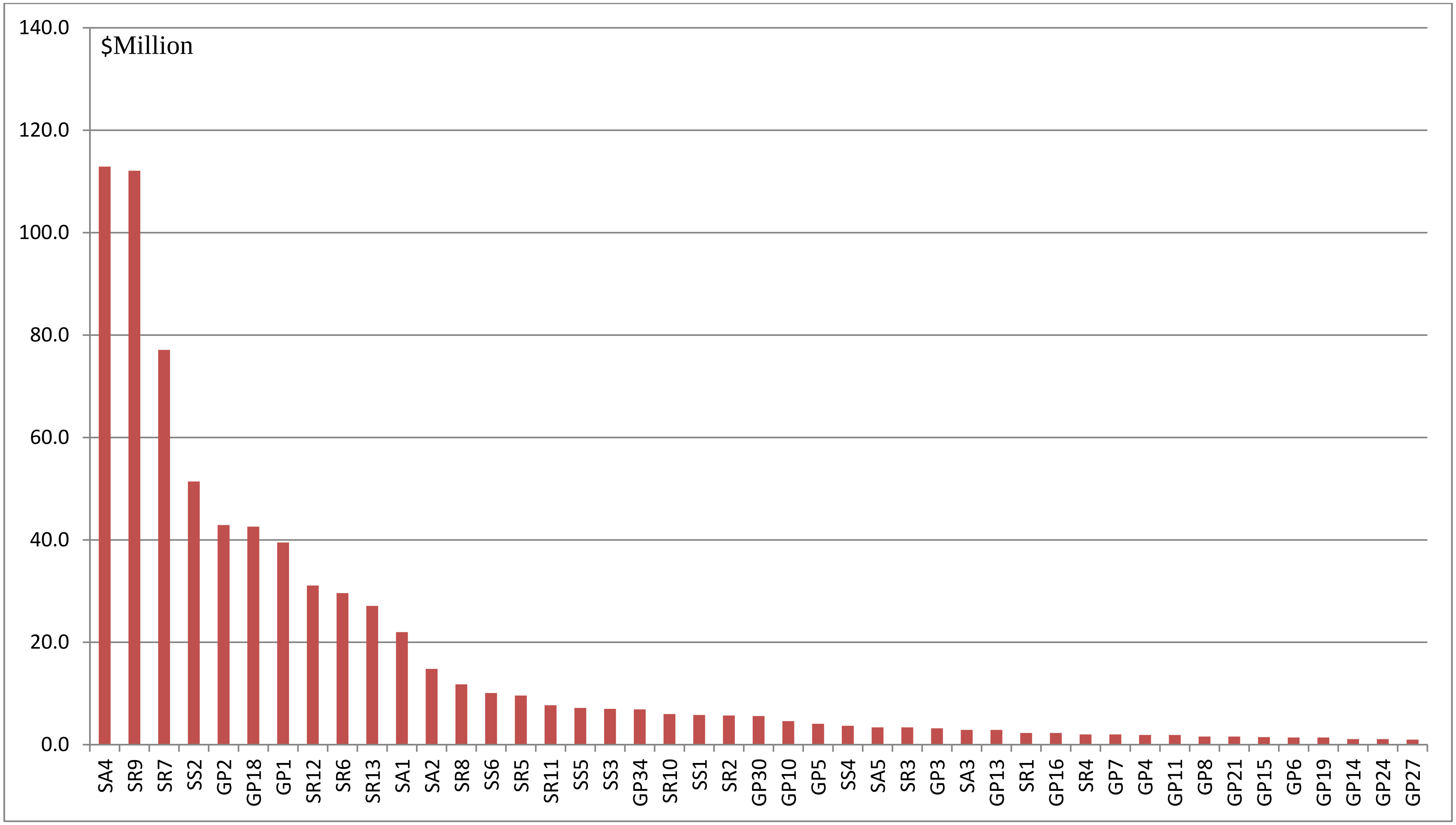


Figure 46 – Investments greater than $1 Million – 2019

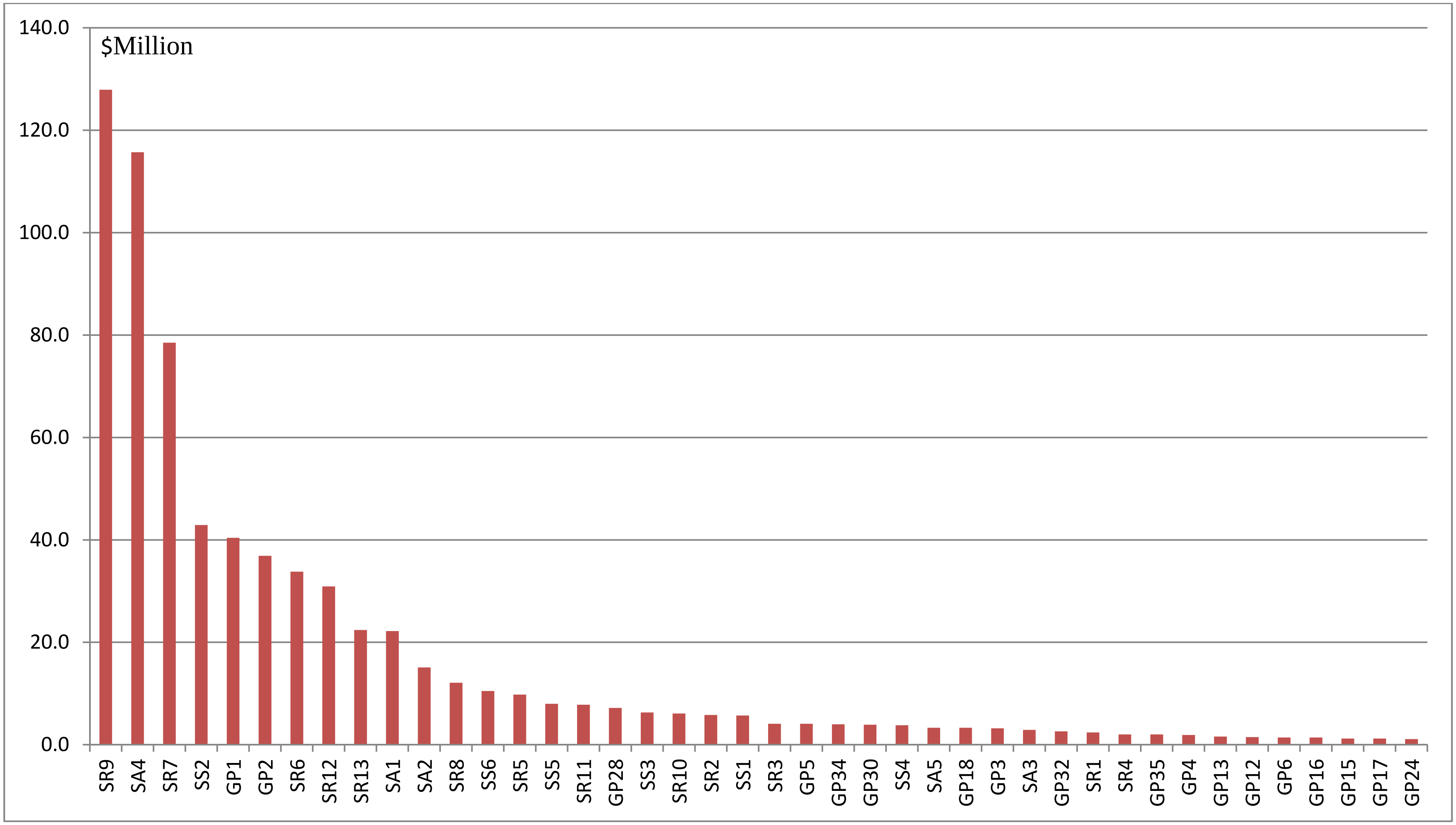


Figure 47 – Investments greater than $1 Million – 2020

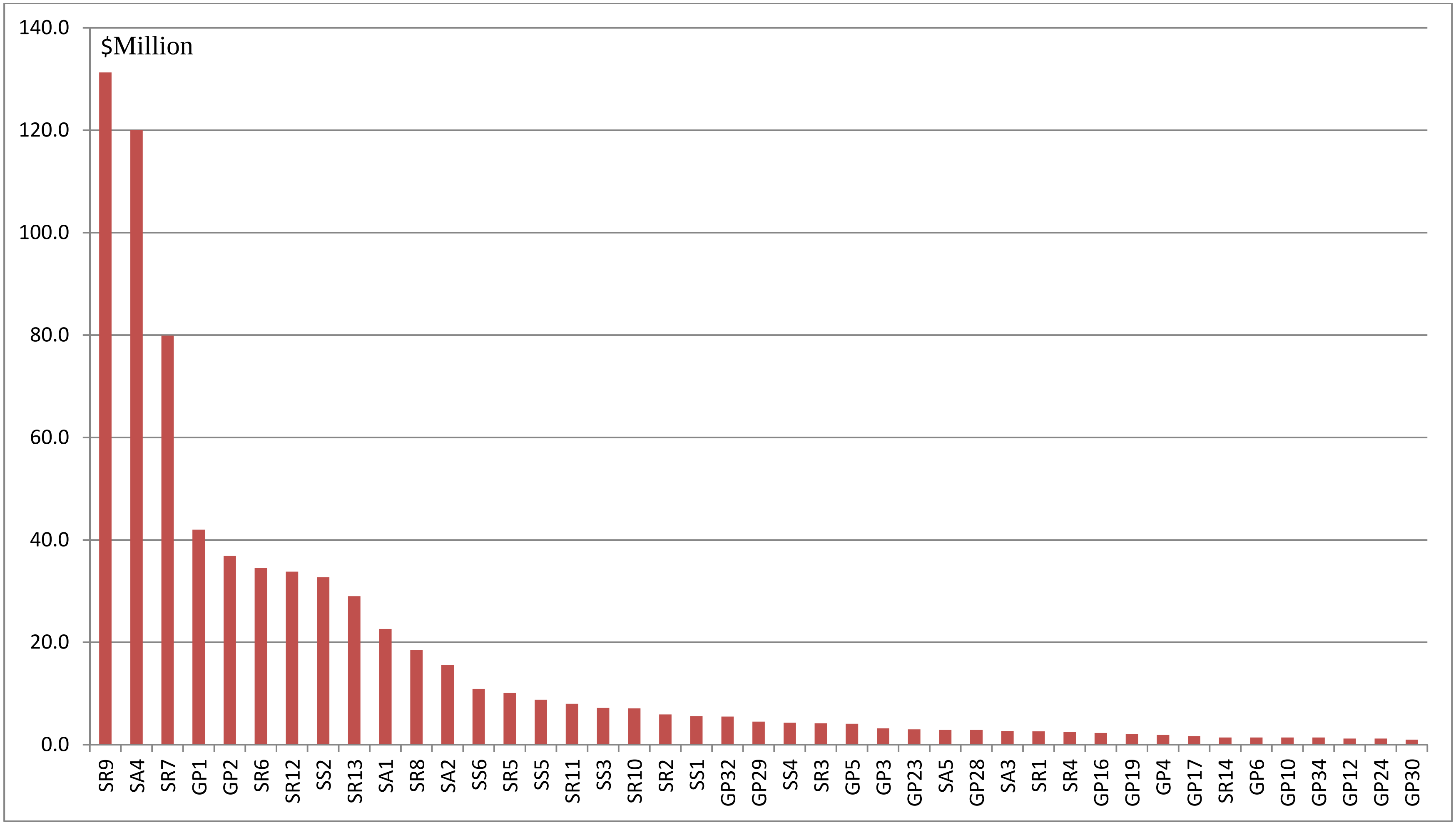


Figure 48 – Investments greater than $1 Million – 2021

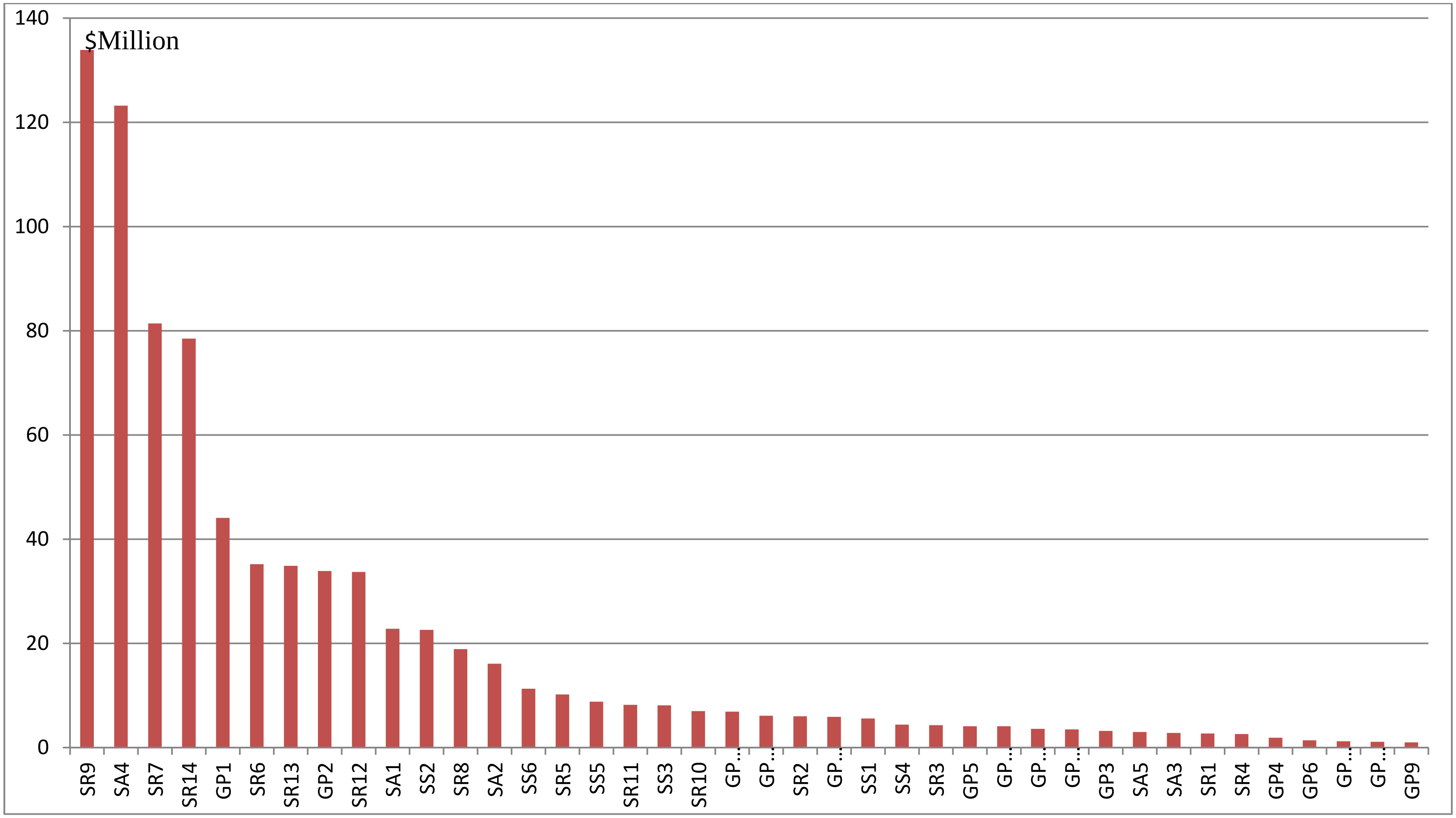


Figure 49 – Investments greater than $1 Million – 2022

Could you just elaborate on that a little bit? Is that a -- it says "originally limited to 4.2 per cent". Was that sort of a financial guideline that was given to the planners?

MR. JESUS: It's the -- referred to as the CAGR rate that's been communicated to our investment community.

MR. BRETT: Right.

MR. JESUS: And so that's what they've articulated for the company, in terms of growth rate of 4.2 per cent.

MR. BRETT: Okay. That's what you told the shareholders, basically, and the public shareholders and private shareholders.

MR. JESUS: Correct.

MR. BRETT: And that, I guess, drives then -- the importance of that to them would be that that number drives a -- effectively drives or has a significant impact on your return on capital, right, or your growth? I guess on your growth, I guess.

MR. JESUS: Well, let me put that number -- let me help you put that number in perspective in terms of what it means to the investment plan. So from an investment planning point of view, there is no target. The planners do not understand what a 4.2 per cent rate impact growth is.

MR. BRETT: Right.

MR. JESUS: They are putting forth plans and investments that address the needs of the system.

MR. BRETT: Right.

MR. JESUS: That are balanced with our customer needs and preferences.

MR. BRETT: Right.

MR. JESUS: That balance the actual rate impacts to our customers.

MR. BRETT: Right.

MR. JESUS: So for all intents and purposes the planners are focused strictly on a bottom-up approach to identify the needs of the system. In fact --

MR. BRETT: Profitability and the growth and the return on equity, essentially.

MR. JESUS: I would suggest not. I think --

MR. BRETT: Sorry, I imputed too much there.

MR. JESUS: I would suggest that from a -- the 4.2 per cent really is -- I think we have all -- in BOMA 31C, we highlight that we have a lot of asset condition needs on the system, and that if we were to address them all we would be spending way more money than the 4.2 per cent that's identified there, so it becomes a matter of pacing those investments to ensure that we are managing our rate impacts to our customers.

So in the end, in the end, that 4.2 per cent is more of a constraint than anything.

MR. BRETT: Right. That's a directive or a guideline from the senior management to the planning, to the corporation, really, to say whatever we do, we can't grow that rate base by more than 4.2 per cent. Is that the idea?

AIP Concepts and Definitions

AIP Term	Definition
Planning Portfolio / Driver	A grouping of investments. Planning Portfolios match the IM driver hierarchy. Ad-hoc Portfolios can be created for reporting and scenario analysis.
Investment Owner (IO) / Planner	Planners who manage investments including alternatives and assign assets, assess risk, benefits, timelines etc.
Portfolio Owner (PO) / Driver Owner	Managers and directors whose primary role is to: i) Review and approve investments alternatives proposed by Investment Owners via AIP workflow ii) Review and validate the optimization output
Parent Portfolio Owner	The highest level of approver for investments
AIP Team	Kevin Mancherjee and his team
Investment Optimization Manager	Responsible for the central AIP process coordination, running optimization and presenting results for validation, reporting and incorporation into the Business Plan
Investment	The best selection and timing of investment alternatives that maximize risk mitigated and benefit while satisfying financial and resource constraints.
Investment Type	Defines if the investment is a Project or Program. Depending on the Investment Type, different fields must be populated
Investment Stage	Tracks the stage of an investment from inception to completion. **IO's can only change the stage to Draft, Short Term Planning or Long Term Planning.** Other stages are updated by the AIP Team. **Draft** – Investment that is still in the development stage **Short Term Planning –** Investment to be included as part of the IPP (occurring within the planning horizon) **Long Term Planning -** Investment likely to occur outside the planning horizon (~6 years +) **Executing –** Investment that currently in-flight (limited to Projects, cash flows are loaded based on the multi-year LOB Forecast) **Complete – Investment is completed** Depending on the in the Investment Stage, different field must be populated
Alternative	Different possibilities for addressing the investment need. Investments may have one or more Alternative An Alternative will have an alternative start date, forecast, risk mitigation, milestones and benefits (optional). **Each Investment must have at least one Alternative**. As part of Optimization, the **choice of Alternative can be changed in order to maximize value**
Forecast	Refers to the area in AIP where you enter the **costs and units** (if applicable) associated with an Alternative. Forecasts will be different for each alternative.
Forecast Accomplishment	Refers to the units of accomplishment (e.g. # of poles, # of breakers, etc.) that are to be completed each year. Forecast Accomplishments will differ for each alternative.

Activity	Used to denote a specific Asset Type (e.g. 230 Kv Breakers), if applicable. Used in combination with Forecast Accomplishment.
Spend Line	Refers to the cost associated with an alternative. It is possible to have multiple spend lines within an alternative.
Spend Group	A bucket used to group similar spend lines and forecast accomplishments
Benefits	Refers to the area in AIP where financial benefits (e.g. FTE Savings) are entered for each Alternative.
Milestones	A Milestone is a key date to be captured for each Alternative and typically applies to Project Investments. Milestones will shift when the Alternative Start Date is modified. Any or all of the following milestones can be entered: BEST Released Date BEST Required Date DETL Released Date DETL Required Date BCS Approval Date (EMPP date) ISD CCRA Date
Risk Mitigation	Refers to the area in AIP where Risk Assessments are entered. Risk mitigation must be entered for each Alternative.
AIP Risk Consequence Table	Table of outcomes used by Investment Owners to aid in completing risk assessments. See: Link to AIP Risk Consequence Table
AIP Risk Matrix	The Risk Matrix residing within AIP. Combines consequence and probability. “Red Zone” is defined as a level of risk that is unacceptable to the company. It is not recommended that any alternative be proposed if any Business Value is identified with residual risk in the ‘red’ area of the Risk Consequence Table.
Baseline	The risk of doing nothing over time (in terms of base probability and base consequence)
Base Risk	The risk value from the AIP Risk Matrix, related to the baseline probability and consequence
Asset Impact	1. The result of making the investment (in terms of probability and consequence) 2. The fields in AIP where risk levels are entered
Residual Risk/Impact	The risk that remains after making the investment, represented by the value from the AIP Risk Matrix (the difference between the baseline risk and the risk mitigated)
Mitigated Risk	The reduction in risk from making the investment (represented by the value from the AIP Risk Matrix)
Value	The calculated value of an investment’s alternative, based on Benefits and Mitigated Risk.
Dependency	Links two investments that need to be approved/shifted together. Please contact AIP Team to create a dependency.
Optimizer	The AIP tool function that determines the best selection and timing of investment alternatives, maximizing risk mitigation and financial benefits, and satisfying the financial constraints and dependencies. It is run by the Investment Optimization Manager (IOM).
Corporate Values (weights)	Safety (20%) Reliability (15%) Customer (20%) Productivity (15%) Employees (10%) Environment (10%) Shareholder Value (10%) Note: Financial Benefits are calculated as 15% in addition to the weighted values.

OEB Staff Interrogatory # 89

Issue:

Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Reference:

B1-01-01 Section 1.1 Page: 35-36
Distribution System Plan Overview, Section 1.1.5 (5.2.1 E) Changes To Asset Management Process

Ref: Exhibit B1/Tab1/ Schedule 1 – DSP Section 2. 1: Investment Planning Process Section 2.1.4.2 Risk Assessment, Pages 2382 – 2384

"Investment Planning Training

> *Investment planning training was restructured into major components of the overall process to assist planners and management in the development of investment plans.*
> *The first training segment outlines key influences on the investment planning process, such as regulatory requirements and details various aspects, requirements and deliverables during the process cycle. This segment is to help ensure planners and managers understand the expectations and conditions in which to develop plans.*
> *The second segment was developed to assist planners in developing appropriate risk assessments for candidate investments. Illustrative examples are used to help planners understand the alignment of investments to the overall corporate business objectives and foster consideration of alternative approaches to articulate investment risk.*
> *The third segment details the elements of the Asset Investment Planning ("AIP") tool to ensure planner awareness of optimization criteria that would affect investment candidates during the optimization process.*
> *In the interest of operating as one company, Hydro One structured training sessions for each of the key asset management business units involved in the planning process to create a focused environment and ensure consistency across the planning groups. Further review of the investment planning process resulted in an initiative for management training on optimization. This detailed overview provides management insight into the optimization process and its effect on their candidate investments within Hydro One's overall investment portfolio."*

Interrogatory:

a) What exactly is being optimized in the AIP?

   i. Please provide the parameters and targets used by Hydro One in the optimization process.

   ii. Please provide examples of projects and programs which have been optimized using the AIP process.

b) Does any of the above training involve learning how to prepare business cases to improve investment optimization? If yes, please provide concrete examples.

c) Hydro One has stated that risk is a product of consequences and probability and the risk assessment is developed by planners. How does the planner develop the risk assessment?

   i. Please explain how the planner differentiates the consequences of each cost driver from “minor” to “catastrophic”

   ii. Please explain how the planner calculates the probability of each consequence from “unlikely” to “very likely”.

   iii. Is this method consistently used for all capital investments?

Response:

a) The Asset Investment Planning tool optimizes the entire portfolio of candidate investments, with the prioritization criteria and financial constraints. Program investments may have multiple alternatives, with varying levels of expenditure and risk mitigation while project investments may have variable timing. The Asset Investment Planning tool identifies a combination of investment alternatives and alternative start dates which maximizes economic value (risk mitigation) within the specified financial parameters.

   i. Table 1 provides the financial parameters used in initial optimization.

Table 1: Financial Parameters

	2018	2019	2020	2021	2022
Distribution Capital	679	703	725	750	779
Distribution OM&A	568	575	583	591	597

Table 34 in section 2.1 of the DSP (Exhibit B1-1-1) provides the proportional weighting of each optimization factor (see Table 34 – Hydro One’s Prioritization Criteria and Weightings, page 2386 of 2930).

ii. Examples of investments optimized include:
- SR-09 Pole Replacement Program; and
- SR-06 Distribution Station Refurbishments.

b) The training does not explicitly include information on how to prepare business cases to improve investment optimization. However, the training includes an overview of the optimization process and investment characteristics that improve the optimization process, including:

i. Investment Flexibility – Identifying multiple program alternatives and flexible project start dates to increase the number of potential optimization solutions that can be considered and assessed; and

ii. Develop Program Investment Alternatives for assets with similar risk profiles – Grouping program investment alternatives with similar risk profiles of potential events.

c) Planners use asset, system and investment specific information, as noted in section 2.1.3 (Needs Assessment) of the DSP (Exhibit B1, Tab 1, Schedule 1), to inform their investment level risk assessment.

i. The consequence component of the risk assessments are assessed against a consequence taxonomy table which includes descriptions of potential negative outcomes for “minor 1” to “catastrophic” for each of the risk factor value measures. Factors such as typical customer impact of equipment failure typically inform the consequence assessment. The consequence taxonomy table for distribution is included as Appendix A.

ii. The probability component of risk assessments are assessed against a probability taxonomy table which includes descriptions for probabilities ranging from “unexpected” to “very likely”. Factors such as asset condition or likelihood of an event occurring typically inform the probability assessment. The probability taxonomy table for distribution is included as Appendix B.

iii. Consistent guidance is provided to all planners regarding the structure and approach to risk assessments through training, and management review is leveraged to drive consistency within business units. A cross-functional calibration session was introduced in 2016 to improve the consistency across business units, by providing transparency to risk assessments and identification of outlier investments.

Appendix A

	SAFETY*		CUSTOMER		ENVIRONMENT		EMPLOYEES	PRODUCTIVITY	RELIABILITY		SHAREHOLDER VALUE				
Event	Workforce Health and Safety: Fatality or serious employee/contractor injuries/illness; failure to meet targeted reduction inOSHA Recordable injuries.	Public Injuries (with Hydro One at fault)	Failure to meet Service Quality Indicies.	Residential and Small Business Customers: Increase in customer dissatisfaction with Hydro One service quality	Adverse Environmental Impact	Adverse emission (carbon footprint / greenhouse gas)	Change in employee engaement survey results.	Failure meet Unit Cost targets per plan	Duration of Distribution Outages Measured in Interruption Hours (Number of customers impacted * Expected duration of Outage)	Frequency of Distribution Outages Number of customers interrupted for > 1 minute	Cost Impact	Shareholder Confidence: Owner/ shareholder involvement in Hydro One operations	Public Profile/Confidence: Negative Media Attention; Opinion leader and Public Criticism	Maintain Credibility With Regulators: Lack of Credibility or poor relationships with Regulators & Reliability Authorities (OEB/ IESO/NERC/NPCC/WSIB etc) including non- compliance.	Compliance: Failure to Meet Legal, Regulatory, Health Safety, Environmental Compliance Requirements or Sanction
Minor1 Noticeable disruption to results; manageable.	Meets planned improvement in health and safety targets	No Change in number of injuries	Achieved or exceeded Overall Expected Performance	Stable satisfaction as per survey responses (as measured by scorecard).	No impact on Hydro One Inc.	Anticipated improvement relative to work program in carbon footprint / greenhouse gas are achieved.	On-plan improvement achieved in Employee Survey Results.	Unit costs reduction less than planned	< 20,000 Customer Interruption Hours	< 10000 Interruptions	0-$500K				No Consequence
Minor2 Noticeable disruption to results; manageable.									20,000 to 50,000 Customer Interruption Hours	10000 to 25000 Interruptions	$500K-$1M				
Minor3 Noticeable disruption to results; manageable.									50,000 to 500,000 Customer Interruption Hours	25000 to 100000 Interruptions	$1M-$2M				
Minor4 Noticeable disruption to results; manageable.									500,000 to 5 Million Customer Interruption Hours (equivalent to SAIDI of <0.8 to 3.8 hrs)	100000 to 200000 Interruptions	$2M-$3M				
Minor5 Noticeable disruption to results; manageable.	Safety targets met, but minor concerns regarding future performance.		Achieve only 95% (to 100%) of Overall Expected Performance	Less than planned improvement in mass market customer satisfaction as per survey responses (as measured by scorecard).	Minor impact on Hydro One Inc property only e.g. <3,000 L non-PCB material released or < 5% increase in non-recoverable spills/leaks above historical levels	Marginally less than anticipated improvement relative to work program in carbon footprint / greenhouse gas.	Less-than-planned improvement achieved in Employee Survey Results.		5 Million to 7 Million Customer Interruption Hours (equivalent to SAIDI of 3.8 to 5.4 hrs)	200,000 to 500,000 Interruptions	$3M-$5M	Some concern with management decisions; Occasional requests from owner for details	Credible letter(s) to Senior Management	Balanced; some challenges.	Regulatory Warning, conditional closeout without sanctions.
Moderate Material deterioration in results; a concern; may not be acceptable; management response would be considered.	Less than planned improvement in health and safety performance	Small Increase in Number of Injuries	Achieve on 90% (to 94%) of Overall Expected Performance	Slight deterioration in mass market customer satisfaction as per survey responses (as measured by scorecard).	Minor local offsite impact (e.g. a single residential property or private water supply); or Significant spill/release with impact on Hydro One Inc property only. e.g. 3,000 - 5,000 L non-PCB material released or 5 - 25% increase in non-recoverable spills/leaks above historical levels	Somewhat less than anticipated improvement relative to work program in carbon footprint / greenhouse gas.	Much Less-than-planned improvement achieved in employee survey results.	Unit Costs not reduced	7 Million to 8 Million Customer Interuption Hours (equivalent to SAIDI of 5.4 to 6.7 hrs)	500,000 to 1.25 Million Interuptions	$5M-$25M	Confidence in question; Owner requests significant changes to business plan; Chair and CEO required to meet with owner to explain	Credible letter(s) to Premier, to Minister of Energy, to Minister of Environment, or to Chair of OEB that require action	Increase in Reporting Detail and Frequency (for HOI only)	Regulatory Order and/or financial sanction that is small, symbolic in nature or acknowledged as routine by the regulator and the industry.
Major Significant deterioration in results; not acceptable; management response.	No improvement in health and safety performance	Moderate Increase in Number of Injuries	Achieve only 80% (to 89%) of Overall Expected Performance	Call centre volumes increase (not storm related) noticeably (15-30%); Noticeable increase in complaints received by field staff doing work on customer premises; Modest deterioration in mass market customer satisfaction as per survey response (as measured by scorecard).	Significant local offsite Impact (e.g.. a public thoroughfare) e.g. >5,000 - 10,000 L non-PCB material released or >25% - 50% increase in non-recoverable spills/leaks above historical levels	No real improvement relative to work program in carbon footprint / greenhouse gas initiatives.	No improvement achieved in employee survey results.	Unit Costs increase by < 5%	8 Million to 10 Million Customer Interruption Hours - note: current performance is 8.8 hrs and 5 year average is 8.4 hrs (equivalent to SAIDI of 6.7 to 8.3 hrs)	1.25 Million to 3.75 Million Interruptions	$25M-$100M	Material erosion in confidence; Shareholder Agreement rewritten to include approval of major investment & operating decisions; One or more Senior Managers replaced by the Board	Significant local attention; Several opinion leaders/customers publicly critical	Some Concerns re: Competence; Difficult Demands	Conviction or regulatory finding of non-compliance with minor fine ("minor" meaning <30% of maximum fine under relevant legislation or regulation, and one that is not unusually high/unprecedented amount for the industry).
Severe Fundamental threat to operating results; immediate senior management attention.	Employee/contractor critical injury due to failure of managed system. Significant deterioration in health and safety performance.	Significant Increase in Number of Injuries	Achieve only 67% (to 79%) of Overall Expected Performance.	Exponential increase (>30%) in: - call centre volumes (not storm related); - complaints received by field staff; - time and effort to resolve; Sharp deterioration in mass market customer satisfaction as per survey responses (as measured by scorecard).	Multiple local offsite impacts (e.g. multiple residential properties or private water supplies) e.g. >10,000 - 20,000 L non-PCB material released or >50% increase in non-recoverable spills/leaks above historical levels	Carbon footprint / greenhouse gas gets somewhat larger relative to work program and more visible to interested stakeholders.	Modest decline in employee survey results.	Unit Costs increase by 6% - 10%	10 Million to 15 Million Customer Interruption Hours (equivalent to SAIDI of 8.3 to 12.5 hrs)	3.75 Million to 7.5 Million Interruptions	$100-$300M	Extensive loss of confidence; Shareholder Agreement rewritten to include approval of all investment and operating decisions; CEO or several Sr. Managers replaced	Provincial media attention; most opinion leaders/customers publicly critical	Some loss of Credibility; Excessive Involvement;	Conviction or regulatory finding of non-compliance with major fine ("major" meaning >30% of maximum fine under relevant legislation or regulation, or an unusually high/unprecedented amount for the industry).
Worst Case Results threaten survival of company in current form; potentially full time senior management response until resolved.	Employee/contractor fatality or major permanent disability due to failure of managed system	Fatality or Major Permanent Disability	Achieve only 25% (to 66%) of Overall Expected Performance.	Letters and complaints to MPPs escalate exponentially; significant numbers of customers begin to default on bill payments	Widespread offsite impacts (e.g. Regional or Municipal water supply) e.g. >20,000 L non-PCB material released	Carbon footprint / greenhouse gas gets substantially larger relative to work program and more visible to interested stakeholders.	Sharp deterioration in employee survey results.	Unit Costs increase by > 10%	>15 Million Customer Interruption Hours (equivalent to SAIDI of >12.5 hrs)	>7.5 Million Interruptions	>$300M	Complete loss of confidence; Shareholder Agreement rewritten to include active involvement in all business operations; CEO and Board replaced by the owner; Shareholder imposes substantial reduction in Hydro One scope and mandate	National media attention; opinion leaders/customers nearly unanimous in public criticism	General loss of Credibility; Intrusive Involvement;	Conviction with Incarceration of Staff

Appendix B

Likelihood Scale	Expectation of Event Frequency in years	Probability in Planning Period (5 years)	Probability in 1 year
Very Likely	>1 in 2	> 95%	>50%
Likely	1 in 2 to 1 in 5	95% to 65%	20 - 50%
Medium	1 in 5 to 1 in 20	65% to 25%	5 – 20%
Unlikely	1 in 20 to 1 in 100	25% to 5%	1 – 5%
Remote	1 in 500 to 1 in 100	1% - 5%	1 in 500 to 1 in 100
Unexpected	<1 in 500	<1%	< 1 in 500

- Asset condition assessments
- OM&A limited to inflation, less a productivity factor as defined by the OEB (total increase no more than 1.5%). Very recently, in October, the OEB reduced the inflation factor by 20bps, which means we will need to update final work plans to reflect no more than a 1.3% revenue growth over the base year
- Rate base/asset growth originally limited to 4.2%, as in the previous business plan.
- 2017 spending/plans consistent with prior OEB decisions
- Cumulative In Service capital for 2016/17 consistent with OEB-approved levels
- Significant emphasis on how planned investments provide value to customers, reflect continuous improvement and improve reliability; and
- Plans must consider and incorporate the findings of the customer consultation process and productivity studies as information becomes available

Asset Owners design their investments to achieve the aforementioned objectives. The result is known in our internal process as "asset optimal level." As noted above, lower levels of investment are also requested – a.k.a. "Vulnerable." The lower level is described as a level that meets minimum compliance and health and safety requirements and is only tolerable for brief periods. At the lower level, asset failure is a distinct possibility.

After completion of manager review, the Investment Management team begins the optimisation process. This is when the rate impact of the plan is first determined. It is at this time that Hydro One introduces a financial constraint to adjust investment levels to align with acceptable customer rate impacts. Investments are eliminated based on weighted optimisation values, which, in our process, weight customer impact and worker and public safety as the highest values. Reliability and Productivity are the second highest values. These top four values comprise 60% of the total weighting. This year, greater emphasis was placed on customer-centric outcomes, including customer experience enhancements and productivity enablement for rate mitigation.

D. RATE APPLICATION FRAMEWORK

Under the current OEB framework for distributors, base distribution rate components, such as OM&A and depreciation, are set on a "cost of service" basis for a rebasing year (2018). This generates a revenue requirement for 2018. This base year revenue is then indexed by a (price or revenue cap) formula, comprised of an inflation adjustment (1.9%), less a productivity stretch (0.6%) factor for a total of 1.3%, and escalated annually from 2019 to 2022. The OEB inflation factor is updated and applies annually. Because 2018 costs form the base for the next four years of revenue, these costs are closely scrutinised. Any variances over this period, negative or positive, are to the utility's account.

The revenues calculated above recover approved costs and a steady state level of capital expenditures only. In addition capital program costs that are not recovered in base rates will be recovered through a custom Capital Factor that drives changes in rates in each year of the rate period, based on the quantum and timing of the capital program. Rate increases each year are highly responsive to the timing of capital placed in service. The revenue requirement generated by this capital factor is added to the revenue requirement outlined in the prior paragraph, for a total customer rate impact.

Past OEB filings: In 2012 (for 2013-2014), Hydro One sought OEB approval for substantial increases over historically approved levels for select investment areas, including wood poles and distribution stations, to address quality of service issues. Hydro One argued that without incremental investment, system reliability would be impacted as Hydro One would be unable to replace or refurbish assets prior to breakdown. Further, Hydro One argued that deferring planned replacement

UNDERTAKING – JT 2.10

Undertaking

To provide a further explanation of the above-discussed matter after reviewing the transcript.

Response

As part of the exchange between Mr. Oakley and Mr. Jesus on March 2, 2018, three topics were discussed:

A. the risk assessment process and Exhibit I-24-Staff-100; and
B. the difference between Hydro One's optimization process and a forced rank order prioritization; and
C. The investment plan's risk profile and placement of the capital budget line.

These three topics are addressed in Part A, Part B and Part C, respectively.

Part A: Risk Assessment Process

Once investment candidate options are identified, as discussed in Section 2.1 of the DSP, they are assessed based on the value created by mitigating risks or their ability to enhance productivity/produce financial benefits.

The risk assessment process incorporates a probability and consequence of outcome to determine the impact on each business objective, as applicable. Based on identified sources of risk, an assessment is made on (a) the worst credible consequence/impact of a given risk on a specific business objective, as measured on a nine-point risk tolerance scale from "minor 1" to "catastrophic" and (b) the likelihood that a given consequence/impact will materialize over the planning period, as measured on a six-point likelihood scale, from "unexpected" to "very likely."

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 difference between the baseline risk and residual risk is the risk mitigation value created by the investment. An example of the output of these baseline and residual risk assessments is included in Exhibit I-24-Staff-100.

Part B: Optimization vs. Prioritization

Based on Hydro One's understanding of Mr. Oakley's line of questioning, a typical forced rank order investment prioritization exercise produces a ranked list of possible investments based on a set of decision criteria resulting in a fixed score (for example absolute risk mitigation). The overall portfolio is ranked using the fixed score, and funding is allocated from highest to lowest priority until all available funding has been allocated, resulting in funded list of investments.

Hydro One's optimization process uses a weighted multi-criteria assessment of the risk mitigated for each of the business values and considers three elements not typically incorporated in a forced rank order prioritization including: (a) alternate project timing, (b) alternate program pacing, and (c) the ability to address multiple constraints, including financial and non-financial constraints and investment dependencies.

Part C: Developing the final Budget Line

The output of the optimization process is an optimized investment portfolio or draft investment plan. This draft plan is then reviewed as part of Operational Stakeholder Engagement as described in section 2.1.5.2 of the DSP to achieve enterprise alignment for meeting business outcomes and objectives. This review may necessitate changes to the draft plan.

The factors that inform and influence the final budget envelope and investment plan include: (a) strategic direction and business outcomes including requirements for performance and additional cost constraints/productivity; (b) customer needs and preferences; (c) asset risks and system needs, including condition and reliability of the distribution system; and (d) the effect on customer rates.

In preparing the Dx Business Plan underpinning this Application, Hydro One considered alternate funding envelopes for its capital plan as described in Exhibit A, Tab 3, Schedule 1, each of which provided different outcomes and different levels of risk mitigation.

Investment Flexibility: Capital (1/2)

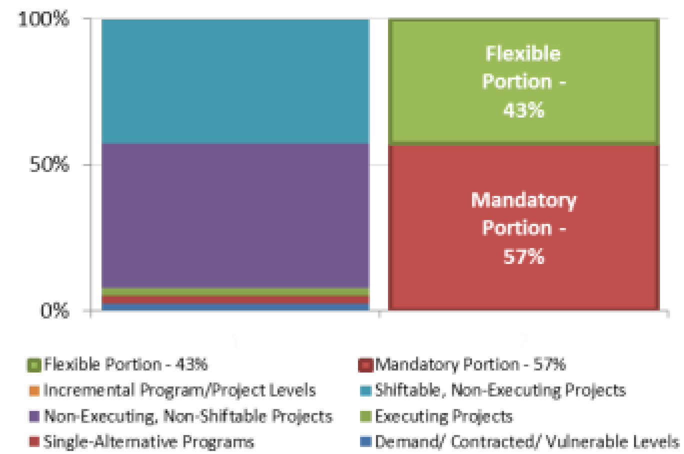
Investment Flexibility

- **43% Flexible** The investments in the Corporate Projects area support the business technology roadmap. Our investments deliver expanded business capability through the introduction of new enabling technologies as well as protecting our current technology by addressing end of life replacements of business applications.

Mandatory/Non-Discretionary Overview

- **Mandatory Overview -** Majority of the investments are 'projects' (as opposed to 'programs'). By default, project investments are deemed mandatory except when explicitly selected as a shiftable project. Examples of projects that are deemed mandatory are: CTI Replacement, GIS Roadmap, Funding for OEB Regulatory Compliance
- **Approach to Mandatory -** Projects that are either in-flight or OEB mandated must proceed. Those that have a higher risk of operational impact (CTI & GIS) should proceed. Other projects (Bill redesign) that will have a customer impact should also proceed. The remaining projects should then be measured on their strategic value and benefits and ranked for delivery according to available funding.
- **Mandatory Drivers -** The bulk of investments classified as mandatory is in response to the level of risk (deemed risky to delay the investment further) as well as delayed benefit to Hydro One if the investment were pushed out. There were also some investments related to regulatory compliance (ex. Demand Interval Conversion, Critical Peak Pricing, Dynamic Pricing).
- **Discretionary Opportunities -** The bulk of investments classified as mandatory is due to the risk assessed as unacceptable. As this is a subjective exercise, depending on the risk appetite, there may be an opportunity to reclassify some investments from mandatory to discretionary.

ISD - Corp Projects - Dx Capex



Mandatory Driver	Approx. %
Legal Regulatory/ Compliance	12%
Released Project	10%
Other – Please Specify (Weighed the risk & the impact of delaying the benefit if the project were to shift)	78%

forward, have to pay for the additional $122.5 million of in-service additions --

MR. BOWNESS: Yes, we believe that the expenditures over the prior period are prudent and that they were required in order to meet the plan needs as well as some emergent needs, especially with respect to joint-use work that we did, as well as storm volumes that were over plan in the 2015 period.

MR. RUBENSTEIN: Even though the Board gave you everything you needed, you needed some more?

MR. BOWNESS: Things did change, yes, and we've explained those variances.

MR. RUBENSTEIN: All right. So let's take a look at what you did during the last few years, and if we can turn to page 25 of the compendium. So you were asked in interrogatory AMPCO 22, part A for an analysis of the actual accomplishments of work compared to the investment plan between 2014 and 2017; do you see that?

MR. BOWNESS: Yes, I see that.

MR. RUBENSTEIN: And if we move over to the next page, where you provide your response, I see a lot of negative numbers, mostly negative numbers; would you agree with me?

MR. BOWNESS: Yes, I would agree that the majority of the unit count numbers are negative.

MR. RUBENSTEIN: And if we go down -- am I correct that where we see in the -- at the table ISD, that means -- and we see the S numbers, S is what you called, at least in the last proceeding, sustaining category of investments; am

I correct?

MR. BOWNESS: Yes, that's correct.

MR. RUBENSTEIN: And those generally map to system renewal? I know it's not perfect, but that's a general type?

MS. GARZOUZI: Generally, that's correct.

MR. RUBENSTEIN: And just -- so if we just look at some of these, I see that you did less transformer replacements than you said you would do in the last proceeding? Do I have that correct?

MS. GARZOUZI: That's correct.

MR. RUBENSTEIN: Less station refurbishments? Do I have that correct?

MS. GARZOUZI: That's correct.

MR. RUBENSTEIN: Less pole replacements? Do I have that correct?

MS. GARZOUZI: That's correct.

MR. RUBENSTEIN: Less PCB lines requiring replacements? Do I have that correct?

MS. GARZOUZI: That's correct.

MR. RUBENSTEIN: Less large sustaining initiatives?

MS. GARZOUZI: That's correct.

MR. RUBENSTEIN: So if we look at each of the ISDs in there, every single one that has an "S", so sustaining programs, every single one shows that Hydro One replaced less assets and did less work than you said you would do over 2015 to 2017; do I have that correct?

MS. GARZOUZI: The table in AMPCO 22 is an insular

Hydro One Distribution – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Station Refurbishments
Work Execution Period: January 2015 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
To refurbish an entire distribution station or part of a distribution station to address assets approaching the end of their expected service life that have a high risk of failure.

Need:
As outlined in Exhibit D1, Tab 2, Schedule 1, distribution station assets are ageing and a number of components are near the end of their expected service life. There are also concerns with the condition of the distribution station assets, including rotting high and low voltage wood structures, failing tube and clamp structures, deteriorated transformers, obsolete or faulty station equipment, fence and grounding systems.

Many assets reaching the end of their projected service life also coincide with poor reliability performance. Station failures could occur with lengthy customer outages realized.

Some other factors contributing to the need for the refurbishment of a station are: loading requirements, lack of mobile unit substation connection facilities, obsolete equipment, customer issues, operational problems, environmental spill risk mitigation, and safety issues or a combination of all of these factors.

Alternatives:
<u>Alternative 1: "Do Nothing"</u>
Wait for components to fail while in service and replace them on a reactive basis, at a premium cost and with increased safety risks.

<u>Alternative 2: "Individual Component Replacements"</u>
Replace individual defective assets in distribution stations on a component basis. While this type of replacement is performed in some cases, it is not ideal. Individual component replacements do not allow efficiencies associated with the integrated replacement of a number of components at once.

Alternative 3: "Station Refurbishment" (Recommended)
Refurbish entire stations or parts of a station to current Hydro One Distribution standards in order to improve the reliability of the distribution system. The refurbishment of the station will result in reduced costs and will extend the life of the station.

Investment Description:
Distribution station assets deteriorate over time and should be replaced as they reach their expected end of service life. Stations are identified and prioritized for refurbishment based on asset risk assessments. Through station refurbishment a higher reliability is obtained by the installation of new equipment and other infrastructure.

The refurbishment will address: aged transformers and structures, defective equipment, site or property issues, customer issues, safety concerns, environmental compliance, and operational issues. The stations will be refurbished to comply with present standards. Noise assessments are completed for station refurbishments that require the replacement of the transformer. If the noise of the transformer is an issue; a new transformer with lower noise levels will be installed. Landscaping, low profile designs, and wood fences are also incorporated into the station design where sites are located in urban areas.

Each station refurbishment will vary in size and scope. The average capital investment for each station refurbishment is below $1 million. The station refurbishments planned over the five year period are outlined below.

Year	Stations		
2015	Abbey DS	Dorchester DS	Perrault Falls DS
	Alexander Kenyon West DS	Exeter DS#2	Plattsville DS
	Berwick DS	Forest Jefferson DS	Princeton DS
	Blenheim DS	Geraldton South DS	Russell DS
	Bolsover DS	Haliburton DS	St. Thomas DS
	Brigden DS	Kemptville Van Buren DS	Stouffville 10th Line DS
	Brockville Park DS	Kingsville Pulford DS	Tara DS
	Brockville Water DS	Kirkland Lake Goodfish	Tralee DS
	Carleton Place	Lindsay Eglinton DS	Trenton McAuley DS
	Chatham Raleigh DS	Little Current DS	Wainfleet DS
	Corbeil DS	Marathon DS	Warkworth DS
	Deep River DS	Merlin DS	Wyoming Churchill DS

Year	Stations		
2016	Adams Point DS	Fenelon Falls Elliot DS	Newport DS
	Bismark DS	Gorrie DS	Nipigon DS
	Bobcaygeon Ann DS	Gravenhurst DS	Pointe Au Baril DS
	Carp DS	Guthrie DS	Port Lambton DS
	Consecon DS	Holland Landing DS	Precious Corners DS
	Craigleith DS	Horsey Bay DS	Shannonville DS
	Crozier DS	Kirkland Lake DS #1	Sutton Base Line #1 DS
	Devlin DS	Longlac East DS	Thorold Turner DS
	Dover Centre DS	McGregor DS	Vanastra DS
	Dundas Sydenham DS	Meaford Louisa DS	Wallaceburg DS
	Elk Lake DS	Meaford Thompson DS	Waupoos DS
	Elliot Lake DS	Mountain Chute DS	Wingham DS
	Elora Union DS	New Liskard Halibton DS	
2017	Arnprior Airport DS	Deseronto DS	Perth DS
	Arnprior Elgin DS	Drumbo DS	Perth North DS
	Arnprior McLachlin DS	Firth Corners DS	Pinelands DS
	Aspdin DS	Galetta DS	Rockland DS
	Athens DS	Hawley DS	Smithfield DS
	Black Corners DS	Kemptville West DS	Sturgeon Falls DS
	Brockville Cedar DS	Killaloe DS	Thamesville North DS
	Brockville Schofield DS	Manitouwadge DS #1	Trenton McNichol DS
	Cameron DS	Marthaville DS	Wartburg DS
	Clarence DS	Meaford Vincent DS	Welcome DS
	Collins Bay DS	Milford DS	Whitney DS
	Corunna DS	Monkton DS	Yarmouth Centre DS
	Cumberland DS	Owen Sound 12 St E DS	
2018	Alexander DS	Forest Jura DS	Owen Sound 2 Ave E DS
	Battersea DS	Glengarry DS	Pleasant Point DS
	Beaumaris DS	Haycroft DS	Red Rock DS
	Bolton Hardwick DS	Horningmill DS	Ridgetown Palmer DS
	Cedar Mills DS	Jones Road DS	Ripley DS
	Clayton DS	Joyceville DS	Rock Mills DS
	Creemore DS	Kennisis Lake DS	Roseville DS
	Dack DS	Kleinburg DS	Rylston DS
	Deleware DS	Lagoon City DS	Sam Lake DS
	DorcasBay DS	Madoc Madawaska DS	Shedden DS
	Dunchurch DS	McCrimmon DS	Shelburne Andrew DS
	Erin DS	Merrikville DS	Snelgrove DS
	Fenelon Falls DS	Mindemoya DS	Wiarton Claude DS
	Flynn Corners DS	Owen Sound 12 St W DS	

Year	Stations		
2019	Aberfoyle DS	Golden Valley DS	Punkidoodles Corners DS
	Addison DS	Huntsville DS	Ruthven DS
	Alexandria Margaret DS	Kerwood DS	Sharon DS
	Blythswood DS	Keswick DS	Sleeman DS
	Bondhead DS	Lanark DS	Smith Falls DS
	Buckhorn DS	North Brook DS	Taylor Kidd DS
	Carleton Place Francis DS	Omemee DS	Thedford DS
	Chatham Raleigh RS	Osgood DS	Vankleek Terry Fox DS
	Chesterville Bran DS	Ospringe DS	Vienna DS
	Cobalt DS	Oxford Mill DS	Virginiatown DS
	Dunedin DS	Park Road DS	Wanup DS
	Emo DS	Picton Barker DS	Wellington Wharf DS
	Farlain Lake DS	Pinegrove DS	Wooler DS
	Fonthill RS	Prospect DS	

Result:

Station refurbishments will result in:

- Addressing the ageing and degrading condition of distribution stations in a cost-effective manner,
- Ensuring the safe and reliable operation of the distribution system, and
- Reducing the risk of lengthy equipment outages caused by equipment failure or malfunction.

Costs:

($M)	2015	2016	2017	2018	2019	Total
Capital* and Minor Fixed Assets (A)	34.6	39.0	40.0	44.5	45.2	203.3
Operations, Maintenance & Administration and Removals (B)	2.4	2.6	2.7	2.9	3.0	13.6
Gross Investment Cost (A+B)	37.0	41.6	42.7	47.4	48.2	216.9
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	34.6	39.0	40.0	44.5	45.2	203.3

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

Investment Category:

System Access	System Renewal	System Service	General Plant
0%	100%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Reduce the number of planned outages at distribution stations that impact customer supply with the integrated approach to station refurbishments.
Operational Effectiveness	• Maintain safe operation and reliability of the distribution station by addressing all ageing and degrading equipment in an integrated manner.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the service reliability indicators by upgrading ageing and degrading equipment prior to failure.
Financial Performance	• Cost savings are recognized when all ageing and degrading components within the station are replaced as part of the same project.

OEB Staff Interrogatory # 159

Issue:

Issue 26: Does the Distribution System Plan address the trade-offs between capital and OM&A spending over the course of the plan period?

Reference:

B1-01-01 Section 3.8 Page: 2611 and 2617
(5.4.5.2) Attachments: Material Investments, ISD: SR-06 Distribution Station Refurbishment
EB-2013-0416 Exhibit D2/Tab2/Schedule 3 –S-07 Station Refurbishment

Interrogatory:

SR-06 Distribution Station Refurbishment

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Program	**Plan Period Cost ($M):**	148.1
Primary Trigger:	Failure Risk		
Secondary Trigger:	Capacity Upgrade		

($ Millions)	2018	2019	2020	2021	2022	Total
Capital* and Minor Fixed Assets	16.2	31.8	36.4	37.1	37.8	159.3
Less Removals	1.1	2.2	2.5	2.6	2.6	11.1
Gross Investment Cost	**15.0**	**29.6**	**33.8**	**34.5**	**35.2**	**148.1**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**15.0**	**29.6**	**33.8**	**34.5**	**35.2**	**148.1**

**Includes Overhead at current rates.*

a) Please explain how this program is related to and coordinated with SR-01 and SR-04.

b) Please confirm that the proposed distribution station refurbishment plan calls for an average of 15 distribution stations to be refurbished each year over the 5-year test period, for a total program spending of $148.1 million, even though this investment plan is identified as having medium priority.

   i. Please explain why so much investment is being planned for a medium priority program.

c) Is it possible for Hydro One to reduce the investment plan by refurbishing only the highest risk distribution stations, or by reducing the plan from 15 distribution stations per year to 10 stations per year over the 5-year test period?

d) In EB-2013-0416, the investment S-07 Station Refurbishment provided several stations planned for refurbishment. Several of these stations are repeated in this application, in investment SR-06 Distribution Station Refurbishment. Please provide an explanation why these stations were not completed as planned in the last application under investment S-07.

e) Please provide a list of stations refurbished in the last three years. The list should include the station name, estimated cost of the station refurbishment, actual cost of the station refurbishment, and an explanation for material variance between estimated and actual cost.

f) For each station refurbishment project provided for the last three year please provide the scope of work to be completed at each station.

Response:

a) All three programs address the replacement of station components but under different conditions, as summarized below. These three programs are coordinated during the investment planning process to ensure work is integrated and there is no duplication.

- SR-01 Distribution Stations Demand Capital program replaces major station components on an unplanned/demand basis where the component is failing or has already failed.
- SR-04 Distribution Station Component Replacement program replaces minor station components (switches, structures, station service, fencing and ground grid) on a planned basis based on the condition of the asset.
- SR-06 Distribution Station Refurbishment program replaces or refurbishes major station components (transformers, reclosers, high voltage and low voltage structures) on a planned basis based on the condition of the station assets.

b) Confirmed. As described in ISD SR-06 in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8; the distribution station refurbishment plan is a medium priority investment and calls for refurbishment of approximately 15 stations per year for a total cost of $148.1 million.

The program is considered a medium priority program in context to all the investments in the proposed plan based on the risk assessment and investment optimization of the Investment

Planning Process described in Exhibit B1, Tab 1, Schedule 1, Section 2.1.4.2. The funding level proposed for this program is based on maintaining the number of stations that are classified as high risk (based on condition assessments) at a stable level.

c) It is possible for Hydro One to target only 10 stations per year for refurbishment and refurbish the highest risk stations first. If 10 station refurbishments were completed per year the average age of the transformer fleet would increase and it is expected that the overall condition of the fleet would deteriorate. As the condition of the fleet deteriorates, it is expected that there would be a corresponding increase in transformer failures which would lead to increased costs in other investments such as: SR-01, SR-02 and SR-03. It is also expected that this will result in higher investment levels beyond the five year term which would be funded by future ratepayers.

d) Station refurbishment projects from EB-2013-0416 S-07 that appear in SR-06 of this application were deferred due to a reprioritization of investments. Please refer to interrogatory response Exhibit I-23-Staff-84 part (c) for further details on the reprioritization process.

e) & f) A list of stations refurbished in the last three years is provided in the table below detailing the costs and scope of work at each station. A variance explanation has been provided for all the material variances (>20%). The major causes for variance from the unit cost are that the unit cost did not consider the following items: dual transformer stations, additional requirements for 115kV connected stations, spill containment, significant expansion of existing station, and installing new HV and LV structures.

Station Name	In Service Year	Estimated Cost ($M)	Actual Cost ($M)	Variance ($M)	Variance Explanation	Scope
Wilsonville DS	2014	2.4	2.9	0.5	Increase as unit cost did not consider expansion of existing site with new HV and LV structures.	Install new 7.5MVA transformer with ULTC. Expand existing site, install new HV and LV structures, reclosers, fence, and ground grid.
Meaford DS #2	2014	2.4	2.8	0.4		Install new 7.5MVA transformer. Expand existing site, install new HV/LV and exit structures, reclosers, fence, and ground grid.
Brighton DS #2	2014	2.4	2.3	-0.1		Replace transformer with spare 7.5MVA unit. Install new reclosers and ground grid. Keep existing HV and LV structures.
Cache Bay DS	2014	2.4	2.3	-0.1		Install new 7.5MVA transformer with ULTC. Install new reclosers, ground grid and fence. Keep existing HV and LV structures.
Oxley DS	2014	2.4	2.3	-0.1		Install new 5MVA transformer. Install new HV and LV structures, reclosers, fence and ground grid. Acquire additional land.
Brockville Parkdale DS	2014	1.9	2.2	0.3		Install iMDS with 7.5MVA transformer. Install new civil structure, HV/LV ingress/egress, and ground grid.
Huntsville RS	2014	2.4	2.2	-0.2		Install new 25MVA regulator transformer with spill containment. Install new 4 pole regulating station structure, fence, ground grid
Berkeley DS	2014	1.0	0.5	-0.5	Decrease as unit cost did not consider use of a non-ULTC transformer.	Replace existing transformer (3 single phase units) with a new 5MVA 3 phase bank.
Currie DS	2014	2.4	1.7	-0.7	Decrease as unit cost did not consider use of a non-ULTC transformer.	Install new 7.5MVA transformer. Expand existing site, install new reclosers, fence, ground grid, LV and exit structures. Keep existing HV structure.

Station Name	In Service Year	Estimated Cost ($M)	Actual Cost ($M)	Variance ($M)	Variance Explanation	Scope
Bothwell DS #2	2014	2.4	0.9	-1.5	Decrease as unit cost did not consider the use of a spare transformer.	Replace transformer with a spare 5MVA unit. Install new reclosers and ground grid. Keep existing HV and LV structures.
Crow River DS	2015	2.4	6.4	4.0	Increase as unit cost did not consider dual transformer station or connection to 115kV system with revenue metering.	Install two new 7.5MVA new transformers. Expand existing site, install new fence, yard lighting, and ground grid. Modify existing LV structures to increase clearances. Install new revenue metering with transfer scheme.
Red Lake DS	2015	2.4	6.0	3.6	Increase as unit cost did not consider spill containment for 4 transformers.	Refurbish existing transformers. Install spill containment around 4 existing transformers. Expand existing site, install new LV exit structures, reclosers, fence and ground grid.
Abitibi Canyon DS	2015	2.4	5.4	3.0	Increase as unit cost did not consider dual transformer stations.	Refurbish two existing 5MVA transformers and re-install on new concrete pads. Install new LV MUS exit structures, reclosers, station fence, and ground grid. Keep existing HV/LV structures. Soil remediation as required
Kirkland Lake Woods DS	2015	2.4	3.7	1.3	Increase as unit cost did not consider expansion of existing site with new LV and exit structures.	Install spare 5MVA transformer and switchgear Expand existing site, install new LV structure, exit structure, reclosers, fence, and ground grid. Keep HV structure.
Trenton Bay DS	2015	2.4	4.2	1.8	Increase as unit cost did not consider expansion of existing site with new HV and LV structures and demolition of existing building.	Install new 7.5MVA transformer with ULTC. Install new HV and LV structures, reclosers, ground grid and fence. Acquire new land. Demolish building that contained the equipment.
Barwick DS	2015	2.4	4.5	2.1	Increase as unit cost did not consider dual transformer stations.	Install two 6MVA repaired transformers. Expand existing site, install new reclosers, fence and ground grid. Keep existing HV and LV structures.

Station Name	In Service Year	Estimated Cost ($M)	Actual Cost ($M)	Variance ($M)	Variance Explanation	Scope
Nestor Falls DS	2015	2.4	3.5	1.1	Increase as unit cost did not consider expansion of existing site or connection to 115kV system with revenue metering.	Install new 7.5MVA transformer with ULTC. Expand existing site, install new HV and LV structures, reclosers, fence, and ground. Incorporate revenue metering to new design including at MUS facilities.
Kemble DS	2015	2.4	3.0	0.6	Increase as unit cost did not consider expansion of existing site and dual transformer stations.	Install two new 7.5MVA transformers. Expand existing site, install new LV exit structures, reclosers, fence, and ground grid. Keep existing HV and LV structures.
Longlac West DS	2015	2.4	2.9	0.5	Increase as unit cost did not consider expansion of existing site.	Install new 10MVA transformer and spare regulator transformer with new 4 pole structure. Expand existing site, install new recloser, fence. Keep existing HV and LV structures.
Bobcaygeon Duke DS	2015	2.4	3.3	0.9	Increase as unit cost did not consider reengineering of structure to mount new components and establishing proper grounding in bedrock.	Install new 7.5MVA transformer. Replace fuses with reclosers. Keep existing HV and LV structures.
Campbellford Industrial DS	2015	1.9	2.3	0.4	Costs higher than anticipated as this was part of iMDS pilot program.	Install new iMDS with 5MVA transformer. Install new civil structure, HV/LV ingress/egress, and ground grid.
Merlin DS	2015	2.4	2.8	0.4		Install new 5MVA transformer with ULTC. Expand existing site, install new reclosers, fence, ground grid. Keep existing HV/LV structures.
Tilbury Peltier DS	2015	2.4	2.6	0.2		Install new 5MVA transformer. Expand existing site, install new HV and LV structures, reclosers, fence, and ground grid.
Meaford Thompson DS	2015	1.9	2.4	0.5	Costs higher than anticipated as project was part of iMDS pilot.	Install new iMDS with 5MVA transformer. Install new civil structure, HV/LV ingress/egress, fence and ground grid.

Station Name	In Service Year	Estimated Cost ($M)	Actual Cost ($M)	Variance ($M)	Variance Explanation	Scope
Lindsay Eastview DS	2015	1.9	2.3	0.4		Install new iMDS with 5MVA transformer. Install new civil structure, HV/LV ingress/egress.
Maxville George DS	2015	2.4	2.3	-0.1		Install new 7.5MVA transformer. Expand existing site, install new reclosers, fence, ground grid. Keep existing HV/LV structures.
Aguasabon DS	2015	1.0	0.9	-0.1		Replace existing hot spare transformer with new 7.5MVA unit.
St.Williams DS	2015	2.4	2.2	-0.2		Install new 7.5MVA transformer with ULTC. Expand existing site, install new HV and LV structures, reclosers, fence and ground grid.
Geraldton South DS	2015	1.9	2.1	0.2		Install new iMDS with 5MVA transformer. Install new civil structure, HV/LV ingress/egress, fence and ground grid.
Bolsover DS	2015	2.4	2.2	-0.2		Install new 7.5MVA transformer. Install new reclosers and ground grid. Keep existing HV and LV structures.
Meaford Louisa DS	2015	1.9	2.1	0.2		Install new iMDS with 5MVA transformer. Install new civil structure, HV/LV ingress/egress, fence and ground grid.
Larder Lake DS	2015	2.4	2.5	0.1		Replace transformer with a spare 5MVA unit. Replace fuses with reclosers. Install new ground grid. Keep existing HV and LV structures.
Essex DS	2015	2.4	2.0	-0.4		Install new 5MVA transformer with ULTC. Install new reclosers, ground grid and fence. Keep existing HV and LV structures.
Owen Sound 3rd Ave DS	2015	1.9	1.8	-0.1		Install new iMDS with 5MVA transformer. Install new civil structure, HV/LV ingress/egress.

Station Name	In Service Year	Estimated Cost ($M)	Actual Cost ($M)	Variance ($M)	Variance Explanation	Scope
Trenton Frankford DS	2015	1.9	1.8	-0.1		Install new iMDS with 7.5MVA transformer. Install new civil structure, HV/LV ingress/egress, fence.
Havelock Industrial DS	2015	1.9	1.7	-0.2		Install new iMDS with 5MVA transformer. Install new civil structure, HV/LV ingress/egress.
Highgate DS	2015	2.4	1.6	-0.8	Decrease as unit cost did not consider use of a non-ULTC transformer.	Install new 5MVA transformers. Expand existing site, install new reclosers, fence, ground grid. Keep existing HV / LV structures.
Otonabee DS	2015	2.4	1.5	-0.9	Decrease as unit cost did not consider the use of a spare transformer.	Install spare 5MVA transformer. Install new reclosers and ground grid. Keep existing HV/ LV structures.
Kenogami DS	2015	2.4	1.7	-0.7	Decrease as unit cost did not consider the use of a spare transformer.	Install spare 10MVA transformer and reclosers. Keep existing HV and LV structures.
Lindsay Eglinton DS	2016	2.4	7.4	5.0	Increase as unit cost did not consider spill containment, soil remediation and landscaping required to obtain approval from municipality.	Install new 5MVA transformer with spill containment. Install new LV structure, reclosers, and ground grid. Keep HV structure. Complete soil remediation and landscaping.
Deep River DS	2016	2.4	5.1	2.7	Increase as unit cost did not consider dual transformer station or connection to 115kV system with revenue metering.	Install two new 7.5MVA transformers with ULTC. Install new reclosers, fence and ground grid. Keep existing HV and LV structures.
Shining Tree DS	2016	2.4	4.2	1.8	Increase as unit cost did not consider expansion of existing site or connection to 115kV system with revenue metering.	Install new 7.5MVA transformer with ULTC. Expand existing site, install new LV structures, reclosers, fence and ground grid. Keep existing HV structures. Reconfigure existing metering to accommodate new structure and MUS facilities.
Little Current DS	2016	2.4	3.8	1.4	Increase as unit cost did not consider development of new land, new HV and LV structures.	Install new 7.5MVA transformer with ULTC, Install new HV and LV structures, reclosers, ground grid, fence, drainage. Acquire new land.

Station Name	In Service Year	Estimated Cost ($M)	Actual Cost ($M)	Variance ($M)	Variance Explanation	Scope
Wyoming Churchill DS	2016	2.4	3.7	1.3	Increase as unit cost did not consider expansion of existing site with new HV and LV structures.	Install new 5MVA transformer with ULTC. Expand existing site, install new HV and LV structures, reclosers, fence, and ground grid.
Perrault Falls DS	2016	2.4	3.9	1.5	Increase as unit cost did not consider expansion of existing site, new HV and LV structures and connection to 115kV system with revenue metering.	Install new 7.5MVA transformer with ULTC. Expand existing site, install new HV/ LV structures, reclosers, fence, ground grid, new revenue metering to meter at main structure and MUS facilities.
Fiddlers Green DS	2016	2.4	3.1	0.7	Increase as unit cost did not consider expansion of existing site with new HV and LV structures.	Install new 7.5MVA transformer with ULTC. Expand existing site, install new HV and LV structures, reclosers, fence, and ground grid.
Brockville Water DS	2016	2.4	3.0	0.6	Increase as unit cost did not consider non-standard stations with minimal space requiring unique design.	Install new 7.5MVA pad mount transformer. Remove existing switchgear and install pad mount reclosers.
Appin DS	2016	2.4	2.8	0.4		Install new 5MVA pad mount transformer. Install new HV and LV structures, reclosers, fence and ground grid. Acquire additional land. Remove approximately 1km of off road 28kV circuit and replace with 600m of on road circuit.
Abbey DS	2016	2.4	2.5	0.1		Install new 5MVA transformer with ULTC. Install new transformer pad, reclosers, ground grid and fence. Keep existing HV/LV structures.
Post Creek DS	2016	2.4	2.2	-0.2		Install new 7.5MVA transformer with ULTC. Expand existing site, install new HV and LV structures, reclosers, fence, and ground grid.

Hydro One Distribution – Investment Summary Document

Sustaining Capital - Lines

Investment Name: Lines PCB Equipment Replacements Program
Work Execution Period: January 2015 to December 2019
Primary Outcome: Public Policy Responsiveness

Objective:
To manage the removal of line equipment with insulating oil containing polychlorinated biphenyls ("PCBs") in compliance with Environment Canada regulations.

Need:
Hydro One Distribution owns and operates approximately 450,000 pole top transformers and approximately 2,000 pole mounted capacitor units. Oil-filled equipment manufactured prior to 1985 may contain chemical compounds known as PCBs. In 2008, Environment Canada enacted legislation mandating the removal of all pole top equipment whose insulating oil contains greater than 50 ppm of PCBs by 2025.

All pole top transformers manufactured prior to 1985 will require oil sampling and PCB analysis as described in Exhibit C1, Tab 2, Schedule 2. From past experience with PCB testing, Hydro One Distribution projects that approximately 8% of these transformers will exceed the 50 ppm threshold and will ultimately require replacement due to PCB contamination. Capacitor units cannot be tested for PCBs without causing them significant damage, therefore all capacitors manufactured before 1985 will require replacement. The removal of PCB contaminated equipment is required to ensure health and safety risks are mitigated and ensure compliance with environmental legislation.

Alternatives:
No alternatives are considered, since failure to remove PCB contaminated line equipment would place Hydro One Distribution in violation of Environment Canada regulations. Replacement at a faster rate would result in unnecessary resource requirements in the short term. Replacement at a slower rate would require a large spike in volumes in the final years of the program to meet the 2025 deadline. Either case would introduce unnecessary and costly variations in the resource levels required to complete this program.

Investment Description:
This program addresses the removal and replacement of pole top equipment whose insulating oil contains PCB contamination levels greater than 50 ppm. Of the approximately 450,000 pole top

transformers in the distribution system, approximately 240,000 were manufactured prior to 1985 and must be tested for PCB contamination. Of these, Hydro One Distribution expects that approximately 19,000 will require replacement.

The replacement of transformers lags the PCB testing program by one year, allowing time for the identification of contaminated transformers and the planning required to replace them with minimal impact to customers.

Hydro One Distribution's plan is to gradually increase the replacement rate over the first few years of the program, as outlined below. This will allow time to optimize the inspection, testing and removal processes. The ultimate replacement level is expected to be approximately 2,200 per year. This rate of replacement minimizes impacts to required resourcing levels and ensures the program will be complete by the 2025 deadline set out by Environment Canada.

Year	**2015**	**2016**	**2017**	**2018**	**2019**
Number of Pole Top Transformer Replacements	400	1,000	2,200	2,200	2,200

This program will also address the removal of all capacitor units manufactured prior to 1985. The specific units to be replaced will be identified by either the distribution line patrols or the PCB equipment inspection program.

Result:
The lines PCB equipment replacement program will result in:
- Mitigating health and safety risks associated with PCB contaminated line equipment, and
- Ensuring compliance with environmental legislation.

Costs:

($M)	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	1.9	5.0	10.6	10.8	11.1	39.3
Operations, Maintenance & Administration and Removals (B)	0.3	0.7	1.6	1.6	1.6	5.8
Gross Investment Cost (A+B)	2.1	5.7	12.2	12.4	12.7	45.1
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	1.9	5.0	10.6	10.8	11.1	39.3

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

Investment Category:

System Access	System Renewal	System Service	General Plant
%	100%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Mitigate potential health and safety hazards to customers and the public by minimizing the PCB oil contamination levels in lines equipment.
Operational Effectiveness	• Ensure continuous improvement of distribution lines by replacing the old PCB contaminated equipment with new equipment built to current standards and compatible with future loading requirements.
Public Policy Responsiveness	• Comply with Environment Canada legislation to remove all oil filled equipment with PCB contamination > 50 ppm by 2025.
Financial Performance	• Failure to complete the mandated PCB elimination by 2025 w ould result in non-compliance penalties.

SR-08 Distribution Lines PCB Equipment Replacement Program

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Program	**Plan Period Cost ($M):**	72.8
Primary Trigger:	Mandated Obligation		
Secondary Trigger:	Substandard Performance		

Investment Need:

Hydro One owns, operates, and maintains 450,000 pole top transformers, 54,000 pad mount/submersible transformers and 3,000 pole mounted capacitor units; all of which are oil filled equipment. Prior to year 1985, a chemical compound known as a polychlorinated biphenyl ("PCB") was widely deployed in dielectric and coolant fluids in the manufacturing of oil filled electrical apparatus. However, this manufacturing practice was discontinued in the late 1970's when it became evident that PCBs build up in the environment and exposure to high levels can cause harmful health effects. In 2008, Environment Canada enacted legislation mandating that all oil-filled equipment whose insulating oil contains greater than 50 ppm of PCBs be removed by December 31, 2025. Therefore Hydro One must remove all such oil-filled equipment. Hydro One's distribution assets which are oil-filled consist solely of pole top transformers, pad mount mount/submersible transformers and pole mounted capacitor unit.

Alternatives:

This investment is non-discretionary. No alternatives are considered, since failure to remove PCB contaminated distribution line equipment would place Hydro One in violation of Environment Canada regulations and result in increased public health and safety risks.

Investment Description:

This program addresses the removal and replacement of distribution line oil-filled equipment (i.e., pad mount transformers, pole top transformers and pole mounted capacitor banks) whose insulating oil contains PCB contamination levels are greater than 50 ppm. All of Hydro One's pad mount transformers have already been tested as part of the PCB inspection and testing program, and all units with greater than 50 ppm of PCBs have been replaced.

All of Hydro One's pole-top transformers manufactured prior to 1985 will require inspection and oil sampling testing. To date, approximately 10 to 15% of the transformers have be inspected and tested. Hydro One proposes to inspect and test the remaining transformers at a consistent rate over the period from 2018 to 2024.

From past experience with PCB testing, approximately 8% of these transformers will exceed the 50 ppm threshold and will ultimately require replacement due to PCB contamination. The replacement of the pole-top transformers is slated to lag the PCB inspection and testing program by one year, allowing time for the identification of contaminated transformers and optimization of a plan to replace the transformers that minimizes the impact to customers. Based on historic sampling results this would result in approximately 2,400 to 2,600 replacements per year to ensure that the program will be completed by the 2025 deadline set out by Environment Canada.

Capacitor units cannot be tested for PCBs without causing them significant damage. Therefore, all of Hydro One's capacitors manufactured before 1985, will require replacement. Hydro One proposes to replace the units at a consistent rate over the period from 2018 to 2024.

Risk Mitigation:

The risk to completion of this investment as planned is based on the uncertainty of the volume and exact location of the PCB contaminated equipment exceeding the allowable threshold of 50 ppm. This risk is mitigated by the establishment of an inspection and testing program to identify all oil filled equipment that must be replaced under legislative requirement and an associated process to replacement the identified contaminated equipment.

Result:

The distribution lines PCB equipment replacement program will result in:

- Mitigating health and safety risks associated with PCB contamination by removing the affected line equipment; and
- Ensuring compliance with environmental legislation.

Outcome Summary:

Customer Focus	• Mitigate potential health and safety hazards to customers and the public by removing the contaminated lines equipment.
Operational Effectiveness	• Realize improvement of distribution lines by replacing the old PCB contaminated equipment with new equipment.
Public Policy Responsiveness	• Comply with Environment Canada legislation to remove all oil filled equipment with PCB contamination > 50 ppm by 2025.
Financial Performance	• Avoid non-compliance penalties arising from a failure to complete the mandated PCB elimination by 2025.

Costs:

The costs for this program are projected based on historic sampling results and future anticipated replacement needs which lag the PCB inspection and testing program by one year. The factors which affect the costs in this investment are any unforeseen issues at each work location, for example all new installations must meet Electrical Safety Authority requirements, so where a transformer is to be replaced, minimum pole height standards are mandated which could result in multiple pole and other equipment replacements.

Controllable costs have been minimized by standardizing the procedure for common activities such as equipment replacement, and coordinating with other sustainment programs where possible.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs****
Capital* and Minor Fixed Assets	13.3	13.6	13.8	21.2	21.6	83.5	113.0
Less Removals	1.7	1.7	1.8	2.7	2.8	10.7	14.4
Gross Investment Cost	**11.6**	**11.8**	**12.1**	**18.5**	**18.9**	**72.9**	**98.6**
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**11.6**	**11.8**	**12.1**	**18.5**	**18.9**	**72.9**	**98.6**

**Includes Overhead at current rates.*
*** Total Project includes amounts spent prior to 2018 and forecasted costs beyond 2022.*

Hydro One Distribution – Investment Summary Document

Sustaining Capital – Lines

Investment Name: Lines Sustainment Initiatives
Work Execution Period: January 2015 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
To refurbish entire feeders or sections of feeders on Hydro One's distribution system in order to address distribution assets approaching the end of their expected service life.

Need:
As outlined in Exhibit D1, Tab 2, Schedule 1, distribution line assets are ageing and a number of components are near or beyond the end of their expected service life. There are concerns with the condition of these assets, including wood poles, crossarms, and insulators. In some areas, our large customers' reliability is reaching unacceptable levels.

In addition to line assets reaching their end of expected service life, a number of component installations do not meet current Hydro One Distribution standards, including conductor sizing, framing, guying, transformer installations and clearance issues. These conditions pose increased safety and reliability risks.

These problems are further compounded when sections of feeders are located off-road and are difficult to access during power interruptions. Many of these lines require rebuilding or relocating to road allowances. Allowing these lines to remain in off-road sites would increase the risk of prolonged outages and safety concerns for the public and Hydro One Distribution personnel. The refurbishment of entire feeders or feeder sections is required in order to address these risks.

Alternatives:
<u>Alternative 1: "Do Nothing"</u>
Wait for components to fail while in service and replace them on a reactive basis, at a premium cost and with increased safety risks.

<u>Alternative 2: "Individual Component Replacements"</u>
Replace individual defective assets on existing structures on a "like for like" component basis. While this type of replacement is performed in some cases, it is not ideal. Individual component replacements do not allow efficiencies associated with the replacement of large numbers of

assets in close proximity to each other. Further, replacing individual components would not address any accessibility concerns and would result in higher ongoing maintenance costs. Finally, “like for like” replacements of current components may require custom-engineered designs not following current Hydro One Distribution standards.

Alternative 3: “Lines Sustainment Initiatives” (Recommended)
Refurbish or rebuild entire feeders or feeder sections to current Hydro One Distribution standards. This will improve the reliability of the distribution system and minimize any safety risks to the public and Hydro One Distribution personnel. Typically the cost of maintaining individual components in the circuit becomes excessive when there are a number of components near the end of their expected service life. By integrating line work to refurbish or rebuild entire feeders or sections, costs can be reduced.

Investment Description:
Distribution line assets deteriorate over time and should be replaced as they reach their expected end of service life. Taking into account the overall condition of poles, conductors and associated components; certain feeder sections have been identified for refurbishment or rebuild. Refurbishing or rebuilding an entire feeder section is preferred when the cost of maintaining or replacing individual components on that section becomes excessive.

There are a number projects identified under this program annually; which vary significantly in size and scope. The projects with capital investment exceeding $1 million are provided in the following table. Each of these projects involves equipment that is near or has exceeded their expected service life. Not proceeding with these investments would result in aged line installations remaining in service resulting in increasing risk of failure causing prolonged outages, reliability issues, and safety concerns.

Year	Project Name	Total ($M)
2015	Bailey's Corner DS F1 Rebuild, *Sudbury*	1.3
	Brant TS M21 Relocation, *Simcoe*	1.5
	Brockville TS 24M2 Relocation Phase 5 of 5, *Brockville*	2.0
	City of Owen Sound Refurbishment Phase 2 of 4, *Owen Sound*	2.3
	Duart TS M6 Relocation Phase 2 of 2, *Kent*	2.3
	Drymond TS M3 Rebuild, *New Liskeard**	6.0
	Manitouwadge TS M2 Rebuild, *Thunder Bay**	6.5
	Martindale TS 9M5 Relocation Phase 5 of 6, *Sudbury*	2.1
	Minden TS 87M2 Relocation Phase 1 of 6, *Minden*	4.1
	Otonabee TS 128M28 Relocation Phase 1 of 3, *Peterborough*	2.0
	Tilsonburg TS 20M10/Norfolk TS M3 Relocation, *Simcoe*	4.3
2016	City of Owen Sound Refurbishment Phase 3 of 4, *Owen Sound*	2.2
	Douglas Point TS Feeder Relocation, *Walkerton*	3.0
	Duart TS M5 Relocation, *Kent*	3.9
	Duart TS M6 Relocation, *Strathroy*	1.2
	Frontenac TS 8M3 Sub Cable Replacement, *Kingston*	1.6
	Kleinburg TS M8 Relocation, *Bolton*	2.0
	Martindale TS 9M5 Relocation Phase 6 of 6, *Sudbury*	1.6
	Minden TS 87M2 Relocation Phase 2 of 6, *Minden*	1.7
	Otonabee TS 128M28 Relocation Phase 2 of 3, *Peterborough*	1.2
	Reddendale DS Sub Cable Replacement, *Kingston*	1.5
	Terrace Bay Rebuild, *Thunder Bay**	4.0

** multi-year projects*

Year	Project Name	Total ($M)
2017	City of Owen Sound Refurbishment Phase 4 of 4, *Owen Sound*	2.1
	G3K Towerline Refurbishment, *Kirkland Lake*	1.0
	Kent TS M16 Relocation, *Kent*	1.2
	Larchwood TS M3 Relocation, *Sudbury**	5.0
	Manitoulin TS M25 Relocation, *Manitoulin*	1.5
	Minden TS 87M2 Relocation Phase 3 of 6, *Minden*	2.0
	Napanee TS 27M2 Relocation Phase 1 of 2, *Picton*	3.0
	Otonabee TS 128M28 Relocation Phase 3 of 3, *Peterborough*	1.5
	Sidney TS 12M7 – Back Up Supply, *Frankford**	6.0
	Sidney TS 12M7 – Wooler Rd. x Smithfield DS Relocation, *Frankford*	1.3
	Wanstead TS M4 Relocation (Brigden DS) Phase 1 of 2, *Lambton*	1.0
2018	Havelock TS 57M1 Apsley to Eel's Lake RS Relocation, *Bancroft*	3.5
	Havelock TS 57M2 Relocation Phase 1 of 2, *Tweed*	2.5
	Minden TS 87M2 Relocation Phase 4 of 6, *Minden*	2.0
	Morrisburg TS 18M26 Relocation, *Winchester*	4.0
	Napanee TS 27M2 Relocation Phase 2 of 2, *Picton*	3.0
	Picton TS 28M5 Relocation Phase 1 of 2, *Picton*	3.0
	Wanstead TS M4 Relocation (Brigden DS) Phase 2 of 2, *Lambton*	1.0
2019	Dobbin TS 20M6 Relocation, *Peterborough*	2.5
	Duart TS M24 Relocation, *Kent*	1.9
	Flynn's Corners DS F3 Phase 1 of 2, *Bancroft*	1.8
	Havelock TS 57M2 Relocation Phase 2 of 2, *Tweed*	2.5
	Lindsay TS D4M7 Relocation Phase 1 of 2, *Fenelon Falls*	2.0
	Longueuil TS 26M23 Relocation, *Vankleek Hill*	3.5
	Minden TS 87M2 Relocation Phase 5 of 6, *Minden*	2.0
	Picton TS 28M5 Relocation Phase 2 of 2, *Picton*	3.0
	Timmins 25 Hz Line Removals, *Timmins*	1.0
	Wallace TS 16M1 Relocation Phase 1 of 2, *Bancroft*	2.5
	Whitefish DS F1 Rebuild, *Sudbury*	1.8

Result:

Lines sustainment initiatives will result in:

- Efficiently addressing a large numbers of aged, substandard or poorly performing assets,
- Improving customer reliability, and
- Eliminating known safety hazards to the public and Hydro One Distribution personnel.

Costs:

($M)	2015	2016	2017	2018	2019	Total
Capital* and Minor Fixed Assets (A)	33.4	39.5	42.9	46.5	47.3	209.6
Operations, Maintenance & Administration and Removals (B)	3.9	4.0	4.3	4.4	4.5	21.1
Gross Investment Cost (A+B)	37.3	43.5	47.2	50.9	51.8	230.7
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	33.4	39.5	42.9	46.5	47.3	209.6

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

Investment Category:

System Access	System Renewal	System Service	General Plant
0%	100%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Reduce the number of planned outages on distribution lines that impact customer supply with the integrated approach to lines sustainment initiatives. In the case where off-road line segments are relocated to more accessible locations, customer interruption time would also be reduced.
Operational Effectiveness	• Maintain safe operation and reliability of the distribution system by addressing ageing and degrading lines equipment in an integrated manner.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the service reliability indicators by upgrading ageing and degrading equipment prior to failure.
Financial Performance	• Cost savings are recognized when all ageing and degrading components along a section of line are replaced as part of the same project. If the line is moved to more accessible location; then cost savings are also achieved in the event of storms, as power restoration time is minimized.

SR-12 Distribution Lines Sustainment Initiatives

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Program	**Plan Period Cost ($M):**	151.7
Primary Trigger:	Failure		
Secondary Trigger:	Reliability		

Investment Need:

Hydro One's distribution system consists of approximately 122,000 circuit kilometers of primary feeder lines across the province with approximately 17% of these feeders lines being located off-road. These off-road sections of feeders are difficult to access during power interruptions and can result in increased risk of prolonged outages.

As outlined in DSP Exhibit 2.3, Hydro One performs line patrols and preventative maintenance programs to assess the condition of its distribution feeder lines. These assessments have identified a number of concerns with the condition of the components on the primary feeders.

In addition to the condition of the distribution feeder line, there are a number of component installations that are of sub-standard design/construction based on changes over time in industry standards and do not meet current Hydro One standards, including conductor sizing, framing, guying, transformer installations and clearance issues. These conditions pose increased safety and reliability risks.

Alternative 1: Reactive Replacements

Wait for the distribution line equipment to fail while in service and replace it on a reactive basis. This alternative is rejected as the cost of emergency replacements is more expensive as materials and resources tend to be at a premium cost. Moreover, reactive management of the distribution line equipment will lead to increased failures resulting in risks to employee and public safety and degraded reliability for Hydro One's customers.

Alternative 2: Planned Components Replacements

Planned replacement of distribution line equipment identified in deteriorated or substandard condition, on a "like for like" component basis. This alternative is viable where an individual component of standard design on a distribution line is in deteriorated condition. However it is not ideal when multiple components are in deteriorated condition or the components are of substandard design, as individual replacement work does not allow for cost efficiencies associated with integration of replacements of assets in close proximity to each other; as well as it would require custom-engineered designs to address substandard equipment. Furthermore, this alternative would not address any accessibility concerns and would result in higher ongoing maintenance costs.

Alternative 3: Planned Lines Sustainment Initiatives (Recommended)

Planned refurbish or rebuild of entire feeders or feeder sections, when multiple components of the distribution line have been identified in deteriorated condition, in order to improve the performance of that distribution line. This alternative is recommended as it addresses the needs identified on the distribution lines in order to maintain the reliability of the distribution system in the most cost effective manner and minimize any safety risks to the public and Hydro One personnel.

Investment Description:

This investment address the refurbishment of entire feeders or feeder sections in an integrated manner to address line equipment with likelihood of failure is high. Distribution line assets deteriorate over time, taking into account the overall condition of poles, conductors and associated components; feeder sections are identified and prioritized for refurbishment or rebuild. Refurbishing or rebuilding an entire feeder section is preferred when the cost of maintaining or replacing individual components on that section becomes excessive.

There are a number projects identified under this program annually; which vary significantly in size and scope. The projects with capital investment exceeding $1 million are provided in the following table.

Year	Project Name	Net Total ($Million)
2018	City of Owen Sound Refurbishment - Part 3 of 4, *Owen Sound*	1.2
	Dundas TS M1 Rebuild Carlisle, *Dundas*	2.0
	Duart TS M6 Relocation, *Strathroy*	4.0
	Dymond TS M3 Rebuild - Part 1 of 2, *New Liskeard*	3.6
	Manitouwadge TS M2 Rebuild - Part 5 of 5, *Thunder Bay*	3.5
	Minden TS M2 - Part 2 of 2, *Minden*	2.5
	Otonabee TS M28 - Part 3 of 3, *Peterborough*	1.5
	Projects Less Than $1M	4.0
2019	Brant TS M21 Relocation, *Simcoe*	1.8
	Brockville TS 24M2-Part 5 of 5, *Brockville*	1.0
	City of Owen Sound Refurbishment-Part 4 of 4, *Owen Sound*	2.2
	Dobbin TS 20M4/6/8 Reconstruction, *Peterborough*	1.3
	Duart TS M5 Relocation, *Kent*	3.9
	Dymond TS M3 Rebuild-Part 2 of 2, *New Liskeard*	3.0
	Errington Street Rebuild—Chelmsford, *Sudbury*	1.6
	Manitoulin TS M25 Relocate, *Manitoulin*	1.1
	Martindale TS M5 Rebuild-Part 6 of 6, *Sudbury*	1.6
	Muskoka TS 30M1 Relocation-Part 1 of 5, *Huntsville*	1.0
	Owen Sound TS M24 Rebuild-Part 2 of 3, *Owen Sound*	2.8
	Tillsonburg TS 20M10/Norfolk TS M3, *Simcoe*	4.3
	Wanstead TS M2 Petrolia Tap Relocation, *Lambton*	3.0
	Projects Less Than $1M	2.4
2020	Angus 44 kV Backlot Relocate, *Barrie*	1.2
	Augasabon DS F1 & F2 Rebuild (Part 1 of 2), *Thunder Bay*	2.5
	Brant TS M22 Relocation, *Beachville*	2.0
	G3K Towerline Refurbishment, *Kirkland Lake*	1.0
	Ingersoll TS M46 Rebuild, *Beachville*	2.5
	Kent TS M16 Relocation, *Kent*	1.2
	Kleinburg TS M8, *Bolton*	2.0
	Muskoka TS M1 Relocation - Part 2 of 5, *Huntsville*	4.0
	Napanee TS M2 Relocation - Part 1 of 2, *Picton*	3.0
	Owen Sound TS M24 Rebuild - Part 3 of 3, *Owen Sound*	2.8
	Palmerston TS M1 Relocation - Part 1 of 2, *Listowel*	3.0
	Sidney TS M7 Reconductor, *Frankford*	1.3
	Weston Lake DS F1 Relocation, *Timmins*	1.0
	Projects Less Than $1M	3.4

Year	Project Name	Net Total ($Million)
2021	Augasabon DS F1 & F2 Rebuild (Part 2 of 2), *Thunder Bay*	2.5
	Clarke TS M2 Relocation, *Strathroy*	2.5
	Colgan DS Inaccessible Switch 2314 Relocation, *Alliston*	1.0
	Havelock TS M2 Rebuild-Part 1 of 2, *Tweed*	2.5
	Lauzon TS M25 Rebuild, *Essex*	2.0
	Longueuil TS 26M23 Relocate, *Vankleek Hill*	3.5
	Meaford TS M1 Lower Valley Rd Rebuild, *Owen Sound*	1.5
	Muskoka TS 30M1 Relocation-Part 3 of 5, *Huntsville*	1.7
	Muskoka TS M2 Relocate, *Huntsville*	1.4
	Napanee TS M2 Relocation-Part 2 of 2, *Picton*	3.0
	Old E1R Ear Falls DS F3, *Dryden*	2.5
	Palmerston TS M1 Relocation-Part 2 of 2, *Listowel*	1.0
	Tillsonburg M1 Refurbishment, *Beachville*	2.7
	Projects Less Than $1M	6.0
2022	Forest Jura DS F1 Relocation, *Lambton*	2.0
	Geraldton Rebuild-Part 1 of 3, *Thunder Bay*	1.0
	Havelock TS M2 Rebuild-Part 2 of 2, *Tweed*	2.5
	Kirkland Lake TS G3K Relocate-Part 1 of 2, *Kirkland Lake*	4.0
	Mair Mills DS F1 Grey Rd 21 Rebuild, *Stayner*	1.0
	Muskoka TS 30M1 Relocation-Part 4 of 5, *Huntsville*	2.5
	Muskoka TS M3 Relocation, *Bracebridge*	2.0
	Palmerston TS M3 Relocation-Part 1 of 2, *Listowel*	2.5
	Picton TS M5 Rebuild (Part 1 of 2), *Picton*	3.0
	Sidney TS M7 Rebuild-Part 1 of 2, *Frankford*	3.0
	Stayner TS M2 Rebuild, *Stayner*	3.4
	Wanstead TS M1 Rebuild Alvinston, *Lambton*	2.0
	Projects Less Than $1M	4.8

Each of these projects involves equipment that is identified as a concern during the condition assessment. The refurbishment or rebuilding of entire feeders or feeder sections entails replacing all components to the present Hydro One' standard and is done in compliance with Electrical Safety Authority (ESA Reg. 22/04) requirements for new construction.

Risk Mitigation:

The risk to completion of this investment as planned is the number of major storm events which decreases the availability of qualified resources, as resources are diverted to storm restoration efforts. However, due to the lower number of major storms in recent years this has not been an issue. This investment assumes the level of major storms to be in line with historical trends.

Result:

The lines sustainment initiatives will result in:

- Mitigating safety risks of defective, substandard or deteriorated assets;
- Maintaining the reliability of the distribution system; and
- Obtaining operational efficiencies by executing work in an integrated manner and reducing customer interruption time.

Outcome Summary:

Customer Focus	• Maintain reliability for customers by reducing the number of planned outages on distribution lines. • Improve response time by relocating off-road line segments to more accessible locations.
Operational Effectiveness	• Maintain safe and reliable operation of the distribution system by proactively addressing lines equipment in an integrated manner.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the existing service reliability performance of the system. • Comply with the Distribution System Code requirement to ensure that appropriate follow up and corrective action is taken regarding problems identified during a line patrol.
Financial Performance	• Realize cost savings by addressing multiple degrading components along a section of line as part of the same project.

Costs:

The factors which affect the costs in this investment are the following:

- The location in which the equipment is being replaced;
- Unforeseen property/easement issues; and
- Availability of required resources.

Controllable costs have been minimized by standardizing the procedure for common activities such as pole and equipment replacement.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	25.3	35.3	35.1	38.2	38.2	172.1
Less Removals	3.0	4.2	4.2	4.4	4.4	20.4
Gross Investment Cost	**22.3**	**31.1**	**30.9**	**33.8**	**33.7**	**151.7**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**22.3**	**31.1**	**30.9**	**33.8**	**33.7**	**151.7**

**Includes Overhead at current rates*

Hydro One Distribution – Investment Summary Document

Development Investment - System Capability Reinforcement

Investment Name: Asset Life Cycle Optimization and Operational Efficiency
Work Execution Period: January 2015 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
To improve operations and asset life cycle planning with additions or upgrades to the distribution system.

Need:
As assets reach end-of-life, the risk of failure under adverse conditions increases, which can lead to lengthy interruptions to customers and can increase the likelihood of exposing the employees and the public to safety hazards. In areas where other issues are also present, such as poor voltage levels and limited load transfer capability, it is often beneficial to address all issues through one project that upgrades or modifies the existing configuration.

Not proceeding with this investment would result in higher expenditures, reduced productivity and inefficient operations. The issues addressed under this investment are a mix of urgent needs and good planning practices that improve overall system operations. By executing projects that simultaneously address these items over individual refurbishment or upgrade projects, overall costs are reduced and fewer resources are required.

Investment Description:
Assets at the end of their expected service life are typically addressed by sustainment projects and programs that focus on like-for-like replacements. However, in some situations it is more efficient from a cost and operations perspective to simultaneously address end-of-life assets and improve operational efficiency by upgrading or modifying the end-of-life assets. In these cases, system capability reinforcement is the preferred option to address asset sustainment needs.

Examples of these types of projects include voltage conversions to eliminate distribution stations and improve system voltage, installing new supply points, or constructing feeders to transfer loads to a new transmission station to replace an existing station.

To improve operations and optimize asset life cycle costs, there are several types of projects that are commonly executed.

Station Decommissioning through Voltage Conversions: One approach to remove a station from service is to convert the voltage of its feeders to match its upstream voltage. For example, to decommission a 27.6kV - 8.32kV station, the 8.32kV feeders could be converted to 27.6kV, which removes the need for the station. This approach is advantageous because it addresses stations that are near end-of-life, and improves the voltage quality and capacity of the downstream feeders.

Station Decommissioning by Constructing New Station/Feeders: Another approach used to decommission stations is to construct new stations in their place. In some cases, a new station may suffice to replace multiple stations that are near end-of-life. These projects also include the construction of new feeders to take over the loads from stations planned for decommissioning.

Voltage Conversions to Address Equipment nearing End of Life & Operational Efficiency: These projects simultaneously address equipment nearing end-of-life and operational improvements through voltage conversions. These are advantageous because not only do they address the reliability and safety issues associated with equipment nearing its end-of-life, but they also improve voltage quality and the capacity of the downstream feeders.

Operational Efficiency Improvements: These are projects that improve operational efficiency, while simultaneously addressing equipment nearing end-of-life, reliability issues and/or accessibility restrictions.

To improve operations and optimize asset life cycle costs, the following projects are planned for the test years of 2015 through 2019. These projects are reprioritized each year to ensure they are addressed in order of criticality. Funding may also need to be reallocated to unplanned projects to serve immediate needs for system capability reinforcement. In these cases, planned projects may be postponed to ensure the most efficient use of resources and funding. However the overall funding requirement of the system capability reinforcement investments in the test years will not be changed. Projects with cash follow above $1M are provided as follows:

2015 Projects	**Total $M**
44kV Extension to Coniston, *Sudbury*	2.8
Belle River DS Voltage Conversion, *Belle River*	1.1
Carlton Place DS Reconstruction, *Carlton Place*	1.3
Mattawa Voltage Converson, *Mattawa*	1.0
Nipigon DS & Red Rock DS Voltage Conversion, *Nipigon*	1.9
Total	**8.1**

2016 Projects	Total $M
Coniston TS Voltage Conversion, *Sudbury*	2.6
Margach DS F1 Voltage Conversion, *Lake of the Woods*	2.0
New Station - Mattawa HVDS, *Mattawa*	5.1
Total	**9.7**

2017 Projects	Total $M
Burford DS Voltage Conversion, *Burford*	1.4
Grand Bend Municipal DS F3 Voltage Conversion, *Grand Bend*	1.3
Hanmer TS Feeder Development, *Sudbury Valley East*	1.4
New Station - Manitou Lake DS, *Manitoulin Island*	3.0
Manitou Lake DS New Feeder Development, *Manitoulin Island*	1.8
Total	**8.9**

2018 Projects	Total $M
Alexandria East Boundary , Margaret, & Kenyon West DSs Voltage Conversion, *Alexandria*	1.8
Eugenia RS Relocation, *Grey County (Grey Highlands)*	1.4
Margach DS F3 Voltage Conversion, *Lake of the Woods*	1.0
Total	**4.2**

2019 Projects	Total $M
Blind River DS Voltage Conversion, *Blind River*	1.0
Clearwater Bay DS F2 Voltage Conversion Stage 3, *Lake of the Woods*	1.7
Perth Wilson DS, Sunset DS, North DS, Halton DS & Scotch Line DS Operational Efficiency Improvements, *Perth*	1.8
Total	**4.5**

Result:

- Replace substandard and end of service life equipment to mitigate reliability and safety risks
- Improve voltage and power quality levels and mitigate customer dissatisfaction risks
- Provide operating flexibility that can be used during planned outages or emergency situations to minimize power outages to customers
- Overall reduction in costs and resources by addressing multiple issues simultaneously
- Reduce line losses

Costs:

	2015	2016	2017	2018	2019	Total
Capital* and Minor Fixed Assets (A)	8.1	9.7	8.9	4.2	4.5	35.4
Operations, Maintenance & Administration and Removals (B)	0.9	0.6	0.8	0.6	0.6	3.5
Gross Investment Cost (A+B)	9.0	10.3	9.7	4.8	5.1	38.9
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	8.1	9.7	8.9	4.2	4.5	35.4

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

Investment Category:

System Access	System Renewal	System Service	General Plant
%	50%	50%	%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Improve voltage and power quality levels to mitigate customer dissatisfaction risks and reduce line losses.
Operational Effectiveness	• Replace substandard and end of service life equipment to mitigate reliability and safety risks and provide operating flexibility that can be used during planned outages or emergency situations to minimize power outages to customers.
Public Policy Responsiveness	• Replace end of life or substandard equipment as required by the DSC.
Financial Performance	• Cost savings are realized by executing projects that simultaneously address a number of system needs rather than individual refurbishment or upgrade projects as overall costs are reduced and fewer resources are required.

SR-13 Life Cycle Optimization & Operational Efficiency Projects

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Program	**Plan Period Cost ($M):**	134.0
Primary Trigger:	Failure Risk		
Secondary Trigger:	System Efficiency		

Investment Need:

Assets at the end of their expected service life are typically addressed by system renewal projects and programs that focus on like-for-like replacements. However, in some situations it is more efficient from a cost and operations perspective to address end-of-life assets by other means such as constructing supply facilities at a different location, upgrading nearby assets, or modifying the network configuration in order to eliminate the need for certain assets.

As assets reach end-of-life, the risk of failure under adverse conditions increases, which can lead to lengthy interruptions to customers and can increase the likelihood of exposing the employees and the public to safety hazards. In situations where other issues are also present, such as poor voltage, limited load transfer capability, or multiple/incompatible system voltages, it is often beneficial to address all issues through one project that upgrades or modifies the existing network configuration. As an example, converting feeders fed from an end-of-life station to a higher operating voltage results in higher load meeting capability, better power quality, and reduced line losses.

These investments provide an opportunity to achieve overall cost savings by bundling asset renewal work on stations and feeders and integrating other system capacity and operational needs under a common solution. Eliminating or combining assets reduces future operating and maintenance costs and improves operational efficiency. Other factors which may lead to addressing end-of-life assets by other than like-for-like means may include environmental factors, property issues, and incompatibility of existing assets with surrounding land uses. Project-specific information is provided in Attachment 1.

Not proceeding with this investment would result in higher expenditures, reduced productivity and inefficient operations. The issues addressed under this investment are a mix of urgent needs and good planning practices that improve overall system operations. By executing projects that simultaneously address these items over individual refurbishment or upgrade projects, overall costs are reduced and fewer resources are required.

Alternative 1: Address End of Life Assets only Through Like-for-Like Replacement

Address all end-of-life asset issues only through like-for-like replacements through other system renewal projects or programs.

This alternative is not recommended since it presents a lost opportunity to achieve overall operational efficiencies and customer benefits which can be achieved by identifying more optimal asset replacement approaches.

Alternative 2: Modify The Distribution System to Eliminate Operationally Inefficient Assets that are Nearing End-of-Life *(Recommended)*

Address specific end-of-life asset needs by means other than like-for-like where there are opportunities to reduce costs and achieve increased operational efficiencies. When stations or lines are approaching their end-of-life based on the condition of their individual components, there may be opportunities to implement system changes other than like-for-like replacement of these assets in order to achieve cost savings and long-term operational efficiencies. It may be possible to eliminate stations or consolidate line assets through voltage conversion projects, or transfers to other stations. Reduced upfront capital costs as well as future maintenance savings can be realized using this approach.

Investment Description:

A number of distribution stations are approaching their end of life. For stations where other alternatives may exist to address renewal needs, an integrated planning approach is taken. This involves assessing other potential system renewal needs in the surrounding network, capacity needs, as well as reliability and operational needs. Alternative solutions are evaluated and an optimal plan is developed which addresses all identified needs in the most cost-effective manner. In cases where stations can be completely eliminated, all existing equipment, structures and materials are removed from the property. Any necessary land remediation needed to remove contaminated soil and site restoration is also included.

To improve operational efficiency and optimize asset life cycle costs, there are several types of projects that are commonly executed.

Station Decommissioning through Voltage Conversions: One approach to remove a station from service is to convert the voltage of its feeders to match its upstream voltage. For example, to decommission a 27.6kV - 8.32kV station, the 8.32kV feeders could be converted to 27.6kV, which removes the need for the station. This approach is advantageous because it addresses stations that are near end-of-life, and improves the voltage quality and capacity of the downstream feeders.

Station Decommissioning by Constructing New Station/Feeders: Another approach used to decommission stations is to construct new stations in their place. In some cases, a new station may suffice to replace multiple stations that are near end-of-life. These projects also include the construction of new feeders to take over the loads from stations planned for decommissioning.

The most common type of project addressed under this investment is the elimination of a distribution station that has reached end-of-life by converting the station's low-voltage feeders to a higher distribution voltage. This may involve feeding the station load directly from the upstream TS supply feeder where it is feasible to do so, or by transferring it to another nearby station operating at a higher voltage. Performing a voltage conversion project may involve replacing feeder assets such as poles, transformers, primary and secondary conductors and secondary service connections, which may also be approaching end-of-life.

A listing of all proposed projects under this investment category with costs in excess of $1 million over 2018 to 2022 time frame is provided in Attachment 1. These projects are reprioritized each year based on updated condition assessment and performance data to ensure they are addressed in order of criticality. Additional funding is included in this investment for projects less than $1 million and to cover emergent needs or to coordinate system renewal needs with work initiated by other third parties such as the transmitter, land developers, municipalities, and road authorities. In these cases, planned projects may be postponed to ensure the most efficient use of resources and funding.

Risk Mitigation:

The main risks to completion of this work are lack of labour resources for design and construction, as well as risks around property rights for poles, anchors and tree trimming required for feeder construction. For projects that require the construction of new stations, there are additional risks associated with the acquisition of new property such as the lack of a willing seller, delays due to negotiations with property owners, municipalities, and in some cases First Nation concerns. These risks will be mitigated by ensuring appropriate planning lead times are followed for project scheduling and by considering constructability issues early in the project definition stage.

Result:

- Eliminated end-of-life assets to mitigate reliability, customer dissatisfaction, and safety risks;
- Improved power quality and load meeting capability of the system;
- Provide enhanced operating flexibility to mitigate customer impacts during planned outages or emergency situations;
- Improvement in overall cost effectiveness by implementing integrated solutions that address end-of-life assets, capacity, and operational needs simultaneously; and
- Reduced line losses.

Outcome Summary:

Customer Focus	• Avoided material deterioration in reliability and customer satisfaction. • Reduced outage duration by eliminating obsolete network equipment with non-standard designs/equipment. • Improved load meeting capability of the network. • Large customer needs for enhanced voltage support and other quality of power criteria addressed.
Operational Effectiveness	• Streamlined operations by eliminating multiple operating voltages and the requisite additional inventory, work methods and training needs. • Minimized cost by taking an integrated planning approach based on area supply needs. • Improved long-term operating and maintenance efficiency due to consolidating and reducing the number of system assets.
Public Policy Responsiveness	• Compliance with DSC requirements to maintain and plan the system in accordance with good utility practice. • Reduced overall environmental impact by eliminating stations where feasible.
Financial Performance	

Costs:

Construction costs for voltage conversion work can vary depending on conditions such as ground conditions, customer density, urban vs. rural, and condition of existing feeder assets. Newer lines built to present day standards can be converted to higher operating voltages at minimal cost, while older lines tend to require complete replacement and upgrading to current standards.

Costs are controlled by avoiding costly or complex design solutions where possible, by sub-contracting specialized civil work to external service providers, and by using intermediate step-down transformers where feasible to reduce the amount of line reconstruction work.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	22.7	31.8	25.3	30.6	35.9	146.2
Less Removals	2.2	4.6	2.9	1.6	0.9	12.2
Gross Investment Cost	**20.5**	**27.1**	**22.4**	**29.0**	**34.9**	**134.0**
Less Capital Contributions						
Net Investment Cost	**20.5**	**27.1**	**22.4**	**29.0**	**34.9**	**134.0**

**Includes Overhead at current rates.*

Attachment 1 – Life Cycle Optimization & Operational Efficiency Projects List of Projects >$1M

Project ID	Project Name	Scope	Need Addressed	Cost $M Net	Year(s)
LC-1	Barrys Bay Voltage Conversion	Convert existing 4.16 kV lines to 12.5 kV and re-supply from adjacent 12.5kV system.	Eliminate end-of-life 4.16kV distribution station and refurbish old 4.16 kV lines.	1.8	2018
LC-2	Burford DS Removal	Convert two 8.32 kV feeders to 27.6kV and remove existing Burford DS.	Eliminate end-of-life station assets.	1.5	2018
LC-3	Margach DS F3 – SD3676 Voltage Conversion	Convert 7.2 kV single-phase line section to 14.4 kV.	Eliminate end-of-life step-down transformer and line equipment.	1.4	2018
LC-4	Beaver Valley RS	Construct New 44 kV Regulating Station & Remove Existing Eugenia RS.	Eliminate End of Life Assets and potential high impact spill risk at Eugenia RS.	1.5	2018
LC-5	Carlton Place DS's Reconstruction	Construct new dual-transformer 27.6 kV station and single-transformer 8.32 kV station with MUS facilities at the site of Carleton Place Bridge DS and Edmund DS. Construct a new 27.6 kV feeder to relieve the existing Carlton Place DS #2 F2 and install step-down transformers to eliminate 4.16 kV station.	Replace end-of-life station assets at Carlton Place DS #2, Carlton Place Bridge DS, and Carlton Place Edmund DS. Improve loop feed capabilities and supply capability in the Town of Carlton Place.	5.9	2018-2019
LC-6	Dresden DS Voltage Conversion	Convert 2-8.32kV feeders to 27.6kV to match incoming supply voltage, and remove Dresden DS.	Elimination of end-of-life station assets at Dresden DS.	2.6	2018-2019
LC-7	Dundas Sydenham DS Voltage Conversion	Convert 8.32kV line section to 27.6kV. Remove existing Dundas Sydenham DS.	Eliminate end-of-life station.	2.9	2018-2019

Project ID	Project Name	Scope	Need Addressed	Cost $M Net	Year(s)
LC-8	Coniston Voltage Conversion	Convert 22 kV 3-wire feeder and 22 kV connected substations to 44 kV operation.	Eliminate obsolete 22 kV system voltage and allow de-commissioning of Coniston TS T1/T2 transformers which are at end of life.	3.9	2018-2019
LC-9	Town of Forest Voltage Conversion	Convert 5-4.16kV feeders to 27.6kV to match incoming supply voltage. Remove Forest Jefferson DS and Forest McNab DS.	Eliminate end-of-life station assets at Forest Jefferson DS and Forest McNab DS.	3.2	2018-2019
LC-10	Hanmer TS Feeder Development	Construct 3 new 44 kV feeders from new Hanmer TS DESN.	Elimination of existing 44 kV off-road line sections fed from Martindale TS which are at end of life.	4.9	2018-2019
LC-11	Lucan Market DS Voltage Conversion	Convert two 4.16 kV feeders to 27.6 kV operation, install 2 x 2.5MVA 27.6-8kV step down transformers to replace existing 5MVA transformers at Lucan Market DS.	Eliminate end-of-life station assets at Lucan Market DS.	3.3	2018-2019
LC-12	Warkworth DS Removal	Offload station by reconfiguring and extending existing feeders from other adjacent stations, and remove Warkworth DS.	Eliminate end-of-life station assets at Warkworth DS.	2.9	2018-2019
LC-13	Grand Bend Downtown Voltage Conversion	Convert loads in downtown Grand Bend currently fed at 8.32 kV to 27.6 kV supply.	Eliminate end-of-life 8.32 kV line assets and reduce line congestion in main business section of Grand Bend.	1.3	2019
LC-14	Brookside DS Removal	Off load Brookside DS by building and reinforcing feeder ties to adjacent stations. Remove Brookside DS.	Eliminate end-of-life station assets at Brookside DS.	1.9	2019-2020

Project ID	Project Name	Scope	Need Addressed	Cost $M Net	Year(s)
LC-15	Drumbo DS Voltage Conversion	Convert two 8.32 kV feeders to 27.6kV to match incoming supply voltage and remove existing Drumbo DS.	Eliminate end-of-life station assets at Drumbo DS.	2.0	2019-2020
LC-16	Lily Lake DS Removal	Off load Lily Lake DS by building and reinforcing feeder ties to adjacent stations including some limited voltage conversion. Remove Lily Lake DS.	Eliminate end-of-life station assets at Lily Lake DS.	3.3	2019-2020
LC-17	Rondeau DS Voltage Conversion	Convert 2-8.32kV feeders to 27.6kV to match incoming supply voltage, and remove Rondeau DS.	Eliminate end-of-life station assets at Rondeau DS.	1.7	2019-2020
LC-18	Thorold Turner DS Voltage Conversion	Replace Thorold Turner DS with padmount transformers.	Eliminate end-of-life station.	1.0	2019-2020
LC-19	Wallaceburg DS Voltage Conversion	Convert 3-8.32kV feeders to 27.6kV to match incoming supply voltage, and remove Wallaceburg DS.	Eliminate end-of-life station assets at Wallaceburg DS.	1.7	2019-2020
LC-20	Devlin DS Rebuild and Voltage Conversion	Refurbish Emo DS and Devlin DS and replace existing 44-12.5 kV transformers with 44-25 kV units. Convert 12.5 kV line sections to 25 kV operation.	Replace end of life station assets including obsolete single phase transformers and standardize to one distribution voltage of 25 kV.	4.0	2020
LC-21	Blind River Voltage Conversion	Convert 12.5 kV feeder to 25 kV to match incoming supply voltage & remove Blind River DS.	Eliminate end of life station assets including obsolete single phase transformers.	1.0	2020
LC-22	Kemptville Area System Upgrades	Upgrade Kemptville West DS from 5 MVA to 7.5 MVA and add new feeder position.	Meet forecast load growth in the Town of Kemptville.	4.2	2020-2021

Project ID	Project Name	Scope	Need Addressed	Cost $M Net	Year(s)
LC-23	Maxville Area System Upgrades	Off load Maxville Prince DS by converting feeders from 4.16 kV to 8.32 kV and transferring to Maxville George DS.	Eliminate end-of-life station assets at Maxville Prince DS and eliminate 4.16 kV system in Town of Maxville.	4.2	2020-2021
LC-24	Prescott Area System Upgrades	Implement system upgrades as per recommendations of pending study.	Eliminate end-of-life system assets and ensure reliable supply.	4.2	2020-2021
LC-25	Wardsville DS Voltage Conversion	Convert 8.32 kV feeder to 27.6kV to match incoming supply voltage and remove existing Wardsville DS.	Eliminate end-of-life station assets at Wardsville DS.	1.1	2020-2021
LC-26	Alexandria Area System Upgrades	Upgrade Alexandria Industrial DS from 5 MVA to 7.5MVA. Remove Alexandria – Margaret DS, East Boundary DS, Kenyon West DS and transfer loads to adjacent DSs. Convert the town 4.16kV feeders to 8.43kV.	Eliminate end-of-life station assets as Kenyon West DS, provide loop feeds for single contingency backup of DS's in the town of Alexandria.	3.8	2021
LC-27	Anderdon DS Voltage Conversion	Convert 2-8.32kV feeders to 27.6kV to match incoming supply voltage, and remove Anderdon DS.	Eliminate end-of-life station assets at Anderdon DS.	1.5	2021
LC-28	Town of Elliot Lake Station Upgrades	Replace Mississauga DS T2 transformer with larger unit and add second transformer at Porridge Lake DS.	Facilitate the elimination of Elliot Lake DS which is at end-of-life and improve load transfer capability in Town of Elliot Lake.	3.5	2021
LC-29	Vanastra DS Voltage Conversion	Convert 8.32 kV lines to 27.6 kV to match incoming supply voltage and install step-down transformers.	Eliminate Vanastra DS which is at end of life.	2.2	2021

Project ID	Project Name	Scope	Need Addressed	Cost $M Net	Year(s)
LC-30	Berwick-Finch Area Upgrades	Offload Crysler DS F2 onto Casselman DS F1 by reinforcing feeder ties.	Crysler DS F2 feeder load is approaching planning guideline.	4.2	2021-2022
LC-31	Brockville Distribution System Upgrades	Upgrade various distribution feeder sections within the Town of Brockville.	Replace end-of-life distribution line assets, including direct buried cable, and eliminate back lot construction.	4.2	2021-2022
LC-32	Chesterville Area Upgrades	Add a second 5 MVA 44-8.32 kV transformer at Frood DS and one with additional feeder. Convert 5 existing 4.16 kV feeders to 8.32kV and remove Chesterville DS#2 & Brennen DS.	Eliminate end-of-life station assets at Chesterville DS #2 and Brennen DS and standardize on a single voltage 8.32 kV in the Town of Chesterville.	4.2	2021-2022
LC-33	Ivy Lea Area System Upgrades	Upgrade Ivy Lea DS station capacity.	Provide load relief to transformer loaded above planned load limit.	4.2	2021-2022
LC-34	Russell Area System Upgrades	Offload Russell DS to the neighbouring stations and Remove Russell DS.	Eliminate end-of-life station assets at Russell DS.	4.2	2021-2022
LC-35	Smiths Falls System Upgrades	System upgrades to allow removal of Smith Falls James DS.	Address end-of-life station assets and reliability risks due to lack of MUS facilities.	4.2	2021-2022
LC-36	Actons Corners Area System Upgrades	Implement system upgrades as per recommendations of pending study.	Eliminate end-of-life system assets and ensure reliable supply.	4.2	2022
LC-37	Sleeman DS Rebuild and Voltage Conversion	Rebuild Sleeman DS at a new location and convert 12.5 kV line sections to 25 kV.	Replace end-of-life station assets including obsolete single phase transformers and standardize to one distribution voltage of 25 kV.	4.4	2022

Hydro One Distribution – Investment Summary Document

System Capability Reinforcement

Investment Name: System Upgrades Driven by Load Growth
Work Execution Period: January 2015 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
To provide adequate supply to accommodate system load growth on the distribution system with new or modified distribution facilities.

Need:
Over time, customer connections accumulate and place additional stress on distribution system elements. Increases in feeder loading can lead distribution system elements, such as conductors, transformers, regulators and switches, to operate at or exceeding their maximum equipment ratings or violate other planning criteria such as voltage or protection limits during periods of heavy load.

In accordance with Section 3.3 of the Distribution System Code, Hydro One Distribution plans and executes enhancement projects on its distribution system to improve system operating characteristics and relieve system capacity constraints. These projects are developed considering the cost-benefits and long-term planning advantages of potential alternatives. The alternatives considered typically involve increasing capacity at distribution stations by upgrading equipment, constructing new stations, constructing new feeders to provide relief to over-loaded feeders, extensions to or reconfigurations of existing feeders to allow them to operate within acceptable ranges, and voltage conversions to increase feeder capacity.

Not relieving heavily loaded equipment will lead to equipment failure and damage, jeopardizing safety, reliability and customer risks.

Further details and a listing of the planned projects from 2015-2019 are found under Investment Description below.

Investment Description:
There are a variety of ways to relieve overloaded equipment. Each area is unique and the optimal solution varies area to area depending on the existing feeder configuration and the state of surrounding lines and stations.

Feeder Reinforcement: One common solution is to redistribute load through reinforcement projects. These projects focus on optimizing load distribution by reconfiguring existing feeders to enable load transfers. By extending feeders, installing new phases and tie points, and updating feeder protections, lightly loaded feeders can offload heavily loaded sections.

Station Upgrade: Station upgrade projects are executed in areas where the existing configuration cannot be utilized to offload equipment that has reached its planned loading limit. Instead, additional capacity must be added to the system. Station upgrades involve an increase in capacity to existing stations by upgrading transformer sizes; installing additional transformers; increasing the station's secondary voltage (voltage conversion at the station); or installing fan monitoring to cool station transformers. These projects also include adding new feeder positions at the station to increase the number of available feeders.

Construct New Station: In some situations, constructing a new station is more effective from a cost and operating perspective than upgrading an existing station. In these cases, a new distribution station is installed and incorporated into the distribution system. New feeders are also used to provide additional capacity to areas that are overloaded. These feeders may be built to compliment the construction of a new distribution station.

Voltage Conversion: To increase equipment ratings and capacity, feeders may also be converted to higher voltage levels. These upgrades may conincide with a station voltage conversion or may involve a reconfiguration with nearby feeders that operate at higher voltage levels.

To ensure system elements remain within their acceptable operating ranges the following investments are planned. These projects are reprioritized each year as new loading information and updated forecasts become available to ensure they are addressed in order of criticality. Funding may also need to be reallocated to unplanned projects to serve immediate needs for system capability reinforcement. In these cases, planned projects may be postponed to ensure the most efficient use of resources and funding. However the overall funding requirement of the system capability reinforcement investments in the test years will not be changed. Projects with cash flow greater than $1 million in any of the test years are listed below:

2015 Projects	Total $M
Brown Hill TS New Feeder Development, Queensville, *East Gwillimbury*	3.5
Clark TS M2 Feeder Reinforcement, *Ilderton*	2.1
Commerce Way TS M3 Feeder Reinforcement, *Woodstock Surrounding Area*	2.1
Courtice DS Upgrades, Courtice, *Clarington Township*	3.0
Courtice DS Voltage Conversion, *Courtice, Clarington Township*	1.8
Grand Bend East DS Upgrades, *Grand Bend, Zurich & Dashwood*	1.0
Manotick DS New Feeder Development, *Manotick, City of Ottawa*	2.6
Nobleton DS Upgrade, Nobleton, *King Township*	3.0
Owen Sound TS M28 Feeder Reinforcement, *Northern Bruce Pennisula*	1.0
Total	**20.1**

2016 Projects	Total $M
Allanburg TS M7 Feeder Reinforcement, Thorold	1.0
Ancaster West DS Upgrades, Anacaster, City of Hamilton	2.0
Armitage TS M22 Feeder Reinforcement, Stouffville & Whitchurch	1.9
Beckwith DS Upgrades, South of Carleton Place (Mississippi Mills)	2.2
Brown Hill TS M4 Feeder Reinforcement, Georgina Township	1.9
Burleigh DS F2 Feeder Reinforcement, East of Fort Frances	1.0
Devlin DS F1 Feeder Reinforcement, Devlin	1.0
Dobbin DS F1 Feeder Reinforcement, Township of Cavan Monaghan	1.0
Grand Bend East DS F3 Feeder Voltage Conversion, Grand Bend & Surrounding Area	2.4
Stouffville 10th Line DS Upgrade, Stouffville & Whitchurch	3.0
Massey DS F3 Feeder Reinforcement, North Shore Algoma	1.0
New Station - Twelve Mile Bay DS, Georgian Bay	3.0
Point Au Baril DS F2 Feeder Reinforcement, Bayfield Inlet/Britt	3.6
Twelve Mile Bay DS Submarine Cables, Georgian Bay/ Honey Harbour	1.4
Total	**26.4**

2017 Projects	Total $M
Arnprior Elgin DS Upgrades, Arnprior	1.0
Arnprior Zervos, Reid & Madawaska DSs Reinforcement, Arnprior	1.0
Awenda DS F1 Feeder Reinforcement, Christian Island (Beausoleil First Nation)	3.6
Beaverton TS M29 Feeder Reinforcement, Uxbridge	1.6
Beckwith DS F3 Feeder Reinforcement, South of Carleton Place (Mississippi Mill)	1.8
Dunchurch DS F2 Feeder Reinforcement, Magnetawan	2.8
Kenilworth DS Upgrade, Northern Wellington County	2.5
Kingsville/Leamington Feeder Reinforcement, Kingsville/Leamington	1.8
Lindsay TS D4M7 Feeder Reinforcement, Bobcaygeon	4.0
New Station - Uxbridge RS #2, Uxbridge	2.0
Orangeville TS M3 Feeder Reinforcement, Caledon	1.8
St. Lawrence TS M27 Feeder Reinforcement, West of Cornwall	2.0
Woods DS Voltage Conversion, Kirkland Lake	2.6
Total	**28.5**

2018 Projects	Total $M
Armitage TS M42 Feeder Reinforcement, King Township	1.6
Colpoys Bay DS F2 Feeder Reinforcement, Northern Bruce Pennisula	1.0
Greely DS New Feeder Development, City of Ottawa	1.3
King City DS New Feeder Development, King Township	1.8
Kingsville/Leamington Feeder Reinforcement, Kingsville/Leamington	4.4
Kirkland Lake DS #1 Voltage Conversion, Kirkland Lake	2.0
Muskoka TS M1 Feeder Extension, Muskoka Lakes	5.3
New Station - King City DS, King Township	3.0
New Station - Old School DS, Mayfield, Southern Caledon	3.0
New Station - Stouffville RS, Stouffville & Whitchurch	2.0
Old School DS New Feeder Development, Mayfield, Southern Caledon	1.8
Rockland DS Upgrades, Rockland	2.6
Stratford TS M6 Feeder Reinforcement, City of Stratford	1.0
Total	**30.8**

2019 Projects	Total $M
Emsdale DS F2 Feeder Reinforcement, Kearney	2.1
Ferndale DS F2 Feeder Reinforcement, Northern Bruce Pennisula	2.1
Goodfish DS Voltage Conversion, Kirkland Lake	2.8
Kenilworth DS Feeder Reinforcement, Northern Wellington County	1.8
Kleinburg TS M26 Feeder Reinforcement, Caledon	3.2
New Station - Mar DS, Northern Bruce Pennisula	3.0
New Station - Mount Albert DS #2, East Gwillimbury	4.0
New Station - Port Elgin North DS, Saugeen Shores	3.0
New Station - Woodbine DS, East Gwillimbury	3.0
Puslinch DS New Feeder Development, Wellington County	2.6
New Station - Wilson Rd DS, Springwater Township	3.5
Woodbine DS New Feeder Development, East Gwillimbury	1.8
Total	**32.9**

Result:

- Balance loads to allow for additional customer connections and to improve voltage and power quality
- Reduce line losses
- Mitigate reliability risks and minimize potential safety hazards associated with overloading system equipment
- Maintain voltage and power quality levels to within standards and mitigate customer dissatisfaction
- Provide additional supply options to relieve overloaded feeders and enable future load growth and customer connections

Costs:

	2015	2016	2017	2018	2019	Total
Capital* and Minor Fixed Assets (A)	20.1	26.4	28.5	30.8	32.9	138.7
Operations, Maintenance & Administration and Removals (B)	1.8	2.2	3.1	2.8	2.2	12.1
Gross Investment Cost (A+B)	21.9	28.6	31.6	33.6	35.1	150.8
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	20.1	26.4	28.5	30.8	32.9	138.7

Investment Category:

System Access	System Renewal	System Service	General Plant
%	%	100%	%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Maintain proper voltage levels and power quality for customers as well as reducing line losses.
Operational Effectiveness	• Improve or maintain reliability in areas that require reinforcement due to load growth or connection of renewable generators.
Public Policy Responsiveness	• Provide system enhancements where required to facilitate load and generation customers and meet DSC requirements.
Financial Performance	• Cost savings are realized when ageing and degrading components on the system are replaced with new and modern equipment.

SS-02 System Upgrades Driven by Load Growth

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Program	**Plan Period Cost ($M):**	190.0
Primary Trigger:	Mandated Service Obligation		
Secondary Trigger:	Reliability		

Investment Need:

Over time, new customers connect to the system, and load growth occurs as a result. This also occurs due to increased loading at some existing customers who may increase their service sizes. This places additional stress on the elements of the distribution system. Increases in distribution station and feeder loading can lead to system elements operating at or exceeding their maximum equipment ratings or violate other planning criteria such as voltage or protection limits during periods of heavy load.

In accordance with Section 3.3 of the Distribution System Code ("DSC"), Hydro One Distribution plans and executes enhancement projects on its distribution system to improve system operating characteristics and relieve system capacity constraints. This investment covers major system upgrades that are needed in response to load growth.

Investments with a gross cost less than $300,000 are normally included in either the Distribution System Modifications (ISD SS-05) or Demand Investments (ISD SS-04) capital programs.

The capability of the Hydro One distribution system to accommodate forecast loading needs is determined through the following four main activities:

1. load versus capability screening at the station and feeder levels;
2. planned feeder studies (six-year cycle studies);
3. system impact assessments for large new load connections; and
4. assessment of field and customer identified issues related to power quality or other operating concerns.

Load versus system capability and planned feeder studies (six-year cycle studies) are the main pro-active planning activities carried out to assess the capability of Hydro One's system to accommodate existing and forecast needs. These activities take into account the capability of the network to meet load needs based on normal anticipated load growth. Load growth rates vary for different segments of the system. For example, the growth rates can differ significantly between urban and rural segments. Normal load growth is determined locally within the system based on historical trends, known or planned development in an area, and information from local municipalities including official plan documents and long-term population projections. In some cases, local power quality or reliability issues may be identified by field staff or customers due to specific local loading issues or changes that develop over time and may need to be addressed through system upgrades. If these issues cannot be accommodated under the Demand Investments capital program (ISD SS-04) then a major capital project may be required.

For all new load connections or customer upgrades above 500 KVA, and for new subdivisions with more than fifteen lots, a distribution system impact assessment is conducted in order to determine the impact of the proposed load with respect to equipment ratings, voltage and protection criteria, and planning guidelines. Where planning criteria will be violated, system upgrades may be required. Where an upgrade is required in order to meet the specific loading needs of one individual customer, a customer contribution may be required based on a discounted cash flow evaluation of future revenues and costs.

For distribution feeders, planning guidelines for load-ability have been established based on feeder voltage level. Planning guidelines are used to conduct high-level screening of system capability to maintain loading within equipment ratings, meet system voltage and protection needs, and ensure a reasonable degree of operating flexibility and efficiency. Planning guidelines are based on typical feeder topology and lengths. In some parts of Hydro One’s distribution system where feeder distances are significantly long or load centers are far from the supply station, technical considerations such as voltage and system protection needs restrict maximum feeder loading to values, which are less than the planning guidelines.

Where major new capacity upgrades are deemed necessary through load screening or other means, Hydro One uses an integrated planning approach to identify and develop the optimal system development plans for a specific area. This involves assessing other potential system needs in the surrounding network from the perspective of capability, performance, operability, sustainment, and efficiency/effectiveness. Once the full long-term needs for the system are determined, integrated solutions are identified to ensure the long term viability of the network in the most cost-effective manner.

Alternative 1: Allow System Assets to Become Overloaded

Wait until overloaded assets reach critical values such that customers are experiencing significant power quality issues, or a material decrease in reliability is observed.

This alternative was rejected since it does not satisfy the DSC requirement for a distributor to enhance its system in response to normal load growth. Also, due to the long lead times needed to implement effective solutions, there would be significant customer dissatisfaction due to on-going power quality issues and reduced reliability.

Alternative 2: Upgrade System to Meet Normal Load Growth (Recommended)

Pro-actively monitor system loading, conduct system studies for forecast new load connections and develop appropriate investment plans to address system needs based on forecast load.

The recommended plan satisfies section 3.3 of the DSC, which requires distributors to plan and expand their systems in response to normal load growth. Identifying and implementing major projects to maintain loading on assets within design ratings ensures acceptable delivery voltage is provided to customers, that reliability is maintained at acceptable levels, and that system assets are not exposed to undue stress.

Investment Description:

System load growth over the next five years is expected to be in line with recent historic growth patterns. Approximately 90,000 new customer connections and 27,000 service upgrades are forecast for the 2018-2022 time period. Cancellation of about 34,000 existing services is also anticipated for an overall increase in customers of 56,000 or 4.4% of the existing customer base over the next five years.

The majority of growth and new customer connections are expected to occur in Hydro One's urban service territories which border major urban centers including the City of Ottawa, City of Kingston, northern York and Peel Regions, Durham Region, and the City of Hamilton. For the remainder of Hydro One's service territory which is mostly rural in nature, load growth and new customer connection activity is expected to be in line with historic rates which are generally lower.

Proposed investments to address load growth include station upgrades, feeder upgrades and modifications, new feeders, construction of new distribution stations and new voltage regulating stations, and conversion of feeders to higher voltages. Also included are feeder development projects in accordance with recommendations of Regional Infrastructure Plans. A list of all planned system upgrades in excess of $1 million along with their proposed timing is provided in Attachment 1. Additional funding is included to cover projects less than $1 million as well to cover emergent needs due to unforeseen customer connections or upgrades.

There are a variety of ways to relieve overloaded equipment. Each area is unique and the optimal solution varies area to area depending on the existing feeder configuration and the state of surrounding lines and stations.

Feeder Reinforcement: One common solution is to redistribute load through reinforcement projects. In urban areas, this can entail upgrading or creating new radial loops. These projects focus on optimizing load distribution by reconfiguring existing feeders to enable load transfers between phases, and between different feeders. By extending feeders, installing new phases and tie points, and updating feeder protections, lightly loaded feeders can offload heavily loaded sections.

Station Upgrade: Station upgrade projects are executed in areas where the existing configuration cannot be utilized to offload equipment that has reached its planned loading limit. Instead, additional capacity must be added to the system. Station upgrades involve an increase in capacity to existing stations by upgrading transformer sizes; installing additional transformers; increasing the station's secondary voltage (voltage conversion at the station); or installing fan monitoring to cool station transformers. These projects also include adding new feeder positions at the station to increase the number of available feeders.

Construct New Station: In some situations, constructing a new station is more effective from a cost and operating perspective than upgrading an existing station. In these cases, a new distribution station is installed and incorporated into the distribution system. New feeders are also used to provide additional capacity to areas that are overloaded. These feeders may be built to compliment the construction of a new distribution station.

Voltage Conversion: To increase equipment ratings and capacity, feeders may also be converted to higher voltage levels. These upgrades may coincide with a station voltage conversion or may involve a reconfiguration with nearby feeders that operate at higher voltage levels.

Risk Mitigation:

The main risks concerning project execution are real estate/property rights, shortage of qualified labour, customer delays, and delays in finalizing development plans.

Construction of new stations requires acquisition of new property and is subject to delays due the lack of a willing seller, negotiations with property owners, municipalities, and in some cases First Nation concerns. Construction or upgrading of feeders requires occupancy rights on road allowances or private property, as well as cutting rights and anchoring easements on private property. Delays, or the inability in obtaining these rights, can lead to the need for re-design, or route alterations. In some cases, road authorities may have coinciding plans for road widening or other construction, which need to be coordinated with new pole locations resulting in delays to line construction work. These risks are mitigated by providing appropriate lead times during the design and estimating stages to allow sufficient time for obtaining necessary property rights. For new station or station upgrade work, Hydro One has recently implemented a new project planning approach where any new property needed will be determined and acquired prior to commencing engineering/design work.

Execution of the proposed station and feeder construction projects identified in this investment driver requires the coordinated efforts of multiple technical and engineering disciplines some of which are highly specialized. Lack of available resources in these specialties can lead to project delays. These risks are mitigated by establishing appropriate project time lines in conjunction with internal and external service providers to reflect available resources for design and construction.

Projects that are being driven by specific customer requests or by specific development needs are also subject to delays due to changes in the customers' or developers' timing.

Projects are reprioritized each year as new loading information and updated forecasts become available to ensure they are addressed in order of criticality. Funding may also need to be reallocated to unplanned projects to serve immediate needs for system capability reinforcement due to unforeseen load growth or specific customer requests. In these cases, planned projects may be postponed to ensure the most efficient use of resources and funding.

Result:

System Upgrades Driven by Load Growth will result in:

- Ensuring there is adequate capacity within the distribution system to meet existing and forecast customer load needs;
- Maintaining acceptable Power Quality throughout the distribution system;
- Ensuring the safe and reliable operation of the distribution system;
- Reducing the risk of lengthy customer outages caused by failure or malfunction of overloaded assets;
- Balancing loads to allow for additional customer connections and to improve voltage and power quality;
- Reducing line losses; and
- Providing additional supply options to relieve overloaded feeders and enable future load growth and customer connections.

Outcome Summary:

Customer Focus	• Meet load needs of existing and new customers. • Ensure acceptable delivery voltage and other quality of power criteria are provided to customers. • Improve customer reliability.
Operational Effectiveness	• Maintain safe and effective operation of the distribution system. • Minimize overall costs by taking an integrated planning approach based on an overall assessment of area supply needs.
Public Policy Responsiveness	• Meet requirements of the Distribution System Code to plan the system to accommodate reasonable forecast load growth. • Comply with equipment standards which include Renewable Energy enabling technologies.
Financial Performance	

Costs:

Costs are primarily affected by design requirements and conditions of construction. Hydro One uses three main styles for new station construction based on rural vs. urban as well as operating requirements. The optimal design solution is based on a number of factors including property availability, capacity requirements, operational needs, compatibility with surrounding land uses, as well as environmental mitigation needs.

Feeder construction costs can vary widely depending on conditions such as ground type (soil vs. rock), tree density where right-of-way clearing or expansion is required, underground vs. overhead, and whether it is green field construction versus upgrading or overbuilding of existing lines. Costs are controlled by avoiding costly or complex design solutions where possible and by sub-contracting specialized civil work to external service providers.

($ Millions) -	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	47.6	55.9	46.6	34.5	24.6	209.2
Less Removals	4.4	4.5	3.6	1.8	2.0	16.3
Gross Investment Cost	**43.2**	**51.4**	**42.9**	**32.7**	**22.6**	**192.9**
Less Capital Contributions	2.8					2.8
Net Investment Cost	**40.4**	**51.4**	**42.9**	**32.7**	**22.6**	**190.0**

**Includes Overhead at current rates.*

Attachment 1 – System Upgrades Driven by Load Growth

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-1	Cumberland DS F4 Development	Extend the lightly loaded F4 feeder from Cumberland DS to meet with the more heavily loaded F2.	Provide a loop feed for the Cumberland urban load area and meet future load needs.	1.2	2018
LG-2	Devlin DS F1 3 Phase Upgrade	Upgrade 3 km of two-phase and 1.5 km of single-phase line to three-phase along Highway 613.	Address single phase line loading above Planning Guidelines.	1.0	2018
LG-3	Kleinburg TS M6 Mayfield Rd Line Extension	Extend 27.6 kV along Mayfield Road, for approximately 4 km, from Airport Rd to Dixie Road.	Improve supply efficiency and reliability and provide capability to supply future loads along Mayfield Road in the Town of Bolton.	1.0	2018
LG-4	Orangeville TS M3 - Mayfield West Line Extension	Extend 44 kV feeder from Chinguacousy Rd, east along Old School Road, for approximately 6 km.	Introduction of 44kV to the Mayfield West area, to facilitate connection of anticipated industrial loads, and to construct a future Old School Road DS.	1.8	2018
LG-5	New Bradford North DS	Construct new 44-27.6 kV DS, as well as associated feeders.	To meet forecast residential and commercial load growth in the Town of Bradford West Gwillimbury.	5.0	2018-2019
LG-6	Caledonia TS M3 Extension	Convert 7.5 km of 4.16 kV line to 27.6kV and transfer load from Jarvis TS M3 to Caledonia TS M3.	Relieve overloaded step-downs and improve reliability to Six Nations.	1.1	2018-2019
LG-7	Alfred DS F2 Feeder Upgrades	Upgrade 6 km of single-phase line to three-phase, balance loads between phases, and between F1 and F2 feeders.	Single phase line section loaded above planning guideline.	2.4	2018-2019
LG-8	Cameron DS Feeder Improvements	Construct new F2 feeder out of Cameron DS and upgrade existing single phase line to three phase along Monarch Road and Hwy 35.	To meet forecast residential load growth in west part of the Town of Lindsay.	1.4	2018-2019
LG-9	Armitage TS M22 Extension	Extend M22 feeder by double circuit with existing M12 feeder, for approximately 6 km. Transfer Wesley DS from M12 to M22.	Provide load relief to Armitage TS feeder M12 which is loaded beyond planning guidelines.	2.0	2018-2019

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-10	City of Owen Sound Tie-Line Reinforcement	Construct new 4.16 kV tie-lines between 24th St West DS and 2nd Ave West DS, and between 6th Street East DS, and 2nd Ave East DS.	To provide loop feeds for single-contingency back up of DS transformers which do not have MUS facilities.	1.3	2018-2019
LG-11	Enfield TS Feeder Development	Construct two new 44 kV feeders out of Enfield TS consisting of 18 km of new feeder line.	To meet forecast load growth in Durham Region.	7.6	2018-2019
LG-12	Grand Bend DS F3 Voltage Conversion	Convert existing 8.32 kV feeder to 27.6 kV and connect to Grand Bend East DS F2 feeder.	To address substandard voltage being experienced by customers along the Lake Huron shoreline south of Grand Bend.	2.4	2018-2019
LG-13	Kirkland Lake Voltage Conversion – Part 1	Rebuild Goodfish DS and replace 44-4.16 kV transformer with a 44-12.5 kV unit. Convert Goodfish DS F8, F9, F10 feeders from 4.16 kV to 12.5 kV.	Meet future load needs in the Town of Kirkland Lake and eliminate obsolete metalclad switchgear at Goodfish DS.	4.8	2018-2019
LG-14	Leamington TS Feeder Development	Build 8 new 27.6 kV feeders from Leamington TS, transfer load and DG from Kingsville to Leamington TS, and partial 8.32 kV DS conversion to 27.6 kV.	Meet future load needs in the towns of Kingsville and Leamington consistent with Supply to Essex County Transmission Reinforcement (SECTR) work.	3.7	2018-2019
LG-15	Manotick DS Feeder Development	Extend new F3 feeder to off-load existing F1 feeder and to connect to new residential subdivisions.	To connect new residential subdivisions in Manotick to new F3 feeder.	2.6	2018-2019
LG-16	Stouffville 10th Line DS New T3 & Feeder	Construct new DS with 2 x 44 - 27.6 kV and 1 x 44 - 8.32 kV transformer.	Replace existing end-of-life 8.32 kV T1 station assets and add more capacity to meet the load growth in the Town of Stouffville.	6.6	2018-2019
LG-17	Town of Shelburne Voltage Conversion	Convert 4.16 kV feeders to 8.32 kV and rebuild Shelburne DS as a single-transformer station, 44-8.32kV. Remove existing T1 and T2 transformers.	Increase transformer and feeder capacity at Shelburne DS to meet forecast load growth.	8.4	2018-2020

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-18	Twelve Mile Bay DS - New Station & Feeders	Construct a new 44-12.5 kV station including 1 km of new 44 kV line with 12.5 kV underbuild, and install 11 km of new three-phase submarine cable in Georgian Bay to connect the new station to the Honey Harbour DS F1 feeder.	Provide load relief to Foots Bay DS which is loaded above its PLL, and to the Honey Harbour DS F1 feeder which does not meet system protection requirements.	4.0	2018-2019
LG-19	Beckwith DS F3 Feeder Development	Extend new Beckwith DS F3 feeder to off-load F1 and T1 transformer.	Relieve T1 overloading and create a three-phase loop feed for urban customers.	1.8	2019
LG-20	Crilly DS Replacement and Transformer Upgrade	Construct new Crilly DS 2 km from existing DS site. New Crilly DS will be supplied from Hydro One 115 kV circuit.	Address overloaded transformer and eliminate non-standard supply from privately owned generating station bus.	6.7	2019
LG-21	Kirkland Lake Voltage Conversion-Part 2	Replace 44-4.16 kV transformer at Woods DS with a 44-12.5 kV unit. Convert Woods DS F5, F6, F7 feeders from 4.16 kV to 12.5 kV.	To meet future load needs in the Town of Kirkland Lake.	2.0	2019
LG-22	Manotick DS F3 New Feeder	Add new feeder position and underground egress to connect new F3 Feeder	To meet forecast residential load growth in the Village of Manotick	1.9	2019
LG-23	Margach DS F3 Voltage Conversion - SW676	Extend Keewatin DS feeder F2 for 3.5 km to off-load part of the Margach DS F1 load onto Keewatin DS F2.	Provide load relief to overloaded step-down transformer.	1.4	2019
LG-24	Muskoka TS M5 x M1 Feeder Tie	Extend the Muskoka TS M5 feeder for 14 km from Ullswater DS to the village of Rosseau by overbuilding existing 12.5 kV feeders with 44 kV.	To facilitate off-loading Parry Sound TS through a load transfer to the Muskoka TS M1 feeder and to create a 44 kV loop feed around Lake Rosseau.	5.3	2019
LG-25	Rockland DS T2 Transformer	Install a second transformer at Rockland DS.	Provide load relief to existing T1 transformer and meet forecast load growth.	2.3	2019
LG-26	Barrie TS - Construct New Feeders	Construct 8 km of New 2-circuit 44 kV Line from Barrie TS to Salem Road.	To meet forecast load needs of InnPower embedded LDC.	2.6	2019-2020
LG-27	Caledonia TS New Feeders	Construct 6 km of new 27.6 kV feeders from Caledonia TS.	Relieve Existing Feeders which are loaded above planning guideline.	4.3	2019-2020

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-28	Dundas TS #2 New Feeders	Construct 2.5 km of new feeders from Dundas TS#2. Construction will be done across the Niagara Escarpment and through a subdivision.	To provide load relieve to Dundas TS T1/T2 DESN.	6.7	2019-2020
LG-29	King City DS - New Station & Feeders	Construct a new 44-13.8kV DS. Build feeder ties with existing 13.8kV feeders from Eversley DS, and balance load between feeders / stations.	Provide a second 13.8 kV source of supply for King City to enable loop feeds and meet future load growth.	4.6	2019-2020
LG-30	New Old School DS	Construct a new 44-27.6kV DS. Construct 27.6kV feeders and tie to Snelgrove DS and Kleinburg TS M6.	Relieve capacity issues at Snelgrove DS, and provide a second 27.6kV source to improve loop feed supply.	7.0	2019-2020
LG-31	Town of Dundalk Voltage Conversion	Construct a new 44-8.32kV DS. Convert existing 4.16kV loads within the town of Dundalk to 8.32 kV, and remove existing 44-4.16kV transformer.	Provide increase station and feeder capacity to meet forecast load growth in Town of Dundalk.	9.5	2019-2021
LG-32	Greely DS F1 Feeder Development	Extend F1 feeder from Greely DS to offload existing feeders.	To meet forecast load growth in south Ottawa.	1.5	2020
LG-33	Kirkland Lake Voltage Conversion-Part 3	Convert Kirkland Lake DS #1 F1, F2, F3 feeders from 4.16 kV to 12.5 kV and re-supply from Goodfish DS and Woods DS. Remove Kirkland Lake DS #1.	Meet future load needs in the Town of Kirkland Lake and eliminate Kirkland Lake DS #1 which has obsolete switchgear and is located inside the Kirkland Lake TS yard.	2.8	2020
LG-34	Midhurst Wilson DS F2 Extend to Doran Rd	Overbuild 6.5km of existing 8.32 kV line with new 27.6 kV feeder from Wilson Road to Doran Road.	To meet future residential subdivision growth in the north-east Midhurst Area (Midhurst Secondary Plan – Neighbourhood 2).	2.2	2020
LG-35	Midhurst Wilson DS F1 Extend to Dobson Rd	Extend Midhurst Wilson DS 27.6 kV feeder for 3.5 km to Dobson Rd by converting existing Grenfel DS F2 feeder from 8.32 kV to 27.6 kV.	Address forecast overloading of Grenfel DS F2 feeder due to residential subdivision load growth.	2.2	2020
LG-36	Perth Area Upgrades	Reconstruct station egress's with higher capacity underground cable.	Provide back feed capability for single contingency station transformer outage.	2.0	2020

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-37	Macville DS - New 27.6kV Station	Extend Kleinburg TS M26 44 kV feeder for 2km and construct a new 44-27.6kV DS.	Provide Additional DS capacity to meet forecast load growth in the Town of Caledon.	3.7	2020-2021
LG-38	Wikwemikong DS & Line Work	Build a 15 kV 44 kV feeder extension by overbuilding existing a 12.5 kV line and construct a new 44-12.5 kV station. Upgrade an additional 3 km of existing 12.5 kV line to double-circuit.	To meet forecast load growth at Wikwemikong First Nation on Manitoulin Island.	6.5	2020-2021
LG-39	Dunchurch DS F2 - Extend to Magnetewan	Upgrade 10 km of existing single-phase line to three-phase and build 1 km new line to extend Dunchurch DS F2 feeder to Town of Magnetewan.	Provide load relief to Burks Falls DS F2 feeder which is loaded above planning guidelines and does not meet system protection criteria.	2.8	2021
LG-40	Fairbanks Lake Line Upgrade	Upgrade 2.6 km existing single-phase line to three-phase and build 8.7 km of new three-phase line.	To Address Substandard Feeder Protection on existing Whitefish DS F1.	2.5	2021
LG-41	Kleinburg TS M26 extension to Mayfield West	Extend Kleinburg TS M26 to Mayfield West (approximately 12 km).	Provide load relief to Pleasant TS M21 feeder based on forecast loading.	3.2	2021
LG-42	Lively DS F2 SW142 Upgrade Black Lake Road	Upgrade 5 km of single-phase line to three-phase.	Address single phase line loading above planning guidelines.	1.4	2021
LG-43	Mar DS – New Station	Construct a new 44-12.5 kV station and 2 km of new 12.5 kV feeders.	Provide load relief to Colpoys Bay DS which is loaded above the transformer Planned Load Limit (PLL).	3.0	2021
LG-44	Ancaster West DS Transformer Upgrade	Upgrade Ancaster West DS transformer from 5 MVA to 7.5 MVA.	Provide DS Capacity to meet forecast load growth.	2.0	2021-2022
LG-45	Brockville 44kV System Upgrades	Extend Brockville M7 and Morrisburg M24 feeders to off load B1R and M5 feeders.	Provide load relief to Brockville TS B1R & M5 feeders which are currently loaded above planning guidelines.	10.5	2021-2022

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-46	Manitoulin TS - Add Third 44 kV Feeder	Add new 44 kV breaker at Manitoulin TS, new feeder tie switches, and construct 1.5 km new 44 kV line to Little Current DS.	To maintain 44 kV feeder loading within protection limits during transformer or breaker outages.	4.6	2021-2022
LG-47	Point Au Baril DS F2 Extension	Extend the Point Au Baril DS F2 feeder for 8.5 km by double-circuit the existing F1 feeder north of Point Au Baril.	To provide load relief to the Point Au Baril DS F1 feeder which has substandard system protection and voltage.	3.6	2021-2022
LG-48	Aspdin DS F1 Feeder Upgrade	Upgrade 5 km of single-phase line to three-phase.	Address single phase line loading above planning guidelines.	1.3	2022

Hydro One Distribution – Investment Summary Document

Development Investment - System Capability Reinforcement

Investment Name: Reliability Improvements
Work Execution Period: January 2015 to December 2019
Primary Outcome: Customer Focus

Objective:
To improve reliability and power quality with system modifications and additions.

Need:
The majority of Hydro One Distribution's system is constructed in a radial configuration, with minimal opportunities to transfer load during outages. To improve overall reliability, investments focused on reconfiguring the system's layout are required. These projects can include new tie-lines between feeders to create loop feeds and alternative supplies, reductions in overall line exposure per feeder, increased sectionalizing, and installing lightning arrestors. The quality of power delivered to customers can be improved by upgrading conductor sizes or installing voltage regulating equipment.

Not proceeding with this investment would leave customers susceptible to longer and more frequent outages that are characteristic of radially configured lines. The risk of serving customers at unacceptable power quality levels will also increase. If left unaddressed, poor power quality can lead to equipment damage and sustained outages for customers.

Investment Description:
There are a variety of ways to improve system reliability. Each area is unique and the optimal solution varies area to area depending on the existing feeder configuration and the state of surrounding lines and stations.

Examples of these types of projects include installing loop-feeds to provide alternative supply capabilities, installing express feeders to critical supply areas to reduce line exposure and improving sectionalizing capabilities to minimize the impact of lengthy outages. These reliability investments typically occur in areas with a higher customer density because of the relative cost-benefits (i.e. more customers benefit from improved reliability in comparison to the investment costs). Further details and a listing of the planned projects from 2015-2019 are found under Investment Details below.

Constructing Alternative Supply Options & Improving Sectionalizing Capabilities: To minimize the duration of an outage experienced, customers can be temporarily supplied by alternative sources as the faulted section of line is addressed. This is typically achieved by connecting two or more feeder sections through tie-lines and ensuring that appropriate equipment is in place to enable switching over to the alternative supply. Improved sectionalizing capabilities help reduce the number of customers impacted by sustained power interruptions.

Reducing Line Exposure: By decreasing the circuit length of a feeder, the total amount of conductor exposed to the elements is lessened. This reduces the likelihood of that circuit experiencing a fault due to natural elements, such as trees.

Improving Power Quality through Line Upgrades: Power quality can be improved by increasing conductor sizes or installing voltage regulating equipment.

Installing Lightning Arrestors: Lightning arrestors are used to prevent power interruptions due to lightning strikes. These are installed on feeders that experience a high frequency of lightning storms.

The following projects are planned for the test years 2015 through 2019. These projects are reprioritized each year to ensure they are addressed in order of criticality. Funding may also need to be reallocated to unplanned projects to serve immediate needs for system capability reinforcement. In these cases, planned projects may be postponed to ensure the most efficient use of resources and funding. However the overall funding requirement of the system capability reinforcement investments in the test years will not be changed. Projects above $1M are provided below:

2015 Projects	**Total $M**
Allanburg TS M7 Feeder Upgrades, *Thorold*	1.0
Brant TS M14 Tie Line, St. George, *Brant County*	1.7
Total	**2.7**

2016 Projects	**Total $M**
2nd Ave East DS, 12th St West DS, & 24th St West DS Tie Lines, *Owen Sound*	1.0
Tilsonburg TS & Norfolk TS Tie Line, Village of Delhi, *Simcoe County*	1.0
Total	**2.0**

2017 Projects	Total $M
Orangeville TS Tie Line, *Caledon*	2.6
Total	**2.6**

2018 Projects	Total $M
New Feeder - Aylmer TS, *Aylmer*	1.6
Total	**1.6**

2019 Projects	Total $M
Brant TS M21 to Wolverton DS F1 Tie Line	1.2
Armitage TS M34 Line Extension	1.0
Total	**2.2**

Result:

- Provide operating flexibility and alternate supply lines that can be used during emergency situations and planned outages to minimize power outage durations to customers
- Provide additional sectionalizing capability to improve supply reliability in the area
- Reduce frequency of outages for customers by reducing line exposure
- Improve overall quality of customers' supply voltage by upgrading line sections and prevent outages caused by unacceptable voltage levels

Costs:

	2015	2016	2017	2018	2019	Total
Capital* and Minor Fixed Assets (A)	2.7	2.0	2.6	1.6	2.2	11.1
Operations, Maintenance & Administration and Removals (B)	0.4	0.3	0.4	0.2	0.3	1.5
Gross Investment Cost (A+B)	3.1	2.3	3.0	1.8	2.5	12.6
Recoverable (C)	-	-	-	-	-	
Net Investment Cost (A+C)	2.7	2.0	2.6	1.6	2.2	11.1

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

Investment Category:

System Access	System Renewal	System Service	General Plant
%	%	100%	%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• These investments address areas where customers are experiencing below average reliability and system improvements are needed to restore customer satisfaction.
Operational Effectiveness	• Provide operating flexibility and alternate supply lines that can be used during emergency situations and planned outages to minimize power outage durations to customers. • Improve overall quality of customers' supply voltage by upgrading line sections and prevent outages caused by unacceptable voltage levels.
Public Policy Responsiveness	
Financial Performance	• These reliability investments typically occur in areas with a higher customer density because of the relative cost-benefits (i.e. more customers benefit from improved reliability in comparison to the investment costs).

SS-03 Reliability Improvements

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Program	**Plan Period Cost ($M):**	33.1
Primary Trigger:	System Efficiency		
Secondary Trigger:	Reliability		

Investment Need:

The Hydro One distribution system is normally planned based on a radial supply configuration. Due to system growth and development over time, there may be alternate feeds available to certain load centres or specific customer locations. However, alternate feeds may not be capable of supplying the entire load. Also, in many cases, only a single radial supply exists so there are no opportunities to transfer load during outages. Extended outages can be particularly disruptive to commercial and industrial customers due to lost business or lost productivity and in some cases lost/damaged product due to processing interruptions. Some industrial customers may also be sensitive to momentary supply interruptions due to lightning or even to voltage fluctuations which may occur when lightning strikes other parts of the system that do not directly supply them.

To improve reliability and increase customer satisfaction in certain areas, investments focused on improving backup capability, adding new tie-lines, and lightning mitigation may be needed.

Alternative 1: Status Quo

Address customer concerns about poor reliability in sensitive areas on a reactive basis only.

This alternative is rejected since it would lead to decreased customer satisfaction and continued poor reliability in areas where concerns have already been expressed. Not proceeding with this investment would leave customers susceptible to longer and more frequent outages that are characteristic of radially configured lines. The risk of serving customers at unacceptable power quality levels will also increase. If left unaddressed, poor power quality can lead to equipment damage and sustained outages for customers.

Alternative 2: Targeted Reliability Improvements (Recommended)

Implement targeted projects to improve reliability in areas where customer concerns have been raised and where practical system development opportunities exist to meaningfully improve system capability and performance.

Investment Description:

There are a variety of ways to improve system reliability. Each area is unique and the optimal solution varies area to area depending on the existing feeder configuration and the state of surrounding lines and stations.

Examples of projects to improve reliability include building tie lines to provide alternative supply capabilities, installing express feeders to critical load centers, improving sectionalizing capabilities on multi-branch feeders, adding voltage regulators or upgrading conductor to improve capability of existing ties, and installation of lightning arrestors on feeders. These reliability investments typically occur in areas with a high customer density because of the relative cost-benefits (i.e. more customers benefit from improved reliability in comparison to the investment costs).

Constructing Alternative Supply Options & Improving Sectionalizing Capabilities: To minimize the duration of an outage experienced, customers can be temporarily supplied by alternative sources as the faulted section of line is addressed. This is typically achieved by connecting two or more feeder sections through tie-lines and ensuring that appropriate equipment is in place to enable switching over to the alternative supply. Improved sectionalizing capabilities help reduce the number of customers impacted by sustained power interruptions.

Reducing Line Exposure: By decreasing the circuit length of a feeder, the total amount of conductor exposed to the elements is lessened. This reduces the likelihood of that circuit experiencing a fault due to natural elements, such as trees.

Improving Power Quality through Line Upgrades: Power quality can be improved by increasing conductor sizes or installing voltage regulating equipment.

Installing Lightning Arrestors: Lightning arrestors are used to prevent power interruptions due to lightning strikes. These are installed on feeders that experience a high frequency of lightning storms.

The proposed overall expenditure includes placeholder funding of approximately $3 million annually for planned reliability improvements to large distribution account customers based on customer engagement sessions.

A list of planned and scoped projects in excess of $1 million over the 2018-2022 period is provided below.

Project ID	Project Name	Scope	Need Addressed	Cost $M Net	Year(s)
RI-1	Nebo TS Feeder Extension to Binbrook	Construct a new 6 km 27.6 kV feeder and tie to Nebo TS M5.	Provide a loop feed for Binbrook area.	2.8	2019-2020
RI-2	Tilbury DS New Feeder	Add a new 27.6 kV feeder position at Tilbury West DS, construct 0.6 km 27.6kV feeder and transfer Tilbury West DS F2 load to the new feeder position	Provide a loop feed for Town of Tilbury and lighthouse cove area.	1.9	2019
RI-3	Puslinch DS 4th Feeder	Construct a new 27.6kV feeder for 2 km out of Puslinch DS.	Provide a dedicated supply to industrial customers for improved reliability.	2.9	2021
RI-4	Orangeville TS M3-M6 Tie Line	Construct approximately 10km of new 44kV line between Caledon DS and Sleswick DS (along Charleston Road).	Provide a loop feed for to enable backfeed during outages.	2.6	2022
RI-5	Tilsonburg-Norfolk Tie Line	Construct 4 km 27.6kV feeder tie between Tilsonburg TS M1 and Norfolk TS M1.	Provide backup supply for Town of Delhi loads.	1.1	2022

Risk Mitigation:

The main risks to completion of this work are lack of labour resources for design and construction, as well as the usual risks around property rights for poles, anchors and tree trimming. These risks will be mitigated by ensuring appropriate planning lead times are followed for project scheduling and by considering constructability issues early in the project definition stage.

Result:

Reliability Improvement projects will:

- Improve customer satisfaction levels, particularly where customer concerns have been raised;
- Reduce outage durations for specific load centers or customers; and
- May improve operational efficiency and safety through increased system flexibility on projects involving tie-line upgrades.

Outcome Summary:

Customer Focus	• Reduce outage durations/frequency for sensitive customer loads. • Reduce lengthy outages to certain areas by providing an alternate feed capability. • Mitigate voltage fluctuations due to lightning activity for industrial customers.
Operational Effectiveness	• Allow increased operational flexibility to supply some loads by an alternate means in order to perform planned and unplanned maintenance.
Public Policy Responsiveness	
Financial Performance	• Cost saving opportunities such as making provisions for future circuits or tie-lines during routine work such as road relocation, end-of-life pole replacements are pursued when possible. • Maximum benefit/cost outcome is a primary factor taken into consideration when selecting appropriate investments under this category.

Costs:

Cost estimates are based on historical actual costs. Costs are mainly affected by design requirements and conditions of construction. Costs are controlled by avoiding costly and complex design solutions where possible and by sub-contracting specialized civil work to external service providers.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	5.2	7.9	7.2	8.2	9.2	37.6
Less Removals	0.6	1.0	0.9	1.0	1.1	4.5
Gross Investment Cost	**4.6**	**7.0**	**6.3**	**7.2**	**8.1**	**33.1**
Less Capital Contributions						
Net Investment Cost	**4.6**	**7.0**	**6.3**	**7.2**	**8.1**	**33.1**

**Includes Overhead at current rates plus Allowance for Funds During Construction*

OEB Staff Interrogatory # 84

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 3.8 (5.4.5.2) Page: 2675

Attachments: Material Investments, ISD: SS-03 Reliability Improvements,

Ref: EB-2013-0416 Exhibit D2/Tab2/Schedule 3 –D-06 Reliability Improvements

"Alternative 2: Targeted Reliability Improvements (Recommended)
Implement targeted projects to improve reliability in areas where customer concerns have been raised and where practical system development opportunities exist to meaningfully improve system capability and performance."

Interrogatory:

a) Please explain for project RI-3 why no capital contribution was provided by customer when the feeder is a dedicated supply to the customer.

b) Is a business case available for each of the projects listed? If no, please provide an explanation to why not. If yes, please provide the business case(s). It is expected the business case(s) will address the following items:
   - List of assets at end-of-life, complete with asset technical specifications, asset analytic results, age, and recent deficiency reports
   - Reliability metrics for stations and feeders involved in each project and the expected improvement
   - Station and feeder capacity
   - Number of customers affected
   - Proposed options, including scope of work, benefits, costs, and expected efficiency savings.

c) Projects RI-4 and RI-5 in investment SS-03 Reliability Improvements were repeated from D-06. Please explain why these projects were not completed and where the approved capital was redirected.

Response:

a) Investment RI-3 is not a dedicated supply for one customer. The feeder is being built to improve reliability for multiple customers.

b) No. 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. At this point in time, all of the Reliability Improvement projects listed in exhibit ISD SS-03 are planned to be in service at a future date, beyond which necessitates the production of a Business Case for the purpose of authorizing the expenditure of funds for execution.

c) These projects were not completed as capital was redirected to other higher priority capital investments through Hydro One's Investment Planning Process. DSP Section 2.1 explains Hydro One's Investment Planning Process in detail. As described in DSP Section 2.1 this process occurs on an annual basis, "Hydro One's planning process is an ongoing cyclical process that develops an annual budget for OM&A and capital investments and a five-year planning forecast consistent with the Board's filing requirement of a consolidated five-year capital plan. All investments follow this same process." The redirected capital for these projects funded part of Hydro One's total 2016 actual and 2017 forecast capital expenditures. DSP Section 3.6 summarizes the result of implementing the cyclical investment planning process. DSP section 3.6.1 summarizes the variances between forecast and historical budgets by OEB Investment Category.

MR. BUCKSTAFF: Okay. Yes, you would want to have a detailed scope, particularly where you are doing a full station rebuild or a major refurbishment. Individual components maybe not, but for the full station rebuild you'd want to have a complete scope so you could estimate what it will take to do it.

MR. SIDLOFSKY: Okay, so I'm going to take you to page 10 of the compendium. And that's an extract from the transcript from the -- sorry, from the technical conference in this proceeding.

And specifically, if we look at page 10, lines 27 to 28, and continuing on to page 11, lines 1 and 2, Ms. Garzouzi indicated in the technical conference that a detailed -- sorry, a detailed business case isn't available in the list of stations that were shown in investment SR06 station refurbishment.

So the comment at the technical conference was:

> "We would prepare a business case very shortly before execution, once we've completed our engineering and our site assessment. And that is when we prepare the business case."

So in other words, a business -- a detailed business case won't be available for the project until just before the investment's approved.

In the absence of a detailed scope, though, what's the impact -- what do you see as the impact of that on annual cost estimates? Is there -- are the actuals likely to vary on a project-by-project basis when there is no detailed scope at the time of the -- at the time of the cost estimates?

MR. BUCKSTAFF: Well, ordinarily when you are doing a big project like this you do cost estimates at several stages, you know, you do one when the idea is first born, when you say we're going to do a project in this area. Roughly what would that cost? You would get a rough estimate, plus or minus maybe 30 percent. Then when you do your preliminary engineering you can make another estimate that gets you greater precision, and then when you actually go to construction, when you're ready to go, you should have a very detailed cost estimate.

But along the way the question is how early can you have those. If you do your engineering a year in advance you'll know that information a long time in advance. If you do your engineering two weeks before you start construction, then you don't have much time.

And some of that depends on what the backlogs are in your engineering group and some of the other things, so there's a variety of factors that affect it. You are going to have multiple stages of estimates, and what's ideal is to have a little bit longer time between when you finish your final estimate and when you build your business case to go forward.

MR. SIDLOFSKY: Is there a reason in your view that a utility couldn't do the detailed cost estimates well in advance of the actual -- of the actual work being done? I realize -- I could imagine that costs will change as you get closer to construction, but would it be preferable to do the detailed costing and get that detailed scope well in advance of the actual construction?

MR. BUCKSTAFF: Again, as early in the process as possible, you'd like to know the details, but until you have finished the different stages of engineering, you can't really do that because you don't know what the scope of work is. And that does tend to change from the start of thinking about a project until you've reached the final stages where you've finished the full design.

And again, some utilities manage to have that engineering work done a year ahead. Most don't. Most, it's shorter than that. But in a long-term plan you might be able to do that.

MR. SIDLOFSKY: Excuse me. Just one moment, sir.

Have you actually looked at Hydro One's station refurbishment plans in the application?

MR. BUCKSTAFF: I'm sorry --

MR. SIDLOFSKY: Sorry about that. Have you actually looked at Hydro One's station refurbishment plans in its application?

MR. BUCKSTAFF: No, not what's in the application.

MR. SIDLOFSKY: Okay. So this is a more general recommendation; it is not based on your review of Hydro One's actual station refurbishment projects?

MR. BUCKSTAFF: Not anything that was submitted as part of the filing here.

MR. SIDLOFSKY: Okay. Back to page 2, just for the

MR. JESUS: Specifically for business cases, we only do that on projects that are not reoccurring. So for program work, those are defined in the ISD in terms of the intent and what we're going to be -- what are the benefits and costs associated with those various programs. So the ISD is a reoccurring type of program where no business case is prepared, other than what you're seeing in the ISD.

The analysis that goes into determining how many poles and how many -- whatever else we're doing from a program point of view is developed by the planners and then bundled into the program. It is a reoccurring expenditure and no business case exists, other than the ISD.

FOLLOW-UP QUESTIONS BY MR. GARNER:

MR. GARNER: Mr. Oakley, do you mind if I ask a follow-up question? This follows from yesterday's panel and here is my confusion.

Yesterday, I asked a question of the panel as to the -- there appeared to be a variance between the capital budgets being shown by Hydro One in this application and then the in-service amounts in the subsequent years. And the response I thought I heard from the panel prior to yourself was that that reason was there was sufficient detail in the planning portion of this application that arose out of that distinction.

But what I'm hearing from you right now is there isn't that level of distinction to derive the difference between in-service and capital budgets.

Can you explain why there would be that difference

3.6 Refurbishment versus Replacement Costs

The cost of replacing a pole is substantially higher than the cost to refurbish a pole, with replacement being approximately 7x more expensive, where refurbishment is an option. Refurbishment is not an option in all cases. For example, it wouldn't make sense to refurbish a 50-year-old pole when its useful life is planned for 60 years. Refurbishment makes the most sense when a pole is found to be failing early in its planned life. Refurbishment has the possibility of extending the life of the pole by 20 to 40 years. In any scenario where a refurbishment can extend the life of the pole by over 20 years, then the economic benefit of refurbishment tends to be clear.

OEB Staff Interrogatory # 122

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.1 Page: 29

Distribution System Plan Overview, Section 1.1.1 (5.2.1 A) KEY ELEMENTS OF THE DSP, pg 29 of 2930; **and**

DSP Section 1.6: (5.2.3) Benchmarking, Section 1.6.3.1 POLE REPLACEMENT PROGRAM STUDY, pg 1992 of 2930.

"The pole replacement program (ISD SR-09) is planned to be lower in 2018, to address customer rate sensitivities. The program will then increase until 2020 and level off in 2021 and 2022. There is a low reliability impact associated with this plan. Hydro One's goal is to sustain or modestly improve the condition of the pole fleet through the investment planning period."

"Recommendation 4: Pole Refurbishment Program

The study found that most of the peer group perform pole refurbishment. The study recommended refurbishing poles where possible. Hydro One will investigate the feasibility and cost benefit analysis of this option and its impact on work methods. The results of this analysis will determine if Hydro One will implement a pole refurbishment program."

Interrogatory:

a) It was recommended that Hydro One consider implementing a pole refurbishment program. Please provide details and the current status of this recommendation.

b) Could implementing a pole refurbishment program potentially take some pressure off the capital cost of pole replacements?

Response:

a) Hydro One is investigating different types of wood pole refurbishments. The two types being considered are structural refurbishment and chemical refurbishment. Structural refurbishment involves attaching a steel member or wood pole stub to an existing pole in order to reinforce it. Chemical refurbishment involves applying a retreatment product to the pole during a drill test to restore the pole's chemical treatment at the ground line.

Chemical refurbishment is the currently preferred alternative. When combined with a drill testing program, this type of refurbishment has a low incremental cost. Preliminary discussions with vendors have occurred, and Hydro One is determining optimal cycle length, optimal candidates for refurbishment, and application licencing.

b) Chemical refurbishments have the potential to extend the life of the wood pole population which, in the long term, has the potential of reducing the annual capital investment in wood pole replacements. However, chemical refurbishments must be applied before any rot has started to develop within the pole otherwise it can be ineffective.

MR. JESUS: Those are the actual results, correct. Those are the risk assessments prior to the baseline risk, identifying the baseline risk, and then what's the residual risk afterwards as a project-by-project risk assessment.

MR. OAKLEY: Again, but it's a table of results, as opposed to showing how you got to the results?

MR. JESUS: So that -- we have asset investment planning tool, a Copperleaf tool, which is a proprietary tool --

MR. OAKLEY: Okay.

MR. JESUS: -- which we enter the financial parameters, that it then allows to optimize from an economic point of view -- i.e., financial parameters -- as well as a timeline perspective. And that's described in the interrogatory that you pulled up.

MR. OAKLEY: Great. Okay. Thanks. And it also then mentions that there's a calibration session.

MR. JESUS: Correct.

MR. OAKLEY: And do you have any materials from such a calibration session? Because this obviously overrides whatever Copperleaf came up with.

MR. JESUS: So -- that's correct. So the calibration session is where we engage all of our enterprise and we come to the meeting and we challenge the risk assessments that were provided during the candidate development.

MR. OAKLEY: So this --

MR. JESUS: So we do have materials that were presented during the calibration session.

MR. OAKLEY: You do have such materials?

MR. JESUS: I believe so.

MR. OAKLEY: Would it be possible to provide those so we can just --

MR. JESUS: Sure [inaudible] --

MR. OAKLEY: -- get a flavour of what happens, because we don't know how material the calibration session is versus the other analyses that you do.

MR. JESUS: Sure.

MR. OAKLEY: Thanks.

MR. SIDLOFSKY: That will be Undertaking JT2.9.

UNDERTAKING NO. JT2.9: TO PROVIDE MATERIALS THAT WERE PRESENTED DURING THE CALIBRATION SESSION.

MR. OAKLEY: Can we move to Staff 115, please. And this is a bit of a discussion about business cases. And I take it from the response to D it means that as a rule intervenors and the OEB will not have the opportunity to review fully developed business cases for planned capital projects until after the projects, or perhaps even different projects with which they are replaced are completed?

MR. JESUS: That's correct. So business cases would be done for individual projects.

MR. OAKLEY: And those wouldn't typically be available prior to an application like this, a custom IR application?

MS. GARZOUZI: So it's the timing of the work execution. We would prepare the business case very shortly before execution, once we've completed our engineering and

OEB Staff Interrogatory # 100

Issue:

Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Reference:

B1-01-01 Section 2.1 Page: 2383
(5.3.1) Investment Planning Process, Section 2.1.4.2 Risk Assessment

> *"A risk assessment is undertaken for two scenarios: (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."*

Interrogatory:

Please provide a comprehensive listing of the results of the risk assessments described in (a) and (b) for all of the System Renewal projects included in the capital forecast in this filing for which this analysis was carried out.

Response:

The table below shows the baseline and residual risk evaluation for System Renewal investments over the 2018-22 period; these assessments are guided by the consequence and probability taxonomy tables included as Appendices A and B to Exhibit I-24-Staff -89.

In addition to the risk assessment, there are other operational considerations that may drive an investment. For example, as noted in ISD SR-013 (Life-Cycle Optimization and Operational Efficiency) in section 3.8 of the DSP, Exhibit B1, Tab 1, Schedule 1 (page 2644 of 2930), projects may provide:

- higher load meeting capability;
- better power quality;
- reduced line losses; and
- opportunities to achieve overall cost savings by bundling asset renewal work.

		Baseline Risk Assessment					Residual Risk Assessment				
Sub Description	**Risk Type**	**2018**	**2019**	**2020**	**2021**	**2022**	**2018**	**2019**	**2020**	**2021**	**2022**
ISD-SR-01 - Distribution Stations Demand Capital Program											
DS Demand/Emergency Capital Program	Customer Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1
DS Demand/Emergency Capital Program	Reliability Risk	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Medium / Minor3	Medium / Minor3	Medium / Minor3	Medium / Minor3	Medium / Minor3
DS Demand/Emergency Capital Program	Safety Risk	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1
DS Demand/Emergency Capital Program	Shareholder Value Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1
ISD-SR-02 - Mobile Unit Substation Program											
DS MUS Purchase Program	Customer Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Minor5	Very Likely / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5
DS MUS Purchase Program	Environment Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Likely / Moderate	Likely / Moderate	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5
DS MUS Purchase Program	Reliability Risk	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Likely / Minor4	Likely / Minor4	Very Likely / Minor3	Very Likely / Minor3	Very Likely / Minor3
DS MUS Purchase Program	Safety Risk	Very Likely / Minor5	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Minor5	Likely / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5
DS MUS Purchase Program	Shareholder Value Risk	Likely / Minor5	Likely / Minor5	Likely / Moderate	Likely / Moderate	Likely / Moderate	Very Likely / Minor1	Very Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1
ISD-SR-03 - Station Spare Transformer Purchases Program											
DS Transformer Purchase Program	Customer Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5
DS Transformer Purchase Program	Environment Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5
DS Transformer Purchase Program	Reliability Risk	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Likely / Minor4	Likely / Minor4	Likely / Minor4	Likely / Minor4	Likely / Minor4
ISD-SR-04 - Distribution Station Planned Component Replacement Program											
DS Component Replacement Program	Customer Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5
DS Component Replacement Program	Environment Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5
DS Component Replacement Program	Reliability Risk	Likely / Minor3	Likely / Minor3	Likely / Minor4	Likely / Minor4	Likely / Minor4	Likely / Minor3	Likely / Minor3	Likely / Minor3	Likely / Minor3	Likely / Minor3
ISD-SR-05 - Distribution Station Feeder Protection Upgrade											

		Baseline Risk Assessment						Residual Risk Assessment				
Sub Description	**Risk Type**	**2018**	**2019**	**2020**	**2021**	**2022**		**2018**	**2019**	**2020**	**2021**	**2022**
DS Recloser Upgrade Program	Customer Risk	Likely / Minor5	Medium / Moderate	Medium / Major	Likely / Major	Likely / Major		Likely / Minor5	Likely / Minor5	Likely / Moderate	Likely / Moderate	Likely / Moderate
DS Recloser Upgrade Program	Reliability Risk	Medium / Minor3	Likely / Minor3	Likely / Minor3	Very Likely / Minor3	Very Likely / Minor3		Medium / Minor3	Medium / Minor3	Medium / Minor3	Likely / Minor3	Likely / Minor3
DS Recloser Upgrade Program	Safety Risk	Medium / Severe	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe		Unlikely / Severe	Unlikely / Severe	Medium / Minor5	Unlikely / Minor5	Unlikely / Minor1
DS Recloser Upgrade Program	Shareholder Value Risk	Medium / Minor5	Unlikely / Major	Medium / Major	Likely / Major	Likely / Major		Medium / Minor5	Medium / Minor5	Unlikely / Major	Medium / Major	Likely / Major
ISD-SR-06 - Distribution Station Refurbishment												
DS Station Refurbishment Program	Customer Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate		Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5
DS Station Refurbishment Program	Environment Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate		Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5
DS Station Refurbishment Program	Reliability Risk	Very Likely / Minor3	Very Likely / Minor3	Very Likely / Minor3	Very Likely / Minor4	Very Likely / Minor4		Very Likely / Minor3	Very Likely / Minor3	Very Likely / Minor3	Very Likely / Minor3	Very Likely / Minor4
ISD-SR-07 - Distribution Lines Trouble Call and Storm Damage Response Program												
Dx Capital Trouble Call Damage Claims	Customer Risk	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Trouble Call Poles & Equipment	Customer Risk	Likely / Major	Likely / Major	Likely / Major	Likely / Major	Likely / Major		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Post Trouble Call & Power Quality	Customer Risk	Likely / Major	Likely / Major	Likely / Major	Likely / Major	Likely / Major		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Storm Damage	Customer Risk	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Trouble Sub and UG Cable	Customer Risk	Likely / Major	Likely / Major	Likely / Major	Likely / Major	Likely / Major		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Trouble Call Damage Claims	Reliability Risk	Likely / Minor3	Likely / Minor3	Likely / Minor3	Likely / Minor3	Likely / Minor3		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Trouble Call Poles & Equipment	Reliability Risk	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Post Trouble Call & Power Quality	Reliability Risk	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Storm Damage	Reliability Risk	Likely / Catastrophic	Likely / Catastrophic	Likely / Catastrophic	Likely / Catastrophic	Likely / Catastrophic		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Trouble Sub and UG Cable	Reliability Risk	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Trouble Call Damage Claims	Safety Risk	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Trouble Call Poles & Equipment	Safety Risk	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Medium / Major		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Post Trouble Call & Power Quality	Safety Risk	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Storm Damage	Safety Risk	Medium / Severe	Medium / Severe	Medium / Severe	Medium / Severe	Medium / Severe		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Trouble Sub and UG Cable	Safety Risk	Medium / Severe	Medium / Severe	Medium / Severe	Medium / Severe	Medium / Severe		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1

		Baseline Risk Assessment						Residual Risk Assessment				
Sub Description	**Risk Type**	**2018**	**2019**	**2020**	**2021**	**2022**		**2018**	**2019**	**2020**	**2021**	**2022**
Dx Capital Trouble Call Damage Claims	Shareholder Value Risk	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Trouble Call Poles & Equipment	Shareholder Value Risk	Likely / Major	Likely / Major	Likely / Major	Likely / Major	Likely / Major		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Post Trouble Call & Power Quality	Shareholder Value Risk	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Storm Damage	Shareholder Value Risk	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Trouble Sub and UG Cable	Shareholder Value Risk	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Medium / Major		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
ISD-SR-08 - Distribution Lines PCB Equipment Replacement Program												
PCB Overhead Equipment Replacement	Shareholder Value Risk	Likely / Major	Likely / Major	Likely / Major	Likely / Major	Likely / Major		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
ISD-SR-09 - Pole Replacement Program												
End of Life Replacement of Wood Poles	Customer Risk	Likely / Major	Likely / Major	Likely / Major	Likely / Major	Likely / Major		Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate
End of Life Replacement of Wood Poles	Reliability Risk	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Medium / Major		Unlikely / Moderate	Unlikely / Moderate	Unlikely / Moderate	Unlikely / Moderate	Unlikely / Moderate
End of Life Replacement of Wood Poles	Safety Risk	Unlikely / Moderate	Unlikely / Moderate	Unlikely / Moderate	Unlikely / Moderate	Unlikely / Moderate		Remote / Minor1	Remote / Minor1	Remote / Minor1	Remote / Minor1	Remote / Minor1
End of Life Replacement of Wood Poles	Shareholder Value Risk	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe		Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate
ISD-SR-10 - Distribution Lines Planned Component Replacement Program												
Component Replacement - Regulators/Recloser	Customer Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5		Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5
Component Replacement - Sentinel Lights	Customer Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Conductor Replacement - Overhead	Customer Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate		Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate
Component Replacement - Nest Platforms	Environment Risk	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate		Unexpected / Minor4	Unexpected / Minor4	Unexpected / Minor4	Unexpected / Minor4	Unexpected / Minor4
Component Replacement - Cross arms	Reliability Risk	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4		Very Likely / Minor3	Very Likely / Minor3	Very Likely / Minor3	Very Likely / Minor3	Very Likely / Minor3
Component Replacement - Nest Platforms	Reliability Risk	Medium / Minor4	Medium / Minor4	Medium / Minor4	Medium / Minor4	Medium / Minor4		Unlikely / Minor2	Unlikely / Minor2	Unlikely / Minor2	Unlikely / Minor2	Unlikely / Minor2
Component Replacement - Regulators/ Recloser	Reliability Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5		Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5
Component Replacement - Switches	Reliability Risk	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5		Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4
Component Replacement - Transformers	Reliability Risk	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate		Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5
Conductor Replacement - Overhead	Reliability Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate		Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate

		Baseline Risk Assessment						Residual Risk Assessment				
Sub Description	**Risk Type**	**2018**	**2019**	**2020**	**2021**	**2022**		**2018**	**2019**	**2020**	**2021**	**2022**
Component Replacement - Cross arms	Safety Risk	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate		Unlikely / Moderate	Unlikely / Moderate	Unlikely / Moderate	Unlikely / Moderate	Unlikely / Moderate
Component Replacement - Transformers	Safety Risk	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate		Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5
Conductor Replacement - Overhead	Safety Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate		Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate
Component Replacement - Nest Platforms	Shareholder Value Risk	Likely / Minor4	Likely / Minor4	Likely / Minor4	Likely / Minor4	Likely / Minor4		Unexpected / Minor2	Unexpected / Minor2	Unexpected / Minor2	Unexpected / Minor2	Unexpected / Minor2
ISD-SR-11 - Submarine Cable Replacement Program												
Conductor Replacement - Submarine	Safety Risk	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe		Medium / Severe	Medium / Severe	Medium / Severe	Medium / Severe	Medium / Severe
Conductor Replacement - Submarine	Shareholder Value Risk	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate		Remote / Moderate	Remote / Moderate	Remote / Moderate	Remote / Moderate	Remote / Moderate
ISD-SR-12 - Distribution Lines Sustainment Initiatives												
Large Sustainment Initiatives	Customer Risk	Unlikely / Moderate	Medium / Major	Medium / Major	Medium / Major	Medium / Major		Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1
Small Sustainment Initiatives	Customer Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5		Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1
Large Sustainment Initiatives	Reliability Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Small Sustainment Initiatives	Reliability Risk	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Large Sustainment Initiatives	Safety Risk	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate		Remote / Minor1	Remote / Minor1	Remote / Minor1	Remote / Minor1	Remote / Minor1
Small Sustainment Initiatives	Safety Risk	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate		Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1
Large Sustainment Initiatives	Shareholder Value Risk	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate		Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1
Small Sustainment Initiatives	Shareholder Value Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5		Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1
ISD-SR-13 - Life Cycle Optimization & Operational Efficiency Projects												
Other Lifecycle Optimization Projects	Customer Risk	/	Medium / Minor5	Medium / Minor5	Likely / Minor5	Likely / Minor5		/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Clearwater Bay voltage conversion Phase	Customer Risk	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1		Likely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1
Carleton Place DS Reconstruction	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Manitou Lake DS & Line Work	Customer Risk	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Clearwater Bay voltage conversion Phas	Customer Risk	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1		Likely / Minor1	Likely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1
Margach F3 voltage conversion	Customer Risk	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1		Likely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1

		Baseline Risk Assessment					Residual Risk Assessment				
Sub Description	**Risk Type**	**2018**	**2019**	**2020**	**2021**	**2022**	**2018**	**2019**	**2020**	**2021**	**2022**
St Thomas DS Voltage Conversion	Customer Risk	Medium / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Ridgetown Palmer DS Voltage Conversion	Customer Risk	Medium / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Beaver Valley RS	Customer Risk	Medium / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Medium / Minor5	Remote / Minor5	Remote / Minor5	Remote / Minor5	Remote / Minor5
Dx Coniston Voltage Conversion	Customer Risk	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Hanmer TS Feeder Development	Customer Risk	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Medium / Major	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Burford DS Removal	Customer Risk	Medium / Minor5	Medium / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Defoe DS Voltage Conversion	Customer Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Princeton DS Voltage Conversion	Customer Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Barry's Bay Voltage Conversion	Customer Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Warkworth DS Removal	Customer Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Alexandria Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Newport DS removal via voltage conversion	Customer Risk	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Front DS Voltage Convers	Customer Risk	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dundas Sydenham DS Voltage Conversion	Customer Risk	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Turner DS Voltage Conversion	Customer Risk	Medium / Minor5	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Ormond Voltage Conversion	Customer Risk	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Cleveland DS Voltage Con	Customer Risk	Medium / Minor5	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Allanport DS Voltage Con	Customer Risk	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Forest Jefferson and Mcnab DS Co	Customer Risk	Medium / Minor5	Medium / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Lucan Market DS Conversion	Customer Risk	Medium / Minor5	Medium / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Wallaceburg DS Conversion	Customer Risk	Medium / Minor5	Medium / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Embrun Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Brockville Town Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Smiths Falls Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1

		Baseline Risk Assessment					Residual Risk Assessment				
Sub Description	**Risk Type**	**2018**	**2019**	**2020**	**2021**	**2022**	**2018**	**2019**	**2020**	**2021**	**2022**
Chesterville Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Ivy Lea Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Actons Corners Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Russell Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Maxville Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Kemptville Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Prescott Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Berwick - Finch Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Dresden DS Conversion	Customer Risk	Medium / Minor5	Medium / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Drumbo DS Conversion	Customer Risk	Medium / Minor5	Medium / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Anderdon DS Conversion	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Likely / Minor5	Likely / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Wardsville DS Conversion	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Likely / Minor5	Likely / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Ridgetown DS Conversion	Customer Risk	Medium / Minor5	Medium / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Brookside DS removal	Customer Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Lily Lake DS Removal	Customer Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Other Lifecycle Optimization Projects	Employees Risk	/	Medium / Minor5	Medium / Minor5	Likely / Minor5	Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Beaver Valley RS	Employees Risk	Unlikely / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Unlikely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Other Lifecycle Optimization Projects	Environment Risk	/	Unlikely / Moderate	Unlikely / Moderate	Unlikely / Moderate	Unlikely / Moderate	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
St Thomas DS Voltage Conversion	Environment Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Ridgetown Palmer DS Voltage Conversion	Environment Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Beaver Valley RS	Environment Risk	Unlikely / Major	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Unlikely / Major	Remote / Minor1	Remote / Minor1	Remote / Minor1	Remote / Minor1
Burford DS Removal	Environment Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Princeton DS Voltage Conversion	Environment Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Barry's Bay Voltage Conversion	Environment Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1

		Baseline Risk Assessment					Residual Risk Assessment				
Sub Description	**Risk Type**	**2018**	**2019**	**2020**	**2021**	**2022**	**2018**	**2019**	**2020**	**2021**	**2022**
Warkworth DS Removal	Environment Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Newport DS removal via voltage conversion	Environment Risk	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Front DS Voltage Convers	Environment Risk	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dundas Sydenham DS Voltage Conversion	Environment Risk	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Turner DS Voltage Conversion	Environment Risk	Medium / Minor5	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Ormond Voltage Conversion	Environment Risk	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Cleveland DS Voltage Con	Environment Risk	Medium / Minor5	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Allanport DS Voltage Con	Environment Risk	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Forest Jefferson and Mcnab DS Co	Environment Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Lucan Market DS Conversion	Environment Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Wallaceburg DS Conversion	Environment Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dresden DS Conversion	Environment Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Drumbo DS Conversion	Environment Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Anderdon DS Conversion	Environment Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Wardsville DS Conversion	Environment Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Ridgetown DS Conversion	Environment Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Brookside DS removal	Environment Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Lily Lake DS Removal	Environment Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Other Lifecycle Optimization Projects	Reliability Risk	/	Medium / Minor3	Medium / Minor3	Likely / Minor3	Likely / Minor3	/	Remote / Minor1	Remote / Minor1	Remote / Minor1	Remote / Minor1
Clearwater Bay voltage conversion Phase	Reliability Risk	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1
Carleton Place DS Reconstruction	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Manitou Lake DS & Line Work	Reliability Risk	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Clearwater Bay voltage conversion Phas	Reliability Risk	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Remote / Minor1	Remote / Minor1	Remote / Minor1
Margach F3 voltage conversion	Reliability Risk	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1

		Baseline Risk Assessment					Residual Risk Assessment				
Sub Description	**Risk Type**	**2018**	**2019**	**2020**	**2021**	**2022**	**2018**	**2019**	**2020**	**2021**	**2022**
St Thomas DS Voltage Conversion	Reliability Risk	Medium / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Ridgetown Palmer DS Voltage Conversion	Reliability Risk	Medium / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Beaver Valley RS	Reliability Risk	Likely / Minor2	Very Likely / Minor2	Very Likely / Minor2	Very Likely / Minor2	Very Likely / Minor2	Likely / Minor2	Remote / Minor1	Remote / Minor1	Remote / Minor1	Remote / Minor1
Dx Coniston Voltage Conversion	Reliability Risk	Medium / Minor2	Medium / Minor2	Medium / Minor2	Medium / Minor2	Medium / Minor2	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Hanmer TS Feeder Development	Reliability Risk	Medium / Minor2	Likely / Minor2	Likely / Minor2	Likely / Minor2	Likely / Minor2	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Burford DS Removal	Reliability Risk	Medium / Minor1	Medium / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Defoe DS Voltage Conversion	Reliability Risk	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Princeton DS Voltage Conversion	Reliability Risk	Likely / Minor1	Likely / Minor1	Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Barry's Bay Voltage Conversion	Reliability Risk	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Warkworth DS Removal	Reliability Risk	Likely / Minor3	Likely / Minor3	Likely / Minor3	Likely / Minor3	Likely / Minor3	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Alexandria Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Newport DS removal via voltage conversion	Reliability Risk	Likely / Minor1	Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Front DS Voltage Convers	Reliability Risk	Likely / Minor1	Likely / Minor1	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dundas Sydenham DS Voltage Conversion	Reliability Risk	Likely / Minor1	Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Turner DS Voltage Conversion	Reliability Risk	Medium / Minor1	Likely / Minor1	Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Ormond Voltage Conversion	Reliability Risk	Likely / Minor1	Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Cleveland DS Voltage Con	Reliability Risk	Medium / Minor1	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Allanport DS Voltage Con	Reliability Risk	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Forest Jefferson and Mcnab DS Co	Reliability Risk	Medium / Minor1	Medium / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Lucan Market DS Conversion	Reliability Risk	Medium / Minor1	Medium / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Wallaceburg DS Conversion	Reliability Risk	Medium / Minor1	Medium / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Embrun Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Brockville Town Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Smiths Falls Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1

		Baseline Risk Assessment					Residual Risk Assessment				
Sub Description	**Risk Type**	**2018**	**2019**	**2020**	**2021**	**2022**	**2018**	**2019**	**2020**	**2021**	**2022**
Chesterville Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Ivy Lea Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Actons Corners Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Russell Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Maxville Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Kemptville Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Prescott Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Berwick - Finch Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Dresden DS Conversion	Reliability Risk	Medium / Minor1	Medium / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Drumbo DS Conversion	Reliability Risk	Medium / Minor1	Medium / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Anderdon DS Conversion	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Likely / Minor1	Likely / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Wardsville DS Conversion	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Likely / Minor1	Likely / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Ridgetown DS Conversion	Reliability Risk	Medium / Minor1	Medium / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Brookside DS removal	Reliability Risk	Likely / Minor3	Likely / Minor3	Likely / Minor3	Likely / Minor3	Likely / Minor3	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Lily Lake DS Removal	Reliability Risk	Likely / Minor3	Likely / Minor3	Likely / Minor3	Likely / Minor3	Likely / Minor3	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Other Lifecycle Optimization Projects	Safety Risk	/	Remote / Minor5	Remote / Minor5	Remote / Minor5	Remote / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Other Lifecycle Optimization Projects	Shareholder Value Risk	/	Medium / Major	Medium / Major	Likely / Major	Likely / Major	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Clearwater Bay voltage conversion Phase	Shareholder Value Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Remote / Minor5	Remote / Minor5	Remote / Minor5	Remote / Minor5	Remote / Minor5
Carleton Place DS Reconstruction	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Manitou Lake DS & Line Work	Shareholder Value Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1
Clearwater Bay voltage conversion Phas	Shareholder Value Risk	Medium / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Remote / Minor5	Remote / Minor5	Remote / Minor5
Margach F3 voltage conversion	Shareholder Value Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Beaver Valley RS	Shareholder Value Risk	Unlikely / Major	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Unlikely / Major	Remote / Minor1	Remote / Minor1	Remote / Minor1	Remote / Minor1
Dx Coniston Voltage Conversion	Shareholder Value Risk	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1

		Baseline Risk Assessment					Residual Risk Assessment				
Sub Description	**Risk Type**	**2018**	**2019**	**2020**	**2021**	**2022**	**2018**	**2019**	**2020**	**2021**	**2022**
Hanmer TS Feeder Development	Shareholder Value Risk	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Medium / Major	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Defoe DS Voltage Conversion	Shareholder Value Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Alexandria Area Study	Shareholder Value Risk	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Medium / Major	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Embrun Area Study	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Brockville Town Area Study	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Smiths Falls Area Study	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	Unexpected / Catastrophic	Unexpected / Catastrophic	Unexpected / Catastrophic
Chesterville Area Study	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Ivy Lea Area Study	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Catastrophic	Unexpected / Catastrophic
Actons Corners Area Study	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Russell Area Study	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Maxville Area Study	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Kemptville Area Study	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Prescott Area Study	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Berwick - Finch Area Study	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
ISD-SR-14 - Advanced Meter Infrastructure Hardware Refresh											
AMI Hardware Refresh (EOL)	Shareholder Value Risk	/	/	/	Likely / Major	Likely / Major	/	/	/	Unlikely / Minor5	Unlikely / Minor5

Please note that typically risk mitigation is not realized until the year of in-service or the year following; as a result, any blank residual risk values reflect an investment not yet in-service, while blank baseline risk assessments indicate potential risks that have not yet presented themselves

OEB Staff Interrogatory # 123

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.5 Page: 1966-1967

(5.2.3) Productivity and Continuous Improvement, Section 1.5.1 Productivity Savings in the Plan, Table 17 – Detailed Productivity Savings Forecast

Table 17 – Detailed Productivity Savings Forecast

$Millions	2018	2019	2020	2021	2022
Move to Mobile	10.3	10.5	10.7	10.7	10.7
Procurement	14.2	15.3	19.1	20.2	20.8
Telematics	1.0	1.0	2.4	2.8	3.1
Total Capital	**25.5**	**26.8**	**32.2**	**33.7**	**34.5**
Move to Mobile	2.7	2.8	2.9	2.9	2.9
Operations	20.0	23.1	24.1	25.4	28.0
Procurement	2.2	2.1	2.5	2.7	2.8
Customer Service	1.8	2.6	3.2	4.1	4.8
Telematics	0.8	0.8	1.4	1.3	2.2
Information Technology	7.3	9.3	9.3	9.3	9.3
Total OMA	**34.8**	**40.7**	**43.4**	**45.8**	**50.0**
Procurement	1.8	1.8	1.8	1.8	1.8
Administrative	1.4	1.5	1.5	1.5	1.5
Total Corporate Common	**3.2**	**3.3**	**3.3**	**3.3**	**3.3**
Total Savings	**63.5**	**70.8**	**78.9**	**82.8**	**87.8**

Interrogatory:

a) Please provide the detailed calculations used to derive the projected productivity savings identified in Table 17 above.

b) Please describe how Hydro One will track these savings.

c) What assurances do ratepayers have that Hydro One will achieve these forecast savings?

Response:

a) The updated evidence filed on December 21, 2017 includes an update to Hydro One's productivity savings forecast that has been embedded into the business plan. A more detailed view of the savings initiatives and the associated assumptions used are included in the table below.

	Category in Rate Filing	Initiative Summary	Measurement and Expected Benefit	Updated Savings 2018	2019	2020	2021	2022
Capital	Move to Mobile	Move to Mobile (Field Force)	Measures Labour Hours per Unit - Historical Baseline vs Actual *Plan allocation to expected unit cost savings in New Connections, Joint Use line Relocations, Pole Replacement, Field Meter Service, Component Replacement*	$ 10.3	$ 10.5	$ 10.7	$ 10.7	$ 10.7
Capital	Procurement	Procurement	Lower Cost per Unit - Historical Baseline vs Actual *Savings are estimated at a category level based on historical spend, expected and achieved negotiated savings, and updated per business plan assumptions (Capital program spend)*	$ 12.7	$ 13.2	$ 17.0	$ 16.7	$ 18.6
Capital	Information Technology	ISD Savings	Infrastructure Rationalization/Contract Reductions *Expected capital allocation of negotiated reductions*	$ -	$ 0.3	$ 0.3	$ 0.3	$ 0.3
Capital	Operations	Stations Efficiencies	Cost Reduction based on Historical spend *Expected Capital allocation based on historical spend for OT reductions and Stations efficiencies*	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01
Capital	Telematics	Telematics	Fleet Rationalization - Unit Based Capital Plan Reduction *Estimated by utilizing Telematics data on fleet utilization and then measures the expected unit based reduction in the capital plan*	$ 13.4	$ 10.1	$ 9.8	$ 9.6	$ 9.3
OM&A	Customer	eBilling	Lower Cost per Customer *Expected customers enrolled in eBilling x Unit Savings*	$ 1.8	$ 2.6	$ 3.2	$ 4.1	$ 4.8
OM&A	Information Technology	ISD Savings	Infrastructure Rationalization/Contract Reductions *Expected savings from server/database decommissioning and negotiated infrastructure and application maintenance contract reductions*	$ 7.4	$ 8.3	$ 11.5	$ 11.5	$ 11.5
OM&A	Information Technology	Contract Rates - Minor Enhancement	(Old Rate - New Rate) * Expected ME Hours *Negotiated savings x Expected need for minor enhancement hours in business plan*	$ 0.9	$ 1.0	$ 0.9	$ 0.9	$ 0.9
OM&A	Information Technology	Telecom Services Contracts	Lower Cost per Contract *Reflects negotiated reduction in contract price*	$ 0.6	$ 0.7	$ 0.7	$ 0.7	$ 0.7
OM&A	Move to Mobile	Move to Mobile (Clerical)	FTE Reduction *Reflects expected reduction in 29 back office support staff by 2020*	$ 2.7	$ 2.8	$ 2.9	$ 2.9	$ 2.9
OM&A	Operations	Cable Locate Outsourcing	(Historical Cost - New Cost) * # of Units *Reflects negotiated savings for planned units being outsourced*	$ 7.6	$ 7.8	$ 7.9	$ 8.1	$ 8.2
OM&A	Operations	Fault Indicator Deployment	Lower Labour Hours per Unit *Estimate based on expected time savings for responding to a line fault. Tracked using historical data compared to actual response time*	$ 0.8	$ 0.8	$ 0.8	$ 0.8	$ 0.8
OM&A	Operations	Forestry Initiatives	Lower Cost per KM *Estimated based on reductions in cost due to staff policy for inclement weather and expected overall unit volume reduction in trouble calls*	$ 2.8	$ 4.1	$ 5.9	$ 6.9	$ 7.9
OM&A	Operations	Stations Efficiencies	Cost Reduction based on Historical spend *Expected OM&A allocation based on historical spend for OT reductions and Stations efficiencies*	$ 0.3	$ 0.4	$ 0.4	$ 0.4	$ 0.4
OM&A	Operations	Engineering Work Team Migration	FTE Reduction *A reduction in support staff that was utilizing the legacy software*	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3
OM&A	Operations	Flexible Bill Window	Lower Cost per Unit for Meter Reads *Expected savings from a unit reduction in demand for manual meter reads and lower unit cost due to gained scheduling efficiencies*	$ 1.5	$ 1.5	$ 1.5	$ 1.5	$ 1.5
OM&A	Procurement	Procurement	IT Software Cost Reduction *Reflects expected and negotiated savings*	$ 0.9	$ 1.7	$ 2.6	$ 2.6	$ 2.6
OM&A	Telematics	Telematics	Lower Liters of Fuel per KM *Reflects results of pilot program with expected reduction in Liters of fuel per KM driven*	$ 0.8	$ 0.8	$ 1.4	$ 1.3	$ 2.2
CCC	Administrative	Corporate Common Head Count Reductions	FTE Reduction *Identified headcount reductions by position in Corporate Common*	$ 1.7	$ 1.9	$ 1.9	$ 1.9	$ 1.9
CCC	Procurement	Procurement	Lower Cost *Realized reduction in contracted spend in Corporate Common*	$ 2.3	$ 2.3	$ 2.3	$ 2.3	$ 2.3

		2018	2019	2020	2021	2022
Total	Capital	$ 36.4	$ 34.2	$ 37.8	$ 37.3	$ 39.0
Total	OM&A	$ 29.4	$ 33.7	$ 40.9	$ 42.9	$ 45.5
Total	Corporate Common	$ 4.0	$ 4.2	$ 4.2	$ 4.2	$ 4.2

b) Hydro One's productivity governance and associated reporting processes are maintained by Finance. Hydro One has implemented a robust governance structure around productivity reporting to ensure productivity savings are accurately reflected on corporate scorecards and that there is continuity of savings in the Business Plan.

All productivity initiatives are approved by Finance prior to reporting any actual savings on corporate scorecards and are audited for compliance throughout the year. Approval by Finance ensures that each initiative is tracked using a detailed calculation methodology.

Finance reviews all productivity reporting to ensure each initiative meets the following criteria:

- Consistently documented (detailed description/logic, identified systems/dependencies, clear calculation methodology/data source and reasonable exclusions/adjustments);
- Auditable with an applicable baseline for reporting;
- In line with Hydro One's definition of productivity ('hard' savings and not cost avoidance); and
- Reviewed and approved by a VP or delegate.

Productivity achievement is reported to the Executive Leadership Team on a monthly basis and is included as a metric on Hydro One's Team Scorecard for management staff.

c) Ratepayers are assured through Hydro One's commitment to achieving the forecast savings targets. This commitment is demonstrated by:

i. The enhanced governance and visibility in Hydro One's productivity reporting process;
ii. Incremental productivity savings being identified in the updated evidence filed on December 21st, 2017;
iii. Embedding the forecast savings into the business plan which puts the achievement risk on Hydro One's Net Income and not on the ratepayer;
iv. Including the savings and associated net income targets on the Team scorecard for management staff; and
v. Ratepayers are protected through the Custom Incentive Rate mechanism which allows for increases in OM&A, limited to inflation less productivity. If Hydro One fails to achieve its productivity savings it will not impact customer rates.

Productivity Savings from Staff-123

Productivity Savings Forecast - OM&A

	2018	2019	2020	2021	2022	Total
Total OM&A - As filed	34.8	40.7	43.4	45.8	50	214.7
Total OM&A - Updated	29.4	33.7	40.9	42.9	45.5	192.4
$ Change	5.4	7	2.5	2.9	4.5	22.3
% Change	15.5	17.2	5.8	6.3	9.0	10.4

Productivity Savings Forecast - Capital

	2018	2019	2020	2021	2022	Total
Total Capital - As filed	25.5	26.8	32.2	33.7	34.5	152.7
Total Capital - Updated	36.4	34.2	37.8	37.3	39	184.7
$ Change	-10.9	-7.4	-5.6	-3.6	-4.5	-32
% Change	-42.7	-27.6	-17.4	-10.7	-13.0	-21.0

Productivity Savings Forecast - Corporate Common

	2018	2019	2020	2021	2022	Total
Total Corp Common - As filed	3.2	3.3	3.3	3.3	3.3	16.4
Total Corp Common - Updated	4	4.2	4.2	4.2	4.2	20.8
$ Change	-0.8	-0.9	-0.9	-0.9	-0.9	-4.4
% Change	-25.0	-27.3	-27.3	-27.3	-27.3	-26.8

Productivity Savings Forecast - Total

	2018	2019	2020	2021	2022	Total
Total - As filed	63.5	70.8	78.9	82.8	87.8	383.8
Total - Updated	69.8	72.1	82.9	84.4	88.7	397.9
$ Change	-6.3	-1.3	-4	-1.6	-0.9	-14.1
% Change	-9.9	-1.8	-5.1	-1.9	-1.0	-3.7

$m	2018	2019	2020	2021	2022
Capital-Productivity Savings	36.4	34.2	37.8	37.3	39
Capital Spending Forecast (DSP)	633.9	756.8	719	740.7	827.2
Percentage	5.74	4.52	5.26	5.04	4.71
OM&A-Productivity Savings	29.4	33.7	40.9	42.9	45.5
OM&A Forecast	576.7	593.3	601.9	610.6	630.4
Percentage	5.10	5.68	6.80	7.03	7.22

Source: Capital Spending Forecast Exh B1-1-1, DSP Section 1.1, p. 13, Table 2, OM&A Forecast 2018 E I Tab 38 Sch SEC-70, p. 2, 2019-2022 E A Tab 3 Sch 2, p.6, Table 1

1 EXECUTIVE SUMMARY

1.1 Introduction

The contents of this report represent the results of a comprehensive field assessment of Hydro One's electric distribution system to help determine the optimal vegetation maintenance cycle to reduce the occurrence of electric disruptions caused by vegetation and improve public safety at a reasonable cost.

Hydro One's maintenance cycle exceeds 8 years and was identified in recent program assessments, including an Ontario Energy Board (OEB) report as the key driver of program performance, each recommending the cycle be shortened to improve reliability, public safety, and cost performance.

As a key driver of overall performance, the optimal cycle is at the intersection between cost, defect, and reliability performance over a specified time horizon. The optimum cycle should result in little or no degradation in feeder performance between treatment intervals and before treatment costs begin to escalate.

The assessment was based on a statistically valid representative sampling of system conditions, future expected workload with historical cost and reliability data modeling to determine an appropriate cycle interval.

Conclusions contained in this report are based on a shift from current practices to a defect prevention based vegetation management program:

- *Defects are defined as:*
    - *Vegetation in contact or showing evidence of contact with energized conductors.*
    - *Trees, limbs, or portions thereof that are dead, dying, diseased, decadent, or structurally unsound located within the strike zone of energized conductors.*
- *Defects are a sub-portion of the tree population, most likely to cause a service interruption, or public safety issue and are easiest to identify and control with appropriate maintenance practices.*
- *Defects prevention is priority and the ultimate goal.*

It should be noted that in their current rate application, Hydro One has presented a long-term strategy to reduce system backlog and improve reliability. Although the filed strategy is an improvement on historical programs, the 3 year cycle strategy proposed in this report will generate similar investment outcomes in one third the time.

not take that same approach to the rest of the sample. To the extent there are other distributors in the States that are serving areas that are mostly not being served, that maybe just have small pockets of customers or whatnot. There is no data set that could make a consistent variable to include in the model.

MR. SIDLOFSKY: Thank you for that.

Mr. Chair, I am aware of the time. I am over already. I have one more area which relates to the inflation assumptions underlying the capital plan.

Now, this may be the better panel to deal with it. If the panel tells me that it is better dealt with by the panel addressing the distribution system plan, I can wait for that, as well. Otherwise I would ask for the Board's indulgence for a few moments.

MR. QUESNELLE: Why don't you pose the question and then we will determine whether or not you're coming up after the break. We'll take the break either way, but let's determine that now as to whether this panel can address your questions or not.

MR. SIDLOFSKY: The line of questions here relate to the capital cost inflation that Hydro One factored into the capital expenditures and capital additions to rate base for the custom IR plan.

I will take you to page 24 of the compendium. In the middle of that page, which is from -- it is page 3 of Exhibit A, tab 3, schedule 1. At the middle of the page, there is a section 5.1.1, titled "budgeting assumptions."

And here Hydro One states that for 2018, Hydro One assumed a 2 percent annual inflation and cost escalators for construction, and OM&A expense growth of 2.5 percent and 2.2 percent, respectively. Those assumptions are explained in further detail in section 2.1.2 of the DSP.

Now, this is about 2018, but it doesn't speak to the rest of the plan term, the four years from 2018 to 2022, correct?

MR. LOPEZ: I think I can answer this one. It is consistent across the planning horizon, so we hold it constant.

MR. SIDLOFSKY: Okay. Sorry, that is constant for both capital and OM&A?

MR. LOPEZ: Yes, across all years in the planning horizon.

MR. SIDLOFSKY: Okay. If I can take you to the next page, the last page of the compendium -- and as I mentioned, if I could have the Excel version of that spreadsheet put up, please. Thank you.

As I mentioned before, this spreadsheet was prepared by Board Staff. It doesn't reflect the December update, but as I said, that is not really the point of the spreadsheet for the purpose of these questions.

So the spreadsheet was prepared based on tables on pages 6 to 8 of Exhibit A32, and that pertains to the custom IR plan. It is also based on the table summarizing the customer and load forecasts at an aggregate level from E1, tab 2, schedule 1.

Staff did this because we weren't able to find the capital cost inflation that was assumed and factored into the capex and capital additions beyond 2018. Staff wanted to see what the growth in capex or capital additions relative to the growth in demand would be, and primarily the growth in customers.

Given that, Staff brought together data from the various tables and calculated the growth rates. Where Staff have done those calculations, they are highlighted in the spreadsheet here. Have you had an opportunity to look at these numbers at all?

MR. ANDRE: Yes, I did see this spreadsheet and look at the numbers when you sent them.

MR. SIDLOFSKY: The non-highlighted numbers are taken from your evidence. Can you confirm they are consistent with the values in your evidence?

MR. ANDRE: Yes, I can confirm that.

MR. SIDLOFSKY: Do you have any comments about the calculations shown in the highlighted rows, the Staff calculations?

MR. ANDRE: One thing that I did note is, for example, on the screen it is on row 16 and it is true whenever Staff calculated a percentage change. Our calculation of a percentage change looks at the increase in an amount over the prior year, and then divides that increase by the prior year's amount to come up with a percentage change. That is how the numbers that Hydro One produced were calculated.

I noticed that Board Staff appear to have calculated the percentage change using natural logarithms. I admit I am not a mathematician. I went online to see what the difference might be. It generates slightly different numbers when you calculate it on a natural logarithm basis. So that's what leads to some of the differences that you see.

But other than that, I was able to follow the calculations.

MR. SIDLOFSKY: I am told it was based on a standard logarithm approach. So you're right in the way you read those calculations.

MR. ANDRE: Right. And a percentage increase. I would just point out when Hydro One calculates the increase in capital over related revenue requirement for example, which is the row 7 if we are looking on the screen, and we say the increase in capital-related revenue requirement is 2.84 percent. That's simply the increase in capital divided by the absolute amount in the prior year. That is normally how I would calculate percent increase.

It ends up with a slightly different number if you use a natural logarithm.

MR. SIDLOFSKY: Okay. If I can point you to rows 20 -- excuse me, rows 16 and 13, row 16 shows annual percentage change in the revenue requirement. I won't read those across that row, but row 23 shows annual changes in customer account, so percentage growth in customers. The 2019 growth rate would be 0.67, 0.67 in 2020, 5.07 in 2021, and I assume that due to the integration of the acquired utilities' customers.

MR. ANDRE: That is correct.

MR. SIDLOFSKY: And then back to 0.65 percent in 2022.

MR. QUESNELLE: Mr. Sidlofsky, is it possible to move the screen to the left-hand margin slightly. It is coming up on the large screen, but on our monitors I can't follow the row numbers here.

MR. SIDLOFSKY: Except for 2021, when the acquired utilities are being integrated, the annual percentage change in revenue requirement exceeds the growth in customers, correct?

MR. ANDRE: Yes, that is what the numbers show. The change in the amount shown on line 16 would be the change in revenue requirement including the capital expenditures, right, so including the capital factor. And yes, those numbers are different than the percent change in customer account.

MR. SIDLOFSKY: In fact, if we look at row 29 of that table, the annual percentage change in revenue requirement as adjusted for changes in customer growth are shown, correct?

MR. ANDRE: That's correct. That was the other thing that I did notice when I looked at this spreadsheet. In row 29, you are translating the percent change in customer account to a revenue requirement impact. Implicit in that assumption is that the impact on revenue requirement for us is completely driven by the change in the number of customers.

That assumption isn't correct, Mr. Sidlofsky. We have in our evidence -- in the rate design evidence, we actually have it. It is Exhibit H1, if we could bring that up, H1, tab 1, schedule 1, page 5.

This is the rate design exhibit and it shows how -- what happens to revenue requirement in 2019. The table that you are looking at there -- so column 1, that is our 2018 revenue requirement, 1551; it is the same number we have seen in other tables. And then in column 2, what you see there is the revenue that would be collected in 2019 if you use the 2019 forecast and 2018 rates.

So you can see that the 2018 revenue requirement under current rates collects $1,499,000, million dollars, and the revenue at those same rates but with the '19 forecast actually ends up collecting you only 1,498,000, so when you are looking at the impact on revenue requirement you can't just look at the change in number of customers. You have to look at -- because fixed revenue represents roughly 50 percent of the -- fixed rates, rather, represent about 50 percent of the revenue. We have a significant amount of revenue that comes from our general-service customers that is driven by the change in peak kilowatts, and then we have a significant component that is driven by the kilowatt-hour consumption.

So when you look at the impact on revenue from the 2019 load forecast, it is actually -- it represents a decrease in the revenue that we would be collecting at the 2019 forecast load.

So your assumption, going back to your other spreadsheet that, you know, .67 is the additional revenue that is being generated by the increase in customer count, when you translate that to line 29 and translate that number and sort of make a one-for-one correlation that this increase in customer count translates to an increase in revenue requirement, that is not correct.

MR. SIDLOFSKY: Sorry, just if I could have a moment, sir.

So just moving on from there, in all cases, though, the customer growth adjusted revenue requirements, revenue requirement increases exceed 2 percent.

MR. ANDRE: Yes.

MR. SIDLOFSKY: And from your custom IR proposal OM&A is being adjusted by the I minus X formula, correct?

MR. ANDRE: Yes, that is correct.

MR. SIDLOFSKY: And in your summary model in Exhibit A-3-1, inflation is assumed at 1.90 percent and your X factor inclusive of the stretch factor is .45 percent. So your assumed OM&A inflation is 1.45 percent, correct?

MR. ANDRE: Yes, that is correct.

MR. SIDLOFSKY: The revenue requirements, the sum of OM&A expenses, and the capital-related revenue requirement, that is depreciation, return on capital, associated taxes?

MR. ANDRE: Yes, that is correct.

MR. SIDLOFSKY: And from Table 1 of Exhibit A-3-2 it looks like capital-related revenue requirement might be about 60 percent of the total revenue requirement with OM&A

about 40 percent, roughly?

MR. ANDRE: I haven't done the math, but I will take your word for it.

MR. SIDLOFSKY: Okay. We will even let you check it if you want. You can take it subject to check.

And from Table 1 of Exhibit A-3-2 we have capital-related revenue requirement for 2018 of $915.1 million, with OM&A at 584.8 million. So the rough calculation is about a 60/40 split.

Capital-related revenue requirement increases over time as capital expenditures increase more than -- more so than OMA. Correct?

MR. D'ANDREA: That is correct.

MR. SIDLOFSKY: Okay. Now, if the revenue-requirement increase is above 2 percent and even above two-and-a-half percent year over year for most of the plan and your OM&A at about 40 percent of the revenue requirement is increasing at 1.45 percent, then my understanding is that your capital-relate revenue requirement must be growing at a higher rate. Is that right?

MR. D'ANDREA: On a year-to-year basis, yes, OM&A contributes less than capital does.

MR. SIDLOFSKY: Okay. So would you agree with me that the growth in the capital-related revenue requirement has to be much higher to give the increases in the aggregate revenue requirement, whether it is adjusted for the number of customers or not?

MR. D'ANDREA: Yes.

MR. SIDLOFSKY: Now, the increases in the capital-related revenue requirement or of the capex or capital additions in each year over the plan will reflect both the quantity of work as well as the inflation in capital prices. Correct? That is both for assets like poles and wires and for equipment and capital labour?

MR. D'ANDREA: Yes.

MR. SIDLOFSKY: Now, Staff haven't been able to determine what portion of the cap ex and capital additions are represented by changes in capital quantities or what is due to inflation in the capital prices over time.

Do you have the capital price inflation for each year of your custom IR plan beyond the 2 percent documented for 2018?

MR. D'ANDREA: Mr. Sidlofsky, we believe that information is in the distribution system plan, and I would refer you to panel 5.

MR. SIDLOFSKY: Okay. That probably covers my next question as well, which is whether the capital price inflation is different than the GDP IPI FDD. Would that be panel 5 as well?

MR. D'ANDREA: Yes.

MR. SIDLOFSKY: And, yeah, I think I will leave it at that. Thank you. I will direct the rest of my questions to panel 5. Thank you. And I apologize for the length of time, Mr. Chair.

MR. QUESNELLE: Thank you, Mr. Sidlofsky.

Why don't we take a break. And given that I think

Table 7: Revenue Requirement ($ Millions)

Components	2017[1]	2018	Reference
OM&A	593.0	584.8	Exhibit C1, Tab 1, Schedule1
Depreciation and Amortization	390.2	392.6	Exhibit C1, Tab 6, Schedule 1
Income Taxes	48.7	61.5	Exhibit C1, Tab 7, Schedule 1
Return on Capital	435.8	461.1	Exhibit D1, Tab 2, Schedule 1
Total Revenue Requirement	**1,467.6**	**1,499.9**	Exhibit E2, Tab 1, Schedule 1
Deduct External Revenues and Other	(52.7)	(53.6)	Exhibit E1, Tab 1, Schedule 2
Rates Revenue Requirement	**1,414.9**	**1,446.3**	
Regulatory Deferral and Variance Accounts Disposition	11.1	6.2	Exhibit F1, Tab 2, Schedule 1, Attachment 1
Rates Revenue Requirement (with Deferral and Variance Accounts)	**1,426.0**	**1,452.4**	

Exhibit Reference: E1-1-1

Note 1: The 2017 revenue requirement is from the OEB approved Hydro One Distribution's 2015 to 2017 rate application in EB-2013-0416

The increase in revenue requirement is largely attributable to the impact of rate base growth, as reflected in the increase in depreciation, return on capital, income tax expenses and lower external revenue forecast as described in Exhibit E1, Tab 1, Schedule 2. These are partially offset by a lower cost of debt and lower OM&A costs.

5.1.1 BUDGETING ASSUMPTIONS

For 2018, Hydro One assumed 2.0% annual inflation and cost escalators for construction and OM&A expense growth of 2.5% and 2.2%, respectively. These assumptions are explained in further detail in Section 2.1.2 of the DSP. Hydro One adopted the US GAAP accounting standard for regulatory purposes, based on the OEB's Decision with Reasons in EB-2011-0268.

5.1.2 LOAD FORECAST SUMMARY

Table 8 sets out Hydro One's 2018-2022 distribution system load forecast, which includes the impact of conservation and demand management and embedded generation.

2.1.2.2 ECONOMIC OUTLOOK

Distribution Cost Escalation for Construction, Operations & Maintenance

Hydro One utilized the HIS Global Insight’s “Distribution Cost Escalators for Construction, Operations & Maintenance” presented in Table 31 below to forecast expenditure level changes for distribution materials and services. These escalators provide a broad average measure of the industry-wide yearly price changes by tracking a representative basket of equipment and labour comprised of: operation, supervision and engineering, load dispatching, stations, lines, meters, customer installations, maintenance, structures, overhead lines, underground lines, line transformers, and miscellaneous.

Table 31 - IHS Global Insight's June 2016 Forecast

%	Historical Years					Bridge Year	Test Years				
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Distribution Cost Escalation for Construction	2.9	3.5	2.9	2.5	-0.4	1.8	2.5	3.0	3.0	3.0	2.9
Distribution Cost Escalation for Operations & Maintenance	2.3	0.8	0.7	-0.8	-0.7	1.6	2.2	2.4	2.3	2.2	2.0

Consumer Price Index

Hydro One, as an Ontario based distributor, has relied on the Ontario Consumer Price Index (“CPI”) presented in Table 32 for its assumptions about inflation and costs. The CPI, published by Statistics Canada, provides a broad measure of the cost of living. Through the monthly CPI, Statistics Canada tracks the change in the retail price of a

The OM&A (line 9) provided for each year in Table 1 is determined based on the 2018 forecast provided in the Application and increased by the Inflation Factor ("I") and reduced by the proposed Productivity Factor ("X"), for a total increase of 1.45% per annum.

Table 1: Summary of Revenue Requirement Components ($ Million)

Line		Reference	2018	2019	2020	2021	2022
1	Rate Base	D1-1-1	7,671.6	8,049.8	8,477.9	9,036.5	9,436.6
2	Return on Debt	E1-1-1	191.6	201.1	211.8	225.7	235.7
3	Return on Equity	E1-1-1	269.4	282.7	297.7	317.4	331.4
4	Depreciation	C1-6-2	392.6	413.5	428.6	448.1	463.0
5	Income Taxes	C1-7-2	61.5	64.7	66.4	72.7	72.7
6	Capital Related Revenue Requirement		915.1	962.0	1,004.5	1,063.9	1,102.8
7	Less Productivity Factor (0.45%)			(4.3)	(4.5)	(4.8)	(5.0)
8	**Total Capital Related Revenue Requirement**		**915.1**	**957.7**	**1,000.0**	**1,059.1**	**1,097.8**
9	OM&A	C1-1-1	584.8	593.3	601.9	610.6	630.4
10	Integration of Acquired Utilities	A-7-1				10.7	
11	**Total Revenue Requirement**		**1,499.9**	**1,551.0**	**1,601.9**	**1,680.4**	**1,728.2**
12	Increase in Capital Related Revenue Requirement			42.6	42.3	59.1	38.8
13	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			2.84%	2.73%	3.69%	2.31%
14	Less Capital Related Revenue Requirement in I-X			0.88%	0.90%	0.91%	0.91%
15	**Capital Factor**			**1.96%**	**1.83%**	**2.78%**	**1.39%**

The 2018 Total Revenue Requirement of $1,499.9 million (line 11) is determined based on a forward test year, cost of service approach and is the rebasing year for this Application.

In 2019, the Capital Related Revenue Requirement (line 6) increases to $962.0 million versus $915.1 million in 2018. Hydro One will reduce the Capital Related Revenue Requirement (line 6) by the proposed Productivity Factor of 0.45% or $4.3 million (line 7), such that the Total Capital Related Revenue Requirement is $957.7 million (line 8). The change in Total Capital Related Revenue Requirement (line 8) in 2019 versus 2018 is $42.6 million (line 12). This difference is equal to 2.84% of the 2018 Total Revenue Requirement of $1,499.9 million ($42.6 million divided by $1,499.9 million).

The 2.84% increase in Total Capital Related Revenue Requirement is the total increase in revenue requirement arising from the higher 2019 Capital Related Revenue Requirement (line 6). However, the 2.84% increase must be offset by the increase in revenue requirement that results from the application of the Inflation and Productivity Factors (I - X) of the RCI. This is done by determining the percentage of the Total Capital Related Revenue Requirement (line 8) that is already provided for by the Inflation and Productivity Factors. In 2019, this equals 0.88% ($915.1 million x 1.45% / $1,499.9 million). The net result of 1.96% (2.84% less 0.88%) is the 2019 Custom Capital Factor. The calculation of the Custom Capital Factor for each of 2020 through 2022 is the same, as set out in Table 1 above.

1.4 REVENUE CAP INDEX SUMMARY

Table 2 below summarizes the Custom Revenue Cap Index by Component that Hydro One is proposing to use in this Application to determine Total Revenue Requirement for rate-making purposes for 2019 through 2022.

Table 2: Custom Cap Index (RCI) by Component (%)

Custom Revenue Cap Index by Component	2019	2020	2021	2022
Inflation Factor (I)	1.90	1.90	1.90	1.90
Productivity Factor (X)	-0.45	-0.45	-0.45	-0.45
Capital Factor (C)	1.96	1.83	2.78	1.39
Custom Revenue Cap Index Total	3.41	3.28	4.23	2.84

Table 3 below summarizes the Total Revenue Requirement that would result from the Board's approval of Hydro One's Custom IR, were the Application to be approved as filed.

Table 3: Revenue Requirement by Year

Year	Formula	Revenue Requirement
2018	Cost of Service	$1,499.9 million
2019	2018 Revenue Requirement x 1.0336	$1,551.0 million
2020	2019 Revenue Requirement x 1.0328	$1,601.9 million
2021*	2020 Revenue Requirement x 1.0423 + 10.7M	$1,680.4 million
2022	2021 Revenue Requirement x 1.0284	$1,728.2 million

*Hydro One is proposing to update the 2021 Total Revenue Requirement with updated cost of capital parameters.

1.5 INTEGRATION OF ACQUIRED UTILITIES

Since its last rebasing application, Hydro One has acquired Norfolk, Haldimand and Woodstock. Consistent with the Board's Mergers, Acquisitions, Amalgamations, and Divestitures ("MAADs") Decisions and ratemaking policies, the Acquired Utilities are currently separate from Hydro One for rate-making purposes. As outlined in Exhibit A, Tab 7, Schedule 1, Hydro One proposes to integrate the Acquired Utilities effective January 1, 2021. As set out in Exhibit G1, Tab 2, Schedule 1, Hydro One will introduce six new rate classes at that time.

Consistent with the Board's MAADs policies, the financial information and the associated revenue requirement relating to the Acquired Utilities have been excluded from Hydro One's financial information for the test years prior to 2021. For the 2021 and 2022 test years, all financial information presented in this Application includes costs relating to both Hydro One and the Acquired Utilities.

This means that the gross fixed assets and accumulated depreciation of the rate base of the Acquired Utilities has been added to the opening balance of Hydro One's gross fixed assets and accumulated depreciation, respectively, effective January 1, 2021. The resulting increase in rate base of $168.4 million (Exhibit D1, Tab 1, Schedule 1) and capital expenditures is reflected in lines 1 through 6 of Table 1 above and captured as part

Table 2: Custom Cap Index (RCI) by Component (%) + lines 13 and 14 of Table 1: Summary of Revenue Requirement Components

Custom Revenue Cap Index by Component		**2018**	**2019**	**2020**	**2021**	**2022**	Exhibit A/3/2/page 7 (updated 2017-06-07)
Inflation Factor (I)	(I)		1.90%	1.90%	1.90%	1.90%	
Productivity Factor (X)	(X)		0.45%	0.45%	0.45%	0.45%	
Increase in Capital Related Revenue Requirement	(CRRR)		2.84%	2.73%	3.69%	2.31%	Exhibit A/3/2/page 6 (updated 2017-06-07)
Less Capital Related Revenue Requirement in I -X			0.88%	0.90%	0.91%	0.91%	Lines 13 and 14
Capital Factor (C)	(C)		1.96%	1.83%	2.78%	1.39%	
Revenue Cap Index (RCI) = I - X + C	(RCI)		3.41%	3.28%	4.23%	2.84%	

Table 3: Revenue Requirement by Year

		2018	**2019**	**2020**	**2021**	**2022**	Exhibit A/3/2/page 8 (updated 2017-06-07)
Revenue Requirement ($M)	(RR)	1499.9	1551	1601.9	1680.4	1728.2	
Annual % change in revenue requirement	(ΔRR)		3.35%	3.23%	4.78%	2.80%	

Table 3: Hydro One Distribution Load and Number of Customers

Exhibit E1/2/1/page 5 (updated 2017-06-07)

Year		**2018**	**2019**	**2020**	**2021**	**2022**
GWh Delivery Forecast		36,019	35,680	35,673	36,363	36,373
Distribution Customer Count		1,300,516	1,309,216	1,317,967	1,386,522	1,395,578
Annual % change in customer count	(g)		0.67%	0.67%	5.07%	0.65%
Capital Related Revenue Requirement adjusted for customer growth	(1+CRRR)/(1+g)-1		2.16%	2.05%	-1.31%	1.65%
Capital Factor adjusted for customer growth	(1+C)/(1+g)-1		1.28%	1.16%	-2.18%	0.73%
Revenue Cap Index adjusted for customer growth	(1+RCI)/(1+g)-1		2.73%	2.60%	-0.80%	2.17%
Revenue Requirement % change adjusted for customer growth	(1+ΔRR)/(1+g)-1		2.67%	2.55%	-0.27%	2.14%

OEB Staff Interrogatory # 73

Issue:

Issue 21: Does the application adequately account for productivity gains in its forecasts and adequately include expectations for gains relative to external benchmarks?

Reference:

B1-01-01 Section 1.5 Page: 7

Interrogatory:

Labour Optimization is planned to "optimize the number of high-skilled regular work staff to the level required to complete core work programs."

a) How many 'high-skilled' regular work staff does Hydro One employ?

b) How many 'high-skilled' regular work staff does Hydro One expect to employ in 2022?

c) To what extent does Hydro One expect this will impact recovery times from a potential major weather event with significant forestry effort requirements?

d) What steps is Hydro One taking to manage impacts to recovery times?

Response:

a) In response to this question, "highly skilled" employees are trades and technical employees who work in the core operations of Hydro One's distribution business. There are approximately 1,700 regular employees who would be considered highly skilled.

b) Hydro One anticipates that the number of regular skilled employees will remain constant up to the year 2022.

c) There will be no negative impacts. Hydro One remains mindful of recovery times and committed to improving current response times and reliability statistics.

d) To ensure there are no negative impacts, Hydro One is looking for operational enhancements in the following areas:
    - Crew alignment/resourcing structure (single person trouble crew, field business centre consolidation); and

- Technology/grid modernization (communicating line indicators, communicating line reclosers, remote operated switches).

Prior to operationalizing these enhancements, Hydro One is completing detailed assessments including pilots with localized implementation to ensure positive results. Once proven, Hydro One will look to implement them throughout its business and drive positive results.

OEB Staff Interrogatory # 204

Issue:

Issue 40: Are the proposed 2018 human resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate (excluding executive compensation)?

Reference:

C1-02-01 Page: 9

Interrogatory:

Table 1 shows Full Time Equivalents from 2017 to 2022 for various employee categories. For 2017 the number of Casual employees is 2802 or about 33% of the total FTEs. This ratio remains the same for 2022.

a) Does Hydro One consider the 33% ratio to be optimal in terms of casual employees?

b) Will the percentage of Casual employees be increased into the 2019 – 2022 period?

Response:

a) Hydro One does consider this ratio to be an effective use of casual resources. The use of the PWU Hiring Hall is not to replace the regular workforce but rather to enable Hydro One to supplement the regular workforce with mobile and flexible workers to perform seasonal and supplemental trades work. Hiring Hall employees are used mainly for specific skills while the regular trade employees use their multi skilled training to perform more complex work. The other category of casual employees, casual construction, perform work based on their scope clauses.

b) Please refer to Table 1 in Exhibit C1 Tab 2 Schedule 1 (page 9). There is a slight increase in the PWU Hiring Hall classification, and the casual construction resource level remains constant.

OEB Staff Interrogatory # 205

Issue:

Issue 40: Are the proposed 2018 human resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate (excluding executive compensation)?

Reference:

C1-02-01 Page: 9

Interrogatory:

Has Hydro One conducted a Staffing study to compare its staffing levels to other distributors and determine the optimal staffing level for its operations?

If so, please file this study or studies, and provide a rationale for current and planned staffing numbers. If not, why not?

Response:

Hydro One has not conducted such a study. The regular and total FTE count is declining over the 2017-2022 period and, as such, it has not been a priority for Hydro One to conduct a broad and likely expensive staffing study.

OEB Staff Interrogatory # 206

Issue:

Issue 40: Are the proposed 2018 human resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate (excluding executive compensation)?

Reference:

C1-02-01 Page: 11-13

Interrogatory:

On these pages Hydro One summarizes efforts underway to manage the total FTE complement and increase efficiency.

Please provide the estimated savings for each initiative for the 2018 test year and future years, under the various categories: Construction (flexible workforce); Engineering (standardized processes, organizational alignment, external resources); Lines (consolidation of first line managers, outsourcing, Move to Mobile and planning for Pole Replacements); Forestry (efficiency initiatives and the "Muskoka Project"); and Stations Maintenance (temporary workforce and new scheduling tool).

Response:

The evidence referenced in C1-02-01 pages 11-13 describes the strategies and process changes Hydro One is employing to gain efficiencies in order to execute on an increasing work plan with a relatively stable FTE compliment. The strategies described in each of the work programs have not been quantified as 'savings' by Hydro One.

Any related savings opportunities that have been quantified and tracked are described in detail in Exhibit I-25-Staff-123.

that can be safely and efficiently planned and managed by internal staff. The current staffing strategy shows a flat regular staffing complement with a plan to utilize a combination of internal resources, engineering subcontracts, construction contracts or arrangements contracted on a fixed-price basis to execute the growth in the work program. This allows Hydro One to grow safely and acquire new capabilities quickly, while maintaining its flexibility to provide the best value to our customers.

Engineering

Hydro One is working to complete both an increasing volume of engineering work as well as advancing engineering deliverables earlier in the project lifecycle to create an intentional backlog of construction-ready projects. Despite substantially growing capital work programs, Hydro One regular staff accountable for Engineering has decreased in recent years and is anticipated to remain generally flat in the coming years.

Improved organizational alignment of different engineering functions has enabled more integrated solutions across project definition and project execution phases, and Hydro One has made a number of process and organizational improvements resulting in increased output from the engineering group. Substantial work has been done to standardize engineering processes and design packages, resulting in improved on-time delivery rates and overall project cost effectiveness. Engineering prepares the technical specifications that feed external Engineering, and acts as Owner’s Engineer to ensure quality and compliance.

Resources to deliver on the growing future capital work programs is planned to be achieved through increased utilization of external engineering partners, coupled with continuous improvement of internal processes. The portion of the engineering portfolio completed externally has continued to grow over recent years, from roughly 14% in 2012 to roughly 25% in 2016, and is anticipated to reach approximately 30% through 2018.

Lines

In early 2016 Provincial Lines consolidated all Technical First Line Managers (FLMs), Supervising Technicians, Meter Technicians, Area Distribution Engineering Technicians and Meter Reader Data Collectors into one technical organization. The creation of this new more focused group ensured that resources are optimized across all the zones and that roles and responsibilities for all are clear and consistent. Provincial Lines moved all distribution project crews and apprentice crews into a single newly created zone. The purpose of this reorganization was to ensure consistent and optimum utilization of hiring hall project crews. It also allowed for more focus on apprentice development.

Outsourcing work has also provided opportunities for resource optimization by ensuring skilled internal resources are available for work programs that better align with qualifications.

Additionally, two key initiatives planned over the test period are expected to positively impact performance: Move to Mobile and the Pole Replacement Program.

The use of innovative technology, being implemented through the Move to Mobile (M2M) project, will enable real time completion and verification of data, reducing administrative office effort and increase field productivity through geographic based auto-scheduling.

The Pole Replacement program focuses on two aspects of planning. The first is to strategically select poles to be replaced based on priority and selection criteria and align this with Forestry's annual trimming cycle. The second is to bundle poles that are nearing end of life or showing premature signs of decay on the same feeder.

Forestry

While the Forestry work program increases significantly throughout the planning period, the core philosophy is to perform more work for the dollars spent. This will be accomplished by maximizing the current Forestry efficiency initiatives (e.g., the Muskoka Project) as well as looking at further opportunities to utilize mechanical crews and resource mix to continue to perform more work for the same dollars.

Stations Maintenance

The overall Stations Work Program is increasing over 2016 levels. The increases are primarily the result of the need to ramp up the PCB testing and retro-fill programs. These programs must be completed by 2025. Maintenance programs outside of the PCB program are essentially flat in Distribution. Stations is managing this by increasing its temporary workforce over the planning period while at the same time reducing its regular workforce to recognize the fact that when the PCB program is completed the overall program will be smaller in size than it is today and efficiency improvements will occur in planning, scheduling and execution.

Stations is planning to introduce a new scheduling tool in 2017 which will allow it to more effectively plan and schedule its work with greater efficiency than currently exists.

7. RECRUITMENT

Hydro One continues to hire, albeit at a lesser level than previous years, into its Apprentice and Graduate Training Programs to help address the significant wave of retirements in its critical trades, technical and engineering groups.

Since January 1, 2004, 473 graduate trainees have been hired through the Company's on-campus recruitment program. Not only do new graduates bring much needed skills but

3.2 (5.4.1 B) CAPITAL EXPENDITURE FORECAST

Table 54 - Historical and Bridge Year Capital Expenditure Summary

Category	Historical and Bridge (previous plan and actual)										
	2013*	2014*	2015			2016			2017 Bridge		
	Actual	Actual	Plan	Actual	Var	Plan	Actual	Var	Plan	Forecast	Var
	$M	$M	$M	$M	%	$M	$M	%	$M	$M	%
System Access	159.5	199.4	183.3	188.1	2.6	182.6	179.0	(1.9)	176.1	168.3	(4.4)
System Renewal	265.7	262.7	250.7	308.4	23.0	265.4	291.2	9.7	285.0	252.2	(11.5)
System Service	96.5	85.5	120.1	71.6	(40.4)	103.3	76.8	(25.7)	110.1	66.6	(39.5)
General Plant	115.3	99.9	94.8	110.1	16.2	103.3	156.3	51.2	90.1	146.3	62.3
Total	637.0	647.5	648.9	678.3	4.5	654.7	703.2	7.4	661.4	633.5	(4.2)
System OM&A**	610.6	674.5	543.1	572.5	5.4	589.1	583.6	(0.9)	593.0	580.5	(2.1)

** 2013 and 2014 were IRM years and therefore do not have Board-approved capital expenditure figures.*

*** System OM&A values include all Operations, Maintenance and Administration expenses.*

3.2 (5.4.1 B) CAPITAL EXPENDITURE FORECAST

Table 54 - Historical and Bridge Year Capital Expenditure Summary

Category	Historical and Bridge (previous plan and actual)										
	2013*	2014*	2015			2016			2017 Bridge		
	Actual	Actual	Plan	Actual	Var	Plan	Actual	Var	Plan	Forecast	Var
	$M	$M	$M	$M	%	$M	$M	%	$M	$M	%
System Access	159.5	199.4	183.3	188.1	2.6	182.6	182.7	0.0	176.1	168.3	(4.4)
System Renewal	265.7	262.7	250.7	308.4	23.0	265.4	288.3	8.6	285.0	252.2	(11.5)
System Service	96.5	85.5	120.1	71.6	(40.4)	103.3	77.4	(25.1)	110.1	66.6	(39.5)
General Plant	115.3	99.9	94.8	110.1	16.2	103.3	145.9	41.2	90.1	146.3	62.3
Total	637.0	647.5	648.9	678.3	4.5	654.7	694.2	6.0	661.4	633.5	(4.2)
System OM&A**	610.6	674.5	543.1	572.5	5.4	589.1	562.6	(4.5)	593.0	572.8	(3.4)

** 2013 and 2014 were IRM years and therefore do not have Board-approved capital expenditure figures.*

*** System OM&A values include all Operations, Maintenance and Administration expenses.*

Response:

a) [C1-1-1] Tables 1

Table 1: Summary of Recoverable OM&A Expenses ($ Millions)

Description	Historic					Bridge		Test
	2014 IRM	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Actual	Approved	Forecast
Sustainment	325.7	304.6	316.5	323.7	361.4	304.7	367.1	346.7
Development	11.0	10.9	15.4	11.9	17.8	8.8	17.0	11.0
Operations	29.5	27.6	35.8	31.5	39.4	31.9	37.5	36.7
Customer Care	209.3	155.4	111.7	118.8	110.9	123.4	111.6	128.7
Common Corporate Costs and Other	94.4	69.1	59.0	72.0	54.8	84.9	54.7	53.9
Property Taxes & Rights Payments	4.6	4.8	4.7	4.6	4.9	5.0	5.0	4.9
Total	**674.5**	**572.5**	**543.1**	**562.6**	**589.1**	**558.7**	**593.0**	**576.7**
% Change (year-over-year)		*-15.1%*	*-19.5%*	*-1.7%*	*8.5%*	*-0.7%*	*0.7%*	*2.1%*
% Change (Test vs. 2016 Actual)						*-0.7%*		*2.5%*

"Approved" figures reflect OEB-directed reductions to Sustainment OM&A and Common Corporate Costs and Other OM&A line items (specifically, budgets for vegetation management, LEAP funding, and compensation).

b) [C1-1-2] Tables 1-5

Please see Exhibit I-38-AMPCO-037.

c) [C1-1-3] Table 1

Table 1: Summary of Development OM&A ($ Millions)

Description	Historic					Bridge		Test
	2014	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Actual	Approved	Forecast
Engineering and Technical Studies	4.0	3.8	4.7	4.2	4.7	3.5	4.7	1.7
Distributed Generation Connections	2.6	2.5	2.2	2.5	2.0	2.6	2.0	2.9
Distribution Standards Program	3.9	3.4	5.6	3.3	5.8	0.9	6.0	4.5
Research Development and Demonstration*	0.4	1.2	2.9	1.8	5.2	1.7	4.3	1.6

OEB Staff Interrogatory # 187

Issue:

Issue 38: Are the proposed OM&A spending levels for Sustainment, Development, Operations, Customer Care, Common Corporate and Property Taxes and Rights Payments, appropriate, including consideration of factors considered in the Distribution System Plan?

Reference:

C1-01-02 Page: 6

Interrogatory:

Table 2 shows that under the Planned Preventative Station Maintenance category, in all years from 2015 to 2017, Hydro One has consistently underspent OEB approved funding levels.

a) What are the major reasons that spending was curtailed from planned levels?

b) Did Hydro One consider the impact on reliability and that more spending would be required in future years to address station maintenance issues?

Response:

a) For the Planned Preventive Station Maintenance program, Hydro One distribution made a decision to change the preventive maintenance strategy on power equipment from primarily time based to a combination of time-based and condition-based. The change in strategy has resulted in a reduction in expenditures.

b) Yes, the reliability impacts were considered, and this change is not expected to have a material impact on reliability. This preventative maintenance strategy is not expected to increase future year expenditures.

OEB Staff Interrogatory # 188

Issue:

Issue 38: Are the proposed OM&A spending levels for Sustainment, Development, Operations, Customer Care, Common Corporate and Property Taxes and Rights Payments, appropriate, including consideration of factors considered in the Distribution System Plan?

Reference:

C1-01-02 Page: 14

Interrogatory:

Table 3 shows that there is underspending for Line Maintenance consistently from 2015 to 2017.

a) What are the major reasons that spending was curtailed from planned levels?

b) Did Hydro One consider the impact on reliability and that more spending would be required in future years to address line maintenance issues?

c) In the same table, Trouble Calls spending is higher than approved levels in all years and 2018 shows a 15% increase from 2017 approved levels. Please comment on the extent the Trouble Calls spending is driven by the underspending in Line Maintenance in previous years.

Response:

a) A 2015 review of the Line Regulator and Recloser Maintenance program led to a shift from maintenance to capital refurbishments, resulting in a $3.5 million maintenance underspend relative to previously approved amounts for Line Maintenance in each year from 2015 to 2017. Additionally, the overall sustainment OM&A (including Line Maintenance) was strategically reduced as discussed on page 5 in Exhibit C1, Tab 1, Schedule 1.

b) Yes.

c) The Trouble Call program is forecasted based on historic spending. The increases in trouble spending forecasts are not directly attributable to the decrease in Line Maintenance spending. However, the Lines Maintenance funding could be impacted by the redirection process as outlined in Exhibit B1, Tab 1, Schedule 1, DSP Section 2.1.6.4.

OEB Staff Interrogatory # 192

Issue:

Issue 38: Are the proposed OM&A spending levels for Sustainment, Development, Operations, Customer Care, Common Corporate and Property Taxes and Rights Payments, appropriate, including consideration of factors considered in the Distribution System Plan?

Reference:

C1-01-02 Page: 20

Interrogatory:

Table 3 shows that there is consistent underspending (from approved levels) for PCB Equipment and Waste Storage from 2015 to 2017.

a) What are the major reasons that spending was curtailed from planned levels?

b) Did Hydro One consider the environmental impact of this lower than planned spending?

c) If so, what was the rationale for the reduced spending?

d) Hydro One also states, on page 20 that proposed spending for the 2018 test year is based on an expected volume of 27,595 PCB Inspections and Testing per year. Please provide a table showing the number of PCB Inspections and Testing per year from 2012 to 2017.

e) Please comment on the trend of the cost per Inspection/Test per year.

Response:

a) Spending was redirected to higher priority investments.

b) Investments that could cause an environmental impact remained funded.

c) Reduced spending was a result of fewer PCB Inspections and Testing being completed.

d) Please see table below for the number of oil-filled distribution line equipment that received PCB Inspections and Testing from 2014 to 2017. The program did not exist in 2012 and 2013.

	2014	**2015**	**2016**	**2017**
PCB Inspections	2,113	13,156	24,558	9,157
PCB Testing	599	1,131	2,831	10,571
Total	**2,712**	**14,287**	**27,389**	**19,728**

e) The trend of the cost per Inspection/Test per year has increased over the 2014 to 2017 period.

OEB Staff Interrogatory # 189

Issue:

Issue 38: Are the proposed OM&A spending levels for Sustainment, Development, Operations, Customer Care, Common Corporate and Property Taxes and Rights Payments, appropriate, including consideration of factors considered in the Distribution System Plan?

Reference:

C1-01-02 Page: 15

Interrogatory:

Hydro One's evidence shows that proposed spending for the 2018 test year is based on an expected volume of trouble calls of 42,645 per year.

a) Please provide a table showing the number of trouble calls per year from 2012 to 2017.

b) Please comment on the trend of the cost per trouble call per year.

Response:

a) Please see table below for the volumes of trouble calls received per year from 2012 to 2017.

2012	2013	2014	2015	2016	2017
44,051	43,038	42,643	43,972	43,939	40,147

b) There is no significant trend of the cost per trouble call per year.

OEB Staff Interrogatory # 190

Issue:

Issue 38: Are the proposed OM&A spending levels for Sustainment, Development, Operations, Customer Care, Common Corporate and Property Taxes and Rights Payments, appropriate, including consideration of factors considered in the Distribution System Plan?

Reference:

C1-01-02 Page: 16

Interrogatory:

With regard to Disconnects/Reconnects, Hydro One's evidence shows that proposed spending for the 2018 test year is based on an expected volume of 14,250 Disconnect/Reconnect calls per year.

a) Please provide a table showing the number of Disconnect/Reconnect calls per year from 2012 to 2017.

b) Please comment on the trend of the cost per Disconnect/Reconnect per year.

c) Hydro One also indicates on page 17 that the numbers of service Disconnect/Reconnect requests have increased over the past several years. Has Hydro One determined why this is the case?

Response:

a) Please see table below for the number of Disconnect/Reconnect received per year (for isolating customer owned assets from the distribution system) from 2012 to 2017.

2012	2013	2014	2015	2016	2017
13,398	14,358	15,836	14,553	15,257	15,249

b) The trend of the cost per Disconnect/Reconnect (for isolating customer owned assets from the distribution system) has increased over the 2012 to 2017 period.

c) No, it is not clear why the number of service Disconnect/Reconnect requests (for isolating customer owned assets from the distribution system) have increased over the past several years. It could be due to better customer safety awareness.

OEB Staff Interrogatory # 191

Issue:

Issue 38: Are the proposed OM&A spending levels for Sustainment, Development, Operations, Customer Care, Common Corporate and Property Taxes and Rights Payments, appropriate, including consideration of factors considered in the Distribution System Plan?

Reference:

C1-01-02 Page: 18

Interrogatory:

Under Maintenance, Hydro One states that proposed spending for the 2018 test year is based on an expected volume of 9,210 defect corrections per year.

a) Please provide a table showing the number of defect corrections per year from 2012 to 2017.

b) Please comment on the trend of the cost per defect correction per year.

c) Hydro One also indicates on page 19 that it expects an increase in the level of defect corrections. Has Hydro One determined why defect corrections are on the rise?

Response:

a) Please see table below for the number of defect corrections per year from 2012 to 2017.

2012	2013	2014	2015	2016	2017
7,859	8,548	5,354	9,286	16,095	7,050

b) The defect correction unit price has been decreasing between 2012 and 2017 at an average rate of $32 per year.

c) The level of defect corrections is increasing in order to address a number of already identified defects in the system. Hydro One does not anticipate an increase in the number of defects identified per year over the five year plan.

OEB Staff Interrogatory # 194

Issue:

Issue 38: Are the proposed OM&A spending levels for Sustainment, Development, Operations, Customer Care, Common Corporate and Property Taxes and Rights Payments, appropriate, including consideration of factors considered in the Distribution System Plan?

Reference:

C1-01-02 Page: 29

Interrogatory:

Table 5 again shows that Vegetation Management spending in each of the 2015, 2016 and 2017 years is below OEB approved levels. Yet, Hydro One's evidence refers to a backlog of maintenance.

a) If Hydro One was aware of backlogs in vegetation management, why did it not at least spend to the approved levels?

b) To what extent is the demonstrated underspending on Vegetation Management contributing to the increase in 2018 levels of <u>Demand</u> Vegetation Management to $10.2 million well above the OEB approved levels of $6.8 million and $6.9 million for 2016 and 2017 respectively?

c) Please provide a table showing the km of Line Cleared and km of Line Brush Control (as in past applications) per year from 2012 to 2017.

d) Please comment on the trend of the cost per km of Line Cleared and km of Line Brush Control and also indicate how its three changes for the Vegetation Management program as noted on page 28, will contribute to lower costs in 2018 and beyond.

Response:

a) Please refer to interrogatory response Exhibit I-38-Staff-186 for an explanation of program underspending.

b) Demand maintenance is driven by poor vegetation conditions created partly by backlogged maintenance. However, increases in demand maintenance are being magnified by a change in approach focused on improving customer relationship, and emergent forest health issues like the emerald ash borer, beech bark disease and spruce budworm outbreaks which are having regional impacts on our system.

c) Please refer to table below for the Line Cleared and Line Brush Control kilometers for the period 2012 to 2016.

Program	2012	2013	2014	2015	2016
Brush Control	11,557 km	10,448 km	6,177 km	3,497 km	14,031 km
Line Clearing	11,195 km	10,378 km	9,474 km	10,366 km	11,753 km

As described in Table 5 of Exhibit C1 Tab 1 Schedule 2, the line clearing and brush control programs were synchronized and amalgamated in 2017 and a result 14,382 km of complete vegetation management was accomplished between the tactical maintenance and cycle clearing programs.

d) Brush control and line clearing unit costs peaked in 2014. As of the end of 2016 the unit costs have fallen below the 2012 unit prices, indicating an improving trend.

The filed program changes in Exhibit C1, Tab 1, Schedule 2 have been superseded by the defect based three year cycle strategy outlined in Exhibit Q, Tab 1, Schedule 1. As outlined in interrogatory response Exhibit I-25-Staff-138, the new strategy is expected to significantly reduce unit prices in 2018, allowing for increased system coverage and reliability/safety risk mitigation while maintaining the same budget envelope.

UNDERTAKING – JT 3.17

Undertaking

To provide the costs compared to the activity for each year from 2012 to 2017.

Response

Please see tables below for the costs for each year (2012 to 2016, and 2017 forecast) associated with the activities noted in Board Staff interrogatories (I-38-Staff-189 to I-38-Staff-192, and I-38-Staff-194).

I-38-Staff-189 *(Reference: C1-01-02 Page: 15)*

Description	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Trouble Calls ($M)	65.5	87.7	77.1	72.9	68.8	76.5

I-38-Staff-190 *(Reference: C1-01-02 Page: 16)*

Description	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Disconnects/Reconnects ($M)	9.3	10.2	11.9	12.5	13.5	12.2

I-38-Staff-191 *(Reference: C1-01-02 Page: 18)*

Description	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Defect Corrections ($M)	5.0	6.1	3.3	4.9	9.2	3.7

I-38-Staff-192 *(Reference: C1-01-02 Page: 20)*

Description	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
PCB Inspection and Testing ($M)	-	-	0.3	2.3	5.6	7.3

I-38-Staff-194 *(Reference: C1-01-02 Page: 29)*

Description	**2012**	**2013**	**2014**	**2015**	**2016**
Brush Control ($M)	34.7	35.6	23.9	7.7	35.0
Line Clearing ($M)	87.4	83.2	97.9	93.7	87.4

As noted in interrogatory response I-38-Staff-194, the line clearing and brush control programs were synchronized and amalgamated in 2017. The cost of this amalgamated vegetation management between the tactical maintenance and cycle clearing programs was $128.8 million.